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Comprehensive Exhibit List for Entry into Hearing Record
Docket 140001-EI
Hearing held December 1-2, 2014

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF				
1		Exhibit List	Comprehensive Exhibit List	
FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)				
2	Sam Forrest	SF-1	Map of FPL's Existing Natural Gas Transportation	
3	Sam Forrest	SF-2	Map of U.S. Natural Gas Transportation Pipelines	
4	Sam Forrest	SF-3	Map of U.S. Shale Gas and Oil Production Locations	
5	Sam Forrest	SF-4	Drilling and Development Agreement **(CONFIDENTIAL)**	
6	Sam Forrest	SF-5	Tax Partnership Agreement **(CONFIDENTIAL)**	
7	Sam Forrest	SF-6	Petro Quest Agreement term Sheet **(CONFIDENTIAL)**	
8	Sam Forrest	SF-7	PetroQuest Transaction Production Profile	
9	Sam Forrest	SF-8	Results of FPL's Economic Evaluation **(CONFIDENTIAL)**	
10	Sam Forrest	SF-9	Proposed Transactional Guidelines	
11	Sam Forrest	SF-10	Customer Savings under FPL and Intervenor Gas Price Forecasts	

12	Sam Forrest	SF-11	Total Volume Traded on NYMEX in 2014	
13	Kim Ousdahl	KO-1	Memorandum of Understanding	
14	Kim Ousdahl	KO-2	Estimated Transfer price Calculation	
15	Kim Ousdahl	KO-3	Purchase Accounting Entry (Estimated)	
16	Kim Ousdahl	KO-4	Example Joint Interest Billing Statement ("JIB")	
17	Kim Ousdahl	KO-5	Year One Proforma Financial Statements	
18	Kim Ousdahl	KO-6	Sample of Supplemental Schedule Fuel Projection Filing	
19	Kim Ousdahl	KO-7	Condensed Chart of Accounts	
20	Kim Ousdahl	KO-8	Environmental Clause Sample Form 42-4P	
21	Tim Taylor	TT-1	Resume of Dr. Timothy D. Taylor	
22	Tim Taylor	TT-2	Difference Between Conventional and Unconventional Natural Gas Deposits	
23	Tim Taylor	TT-3	Historic and Projected Growth of Shale Gas Volumes	
24	Tim Taylor	TT-4	"Behind-Pipe" Zones	
25	Tim Taylor	TT-5	Map of the Woodford Shale	
26	Tim Taylor	TT-6	Location Map of the PetroQuest Acreage	
27	Tim Taylor	TT-7	EUR Type Curve Map	

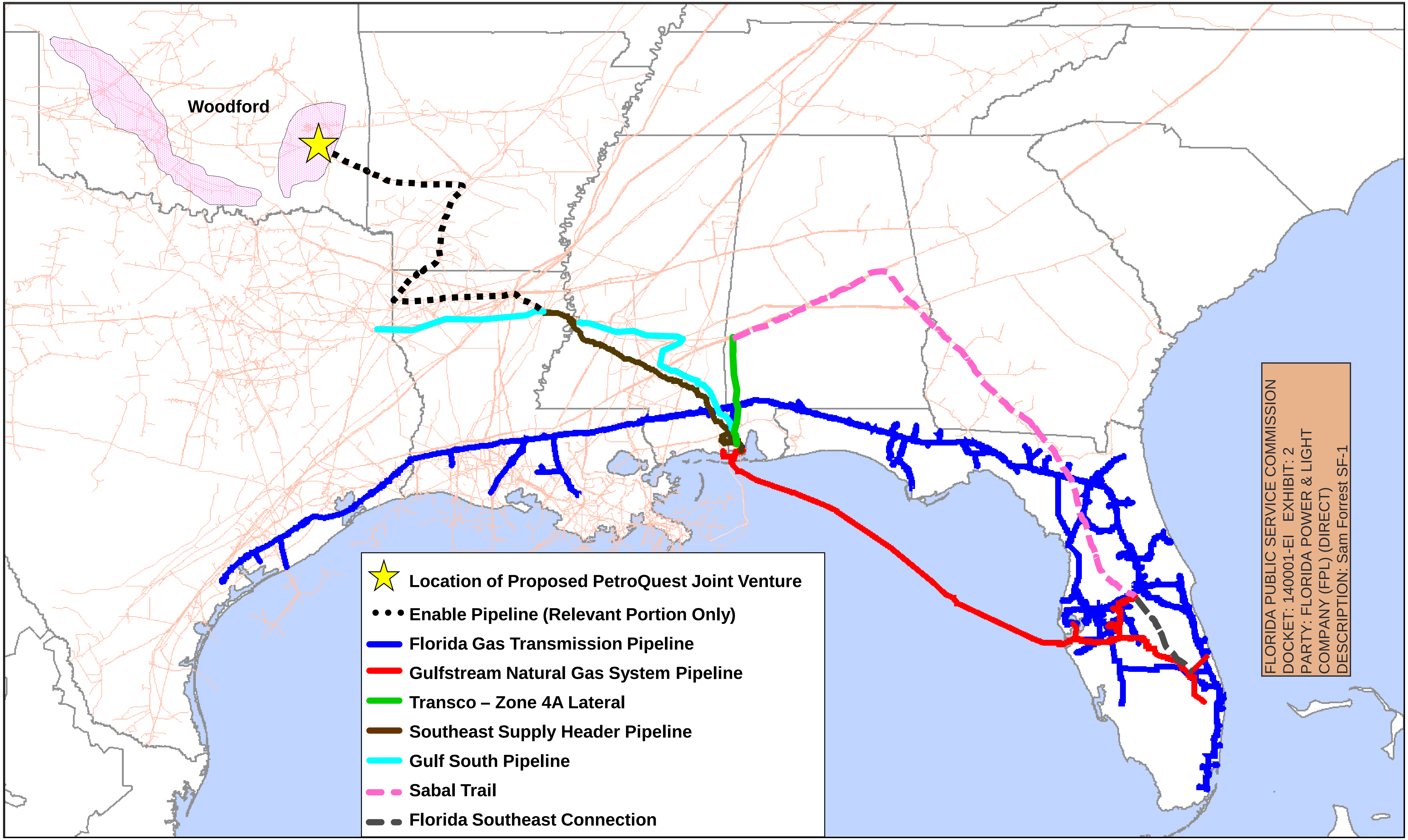
28	Tim Taylor	TT-8	Projected Drill Schedule Map	
29	Tim Taylor	TT-9	Volume Forecast for FPL **(CONFIDENTIAL)**	
30	Tim Taylor	TT-10	Forrest A. Garb & Associates Report **(CONFIDENTIAL)**	
31	Tim Taylor	TT-11	Type Curve 1: 5.3 Bcf Estimated Ultimate Recovery (“EUR”)	
32	Tim Taylor	TT-12	Type Curve 2: 7.4 Bcf EUR	
33	Terry Deason	JTD-1	Curriculum vita	
OFFICE OF PUBLIC COUNSEL (OPC)(DIRECT)				
34	D. Ramas	DMR-1	Qualifications of Donna Ramas	
35	D. Lawton	DJL-1	Résumé of Daniel J. Lawton	
36	D. Lawton	DJL-2	Market Price Sensitivity **[CONFIDENTIAL]**	
37	D. Lawton	DJL-3	Results, FPL’s High Output/Reduced Market Price Case **(CONFIDENTIAL)**	
38	D. Lawton	DJL-4	Woodford Results, 3.7% Annual Market Price Assumption **[CONFIDENTIAL]**	
39	D. Lawton	DJL-5	NGI’s 2014 North American Shale & Resource Plays Factbook (Excerpt)	
FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG) (DIRECT)				
40	Jeff Pollock	JP-1	FPL Base Production Cost,Benefit Analysis with Escalated Production and Transportation Costs	

41	Jeff Pollock	JP-2	FPL Comparison of Projected Natural Gas Prices	
42	Jeff Pollock	JP-3	FPL Base Production Cost/Benefit Analysis Gas Price Forecast	
43	Jeff Pollock	JP-4	NorthWestern Energy Press Release	
STAFF				
44			FPL's Responses to Staff's Second Set of Interrogatories (Nos. 12-54 and 56-94), including the supplemental response to No. 78 *[Bates Nos. 00001-00096]*	
45			FPL's Responses to Staff's Third Set of Interrogatories (Nos. 95-134) *[Bates Nos. 00097-00150]*	
46			FPL's Responses to Staff's Fourth Set of Interrogatories (Nos. 135-139, 140 **(CONFIDENTIAL),** 141-144, 145 **(only pp. 1-4 of the Attachment, which is CONFIDENTIAL)**, and 146-153), including the supplemental response to No. 145 **(only pp. 1-4 of the Attachment, which is CONFIDENTIAL)** *[Bates Nos. 00151-00189]*	
47			FPL's Responses to Staff's Seventh Set of Interrogatories (Nos. 167-173) *[Bates Nos. 00190-00207]*	
48			FPL's Responses to Staff's Eighth Set of Interrogatories (Nos. 174-177) *[Bates Nos. 00208-00215]*	

49			FPL's Responses to OPC's Second Set of Interrogatories (Nos. 11-14, 16, and 17) *[Bates Nos. 00216-00225]*	
50			FPL's Responses to OPC's Third Set of Interrogatories (Nos. 37, 38-41, 45, 46, 47 and 50) *[Bates Nos. 00226-00246]*	
51			FPL's Responses to OPC's Fifth Set of Interrogatories (Nos. 63 and 64) *[Bates Nos. 00247-00250]*	
52			FPL's Responses to OPC's Sixth Set of Interrogatories (No. 65) **(CONFIDENTIAL)** *[Bates Nos. 00251-00255]*	
53			FPL's Responses to OPC's Seventh Set of Interrogatories (Nos. 72, 75-78, 80-84, 87, and 89-103) *[Bates Nos. 00256-00289]*	
54			FPL's Responses to OPC's Sixth Request For Production of Documents (Nos. 35, 36, and 37) *[Bates Nos. 00290-00371]*	
55			Deposition of Sam Forrest, 11/14/14 **(CONFIDENTIAL)**, including late-filed exhibit #1 *[Bates Nos. 00372-00658]*	
56			Deposition of Kim Ousdahl, 11/12/14, including late-filed exhibits #1 and 2 *[Bates Nos. 00659-00906]*	
57			Deposition of Tim Taylor, 11/12/14, including late-filed exhibits 2 and 3 *[Bates Nos. 00907-01124]*	
58			Deposition of Terry Deason, 11/14/14 *[Bates Nos. 01125-01292]*	
OTHER HEARING EXHIBITS				

59	Forrest	FIPUG	Objections to Interrogatories	
60	Forrest	OPC	Final Order for Northwest Energy by Montana PSC	
61	Forrest	OPC	Oklahoma Commission memo on seismic activity	Withdrawn
62	Forrest	OPC	Commission order clarifying Hedging Order	(order)
63	Forest	OPC	Redacted Revised SF-8 Fuel Forecast	
64	Forrest	OPC	3 variations on customer fuel savings sensitivity matrix	
65	Ousdahl and Deason	OPC	Order 14546	
66	Taylor	FIPUG	Excerpt of PetroQuest 2013 Annual Report	
67	Deason	OPC	Bloomberg Article [Duke Energy Sees Potential Shale Gas Investment]	
68	Forrest	FIPUG	Excerpt of Moody's Investor Services	
69	Forrest	FIPUG	Standard and Poor's rating definitions	

Exhibit SF-1: Map of FPL's Existing Natural Gas Transportation



Map of FPL's Existing Natural Gas Transportation, Exhibit SF-1, Page 1 of 1

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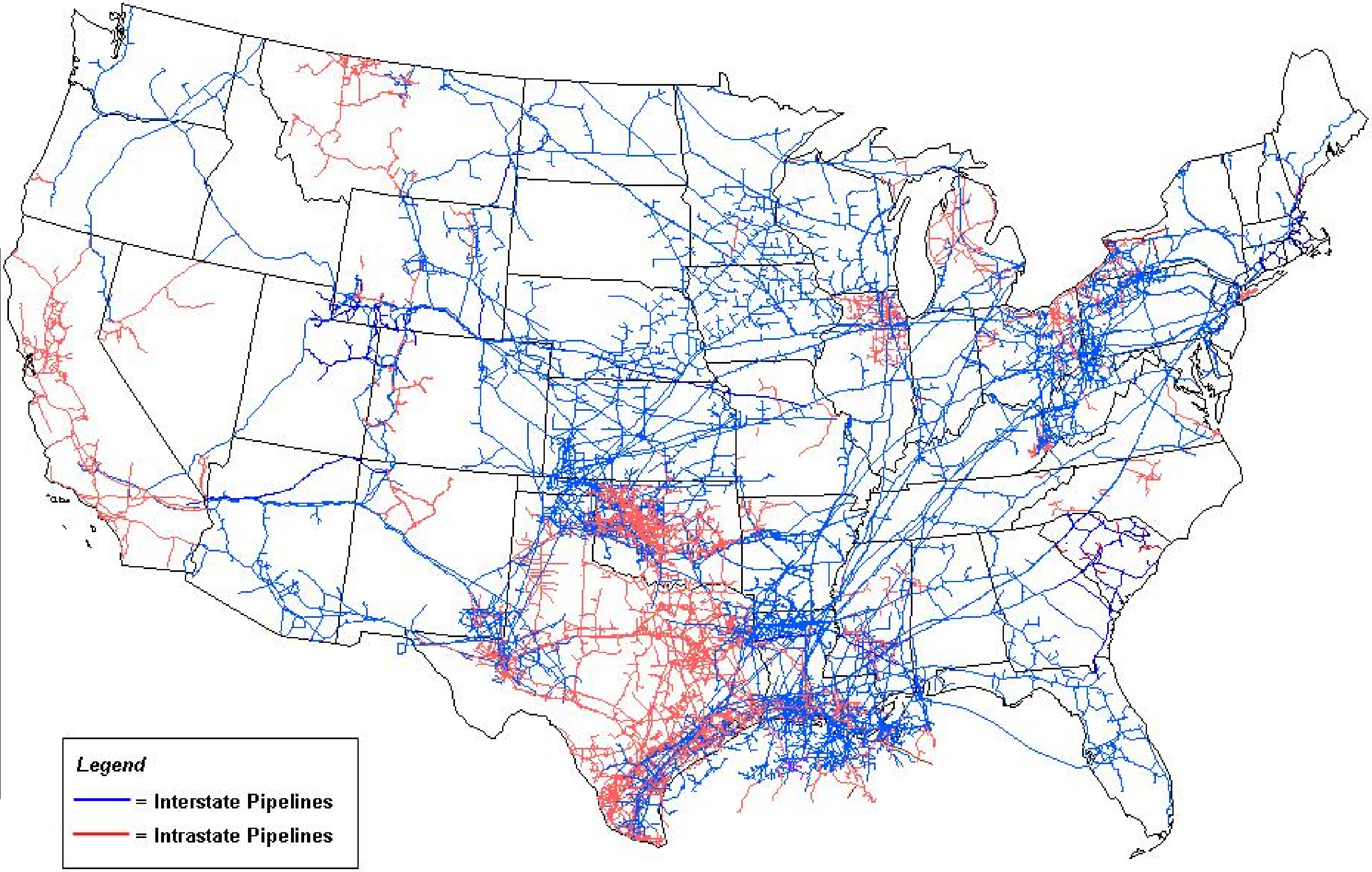
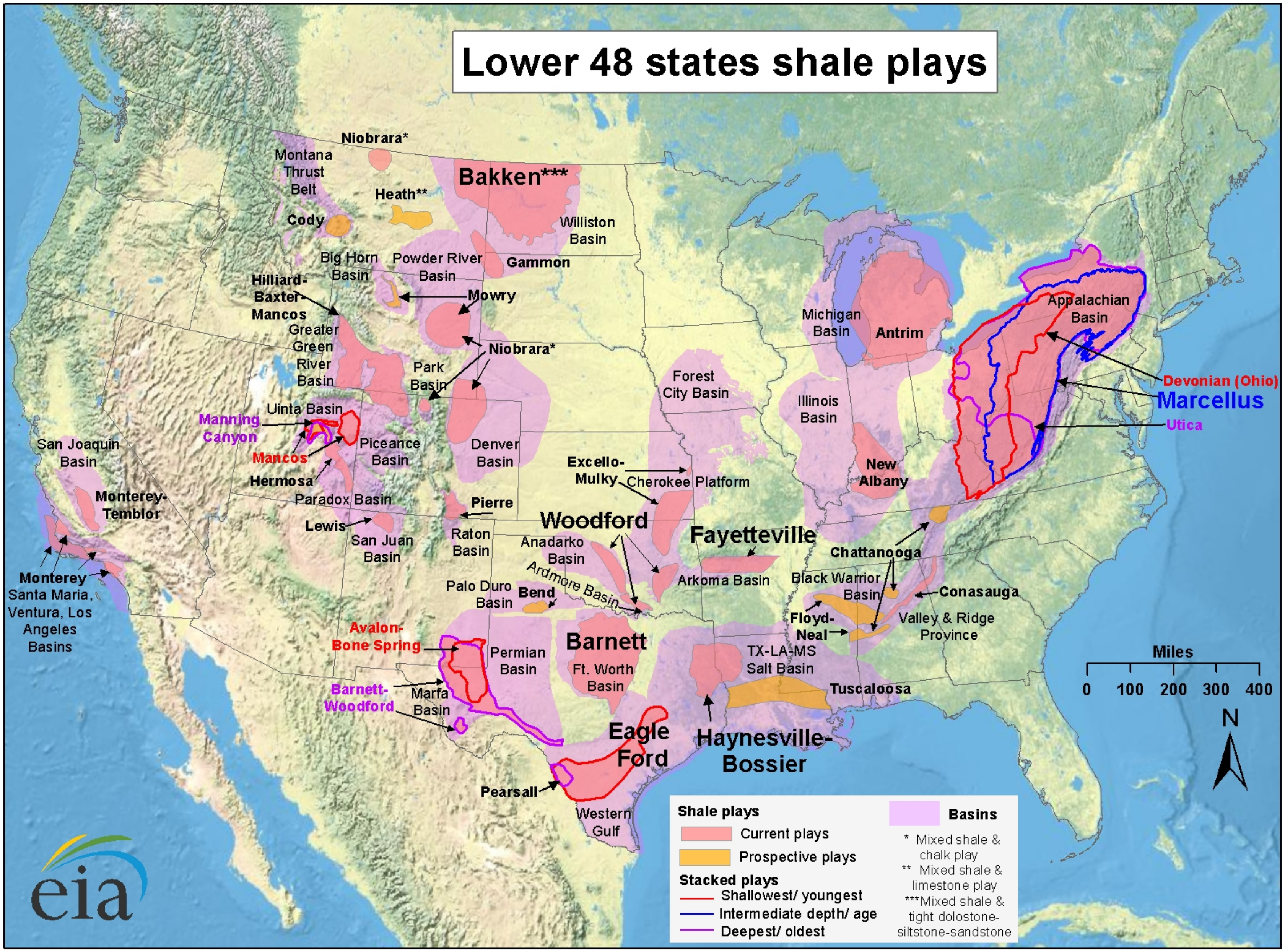
EXHIBIT SF-2: Map of U.S. Natural Gas Transportation Pipelines



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

EXHIBIT SF-3: Map of U.S. Shale Gas and Oil Production Locations



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Exhibit SF-4
Drilling and Development Agreement
Pages 1 - 78
IS CONFIDENTIAL IN ITS ENTIRETY

Exhibit SF-5
Tax Partnership Agreement
Pages 1 - 19
IS CONFIDENTIAL IN ITS ENTIRETY

TERM SHEET
TO PURCHASE AND DEVELOP GAS RESERVES

This Term Sheet ("Term Sheet") sets forth below the principal terms and conditions of the sale and development of certain oil and gas interests by PetroQuest Energy, Inc.'s wholly-owned subsidiary, PetroQuest Energy, LLC ("Seller" or "PQ") to and with Florida Power and Light Company ("FPL") and USG Properties Woodford I, LLC ("USG"), (collectively "Buyer") in the Woodford Shale in Oklahoma ("Agreement").

Counterparty:	USG is the initial transacting counterparty and would, subject to Florida Public Service Commission approval, transfer all of its rights and obligations under the Agreement along with its undivided Working Interest in the AMI, as outlined in the MOU between FPL and USG, to FPL or a wholly-owned FPL subsidiary at net book value which is estimated to be \$68.4 million as of January 1, 2015. Seller is the contracting party as a Working Interest owner and the operator of the subject assets within the AMI. The Parties each own equal undivided Working Interests in and to the oil, gas or mineral leases and interests in the well to be drilled. USG may transfer all of its rights and obligations under the Agreement to FPL or any other affiliated third party.
Area of Mutual Interest:	The 19 sections of land identified by Seller in the Woodford Shale (hereinafter, Area of Mutual Interest or "AMI") which contains 19 existing flowing wells that will not be part of this transaction, and 38 wells to be drilled.
Development and Drilling Costs:	The drilling and completion of the remaining wells in the AMI shall commence in accordance with Seller's drilling schedule, which is incorporated in the final, definitive Agreement. Unless Buyer non-consents to participating in a section(s) as hereinafter set forth, Buyer agrees to pay [redacted] of the Party's combined Working Interest share of the costs to drill and complete each well and Buyer shall earn [redacted] of the Party's combined Working Interest.
Operator:	Seller is the Operator and shall provide Buyer with drilling, completion, and production data, including well logs and other acquired engineering data by well. Seller shall provide or contract for all appropriate equipment and services necessary to meet the drilling schedule. Buyer has the right to audit Seller data as it pertains to any development under the Agreement. Buyer shall pay operating expenses incurred by Seller to the extent chargeable under Applicable Operating Agreement related to Buyer's Working Interest share with no carry.

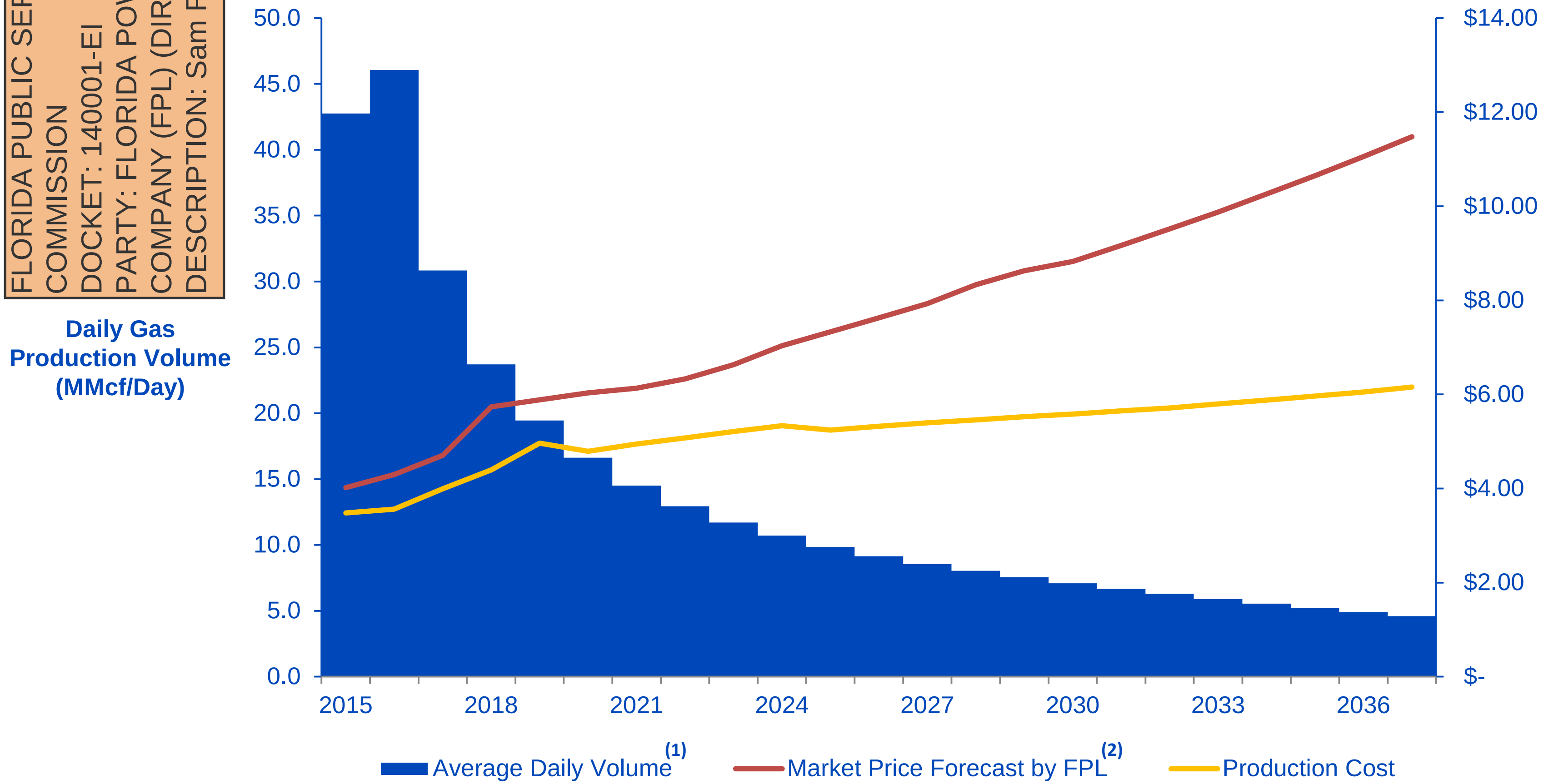
Lease Assignment:	Within 5 Business Days of the later of (i) Buyer's payment of its share of drilling costs (inclusive of the carried costs) set forth in an authorization for expenditure with respect to the estimated total drilling costs for a proposed well, or (ii) the spud date for such commitment well, the Parties shall execute, acknowledge and deliver an assignment from Seller to Buyer for a portion of the leased acreage and mineral rights in which the commitment well resides. Such assignments shall be made progressively on a well by well basis within each section.
Drilling Elections:	Buyer is committed to participate in drilling at least 15 wells in the AMI by December 31, 2015. Buyer may non-consent on a well-by-well basis, however, should Buyer fail to participate in at least 15 proposed wells by December 31, 2015, Buyer shall pay Seller [redacted] per well for each well short of the lesser of 15 wells or the number of wells proposed before December 31, 2015. This payment is waived in the event that: (i) Seller's average drilling costs exceeds [redacted] for the four wells immediately preceding the non-consented well; or (ii) Seller's operation of assets in the AMI is in material non-compliance with or material violation of a material Environmental or Safety Law. Should Buyer non-consent on a well, Buyer shall not pay any carry costs for that well and will not be entitled to output from that well. Buyer may non-consent on a well-by-well basis to any proposed wells after December 31, 2015 without penalty in accordance with the Applicable Operating Agreement. If Seller fails to commence drilling operations for a proposed well on or before one hundred twenty (120) days following Buyer's election (deemed or otherwise) whether or not to participate in such operations, then Seller shall resubmit a new well proposal to Buyer prior to conducting operations for such well.
Take In Kind Gas and Delivery:	Seller acknowledges that Buyer has the right under each Applicable Operating Agreement to take all (and not less than all) of its entitlement to gas production in kind, provided that any such election to take in kind must be made in writing not less than thirty (30) Days prior to the Day upon which Buyer will commence taking its share of production in kind.
Lease Accounting and Royalties:	Seller shall be responsible for all lease accounting and royalty issues of any kind on both Seller's and Buyer's share of production in accordance with the relevant lease provisions covering the lands developed under the Agreement, and Buyer would pay Seller for Buyer's portion of the royalty payments. All royalties due third parties with respect to gas delivered to Buyer shall be based on the value of gas applicable to the Delivery receipt point or on terms otherwise acceptable to Buyer.

Tax Benefit:	A tax-partnership mechanism has been put into place to assure Buyer's ability to deduct the IDC, including the "carried" portion, in proportion to Buyer's capital contributed.

AMI Procedures:	The AMI will be administered in accordance with the following provisions:
	• Buyer or Seller may lease or acquire AMI Interests from third parties that have a working interest in the AMI
	  o Such acquisition may occur due to a non-consent by the third party to a Seller proposed well in the AMI
	  o In the event of such third party non-consent, Buyer has the right but not the obligation to acquire the third party's interest in the well
	• In the event either Party enters into an agreement to acquire any AMI Interest including through a third party non-consent, then such Acquiring Party shall notify the other, Non-Acquiring Party in writing of such acquisition and offer the Non-Acquiring Party an opportunity to participate in that interest (Offered AMI interest)
	• The Non-Acquiring Party may elect to acquire its AMI Share in the Offered AMI Interest by notifying the Acquiring Party in writing within 15 days of notice
	  o The "AMI Share" of each Party is as follows:
	    ▪ PQ [redacted]
	    ▪ USG/FPL
	  o The "AMI Cost Share" of each Party is as follows:
	    ▪ PQ [redacted]
	    ▪ USG/FPL
	• If the Non-Acquiring Party does not elect to acquire its AMI Share of the Offered AMI Interest, then such Non-Acquiring Party shall have no further rights to the Offered AMI Interest and such Offered AMI Interest shall be excluded from this Agreement
	• If the AMI Interest covers contiguous lands both within and out of the AMI, the Acquiring Party shall only be obligated to offer the portion of the AMI Interest covering lands within the AMI to the Non-Acquiring Parties

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Sam Forrest SF-7

PetroQuest Transaction Production Profile



(1) Based on estimates

(2) As of October 2013

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PetroQuest Transaction Production Profile
Exhibit SF-7, Page 1 of 1

CONFIDENTIAL

Results of FPL's Economic Evaluation

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor[3]	Discounted Customer Savings ($MM)
2015	15.6	[redacted]	[redacted]	[redacted]	[redacted]	$3.48	$4.02	$8.4	0.9302	$7.8
2016	16.8	[redacted]	[redacted]	[redacted]	[redacted]	$3.56	$4.30	$12.4	0.8649	$10.7
2017	11.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.00	$4.70	$8.0	0.8043	$6.4
2018	8.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.40	$5.74	$11.6	0.7480	$8.7
2019	7.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.96	$5.89	$6.6	0.6956	$4.6
2020	6.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.79	$6.03	$7.6	0.6468	$4.9
2021	5.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.94	$6.13	$6.3	0.6015	$3.8
2022	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.08	$6.33	$5.9	0.5594	$3.3
2023	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.21	$6.63	$6.1	0.5202	$3.2
2024	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.34	$7.03	$6.6	0.4837	$3.2
2025	3.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.24	$7.33	$7.5	0.4498	$3.4
2026	3.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.32	$7.63	$7.7	0.4183	$3.2
2027	3.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.39	$7.93	$7.9	0.3890	$3.1
2028	2.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.46	$8.33	$8.4	0.3617	$3.1
2029	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.52	$8.63	$8.6	0.3364	$2.9
2030	2.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$8.83	$8.4	0.3129	$2.6
2031	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$9.17	$8.6	0.2910	$2.5
2032	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.71	$9.52	$8.7	0.2705	$2.4
2033	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.80	$9.88	$8.8	0.2516	$2.2
2034	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.88	$10.26	$8.8	0.2340	$2.1
2035	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.97	$10.65	$8.9	0.2176	$1.9
2036	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$6.05	$11.06	$9.0	0.2023	$1.8
2037-65	23.1	[redacted]	[redacted]	[redacted]	[redacted]	$7.88	$17.16	$213.8	0.0894	$19.1
Totals[1]	137.8	$323.2	$190.8	$195.5	$709.4			$394.7		$106.9

Notes:
(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.
(2) Return rate includes return on the assets and return of financing costs.
(3) Based on a discount rate of 7.5%, which reflects FPL's weighted average cost of capital.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 9
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Sam Forrest SF-8

GAS RESERVES GUIDELINES

Florida Power and Light Company's ("FPL" or "the Company") goals in purchasing natural gas to supply its power plants are reliability, price stability and low cost. Participating in gas reserve projects through a joint development agreement is a form of long-term hedging that can be a valuable supplement to FPL's existing short-term hedging program.

The Florida Public Service Commission ("Commission") previously has found "that the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers, in the face of price volatility for the fuels (and fuel price-indexed purchased power energy costs) that the IOU must pay in order to provide electric service." Further, the Commission found the primary purpose of hedging is to "reduce the variability or volatility in fuel costs paid by customers over time." *(Order No. PSC-08-0667-PAA-EI, Attachment A, page 2)*

Because of the natural depletion rate of shale-based gas production, it is understood that FPL will need to continue pursuing new gas reserve project opportunities to compensate for declining production from existing projects, as well as to expand the percentage of FPL's gas requirements that are hedged long-term. Moreover, it is clear that market participants and potential counterparties expect and value the ability to respond to opportunities quickly. Accordingly, a successful market strategy requires an established framework within which FPL may negotiate and consummate transactions.

I. SCOPE OF GAS RESERVE PROJECT PARTICIPATION

- Gas reserve projects will help reduce the overall portfolio price volatility and supply risk. The transactions will lessen the impact to customers if gas prices spike or rise and stay high for an extended period of time. Even though each transaction individually will represent a very small percentage of the Company's supply portfolio, collectively these transactions would help dampen the effects of price volatility.
- Guideline I.A: Overall, the estimated aggregate output of all gas reserve projects will not exceed the following percentages of FPL's projected average daily natural gas burn:

Year	Maximum Volume as a Percentage of Average Daily Burn
2015	[redacted]
2016	
2017	

- Guideline I.B: FPL will provide an annual update to the three year window presented in Guideline I.A as part of its Risk Management Plan filed in early August each year with the Estimated/Actual Testimony filing.
- Guideline I.C: Because gas reserve transactions provide a hedging benefit for FPL and its customers, the estimated aggregate volumes of natural gas from all gas reserve transactions in each calendar year will be netted against the amounts that FPL forecasts

GAS RESERVES GUIDELINES

to hedge pursuant to FPL's annual Risk Management Plan. FPL will hedge the net amount as prescribed in the Risk Management Plan.

- Guideline I.D: FPL will not obligate itself to invest more than [redacted] in the aggregate on gas reserve projects over the course of any one calendar year.

II. CUSTOMER SAVINGS

- Investment in gas reserve projects can offer significant price stability for the volumes produced, while also providing customer savings in a market of rising gas prices. A benefit of a well-managed gas reserves investment program is secure low-cost natural gas for our customers for years into the future that delivers an expected pricing discount relative to the forward curve. Since typical wells produce for 40 to 60 years, gas production joint ventures can provide stable pricing for decades to come, thus helping to achieve the Commission's stated goal for hedging to reduce price volatility for customers.
- Transactions of this type can result in lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the gas reserves investments were made. However, since only a portion of FPL's fuel requirements is procured through gas reserves investments, FPL maintains the ability to purchase low priced fuel when the opportunity arises. Moreover, in some projects it may be possible to delay the drilling plan and/or reduce the production volume from existing wells in the event of unexpected price declines. Conversely, when fuel prices settle at higher levels than at the time the gas reserves investments were made, increased customer savings are a direct result of the gas production joint venture.
- Guideline II.A: Evaluation of the prudence of FPL's having entered into a new gas reserve project will be based on a showing that the project is estimated to generate savings for customers on a net present value basis, relying solely on information relative to these Guidelines available to FPL at the time the transaction was entered, including the use of an independent third party reserve engineering report and FPL's standard fuel price forecasting methodology.

III. SUPPLY DIVERSITY

- Gas reserve projects will provide beneficial geographic diversity of fuel supply. Catastrophic events, such as hurricanes, affect FPL's ability to procure and deliver fuel. Investments in multiple gas reserves across various regions will reduce the impact of a single event disrupting FPL's entire fuel supply.
- Gas reserve projects also will increase the diversity of FPL's supply from a physical perspective, as well as a financial one. The longer time frame of these investments

GAS RESERVES GUIDELINES

offers diversity when compared to the current financial and physical contract lengths in the existing hedging program.

- FPL intends over time to transact with a wide range of suppliers so as to minimize concentration of supply with any one producer. This will allow FPL to transact in multiple regions and will also provide for reduced credit exposure to any one entity.
- Guideline III.A: FPL will only enter into transactions for onshore gas reserve projects, located in areas with reserves that have a well-established history of gas production. Florida does not meet these criteria.
- Guideline III.B: Because one of the primary purposes of gas reserve projects is a physical source of supply to serve its substantial gas needs, FPL will only enter into a transaction if there is a transportation path available to deliver the gas produced from that project to FPL's service territory. Texas, Louisiana, Oklahoma, Arkansas, Mississippi, Alabama, West Virginia, Ohio, and Pennsylvania currently meet this criterion. FPL will make use of its transportation portfolio, along with considering new physical paths. The costs of any new transportation needed to deliver gas from a gas reserve project will be taken into consideration when analyzing the economics of that project.

IV. CHARACTERISTICS OF GAS RESERVES

- Natural gas production consists of a combination of hydrocarbons, which can include methane, natural gas liquids ("NGLs"), and oil. The composition of natural gas production varies region by region and within individual regions.
- FPL's natural gas plants burn primarily methane and can accommodate only a very small percentage of other hydrocarbons. However, there are active third party markets for purchase and sale of NGLs and oil.
- There are a range of designations for reserves denoting the degree of certainty that the predicted quantity of gas is commercially recoverable from the well under current conditions: Proved, Probable, and Possible. FPL's gas reserve portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of those categories.
- Guideline IV.A: Although there is significant customer value in the production and sale of NGLs and oil, the purpose of FPL's gas reserves program is to provide a source of physical supply of natural gas to serve its power plants. For that reason, FPL will only enter into a transaction for a gas reserve project if the estimated output of the wells in the project contains at least [redacted] from methane by volume.

o Guideline IV.B: All NGLs and oil produced from a gas reserve project will be sold at market prices and the resulting revenues will be credited to the Fuel Clause to offset the production costs for which customers are responsible, thus lowering the effective cost of natural gas. The projected revenues from NGLs and oil produced from a gas reserve project will be taken into consideration when analyzing the economics of that project.

GAS RESERVES GUIDELINES

Flexibility to respond to market opportunities is in the best interest of FPL and its customers. Therefore, it is understood that FPL may (i) propose modifications to these guidelines in the annual update provided pursuant to Guideline I.B above, and (ii) seek Fuel Clause recovery for a project that deviates from one or more of the guidelines upon a showing that the project nonetheless is expected to benefit FPL customers.

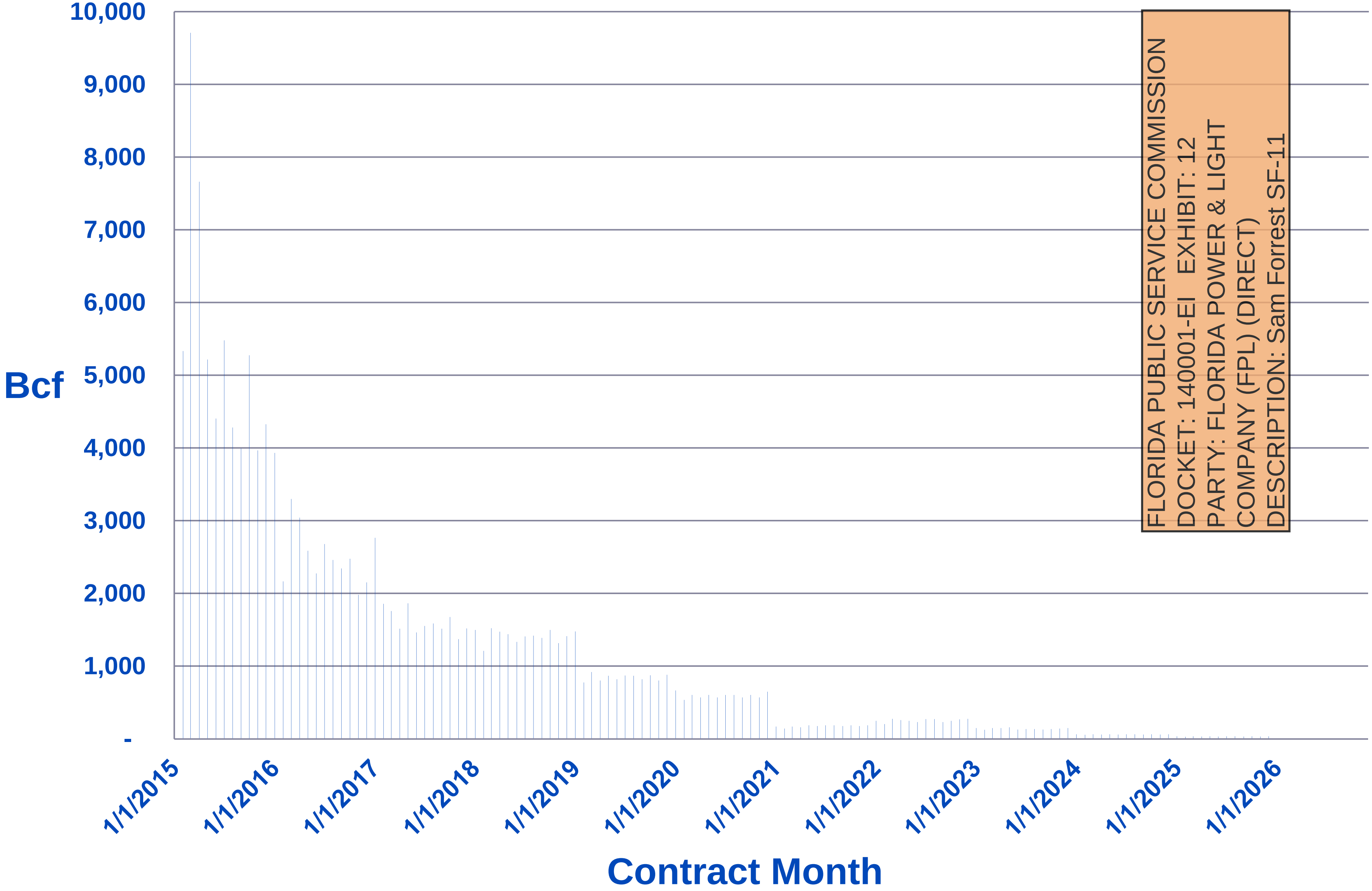
Customer Savings under FPL and Intervenor Gas Price Forecasts

Year	NYMEX Price Curve[1] $/MMBtu	Customer Savings $MM	EIA 3.7% Escalation[2] $/MMBtu	Customer Savings $MM	EIA Forecast[3] $/MMBtu	Customer Savings $MM	FPL Base Forecast $/MMBtu	Customer Savings $MM
2015	$3.86	$5.9	$4.02	$8.4	$3.93	$7.0	**$4.02**	**$8.4**
2016	$4.01	$7.5	$4.17	$10.2	$4.41	$14.3	**$4.30**	**$12.4**
2017	$4.15	$1.7	$4.32	$3.7	$4.76	$8.6	**$4.70**	**$8.0**
2018	$4.25	-$1.3	$4.48	$0.8	$5.27	$7.6	**$5.74**	**$11.6**
2019	$4.35	-$4.3	$4.65	-$2.2	$5.19	$1.7	**$5.89**	**$6.6**
2020	$4.49	-$1.8	$4.82	$0.2	$4.96	$1.0	**$6.03**	**$7.6**
2021	$4.62	-$1.7	$5.00	$0.3	$5.37	$2.3	**$6.13**	**$6.3**
2022	$4.74	-$1.6	$5.18	$0.5	$5.64	$2.7	**$6.33**	**$5.9**
2023	$4.82	-$1.7	$5.38	$0.7	$5.90	$3.0	**$6.63**	**$6.1**
2024	$4.90	-$1.7	$5.57	$0.9	$6.20	$3.4	**$7.03**	**$6.6**
2025	$4.97	-$1.0	$5.78	$1.9	$6.45	$4.3	**$7.33**	**$7.5**
2026	$5.08	-$0.8	$6.00	$2.2	$6.72	$4.7	**$7.63**	**$7.7**
2027	$5.51	$0.4	$6.22	$2.6	$7.00	$5.0	**$7.93**	**$7.9**
2028	$5.73	$0.8	$6.45	$2.9	$7.26	$5.3	**$8.33**	**$8.4**
2029	$6.00	$1.3	$6.69	$3.2	$7.63	$5.8	**$8.63**	**$8.6**
2030	$6.35	$2.0	$6.93	$3.5	$8.12	$6.6	**$8.83**	**$8.4**
2031	$6.69	$2.5	$7.19	$3.8	$8.47	$6.9	**$9.17**	**$8.6**
2032	$7.01	$3.0	$7.46	$4.0	$8.91	$7.3	**$9.52**	**$8.7**
2033	$7.39	$3.4	$7.73	$4.2	$9.41	$7.8	**$9.88**	**$8.8**
2034	$7.77	$3.8	$8.02	$4.3	$9.83	$8.0	**$10.26**	**$8.8**
2035	$8.13	$4.1	$8.31	$4.5	$10.31	$8.3	**$10.65**	**$8.9**
2036	$8.59	$4.5	$8.62	$4.6	$10.93	$8.7	**$11.06**	**$9.0**
2037-65	$15.82	$183.0	$13.49	$129.2	$21.62	$316.8	**$17.16**	**$213.8**
Totals Savings (Undiscounted)		**$208.2**		**$194.4**		**$446.9**		**$394.7**
Totals Savings (Discounted)		**$26.8**		**$43.8**		**$90.8**		**$106.9**

1) Utilizes NYMEX forecast as suggested by FIPUG witness Pollock
2) Applies EIA 2012-2040 real price annual escalation rate of 3.7% to FPL 2015 nominal forecast price as suggested by OPC witness Lawton
3) Utilizes EIA nominal price forecast from their 2014 Annual Energy Outlook

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT
COMPANY (FPL) (DIRECT)
DESCRIPTION: Sam Forrest SF-10

Total Volume[1] Traded on NYMEX[2] in 2014



(1) Henry Hub Natural Gas Futures (NG) contract symbol NN (trades in 2500 mmBtu per day)

(2) The New York Mercantile Exchange (NYMEX) is a commodity futures exchange owned and operated by CME Group

MEMORANDUM OF UNDERSTANDING

This MEMORANDUM OF UNDERSTANDING ("MOU") has been prepared to document the understanding between USG Energy Gas Producer Holdings, LLC, Delaware limited liability company ("USG") and Florida Power & Light Company ("FPL") with respect to the matters set forth herein below.

A. On June 18, 2014 (the "Closing Date"), PetroQuest Energy, L.L.C., a Louisiana limited liability company ("PQ") and USG Properties Woodford 1, LLC, a Delaware limited liability company ("USG Woodford" a wholly-owned subsidiary of USG), entered into a Drilling and Development Agreement (the "DDA" and together with the exhibits and schedules thereto and all ancillary documents, the "Project Documents") pursuant to which USG Woodford acquired certain rights and obligations to participate as a non-operating, working interest owner in the oil and gas leases, oil, gas and mineral leases, mineral servitudes, subleases and other leaseholds, royalties, overriding royalties, net profits interests, carried interests, mineral fee interests, farmout rights and operating rights with respect to a drilling program for future wells to be drilled by PQ within the Woodford Shale located in Pittsburg County, Oklahoma (the "Project").

B. The DDA requires that, beginning on the Closing Date, PQ will begin to execute the drilling plan as agreed with USG Woodford. That plan contemplates the Project having fourteen (14) wells in some stage of development, including four (4) actively producing wells, before December 31, 2014.

C. USG owns existing interests in the Project acreage under a 2010 joint venture between WSGP Gas Producing, LLC, a subsidiary of USG, and PQ (the "Original JV"). Under the Original JV, USG paid PQ a carry in order to earn its interest in the Project acreage. From the earliest negotiations of the Project Documents, it has been contemplated that FPL would acquire USG Woodford's rights, obligations and liabilities with respect to the Project. To that end, FPL and USG sought, analyzed, performed due diligence on the Project, and negotiated the Project Documents collectively. Each company has independently approved the Project, on the basis that each company was willing to assume for itself all of the rights, obligations, and liabilities of the Project as of the Closing Date and the potential rights, obligations, and liabilities of the Project that may arise in the future. Each party has engaged and paid for third party consultants including external legal counsel for the purposes of due diligence, and negotiations in the Project.

D. FPL determined, and USG Woodford agreed, that FPL would not acquire the Project unless and until the Florida Public Service Commission ("FPSC") confirms that acquisition of the Project is prudent and that the costs for the Project are eligible for recovery through the Fuel and Purchased Power Cost Recovery Clause ("FPSC Approval").

E. USG Woodford is acquiring the Project on the Closing Date with the understanding and agreement that, upon FPSC Approval, FPL intends to acquire the Project from USG Woodford on the following terms:

a. Within 30 days following FPSC Approval, USG Woodford shall assign all of its rights, obligations and liabilities with respect to the Project and the Project Documents to either FPL or to a subsidiary established by FPL to hold the Project ("Assignee").

b. In accordance with the terms of the DDA, USG Woodford shall be relieved of all of its direct obligations and liabilities with respect to the contracts and asset ownership, and Assignee shall assume all of USG Woodford's obligations and liabilities with respect to the Project Documents and asset ownership, upon such transfer and assignment.

c. Such transfer to FPL shall be made at USG Woodford's net book value for the Project at the time of transfer, calculated as the sum of:

i. the net book value of any new producing wells (the new "PDP") determined using the capital investment made by USG Woodford after the Closing Date less the cost associated with the percentage of gas extracted from the new wells drilled prior to transfer to FPL (otherwise known as "Depletion"). The net book value calculation is depicted as follows: Capital Expenditures made by USG Woodford up to the time of transfer x (1 - Production/Estimated Ultimate Recovery); and

ii. the net book value of the undeveloped interests, calculated as the carry less any depletion allocated among the following three categories of properties in the Project as of May 31, 2014 (the most current information available on the Closing Date): (1) the existing PDP wells (not to be transferred to FPL), (2) future wells that are categorized as proven undeveloped ("PUD") wells, and (3) probable wells ("PROB"). The carry is allocated among these three categories based on the number of wells of each type, existing and planned, for each section of the Project as of the Closing Date. FPL shall pay the share of the carry borne to earn acreage for the latter two categories, PUD and PROB, less any depletion applied to those categories, representing the Project acreage that will be assigned to FPL.

d. All revenues, expenses, working capital assets, and liabilities that accrue with respect to the Project at date of transfer shall be reflected as adjustments to the net book value; provided, however, that USG Woodford shall bear all of the costs and is entitled to all benefits resulting from any hedges put in place by USG Woodford for gas extracted from the wells. FPL will bear all incremental transfer costs.

F. It is the intent of this MOU that USG Woodford will not gain from the transfer of the Project, and that FPL will be put essentially in the position of USG Woodford as the initial purchaser of the Project.

G. USG and FPL understand that the Project Documents and terms of the Project are confidential and subject to confidentiality and non-disclosure restrictions provided for in the Project Documents.

IN WITNESS HEREOF, the parties hereto have executed this MOU.

USG Energy Gas Producer Holdings, LLC

By: ______________________

Name: Lawrence A. Wall, Jr.

Title: President

Date: June 24, 2014

Florida Power & Light Company

By: ______________________

Name: Sam Forrest

Title: Vice President Energy Marketing and Trading

Date: June 24, 2014

Gas Reserves Company
ESTIMATED TRANSFER PRICE CALCULATION
Assuming transfer date of January 1, 2015

Line No.	Item Description	Balance
1	Earned Acreage at May 31, 2014	$ 10,205,471
2	Cumulative capital expenditures made through 2014	58,240,800
3	**Net Book Value**	**$ 68,446,271**

Gas Reserves Company
Gas Reserves Acquisition - Estimated Purchase Accounting Entry

Line No.	GL Account	Entry Description	Debit	Credit
1	211	Unproved Property Acquisition Costs	$ 23,005,091	
2	221	Proved Property Acquisition Costs	45,441,180	
3	101	Cash		$ 68,446,271
4			$ 68,446,271	$ 68,446,271
5				
7		To record gas reserve acquisition from USG.		
8				
9	**Note:**			
10	Detail of entries for Accounts 211 and 221 shown above			

Line No.		DRILLING COSTS	ACREAGE INTEREST	Total
11		DRILLING COSTS	ACREAGE INTEREST	Total
12	Proved	$ 41,274,000	$ 4,167,180	$ 45,441,180
13	Probable	16,966,800	6,038,291	23,005,091
14		$ 58,240,800	$ 10,205,471	$ 68,446,271

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Kim Ousdahl KO-3

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY (a)
15467 EAST 107TH AVENUE
HOUSTON, TX 77046

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
PROPERTY: N. MOORE LEASE

Summary Statement and Invoice

Owner No.	Owner Name	Working Interest	Amount
1123500	ABC OIL	.0447897	$ 24,033.14
1118600	CORONADO HILLS PARTNERS	.0635633	34,106.62
5117300	COUGAR PETROLEUM	.0153747	8,249.72
2954800	WILL B. SMITH	.0226632	12,160.56
1431400 - (a)	COUNTRY SERVICE COMPANY	.0547563 - (a)	29,380.99
0488500	J.B. JONES	.0258106	13,849.38
8224400	BDF OIL & GAS	.3833124	205,676.74
0000001	BIG OIL USA, INC.	.3897298	209,120.16
		1.0000000	
Total Current Period Charges to Joint Account			$536,577.31
TO INVOICE YOU FOR:			
Drilling and Development Charges - **See Page 2** $531,491.65*0.0547563 = $29,102.52			$ 29,102.52
Lease Operating Expenses - **See Page 3** - $5,085.66*0.0547563 = $278.47			278.47
Total Current Period Charges			29,380.99
Previous Balance Carried Forward			
Total Due			$ 29,380.99

REMITTANCE INSTRUCTIONS
Please reference the above invoice number and mail payment to:
Big Oil USA, Inc.
P.O. Box 12345
Denton, TX 76201

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY
15467 EAST 107 AVENUE
HOUSTON, TX 77046
PROPERTY: N. Moore Lease
WEILL: N. Moore #2

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
AFE No.: 102

Drilling and Development Charges

S/L	Description	Amount	Total
104	Tubing	$ 147,780.21	
105	Wellhead Assembly	764.88	
115	Misc. Non-Cont. Surface Well Material	684.79	
122	Production & Other Lease Facilities	14,111.02	
133	Installation Cost	4,245.70	
244	Permits, Shite Prep & Clean-up	8,638.74	
248	Other Contract Services	116.25	
249	Contract Drilling	301,903.89	
251	Direct Supervision	7,870.42	
255	Bits	(1,297.06)	
267	Equipment Rentals	3,449.50	
268	Small Tools & Supplies	206.90	
269	Transportation Land	6,156.29	
273	Communications	177.66	
275	Testing, Drafting & Inspection	22,083.03	
277	Perforating	8,280.20	
280	Drilling Overhead Charge	5,000.00	
283	Loss & Damage	1,319.23	
	Total Drilling and Development Charges		$ 531,491.65

Docket No. 140001-EI
Example Joint Interest Billing Statement ("JIB"), Exhibit KO-4, Page 2 of 3

Joint Interest Billing - Example

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY
15467 EAST 107TH AVENUE
HOUSTON, TX 77046
PROPERTY: N. Moore Lease
WELL: N. Moore #1

INVOICE NO.: 1023174
INVOICE DATE: MAY 24, 2010
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2010
AFE No.: N/A

Lease Operating Expense			
S/L	Description	Amount	Total
120	Contract Labor	$2,903.61	
121	Rig Services	406.71	
125	Gas Handling	6.81	
128	Salt Water Disposal	375.75	
140	Chemicals	44.72	
141	Small Tolls & Supplies	55.34	
143	Automotive Expense	198.36	
170	Telephone & Telegraph	53.50	
180	Employee Travel & Gen Exp	68.13	
800	General Services	112.08	
824	Area Expense	510.65	
880	Production Overhead	350.00	
	Total Lease Operating Expense		$5,085.66

Gas Reserves Company
Income Statement
Twelve Months Ended December 31, 2015

Line No.	Account No. [1]	Account Description		
1		**Revenues**		
2	602	Gas Revenues	$	45,473,295
3				
4		**Expenses**		
5	710	Lease Operating Expenses	$	13,905,562
6	725	DD&A		18,336,336
7	900	G&A Expenses		300,000
8	920	Interest expense		2,011,223
9	940	Income Tax Provision		4,247,948
10				
11				
12		**Net Income**	$	6,672,226

[1] Accounts refer to industry standard accounts. Refer to Exhibit KO-7

Gas Reserves Company
At Year End 12/31/2015
Balance Sheet

Line No.	Account No. (6)	Account Description	Day 1 Balance Sheet Total	BS - YE 12/31/2015 2015 Activity	Distribution to Parent @ YE (4) (5)	Year End Balance Total
1	**Current Assets**					
2	101	Cash	$ -	$ 29,256,510	$ (25,008,562)	$ 4,247,948
3	221/231/233	Gas Reserves Investment	68,446,271	122,321,700		190,767,971
4	226/232/234	Accumulated Amortization	-	(18,336,336)		(18,336,336)
5	127	Accrued Receivables (Income Taxes)	-	29,033,436 (1)		29,033,436
6		**Totals Assets**	$ 68,446,271			**$ 205,713,018**
7	**Current Liabilities**					
8	401	Payable Intercompany Debt (2)	$ (27,652,293)	$ (49,417,967)	$ 7,407,880	$ (69,662,380)
9	420	Deferred Income Taxes (3)	-	(33,281,384)		(33,281,384)
10	501	Common Stock (Paid in Capital) (2)	(40,793,978)	(72,903,733)	17,600,683	(96,097,028)
11	525	Retained Earnings		(6,672,226)		(6,672,226)
12		**Totals Liabilities**	$ (68,446,271)			**$ (205,713,018)**
13						
14	**Notes:**					
15	(1)	To calculate Income Tax Receivable:				
16		Depletion	$ 18,336,336			
17		Current IT	4,247,948			
18		Current year - after tax income	6,672,226			
19		Tax Depreciation Expense	(103,892,593)			
20		Subtotal	(74,636,083)			
21		Income Tax Receivable@ 38.9%	$ (29,033,436)			
22		For first year of operations GRCO will incurr a loss for income tax purposes due to the deduction for tax purposes of drilling costs. This will be utilized by the parent company in their consolidated income tax calculation.				
23						
24	(2)	The subsidiary capital structure will be based on the debt and equity ratios of FPL.				
25						
26	(3)	To calculate DTL:				
27		Depletion	$ 18,336,336			
28		Tax Depreciation Expense	(103,892,593)			
29		Subtotal	(85,556,257)			
30		DTL @ 38.9%	$ (33,281,384)			
31		For first year of operations GRCO will record a deferred income tax liability applicable to the deduction for tax purposes of the drilling and depletion costs.				
32						
33	(4)	Components of distribution made to parent:				
34		Depletion	$ (18,336,336)			
35		Retained Earnings	(6,672,226)			
36			$ (25,008,562)			
37						
38	(5)	Cash to parent - Repayment of:				
39		Payable Intercompany Debt	$ 7,407,880			
40		Common Stock	17,600,683			
41			$ 25,008,562			
42		Represents the distribution to parent of the cash generated by the subsidiary during its first year of operations.				
43						
44	(6)	Accounts refer to industry standard accounts. Refer to Exhibit KO-7				

Exhibit KO-5 - **Summary of changes made:**

Changes made to Exhibit KO-5 were to update the year one proforma financial statements as result of assumption changes and updates made to Exhibit KO-6.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January ESTIMATED	February ESTIMATED	March ESTIMATED	April ESTIMATED	May ESTIMATED	June ESTIMATED	Six Month Amount
1.	Investments								
	a. Capital addition		$5,045,400	$19,260,000	$14,214,600	$19,260,000	$5,045,400	$19,260,000	$82,085,400
2.	Gas Reserve Investment / DD&A Base (A)	$68,446,271	73,491,671	92,751,671	106,966,271	126,226,271	131,271,671	150,531,671	n/a
3.	Less: Accumulated Depletion Reserve	$0	238,144	594,867	1,179,341	2,029,642	3,172,825	4,591,220	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$68,446,271	$73,253,527	$92,156,804	$105,786,930	$124,196,629	$128,098,846	$145,940,451	n/a
5.	Average Rate Base (D)		70,849,899	82,705,165	98,971,867	114,991,779	126,147,737	137,019,648	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		472,897	552,027	660,601	767,528	841,990	914,556	$4,209,597
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		87,096	101,669	121,666	141,359	155,073	168,438	$775,302
	Subtotal (Debt & Equity Return)		559,993	653,696	782,267	908,887	997,063	1,082,994	
7.	Investment and Operating Expenses								
	a. Transportation Costs		285,676	359,088	507,406	615,425	772,784	833,646	$3,374,026
	b. Depletion		238,144	356,723	584,474	850,301	1,143,183	1,418,395	$4,591,220
	c. Lease Operating Expenses (LOE)		47,592	103,946	121,077	169,423	201,640	240,162	$883,839
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	$480,766
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	$150,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$1,236,533	$1,578,581	$2,100,351	$2,649,165	$3,219,797	$3,680,324	$14,464,751

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Working capital balance has not been forecasted for inclusion in Average Rate Base but will be included in the true-up filings when actual balances are known.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July ESTIMATED	August ESTIMATED	September ESTIMATED	October ESTIMATED	November ESTIMATED	December ESTIMATED	Twelve Month Amount
1.	Investments								
	a. Capital addition		$16,276,500	$9,630,000	$2,522,700	$8,368,650	$3,438,450	$0	$122,321,700
2.	Gas Reserve Investment / DD&A Base (A)	$150,531,671	166,808,171	176,438,171	178,960,871	187,329,521	190,767,971	190,767,971	n/a
3.	Less: Accumulated Depletion Reserve	$4,591,220	6,271,949	8,224,436	10,639,750	13,222,515	15,746,805	18,336,336	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$145,940,451	$160,536,222	$168,213,735	$168,321,121	$174,107,006	$175,021,166	$172,431,635	n/a
5.	Average Rate Base (D)		153,238,336	164,374,978	168,267,428	171,214,063	174,564,086	173,726,400	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,022,809	1,097,142	1,123,123	1,142,791	1,165,151	1,159,560	10,920,174
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		188,376	202,066	206,851	210,473	214,592	213,562	2,011,223
	Subtotal (Debt & Equity Return)		1,211,185	1,299,209	1,329,974	1,353,264	1,379,743	1,373,122	
7.	Investment and Operating Expenses								
	a. Transportation Costs		898,337	987,416	1,166,726	1,186,225	1,133,535	1,158,547	9,904,811
	b. Depletion		1,680,729	1,952,487	2,415,314	2,582,765	2,524,290	2,589,531	18,336,336
	c. Lease Operating Expenses (LOE)		218,151	349,126	391,672	397,235	413,250	385,946	3,039,218
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	961,533
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	300,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$4,113,530	$4,693,365	$5,408,814	$5,624,617	$5,555,945	$5,612,274	45,473,295

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Simplified example omits the working capital items that would be included in the actual clause filings

Totals may not add due to rounding.

Exhibit KO-6 **as filed** totaled $52,473,402

1) Update made to WACC components Debt/Equity per FPSC Order No. PSC-12-0425-PAA-EU

As Filed	Debt	1.5658%
	Equity	4.9230%
As Updated	Debt	1.4751%
	Equity	4.8938%

2) Transportation costs were reduced.
Exhibit KO-6 is intended to reflect costs purely associated with GRCO. The transportation costs as reflected in the "as filed" exhibit contained approximately $4.550 million of transportation costs that will be incurred by FPL directly, not the GRCO.
Therefore Exhibit KO-6 was updated to reflect the reduction of transportation costs.

3) Version of Exhibit KO-6 provided as part of the response to OPC 3rd Set of Interrogatories No. 43 footnote (c) incorrectly reflected the debt component (WACC)
It should have shown 1.4751%, instead reflected 1.4151%. Note that this only affected the footnote, the calculation was correctly presented.

4) Exhibit KO-6, Page 2, line 5, missing the footnote pointing to note (D)

5) Depletion calculation was updated to reflect timing of investment made instead of assumption of all investment made at day 1.
Revised Exhibit KO-6 total $45,473,295

Condensed Chart of Accounts

Gas Reserve Company (GRCO)		Florida Power & Light (FPL) - FERC Gas	
Current Assets		**Current Assets**	
101	Cash	131	Cash
120	AR-Oil & Gas Sales	143	Other Accounts Receivable
121	AR-Gas Imbalances		"
123	AR-Joint Interest Billings		"
126	AR-Other		"
127	Accrued Receivables	173	Accrued Utility Revenues
129	Allowance for Doubtful Accounts	144	Accumulated Provision for Uncollectible Accounts
130	Inventory-Oil	151	Fuel Stock
131	Inventory-Gas		"
132	Inventory-Supplies	154	Plant Materials and Operating Supplies
140	Prepaid Expenses	165	Prepayments
Gas Property		**Gas Property**	
211	Unproved Property Acquisition Costs	105.1	Production Properties Held for Future Use
219	Impairment Allowance		"
221	Proved Property Acquisition Costs	101	Gas Plant in Service
226	Accum. Amortization of #221	111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
230	Asset Retirement Costs	101	Gas Plant in Service
231	Proved Properties-Intangibles	111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
232	Accum. Amortization of #231		"
233	Tangible Costs, of Wells & Development Costs	101	Gas Plant in Service
234	Accum. Amortization of #233	111	Accumulated Provision for Amortization and Depletion of Gas Utility Plant
235	Accum., Amortization of #230		"
241	WIP-Intangibles	107	Construction Work in Progress - Gas
243	WIP-Tangibles		"
290	Deferred Tax Asset	190	Accumulated Deferred Income Taxes
Current Liabilities		**Current Liabilities**	
301	Vouchers Payable	232	Accounts Payable
302	Revenue Distributions Payable		"
306	Gas Imbalance Payables		"
307	Accrued Liabilities	242	Miscellaneous Current and Accrued Liabilities
320	Production Taxes Payable		"
330	Income Taxes Payable		"
335	Other Current Liabilities		"
360	Revenue Clearing		"
361	Billings Clearing		"
Long Term Liabilities		**Long Term Liabilities**	
401	Notes Payable	231	Notes Payable
410	Asset Retirement Obligation (ARO)	230	Asset Retirement Obligation
Deferred Income Taxes		**Deferred Income Taxes**	
420	Deferred Income Taxes	281-283	Accumulated Deferred Income Taxes
Stockholder's Equity		**Stockholder's Equity**	
501	Common Stock	201	Common Stock
525	Retained Earnings	216	Unappropriated Retained Earnings
Revenues		**Revenues**	
602	Gas Revenues	400	Operating Revenues
603	NGL Revenues		"
Expenses		**Expenses**	
701	Marketing Expenses	401	Operation Expense
710	Lease Operating Expenses		"
725	Depreciation, Depletion & Amortization	405-405	Amortization and Depletion of Producing Natural Gas Land and Land Rights
735	Amortization of Capitalized ARO	403	Depreciation Expense
761	Provision for Impairment of Oil & Gas Properties		
800	Exploration Expenses	401	Operation Expense
900	G&A Expenses		"
920	Interest Expense	427	Interest on Long-term Debt
924	Accretion Cost on Asset Retirement Obligations	403	Depreciation Expense
940	Income Tax Provision	409.1	Income Taxes, Utility Operating Income

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Kim Ousdahl KO-7

FORM: 42-4P

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE
RETURN ON CAPITAL INVESTMENTS, DEPRECIATION AND TAXES

JANUARY 2015 THROUGH DECEMBER 2015

	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
31 - Clean Air Interstate Rule (CAIR) Compliance														
1. Investments														
a. Expenditures/Additions		$0	$298,877	$363,065	$280,118	$197,150	$168,897	$38,764	$11,445	$7,612	$8,429	$104,174	$57,993	$1,536,524
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,469,769	$2,469,769
c. Retirements		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. Plant-In-Service/Depreciation Base [(a)]	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$523,657,056	$526,126,825	N/A
3. Less: Accumulated Depreciation	$43,384,566	$44,519,623	$45,654,680	$46,789,737	$47,924,793	$49,059,850	$50,194,907	$51,329,964	$52,465,021	$53,600,078	$54,735,135	$55,870,191	$57,007,924	N/A
4. CWIP - Non Interest Bearing	$933,245	$933,245	$1,232,122	$1,595,187	$1,875,305	$2,072,455	$2,241,352	$2,280,116	$2,291,561	$2,299,173	$2,307,602	$2,411,776	$0	N/A
5. Net Investment (Lines 2 - 3 + 4)	$481,205,734	$480,070,678	$479,234,498	$478,462,506	$477,607,567	$476,669,660	$475,703,500	$474,607,207	$473,483,596	$472,356,151	$471,229,523	$470,198,640	$469,118,901	N/A
6. Average Net Investment		$480,638,206	$479,652,588	$478,848,502	$478,035,036	$477,138,614	$476,186,580	$475,155,354	$474,045,402	$472,919,873	$471,792,837	$470,714,081	$469,658,770	N/A
7. Return on Average Net Investment														
a. Equity Component grossed up for taxes [(b)(g)]		$3,191,109	$3,184,565	$3,179,227	$3,173,826	$3,167,874	$3,161,553	$3,154,707	$3,147,337	$3,139,865	$3,132,382	$3,125,220	$3,118,213	$37,875,877
b. Debt Component (Line 6 x debt rate x 1/12) [(c)(g)]		$590,849	$589,637	$588,648	$587,648	$586,546	$585,376	$584,108	$582,744	$581,360	$579,975	$578,649	$577,352	$7,012,893
8. Investment Expenses														
a. Depreciation [(d)]		$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,135,057	$1,137,732	$13,623,358
b. Amortization [(e)]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
c. Dismantlement [(f)]		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
d. Property Expenses		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
e. Other		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. Total System Recoverable Expenses (Lines 7 & 8)		$4,917,014	$4,909,259	$4,902,932	$4,896,531	$4,889,478	$4,881,986	$4,873,872	$4,865,138	$4,856,282	$4,847,414	$4,838,925	$4,833,297	$58,512,128

(a) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-36.

(b) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.8938% is based on May 2014 ROR Surveillance Report and reflects a 10.5% return on equity per FPSC Order No PSC-12-0425-PAA-EU.

(c) The Debt Component is 1.4751% based on May 2014 ROR Surveillance Report and reflects a 10.5% ROE per FPSC Order No. PSC-12-0425-PAA-EU.

(d) Applicable depreciation rate or rates. See Form 42-4P, pages 33-36

(e) Applicable amortization period(s). See Form 42-4P, pages 33-36.

(f) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39)

(g) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment: See footnotes (b) and (c).

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.4207% based on the May 2014 ROR Surveillance Report and reflects a 10.5% return on equity.

Debt Component: Return of 1.8538% based on the May 2014 ROR Surveillance Report and reflects a 10.5% ROE. Per FPSC Order PSC 12-0425-PAA-EU.

Note: Totals may not add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Kim Ousdahl KO-8

Docket No. 140001-EI
Environmental Clause Sample Form 42-4P
Exhibit KO-8, Page 1 of 1

Timothy (Tim) D. Taylor, PhD

work (713) 374-1503, *email* tim.taylor@nee.com

PROFESSIONAL EXPERIENCE

NextEra Energy Project Management, LLC, Houston, Texas Aug. 2012 – Present
Chief Technology Officer
Brought reserve function in-house and accomplished the first corporate SEC compliant reserve report working with third party consultants. Built internal LOS statements and documented oil, gas and ngl price differentials, yields, shrinks, BTU values, etc. Evaluate all incoming acquisition opportunities and capital redeployment strategies through divestitures. Support six internal operations groups in evaluating AFEs and acreage leasing. Work with operating partner companies on log interpretation, picking perforations, completion techniques, etc.

Independent Consultant Oct. 2011 – July 2012
Technical consultant to various oil and gas industry companies, primarily for PostRock Energy, a public oil and gas company headquartered in Oklahoma City. Brought reserve function in-house and managed the relationship with the third party reserve engineers resulting in increased Proved Developed Producing year-end reserves of 320,000 BO and 12 BCF. Organized and managed programs to lower operating costs in 2,800 wells, modified fracking techniques, identified secondary recovery potential in oil reservoirs, modified drilling schedules to focus on oil opportunities while preserving expiring gas acreage, established a true in-house reservoir engineering function, mentored young engineering staff, etc.

Texas American Resources Company, Austin, Texas 2008 – Oct. 2011
Chief Operating Officer / Executive Vice President / Director
Responsible for all aspects of operations and value enhancement, managing and optimizing four operated waterfloods and generating new business opportunities. Instrumental in forming three joint ventures for developing the Eagle Ford Shale play in S. Texas and in the recent divestiture of the company's DJ Basin assets for $150 MM. Guided drilling and workover programs in south, east and north Texas, Colorado and Wyoming. Responsible for development planning, strategic reserve category shifting to maximize Proved reserves and third party reserve reporting. Versed in vertical and horizontal drilling, secondary and enhanced oil recovery and hydraulic fracturing.

The University of Texas at Austin, Austin, Texas 2002 – 2008
Faculty member in the Petroleum and Geosystems Engineering Department.
Senior Lecturer / Program Coordinator
Taught application based courses focused on field development, project management, reserve determination, well and project economics, secondary and enhanced recovery, and petrophysics. Organized and led the effort to revitalize the recruiting program resulting in a 250% increase in undergraduate enrollment in four years while increasing student quality. Stayed active with industry companies and technology and taught numerous domestic and international petroleum engineering short courses.

Independent Consultant 2000 – 2002
President of Cox, Taylor, Bommer, LLC
Formed this petroleum engineering consulting company to help a group of friends in providing management and technical expertise to the oil and gas industry. (My involvement was not on a day-to-day basis as I was taking a break from the grind of international operations.

PROFESSIONAL EXPERIENCE *(Continued)*

Snyder Oil Corporation / SOCO International, plc 1990 - 2000
Engineering Manager / Acquisitions Manager / Chief Operating Officer - Joined Snyder Oil Corporation in 1990 as Engineering Manager responsible for building a new engineering department, performing in-house engineering and economic evaluations for SEC reporting, acquisitions and special project studies. Managed an annual 4,000 well evaluation program and provided engineering analysis and project planning for a 500+ well drilling program.

Vice President and Chief Operating Officer, SOCO International, plc - Instrumental in taking company public on the London Stock Exchange. Managed exploration and development projects in Russia, UK, Mongolia and Australia and served in a technical advisory role for projects in India, Australia, Yemen, Thailand and Vietnam, including evaluating all productive horizons for secondary and/or EOR potential.

Worked with financial advisors to successfully secure $100MM financing from the European Bank for Reconstruction and Development (EBRD) for our Russian Joint Venture, Permtex. Functioned as Country Manager for that project and brought production from zero to 6,000 Bbl./day in two years with 100% exports. Closely involved in all contract negotiations for all of SOCO International's projects. Served as President of an onshore UK subsidiary and streamlined the organization and operations in preparation for the sale of the asset.

Performed all economic and reserve evaluations company-wide and managed the third-party reserve reporting process for each country of operation.

Prior Experience
Taylor, Caudle & Associates, Inc. 1983 - 1990
President and Chief Executive Officer of this petroleum engineering consulting firm founded for the purpose of providing special field studies, secondary and enhanced oil recovery studies and reserves and economic evaluations for the petroleum industry. Successfully managed a large client base before selling the firm to join Snyder Oil Corporation.

Sipes, Williamson & Associates, Inc. 1980 - 1983
Manager of Enhanced Recovery for this Midland, Texas based petroleum engineering firm performing EOR studies and reserve and economic evaluations for the industry.

Gulf Oil Company 1972 - 1980
Served in various engineering capacities in the Gulf Coast and West Texas, the last of which was Chief Enhanced Recovery Engineer. Served on all technical committees for non-operated projects in which Gulf had a working interest.

Education
BS, MS and PhD degrees in Petroleum Engineering, all from The University of Texas at Austin.

Affiliations
Member of Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers and is a Registered Professional Engineer in the state of Texas.

Exhibit TT-2: Difference Between Conventional and Unconventional Natural Gas Deposits

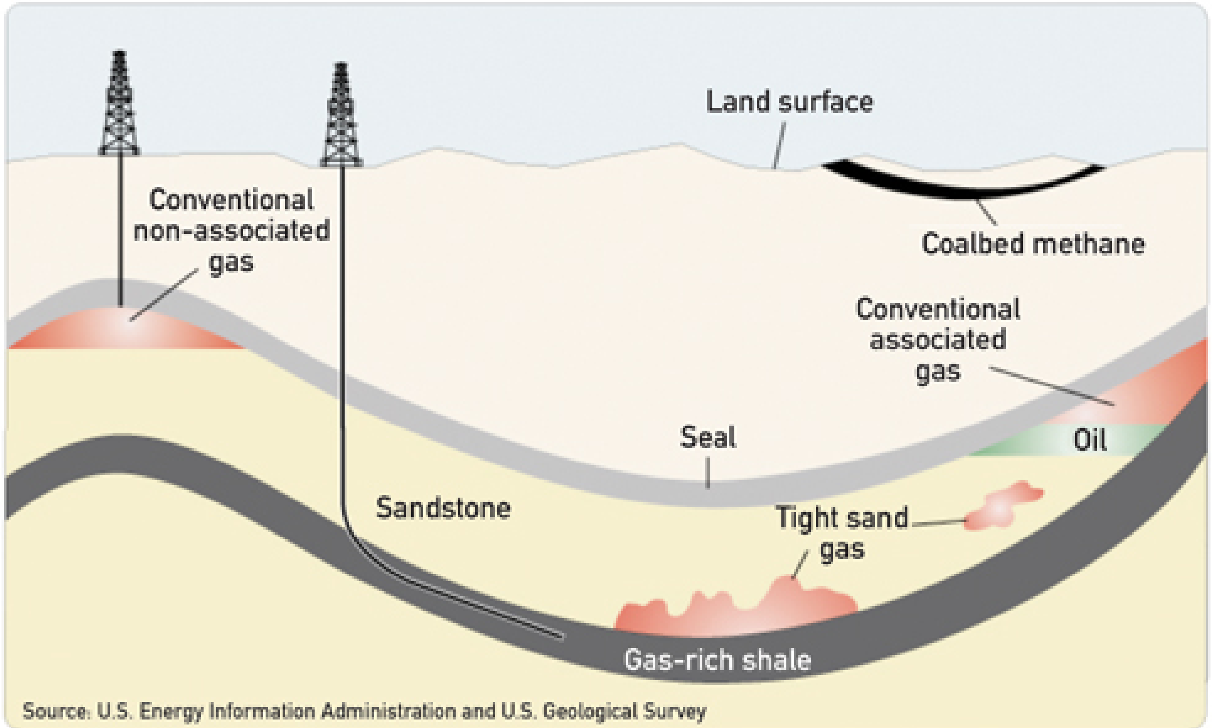
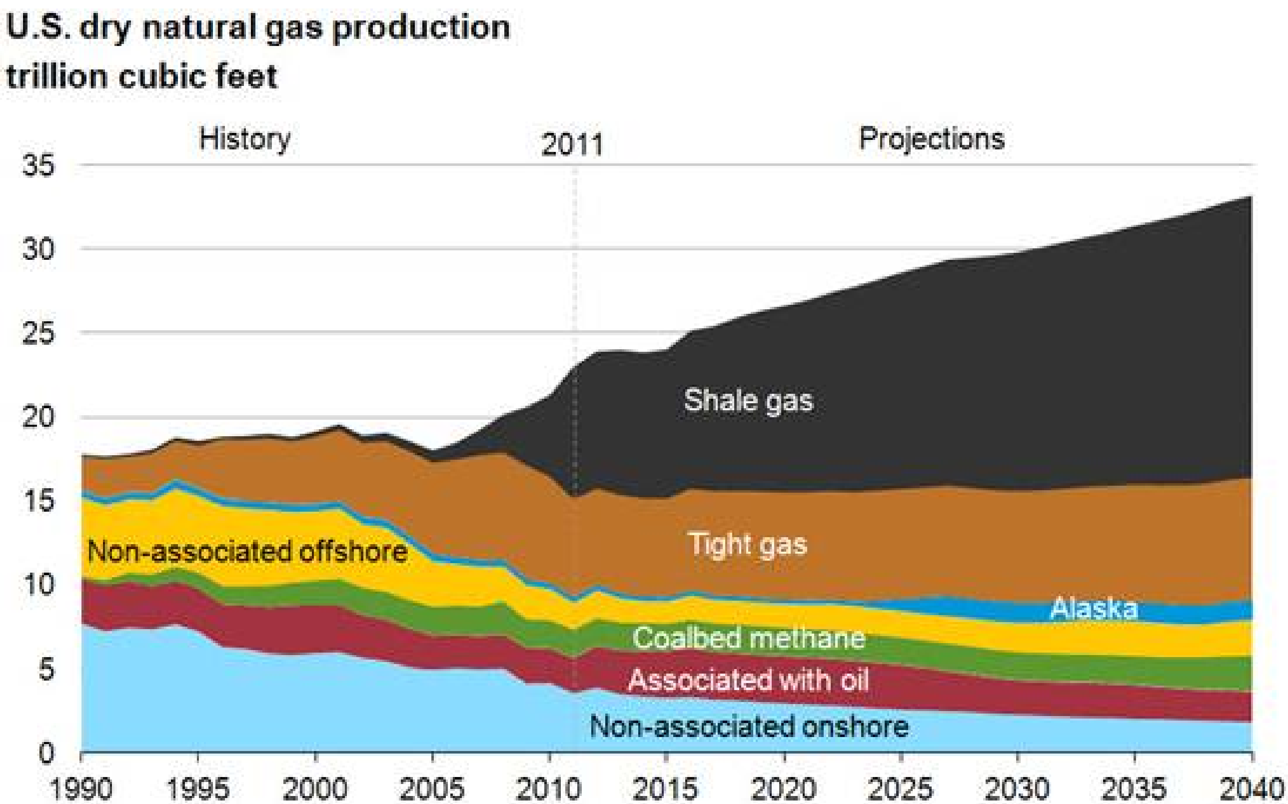
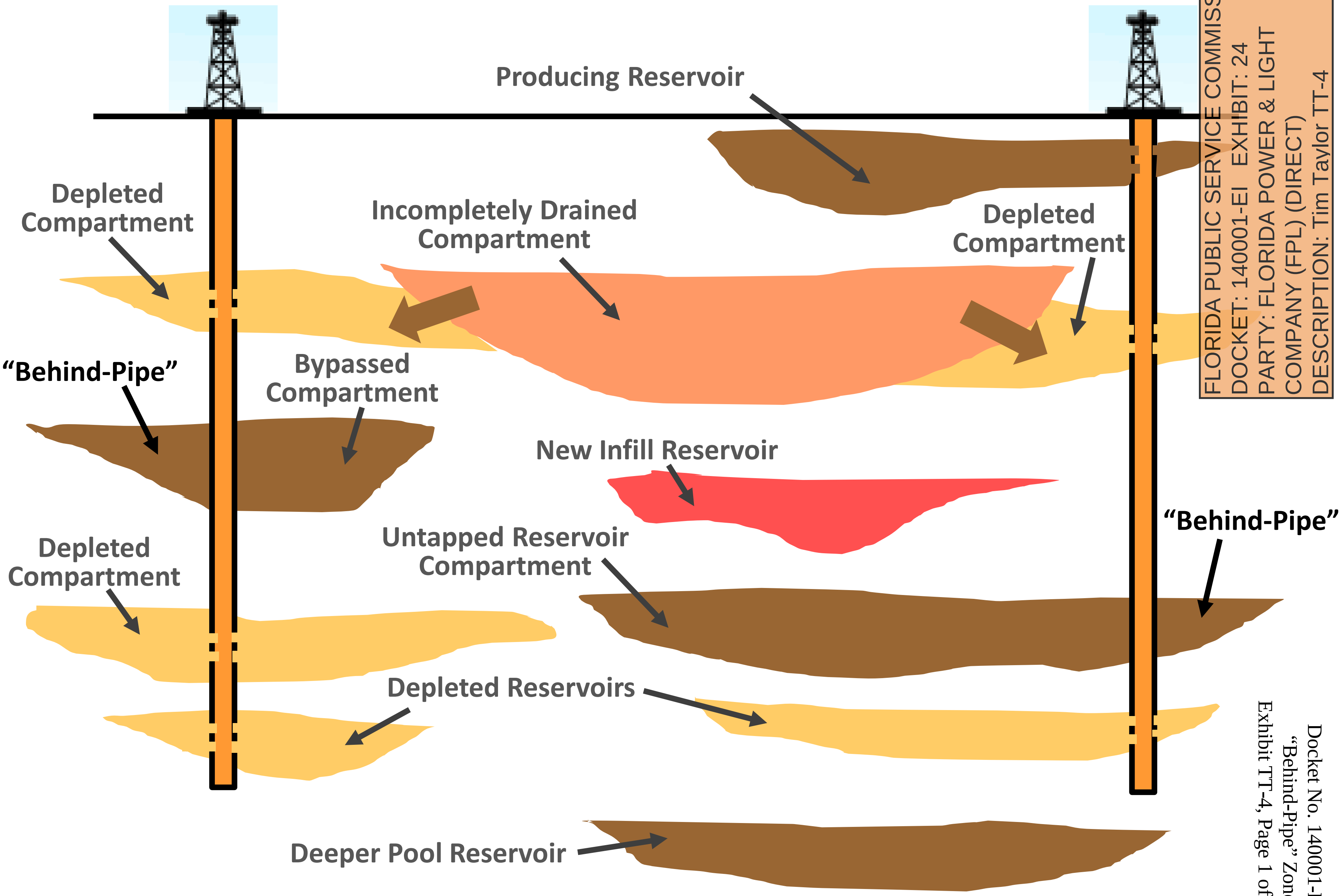


Exhibit TT-3: Historic and Projected Growth of Shale Gas Volumes



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2013 Early Release*

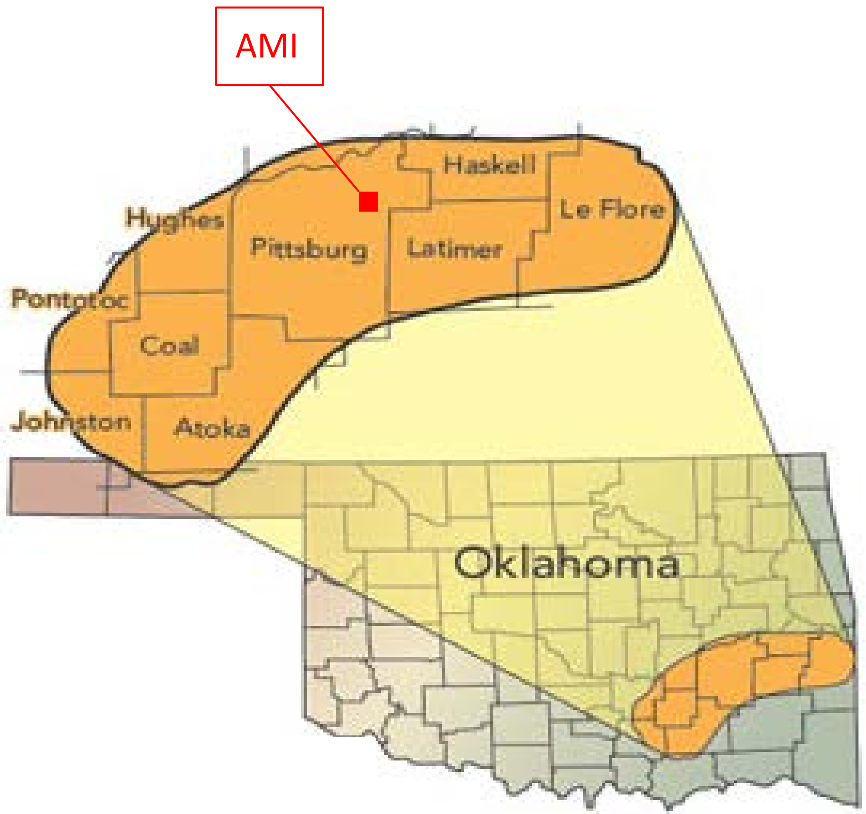
Exhibit TT-4: "Behind-Pipe" Zones



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 24
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-4

Docket No. 140001-EI
"Behind-Pipe" Zones
Exhibit TT-4, Page 1 of 1

Exhibit TT-5: Woodford Shale Area
Arkoma Basin

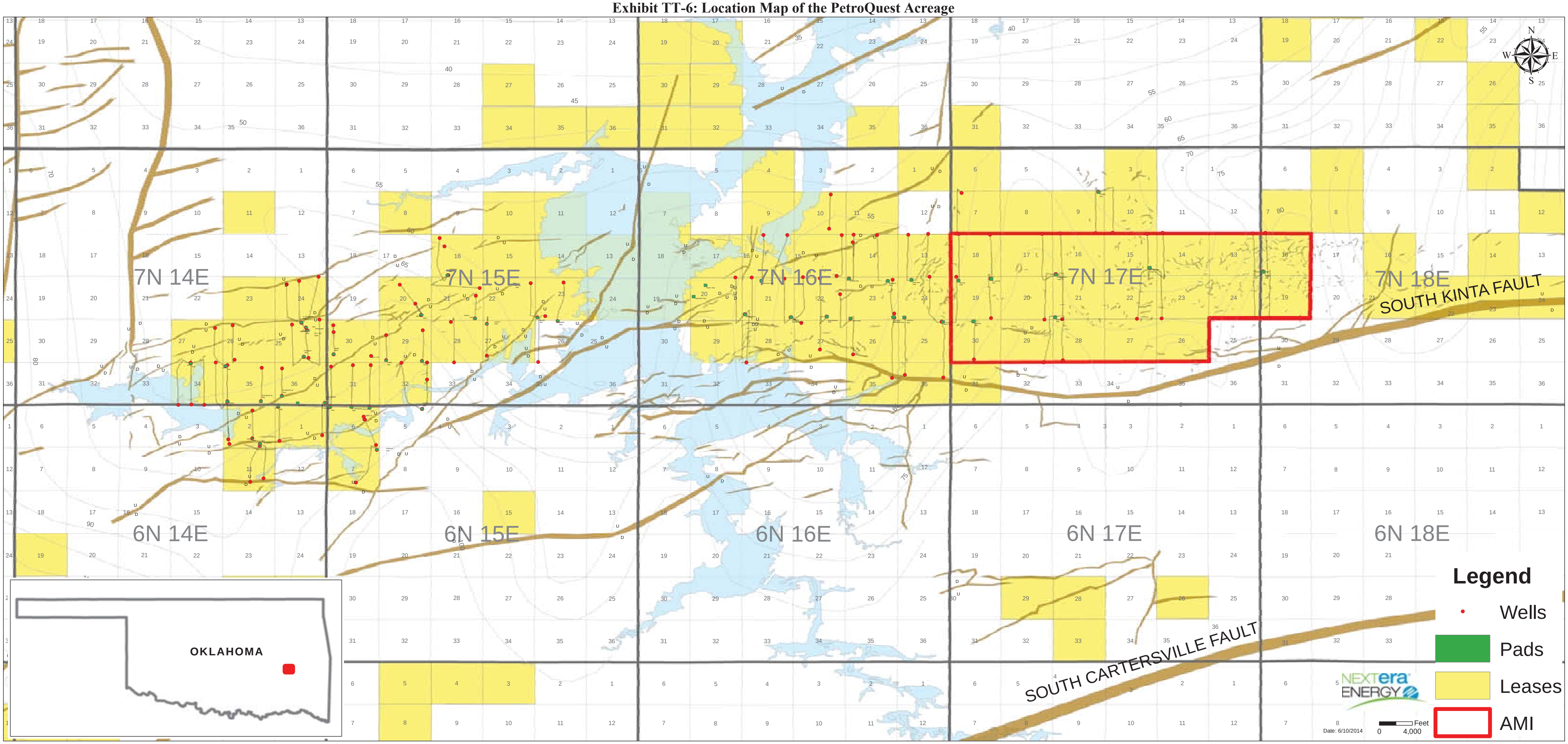


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 25
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-5

Docket No. 140001-EI
Map of the Woodford Shale
Exhibit TT-5, Page 1 of 1

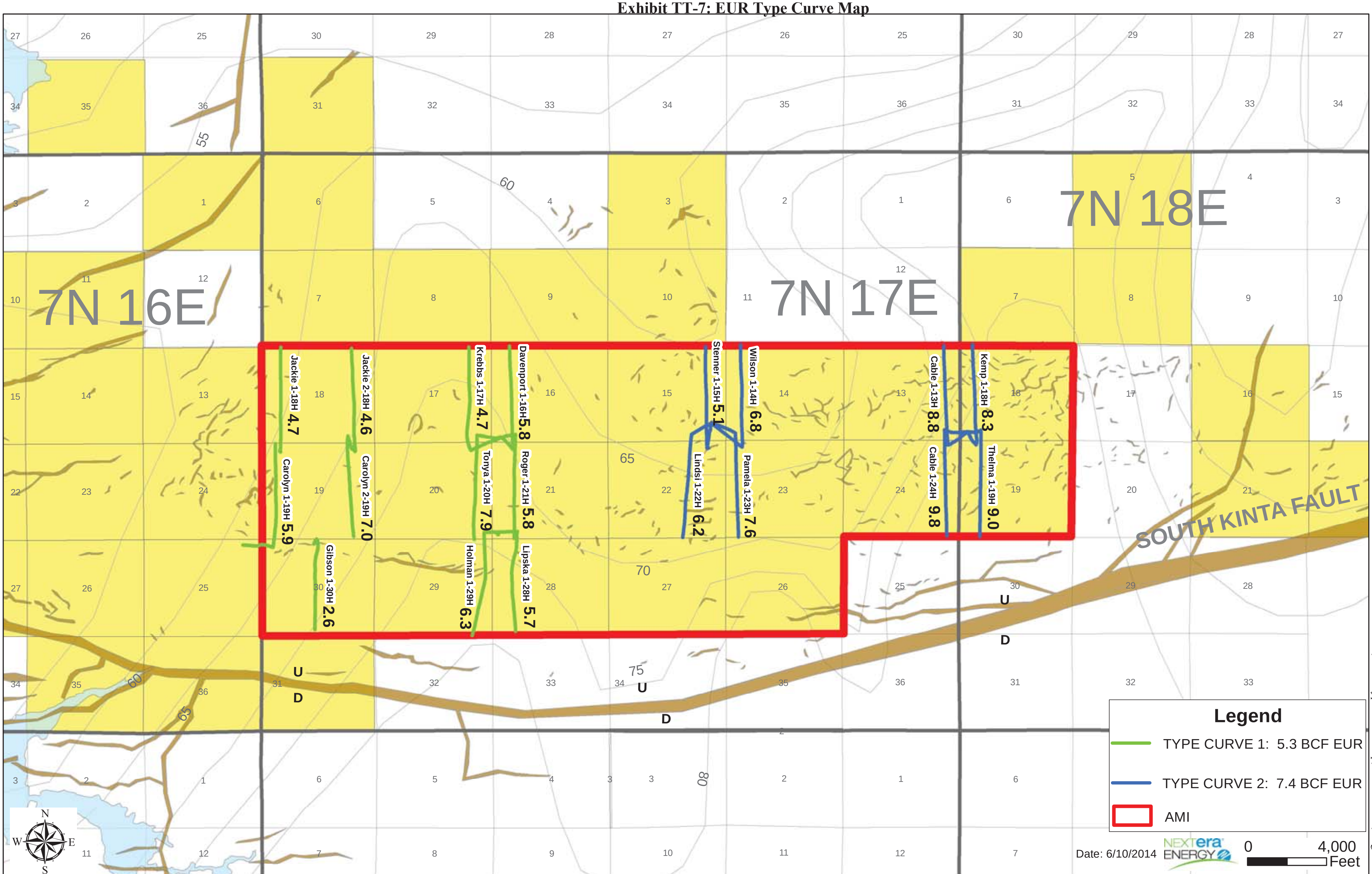
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 26
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-6

Exhibit TT-6: Location Map of the PetroQuest Acreage



Docket No. 140001-EI, Location Map of the PetroQuest Acreage, Exhibit TT-6, Page 1 of 1

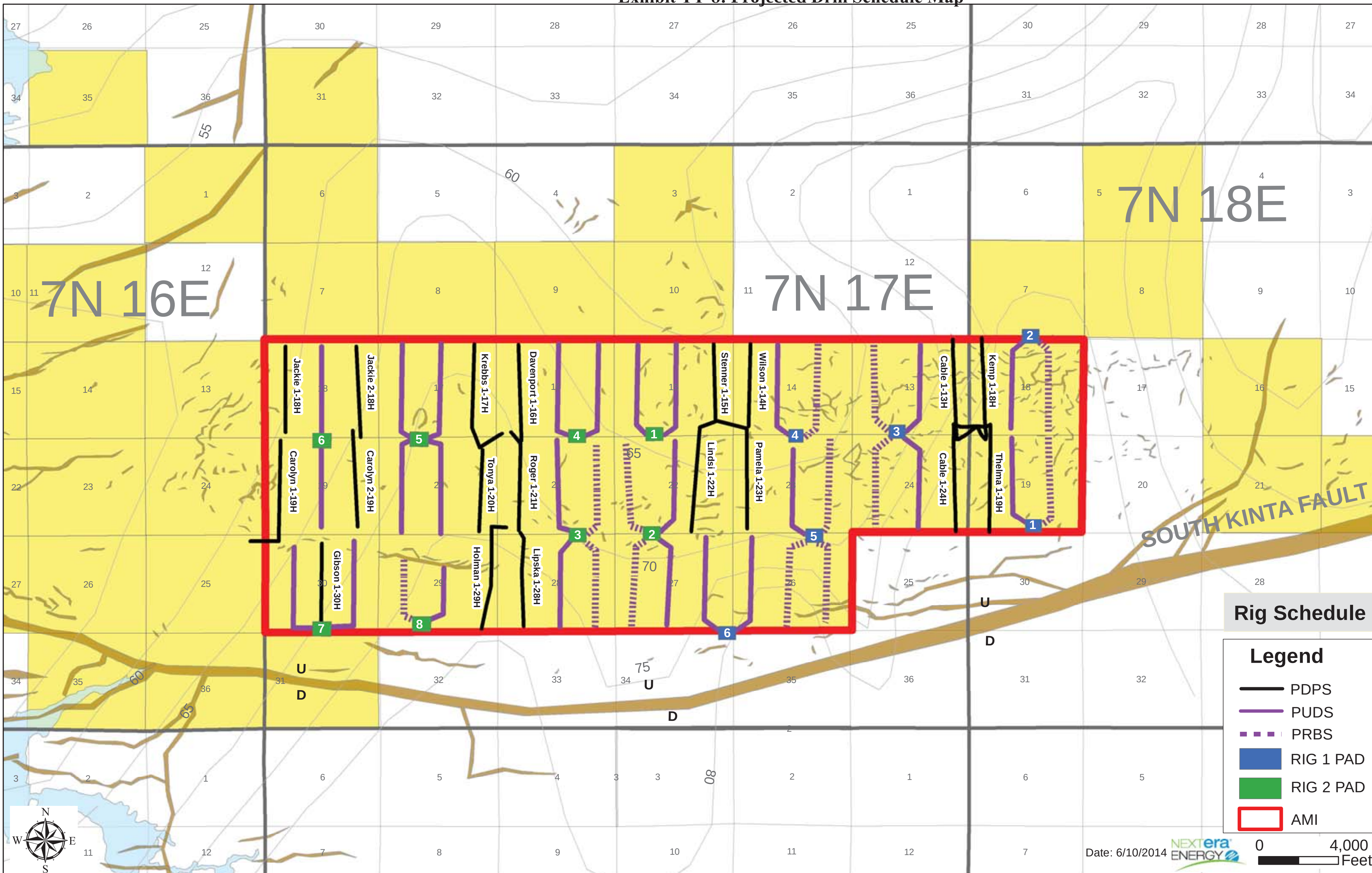
Exhibit TT-7: EUR Type Curve Map



Docket No. 140001-EI, EUR Type Curve Map, Exhibit TT-7, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 27
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-7

Exhibit TT-8: Projected Drill Schedule Map



Docket No. 140001-EI, Projected Drill Schedule Map, Exhibit TT-8, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 28
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-8

Woodford Project Grand Total

Monthly Cash Flows

CONFIDENTIAL

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2014	0.00	0.00	[redacted]						
8/1/2014	0.00	0.00							
9/1/2014	0.00	0.00							
10/1/2014	0.00	0.00							
11/1/2014	121.68	74.40							
12/1/2014	594.50	363.49							
1/1/2015	819.40	501.19							
2/1/2015	1,029.01	629.98							
3/1/2015	1,450.07	890.19							
4/1/2015	1,749.12	1,079.69							
5/1/2015	2,215.32	1,355.76							
6/1/2015	2,398.29	1,462.54							
7/1/2015	2,584.73	1,576.03							
8/1/2015	2,833.66	1,732.31							
9/1/2015	3,345.99	2,046.89							
10/1/2015	3,400.85	2,081.10							
11/1/2015	3,252.57	1,988.66							
12/1/2015	3,329.63	2,032.54							
1/1/2016	3,316.62	2,024.05							
2/1/2016	2,934.16	1,790.81							
3/1/2016	2,978.15	1,817.80							
4/1/2016	2,743.53	1,674.70							
5/1/2016	2,706.91	1,652.45							
6/1/2016	2,507.80	1,530.98							
7/1/2016	2,486.66	1,518.14							
8/1/2016	2,389.61	1,458.95							
9/1/2016	2,227.86	1,360.25							
10/1/2016	2,221.62	1,356.48							
11/1/2016	2,077.93	1,268.78							
12/1/2016	2,078.20	1,268.98							
1/1/2017	2,012.98	1,229.19							
2/1/2017	1,765.81	1,078.29							
3/1/2017	1,900.71	1,160.69							
4/1/2017	1,788.36	1,092.10							
5/1/2017	1,798.41	1,098.26							
6/1/2017	1,695.22	1,035.26							
7/1/2017	1,707.67	1,042.88							
8/1/2017	1,665.34	1,017.05							
9/1/2017	1,573.46	960.95							

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 29
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-9

Woodford Project Grand Total

Monthly Cash Flows

CONFIDENTIAL

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2017	1,588.52	970.15	[redacted]						
11/1/2017	1,502.88	917.86	[redacted]						
12/1/2017	1,519.16	927.82	[redacted]						
1/1/2018	1,486.42	907.83	[redacted]						
2/1/2018	1,315.71	803.58	[redacted]						
3/1/2018	1,428.25	872.32	[redacted]						
4/1/2018	1,354.94	827.55	[redacted]						
5/1/2018	1,373.17	838.70	[redacted]						
6/1/2018	1,303.88	796.39	[redacted]						
7/1/2018	1,322.59	807.82	[redacted]						
8/1/2018	1,298.43	793.07	[redacted]						
9/1/2018	1,234.44	753.99	[redacted]						
10/1/2018	1,253.63	765.72	[redacted]						
11/1/2018	1,192.73	728.52	[redacted]						
12/1/2018	1,212.12	740.37	[redacted]						
1/1/2019	1,192.17	728.19	[redacted]						
2/1/2019	1,060.24	647.61	[redacted]						
3/1/2019	1,156.13	706.18	[redacted]						
4/1/2019	1,101.70	672.94	[redacted]						
5/1/2019	1,121.31	684.92	[redacted]						
6/1/2019	1,069.11	653.04	[redacted]						
7/1/2019	1,088.72	665.03	[redacted]						
8/1/2019	1,072.95	655.40	[redacted]						
9/1/2019	1,023.79	625.37	[redacted]						
10/1/2019	1,043.35	637.32	[redacted]						
11/1/2019	996.01	608.40	[redacted]						
12/1/2019	1,015.49	620.31	[redacted]						
1/1/2020	1,001.95	612.04	[redacted]						
2/1/2020	925.40	565.28	[redacted]						
3/1/2020	976.84	596.71	[redacted]						
4/1/2020	933.49	570.22	[redacted]						
5/1/2020	952.70	581.96	[redacted]						
6/1/2020	910.75	556.34	[redacted]						
7/1/2020	929.83	568.00	[redacted]						
8/1/2020	918.67	561.18	[redacted]						
9/1/2020	878.68	536.76	[redacted]						
10/1/2020	897.55	548.28	[redacted]						
11/1/2020	858.76	524.59	[redacted]						
12/1/2020	877.47	536.02	[redacted]						

Woodford Project Grand Total

Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2021	867.64	530.02	[redacted]						
7	2/1/2021	775.42	473.69	[redacted]						
8	3/1/2021	849.58	518.99	[redacted]						
9	4/1/2021	813.45	496.92	[redacted]						
10	5/1/2021	831.76	508.11	[redacted]						
11	6/1/2021	796.61	486.63	[redacted]						
12	7/1/2021	814.75	497.72	[redacted]						
13	8/1/2021	806.39	492.61	[redacted]						
14	9/1/2021	772.60	471.97	[redacted]						
15	10/1/2021	790.49	482.90	[redacted]						
16	11/1/2021	757.54	462.77	[redacted]						
17	12/1/2021	775.26	473.60	[redacted]						
18	1/1/2022	767.77	469.02	[redacted]						
19	2/1/2022	687.16	419.78	[redacted]						
20	3/1/2022	753.94	460.58	[redacted]						
21	4/1/2022	722.90	441.62	[redacted]						
22	5/1/2022	740.20	452.19	[redacted]						
23	6/1/2022	709.88	433.66	[redacted]						
24	7/1/2022	727.01	444.13	[redacted]						
25	8/1/2022	720.50	440.15	[redacted]						
26	9/1/2022	691.18	422.24	[redacted]						
27	10/1/2022	708.06	432.55	[redacted]						
28	11/1/2022	679.37	415.03	[redacted]						
29	12/1/2022	696.08	425.24	[redacted]						
30	1/1/2023	690.16	421.62	[redacted]						
31	2/1/2023	618.38	377.77	[redacted]						
32	3/1/2023	679.20	414.93	[redacted]						
33	4/1/2023	651.95	398.28	[redacted]						
34	5/1/2023	668.26	408.25	[redacted]						
35	6/1/2023	641.55	391.93	[redacted]						
36	7/1/2023	657.70	401.80	[redacted]						
37	8/1/2023	652.48	398.61	[redacted]						
38	9/1/2023	626.54	382.76	[redacted]						
39	10/1/2023	642.46	392.49	[redacted]						
40	11/1/2023	617.01	376.94	[redacted]						
41	12/1/2023	632.77	386.57	[redacted]						
42	1/1/2024	627.97	383.64	[redacted]						
43	2/1/2024	583.18	356.27	[redacted]						
44	3/1/2024	618.90	378.10	[redacted]						

Woodford Project Grand Total

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Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2024	594.58	363.24	[redacted]						
5/1/2024	609.97	372.64							
6/1/2024	586.08	358.04							
7/1/2024	601.32	367.36							
8/1/2024	597.03	364.74							
9/1/2024	573.74	350.51							
10/1/2024	588.77	359.69							
11/1/2024	565.88	345.71							
12/1/2024	580.77	354.80							
1/1/2025	576.79	352.37							
2/1/2025	517.60	316.21							
3/1/2025	569.38	347.85							
4/1/2025	547.39	334.41							
5/1/2025	561.94	343.30							
6/1/2025	540.29	330.08							
7/1/2025	554.71	338.89							
8/1/2025	551.11	336.69							
9/1/2025	529.96	323.76							
10/1/2025	544.18	332.45							
11/1/2025	523.34	319.72							
12/1/2025	537.44	328.34							
1/1/2026	534.08	326.29							
2/1/2026	479.55	292.97							
3/1/2026	527.82	322.46							
4/1/2026	507.72	310.18							
5/1/2026	521.51	318.61							
6/1/2026	501.70	306.50							
7/1/2026	515.37	314.86							
8/1/2026	512.31	312.99							
9/1/2026	492.91	301.13							
10/1/2026	506.40	309.38							
11/1/2026	487.26	297.69							
12/1/2026	500.64	305.86							
1/1/2027	497.77	304.11							
2/1/2027	447.16	273.19							
3/1/2027	492.40	300.83							
4/1/2027	473.88	289.51							
5/1/2027	486.99	297.52							
6/1/2027	468.70	286.35							

1 # Woodford Project Grand Total

2 ## Monthly Cash Flows

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4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2027	481.70	294.29	[redacted]						
7	8/1/2027	479.06	292.67							
8	9/1/2027	461.12	281.72							
9	10/1/2027	473.95	289.56							
10	11/1/2027	456.24	278.73							
11	12/1/2027	468.96	286.51							
12	1/1/2028	466.46	284.98							
13	2/1/2028	434.12	265.22							
14	3/1/2028	461.68	282.06							
15	4/1/2028	444.47	271.54							
16	5/1/2028	456.90	279.14							
17	6/1/2028	439.88	268.74							
18	7/1/2028	452.19	276.26							
19	8/1/2028	449.82	274.82							
20	9/1/2028	433.07	264.58							
21	10/1/2028	445.20	271.99							
22	11/1/2028	428.61	261.86							
23	12/1/2028	440.62	269.19							
24	1/1/2029	438.31	267.78							
25	2/1/2029	393.92	240.66							
26	3/1/2029	433.95	265.12							
27	4/1/2029	417.79	255.24							
28	5/1/2029	429.49	262.39							
29	6/1/2029	413.49	252.62							
30	7/1/2029	425.08	259.70							
31	8/1/2029	422.85	258.34							
32	9/1/2029	407.10	248.71							
33	10/1/2029	418.50	255.68							
34	11/1/2029	402.91	246.16							
35	12/1/2029	414.20	253.05							
36	1/1/2030	412.03	251.73							
37	2/1/2030	370.30	226.23							
38	3/1/2030	407.93	249.22							
39	4/1/2030	392.74	239.94							
40	5/1/2030	403.74	246.66							
41	6/1/2030	388.70	237.47							
42	7/1/2030	399.59	244.12							
43	8/1/2030	397.49	242.85							
44	9/1/2030	382.69	233.80							

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Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2030	393.41	240.35	[redacted]						
11/1/2030	378.76	231.40	[redacted]						
12/1/2030	389.36	237.88	[redacted]						
1/1/2031	387.32	236.63	[redacted]						
2/1/2031	348.10	212.67	[redacted]						
3/1/2031	383.47	234.28	[redacted]						
4/1/2031	369.19	225.55	[redacted]						
5/1/2031	379.53	231.87	[redacted]						
6/1/2031	365.39	223.23	[redacted]						
7/1/2031	375.63	229.49	[redacted]						
8/1/2031	373.66	228.28	[redacted]						
9/1/2031	359.74	219.78	[redacted]						
10/1/2031	369.82	225.94	[redacted]						
11/1/2031	356.05	217.52	[redacted]						
12/1/2031	366.02	223.62	[redacted]						
1/1/2032	364.10	222.44	[redacted]						
2/1/2032	338.88	207.04	[redacted]						
3/1/2032	360.42	220.19	[redacted]						
4/1/2032	346.99	211.99	[redacted]						
5/1/2032	356.71	217.93	[redacted]						
6/1/2032	343.43	209.81	[redacted]						
7/1/2032	353.05	215.69	[redacted]						
8/1/2032	351.20	214.56	[redacted]						
9/1/2032	338.12	206.57	[redacted]						
10/1/2032	347.59	212.35	[redacted]						
11/1/2032	334.64	204.45	[redacted]						
12/1/2032	344.01	210.17	[redacted]						
1/1/2033	342.21	209.07	[redacted]						
2/1/2033	307.55	187.90	[redacted]						
3/1/2033	338.81	206.99	[redacted]						
4/1/2033	326.19	199.28	[redacted]						
5/1/2033	335.32	204.86	[redacted]						
6/1/2033	322.84	197.23	[redacted]						
7/1/2033	331.88	202.76	[redacted]						
8/1/2033	330.14	201.70	[redacted]						
9/1/2033	317.84	194.18	[redacted]						
10/1/2033	326.74	199.62	[redacted]						
11/1/2033	314.57	192.19	[redacted]						
12/1/2033	323.39	197.57	[redacted]						

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Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2034	321.69	196.53	[redacted]						
2/1/2034	289.11	176.63	[redacted]						
3/1/2034	318.49	194.58	[redacted]						
4/1/2034	306.63	187.33	[redacted]						
5/1/2034	315.22	192.58	[redacted]						
6/1/2034	303.48	185.41	[redacted]						
7/1/2034	311.98	190.60	[redacted]						
8/1/2034	310.34	189.60	[redacted]						
9/1/2034	298.78	182.54	[redacted]						
10/1/2034	307.15	187.65	[redacted]						
11/1/2034	295.71	180.66	[redacted]						
12/1/2034	304.00	185.72	[redacted]						
1/1/2035	302.40	184.75	[redacted]						
2/1/2035	271.78	166.04	[redacted]						
3/1/2035	299.40	182.91	[redacted]						
4/1/2035	288.24	176.10	[redacted]						
5/1/2035	296.32	181.03	[redacted]						
6/1/2035	285.28	174.29	[redacted]						
7/1/2035	293.27	179.17	[redacted]						
8/1/2035	291.74	178.23	[redacted]						
9/1/2035	280.87	171.59	[redacted]						
10/1/2035	288.74	176.40	[redacted]						
11/1/2035	277.98	169.83	[redacted]						
12/1/2035	285.77	174.59	[redacted]						
1/1/2036	284.27	173.67	[redacted]						
2/1/2036	264.58	161.64	[redacted]						
3/1/2036	281.40	171.92	[redacted]						
4/1/2036	270.92	165.51	[redacted]						
5/1/2036	278.50	170.15	[redacted]						
6/1/2036	268.13	163.81	[redacted]						
7/1/2036	275.64	168.40	[redacted]						
8/1/2036	274.20	167.52	[redacted]						
9/1/2036	263.98	161.28	[redacted]						
10/1/2036	271.38	165.80	[redacted]						
11/1/2036	261.27	159.62	[redacted]						
12/1/2036	268.59	164.09	[redacted]						
1/1/2037	267.18	163.23	[redacted]						
2/1/2037	240.12	146.70	[redacted]						
3/1/2037	264.52	161.61	[redacted]						

Woodford Project Grand Total

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Monthly Cash Flows

A Year	B Gas Gross (MMcf)	C Gas Net (MMcf)	D Gas Price ($/Mcf)	E Oil & Gas Rev. Net (M$)	F Costs Net (M$)	G Taxes Net (M$)	H Invest. Net (M$)	I NonDisc. CF Annual (M$)	J Cum Disc. CF Annual (M$)
4/1/2037	254.67	155.59	[redacted]						
5/1/2037	261.80	159.95	[redacted]						
6/1/2037	252.05	153.99	[redacted]						
7/1/2037	259.11	158.30	[redacted]						
8/1/2037	257.76	157.47	[redacted]						
9/1/2037	248.16	151.61	[redacted]						
10/1/2037	255.11	155.85	[redacted]						
11/1/2037	245.60	150.05	[redacted]						
12/1/2037	252.48	154.25	[redacted]						
1/1/2038	251.16	153.44	[redacted]						
2/1/2038	225.72	137.90	[redacted]						
3/1/2038	248.66	151.92	[redacted]						
4/1/2038	239.40	146.26	[redacted]						
5/1/2038	246.11	150.36	[redacted]						
6/1/2038	236.94	144.76	[redacted]						
7/1/2038	243.58	148.81	[redacted]						
8/1/2038	242.30	148.03	[redacted]						
9/1/2038	233.28	142.52	[redacted]						
10/1/2038	239.81	146.51	[redacted]						
11/1/2038	230.88	141.05	[redacted]						
12/1/2038	237.34	145.00	[redacted]						
1/1/2039	236.10	144.24	[redacted]						
2/1/2039	212.19	129.64	[redacted]						
3/1/2039	233.75	142.81	[redacted]						
4/1/2039	225.05	137.49	[redacted]						
5/1/2039	231.35	141.34	[redacted]						
6/1/2039	222.73	136.08	[redacted]						
7/1/2039	228.97	139.89	[redacted]						
8/1/2039	227.77	139.16	[redacted]						
9/1/2039	219.29	133.97	[redacted]						
10/1/2039	225.43	137.72	[redacted]						
11/1/2039	217.03	132.60	[redacted]						
12/1/2039	223.11	136.31	[redacted]						
1/1/2040	221.94	135.59	[redacted]						
2/1/2040	206.57	126.20	[redacted]						
3/1/2040	219.70	134.22	[redacted]						
4/1/2040	211.52	129.22	[redacted]						
5/1/2040	217.44	132.84	[redacted]						
6/1/2040	209.34	127.90	[redacted]						

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1 # Woodford Project Grand Total
2 ## Monthly Cash Flows

3

4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2040	215.21	131.48	[redacted]						
7	8/1/2040	214.08	130.79							
8	9/1/2040	206.11	125.92							
9	10/1/2040	211.88	129.44							
10	11/1/2040	203.99	124.62							
11	12/1/2040	209.70	128.11							
12	1/1/2041	208.60	127.44							
13	2/1/2041	187.47	114.54							
14	3/1/2041	206.53	126.18							
15	4/1/2041	198.83	121.48							
16	5/1/2041	204.40	124.88							
17	6/1/2041	196.79	120.23							
18	7/1/2041	202.30	123.59							
19	8/1/2041	201.24	122.95							
20	9/1/2041	193.75	118.37							
21	10/1/2041	199.17	121.68							
22	11/1/2041	191.76	117.15							
23	12/1/2041	197.13	120.43							
24	1/1/2042	196.09	119.80							
25	2/1/2042	176.23	107.67							
26	3/1/2042	194.14	118.61							
27	4/1/2042	186.91	114.19							
28	5/1/2042	192.15	117.39							
29	6/1/2042	184.99	113.02							
30	7/1/2042	190.17	116.18							
31	8/1/2042	189.18	115.58							
32	9/1/2042	182.13	111.27							
33	10/1/2042	187.23	114.39							
34	11/1/2042	180.26	110.13							
35	12/1/2042	185.31	113.21							
36	1/1/2043	184.34	112.62							
37	2/1/2043	165.67	101.21							
38	3/1/2043	182.50	111.50							
39	4/1/2043	175.70	107.35							
40	5/1/2043	180.63	110.35							
41	6/1/2043	173.90	106.24							
42	7/1/2043	178.77	109.22							
43	8/1/2043	177.83	108.65							
44	9/1/2043	171.21	104.60							

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Woodford Project Grand Total
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2043	176.00	107.53	[redacted]						
11/1/2043	169.45	103.52	[redacted]						
12/1/2043	174.20	106.42	[redacted]						
1/1/2044	173.28	105.87	[redacted]						
2/1/2044	161.28	98.53	[redacted]						
3/1/2044	171.53	104.80	[redacted]						
4/1/2044	165.14	100.89	[redacted]						
5/1/2044	169.77	103.72	[redacted]						
6/1/2044	163.44	99.85	[redacted]						
7/1/2044	168.02	102.65	[redacted]						
8/1/2044	167.14	102.11	[redacted]						
9/1/2044	160.92	98.31	[redacted]						
10/1/2044	165.42	101.06	[redacted]						
11/1/2044	159.26	97.30	[redacted]						
12/1/2044	163.72	100.02	[redacted]						
1/1/2045	162.87	99.50	[redacted]						
2/1/2045	146.37	89.42	[redacted]						
3/1/2045	161.25	98.51	[redacted]						
4/1/2045	155.24	94.84	[redacted]						
5/1/2045	159.59	97.50	[redacted]						
6/1/2045	153.64	93.87	[redacted]						
7/1/2045	157.95	96.50	[redacted]						
8/1/2045	157.12	95.99	[redacted]						
9/1/2045	151.27	92.42	[redacted]						
10/1/2045	155.50	95.00	[redacted]						
11/1/2045	149.71	91.47	[redacted]						
12/1/2045	153.91	94.03	[redacted]						
1/1/2046	153.10	93.53	[redacted]						
2/1/2046	137.59	84.06	[redacted]						
3/1/2046	151.58	92.60	[redacted]						
4/1/2046	145.93	89.16	[redacted]						
5/1/2046	150.02	91.65	[redacted]						
6/1/2046	144.43	88.24	[redacted]						
7/1/2046	148.48	90.71	[redacted]						
8/1/2046	147.70	90.24	[redacted]						
9/1/2046	142.20	86.87	[redacted]						
10/1/2046	146.18	89.31	[redacted]						
11/1/2046	140.74	85.98	[redacted]						
12/1/2046	144.68	88.39	[redacted]						

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1 # Woodford Project Grand Total
2 ## Monthly Cash Flows
3

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2047	143.92	87.93	[redacted]						
7	2/1/2047	129.34	79.02							
8	3/1/2047	142.49	87.05							
9	4/1/2047	137.18	83.81							
10	5/1/2047	141.02	86.16							
11	6/1/2047	135.77	82.95							
12	7/1/2047	139.57	85.27							
13	8/1/2047	138.84	84.82							
14	9/1/2047	133.67	81.67							
15	10/1/2047	137.42	83.95							
16	11/1/2047	132.30	80.83							
17	12/1/2047	136.00	83.09							
18	1/1/2048	135.29	82.65							
19	2/1/2048	125.92	76.93							
20	3/1/2048	133.92	81.82							
21	4/1/2048	128.93	78.77							
22	5/1/2048	132.55	80.98							
23	6/1/2048	127.61	77.96							
24	7/1/2048	131.18	80.14							
25	8/1/2048	130.50	79.73							
26	9/1/2048	125.64	76.76							
27	10/1/2048	129.15	78.91							
28	11/1/2048	124.34	75.97							
29	12/1/2048	127.83	78.09							
30	1/1/2049	127.16	77.69							
31	2/1/2049	114.28	69.82							
32	3/1/2049	125.89	76.91							
33	4/1/2049	121.20	74.05							
34	5/1/2049	124.60	76.12							
35	6/1/2049	119.96	73.29							
36	7/1/2049	123.32	75.34							
37	8/1/2049	122.67	74.94							
38	9/1/2049	118.10	72.15							
39	10/1/2049	121.41	74.17							
40	11/1/2049	116.89	71.41							
41	12/1/2049	120.16	73.41							
42	1/1/2050	119.53	73.03							
43	2/1/2050	107.43	65.63							
44	3/1/2050	118.34	72.30							

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Woodford Project Grand Total
Monthly Cash Flows

A Year	B Gas Gross (MMcf)	C Gas Net (MMcf)	D Gas Price ($/Mcf)	E Oil & Gas Rev. Net (M$)	F Costs Net (M$)	G Taxes Net (M$)	H Invest. Net (M$)	I NonDisc. CF Annual (M$)	J Cum Disc. CF Annual (M$)
4/1/2050	113.94	69.61	[redacted]						
5/1/2050	117.13	71.56	[redacted]						
6/1/2050	112.76	68.89	[redacted]						
7/1/2050	115.92	70.82	[redacted]						
8/1/2050	115.32	70.45	[redacted]						
9/1/2050	111.02	67.83	[redacted]						
10/1/2050	114.13	69.73	[redacted]						
11/1/2050	109.88	67.13	[redacted]						
12/1/2050	112.96	69.01	[redacted]						
1/1/2051	112.37	68.65	[redacted]						
2/1/2051	100.99	61.70	[redacted]						
3/1/2051	111.25	67.97	[redacted]						
4/1/2051	107.10	65.43	[redacted]						
5/1/2051	110.10	67.27	[redacted]						
6/1/2051	106.00	64.76	[redacted]						
7/1/2051	108.97	66.58	[redacted]						
8/1/2051	108.40	66.23	[redacted]						
9/1/2051	104.36	63.76	[redacted]						
10/1/2051	107.29	65.55	[redacted]						
11/1/2051	103.29	63.10	[redacted]						
12/1/2051	106.18	64.87	[redacted]						
1/1/2052	105.63	64.53	[redacted]						
2/1/2052	98.31	60.06	[redacted]						
3/1/2052	104.56	63.88	[redacted]						
4/1/2052	100.67	61.50	[redacted]						
5/1/2052	103.48	63.22	[redacted]						
6/1/2052	99.63	60.87	[redacted]						
7/1/2052	102.42	62.57	[redacted]						
8/1/2052	101.88	62.25	[redacted]						
9/1/2052	98.09	59.93	[redacted]						
10/1/2052	100.84	61.61	[redacted]						
11/1/2052	97.08	59.31	[redacted]						
12/1/2052	99.80	60.97	[redacted]						
1/1/2053	99.28	60.65	[redacted]						
2/1/2053	89.22	54.51	[redacted]						
3/1/2053	98.29	60.05	[redacted]						
4/1/2053	94.63	57.81	[redacted]						
5/1/2053	97.28	59.43	[redacted]						
6/1/2053	93.66	57.22	[redacted]						

1 # Woodford Project Grand Total

2 ## Monthly Cash Flows

3

4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2053	96.28	58.82	[redacted]						
7	8/1/2053	95.78	58.51	[redacted]						
8	9/1/2053	92.21	56.33	[redacted]						
9	10/1/2053	94.79	57.91	[redacted]						
10	11/1/2053	91.26	55.75	[redacted]						
11	12/1/2053	93.82	57.32	[redacted]						
12	1/1/2054	93.32	57.02	[redacted]						
13	2/1/2054	83.87	51.24	[redacted]						
14	3/1/2054	92.40	56.45	[redacted]						
15	4/1/2054	88.96	54.35	[redacted]						
16	5/1/2054	91.45	55.87	[redacted]						
17	6/1/2054	88.04	53.79	[redacted]						
18	7/1/2054	90.51	55.29	[redacted]						
19	8/1/2054	90.03	55.00	[redacted]						
20	9/1/2054	86.68	52.96	[redacted]						
21	10/1/2054	89.11	54.44	[redacted]						
22	11/1/2054	85.79	52.41	[redacted]						
23	12/1/2054	88.19	53.88	[redacted]						
24	1/1/2055	87.73	53.60	[redacted]						
25	2/1/2055	78.84	48.17	[redacted]						
26	3/1/2055	86.86	53.06	[redacted]						
27	4/1/2055	83.62	51.09	[redacted]						
28	5/1/2055	85.96	52.52	[redacted]						
29	6/1/2055	82.76	50.56	[redacted]						
30	7/1/2055	85.08	51.98	[redacted]						
31	8/1/2055	84.63	51.71	[redacted]						
32	9/1/2055	81.48	49.78	[redacted]						
33	10/1/2055	83.76	51.18	[redacted]						
34	11/1/2055	80.64	49.27	[redacted]						
35	12/1/2055	82.90	50.65	[redacted]						
36	1/1/2056	82.47	50.38	[redacted]						
37	2/1/2056	76.76	46.89	[redacted]						
38	3/1/2056	81.63	49.87	[redacted]						
39	4/1/2056	78.59	48.02	[redacted]						
40	5/1/2056	80.80	49.36	[redacted]						
41	6/1/2056	77.79	47.52	[redacted]						
42	7/1/2056	79.96	48.85	[redacted]						
43	8/1/2056	79.55	48.60	[redacted]						
44	9/1/2056	76.58	46.79	[redacted]						

Woodford Project Grand Total
Monthly Cash Flows

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A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2056	78.73	48.10	[redacted]						
11/1/2056	75.80	46.31	[redacted]						
12/1/2056	77.92	47.60	[redacted]						
1/1/2057	77.51	47.35	[redacted]						
2/1/2057	69.66	42.56	[redacted]						
3/1/2057	76.74	46.88	[redacted]						
4/1/2057	73.88	45.14	[redacted]						
5/1/2057	75.95	46.40	[redacted]						
6/1/2057	73.12	44.67	[redacted]						
7/1/2057	75.17	45.92	[redacted]						
8/1/2057	74.78	45.68	[redacted]						
9/1/2057	71.99	43.98	[redacted]						
10/1/2057	74.01	45.21	[redacted]						
11/1/2057	71.25	43.53	[redacted]						
12/1/2057	73.25	44.75	[redacted]						
1/1/2058	72.86	44.52	[redacted]						
2/1/2058	65.48	40.01	[redacted]						
3/1/2058	72.14	44.07	[redacted]						
4/1/2058	69.45	42.43	[redacted]						
5/1/2058	71.40	43.62	[redacted]						
6/1/2058	68.74	41.99	[redacted]						
7/1/2058	70.66	43.17	[redacted]						
8/1/2058	70.29	42.94	[redacted]						
9/1/2058	67.67	41.35	[redacted]						
10/1/2058	69.57	42.50	[redacted]						
11/1/2058	66.98	40.92	[redacted]						
12/1/2058	68.85	42.07	[redacted]						
1/1/2059	68.49	41.85	[redacted]						
2/1/2059	61.56	37.61	[redacted]						
3/1/2059	67.81	41.43	[redacted]						
4/1/2059	65.29	39.89	[redacted]						
5/1/2059	67.12	41.00	[redacted]						
6/1/2059	64.62	39.48	[redacted]						
7/1/2059	66.43	40.58	[redacted]						
8/1/2059	66.08	40.37	[redacted]						
9/1/2059	63.62	38.87	[redacted]						
10/1/2059	65.40	39.95	[redacted]						
11/1/2059	62.96	38.47	[redacted]						
12/1/2059	64.73	39.54	[redacted]						

Woodford Project Grand Total
Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2060	64.39	39.34	[redacted]						
7	2/1/2060	59.93	36.61							
8	3/1/2060	63.74	38.94							
9	4/1/2060	61.36	37.49							
10	5/1/2060	63.08	38.54							
11	6/1/2060	60.73	37.10							
12	7/1/2060	62.43	38.14							
13	8/1/2060	62.11	37.94							
14	9/1/2060	59.79	36.53							
15	10/1/2060	61.47	37.55							
16	11/1/2060	59.18	36.15							
17	12/1/2060	60.84	37.17							
18	1/1/2061	60.52	36.97							
19	2/1/2061	54.39	33.23							
20	3/1/2061	59.91	36.60							
21	4/1/2061	57.68	35.24							
22	5/1/2061	59.30	36.23							
23	6/1/2061	57.09	34.88							
24	7/1/2061	58.69	35.86							
25	8/1/2061	58.38	35.67							
26	9/1/2061	56.21	34.34							
27	10/1/2061	57.78	35.30							
28	11/1/2061	55.63	33.99							
29	12/1/2061	57.19	34.94							
30	1/1/2062	56.89	34.76							
31	2/1/2062	51.13	31.24							
32	3/1/2062	56.32	34.41							
33	4/1/2062	54.22	33.13							
34	5/1/2062	55.74	34.06							
35	6/1/2062	53.67	32.79							
36	7/1/2062	55.17	33.71							
37	8/1/2062	54.88	33.53							
38	9/1/2062	52.84	32.28							
39	10/1/2062	54.32	33.18							
40	11/1/2062	52.29	31.95							
41	12/1/2062	53.76	32.84							
42	1/1/2063	53.48	32.67							
43	2/1/2063	48.06	29.36							
44	3/1/2063	52.95	32.35							

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Woodford Project Grand Total

Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2063	50.97	31.14	[redacted]						
5/1/2063	52.40	32.01							
6/1/2063	50.45	30.82							
7/1/2063	51.86	31.68							
8/1/2063	51.59	31.52							
9/1/2063	49.67	30.34							
10/1/2063	51.06	31.19							
11/1/2063	49.16	30.03							
12/1/2063	50.54	30.87							
1/1/2064	291.40	178.03							

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Woodford Project PUD
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2014	0.00	0.00	[redacted]						
8/1/2014	0.00	0.00	[redacted]						
9/1/2014	0.00	0.00	[redacted]						
10/1/2014	0.00	0.00	[redacted]						
11/1/2014	91.26	55.04	[redacted]						
12/1/2014	445.87	268.89	[redacted]						
1/1/2015	545.91	330.46	[redacted]						
2/1/2015	628.59	381.88	[redacted]						
3/1/2015	842.94	515.06	[redacted]						
4/1/2015	981.39	605.90	[redacted]						
5/1/2015	1,211.51	742.02	[redacted]						
6/1/2015	1,368.65	833.58	[redacted]						
7/1/2015	1,458.51	885.79	[redacted]						
8/1/2015	1,466.04	889.66	[redacted]						
9/1/2015	2,110.39	1,285.61	[redacted]						
10/1/2015	2,202.17	1,342.59	[redacted]						
11/1/2015	2,158.45	1,314.59	[redacted]						
12/1/2015	2,252.39	1,368.95	[redacted]						
1/1/2016	2,203.99	1,339.54	[redacted]						
2/1/2016	1,945.23	1,182.37	[redacted]						
3/1/2016	1,970.33	1,197.71	[redacted]						
4/1/2016	1,811.74	1,101.38	[redacted]						
5/1/2016	1,784.64	1,084.96	[redacted]						
6/1/2016	1,650.96	1,003.74	[redacted]						
7/1/2016	1,634.90	994.01	[redacted]						
8/1/2016	1,569.20	954.11	[redacted]						
9/1/2016	1,461.42	888.61	[redacted]						
10/1/2016	1,455.91	885.29	[redacted]						
11/1/2016	1,360.54	827.31	[redacted]						
12/1/2016	1,359.60	826.77	[redacted]						
1/1/2017	1,315.93	800.23	[redacted]						
2/1/2017	1,153.58	701.52	[redacted]						
3/1/2017	1,240.93	754.65	[redacted]						
4/1/2017	1,166.88	709.63	[redacted]						
5/1/2017	1,172.79	713.24	[redacted]						
6/1/2017	1,104.91	671.97	[redacted]						
7/1/2017	1,112.49	676.59	[redacted]						
8/1/2017	1,084.41	659.52	[redacted]						
9/1/2017	1,024.14	622.88	[redacted]						

Woodford Project PUD

Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2017	1,033.52	628.59	[redacted]						
11/1/2017	977.43	594.48							
12/1/2017	987.66	600.71							
1/1/2018	966.05	587.57							
2/1/2018	854.83	519.93							
3/1/2018	927.67	564.24							
4/1/2018	879.80	535.13							
5/1/2018	891.39	542.18							
6/1/2018	846.19	514.70							
7/1/2018	858.12	521.95							
8/1/2018	842.24	512.30							
9/1/2018	800.55	486.94							
10/1/2018	812.81	494.41							
11/1/2018	773.17	470.29							
12/1/2018	785.58	477.85							
1/1/2019	772.49	469.89							
2/1/2019	686.88	417.82							
3/1/2019	748.88	455.53							
4/1/2019	713.50	434.01							
5/1/2019	726.08	441.67							
6/1/2019	692.17	421.04							
7/1/2019	704.76	428.70							
8/1/2019	694.45	422.43							
9/1/2019	662.54	403.02							
10/1/2019	675.10	410.66							
11/1/2019	644.38	391.98							
12/1/2019	656.90	399.60							
1/1/2020	648.06	394.22							
2/1/2020	598.48	364.06							
3/1/2020	631.68	384.26							
4/1/2020	603.57	367.16							
5/1/2020	615.93	374.68							
6/1/2020	588.75	358.15							
7/1/2020	601.02	365.61							
8/1/2020	593.75	361.19							
9/1/2020	567.85	345.44							
10/1/2020	579.98	352.82							
11/1/2020	554.87	337.54							
12/1/2020	566.90	344.87							

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Woodford Project PUD
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2021	560.50	340.97	[redacted]						
2/1/2021	500.89	304.71	[redacted]						
3/1/2021	548.75	333.83	[redacted]						
4/1/2021	525.38	319.61	[redacted]						
5/1/2021	537.16	326.78	[redacted]						
6/1/2021	514.42	312.94	[redacted]						
7/1/2021	526.09	320.05	[redacted]						
8/1/2021	520.66	316.74	[redacted]						
9/1/2021	498.81	303.45	[redacted]						
10/1/2021	510.32	310.45	[redacted]						
11/1/2021	489.02	297.49	[redacted]						
12/1/2021	500.43	304.43	[redacted]						
1/1/2022	495.56	301.47	[redacted]						
2/1/2022	443.50	269.80	[redacted]						
3/1/2022	486.57	296.01	[redacted]						
4/1/2022	466.52	283.81	[redacted]						
5/1/2022	477.65	290.58	[redacted]						
6/1/2022	458.06	278.66	[redacted]						
7/1/2022	469.08	285.37	[redacted]						
8/1/2022	464.86	282.80	[redacted]						
9/1/2022	445.92	271.28	[redacted]						
10/1/2022	456.78	277.89	[redacted]						
11/1/2022	438.25	266.62	[redacted]						
12/1/2022	449.01	273.16	[redacted]						
1/1/2023	445.17	270.83	[redacted]						
2/1/2023	398.85	242.65	[redacted]						
3/1/2023	438.06	266.50	[redacted]						
4/1/2023	420.47	255.80	[redacted]						
5/1/2023	430.97	262.19	[redacted]						
6/1/2023	413.72	251.70	[redacted]						
7/1/2023	424.12	258.02	[redacted]						
8/1/2023	420.73	255.96	[redacted]						
9/1/2023	403.99	245.78	[redacted]						
10/1/2023	414.24	252.01	[redacted]						
11/1/2023	397.81	242.02	[redacted]						
12/1/2023	407.96	248.19	[redacted]						
1/1/2024	404.85	246.30	[redacted]						
2/1/2024	375.96	228.72	[redacted]						
3/1/2024	398.97	242.72	[redacted]						

Woodford Project PUD

Monthly Cash Flows

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A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2024	383.28	233.18	[redacted]						
5/1/2024	393.19	239.21							
6/1/2024	377.77	229.83							
7/1/2024	387.59	235.80							
8/1/2024	384.81	234.11							
9/1/2024	369.79	224.97							
10/1/2024	379.46	230.86							
11/1/2024	364.69	221.87							
12/1/2024	374.28	227.70							
1/1/2025	371.70	226.13							
2/1/2025	333.55	202.92							
3/1/2025	366.91	223.22							
4/1/2025	352.72	214.59							
5/1/2025	362.09	220.29							
6/1/2025	348.13	211.79							
7/1/2025	357.41	217.44							
8/1/2025	355.08	216.03							
9/1/2025	341.44	207.73							
10/1/2025	350.60	213.30							
11/1/2025	337.16	205.12							
12/1/2025	346.24	210.64							
1/1/2026	344.06	209.32							
2/1/2026	308.93	187.95							
3/1/2026	340.01	206.86							
4/1/2026	327.06	198.98							
5/1/2026	335.94	204.38							
6/1/2026	323.16	196.61							
7/1/2026	331.96	201.96							
8/1/2026	329.98	200.76							
9/1/2026	317.48	193.15							
10/1/2026	326.16	198.43							
11/1/2026	313.83	190.93							
12/1/2026	322.44	196.17							
1/1/2027	320.58	195.04							
2/1/2027	287.98	175.21							
3/1/2027	317.11	192.93							
4/1/2027	305.18	185.67							
5/1/2027	313.61	190.80							
6/1/2027	301.83	183.63							

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Woodford Project PUD
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2027	310.19	188.72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2027	308.49	187.68	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2027	296.93	180.65	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2027	305.19	185.67	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2027	293.77	178.73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2027	301.96	183.71	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2028	300.34	182.73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2028	279.52	170.06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2028	297.26	180.85	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2028	286.17	174.11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2028	294.18	178.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2028	283.21	172.31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2028	291.14	177.13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2028	289.61	176.20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2028	278.83	169.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2028	286.64	174.39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2028	275.96	167.89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2028	283.69	172.60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2029	282.20	171.69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2029	253.62	154.30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2029	279.40	169.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2029	268.99	163.65	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2029	276.52	168.24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2029	266.22	161.97	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2029	273.68	166.51	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2029	272.25	165.63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2029	262.11	159.47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2029	269.45	163.93	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2029	259.41	157.83	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2029	266.68	162.25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2030	265.28	161.40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2030	238.42	145.05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2030	262.64	159.79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2030	252.86	153.84	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2030	259.94	158.15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2030	250.26	152.26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2030	257.27	156.52	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2030	255.92	155.70	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2030	246.39	149.90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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1 # Woodford Project PUD
2 ## Monthly Cash Flows

	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2030	253.29	154.10	[redacted]						
7	11/1/2030	243.86	148.36	[redacted]						
8	12/1/2030	250.69	152.52	[redacted]						
9	1/1/2031	249.38	151.72	[redacted]						
10	2/1/2031	224.12	136.35	[redacted]						
11	3/1/2031	246.90	150.21	[redacted]						
12	4/1/2031	237.70	144.62	[redacted]						
13	5/1/2031	244.36	148.67	[redacted]						
14	6/1/2031	235.26	143.13	[redacted]						
15	7/1/2031	241.85	147.14	[redacted]						
16	8/1/2031	240.58	146.37	[redacted]						
17	9/1/2031	231.62	140.92	[redacted]						
18	10/1/2031	238.11	144.86	[redacted]						
19	11/1/2031	229.24	139.47	[redacted]						
20	12/1/2031	235.66	143.37	[redacted]						
21	1/1/2032	234.42	142.62	[redacted]						
22	2/1/2032	218.19	132.74	[redacted]						
23	3/1/2032	232.05	141.18	[redacted]						
24	4/1/2032	223.41	135.92	[redacted]						
25	5/1/2032	229.67	139.73	[redacted]						
26	6/1/2032	221.11	134.52	[redacted]						
27	7/1/2032	227.31	138.29	[redacted]						
28	8/1/2032	226.12	137.57	[redacted]						
29	9/1/2032	217.69	132.44	[redacted]						
30	10/1/2032	223.79	136.15	[redacted]						
31	11/1/2032	215.46	131.08	[redacted]						
32	12/1/2032	221.49	134.75	[redacted]						
33	1/1/2033	220.33	134.05	[redacted]						
34	2/1/2033	198.02	120.47	[redacted]						
35	3/1/2033	218.14	132.71	[redacted]						
36	4/1/2033	210.01	127.77	[redacted]						
37	5/1/2033	215.90	131.35	[redacted]						
38	6/1/2033	207.85	126.46	[redacted]						
39	7/1/2033	213.68	130.00	[redacted]						
40	8/1/2033	212.56	129.32	[redacted]						
41	9/1/2033	204.64	124.50	[redacted]						
42	10/1/2033	210.37	127.99	[redacted]						
43	11/1/2033	202.54	123.22	[redacted]						
44	12/1/2033	208.21	126.67	[redacted]						

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1 # Woodford Project PUD

2 ## Monthly Cash Flows

3

4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	1/1/2034	207.12	126.01	[redacted]						
7	2/1/2034	186.14	113.25	[redacted]						
8	3/1/2034	205.06	124.76	[redacted]						
9	4/1/2034	197.42	120.11	[redacted]						
10	5/1/2034	202.95	123.47	[redacted]						
11	6/1/2034	195.39	118.88	[redacted]						
12	7/1/2034	200.86	122.21	[redacted]						
13	8/1/2034	199.81	121.57	[redacted]						
14	9/1/2034	192.37	117.04	[redacted]						
15	10/1/2034	197.76	120.32	[redacted]						
16	11/1/2034	190.39	115.83	[redacted]						
17	12/1/2034	195.73	119.08	[redacted]						
18	1/1/2035	194.70	118.45	[redacted]						
19	2/1/2035	174.98	106.46	[redacted]						
20	3/1/2035	192.76	117.28	[redacted]						
21	4/1/2035	185.58	112.91	[redacted]						
22	5/1/2035	190.78	116.07	[redacted]						
23	6/1/2035	183.68	111.75	[redacted]						
24	7/1/2035	188.82	114.88	[redacted]						
25	8/1/2035	187.83	114.28	[redacted]						
26	9/1/2035	180.84	110.02	[redacted]						
27	10/1/2035	185.90	113.10	[redacted]						
28	11/1/2035	178.98	108.89	[redacted]						
29	12/1/2035	183.99	111.94	[redacted]						
30	1/1/2036	183.03	111.35	[redacted]						
31	2/1/2036	170.35	103.64	[redacted]						
32	3/1/2036	181.17	110.23	[redacted]						
33	4/1/2036	174.43	106.12	[redacted]						
34	5/1/2036	179.31	109.09	[redacted]						
35	6/1/2036	172.63	105.03	[redacted]						
36	7/1/2036	177.47	107.97	[redacted]						
37	8/1/2036	176.54	107.41	[redacted]						
38	9/1/2036	169.96	103.41	[redacted]						
39	10/1/2036	174.72	106.30	[redacted]						
40	11/1/2036	168.22	102.34	[redacted]						
41	12/1/2036	172.93	105.21	[redacted]						
42	1/1/2037	172.02	104.66	[redacted]						
43	2/1/2037	154.60	94.06	[redacted]						
44	3/1/2037	170.31	103.62	[redacted]						

1 # Woodford Project PUD
2 ## Monthly Cash Flows

3

4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2037	163.97	99.76	[redacted]						
7	5/1/2037	168.56	102.55							
8	6/1/2037	162.28	98.73							
9	7/1/2037	166.83	101.50							
10	8/1/2037	165.95	100.97							
11	9/1/2037	159.77	97.21							
12	10/1/2037	164.25	99.93							
13	11/1/2037	158.13	96.21							
14	12/1/2037	162.56	98.90							
15	1/1/2038	161.71	98.38							
16	2/1/2038	145.33	88.42							
17	3/1/2038	160.10	97.40							
18	4/1/2038	154.14	93.78							
19	5/1/2038	158.45	96.40							
20	6/1/2038	152.55	92.81							
21	7/1/2038	156.82	95.41							
22	8/1/2038	156.00	94.91							
23	9/1/2038	150.19	91.38							
24	10/1/2038	154.40	93.94							
25	11/1/2038	148.65	90.44							
26	12/1/2038	152.81	92.97							
27	1/1/2039	152.01	92.48							
28	2/1/2039	136.62	83.12							
29	3/1/2039	150.50	91.56							
30	4/1/2039	144.89	88.15							
31	5/1/2039	148.95	90.62							
32	6/1/2039	143.40	87.25							
33	7/1/2039	147.42	89.69							
34	8/1/2039	146.65	89.22							
35	9/1/2039	141.19	85.90							
36	10/1/2039	145.14	88.30							
37	11/1/2039	139.74	85.01							
38	12/1/2039	143.65	87.40							
39	1/1/2040	142.90	86.94							
40	2/1/2040	133.00	80.92							
41	3/1/2040	141.45	86.06							
42	4/1/2040	136.18	82.85							
43	5/1/2040	140.00	85.17							
44	6/1/2040	134.78	82.00							

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Woodford Project PUD
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2040	138.56	84.30	[redacted]						
8/1/2040	137.83	83.86							
9/1/2040	132.70	80.73							
10/1/2040	136.42	82.99							
11/1/2040	131.33	79.90							
12/1/2040	135.01	82.14							
1/1/2041	134.31	81.71							
2/1/2041	120.70	73.44							
3/1/2041	132.97	80.90							
4/1/2041	128.02	77.89							
5/1/2041	131.60	80.07							
6/1/2041	126.70	77.08							
7/1/2041	130.25	79.24							
8/1/2041	129.57	78.83							
9/1/2041	124.74	75.89							
10/1/2041	128.24	78.02							
11/1/2041	123.46	75.11							
12/1/2041	126.92	77.22							
1/1/2042	126.25	76.81							
2/1/2042	113.47	69.03							
3/1/2042	125.00	76.05							
4/1/2042	120.34	73.22							
5/1/2042	123.71	75.27							
6/1/2042	119.10	72.46							
7/1/2042	122.44	74.49							
8/1/2042	121.80	74.10							
9/1/2042	117.26	71.34							
10/1/2042	120.55	73.34							
11/1/2042	116.06	70.61							
12/1/2042	119.31	72.59							
1/1/2043	118.68	72.21							
2/1/2043	106.66	64.89							
3/1/2043	117.50	71.49							
4/1/2043	113.13	68.83							
5/1/2043	116.29	70.75							
6/1/2043	111.96	68.12							
7/1/2043	115.10	70.03							
8/1/2043	114.50	69.66							
9/1/2043	110.23	67.06							

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Woodford Project PUD

Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2043	113.32	68.94	[redacted]						
11/1/2043	109.10	66.38							
12/1/2043	112.15	68.23							
1/1/2044	111.57	67.88							
2/1/2044	103.84	63.18							
3/1/2044	110.44	67.19							
4/1/2044	106.33	64.69							
5/1/2044	109.30	66.50							
6/1/2044	105.23	64.02							
7/1/2044	108.18	65.82							
8/1/2044	107.61	65.47							
9/1/2044	103.60	63.03							
10/1/2044	106.51	64.80							
11/1/2044	102.54	62.38							
12/1/2044	105.41	64.13							
1/1/2045	104.86	63.80							
2/1/2045	94.24	57.33							
3/1/2045	103.82	63.16							
4/1/2045	99.95	60.81							
5/1/2045	102.75	62.51							
6/1/2045	98.92	60.18							
7/1/2045	101.69	61.87							
8/1/2045	101.16	61.55							
9/1/2045	97.39	59.25							
10/1/2045	100.12	60.91							
11/1/2045	96.39	58.64							
12/1/2045	99.09	60.29							
1/1/2046	98.57	59.97							
2/1/2046	88.59	53.90							
3/1/2046	97.59	59.37							
4/1/2046	93.96	57.16							
5/1/2046	96.59	58.76							
6/1/2046	92.99	56.58							
7/1/2046	95.60	58.16							
8/1/2046	95.09	57.86							
9/1/2046	91.55	55.70							
10/1/2046	94.12	57.26							
11/1/2046	90.61	55.13							
12/1/2046	93.15	56.67							

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Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2047	92.66	56.37	[redacted]						
2/1/2047	83.28	50.67							
3/1/2047	91.74	55.81							
4/1/2047	88.32	53.74							
5/1/2047	90.80	55.24							
6/1/2047	87.42	53.18							
7/1/2047	89.86	54.67							
8/1/2047	89.39	54.39							
9/1/2047	86.06	52.36							
10/1/2047	88.47	53.83							
11/1/2047	85.18	51.82							
12/1/2047	87.56	53.27							
1/1/2048	87.11	52.99							
2/1/2048	81.07	49.32							
3/1/2048	86.22	52.46							
4/1/2048	83.01	50.50							
5/1/2048	85.34	51.92							
6/1/2048	82.16	49.99							
7/1/2048	84.46	51.39							
8/1/2048	84.02	51.12							
9/1/2048	80.89	49.21							
10/1/2048	83.15	50.59							
11/1/2048	80.06	48.71							
12/1/2048	82.30	50.07							
1/1/2049	81.87	49.81							
2/1/2049	73.58	44.76							
3/1/2049	81.05	49.31							
4/1/2049	78.04	47.48							
5/1/2049	80.22	48.81							
6/1/2049	77.23	46.99							
7/1/2049	79.40	48.30							
8/1/2049	78.98	48.05							
9/1/2049	76.04	46.26							
10/1/2049	78.17	47.56							
11/1/2049	75.26	45.79							
12/1/2049	77.37	47.07							
1/1/2050	76.96	46.82							
2/1/2050	69.17	42.08							
3/1/2050	76.19	46.36							

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1 # Woodford Project PUD
2 ## Monthly Cash Flows

3

4	A	B	C	D	E	F	G	H	I	J
5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	4/1/2050	73.36	44.63	[redacted]						
7	5/1/2050	75.41	45.88							
8	6/1/2050	72.60	44.17							
9	7/1/2050	74.64	45.41							
10	8/1/2050	74.25	45.17							
11	9/1/2050	71.48	43.49							
12	10/1/2050	73.48	44.71							
13	11/1/2050	70.74	43.04							
14	12/1/2050	72.73	44.25							
15	1/1/2051	72.35	44.01							
16	2/1/2051	65.02	39.56							
17	3/1/2051	71.63	43.58							
18	4/1/2051	68.96	41.95							
19	5/1/2051	70.89	43.13							
20	6/1/2051	68.25	41.52							
21	7/1/2051	70.16	42.69							
22	8/1/2051	69.79	42.46							
23	9/1/2051	67.19	40.88							
24	10/1/2051	69.08	42.03							
25	11/1/2051	66.50	40.46							
26	12/1/2051	68.37	41.59							
27	1/1/2052	68.01	41.38							
28	2/1/2052	63.30	38.51							
29	3/1/2052	67.32	40.96							
30	4/1/2052	64.81	39.43							
31	5/1/2052	66.63	40.54							
32	6/1/2052	64.15	39.03							
33	7/1/2052	65.94	40.12							
34	8/1/2052	65.60	39.91							
35	9/1/2052	63.15	38.42							
36	10/1/2052	64.92	39.50							
37	11/1/2052	62.50	38.03							
38	12/1/2052	64.26	39.09							
39	1/1/2053	63.92	38.89							
40	2/1/2053	57.45	34.95							
41	3/1/2053	63.28	38.50							
42	4/1/2053	60.93	37.07							
43	5/1/2053	62.63	38.11							
44	6/1/2053	60.30	36.69							

1 # Woodford Project PUD

2 ## Monthly Cash Flows

3

	A	B	C	D	E	F	G	H	I	J
4-5	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	7/1/2053	61.99	37.71	[redacted]						
7	8/1/2053	61.66	37.52							
8	9/1/2053	59.37	36.12							
9	10/1/2053	61.03	37.13							
10	11/1/2053	58.76	35.75							
11	12/1/2053	60.40	36.75							
12	1/1/2054	60.09	36.56							
13	2/1/2054	54.00	32.85							
14	3/1/2054	59.49	36.19							
15	4/1/2054	57.27	34.84							
16	5/1/2054	58.88	35.82							
17	6/1/2054	56.68	34.49							
18	7/1/2054	58.27	35.45							
19	8/1/2054	57.97	35.27							
20	9/1/2054	55.81	33.95							
21	10/1/2054	57.37	34.90							
22	11/1/2054	55.23	33.60							
23	12/1/2054	56.78	34.55							
24	1/1/2055	56.48	34.36							
25	2/1/2055	50.76	30.88							
26	3/1/2055	55.92	34.02							
27	4/1/2055	53.84	32.76							
28	5/1/2055	55.35	33.67							
29	6/1/2055	53.29	32.42							
30	7/1/2055	54.78	33.33							
31	8/1/2055	54.49	33.15							
32	9/1/2055	52.46	31.92							
33	10/1/2055	53.93	32.81							
34	11/1/2055	51.92	31.59							
35	12/1/2055	53.38	32.47							
36	1/1/2056	53.10	32.30							
37	2/1/2056	49.42	30.07							
38	3/1/2056	52.56	31.98							
39	4/1/2056	50.60	30.79							
40	5/1/2056	52.02	31.65							
41	6/1/2056	50.08	30.47							
42	7/1/2056	51.48	31.32							
43	8/1/2056	51.22	31.16							
44	9/1/2056	49.31	30.00							

Woodford Project PUD

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Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2056	50.69	30.84	[redacted]						
11/1/2056	48.80	29.69	[redacted]						
12/1/2056	50.17	30.52	[redacted]						
1/1/2057	49.90	30.36	[redacted]						
2/1/2057	44.85	27.29	[redacted]						
3/1/2057	49.41	30.06	[redacted]						
4/1/2057	47.57	28.94	[redacted]						
5/1/2057	48.90	29.75	[redacted]						
6/1/2057	47.08	28.64	[redacted]						
7/1/2057	48.40	29.45	[redacted]						
8/1/2057	48.14	29.29	[redacted]						
9/1/2057	46.35	28.20	[redacted]						
10/1/2057	47.65	28.99	[redacted]						
11/1/2057	45.87	27.91	[redacted]						
12/1/2057	47.16	28.69	[redacted]						
1/1/2058	46.91	28.54	[redacted]						
2/1/2058	42.16	25.65	[redacted]						
3/1/2058	46.45	28.26	[redacted]						
4/1/2058	44.72	27.21	[redacted]						
5/1/2058	45.97	27.97	[redacted]						
6/1/2058	44.26	26.93	[redacted]						
7/1/2058	45.50	27.68	[redacted]						
8/1/2058	45.26	27.53	[redacted]						
9/1/2058	43.57	26.51	[redacted]						
10/1/2058	44.79	27.25	[redacted]						
11/1/2058	43.12	26.24	[redacted]						
12/1/2058	44.33	26.97	[redacted]						
1/1/2059	44.10	26.83	[redacted]						
2/1/2059	39.63	24.11	[redacted]						
3/1/2059	43.66	26.56	[redacted]						
4/1/2059	42.03	25.57	[redacted]						
5/1/2059	43.21	26.29	[redacted]						
6/1/2059	41.60	25.31	[redacted]						
7/1/2059	42.77	26.02	[redacted]						
8/1/2059	42.54	25.88	[redacted]						
9/1/2059	40.96	24.92	[redacted]						
10/1/2059	42.11	25.62	[redacted]						
11/1/2059	40.54	24.66	[redacted]						
12/1/2059	41.67	25.35	[redacted]						

Woodford Project PUD
Monthly Cash Flows

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A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2060	41.46	25.22	[redacted]						
2/1/2060	38.58	23.47							
3/1/2060	41.04	24.97							
4/1/2060	39.51	24.04							
5/1/2060	40.61	24.71							
6/1/2060	39.10	23.79							
7/1/2060	40.20	24.46							
8/1/2060	39.99	24.33							
9/1/2060	38.50	23.42							
10/1/2060	39.58	24.08							
11/1/2060	38.10	23.18							
12/1/2060	39.17	23.83							
1/1/2061	38.96	23.70							
2/1/2061	35.02	21.30							
3/1/2061	38.58	23.47							
4/1/2061	37.14	22.60							
5/1/2061	38.18	23.23							
6/1/2061	36.76	22.36							
7/1/2061	37.79	22.99							
8/1/2061	37.59	22.87							
9/1/2061	36.19	22.02							
10/1/2061	37.20	22.63							
11/1/2061	35.82	21.79							
12/1/2061	36.82	22.40							
1/1/2062	36.63	22.28							
2/1/2062	32.92	20.03							
3/1/2062	36.26	22.06							
4/1/2062	34.91	21.24							
5/1/2062	35.89	21.84							
6/1/2062	34.55	21.02							
7/1/2062	35.52	21.61							
8/1/2062	35.33	21.50							
9/1/2062	34.02	20.70							
10/1/2062	34.97	21.28							
11/1/2062	33.67	20.48							
12/1/2062	34.61	21.06							
1/1/2063	34.43	20.95							
2/1/2063	30.94	18.83							
3/1/2063	34.09	20.74							

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Woodford Project PUD
Monthly Cash Flows

A	B	C	D	E	F	G	H	I	J
Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2063	32.82	19.97	[redacted]						
5/1/2063	33.74	20.53	[redacted]						
6/1/2063	32.48	19.76	[redacted]						
7/1/2063	33.39	20.31	[redacted]						
8/1/2063	33.22	20.21	[redacted]						
9/1/2063	31.98	19.46	[redacted]						
10/1/2063	32.87	20.00	[redacted]						
11/1/2063	31.65	19.26	[redacted]						
12/1/2063	32.54	19.80	[redacted]						
1/1/2064	187.61	114.14	[redacted]						

Woodford Project PROB

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Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2014	0.00	0.00	[redacted]						
8/1/2014	0.00	0.00	[redacted]						
9/1/2014	0.00	0.00	[redacted]						
10/1/2014	0.00	0.00	[redacted]						
11/1/2014	30.42	19.36	[redacted]						
12/1/2014	148.62	94.60	[redacted]						
1/1/2015	273.49	170.73	[redacted]						
2/1/2015	400.41	248.10	[redacted]						
3/1/2015	607.14	375.12	[redacted]						
4/1/2015	767.74	473.79	[redacted]						
5/1/2015	1,003.80	613.74	[redacted]						
6/1/2015	1,029.64	628.96	[redacted]						
7/1/2015	1,126.22	690.24	[redacted]						
8/1/2015	1,367.62	842.65	[redacted]						
9/1/2015	1,235.60	761.27	[redacted]						
10/1/2015	1,198.69	738.51	[redacted]						
11/1/2015	1,094.12	674.07	[redacted]						
12/1/2015	1,077.24	663.59	[redacted]						
1/1/2016	1,112.62	684.51	[redacted]						
2/1/2016	988.93	608.44	[redacted]						
3/1/2016	1,007.83	620.09	[redacted]						
4/1/2016	931.78	573.32	[redacted]						
5/1/2016	922.27	567.49	[redacted]						
6/1/2016	856.85	527.24	[redacted]						
7/1/2016	851.77	524.13	[redacted]						
8/1/2016	820.41	504.84	[redacted]						
9/1/2016	766.44	471.64	[redacted]						
10/1/2016	765.71	471.20	[redacted]						
11/1/2016	717.39	441.47	[redacted]						
12/1/2016	718.60	442.22	[redacted]						
1/1/2017	697.05	428.96	[redacted]						
2/1/2017	612.24	376.77	[redacted]						
3/1/2017	659.78	406.03	[redacted]						
4/1/2017	621.48	382.47	[redacted]						
5/1/2017	625.63	385.02	[redacted]						
6/1/2017	590.30	363.29	[redacted]						
7/1/2017	595.18	366.29	[redacted]						
8/1/2017	580.93	357.53	[redacted]						
9/1/2017	549.32	338.07	[redacted]						

Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2017	554.99	341.57	[redacted]						
11/1/2017	525.45	323.38							
12/1/2017	531.49	327.11							
1/1/2018	520.37	320.26							
2/1/2018	460.88	283.65							
3/1/2018	500.57	308.08							
4/1/2018	475.13	292.43							
5/1/2018	481.77	296.51							
6/1/2018	457.69	281.69							
7/1/2018	464.47	285.87							
8/1/2018	456.19	280.77							
9/1/2018	433.89	267.05							
10/1/2018	440.82	271.31							
11/1/2018	419.56	258.23							
12/1/2018	426.54	262.53							
1/1/2019	419.67	258.30							
2/1/2019	373.35	229.79							
3/1/2019	407.25	250.65							
4/1/2019	388.20	238.93							
5/1/2019	395.23	243.26							
6/1/2019	376.94	232.00							
7/1/2019	383.96	236.32							
8/1/2019	378.50	232.96							
9/1/2019	361.26	222.35							
10/1/2019	368.25	226.65							
11/1/2019	351.62	216.42							
12/1/2019	358.59	220.71							
1/1/2020	353.89	217.82							
2/1/2020	326.92	201.22							
3/1/2020	345.17	212.45							
4/1/2020	329.91	203.06							
5/1/2020	336.77	207.28							
6/1/2020	322.01	198.20							
7/1/2020	328.81	202.39							
8/1/2020	324.93	199.99							
9/1/2020	310.84	191.32							
10/1/2020	317.57	195.46							
11/1/2020	303.89	187.05							
12/1/2020	310.56	191.15							

Woodford Project PROB

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Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2021	307.13	189.04	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2021	274.53	168.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2021	300.83	185.16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2021	288.08	177.32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2021	294.60	181.33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2021	282.19	173.69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2021	288.66	177.67	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2021	285.73	175.87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2021	273.79	168.52	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2021	280.17	172.45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2021	268.52	165.28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2021	274.84	169.17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2022	272.21	167.55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2022	243.66	149.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2022	267.37	164.57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2022	256.39	157.81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2022	262.55	161.61	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2022	251.82	155.00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2022	257.92	158.76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2022	255.64	157.35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2022	245.26	150.96	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2022	251.27	154.66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2022	241.11	148.41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2022	247.07	152.08	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2023	244.99	150.80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2023	219.53	135.12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2023	241.14	148.43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2023	231.48	142.48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2023	237.29	146.06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2023	227.83	140.23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2023	233.58	143.78	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2023	231.74	142.64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2023	222.55	136.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2023	228.22	140.47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2023	219.19	134.92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2023	224.81	138.38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2024	223.12	137.34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2024	207.22	127.55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2024	219.93	135.37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Woodford Project PROB

Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2024	211.30	130.06	[redacted]						
5/1/2024	216.78	133.44	[redacted]						
6/1/2024	208.30	128.22	[redacted]						
7/1/2024	213.73	131.56	[redacted]						
8/1/2024	212.22	130.63	[redacted]						
9/1/2024	203.96	125.54	[redacted]						
10/1/2024	209.31	128.84	[redacted]						
11/1/2024	201.18	123.84	[redacted]						
12/1/2024	206.49	127.10	[redacted]						
1/1/2025	205.09	126.24	[redacted]						
2/1/2025	184.05	113.29	[redacted]						
3/1/2025	202.47	124.63	[redacted]						
4/1/2025	194.66	119.82	[redacted]						
5/1/2025	199.85	123.01	[redacted]						
6/1/2025	192.16	118.28	[redacted]						
7/1/2025	197.30	121.44	[redacted]						
8/1/2025	196.03	120.66	[redacted]						
9/1/2025	188.51	116.04	[redacted]						
10/1/2025	193.58	119.16	[redacted]						
11/1/2025	186.18	114.60	[redacted]						
12/1/2025	191.20	117.69	[redacted]						
1/1/2026	190.02	116.96	[redacted]						
2/1/2026	170.62	105.03	[redacted]						
3/1/2026	187.81	115.60	[redacted]						
4/1/2026	180.66	111.21	[redacted]						
5/1/2026	185.58	114.23	[redacted]						
6/1/2026	178.54	109.90	[redacted]						
7/1/2026	183.41	112.90	[redacted]						
8/1/2026	182.33	112.23	[redacted]						
9/1/2026	175.43	107.98	[redacted]						
10/1/2026	180.24	110.94	[redacted]						
11/1/2026	173.43	106.76	[redacted]						
12/1/2026	178.20	109.69	[redacted]						
1/1/2027	177.19	109.07	[redacted]						
2/1/2027	159.18	97.98	[redacted]						
3/1/2027	175.29	107.90	[redacted]						
4/1/2027	168.70	103.84	[redacted]						
5/1/2027	173.38	106.72	[redacted]						
6/1/2027	166.87	102.72	[redacted]						

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Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2027	171.50	105.57	[redacted]						
8/1/2027	170.57	104.99							
9/1/2027	164.19	101.07							
10/1/2027	168.77	103.88							
11/1/2027	162.46	100.00							
12/1/2027	167.00	102.80							
1/1/2028	166.11	102.25							
2/1/2028	154.60	95.16							
3/1/2028	164.42	101.21							
4/1/2028	158.30	97.44							
5/1/2028	162.73	100.17							
6/1/2028	156.67	96.43							
7/1/2028	161.05	99.13							
8/1/2028	160.21	98.61							
9/1/2028	154.24	94.94							
10/1/2028	158.56	97.60							
11/1/2028	152.65	93.97							
12/1/2028	156.93	96.60							
1/1/2029	156.11	96.09							
2/1/2029	140.30	86.36							
3/1/2029	154.56	95.14							
4/1/2029	148.80	91.59							
5/1/2029	152.97	94.16							
6/1/2029	147.27	90.65							
7/1/2029	151.39	93.19							
8/1/2029	150.60	92.70							
9/1/2029	144.99	89.25							
10/1/2029	149.05	91.75							
11/1/2029	143.50	88.33							
12/1/2029	147.52	90.81							
1/1/2030	146.75	90.33							
2/1/2030	131.89	81.18							
3/1/2030	145.29	89.43							
4/1/2030	139.88	86.10							
5/1/2030	143.79	88.51							
6/1/2030	138.44	85.22							
7/1/2030	142.32	87.60							
8/1/2030	141.57	87.14							
9/1/2030	136.30	83.90							

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Woodford Project PROB

Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2030	140.12	86.25	[redacted]						
11/1/2030	134.90	83.03							
12/1/2030	138.67	85.36							
1/1/2031	137.95	84.91							
2/1/2031	123.98	76.31							
3/1/2031	136.58	84.07							
4/1/2031	131.49	80.94							
5/1/2031	135.17	83.20							
6/1/2031	130.14	80.11							
7/1/2031	133.78	82.35							
8/1/2031	133.08	81.92							
9/1/2031	128.13	78.87							
10/1/2031	131.71	81.08							
11/1/2031	126.81	78.06							
12/1/2031	130.36	80.24							
1/1/2032	129.68	79.82							
2/1/2032	120.70	74.29							
3/1/2032	128.37	79.01							
4/1/2032	123.58	76.07							
5/1/2032	127.05	78.20							
6/1/2032	122.31	75.29							
7/1/2032	125.74	77.40							
8/1/2032	125.08	76.99							
9/1/2032	120.42	74.13							
10/1/2032	123.80	76.20							
11/1/2032	119.18	73.36							
12/1/2032	122.52	75.42							
1/1/2033	121.88	75.02							
2/1/2033	109.54	67.42							
3/1/2033	120.67	74.28							
4/1/2033	116.17	71.51							
5/1/2033	119.43	73.51							
6/1/2033	114.98	70.78							
7/1/2033	118.20	72.76							
8/1/2033	117.58	72.38							
9/1/2033	113.20	69.68							
10/1/2033	116.37	71.63							
11/1/2033	112.04	68.96							
12/1/2033	115.18	70.90							

Woodford Project PROB

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Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2034	114.57	70.52	[redacted]						
2/1/2034	102.97	63.38	[redacted]						
3/1/2034	113.43	69.82	[redacted]						
4/1/2034	109.21	67.22	[redacted]						
5/1/2034	112.27	69.11	[redacted]						
6/1/2034	108.09	66.53	[redacted]						
7/1/2034	111.11	68.40	[redacted]						
8/1/2034	110.53	68.04	[redacted]						
9/1/2034	106.41	65.50	[redacted]						
10/1/2034	109.39	67.34	[redacted]						
11/1/2034	105.32	64.83	[redacted]						
12/1/2034	108.27	66.65	[redacted]						
1/1/2035	107.70	66.30	[redacted]						
2/1/2035	96.80	59.58	[redacted]						
3/1/2035	106.63	65.64	[redacted]						
4/1/2035	102.66	63.19	[redacted]						
5/1/2035	105.54	64.96	[redacted]						
6/1/2035	101.61	62.54	[redacted]						
7/1/2035	104.45	64.29	[redacted]						
8/1/2035	103.90	63.96	[redacted]						
9/1/2035	100.03	61.58	[redacted]						
10/1/2035	102.84	63.30	[redacted]						
11/1/2035	99.01	60.94	[redacted]						
12/1/2035	101.78	62.65	[redacted]						
1/1/2036	101.25	62.32	[redacted]						
2/1/2036	94.23	58.00	[redacted]						
3/1/2036	100.22	61.69	[redacted]						
4/1/2036	96.49	59.39	[redacted]						
5/1/2036	99.19	61.06	[redacted]						
6/1/2036	95.50	58.78	[redacted]						
7/1/2036	98.17	60.43	[redacted]						
8/1/2036	97.66	60.11	[redacted]						
9/1/2036	94.02	57.87	[redacted]						
10/1/2036	96.65	59.49	[redacted]						
11/1/2036	93.05	57.28	[redacted]						
12/1/2036	95.66	58.88	[redacted]						
1/1/2037	95.16	58.57	[redacted]						
2/1/2037	85.52	52.64	[redacted]						
3/1/2037	94.21	57.99	[redacted]						

Woodford Project PROB

Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2037	90.70	55.83	[redacted]						
5/1/2037	93.24	57.40							
6/1/2037	89.77	55.26							
7/1/2037	92.28	56.81							
8/1/2037	91.80	56.51							
9/1/2037	88.38	54.40							
10/1/2037	90.86	55.93							
11/1/2037	87.47	53.84							
12/1/2037	89.92	55.35							
1/1/2038	89.45	55.06							
2/1/2038	80.39	49.49							
3/1/2038	88.56	54.51							
4/1/2038	85.26	52.48							
5/1/2038	87.65	53.95							
6/1/2038	84.39	51.94							
7/1/2038	86.75	53.40							
8/1/2038	86.30	53.12							
9/1/2038	83.08	51.14							
10/1/2038	85.41	52.57							
11/1/2038	82.23	50.62							
12/1/2038	84.53	52.03							
1/1/2039	84.09	51.76							
2/1/2039	75.57	46.52							
3/1/2039	83.25	51.25							
4/1/2039	80.15	49.34							
5/1/2039	82.40	50.72							
6/1/2039	79.33	48.83							
7/1/2039	81.55	50.20							
8/1/2039	81.12	49.93							
9/1/2039	78.10	48.07							
10/1/2039	80.29	49.42							
11/1/2039	77.30	47.58							
12/1/2039	79.46	48.91							
1/1/2040	79.05	48.66							
2/1/2040	73.57	45.29							
3/1/2040	78.25	48.16							
4/1/2040	75.33	46.37							
5/1/2040	77.44	47.67							
6/1/2040	74.56	45.89							

Woodford Project PROB

Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2040	76.65	47.18	[redacted]						
8/1/2040	76.25	46.93	[redacted]						
9/1/2040	73.41	45.18	[redacted]						
10/1/2040	75.46	46.45	[redacted]						
11/1/2040	72.65	44.72	[redacted]						
12/1/2040	74.69	45.97	[redacted]						
1/1/2041	74.29	45.73	[redacted]						
2/1/2041	66.77	41.10	[redacted]						
3/1/2041	73.56	45.28	[redacted]						
4/1/2041	70.82	43.59	[redacted]						
5/1/2041	72.80	44.81	[redacted]						
6/1/2041	70.09	43.14	[redacted]						
7/1/2041	72.05	44.35	[redacted]						
8/1/2041	71.67	44.12	[redacted]						
9/1/2041	69.00	42.48	[redacted]						
10/1/2041	70.94	43.66	[redacted]						
11/1/2041	68.30	42.04	[redacted]						
12/1/2041	70.21	43.22	[redacted]						
1/1/2042	69.84	42.99	[redacted]						
2/1/2042	62.77	38.64	[redacted]						
3/1/2042	69.15	42.56	[redacted]						
4/1/2042	66.57	40.98	[redacted]						
5/1/2042	68.43	42.12	[redacted]						
6/1/2042	65.89	40.56	[redacted]						
7/1/2042	67.73	41.69	[redacted]						
8/1/2042	67.38	41.47	[redacted]						
9/1/2042	64.87	39.93	[redacted]						
10/1/2042	66.68	41.05	[redacted]						
11/1/2042	64.20	39.52	[redacted]						
12/1/2042	66.00	40.62	[redacted]						
1/1/2043	65.65	40.41	[redacted]						
2/1/2043	59.00	36.32	[redacted]						
3/1/2043	65.00	40.01	[redacted]						
4/1/2043	62.58	38.52	[redacted]						
5/1/2043	64.33	39.60	[redacted]						
6/1/2043	61.94	38.12	[redacted]						
7/1/2043	63.67	39.19	[redacted]						
8/1/2043	63.34	38.99	[redacted]						
9/1/2043	60.98	37.53	[redacted]						

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1 # Woodford Project PROB
2 ## Monthly Cash Flows
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	Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
6	10/1/2043	62.69	38.59	[redacted]						
7	11/1/2043	60.35	37.15							
8	12/1/2043	62.04	38.19							
9	1/1/2044	61.72	37.99							
10	2/1/2044	57.44	35.36							
11	3/1/2044	61.09	37.60							
12	4/1/2044	58.82	36.20							
13	5/1/2044	60.46	37.22							
14	6/1/2044	58.21	35.83							
15	7/1/2044	59.84	36.84							
16	8/1/2044	59.53	36.64							
17	9/1/2044	57.31	35.28							
18	10/1/2044	58.92	36.27							
19	11/1/2044	56.72	34.92							
20	12/1/2044	58.31	35.89							
21	1/1/2045	58.01	35.70							
22	2/1/2045	52.13	32.09							
23	3/1/2045	57.43	35.35							
24	4/1/2045	55.29	34.03							
25	5/1/2045	56.84	34.99							
26	6/1/2045	54.72	33.68							
27	7/1/2045	56.25	34.63							
28	8/1/2045	55.96	34.45							
29	9/1/2045	53.88	33.16							
30	10/1/2045	55.38	34.09							
31	11/1/2045	53.32	32.82							
32	12/1/2045	54.81	33.74							
33	1/1/2046	54.53	33.56							
34	2/1/2046	49.01	30.16							
35	3/1/2046	53.99	33.23							
36	4/1/2046	51.97	31.99							
37	5/1/2046	53.43	32.89							
38	6/1/2046	51.44	31.66							
39	7/1/2046	52.88	32.55							
40	8/1/2046	52.60	32.38							
41	9/1/2046	50.64	31.17							
42	10/1/2046	52.06	32.05							
43	11/1/2046	50.12	30.85							
44	12/1/2046	51.53	31.72							

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Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2047	51.26	31.55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2047	46.07	28.36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2047	50.75	31.24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2047	48.86	30.07	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2047	50.23	30.92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2047	48.36	29.77	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2047	49.71	30.60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2047	49.45	30.44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2047	47.61	29.30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2047	48.94	30.13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2047	47.12	29.00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2047	48.44	29.82	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2048	48.18	29.66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2048	44.85	27.61	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2048	47.70	29.36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2048	45.92	28.27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2048	47.21	29.06	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2048	45.45	27.98	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2048	46.72	28.76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2048	46.48	28.61	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2048	44.75	27.54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2048	46.00	28.31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2048	44.29	27.26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2048	45.53	28.02	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2049	45.29	27.88	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2049	40.70	25.05	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2049	44.84	27.60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4/1/2049	43.17	26.57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5/1/2049	44.38	27.32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6/1/2049	42.72	26.30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7/1/2049	43.92	27.03	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8/1/2049	43.69	26.89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9/1/2049	42.06	25.89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10/1/2049	43.24	26.62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11/1/2049	41.63	25.63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12/1/2049	42.80	26.34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1/1/2050	42.57	26.21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2/1/2050	38.26	23.55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3/1/2050	42.15	25.94	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2050	40.58	24.98	[redacted]						
5/1/2050	41.72	25.68							
6/1/2050	40.16	24.72							
7/1/2050	41.29	25.41							
8/1/2050	41.07	25.28							
9/1/2050	39.54	24.34							
10/1/2050	40.65	25.02							
11/1/2050	39.13	24.09							
12/1/2050	40.23	24.76							
1/1/2051	40.02	24.63							
2/1/2051	35.97	22.14							
3/1/2051	39.62	24.39							
4/1/2051	38.15	23.48							
5/1/2051	39.21	24.14							
6/1/2051	37.75	23.24							
7/1/2051	38.81	23.89							
8/1/2051	38.61	23.76							
9/1/2051	37.17	22.88							
10/1/2051	38.21	23.52							
11/1/2051	36.79	22.64							
12/1/2051	37.82	23.28							
1/1/2052	37.62	23.16							
2/1/2052	35.01	21.55							
3/1/2052	37.24	22.92							
4/1/2052	35.85	22.07							
5/1/2052	36.86	22.69							
6/1/2052	35.48	21.84							
7/1/2052	36.48	22.45							
8/1/2052	36.29	22.34							
9/1/2052	34.94	21.50							
10/1/2052	35.91	22.11							
11/1/2052	34.58	21.28							
12/1/2052	35.54	21.88							
1/1/2053	35.36	21.76							
2/1/2053	31.78	19.56							
3/1/2053	35.01	21.55							
4/1/2053	33.70	20.75							
5/1/2053	34.65	21.33							
6/1/2053	33.36	20.53							

Woodford Project PROB

Monthly Cash Flows

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Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
7/1/2053	34.29	21.11	[redacted]						
8/1/2053	34.11	21.00							
9/1/2053	32.84	20.21							
10/1/2053	33.76	20.78							
11/1/2053	32.50	20.01							
12/1/2053	33.41	20.57							
1/1/2054	33.24	20.46							
2/1/2054	29.87	18.39							
3/1/2054	32.91	20.26							
4/1/2054	31.68	19.50							
5/1/2054	32.57	20.05							
6/1/2054	31.36	19.30							
7/1/2054	32.23	19.84							
8/1/2054	32.07	19.74							
9/1/2054	30.87	19.00							
10/1/2054	31.74	19.53							
11/1/2054	30.55	18.81							
12/1/2054	31.41	19.33							
1/1/2055	31.25	19.23							
2/1/2055	28.08	17.29							
3/1/2055	30.93	19.04							
4/1/2055	29.78	18.33							
5/1/2055	30.62	18.85							
6/1/2055	29.48	18.14							
7/1/2055	30.30	18.65							
8/1/2055	30.14	18.55							
9/1/2055	29.02	17.86							
10/1/2055	29.83	18.36							
11/1/2055	28.72	17.68							
12/1/2055	29.53	18.17							
1/1/2056	29.37	18.08							
2/1/2056	27.34	16.83							
3/1/2056	29.07	17.90							
4/1/2056	27.99	17.23							
5/1/2056	28.78	17.71							
6/1/2056	27.70	17.05							
7/1/2056	28.48	17.53							
8/1/2056	28.33	17.44							
9/1/2056	27.28	16.79							

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Woodford Project PROB
Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
10/1/2056	28.04	17.26	[redacted]						
11/1/2056	27.00	16.62	[redacted]						
12/1/2056	27.75	17.08	[redacted]						
1/1/2057	27.61	16.99	[redacted]						
2/1/2057	24.81	15.27	[redacted]						
3/1/2057	27.33	16.82	[redacted]						
4/1/2057	26.31	16.20	[redacted]						
5/1/2057	27.05	16.65	[redacted]						
6/1/2057	26.04	16.03	[redacted]						
7/1/2057	26.77	16.48	[redacted]						
8/1/2057	26.63	16.39	[redacted]						
9/1/2057	25.64	15.78	[redacted]						
10/1/2057	26.36	16.22	[redacted]						
11/1/2057	25.38	15.62	[redacted]						
12/1/2057	26.09	16.06	[redacted]						
1/1/2058	25.95	15.97	[redacted]						
2/1/2058	23.32	14.36	[redacted]						
3/1/2058	25.69	15.81	[redacted]						
4/1/2058	24.74	15.23	[redacted]						
5/1/2058	25.43	15.65	[redacted]						
6/1/2058	24.48	15.07	[redacted]						
7/1/2058	25.17	15.49	[redacted]						
8/1/2058	25.04	15.41	[redacted]						
9/1/2058	24.10	14.84	[redacted]						
10/1/2058	24.78	15.25	[redacted]						
11/1/2058	23.86	14.68	[redacted]						
12/1/2058	24.52	15.10	[redacted]						
1/1/2059	24.39	15.02	[redacted]						
2/1/2059	21.92	13.50	[redacted]						
3/1/2059	24.15	14.87	[redacted]						
4/1/2059	23.25	14.31	[redacted]						
5/1/2059	23.90	14.71	[redacted]						
6/1/2059	23.01	14.17	[redacted]						
7/1/2059	23.66	14.56	[redacted]						
8/1/2059	23.53	14.49	[redacted]						
9/1/2059	22.66	13.95	[redacted]						
10/1/2059	23.29	14.34	[redacted]						
11/1/2059	22.42	13.80	[redacted]						
12/1/2059	23.05	14.19	[redacted]						

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Woodford Project PROB

Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
1/1/2060	22.93	14.12	[redacted]						
2/1/2060	21.34	13.14							
3/1/2060	22.70	13.97							
4/1/2060	21.85	13.45							
5/1/2060	22.47	13.83							
6/1/2060	21.63	13.31							
7/1/2060	22.24	13.69							
8/1/2060	22.12	13.62							
9/1/2060	21.30	13.11							
10/1/2060	21.89	13.48							
11/1/2060	21.08	12.97							
12/1/2060	21.67	13.34							
1/1/2061	21.55	13.27							
2/1/2061	19.37	11.92							
3/1/2061	21.34	13.14							
4/1/2061	20.54	12.65							
5/1/2061	21.12	13.00							
6/1/2061	20.33	12.52							
7/1/2061	20.90	12.87							
8/1/2061	20.79	12.80							
9/1/2061	20.02	12.32							
10/1/2061	20.58	12.67							
11/1/2061	19.81	12.20							
12/1/2061	20.37	12.54							
1/1/2062	20.26	12.47							
2/1/2062	18.21	11.21							
3/1/2062	20.06	12.35							
4/1/2062	19.31	11.89							
5/1/2062	19.85	12.22							
6/1/2062	19.11	11.77							
7/1/2062	19.65	12.09							
8/1/2062	19.55	12.03							
9/1/2062	18.82	11.58							
10/1/2062	19.35	11.91							
11/1/2062	18.62	11.46							
12/1/2062	19.15	11.79							
1/1/2063	19.05	11.72							
2/1/2063	17.12	10.54							
3/1/2063	18.86	11.61							

Woodford Project PROB

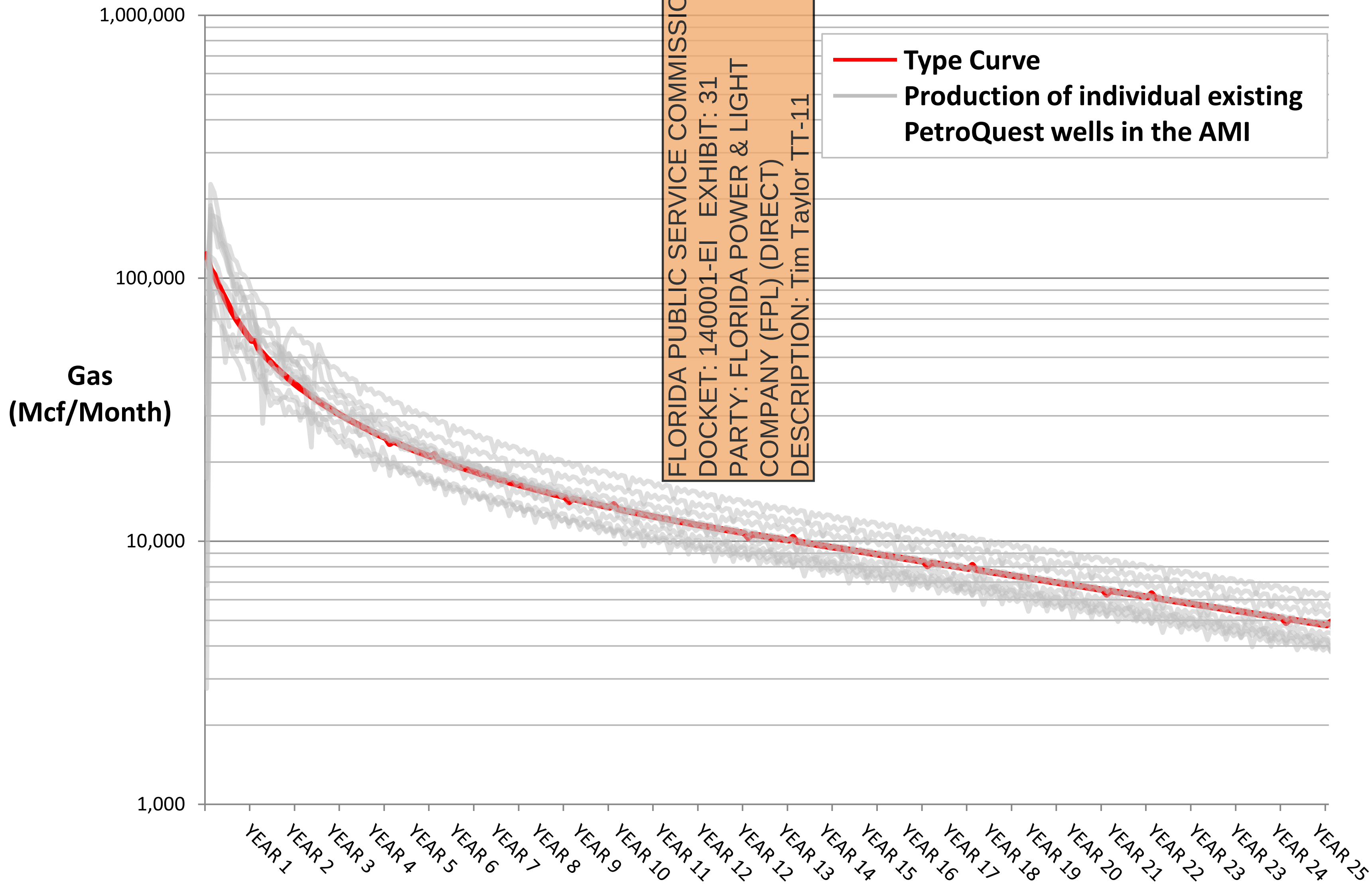
CONFIDENTIAL

Monthly Cash Flows

Year	Gas Gross (MMcf)	Gas Net (MMcf)	Gas Price ($/Mcf)	Oil & Gas Rev. Net (M$)	Costs Net (M$)	Taxes Net (M$)	Invest. Net (M$)	NonDisc. CF Annual (M$)	Cum Disc. CF Annual (M$)
4/1/2063	18.15	11.17	[redacted]						
5/1/2063	18.66	11.49							
6/1/2063	17.97	11.06							
7/1/2063	18.47	11.37							
8/1/2063	18.37	11.31							
9/1/2063	17.69	10.89							
10/1/2063	18.19	11.19							
11/1/2063	17.51	10.78							
12/1/2063	18.00	11.08							
1/1/2064	103.78	63.88							

Exhibit TT-10
Forrest A. Garb & Associates Report
Pages 1 - 30
IS CONFIDENTIAL IN ITS ENTIRETY

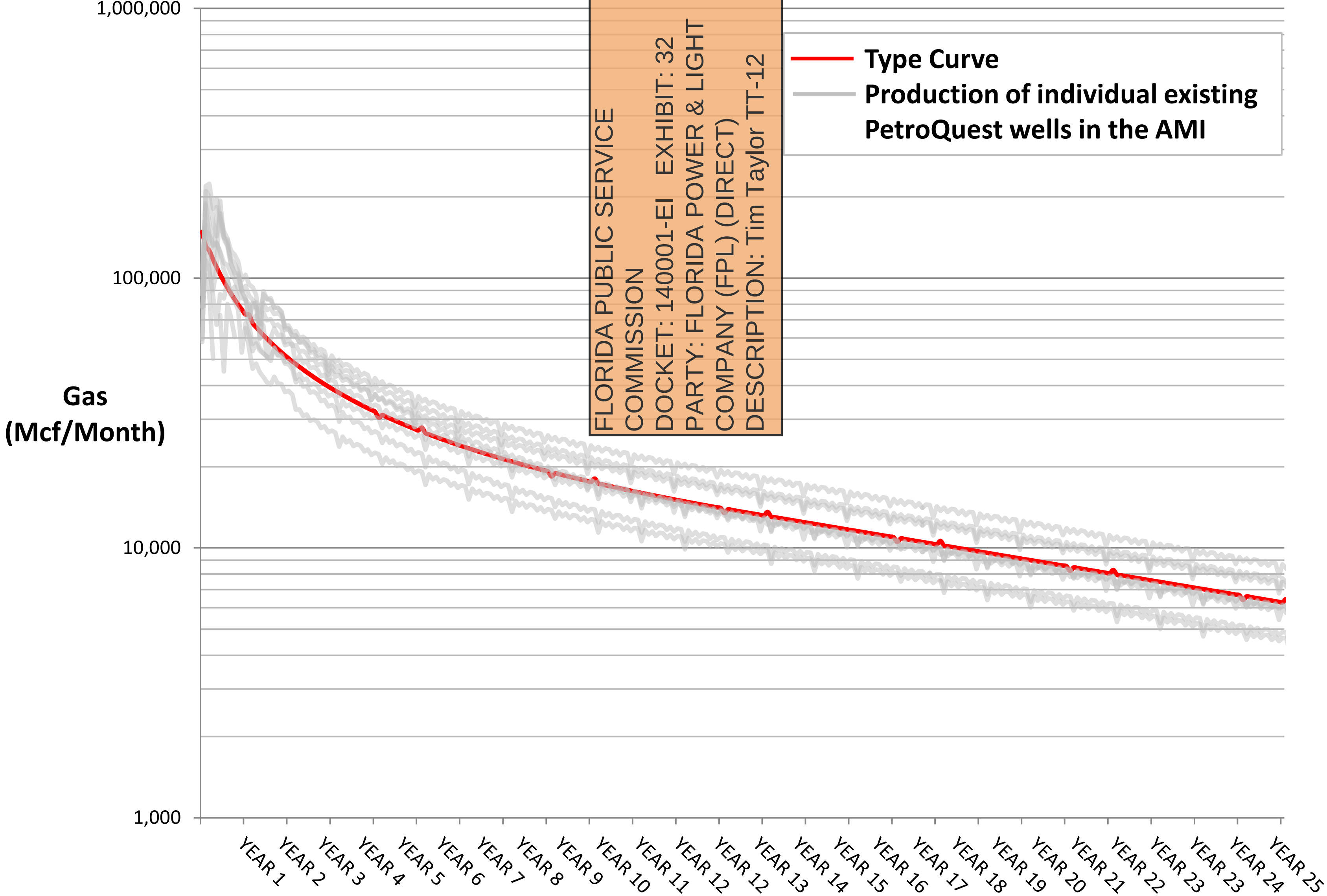
Exhibit TT-11: Type Curve 1 (Western): 5.3 Bcf Estimated Ultimate Recovery (EUR)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 31
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-11

Docket No. 140001-EI
Type Curve 1 (Western): 5.3 Bcf Estimated Ultimate Recovery (EUR)
Exhibit TT-11, Page 1 of 1

Exhibit TT-12: Type Curve 2 (Eastern): 7.4 Bcf Estimated Ultimate Recovery (EUR)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 32
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Tim Taylor TT-12

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 33
PARTY: FLORIDA POWER & LIGHT COMPANY (FPL) (DIRECT)
DESCRIPTION: Terry Deason JTD-1

Terry Deason*

Special Consultant (Non-Lawyer)*
Phone: (850) 425-6654
Fax: (850) 425-6694
E-Mail: tdeason@radeylaw.com

Practice Areas:

- Energy, Telecommunications, Water and Wastewater and Public Utilities

Education:
- United States Military Academy at West Point, 1972
- Florida State University, B.S., 1975, Accounting, summa cum laude
- Florida State University, Master of Accounting, 1989

Professional Experiences:
- The Radey Law Firm, Special Consultant, 2007 - Present
- Florida Public Service Commission, Commissioner, 1991 – 2007
- Florida Public Service Commission, Chairman, 1993 – 1995, 2000 – 2001
- Office of the Public Counsel, Chief Regulatory Analyst, 1987 – 1991
- Florida Public Service Commission, Executive Assistant to the Commissioner, 1981 – 1987
- Office of the Public Counsel, Legislative Analyst II and III, 1979 - 1981
- Ben Johnson Associates, Inc., Research Analyst, 1978 – 1979
- Office of the Public Counsel, Legislative Analyst I, 1977 – 1978
- Quincy State Bank Trust Department, Staff Accountant and Trust Assistant, 1976 - 1977

Professional Associations and Memberships:
- National Association of Regulatory Utility Commissioners (NARUC), 1993 – 1998, *Member, Executive Committee*
- National Association of Regulatory Utility Commissioners (NARUC), 1999 – 2006, *Board of Directors*

RADEY
ATTORNEYS & COUNSELORS at LAW

Terry Deason*

- National Association of Regulatory Utility Commissioners (NARUC), 2005-2006, *Member, Committee on Electricity*
- National Association of Regulatory Utility Commissioners (NARUC), 2004 – 2005, *Member, Committee on Telecommunications*
- National Association of Regulatory Utility Commissioners (NARUC), 1991 – 2004, *Member, Committee on Finance and Technology*
- National Association of Regulatory Utility Commissioners (NARUC), 1995 – 1998, *Member, Committee on Utility Association Oversight*
- National Association of Regulatory Utility Commissioners (NARUC) 2002 *Member, Rights-of-Way Study*
- Nuclear Waste Strategy Coalition, 2000 – 2006, *Board Member*
- Federal Energy Regulatory Commission (FERC) South Joint Board on Security Constrained Economic Dispatch, 2005 – 2006, *Member*
- Southeastern Association of Regulatory Utility Commissioners, 1991 – 2006, *Member*
- Florida Energy 20/20 Study Commission, 2000 – 2001, *Member*
- FCC Federal/State Joint Conference on Accounting, 2003 – 2005, *Member*
- Joint NARUC/Department of Energy Study Commission on Tax and Rate Treatment of Renewable Energy Projects, 1993, *Member*
- Bonbright Utilities Center at the University of Georgia, 2001, *Bonbright Distinguished Service Award Recipient*
- Eastern NARUC Utility Rate School - Faculty Member

RADEY
ATTORNEYS & COUNSELORS at LAW

EXHIBIT DMR-1
QUALIFICATIONS OF DONNA RAMAS

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant, licensed in the State of Michigan, and a senior regulatory consultant and Principal of the firm Ramas Regulatory Consulting, LLC, located in Commerce Township, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated with honors from Oakland University in Rochester, Michigan in 1991. From 1991 through October 2012, I was employed by the firm of Larkin & Associates, PLLC. In November 2012, I formed Ramas Regulatory Consulting, LLC. As a certified public accountant and regulatory consultant, I have analyzed utility rate cases and regulatory issues, researched accounting and regulatory developments, prepared computer models and spreadsheets, prepared testimony and schedules and testified in regulatory proceedings. While employed by Larkin & Associates, PLLC, I also developed and conducted five training programs on behalf of the Department of Defense - Navy Rate Intervention Office on measuring the financial capabilities of firms bidding on Navy assets and one training program on calculating the revenue requirement for municipal owned water and wastewater utilities. Additionally, I have served as an instructor at the Michigan State University - Institute of Public Utilities as part of their Annual Regulatory Studies programs, Advanced Regulatory Studies Program, and in a Basics of Utility Regulation and Ratemaking course.

I have prepared and submitted expert testimony and/or testified in the following cases, many of which were filed under the name of Donna DeRonne:

Arizona: Ms. Ramas prepared testimony on behalf of the Staff of the Arizona Corporation Commission in the following case before the Arizona Corporation Commission: Southwest Gas Corporation (Docket No. G-01551A-00-0309).

California: Ms. Ramas prepared testimony on behalf of the Division of Ratepayer Advocates of the California Public Utilities Commission in the following cases before the California Public Utilities Commission:

San Gabriel Valley Water Company, Fontana Water Division (Docket No. A.05-08-021), Request for Order Authorizing the Sale by Thames GmbH of up to 100% of the Common Stock of American Water Works Company, Inc., Resulting in Change of Control of California-American Water Company (Application 06-05-025), California Water Services Company (Docket No. 07-07-001*), Golden State Water Company (Docket No. 08-07-010), and Golden State Water Company (Docket No. 11-07-017*), Golden State Water Company – Rehearing (Docket No. 08-07-010*), and California Water Services Company (Docket No. 12-07-007*).

Ms. Ramas also prepared testimony on behalf of the Department of Defense in the following cases before the California Public Utilities Commission: San Diego Gas and Electric Company (Docket No. 98-07-006) and Southern California Edison Company and San Diego Gas & Electric Company (Docket No. 05-11-008*).

Additionally, Ms. Ramas prepared testimony on behalf of the City of Fontana in the following rate cases before the California Public Utilities Commission: San Gabriel Valley Water Company, Fontana Water Division (Docket No. A.08-07-009) - Phases 1 and 2; San Gabriel Valley Water Company, Los Angeles Division (Docket No. A.10-07-019*), and San Gabriel Valley Water Company, Fontana Water Division (Docket No. A.11-07-005).

Ms. Ramas also prepared testimony on behalf of The Utilities Reform Network in the following rate case before the California Public Utilities Commission: California American Water Company (Docket No. 10-07-007).

Connecticut: Ms. Ramas has prepared testimony on behalf of the Connecticut Office of Consumers Counsel in the following cases before the State of Connecticut, Department of Public Utility Control:

Connecticut Light & Power Company (Docket No. 92-11-11), Connecticut Natural Gas Corporation (Docket No. 93-02-04), Connecticut Natural Gas Corporation (Docket No. 95-02-07), Southern Connecticut Gas Company (Docket No. 97-12-21), Connecticut Light & Power Company (Docket No. 98-01-02), Southern Connecticut Gas Company (Docket No. 99-04-18 Phase I), Southern Connecticut Gas Company (Docket No. 99-04-18 Phase II), Connecticut Natural Gas Corporation (Docket No. 99-09-03 Phase I), Connecticut Natural Gas Corporation (Docket No. 99-09-03 Phase II), Connecticut Light & Power Company (Docket No. 00-12-01), Yankee Gas Services Company (Docket No. 01-05-19), United Illuminating Company (Docket No. 01-10-10), Connecticut Light & Power Company (Docket No. 03-07-02), Southern Connecticut Gas Company (Docket No. 03-11-20), Yankee Gas Services Company (Docket No. 04-06-01*), The Southern Connecticut Gas Company (Docket No. 05-03-17PH01), The United

Illuminating Company (Docket No. 05-06-04), Connecticut Natural Gas Corporation (Docket No. 06-03-04* Phase I), Yankee Gas Services Company (Docket No. 06-12-02PH01*), Aquarion Water Company of Connecticut (Docket No. 07-05-19), Connecticut Light & Power Company (Docket No. 07-07-01), The United Illuminating Company (Docket No. 08-07-04), Connecticut Light & Power Company (Docket No. 09-12-05), and Yankee Gas Services Company (Docket No. 10-12-02).

Ms. Ramas also assisted the Connecticut Office of Consumer Counsel by conducting cross-examination of utility witnesses in the following cases: Southern Connecticut Gas Company (Docket No. 08-12-07), Connecticut Natural Gas Corporation (Docket No. 08-12-06), UIL Holdings Corporation and Iberdrola USA, Inc. (Docket No. 10-07-09), and Northeast Utilities/NSTAR Merger (Docket No. 12-01-07).

Ms. Ramas also assisted the Connecticut Public Utility Regulatory Authority staff in the following cases for which testimony was not provided. As part of the assistance, Ms. Ramas conducted cross examination on behalf of staff: Connecticut Light & Power Company Major Storm case (Docket No. 13-03-23).

District of Columbia: Ms. Ramas prepared testimony on behalf of the Office of the People's Counsel of the District of Columbia in the following case before the Public Service Commission of the District of Columbia: Washington Gas Light Company (Formal Case No. 1054*), Potomac Electric Power Company (Formal Case No. 1076), Potomac Electric Power Company (Formal Case No. 1087), Washington Gas Light Company (Formal Case No. 1093), and Potomac Electric Power Company (Formal Case No. 1103).

Florida: Ms. Ramas prepared testimony on behalf of the Florida Office of Public Counsel in the following cases before the Florida Public Service Commission:

Southern States Utilities (Docket No. 950495-WS), United Water Florida (Docket No. 960451-WS), Aloha Utilities, Inc. – Seven Springs Water Division (Docket No. 010503-WU), Florida Power Corporation (Docket No. 000824-EI*), Florida Power & Light Company (Docket No. 001148-EI**), Tampa Electric Company d/b/a Peoples Gas System (Docket No. 020384-GU*), The Woodlands of Lake Placid, L.P. (Docket No. 020010-WS), Utilities, Inc. of Florida (Docket No. 020071-WS), Florida Public Utilities Company (Docket No. 030438-EI*), The Woodlands of Lake Placid, L.P. (Docket No. 030102-WS), Florida Power & Light Company (Docket No. 050045-EI*), Progress Energy Florida, Inc. (Docket No. 050078-EI*), Florida Power & Light Company (Docket No. 060038-EI), Water Management Services, Inc. (Docket No. 100104-WU), Gulf Power Company (Docket No. 110138-EI), Florida Power & Light Company (Docket No. 120015-EI), Tampa Electric Company (Docket No. 130040-EI*), and Florida Public Utilities Company (Docket No. 140025-EI*).

Illinois: Ms. Ramas prepared testimony on behalf of the Illinois Office of the Attorney General, Apple Canyon Lake Property Owners Association and Lake Wildwood Association, Inc. in the following cases before the Illinois Commerce Commission: Apple Canyon Utility Company (Docket No. 12-0603) and Lake Wildwood Utilities Corporation (Docket No. 12-0604).

Louisiana: Ms. Ramas prepared testimony on behalf of various consumers in the following case before the Louisiana Public Service Commission: Atmos Energy Corporation d/b/a Trans Louisiana Gas Company (Docket No. U-27703*).

Maryland: Ms. Ramas prepared testimony on behalf of the Maryland Office of People's Counsel in the following case before the Public Service Commission of Maryland: Potomac Electric Power Company (Case No. 9336).

Massachusetts: Ms. Ramas prepared testimony on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy in the following cases before the Massachusetts Department of Public Utilities: New England Gas Company (DPU 10-114), Fitchburg Electric Company (DPU 11-01), Fitchburg Gas Company (DPU 11-02); NStar/Northeast Utilities Merger (DPU 10-170); and Bay State Gas Company d/b/a Columbia Gas of Massachusetts (DPU 13-75).

New York: Ms. Ramas prepared testimony on behalf of the New York Consumer Protection Board in the following cases before the New York Public Service Commission:
New York State Electric & Gas Corporation (Case No. 05-E-1222), KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island (Case Nos. 06-G-1185 and 06-G-1186*), Consolidated Edison Company of New York, Inc. (Case No. 06-G-1332*), and Consolidated Edison Company of New York, Inc. (Case No. 07-E-0523).

Nova Scotia: Ms. Ramas prepared testimony on behalf of the Nova Scotia Utility and Review Board – Board Counsel in the following case: Halifax Regional Water Commission (W-HRWC-R-10); Nova Scotia Power Incorporated (NSPI-P-892*); Heritage Gas Limited (NG-HG-R-11*); NPB Load Retention Rate Application – NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd. (NSPI-P-202); Nova Scotia Power Incorporated (NSPI-P-893*); and Halifax Regional Water Commission (W-HRWC-R-13).

North Carolina: Ms. Ramas assisted Nucor Steel-Hertford, A Division of Nucor Corporation in the review of an application filed by Dominion North Carolina Power for an Increase in rates (Docket no. E-22, Sub 459**). The case was settled prior to the submittal of intervenor testimony.

Utah: Ms. Ramas prepared testimony on behalf of the Utah Committee of Consumer Services in the following cases before the Public Service Commission of Utah:

PacifiCorp dba Utah Power & Light Company (Docket No. 99-035-10), PacifiCorp dba Utah Power & Light Company (01-035-01*), PacifiCorp dba Utah Power & Light Company (Docket No. 01-035-23 Interim (Oral testimony)), PacifiCorp dba Utah Power & Light Company (Docket No. 01-035-23**), Questar Gas Company (Docket No. 02-057-02*), PacifiCorp (Docket No. 04-035-42*), PacifiCorp (Docket No. 06-035-21*), Rocky Mountain Power (Docket Nos. 07-035-04, 06-035-163 and 07-035-14), Rocky Mountain Power (Docket No. 07-035-93), Questar Gas Company (Docket No. 07-057-13*), Rocky Mountain Power (Docket No. 08-035-93*), Rocky Mountain Power (Docket No. 08-035-38*), Rocky Mountain Power Company (Docket No. 09-035-23), Questar Gas Company (Docket No. 09-057-16**), Rocky Mountain Power Company (Docket No. 10-035-13), Rocky Mountain Power Company (Docket No. 10-035-38), Rocky Mountain Power Company (Docket No. 10-035-89), Rocky Mountain Power Company (Docket

No. 10-035-124*), Rocky Mountain Power Company (Docket No. 11-035-200*) and Rocky Mountain Power Company (Docket No. 13-035-184*).

Vermont: Ms. Ramas prepared testimony on behalf of the Vermont Department of Public Service in the following cases before the Vermont Public Service Board: Citizens Utilities Company – Vermont Electric Division (Docket No. 5859), Central Vermont Public Service Corporation (Docket No. 6460*), and Central Vermont Public Service Corporation (Docket No. 6946 & 6988).

Washington: Ms. Ramas prepared testimony on behalf of the Public Counsel Section of the Washington Attorney General's Office in the following case before the Washington Utilities and Transportation Commission: PacifiCorp (Docket No. UE-090205*).

West Virginia: Ms. Ramas has prepared testimony on behalf of the West Virginia Consumer Advocate Division in the following cases before the Public Service Commission of West Virginia: Monongahela Power Company (Case No. 94-0035-E-42T), Potomac Edison Company (Case No. 94-0027-E-42T), Hope Gas, Inc. (Case No. 95-0003-G-42T*), and Mountaineer Gas Company (Case No. 95-0011-G-42T*).

* Case Settled / ** Testimony not filed/submitted due to settlement

DANIEL J. LAWTON
LAWTON CONSULTING
B.A. ECONOMICS, MERRIMACK COLLEGE
M.A. ECONOMICS, TUFTS UNIVERSITY

Prior to beginning his own consulting practice Diversified Utility Consultants, Inc., in 1986 where he practiced as a firm principal through December 31, 2005, Mr. Lawton had been in the utility consulting business with a national engineering and consulting firm. In addition, Mr. Lawton has been employed as a senior analyst and statistical analyst with the Department of Public Service in Minnesota. Prior to Mr. Lawton's involvement in utility regulation and consulting he taught economics, econometrics, statistics and computer science at Doane College.

Mr. Lawton has conducted numerous financial and cost of capital studies on electric, gas and telephone utilities for various interveners before local, state and federal regulatory bodies. In addition, Mr. Lawton has provided studies, analyses, and expert testimony on statistics, econometrics, accounting, forecasting, and cost of service issues. Other projects in which Mr. Lawton has been involved include rate design and analyses, prudence analyses, fuel cost reviews and regulatory policy issues for electric, gas and telephone utilities. Mr. Lawton has developed software systems, databases and management systems for cost of service analyses.

In addition, Mr. Lawton has developed and reviewed numerous forecasts of energy and demand used for utility generation expansion studies as well as municipal financing. Mr. Lawton has represented numerous municipalities as a negotiator in utility related matters. Such negotiations ranges from the settlement of electric rate cases to the negotiation of provisions in purchase power contracts.

A list of cases in which Mr. Lawton has provided testimony is attached.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY DANIEL J. LAWTON

JURISDICTION/COMPANY	DOCKET NO.	TESTIMONY TOPIC
ALASKA REGULATORY COMMISSION		
Beluga Pipe Line Company Municipal Light & Power	P-04-81 U-13-184	Cost of Capital Cost of Capital

PUBLIC UTILITIES COMMISSION OF CALIFORNIA		
Southern California Edison	12-0415	Cost of Capital
San Diego Gas and Electric	12-0416	Cost of Capital
Southern California Gas	12-0417	Cost of Capital
Pacific Gas and Electric	12-0418	Cost of Capital

GEORGIA PUBLIC SERVICE COMMISSION		
Georgia Power Co.	25060-U	Cost of Capital

FEDERAL ENERGY REGULATORY COMMISSION		
Alabama Power Company	ER83-369-000	Cost of Capital
Arizona Public Service Company	ER84-450-000	Cost of Capital
Florida Power & Light	EL83-24-000	Cost Allocation, Rate Design
Florida Power & Light	ER84-379-000	Cost of Capital, Rate Design, Cost of Service
Southern California Edison	ER82-427-000	Forecasting

LOUISIANA PUBLIC SERVICE COMMISSION		
Louisiana Power & Light	U-15684	Cost of Capital, Depreciation
Louisiana Power & Light	U-16518	Interim Rate Relief
Louisiana Power & Light	U-16945	Nuclear Prudence, Cost of Service

MARYLAND PUBLIC SERVICE COMMISSION		
Baltimore Gas and Electric Company	9173	Financial
Baltimore Gas and Electric Company	9326	Financial

MINNESOTA PUBLIC UTILITIES COMMISSION		
Continental Telephone	P407/GR-81-700	Cost of Capital
Interstate Power Co.	E001/GR-81-345	Financial
Montana Dakota Utilities	G009/GR-81-448	Financial, Cost of Capital
New ULM Telephone Company	P419/GR81767	Financial
Norman County Telephone	P420/GR-81-230	Rate Design, Cost of Capital
Northern States Power	G002/GR80556	Statistical Forecasting, Cost of Capital
Northwestern Bell	P421/GR80911	Rate Design, Forecasting

MISSOURI PUBLIC SERVICE COMMISSION		
Missouri Gas Energy	GR-2009-0355	Financial
Ameren UE	ER-2010-0036	Financial

FLORIDA PUBLIC SERVICE COMMISSION		
Progress Energy	070052-EI	Cost Recovery
Florida Power and Light	080677-EI	Financial
Florida Power and Light	090130-EI	Depreciation
Progress Energy	090079-EI	Depreciation
Florida Power and Light	120015-EI	Financial Metrics

NORTH CAROLINA UTILITIES COMMISSION		
North Carolina Natural Gas	G-21, Sub 235	Forecasting, Cost of Capital, Cost of Service

OKLAHOMA PUBLIC SERVICE COMMISSION		
Arkansas Oklahoma Gas Corporation	200300088	Cost of Capital
Public Service Company of Oklahoma	200600285	Cost of Capital
Public Service Company of Oklahoma	200800144	Cost of Capital
Public Service Company of Oklahoma	201200054	Financial and Earnings Related

PUBLIC SERVICE COMMISSION OF INDIANA		
Kokomo Gas & Fuel Company	38096	Cost of Capital

PUBLIC UTILITY COMMISSION OF NEVADA		
Nevada Bell	99-9017	Cost of Capital
Nevada Power Company	99-4005	Cost of Capital
Sierra Pacific Power Company	99-4002	Cost of Capital
Nevada Power Company	08-12002	Cost of Capital
Southwest Gas Corporation	09-04003	Cost of Capital
Sierra Pacific Power Company	10-06001 & 10-06002	Cost of Capital & Financial
Nevada Power Co. and Sierra Pacific Power Co.	11-06006 11-06007 11-06008	Cost of Capital
Southwest Gas Corp.	12-04005	Cost of Capital
Sierra Power Company	13-06002 13-06003 13-06003	Cost of Capital
NV Energy & MidAmerican Energy Holdings Co. Nevada Power Company	13-07021 14-05004	Merger and Public Interest Financial Cost of Capital

PUBLIC SERVICE COMMISSION OF UTAH		
PacifiCorp	04-035-42	Cost of Capital
Rocky Mountain Power	08-035-38	Cost of Capital
Rocky Mountain Power	09-035-23	Cost of Capital
Rocky Mountain Power	10-035-124	Cost of Capital
Rocky Mountain Power	11-035-200	Cost of Capital

Questar Gas Company Rocky Mountain Power	13-057-05 13-035-184	Cost of Capital Cost of Capital

SOUTH CAROLINA PUBLIC SERVICE COMMISSION		
Piedmont Municipal Power	82-352-E	Forecasting

PUBLIC UTILITY COMMISSION OF TEXAS		
Central Power & Light Company	6375	Cost of Capital, Financial Integrity
Central Power & Light Company	9561	Cost of Capital, Revenue Requirements
Central Power & Light Company	7560	Deferred Accounting
Central Power & Light Company	8646	Rate Design, Excess Capacity
Central Power & Light Company	12820	STP Adj. Cost of Capital, Post Test-year adjustments, Rate Case Expenses
Central Power & Light Company	14965	Salary & Wage Exp., Self-Ins. Reserve, Plant Held for Future use, Post Test Year Adjustments, Demand Side Management, Rate Case Exp.
Central Power & Light Company	21528	Securitization of Regulatory Assets
El Paso Electric Company	9945	Cost of Capital, Revenue Requirements, Decommissioning Funding
El Paso Electric Company	12700	Cost of Capital, Rate Moderation Plan, CWIP, Rate Case Expenses
Entergy Gulf States Incorporated	16705	Cost of Service, Rate Base, Revenues, Cost of Capital, Quality of Service
Entergy Gulf States Incorporated	21111	Cost Allocation
Entergy Gulf States Incorporated	21984	Unbundling
Entergy Gulf States Incorporated	22344	Capital Structure

Entergy Gulf States Incorporated	22356	Unbundling
Entergy Gulf States Incorporated	24336	Price to Beat
Gulf States Utilities Company	5560	Cost of Service
Gulf States Utilities Company	6525	Cost of Capital, Financial Integrity
Gulf States Utilities Company	6755/7195	Cost of Service, Cost of Capital, Excess Capacity
Gulf States Utilities Company	8702	Deferred Accounting, Cost of Capital, Cost of Service
Gulf States Utilities Company	10894	Affiliate Transaction
Gulf States Utilities Company	11793	Section 63, Affiliate Transaction
Gulf States Utilities Company	12852	Deferred acctng., self-Ins. reserve, contra AFUDC adj., River Bend Plant specifically assignable to Louisiana, River Bend Decomm., Cost of Capital, Financial Integrity, Cost of Service, Rate Case Expenses
GTE Southwest, Inc.	15332	Rate Case Expenses
Houston Lighting & Power	6765	Forecasting
Houston Lighting & Power	18465	Stranded costs
Lower Colorado River Authority	8400	Debt Service Coverage, Rate Design
Southwestern Electric Power Company	5301	Cost of Service
Southwestern Electric Power Company	4628	Rate Design, Financial Forecasting
Southwestern Electric Power Company	24449	Price to Beat Fuel Factor
Southwestern Bell Telephone Company	8585	Yellow Pages
Southwestern Bell Telephone Company	18509	Rate Group Re-Classification
Southwestern Public Service Company	13456	Interruptible Rates

Southwestern Public Service Company	11520	Cost of Capital
Southwestern Public Service Company	14174	Fuel Reconciliation
Southwestern Public Service Company	14499	TUCO Acquisition
Southwestern Public Service Company	19512	Fuel Reconciliation
Texas-New Mexico Power Company	9491	Cost of Capital, Revenue Requirements, Prudence
Texas-New Mexico Power Company	10200	Prudence
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	21112	Acquisition risks/merger benefits
Texas Utilities Electric Company	9300	Cost of Service, Cost of Capital
Texas Utilities Electric Company	11735	Revenue Requirements
TXU Electric Company	21527	Securitization of Regulatory Assets
West Texas Utilities Company	7510	Cost of Capital, Cost of Service
West Texas Utilities Company	13369	Rate Design

RAILROAD COMMISSION OF TEXAS		
Energas Company	5793	Cost of Capital
Energas Company	8205	Cost of Capital
Energas Company	9002-9135	Cost of Capital, Revenues, Allocation
Lone Star Gas Company	8664	Rate Design, Cost of Capital, Accumulated Depr. & DFIT, Rate Case Exp.
Lone Star Gas Company-Transmission	8935	Implementation of Billing Cycle Adjustment
Southern Union Gas Company	6968	Rate Relief

Southern Union Gas Company	8878	Test Year Revenues, Joint and Common Costs
Texas Gas Service Company	9465	Cost of Capital, Cost of Service, Allocation
TXU Lone Star Pipeline	8976	Cost of Capital, Capital Structure
TXU-Gas Distribution	9145-9151	Cost of Capital, Transport Fee, Cost Allocation, Adjustment Clause
TXU-Gas Distribution	9400	Cost of Service, Allocation, Rate Base, Cost of Capital, Rate Design
Westar Transmission Company	4892/5168	Cost of Capital, Cost of Service
Westar Transmission Company	5787	Cost of Capital, Revenue Requirement
Atmos	10000	Cost of Capital

TEXAS WATER COMMISSION		
Southern Utilities Company	7371-R	Cost of Capital, Cost of Service

SCOTSBLUFF, NEBRASKA CITY COUNCIL		
K. N. Energy, Inc.		Cost of Capital

HOUSTON CITY COUNCIL		
Houston Lighting & Power Company		Forecasting

PUBLIC UTILITY REGULATION BOARD OF EL PASO, TEXAS		
Southern Union Gas Company		Cost of Capital

DISTRICT COURT CAMERON COUNTY, TEXAS

City of San Benito, et. al. vs. PGE Gas Transmission et. al.	96-12-7404	Fairness Hearing

DISTRICT COURT HARRIS COUNTY, TEXAS		
City of Wharton, et al vs. Houston Lighting & Power	96-016613	Franchise fees

DISTRICT COURT TRAVIS COUNTY, TEXAS		
City of Round Rock, et al vs. Railroad Commission of Texas et al	GV 304,700	Mandamus

SOUTH DAYTONA, FLORIDA		
City of South Daytona v. Florida Power and Light	2008-30441-CICI	Stranded Costs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 36
PARTY: OFFICE OF PUBLIC COUNSEL (OPC)(DIRECT)
DESCRIPTION: D. Lawton DJL-2

Redacted, Public Version

Docket No. 140001-EI
Market Price Sensitivity
Exhibit ___ Schedule (DJL-2)
Page 1 of 1

Results of FPL's Economic Evaluation With Low Forecast Price Assumption

	A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J(3)	L
Period	Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate(2) ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)	Cumulative Customer Savings ($MM)
1	2015	15.6	[redacted]	[redacted]	[redacted]	[redacted]	$3.48	$3.14	-$5.4	0.9302	-$5.0	-$5.0
2	2016	16.8	[redacted]	[redacted]	[redacted]	[redacted]	$3.56	$3.35	-$3.5	0.8649	-$3.0	-$8.0
3	2017	11.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.00	$3.67	-$3.7	0.8043	-$2.9	-$11.0
4	2018	8.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.40	$4.48	$0.6	0.7480	$0.6	-$10.4
5	2019	7.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.98	$4.60	-$2.6	0.6956	-$1.8	-$12.2
6	2020	6.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.79	$4.71	-$0.4	0.6468	-$0.3	-$12.5
7	2021	5.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.94	$4.78	-$0.8	0.6015	-$0.5	-$13.0
8	2022	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.08	$4.95	-$0.6	0.5594	-$0.3	-$13.3
9	2023	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.21	$5.18	-$0.1	0.5202	-$0.1	-$13.4
10	2024	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.34	$5.50	$0.6	0.4837	$0.3	-$13.1
11	2025	3.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.24	$5.73	$1.8	0.4498	$0.8	-$12.3
12	2026	3.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.32	$5.97	$2.1	0.4183	$0.9	-$11.4
13	2027	3.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.38	$6.20	$2.5	0.3880	$1.0	-$10.4
14	2028	2.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.46	$6.51	$3.1	0.3617	$1.1	-$9.3
15	2029	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.52	$6.75	$3.4	0.3364	$1.1	-$8.1
16	2030	2.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$6.91	$3.4	0.3128	$1.1	-$7.1
17	2031	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$7.17	$3.7	0.2910	$1.1	-$6.0
18	2032	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.71	$7.45	$4.0	0.2705	$1.1	-$4.9
19	2033	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.80	$7.73	$4.2	0.2516	$1.0	-$3.9
20	2034	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.88	$8.09	$4.3	0.2340	$1.0	-$2.9
21	2035	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.97	$8.38	$4.6	0.2176	$1.0	-$1.9
22	2036	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$6.05	$8.66	$4.7	0.2023	$0.9	-$0.9
	2037-65	23.1	[redacted]	[redacted]	[redacted]	[redacted]	$7.66	$13.43	$128.0	0.0876	$11.2	$10.3
	Totals(1)	137.8	$323.2	$190.9	$195.5	$709.4			$154.0		$10.3	

Notes:
(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.
(2) Return rate includes return on the assets and return of financing costs.
(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital
Florida Power & Light Company
Docket No. 140001-EI
OPC's 5th Request for PODs
Attachment 1/ Request No. 34
Entire workbook CONFIDENTIAL in its entirety
Bates Nos. FCR-14-03400 through FCR-14-040

Redacted, Public Version

Docket No. 140001-EI
Results, FPL's High Output/Reduced Market Price Case
Exhibit ___ Schedule (DJL-3)
Page 1 of 1

Results of FPL's Economic Evaluation With High Production Low Forecast Assumption

	A	B	C	D	E	F=C+D+E	G=F/B	H	I=B x (H-G)	J	K=I x J	L
Period	Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)	Cumulative Customer Savings ($MM)
1	2015	17.2	[redacted]	[redacted]	[redacted]	[redacted]	$3.25	$3.14	-$2.1	0.9302	-$1.9	-$1.9
2	2016	18.5	[redacted]	[redacted]	[redacted]	[redacted]	$3.33	$3.35	$0.5	0.8649	$0.4	-$1.5
3	2017	12.4	[redacted]	[redacted]	[redacted]	[redacted]	$3.74	$3.67	-$0.8	0.8043	-$0.7	-$2.2
4	2018	9.5	[redacted]	[redacted]	[redacted]	[redacted]	$4.12	$4.48	$3.5	0.7480	$2.6	$0.4
5	2019	7.8	[redacted]	[redacted]	[redacted]	[redacted]	$4.67	$4.60	-$0.6	0.6956	-$0.4	$0.0
6	2020	6.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.46	$4.71	$1.7	0.6468	$1.1	$1.1
7	2021	5.8	[redacted]	[redacted]	[redacted]	[redacted]	$4.80	$4.79	$1.1	0.6015	$0.7	$1.8
8	2022	5.2	[redacted]	[redacted]	[redacted]	[redacted]	$4.72	$4.95	$1.2	0.5594	$0.7	$2.4
9	2023	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.84	$5.18	$1.6	0.5202	$0.8	$3.3
10	2024	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.98	$5.50	$2.3	0.4837	$1.1	$4.4
11	2025	4.0	[redacted]	[redacted]	[redacted]	[redacted]	$4.94	$5.73	$3.1	0.4498	$1.4	$5.8
12	2026	3.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.02	$5.97	$3.5	0.4183	$1.5	$7.3
13	2027	3.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.09	$6.20	$3.6	0.3890	$1.5	$8.7
14	2028	3.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.16	$6.51	$4.4	0.3617	$1.6	$10.3
15	2029	3.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.23	$6.75	$4.6	0.3364	$1.6	$11.9
16	2030	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.28	$6.91	$4.6	0.3128	$1.4	$13.3
17	2031	2.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.35	$7.17	$4.9	0.2910	$1.4	$14.7
18	2032	2.5	[redacted]	[redacted]	[redacted]	[redacted]	$5.42	$7.45	$5.1	0.2705	$1.4	$16.1
19	2033	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.51	$7.73	$5.3	0.2516	$1.3	$17.4
20	2034	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$8.03	$5.4	0.2340	$1.3	$18.7
21	2035	2.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.68	$8.33	$5.5	0.2176	$1.2	$19.9
22	2036	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.77	$8.65	$5.7	0.2023	$1.2	$21.1
	2037-65	25.4	[redacted]	[redacted]	[redacted]	[redacted]	$7.66	$13.43	$148.8	0.0886	$13.0	$34.1
	Totals[1]	161.6	$352.3	$100.8	$186.5	$738.5			$211.1		$34.1	

Notes:
(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.
(2) Return rate includes return on the assets and return of financing costs.
(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital

Florida Power & Light Company
Docket No. 140001-EI
OPC's 5th Request for PODs
Attachment 1 / Request No. 24

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 37
PARTY: OFFICE OF PUBLIC COUNSEL (OPC)(DIRECT)
DESCRIPTION: D. Lawton DJL-3

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Docket No. 140001-EI
Woodford Results, 3.7% Annual
Market Price Assumption
Exhibit___Schedule (DJL-4)
Page 1 of 1

CONFIDENTIAL FPL ANALYSIS OF WOODFORD PROJECT ASSUMING A 3.7% ANNUAL GROWTH IN MARKET PRICES

		FPL BASE ECONOMIC ANALYSIS						ALTERNATIVE MARKET PRICE FORECAST @ 3.7% ANNUALLY		
		A	B	C	D	E	F	G 1.037	H	I
LINE NO.	YEAR	ANNUAL PRODUCTION (Bcf)	WOODFORD REVENUE REQUIREMENT ($MM)	WOODFORD UNIT COST ($MMBtu)	FPL MARKET PRICE FORECAST ($MMBtu)	NOMINAL CONSUMER SAVINGS/ (COSTS)	NET PRESENT VALUE SAVINGS/ (COSTS)	ALTERNATIVE MARKET FORECAST AT 3.7% ANNUAL RATE	ALTERNATIVE NOMINAL CONSUMER SAVINGS/ (COSTS)	ALTERNATIVE NET PRESENT VALUE SAVINGS/ (COSTS)
1	2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.02	$9.41	$7.81
2	2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.17	$10.17	$8.80
3	2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.33	$3.90	$3.14
4	2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.49	$0.87	$0.79
5	2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.65	-$1.21	-$1.34
6	2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$4.83	$0.35	$0.23
7	2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5.00	$0.35	$0.20
8	2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5.19	$0.41	$0.23
9	2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5.38	$0.89	$0.46
10	2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$0.88	$0.43
11	2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5.79	$1.97	$0.69
12	2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6.00	$2.01	$0.84
13	2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6.22	$2.44	$0.95
14	2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6.45	$2.68	$0.97
15	2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6.69	$3.52	$1.19
16	2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6.94	$3.59	$1.13
17	2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$7.20	$3.52	$1.03
18	2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$7.46	$4.05	$1.10
19	2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$7.74	$4.55	$1.15
20	2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8.03	$4.18	$0.98
21	2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8.32	$4.47	$0.98
22	2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8.63	$4.69	$0.96
23	2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8.95	$4.87	$0.92
24	2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$9.28	$4.97	$0.88
25	2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$9.62	$4.88	$0.82
26	2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$9.98	$4.81	$0.75
27	2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$10.35	$4.79	$0.68
28	2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$10.73	$4.57	$0.60
29	2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$11.15	$5.39	$0.66
30	2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$11.54	$5.04	$0.58
31	2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$11.97	$4.62	$0.49
32	2046	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$12.41	$4.65	$0.48
33	2047	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$12.87	$4.91	$0.45
34	2048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$13.35	$4.79	$0.41
35	2049	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$13.84	$4.76	$0.38
36	2050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$14.35	$4.67	$0.35
37	2051	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$14.88	$4.54	$0.31
38	2052	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$15.43	$4.65	$0.30
39	2053	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$16.01	$4.42	$0.26
40	2054	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$16.60	$4.46	$0.25
41	2055	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$17.21	$4.35	$0.22
42	2056	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$17.85	$4.26	$0.20
43	2057	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$18.51	$4.20	$0.19
44	2058	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$19.19	$4.09	$0.17
45	2059	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$19.90	$3.95	$0.15
46	2060	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$20.64	$3.87	$0.14
47	2061	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$21.40	$3.75	$0.13
48	2062	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$22.20	$3.71	$0.12
49	2063	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$23.02	$3.63	$0.11
50	2064	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$23.87	$3.54	$0.10
51	TOTAL	[redacted]	[redacted]			[redacted]	[redacted]		$191.43	$43.76

COLUMNS A-F Florida Power & Light Company
Docket No. 140001-EI
OPC's 4th Request for PODs
Attachment 1 / Request No. 12
Entire workbook CONFIDENTIAL in its entirety
FPL-14-00742 through FPL-14-01224.

COLUMN G GROW FPL 2015 PRICE OF $4.02 AT A 3.7% ANNUAL RATE

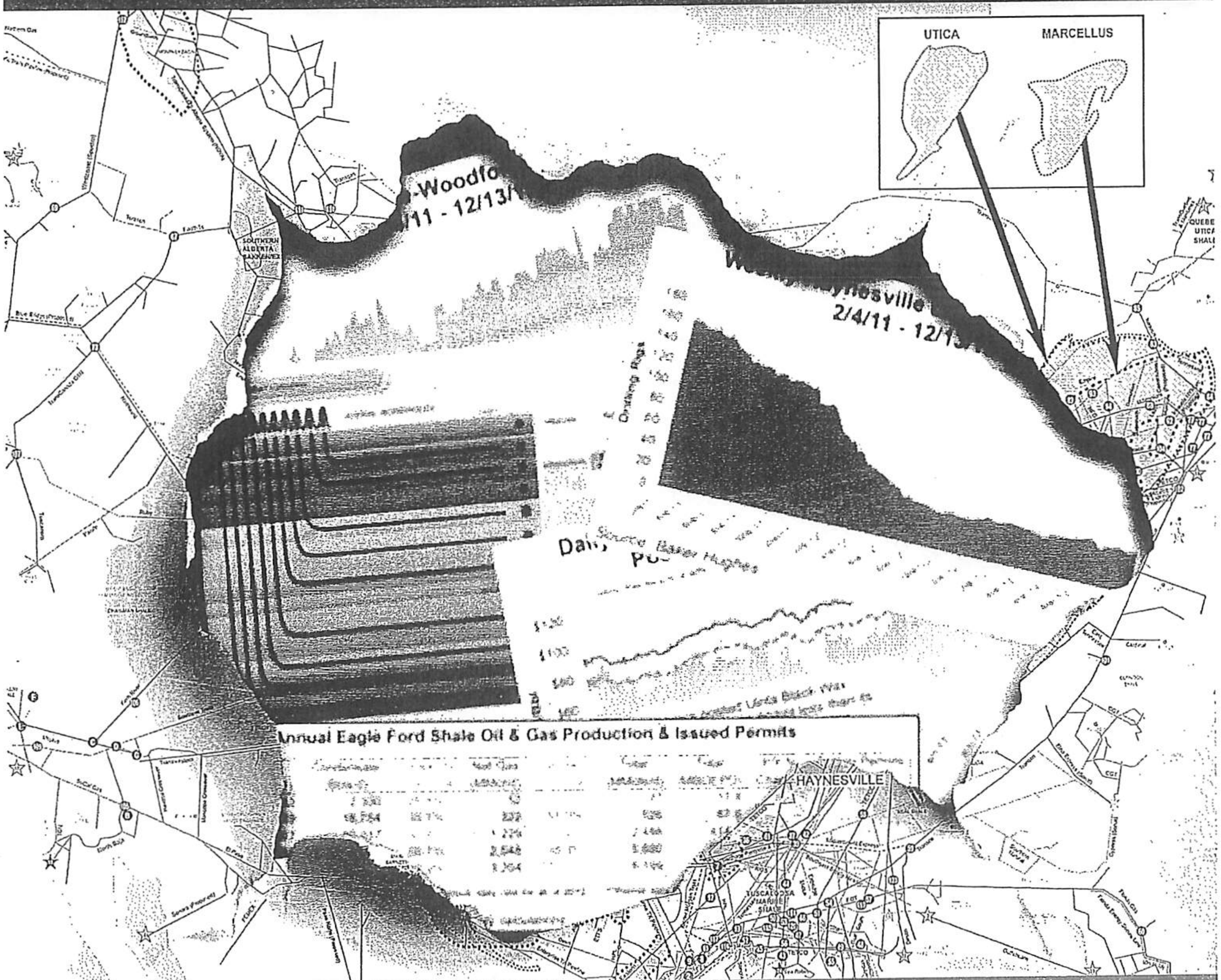
COLUMNS H & I CALCULATED THE SAME AS E & F

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 38
PARTY: OFFICE OF PUBLIC COUNSEL (OPC)(DIRECT)
DESCRIPTION: D. Lawton DJL-4

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 39
PARTY: OFFICE OF PUBLIC COUNSEL (OPC)(DIRECT)
DESCRIPTION: D. Lawton DJL-5

NGI'S NORTH AMERICAN SHALE & RESOURCE PLAYS FACTBOOK

RESEARCH • INSIGHT • ANALYSIS • KEY BASIN STATS

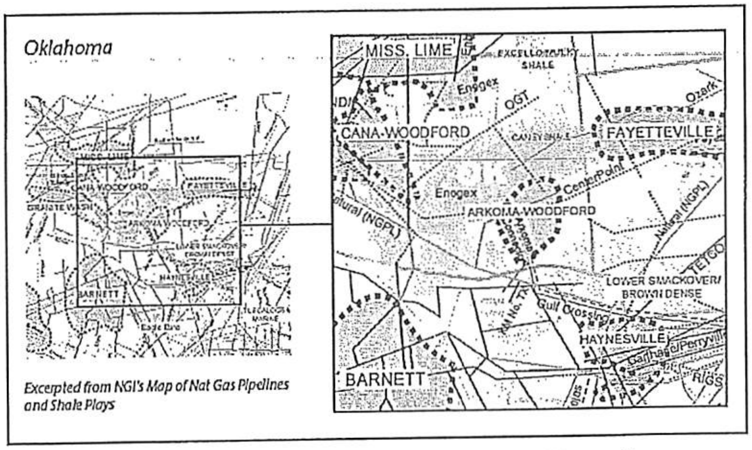


NGI Natural Gas Intelligence

MID-CONTINENT

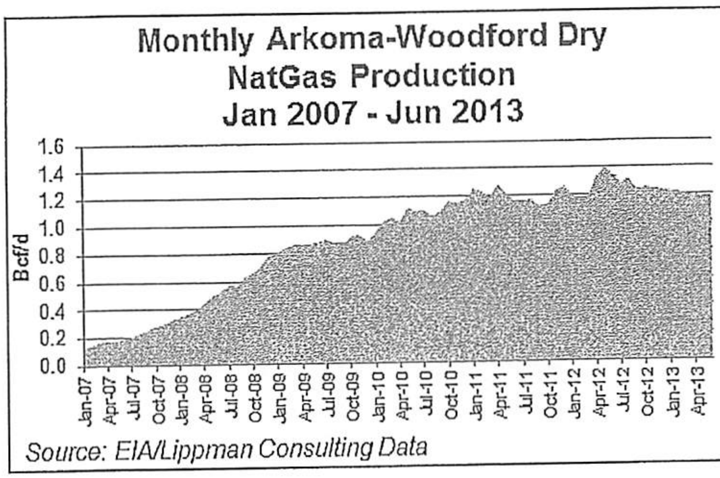
ARKOMA-WOODFORD SHALE

The Arkoma-Woodford may have been one of the first unconventional plays to emerge in the United States, but a "first mover" advantage doesn't always lead to longer-term success. According to the Tulsa Geological Society, the play kicked off with vertical drilling in 2003, and saw its first horizontal well in late 2004. The Arkoma-Woodford is primarily a dry natural gas formation, although as Copano Energy has reported, gas on the western half of the play tends to be somewhat more liquids rich than that on its eastern half. The majority of horizontal drilling in the Arkoma-Woodford has been centered in Atoka, Coal, Hughes, and Pittsburg Counties in Southeastern Oklahoma, with some scattered activity in McIntosh County, OK as well.



Excerpted from NGI's Map of Nat Gas Pipelines and Shale Plays

At one point in 2008, there were more than 50 drilling rigs working the Arkoma-Woodford, but low gas prices, especially relative to crude oil and NGL prices, have all but choked off investment in the region. Most publicly traded companies barely even mention the play in their investor relations presentations anymore, and rig activity in the Arkoma-Woodford has slowed to a near standstill. There were just 5 drilling rigs in the Arkoma-Woodford as of 12/13/13. This lack of drilling has led to a decline in dry gas production in the basin, falling from its peak of 1.4 Bcf/d in May 2012 to 1.2 Bcf/d a year later.



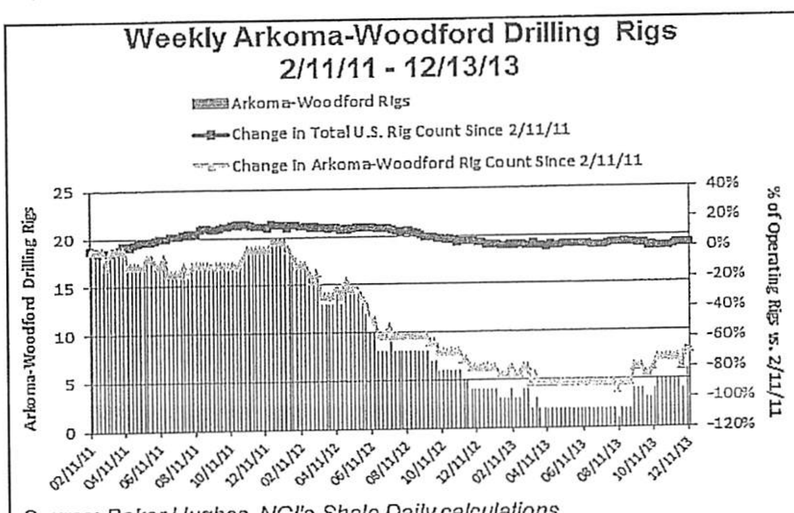
ExxonMobil is the largest acreage holder in the play, followed by Newfield Exploration, BP, Vanguard Natural Resources, PetroQuest, and Devon Energy.

Counties

Oklahoma: Atoka, Coal, Hughes, McIntosh, Pittsburg

NatGas Pipelines

Arkoma Connector, CenterPoint Energy, Enogex, Gulf Crossing, Midcontinent Express, NGPL, OGT, Ozark



Docket No. 140001-EI
NGI's 2014 North American Shale & Resource Plays Factbook (Excerpt)
Exhibit__Schedule (DJL-5)
Page 3 of 3

Arkoma-Woodford Shale (continued)

Arkoma-Woodford Shale
Net Acreage Positions
Last Updated 01/14/14

Company	Net Acres
ExxonMobil[1]	385,000
Newfield Exploration	160,000
BP	90,000
Vanguard Natural Resources	66,000
PetroQuest	60,000
Devon Energy	40,000
Cinco Resources	33,000
Continental Resources	26,291
Panhandle Oil & Gas	7,037
Constellation Energy Partners	N/A
Jones Energy	N/A
Pablo Energy II	N/A
Presidium Energy	N/A
Silver Creek Oil & Gas	N/A
Sinclair Oil	N/A
SM Energy	N/A
Southridge Energy	N/A
Unit Corporation	N/A
Ward Petroleum	N/A

[1]May include some Ardmore Basin acreage.

Source: Compiled by NGI's Shale Daily from company reports

FLORIDA PUBLIC SERVICE COMMISSION DOCKET: 140001-EI EXHIBIT: 40 PARTY: FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG) (DIRECT) DESCRIPTION: Jeff Pollock JP-1

CONFIDENTIAL

Docket No. 140001-EI
Expense Sensitivity
Exhibit JP-1

FLORIDA POWER AND LIGHT COMPANY

Base Production Cost/Benefit Analysis with Escalated Production and Transportation Costs

($ in Millions)

Line	Year	Annual Production (Bcf)	Operating Expenses	Depreciation	Return Rate	Revenue Requirement	Effective Cost ($/MMBtu)	FPL Gas Price Forecast ($/MMBtu)	Undiscounted Customer Savings	FPL Discount Factor	Discounted Customer Savings
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	2015	15.6	[redacted]	[redacted]	[redacted]	[redacted]	$3.48	$4.02	$8.4	0.9302	$7.8
2	2016	16.8	[redacted]	[redacted]	[redacted]	[redacted]	$3.58	$4.30	$12.0	0.8649	$10.4
3	2017	11.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.05	$4.70	$7.4	0.8043	$5.9
4	2018	8.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.48	$5.74	$10.9	0.7480	$8.1
5	2019	7.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.09	$5.89	$5.7	0.6956	$3.9
6	2020	6.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.92	$6.03	$6.8	0.6468	$4.4
7	2021	5.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.10	$6.13	$5.4	0.6015	$3.3
8	2022	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.28	$6.33	$5.0	0.5594	$2.8
9	2023	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.45	$6.63	$5.0	0.5202	$2.6
10	2024	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.62	$7.03	$5.5	0.4837	$2.7
11	2025	3.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.53	$7.33	$6.5	0.4498	$2.9
12	2026	3.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$7.63	$6.6	0.4183	$2.8
13	2027	3.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.76	$7.93	$6.8	0.3890	$2.6
14	2028	2.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.87	$8.33	$7.2	0.3617	$2.6
15	2029	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.99	$8.63	$7.3	0.3364	$2.4
16	2030	2.6	[redacted]	[redacted]	[redacted]	[redacted]	$6.10	$8.83	$7.1	0.3129	$2.2
17	2031	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$6.22	$9.17	$7.2	0.2910	$2.1
18	2032	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$6.35	$9.52	$7.3	0.2705	$2.0
19	2033	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$6.50	$9.88	$7.3	0.2516	$1.8
20	2034	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$6.66	$10.26	$7.3	0.2340	$1.7
21	2035	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$6.82	$10.65	$7.3	0.2176	$1.6
22	2036	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$6.98	$11.06	$7.3	0.2023	$1.5
23	2037-65	23.1	[redacted]	[redacted]	[redacted]	[redacted]	$10.96	$17.16	$142.9	0.0894	$12.8
24	**Totals**	**137.8**	[redacted]	[redacted]	[redacted]	[redacted]			**$300.0**		**$91.0**

Source: Response to OPC POD No. 12.

(2) Reflects 2% annual escalation of Transportation and Production O&M expenses.

FLORIDA POWER AND LIGHT COMPANY
Comparison of Projected Natural Gas Prices

Line	Year	Current Forecast	FPL Forecast	Difference	Percent Difference
		(1)	(2)	(3)	(4)
1	2015	$3.86	$4.02	($0.16)	-4.0%
2	2016	$4.01	$4.30	($0.29)	-6.8%
3	2017	$4.15	$4.70	($0.55)	-11.8%
4	2018	$4.25	$5.74	($1.49)	-25.9%
5	2019	$4.35	$5.89	($1.54)	-26.1%
6	2020	$4.49	$6.03	($1.55)	-25.6%
7	2021	$4.62	$6.13	($1.51)	-24.6%
8	2022	$4.74	$6.33	($1.60)	-25.2%
9	2023	$4.82	$6.63	($1.81)	-27.3%
10	2024	$4.90	$7.03	($2.14)	-30.4%
11	2025	$4.97	$7.33	($2.36)	-32.2%
12	2026	$5.08	$7.63	($2.55)	-33.4%
13	2027	$5.51	$7.93	($2.42)	-30.5%
14	2028	$5.73	$8.33	($2.60)	-31.2%
15	2029	$6.00	$8.63	($2.63)	-30.5%
16	2030	$6.35	$8.83	($2.48)	-28.1%
17	2031	$6.69	$9.17	($2.48)	-27.1%
18	2032	$7.01	$9.52	($2.51)	-26.4%
19	2033	$7.39	$9.88	($2.49)	-25.2%
20	2034	$7.77	$10.26	($2.49)	-24.3%
21	2035	$8.13	$10.65	($2.51)	-23.6%
22	2036	$8.59	$11.06	($2.47)	-22.3%
23	2037	$8.95	$11.48	($2.52)	-22.0%
24	2038	$9.20	$11.91	($2.72)	-22.8%
25	2039	$9.53	$12.37	($2.84)	-22.9%
26	2040	$10.00	$12.84	($2.84)	-22.1%
27	2041	$10.56	$13.33	($2.77)	-20.8%
28	2042	$11.16	$13.84	($2.68)	-19.4%
29	2043	$11.79	$14.36	($2.58)	-17.9%
30	2044	$12.45	$14.91	($2.46)	-16.5%
31	2045	$13.15	$15.48	($2.32)	-15.0%
32	2046	$13.90	$16.07	($2.17)	-13.5%
33	2047	$14.68	$16.68	($2.00)	-12.0%
34	2048	$15.51	$17.32	($1.81)	-10.4%
35	2049	$16.38	$17.97	($1.59)	-8.8%
36	2050	$17.31	$18.66	($1.35)	-7.2%

FLORIDA POWER AND LIGHT COMPANY
Comparison of Projected Natural Gas Prices

Line	Year	Current Forecast	FPL Forecast	Difference	Percent Difference
37	2051	$18.28	$19.36	($1.08)	-5.6%
38	2052	$19.31	$20.10	($0.79)	-3.9%
39	2053	$20.40	$20.87	($0.46)	-2.2%
40	2054	$21.55	$21.66	($0.11)	-0.5%
41	2055	$22.77	$22.48	$0.28	1.3%
42	2056	$24.05	$23.34	$0.71	3.0%
43	2057	$25.40	$24.22	$1.18	4.9%
44	2058	$26.83	$25.14	$1.69	6.7%
45	2059	$28.34	$26.10	$2.24	8.6%
46	2060	$29.93	$27.09	$2.84	10.5%
47	2061	$31.62	$28.12	$3.50	12.5%
48	2062	$33.40	$29.19	$4.21	14.4%
49	2063	$35.28	$30.30	$4.98	16.4%
50	2064	$37.26	$31.45	$5.81	18.5%

Source: (1) 2015 through 2026 is average 30 day closing price of Henry Hub Futures (8/20/2014 - 9/18/2014) obtained from SNL Financial.

2027 through 2040 prices were escalated based on annual increases from the Energy Information Administration (EIA).

2041 through 2064 prices were escalated based on average EIA annual increases from 2012-2040.

Perryville basis adjustment was applied to all prices.

(2) Response to OPC POD No. 12. Confidential

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 42
PARTY: FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG) (DIRECT)
DESCRIPTION: Jeff Pollock JP-3

CONFIDENTIAL

Docket No. 140001-EI
Natural Gas Price Sensitivity
Exhibit JP-3

FLORIDA POWER AND LIGHT COMPANY
Base Production Cost/Benefit Analysis
Updated Gas Price Forecast
($ in Millions)

Line	Year	Annual Production (Bcf)	Operating Expenses	Depreciation	Return Rate	Revenue Requirement	Effective Cost ($/MMBtu)	Current Price Forecast ($/MMBtu)	Undiscounted Customer Savings	FPL Discount Factor	Discounted Customer Savings
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	2015	15.6	[redacted]	[redacted]	[redacted]	[redacted]	$3.48	$3.86	$5.9	0.9302	$5.5
2	2016	16.8	[redacted]	[redacted]	[redacted]	[redacted]	$3.56	$4.01	$7.5	0.8649	$6.5
3	2017	11.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.00	$4.15	$1.7	0.8043	$1.4
4	2018	8.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.40	$4.25	($1.2)	0.7480	($0.9)
5	2019	7.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.96	$4.35	($4.4)	0.6956	($3.0)
6	2020	6.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.79	$4.49	($1.8)	0.6468	($1.2)
7	2021	5.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.94	$4.62	($1.7)	0.6015	($1.0)
8	2022	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.08	$4.74	($1.6)	0.5594	($0.9)
9	2023	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.21	$4.82	($1.7)	0.5202	($0.9)
10	2024	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.34	$4.90	($1.7)	0.4837	($0.8)
11	2025	3.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.24	$4.97	($1.0)	0.4498	($0.4)
12	2026	3.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.32	$5.08	($0.8)	0.4183	($0.3)
13	2027	3.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.39	$5.51	$0.4	0.3890	$0.1
14	2028	2.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.46	$5.73	$0.8	0.3617	$0.3
15	2029	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.52	$6.00	$1.3	0.3364	$0.4
16	2030	2.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$6.35	$2.0	0.3129	$0.6
17	2031	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$6.69	$2.5	0.2910	$0.7
18	2032	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.71	$7.01	$3.0	0.2705	$0.8
19	2033	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.80	$7.39	$3.4	0.2516	$0.9
20	2034	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.88	$7.77	$3.8	0.2340	$0.9
21	2035	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.97	$8.13	$4.1	0.2176	$0.9
22	2036	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$6.05	$8.59	$4.5	0.2023	$0.9
23	2037-65	23.1	[redacted]	[redacted]	[redacted]	[redacted]	$7.88	$15.82	$183.1	0.0894	$16.4
24	Totals	137.8	[redacted]	[redacted]	[redacted]	[redacted]			$208.2		$26.8

Source: Response to OPC POD No. 12.
(7) Current gas price forecast shown on Exhibit JP-2.

News Article

NORTHWESTERN ENERGY PURCHASES BATTLE CREEK NATURAL GAS FIELD

Sep 22, 2010

NorthWestern Energy announces it has purchased a majority interest in the Battle Creek Natural Gas Field on the Sweetgrass Arch in Blaine County, Montana, from a private owner.

Butte, Mont. – Sept. 22, 2010 – NorthWestern Corporation d/b/a NorthWestern Energy (NYSE: NWE) today announced that it has purchased a majority interest in the Battle Creek Natural Gas Field on the Sweetgrass Arch in Blaine County, Montana ("Battle Creek Field"), from a private owner. The purchase also includes the seller's interest in the Battle Creek Gas Gathering System Joint Venture.

The Battle Creek Field purchase consists of the seller's interests in producing wells and a gathering system. The amount of net proven developed producing reserves purchased are estimated to be 7.6 billion cubic feet ("Bcf"). Annual net production attributable to the purchase is currently approximately 0.5 Bcf or about 2.2% of NorthWestern's current annual consumption in Montana.

"Owning natural gas reserves is intended to provide customers with a source of rate-based energy that helps hedge against price volatility," said Bob Rowe, President and CEO. "We are excited that we were able to purchase this relatively small production field which already serves our natural gas customers under a soon-to-expire purchase agreement. With this acquisition, we will continue to dedicate this resource to our natural gas customers and will not use it as a source of supply for our soon-to-be-completed Mill Creek generation station."

Under the terms of the agreement, NorthWestern paid the seller $11.4 million cash for the majority interest in the Battle Creek Field assets including the gathering system. NorthWestern funded the transaction by drawing on its revolving credit facility, which after the purchase has an availability of approximately $160 million.

"We plan to seek approval of the Montana Public Service Commission to add our interest in the Battle Creek Field and the gathering system into our regulated rate base," added Rowe. "It is both in our service territory, near Havre, Montana, and connected to our existing natural gas system. In addition, acquiring this well-defined and established producing field is consistent with our low risk profile by staying away from exploration."

During the 2009 Montana legislative session, changes in state law occurred that allow NorthWestern to acquire natural gas production and gathering resources and, subject to regulatory approval, include them in the rate base.

About NorthWestern Energy

NorthWestern Energy is one of the largest providers of electricity and natural gas in the Upper Midwest and Northwest, serving approximately 661,000 customers in Montana, South Dakota and Nebraska. More information on NorthWestern Energy is available on the Company's Web site at www.northwesternenergy.com.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 43
PARTY: FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG) (DIRECT)
DESCRIPTION: Jeff Pollock JP-4

44

FPL's Responses to Staff's Second Set of Interrogatories (Nos. 12-54 and 56-94), including the Supplemental Response to No. 78

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 44
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Second Set of Interrogatories (Nos. 12-54 and

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl:
Please refer to page 7, lines 14-16. This testimony states that "additional capital investment will be required." Please identify the minimum and maximum estimates for this investment.

A.

Additional capital investment refers to the currently contemplated drilling program consisting of 38 wells. Although PetroQuest has drilled the 19 existing wells in the AMI, additional capital investment will be needed to complete the proposed 38 drilling locations. In the base case described in witness Forrest's testimony, FPL's share of the capital investment for these 38 wells is projected to be $190.8 MM. Per the Drilling and Development Agreement, FPL has a minimum obligation to participate in 15 wells before the end of 2015. If FPL only participates in the 15 wells required as the minimum commitment, assuming all other inputs in the base case remain constant, then total CapEx to drill those 15 wells would be an estimated $80.4 MM.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl:
Please refer to page 8, line 2. How was the net book value of $58.2 million calculated? Describe what changes could make that value go up or down between now and January 1, 2015.

A.

FPL witness Ousdahl direct testimony, Page 11, line 21 through page 12, lines 1 through 9 describes the net book value calculation. The net book value was derived by taking the drilling schedule provided by PetroQuest to USG and totaling the resulting forecasted capital spent by USG between the reporting date in the period the transaction closed on June 30, 2014 and the expected transfer date in between USG and FPL; assumed to be January 1, 2015. This amount was then reduced by the depletion from the wells during the same period of time, which was de minimis and therefore excluded for forecasting purposes.

Drivers that could impact the net book value that FPL will record are changes in capital expenditures, actual amount of gas extracted (depletion), or the transfer date to FPL.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 8, lines 6-10. The witness states that $122.4 million is "FPL's maximum estimated participation" amount for drilling costs. Please identify the minimum required investment amount for drilling costs.

A.

The $122.4 MM estimated in the base case reflects the additional amount of capital FPL anticipates spending after transfer from USG to complete the 38 well drilling program. This amount, in addition to the estimated $58.2 MM paid to reimburse USG for the net book value of the assets and the estimated $10.2 MM paid to USG for the net book value of the acreage, total the $190.8 MM estimated total base case spend. Per the Drilling and Development Agreement, FPL is only required to participate in 15 wells before the end of 2015. If FPL chooses to participate in the drilling of those 15 wells, the estimated CapEx required would be $80.4 MM, assuming all other inputs in the base case remain constant.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 23, lines 12-13. The witness states that this investment is "solely intended to secure natural gas for the operation of FPL's generating plants." Is FPL precluded from selling Woodford Project gas for other purposes? Please explain your response.

A.

No. For evaluation purposes, FPL assumed the gas would be consumed by its generation portfolio. However, as described in the answers to Interrogatories 52-56, the gas produced from the Woodford Project will be considered as part of the larger procurement portfolio and will be eligible for any asset optimization opportunities that present potential savings for FPL's customers.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 19, line 15. Will FPL file Joint Interest Billing (JIB) statements with the Commission? Why or why not? Please explain your response.

A.

The JIBs will not be filed with the Commission; however, they will be available for inspection by the FPSC auditors through the annual Fuel Clause audit. The JIBs represent invoices from the operator. The Company does not file invoices from vendors with the Commission; as these are supporting documents for its books and records which are available to the Commission in the annual clause audit.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 24, line 8. The witness states that "all of the investment and operating costs . . . would be included for recovery in the Fuel Clause." Are there any costs that will not be recovered through the Fuel Clause? If so, please identify.

A.

There are no investment and operating costs associated with the Woodford Project that will not be recovered through the fuel clause. All incremental costs (i.e. transportation charges, depletion, return on investment etc) that will be recovered in the fuel clause are the result of activity of the subsidiary. The capitalization, however is consistent with the approach used for all clause recoveries and will be based on the consolidated adjusted retail capital structure.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 25, lines 1-2. The witness states that certain charges will be recorded as "fuel expenses for that month." Will these expenses be separately identified (as line items) on FPL's "A-schedule" filings? If so, please identify which schedules will address these expenses.

A.

FPL is not proposing to alter the current A-Schedules which aggregate all fuel and fuel related costs to be recovered through the fuel clause. Instead, a supporting schedule, similar to FPL witness Ousdahl Exhibit KO-6 will be filed with the annual filings: Estimated/Actual, Final True-up and Projection filings. The schedule will separately identify the expenses associated with the gas reserves. Additionally, results related to this activity will be provided through the two annual hedging filings; refer to response provided to Staff's Second Set Interrogatories No. 46.

Q.

For the following interrogatories, please refer to the testimony of Kim Ousdahl: Please refer to page 25, lines 6-7, which describes Exhibit KO-6. The witness states Exhibit KO-6 is a "Projection" exhibit. Will similar exhibits be prepared and filed when Actual/Estimated and Final True-Up testimonies are filed? Why or why not? Please explain your response.

A.

Yes. The Company intends to produce a schedule similar to KO-6 to reflect the actual/estimated and final trueups associated with the exploration and production (E&P) activities.

Q.

For the following interrogatories, please refer to the testimony of FPL witness Sam Forrest:

Please refer to page 6, line 12, where the testimony refers to a figure of 600 billion cubic feet (Bcf) of gas that FPL may purchase annually for all natural gas generation.

a. Assuming Commission approval of FPL's Petition, and that 600 Bcf was the forecasted need for 2015, what proportion of 2015's forecasted amount will be met with gas from the Woodford Project?

b. As it awaits Commission approval of FPL's Petition, does FPL or an affiliated entity have a long-term supply contract arranged to provide needed gas for FPL's gas-fired generating plants? Please explain your response.

A.

a. Based on an annual consumption of 600 Bcf, the Woodford Project would meet approximately 2.52% of FPL's daily needs. However, based on FPL's 2014 Ten Year Site Plan, which projects a 2015 annual gas consumption of 544.7 Bcf, the Woodford Project would meet 2.78% of FPL's daily needs.

b. FPL currently procures 100% of its natural gas needs from over 40 non-affiliated entities. FPL maintains a portfolio of purchases that range from three years in advance down to next day. Long-term purchases (annual purchases up to 3 years in length) provide a base load supply of natural gas for FPL's generation portfolio. Medium-term (monthly and seasonal) purchases allow FPL to manage the variations in natural gas requirements that happen from season to season and month to month. Daily procurement activities are utilized to handle the swings in required volume (typically above long-term and medium-term supply) due to load fluctuations caused by weather, generation availability, etc. All of these physical purchases, whether made well in advance or day ahead, are made at market prices – prices that are entirely dictated by the market. There is no shortage of opportunities to procure gas at market prices. If FPL does not receive approval for the Woodford Project by January 1, 2015, given the liquidity and availability of gas at the Perryville Hub, it will have little difficulty in replacing this relatively minor volume of gas in the market by procuring on a day-to-day basis or even longer term, depending on the length of delay or a denial of the petition. FPL and its customers would, however, forego savings from the Woodford Project during the delay in approval.

Q.

For the following interrogatories, please refer to the testimony of FPL witness Sam Forrest:

Please refer to page 6, line 23, where the testimony refers to "stable pricing over the production term." Please describe the fuel forecast(s) FPL evaluated to support this statement.

a. Identify the forecasting assumptions in FPL's long-term natural gas forecast.

b. Describe FPL's fuel forecasting methodology, and identify what forecasted prices are indexed against.

c. Identify non-FPL sources or consultants that were involved in producing the fuel forecast(s) FPL evaluated to support this statement.

d. How should natural gas price forecasts be used each year in evaluating the Woodford Project?

A.

a. FPL's long-term natural gas forecast utilizes the NYMEX forward curve, projections from The PIRA Energy Group (PIRA) and rates of escalation from the Department of Energy's (DOE) Energy Information Administration (EIA). PIRA, a world-recognized consulting firm with expertise in all aspects of the natural gas industry, supplies FPL with an extensive database to support its short-term (monthly, 1 to 18 months out) and long-term (annually through 2030) projections of future natural gas prices. FPL utilizes the NYMEX forward curve for natural gas to project the first few years of the forecast (short-term) and applies escalation rates, provided by the EIA, to the long-term natural gas projections provided by PIRA. For 2014 through 2015, the methodology used the October 7, 2013 NYMEX forward curve for Henry Hub natural gas commodity prices. For the next two years (2016 and 2017), FPL used a 50/50 blend of the October 7, 2013 NYMEX forward curve and the most current projections at the time from PIRA. For the 2018 through 2030 period, FPL used the annual projections from PIRA. For the period beyond 2030, FPL used the real rate of escalation from the EIA. The addition of commodity and transportation forecasts resulted in delivered price forecasts. The development of FPL's Low and High price forecasts for natural gas prices are based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty that exists within natural gas prices. These forecasts reflect a range of reasonable forecast outcomes.

b. Please refer to the response provided to part (a) of this interrogatory.

c. As described in the response to part (a) of this interrogatory, FPL's natural gas price forecast utilizes price projections from PIRA. For over 35 years, PIRA has provided some of the most comprehensive and independent fundamental market research, analysis and intelligence on energy markets. PIRA's expertise is derived by working with nearly every major energy company, refinery and commodity trading firm in the world. PIRA's services are designed to provide a comprehensive evaluation of key U.S. and international energy issues that impact the behavior and performance of the industry and its various markets and sectors. Through a PIRA retainer service, FPL receives updated and constantly refined "deliverables" which provide both information and insight. One of the deliverables from PIRA is a fuel market forecast that looks ahead to both the short-term (monthly, 1 to 18 months out), as well as the long-term (annually through 2030). In addition, FPL's natural gas price forecast utilizes escalation rates from the EIA. The EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding of energy and its interaction with the economy and the environment. The EIA provides a wide range of information and data products covering energy production, stocks, demand, imports, exports, and prices; and prepares analyses and special reports on topics of current interest.

d. FPL does not believe it is necessary or appropriate to re-evaluate the Woodford Project utilizing updated natural gas price forecasts on an annual basis. As with any transaction that FPL enters, the Woodford Project was evaluated with the best information available at the time. That evaluation showed that the Woodford Project is projected to deliver approximately $107 million of customer savings on a net present value basis. The actual results of this physical hedging activity will be included in FPL's annual hedging reports filed with the Commission. Please see the response to Interrogatory No. 46 for additional information regarding hedging filings.

Q.

For the following interrogatories, please refer to the testimony of FPL witness Sam Forrest:
Please refer to page 13, lines 10-13. Has PetroQuest or any entity involved in the Woodford Project been party to a long-term (30 or more years in length) fixed-price hedge for gas? If so, please provide a detailed response.

A.

To FPL's knowledge, neither PetroQuest nor any other entity involved in the Woodford Project has been party to a long-term (30 or more years in length) fixed-price hedge for gas. PetroQuest maintains a commodity hedging program and expects to continue to actively hedge a portion of its future planned production to mitigate the impact of commodity price fluctuations and achieve more predictable cash flows. According to PetroQuest's July 2014 Investor Presentation, PetroQuest hedged approximately 15 Bcfe (billion cubic feet equivalent) out of its expected annual production of 48 Bcfe for 2014, or approximately 31% of expected production. For 2015 PetroQuest's hedged volumes fall to 1.8 Bcf with no hedges in place for 2016 and beyond. PetroQuest's hedging program is similar in tenor to FPL's hedging program in that hedges are executed only for the following year.

Q.

For the following interrogatories, please refer to the testimony of FPL witness Sam Forrest:
Please refer to page 27, lines 14 and 19 to answer the following: The PetroQuest Agreement contemplates that 38 wells will be drilled, although line 19 refers to the prospect that "additional wells" may be included. For purposes of estimating its capital investment, did FPL model 38 wells, or another quantity? Please explain your response.

A.

FPL's model, which supports the filing, assumes exactly 38 wells are drilled. By the nature of drilling the 38 wells and purchasing the rights from USG, FPL will have earned an interest in the corresponding acreage for the 38 wells. Should economics at a later date justify the drilling of additional wells in that acreage, FPL will have the right, but not the obligation, to participate in any future well drilled. No incremental value or economic benefit has been assumed in the economics of the Woodford Project beyond the initial 38 wells.

Q.

Please refer to page 35 of the testimony of witness Forrest and to Exhibit SF-1. On lines 8 through 10 witness Forrest states FPL will procure firm transportation for the Woodford Project. Will this be on the Enable Pipeline? Please explain the response and state the full name of the pipeline.

A.

For the purpose of the economic evaluation, FPL assumed it would procure firm transportation on Enable Gas Transmission, LLC ("Enable Pipeline", formerly known as CenterPoint Energy Gas Transmission Company, LLC), to transport gas from the gathering system to the Perryville Hub in Louisiana. Enable Gas Transmission, LLC is a FERC regulated interstate pipeline. FPL is currently investigating the acquisition of firm transportation and has not contracted for transportation service from the Woodford Project to FPL's existing natural gas transportation on the Enable Pipeline, or any other pipeline.

Q.

What is the current status of FPL acquiring firm transportation for the Woodford Project?

A.

FPL is currently investigating the acquisition of firm transportation for the Woodford Project and has not contracted for transportation service from the Woodford Project to FPL's existing natural gas transportation. The decision to enter into firm transportation is conditioned on the Commission's approval of FPL's request for the Woodford Project.

Q.

If the Commission approves FPL's request for the Woodford Project, how long will it take for FPL to acquire the necessary firm transportation?

A.

FPL anticipates that it will be prepared to acquire, within 30 days of a Commission order, if not sooner, the necessary firm transportation service for the Woodford Project.

Q.

What is the cost for 2015 of firm transportation assumed by FPL? As a part of the response, please state the assumed total annual cost and the assumed cost per unit for the assumed volume of gas transported.

A.

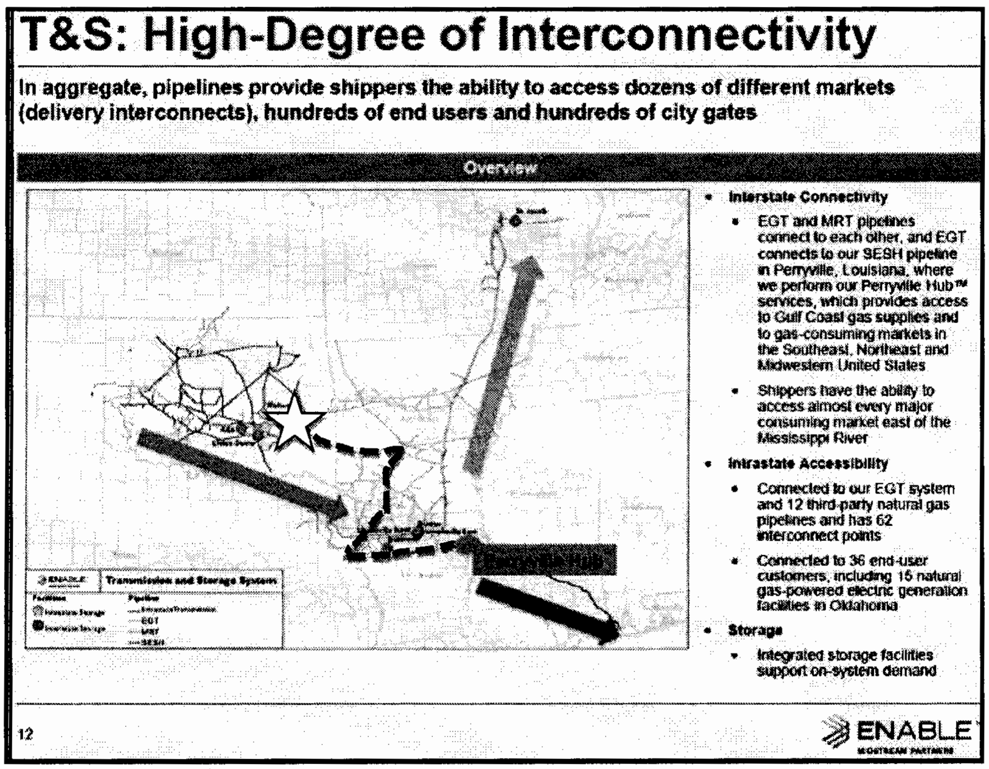
The estimated cost used in the model for firm transportation on the Enable Pipeline in 2015 is $6.13 MM, or $0.39 per Mcf (thousand cubic feet). This cost is comprised of two components; transportation equal to $4.55 MM ($0.29 per Mcf), and 2.83% fuel retention equal to $1.58 MM ($0.10 per Mcf). These costs represent the maximum posted tariff rates on the Enable Pipeline and are a conservative estimate of the actual costs that FPL will incur. These total firm transportation costs have been imbedded in the calculations that lead to the expected FPL customer savings of approximately $107 million.

Q.

Looking at the map on SF-1, why was the Enable Pipeline selected given that this pipeline does not appear to be a direct route from the Woodford Project to the Perryville Hub. Please explain this apparently less than direct route.

A.

The Enable Pipeline was selected because it has sufficient cost effective firm transportation available from the Woodford Project to FPL's existing natural gas transportation. The Enable Pipeline is a complex system linking multiple production areas to multiple market areas, intrastate and interstate pipelines, storage fields and hubs (see below). The path shown on SF-1 and overlaid on the slide below is the specific physical path available on the Enable Pipeline system to flow gas from the Woodford Project to Perryville Hub.



Location of Proposed PetroQuest Joint Venture

Enable Pipeline (Relevant Portion Only)

Source: Enable Midstream Partners, LP – CenterPoint Energy June 2014 Investor and Analyst Day, 6/30/14

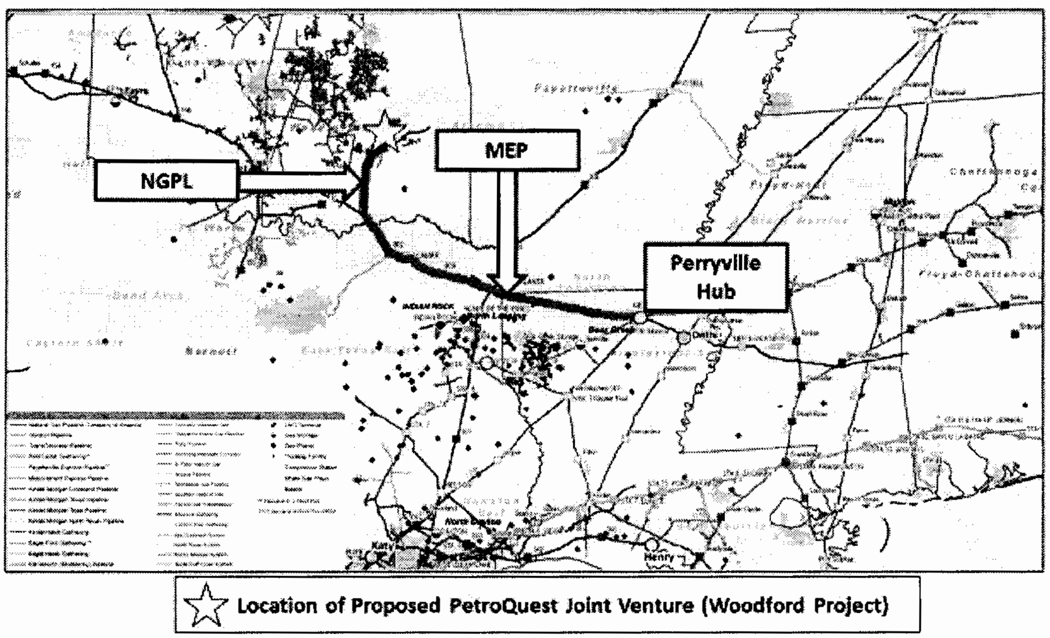
Q.

In developing the cost of transporting natural gas from the Woodford Project to Perryville, what routes and pipelines did FPL consider in developing the cost of transportation?

A.

FPL consulted with PetroQuest who is an experienced operator in the Woodford Shale and familiar with the regional pipeline system in order to determine the most appropriate route. The gathering system that serves the Woodford Project connects to two pipeline routes that can move gas east toward Florida, namely, Enable Pipeline and Natural Gas Pipeline Company of America ("NGPL"). The Enable Pipeline is directly interconnected to the Perryville Hub where FPL has existing firm transportation. The NGPL route would require contracting with a second pipeline, the Midcontinent Express Pipeline ("MEP"), to deliver gas to Perryville as shown below.

Alternate Pipeline Route



Q.

Please refer to SF-1. How is FPL's selection of the Enable pipeline and route the most cost effective of the pipelines and routes considered?

A.

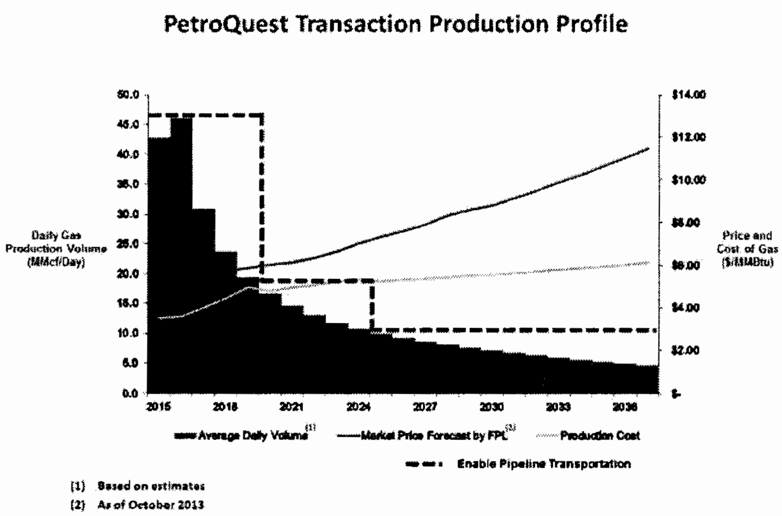
Of the two pipeline route options discussed in the response to Interrogatory No. 29, only the Enable Pipeline route had readily available firm transportation that could accommodate delivery of the estimated gas volumes from the Woodford Project to FPL's existing natural gas transportation. Furthermore, even if firm transportation service was readily available on NGPL and MEP to Perryville, the Enable Pipeline route is more cost effective.

Q.

Please refer to page 35 of the testimony of witness Forrest and to Exhibit SF-1. On lines 13 through 16, witness Forrest describes the cost of incremental natural gas transportation for the Woodford Project. How do the transportation costs reflect a conservative approach?

A.

The incremental gas transportation costs are based on securing sufficient firm transportation at the maximum posted transportation rate (see the response to Interrogatory No. 27) for the peak projected production volumes from the Woodford Project. Since it is unlikely that FPL can contract for firm transportation service that perfectly matches production volumes, FPL selected a fixed contract volume for a minimum contract term of five years as shown on the overlay to Exhibit SF-7 below.



FPL believes that this is a very conservative approach because it may be possible for FPL to secure firm gas transportation service for a volume profile that more closely matches the projected production profile of the Woodford Project. This would effectively reduce the amount of unused transportation on the Enable Pipeline and reduce the incremental transportation cost to FPL customers. Additional cost savings would be realized if FPL, through negotiation with the pipeline company or with another third party that possesses transportation on Enable Pipeline, is able to secure a discount to the maximum rate on any or all of its firm transportation service requirements.

Q.

Please refer to page 35 of the testimony of witness Forrest and to Exhibit SF-1. If the Commission approves FPL's request regarding the Woodford Project, how will this affect FPL's historical and current utilization of its firm capacity on the Southeast Supply Header pipeline?

A.

The Woodford Project will help FPL maintain its high utilization factor (84% from January 2012 through June 2014, and 94% for June-September of 2012 and 2013) on the Southeast Supply Header ("SESH") and will not impact its utilization of SESH. This high utilization factor on SESH will continue if the Woodford Project is approved. FPL intends to deliver the Woodford Project gas to Perryville where it will be delivered into SESH for delivery into either FGT or Gulfstream. The Woodford Project gas will simply replace a portion of the gas that FPL procures today at market prices at Perryville.

Q.

For the following interrogatories, please refer to the testimony of FPL witness Sam Forrest:
If the Commission approves FPL's request regarding the Woodford Project, will this affect pricing of natural gas and basis at the Mobile Hub? At the Perryville Hub? Please explain.

A.

No. There will be no impact to the price of gas at either FGT Zone 3 (Mobile Hub) or at the Perryville Hub. The volume of gas produced by the Woodford Project will be very minor in comparison to the volumes traded at Perryville and will replace gas that FPL would have otherwise procured at market prices at Perryville. Gas procured by FPL at Perryville, along with the gas delivered to Perryville from the Woodford Project, will be delivered on SESH to FGT Zone 3 and will not impact FGT Zone 3 prices.

Q.

Has FPL evaluated the creditworthiness and counterparty risks of PetroQuest Energy, Inc.? If so, please explain this evaluation and describe the results of FPL's evaluation of the creditworthiness and counterparty risk of PetroQuest.

A.

Yes, FPL has evaluated the creditworthiness and counterparty risks of PetroQuest Energy, Inc. ("PetroQuest"). Based upon that assessment, FPL focused upon proven PetroQuest assets previously developed by PetroQuest and negotiated contract terms designed to mitigate risks. FPL's assessment of PetroQuest's creditworthiness and counterparty risk began with a review of PetroQuest's S&P and Moody's credit ratings. FPL then turned to a review of its publicly available financial statements and reports. This included a review of their most recent 10K and 10Q reports filed with the Securities and Exchange Commission (SEC). Based upon those assessments, FPL began contract negotiations as described below designed to mitigate counterparty performance risks.

FPL's initial assessment of PetroQuest's risk profile was that it was typical of the risk profiles of gas exploration and production entities. PetroQuest's S&P and Moody's credit ratings are below investment grade, but that is not uncommon for this size company in the gas exploration and development industry. Similarly, PetroQuest's counterparty risks were higher than FPL's typical counterparties, but PetroQuest's experience operating in the Woodford shale provided FPL with sufficient comfort to move forward with its analysis of and negotiations with PetroQuest for participation in the Woodford Project. To mitigate some of the initially perceived risks, FPL undertook several courses of conduct. First, it consulted with Dr. Taylor, a well-respected and experienced petroleum engineer, to assess the potential productivity of the assets to be developed. Based upon his knowledge and expertise, FPL was able to assess that the production risk from the assets was much lower than it would be if the developer was developing new and unproven assets. This assessment was further supported by the findings of the independent petroleum engineering firm Forrest A. Garb & Associates, Inc., which is familiar with both the Woodford shale and PetroQuest's operational history. Second, FPL negotiated contract terms designed to mitigate some of the counterparty risks. Those terms include: non-consent rights, caps on drilling costs, Environmental and Safety Law compliance, establishment of a limited liability wholly-owned subsidiary of FPL to hold the Woodford Project, limited prepayment with half of the drilling cost for a well due immediately prior to commencement of drilling operations and half due upon completion of that well (the typical period between the commencement of drilling operations and the well completion date is 45-75 days), ability for FPL to propose wells and conduct operations if at any time PetroQuest fails to propose any wells in the Woodford Project for a period of 120 consecutive days, and the right for FPL to audit PetroQuest's records. Third, since FPL will opt to receive its share of production in kind rather than have PetroQuest control the process of selling the gas and paying FPL the proceeds, this further reduces any credit or financial risk that may be inherent with other non-operating working interest owners. Lastly, FPL relied upon the prior experience of its affiliate's working with PetroQuest, which showed that PetroQuest had been a good counterparty.

Based upon these assessments and mitigating activities, FPL concluded that entering into the PetroQuest Agreement was prudent. The projected cost savings, the proven assets, the reputation of PetroQuest and the contract provisions in place outweigh the mitigated risks being assumed. Therefore, FPL concluded that entry of the contract was in the best interests of its customers.

Q.

Does PetroQuest Energy, Inc. have a bond rating from Standard & Poor's, Moody's, or Fitch? If yes, please identify the rating(s).

A.

PetroQuest's bond rating from Standard & Poor's and Moody's is B/Stable and B3/Stable, respectively.

Q.

Has PetroQuest Energy, Inc. or any of its subsidiaries defaulted on debt payments in the last 5 years? If yes, please explain.

A.

No. PetroQuest has not defaulted on any debt payments in the last 5 years.

Q.

Is PetroQuest Energy, Inc. or any of its subsidiaries involved in litigation that might result in significant financial changes for the company? If yes, please explain.

A.

No. Publicly held companies such as PetroQuest must report in their annual and quarterly filings with the Securities and Exchange Commission ("SEC") all pending or threatened litigation that might have a material impact on their financial statement. According to PetroQuest's most recent 10K and 10Q filed with the SEC, PetroQuest and its management have represented to the SEC and its investors that existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

Q.

Is PetroQuest Energy, Inc. or any of its subsidiaries involved in federal, state, or local regulatory proceedings that might result in significant financial changes for the company? If yes, please explain.

A.

No. Publicly held companies such as PetroQuest ("PQ") must report in their annual and quarterly filings with the Securities and Exchange Commission ("SEC") all pending or threatened litigation that might have a material impact on their financial statement. Such litigation should include federal, state or regulatory proceedings. According to PQ's most recent 10K and 10Q filings with the SEC, PQ and its management have represented to the SEC and its investors that they expect no material impact of pending litigation.

Q.

Will Standard & Poor's impute debt to FPL for costs associated with the Woodford Project in its credit analysis? If so, will FPL seek to add this imputed debt to its regulatory capital structure? Please explain your response.

A.

FPL does not expect Standard & Poor's ("S&P"), as a part of its credit analysis, to impute debt to FPL's adjusted balance sheet or make financial adjustments to FPL's financial metrics to reflect an increase in FPL's credit exposure for those costs associated with the Woodford Project. Standard & Poor's imputes debt when a utility enters into a power purchase agreement ("PPA"), because in its view, a PPA creates a fixed, debt-like, financial obligation that represents a substitute for a debt-financed capital investment in generation capacity. Disparate to a PPA, this investment will be financed with a mix of debt and equity as a component of FPL's permanent capital structure. FPL will target a capital structure for this investment consistent with its overall approved regulatory capital structure.

Q.

Please refer to pages 22 through 24 of the testimony of FPL witness Ousdahl. Also, please refer to pages 8 and 9 of the testimony of FPL witness Forrest and to the reference on page 9 to Order No. 14546 and "fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers." Does FPL consider the costs of an interest in a natural gas reserve project to be a cost normally recovered through base rates for an investor-owned electric utility? Please explain.

A.

As noted on page 22 of FPL witness Ousdahl's testimony, Order No. 14546 is referenced for the Commission's policy that "Fuel Clause recovery is appropriate for projects that are intended to lower the delivered prices of fuel when those costs were 'not recognized or anticipated in the cost levels used to determine base rates.'" This clearly applies to the costs for the Woodford Project, because (1) it is intended (and reasonably projected) to lower the delivered price of natural gas for FPL and our customers; and (2) it was not recognized or anticipated when FPL prepared the 2013 test year MFRs that were the basis for determining FPL's current base rates in Docket No. 120015-EI. FPL also notes that, while the unit cost of production is projected to remain stable over the period when gas will be produced by the Woodford Project, the volume of production and hence the total production costs per year are projected to decline relatively rapidly in the first few years. This pattern of declining total cost levels also supports the appropriateness of Fuel Clause recovery, where the level of cost recovery can be readily adjusted from one year to the next.

For the reasons just discussed, FPL does not believe that base rates would be appropriate as the mechanism for recovering the costs of gas reserve projects, but notes that an investor-owned utility is entitled to recover its reasonable and prudent costs through some form of rates.

Q.

Please identify the FERC account(s) FPL would use to record the costs of the Woodford Project.

A.

Similar to natural gas otherwise purchased by FPL, the accounts that will be used are FERC accounts 547 and 501. The determination of which of the two accounts will ultimately be used will depend on which plant burns the natural gas (i.e. other generation or steam). Gas placed in inventory/received will go to FERC account 151.

Q.

Has FPL ever recovered the cost of an interest in a natural gas reserve project through base rates? If so, please provide a detailed response.

A.

No. FPL has never incurred nor recorded any costs related to this type of activity in any of its rates. Similar costs are incurred by third parties and are billed to FPL as gas purchases which are included in FPL's fuel clause.

Q.

Please refer to pages 12 through 14 of the testimony of witness Forrest. Does FPL believe the monthly changes in spot gas prices since 2009 warrant an increase in gas price hedging? Please explain.

A.

No, as stated in witness Forrest's testimony, one of the objectives of the hedging program is to achieve fuel price stability (volatility minimization). The current natural gas being hedged by FPL provides stability if gas prices decrease. As further stated in witness Forrest's testimony, FPL is not proposing to increase, or change in any way, the hedging percentage of natural gas, but is rather proposing to switch the allocation from financial hedges to physical gas received.

Q.

Does FPL believe the volatility of gas prices will increase over the next five years relative to the volatility of gas prices for the past five years? Please explain your response.

A.

There are a number of factors, including LNG exportation, further natural gas discoveries, and the depletion of the Gulf of Mexico that will dictate the future of gas prices as well as volatility of future gas prices. FPL cannot predict the volatility of those future gas prices, but believes the Woodford Project will assist in mitigating the volatility inherent in FPL's long-term natural gas procurement.

Florida Power & Light Company
Docket No. 140001-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 45

Q.

Please refer to page 17 of the testimony of witness Forrest, lines 7 through 21. If the Commission approves FPL's request to acquire an interest in the Woodford Project, will this reduce the portion of projected gas consumption that is financially hedged? Please explain your response and, if necessary, discuss the reduction in the portion of projected gas consumption that will be financially hedged.

A.

Yes. FPL intends to replace a corresponding amount of financial hedges with the gas projected to be produced by the Woodford Project. For example, in 2015, FPL expects to hedge approximately [redacted] of its projected natural gas requirements. The Woodford Project is projected to produce approximately 43,000 MMBtu/day, which is approximately 2.9% of FPL's daily needs. As a result, FPL will financially hedge [redacted] of its projected gas needs and utilize the Woodford Project gas to achieve a [redacted] hedged level.

Q.

For financial hedging, FPL reports on the period August 1 through December 31 in testimony filed the following April. For the period January 1 through July 31 of the current year, FPL reports the results of financial hedging activities in an August 15 report and in subsequent testimony. If the Commission approves FPL's request to acquire an interest in this natural gas reserve project, will FPL include the results of this physical hedging activity in the above-cited testimony and reports? Please explain your response.

A.

Yes. FPL will include the results of the Woodford Project as physical hedges in the Hedging Activity Final True-Up Report in April and the Hedging Activity Supplemental Report in August of each year.

Q.

If the Commission approves FPL's request to acquire an interest in the Woodford Project, how will this affect FPL's risk management plans?

A.

FPL files an annual risk management plan to discuss hedging activity for the upcoming year, among other things. As explained in the answer to Interrogatory No. 45, FPL expects to utilize the gas produced by the Woodford Project to replace a corresponding percentage of financial hedges. FPL will discuss the forecasted volumes and percentages of financial hedges and physical gas in its annual filing of the risk management plan. In effect, the combination of financial hedges and the physical gas produced by the Woodford Project will total the expected level of hedging in the risk management plan.

Q.

If FPL acquires an interest in the Woodford Project, will this project substitute for, act as, or be used as gas storage? Please explain.

A.

No. Gas storage is utilized to help mitigate supply disruptions and for balancing daily swings in gas demand. The gas produced by the Woodford Project will become part of FPL's overall natural gas procurement portfolio. Therefore, participation in the Woodford Project does not alleviate the need for gas storage, as FPL will continue to be at risk for supply disruptions. Additionally, the need for balancing the swings in daily requirements due to load and generation changes will continue.

Q.

If the Commission approves FPL's request to acquire an interest in the Woodford Project, will this affect FPL's current firm gas storage capacity and use? If yes, how?

A.

No. Acquiring an interest in the Woodford Project will not impact FPL's current firm storage capacity or the utilization of that capacity. The gas produced by the Woodford Project will replace a corresponding volume of gas procured as part of the normal, day to day procurement activities.

Q.

If the Commission approves FPL's request to acquire an interest in the Woodford Project, will this affect FPL's plans, if any, for future gas storage? If yes, how?

A.

Please see response to Interrogatory No. 49.

Q.

Please refer to page 20 of the petition, paragraph 41. Refer to the following statement: FPL will be able to roll off the hedges in a relatively short period of time by natural attrition due to the accelerated production (and hence depletion) of the gas reserves that occurs in the first few years of their operation. Please explain this statement.

A.

The expected production profile for the gas from the Woodford Project has a steep decline rate, such that in the first 6 years of production, 50% of the expected output of the well is already extracted. Since this expected depletion occurs in a relatively short period of time when compared to the expected life of the wells, which is over 30 years, this gives greater flexibility for FPL to decide to purchase lower priced gas in the market after the first few years if available, rather than replacing the diminished output of the Woodford Project with additional gas reserve projects.

Q.

Order No. PSC-13-0023-S-EI approved a stipulation and settlement of FPL's most recent base rate proceeding. This stipulation allows FPL to implement an incentive mechanism that included functions such as gas storage utilization, city-gate gas sales, production area gas sales, and capacity release of gas transportation. How will the incentive mechanism interact with this proposal to acquire an interest in this natural gas reserve project (the Woodford Project)? Identify and describe each way the two programs can interact, including but not limited to production area sales, Florida market sales, city gas sales, release of pipeline capacity, gas storage utilization, etc.

A.

The decision to enter into the PetroQuest transaction was made independent of the incentive mechanism and the economics that have been presented to the Commission do not reflect any potential asset optimization gains from any part of the PetroQuest transaction. If the Commission approves the PetroQuest transaction and FPL takes assignment of the agreement, the gas delivered under the agreement will become part of the larger FPL procurement portfolio and will be treated in the same manner as the rest of the portfolio. Therefore, production area sales will certainly be considered whenever they have the potential of generating savings for FPL's customers. Additionally, any transportation procured for the delivery of the PetroQuest gas to FPL's current transportation portfolio would be eligible for capacity release, which likewise would be considered when the potential for customer savings exists.

As mentioned in the response to Interrogatory No. 31, FPL has made a conservative estimate of the gas transportation required to serve the Woodford Project. To remain conservative, that estimate does not assume any savings associated with asset optimization. Should the Commission approve the Woodford Project, FPL will seek to secure a deal for transportation that makes the most sense for our customers at the time that we actually enter into the transportation arrangement. Thereafter, asset optimization opportunities such as capacity releases will be pursued if and when they would benefit the larger procurement portfolio and provide additional customer savings.

Q.

Please refer to Exhibit SF-1, attached to the testimony of witness Forrest. Will pipeline capacity on the Enable Pipeline used to transport gas from the Woodford Project to the Southeast Supply Header pipeline be released/sold as part of the incentive mechanism? Please explain the response.

A.

FPL has not committed to procuring capacity on the Enable pipeline at this time. The economics shown as part of the PetroQuest petition include the transportation costs for the Enable pipeline in a way that represents the most conservative estimate, but FPL continues to pursue other transportation options that may provide improved economics. If FPL receives approval from the Commission for the Woodford Project, we will seek a gas transportation agreement that makes the most sense for our customers and will seek to more closely mirror the production profile of the Woodford Project. FPL then would address the day to day transportation needs to delivery of gas produced under the PetroQuest agreement as part of the daily optimization activities. At this time, it is not possible to project the value that these optimization activities might have for the Woodford Project.

Q.

Please refer to Exhibit SF-1 attached to the testimony of witness Forrest. Regarding FPL's firm capacity on the Southeast Supply Header Pipeline, Florida Gas Transmission Pipeline, Gulfstream Pipeline, Transco - Zone 4A Lateral, Gulf South Pipeline, and planned firm capacity on the Sabal Trail and Florida Southeast Connection pipelines, how will FPL's participation in the Woodford Project affect the amount of firm capacity that can be released/sold for incentive mechanism purposes?

A.

There is no impact to the existing or planned (Sabal Trail and FSC) transportation capacity in FPL's portfolio. The gas delivered from the Woodford Project is upstream of that transportation and will be part of the larger procurement portfolio that uses those existing transportation agreements to deliver the gas to FPL's power plants.

Q.

Does the outsourcing of the asset optimization functions in the incentive mechanism continue to be a viable option if FPL acquires an interest in the Woodford Project? Please explain your response.

A.

Yes. While there have only been a few opportunities to execute Asset Management Agreements ("AMA"), they can provide FPL an opportunity to "lock in" value for FPL's customers by outsourcing a portion of the asset optimization function to third parties who pay FPL a premium to take assignment of some portion of the fuel transportation or storage portfolio. These agreements may represent value above and beyond what FPL can deliver based on the premium paid by the third party at no impact to reliability. The Woodford Project does not change that fact and, in fact, may present additional opportunities to enter AMA's if a third party is willing to pay a premium to manage some portion of the Woodford Project. Again, FPL has not assumed any AMA value in the economics presented as part of the Woodford Project and has not entered into any negotiations or discussions regarding an AMA of the Woodford Project assets.

Q.

Please refer to witness Ousdahl's direct testimony on page 11, lines 19-21. Please provide the full reference (e.g. 805-10-20-2) with all the specific subsection(s) of Accounting Standards Codification 805 concerning the transfer of investment at net book value.

A.

The accounting for the transfer of assets under common control is governed by ASC 805-50-30-5, which states: "When accounting for a transfer of assets or exchange of shares between entities under common control, the entity that receives the net assets or the equity interests shall initially measure the recognized assets and liabilities transferred at their carrying amounts in the accounts of the transferring entity at the date of transfer." FPL and USG are considered entities under common control because they share a common parent in NextEra Energy, Inc. In this case, the carrying amount of the assets on USG's books is net book value.

Q.

With the issuance of International Financial Reporting Standard 6, are entities allowed to continue applying their accounting policy with respect to exploration and evaluation until a more comprehensive solution regarding accounting policy is developed?

A.

FPL is not subject to International Financial Reporting Standards. The U.S. GAAP standard applicable to FPL is ASC 932 Extractive Activities – Oil and Gas. Under this standard, FPL is required to select a method of accounting (full cost or successful efforts) and apply it consistently.

Q.

According to International Financial Reporting Standard 3, does the Woodford Project transaction constitutes a "business"? If not, please explain why.

A.

FPL is not subject to International Financial Reporting Standards. The U.S. GAAP standard applicable to FPL is ASC 805 Business Combinations. The Woodford Project transaction is a transfer of assets under common control since USG and FPL share a common parent in NextEra Energy, Inc. Transactions between entities under common control are specifically not part of the business combination guidance under ASC 805-10-15-4. As such, the determination of whether or not the Woodford Project transaction constitutes a business is not applicable.

Q.

If the answer to Question 59 above is "yes", is a deferred tax asset or liability arising from the assets acquired and liabilities assumed recognized pursuant to International Accounting Standard 12? If not, please explain why.

A.

FPL is not subject to International Accounting Standards. Under U.S. GAAP the Woodford Project is not considered a business combination; refer to response to Staff's 2nd Set Interrogatories number 59.

Q.

Please refer to witness Ousdahl's direct testimony on page 16, line 16. Other than the basis that the SEC prefers the "successful efforts" method, does FPL have any other basis why this method should be utilized instead of the "full cost" method?

A.

Yes. SEC Staff Accounting Bulletin Topic 12.C ("SAB Topic 12.C") states that a consolidated entity must apply a consistent accounting method for all subsidiaries. FPL's parent, NextEra Energy, Inc. has elected the successful efforts method of accounting through its subsidiary, USG. Therefore, FPL is also required to follow the successful efforts method of accounting. Below is an excerpt from SAB Topic 12.C:

Question 1: If a parent company uses the successful efforts method of accounting for oil and gas producing activities, may a subsidiary of the parent use the full cost method?

Interpretive Response: No. The use of different methods of accounting in the consolidated financial statements by a parent company and its subsidiary would be inconsistent with the full cost requirement that a parent and its subsidiaries all use the same method of accounting.

Q.

According to the Energy Policy Act of 2005 [26 U.S.C. 167(h)], is a tax deduction for geological and geophysical assessments by smaller oil and gas companies required to be recognized over a 24-month amortization period? If not, what is the appropriate amortization period?

A.

Yes. The amortization period for tax purposes for costs incurred for geological and geophysical assessments is 24-months under IRC Section 167(h).

Q.

Will PetroQuest or FPL, through its Tax Partnership Agreement, take advantage of the Special Percentage Depletion Allowance for tax purposes?

A.

It is uncertain at this time whether or not FPL will be able to take advantage of the Special Percentage Depletion Allowance for tax purposes due to the fact that FPL will be taking the gas "in-kind" for consumption in FPL's power plants. The Special Percentage Depletion Allowance for natural gas wells is calculated based on the amount of gross income derived from each well. Since FPL will be consuming the gas instead of selling it to generate gross income there appears to be no basis upon which to calculate the deduction. A similar issue was addressed in Roundup Coal Mining Co., 20 TC 388, 05/21/1953, where it was determined that a mining company that mined coal and consumed a portion of the coal in its powerhouse as fuel was not entitled to claim a Percentage Depletion deduction on the amount of coal that was consumed in the powerhouse.

Q.

Will PetroQuest or FPL, through its Tax Partnership Agreement, take advantage of the tax deduction associated with geological and geophysical assessments?

A.

Yes. Under the tax sharing agreement, FPL will recognize the tax deduction related to its share of the cost for geological and geophysical assessments over 24 months.

Q.

Will PetroQuest or FPL, through its Tax Partnership Agreement, take advantage of the Section 199: Domestic Production Activities Deduction for tax purposes?

A.

Yes. Under the tax sharing agreement, FPL will calculate the Section 199 deduction on its share of eligible costs and, to the extent allowed under the Internal Revenue Code, will take the deduction.

Q.

If any of the answers to Questions 63, 64 and/or 65 above are "yes", is FPL's requested recovery of the Woodford Project net of the dollar impact associated with these deferred income taxes and tax credits? If so, please indicate where in FPL's petition and direct testimony this netting is recognized.

A.

The investment and the deferred income taxes associated with the Woodford gas reserve project will be recorded in the general ledger of the subsidiary. For regulatory reporting, this subsidiary will be consolidated with FPL thus reporting "total regulated operations". The net investment in the gas reserve project and related working capital items will be eliminated for base rates since they will be earning their own return through the fuel clause. The deferred income taxes recorded for the gas subsidiary will be included in the consolidated capital structure. This capital structure will be utilized in the determination of the return to be provided to clause investments based on the May Earnings Surveillance Report, per FPSC Order No. PSC-12-0425-PAA-EU. The clause treatment described in this response is reflected in FPL witness Ousdahl Exhibit KO-6.

Q.

If the answer to Question 66 above is "no", please explain why not given the amounts of deferred income taxes and tax credits effectively generated by the Woodford Project.

A.

Refer to response provided to Staff's 2nd Set of Interrogatories No. 66.

Q.

If the answer to Question 66 above is "no", please provide the dollar impact associated with these deferred income taxes and tax credits.

A.

As shown on KO-5, page 2 of 2, the estimated deferred income tax liability at the end of December 2015 is approximately $32 million which would decrease over the remaining life of the asset.

Q.

If any of the answers to Questions 63, 64 and/or 65 above are "no", please explain why PetroQuest or FPL, through its Tax Partnership Agreement, will not be taking advantage of these deferred income taxes and tax credits.

A.

Not applicable.

Q.

Please refer to witness Forrest's direct testimony, page 23, lines 7-14. Is the capitalized amount of the intangible drilling costs (IDCs) recovered over a 60-month period for tax purposes? If not, please explain why.

A.

No. The intangible drilling cost will be expensed immediately for income tax purposes under Internal Revenue Code Section 263(c) and will not be recovered over a 60-month period.

FPL witness Forrest's testimony states, "FPL will have a tax partnership agreement with PetroQuest that will allow FPL to expense, for tax purposes, Intangible Drilling Cost ("IDC") incurred during drilling."

Q.

According to the Internal Revenue Service Publication 535 (2013) – Business Expenses, is the capitalized amount of the domestic exploration costs amortized over a 60-month period? If not, please explain why.

A.

The domestic exploration cost referenced in Internal Revenue Service Publication 535 (2013) relates to mineral deposits and the development of a mine. The domestic exploratory costs for gas and oil would either be deductible as geological and geophysical assessments (G&G) under Internal Revenue Code section 167(h) or as intangible drilling costs (IDC) under Internal Revenue Code Section 263(c). G&G are the costs (internal and external) of gathering and analyzing seismic and geological data or if a core-hole well were drilled to gather geological data and should be capitalized under IRC section 167(h) and amortized for tax purposes over 24 months. Drilling cost aimed at production, even if exploratory in nature, should be deductible as IDC and expensed currently for tax purposes.

Q.

Please refer to witness Forrest's direct testimony, page 40, line 20 through page 41, line 5. If the mix of hydrocarbons is implemented in future projects, would PetroQuest or FPL, through its Tax Partnership Agreement, take advantage of the Section 193: Deduction for Tertiary Injectants? If not, please explain why?

A.

The testimony referred to above does not relate to the use of hydrocarbons for tertiary injectants. Tertiary injectants refers to items injected into older reservoirs to help continue production, whereas FPL witness Forrest's direct testimony on page 40, line 20 through page 41, line 5 relates to the type of commodities (hydrocarbons) which may be obtained from future proposed drilling. These commodities range from methane to natural gas liquids to oil. As witness Forrest points out in testimony FPL will focus on natural gas to supply its power plant, but should future drilling produce natural gas liquids or oil, the economic benefit from the sale of those commodities will be recognized in lowering the ultimate cost recoverable through the fuel clause.

Q.

If the answer to Question 72 above is "yes", should any Commission-approved future fuel clause recovery of the projects using hydrocarbons be netted against the dollar impact associated with the Section 193 tax credit?

A.

Not applicable.

Q.

If the answer to Question 73 above is "no", please explain why not given the amount of tax credits effectively generated by the introduction of hydrocarbons of future projects?

A.

Not applicable.

Q.

Please refer to page 6, paragraph 10, of the petition. For the five-year period 2009 to 2013, provide a table comparing the cost of production from Woodford shale gas reserves to market prices.

A.

FPL was unable to obtain pricing for the Woodford shale for the year 2009. However, according to the global energy research and consulting firm Wood Mackenzie, the break-even price for producers in the Arkoma Basin of the Woodford Arkoma (which is the area of interest for the Woodford Project) is included in the following table:

	2010	2011 1H	2011 2H	2012 1H	2012 2H	2013 1H	2013 2H
Woodford Arkoma (Core)	$ 4.75	$ 4.96	$ 4.40	$ 4.11	$ 3.87	$ 4.04	$ 3.89
NYMEX Henry Hub	$ 4.39	$ 4.21	$ 3.87	$ 2.48	$ 3.10	$ 3.71	$ 3.59

Wood Mackenzie describes the break-even price as the Henry Hub equivalent price at which producers could sell their production while covering all operating costs and earning a 10% rate of return. The table illustrates the central point of Paragraph 10, which is that the cost of production is more stable than the NYMEX market prices. Those market prices were exceptionally low in the 2010-2013 period, but are not projected to remain that low into the future. Rather, they are expected to increase over time and consistently exceed the projected cost of production, which is the point of the last sentence in Paragraph 10 and is illustrated in Exhibit SF-7.

Q.

Please refer to page 16 of the petition, paragraph 33(b.). How is the "carry" amount determined? Please show all calculations and inputs.

A.

The carry amount is a negotiated term between the operator and the acquiring non-working interest owner. This reflects the amount the non-working interest owner will "carry" the operator for their share of the drilling costs in excess of the interest in the gas received. As described in witness Forrest's testimony, the carry is meant to provide payment for an ownership interest in the leasehold and associated mineral rights. Additionally the carry compensates PetroQuest for acting as the operator and to reimburse it for previous expenses incurred and risks taken in purchasing the mineral rights, developing the acreage and enhancing the drilling and completion tactics that increase the productivity of future wells in that acreage. There is no specific formula to arrive at how the carry is negotiated; it is only a figure that makes the economics work for both transacting parties.

Q.

Please refer to page 17 of the petition, paragraph 34. Will FPL be compensated by USG if the market decreases between the time of the initial purchase and the transfer to FPL? Please explain the response.

A.

No. It is contemplated that the PetroQuest transaction will be transferred to FPL at net book value ("NBV"). There is no consideration for the forward price for natural gas at the time of transfer. Regardless of whether prices increase or decrease, FPL will take possession of the agreement at NBV. In reality, USG is taking on risk during this interim period for which they are not being compensated. If forward gas prices decrease during this period and should the Commission not approve the transaction, USG will continue to partner with PetroQuest and will have seen the value of the JV decay based on the lower forward prices.

Q.

Please refer to pages 20 and 21, paragraph 42, of the petition. For 2015, provide an estimate of each type of recoverable cost.

A.

Refer to FPL witness Ousdahl, Exhibit KO-16 for the 2015 detail estimate by month of expenses associated with this project. We have not attempted to forecast all working capital amounts so there are no values presented to those accounts.

Please refer to the document provided as part of this response entitled "Staffs 2nd Set No. 78 Exhibit KO-6 Fuel Projection Filing (Updated).xlsx" for the 2015 detail estimate by month of expenses associated with this project. Note that the values reflected in the update differ from Exhibit KO-6 as filed only in that the weighted average cost of capital ("WACC") applied to the net investment has been revised consistent with the Commission-approved methodology for calculating the WACC used in clause filings. FPL intends to include the costs shown on this updated estimate in its 2015 Fuel Clause projection filing. As was the case in the original Exhibit KO-6, FPL has not attempted to forecast working capital balances, but will reflect the actual balances in the Fuel Clause true-up filings for 2015.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January ESTIMATED	February ESTIMATED	March ESTIMATED	April ESTIMATED	May ESTIMATED	June ESTIMATED	Six Month Amount
1.	Investments								
	a. Capital addition		$5,045,400	$19,260,000	$14,214,600	$19,260,000	$5,045,400	$19,260,000	$82,085,400
2.	Gas Reserve Investment / DD&A Base (A)	$68,446,271	73,491,671	92,751,671	106,966,271	126,226,271	131,271,671	150,531,671	n/a
3.	Less: Accumulated Depletion Reserve	$0	377,307	971,330	1,901,685	3,106,386	4,682,419	6,426,341	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$68,446,271	$73,114,364	$91,780,341	$105,064,586	$123,119,885	$126,589,252	$144,105,330	n/a
5.	Average Rate Base (D)		70,780,318	82,447,352	98,422,463	114,092,236	124,854,569	135,347,291	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		472,433	550,306	656,934	761,524	833,358	903,393	$4,177,947
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		87,010	101,353	120,991	140,254	153,484	166,382	$769,473
	Subtotal (Debt & Equity Return)		559,443	651,658	777,924	901,777	986,842	1,069,776	
7.	Investment and Operating Expenses								
	a. Transportation Costs		416,920	524,058	740,515	898,160	1,127,811	1,216,633	$4,924,097
	b. Depletion		377,307	594,024	930,354	1,204,701	1,576,033	1,743,922	$6,426,341
	c. Lease Operating Expenses (LOE)		47,592	103,946	121,077	169,423	201,640	240,162	$883,839
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	$480,766
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	$150,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$1,506,389	$1,978,814	$2,674,998	$3,279,189	$3,997,453	$4,375,621	$17,812,464

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%. The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Working capital balance has not been forecasted for inclusion in Average Rate Base but will be included in the true-up filings when actual balances are known.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July ESTIMATED	August ESTIMATED	September ESTIMATED	October ESTIMATED	November ESTIMATED	December ESTIMATED	Twelve Month Amount
1.	Investments								
a.	Capital addition		$16,276,500	$9,630,000	$2,522,700	$8,368,650	$3,438,450	$0	$122,321,700
2.	Gas Reserve Investment / DD&A Base (A)	$150,531,671	166,808,171	176,438,171	178,960,871	187,329,521	190,767,971	190,767,971	n/a
3.	Less: Accumulated Depletion Reserve	$6,426,341	8,323,765	10,424,370	12,999,989	15,630,310	18,154,600	20,744,130	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$144,105,330	$158,484,406	$166,013,801	$165,960,882	$171,699,211	$172,613,371	$170,023,841	n/a
5.	Average Rate Base		151,294,868	162,249,103	165,987,341	168,830,047	172,156,291	171,318,606	n/a
6.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		1,009,838	1,082,953	1,107,904	1,126,878	1,149,080	1,143,489	10,798,089
b.	Debt Component (Line 5 x debt rate x 1/12) (C)		185,987	199,453	204,048	207,543	211,632	210,602	1,988,738
	Subtotal (Debt & Equity Return)		1,195,824	1,282,406	1,311,953	1,334,421	1,360,712	1,354,091	
7.	Investment and Operating Expenses								
a.	Transportation Costs		1,311,045	1,441,048	1,702,735	1,731,192	1,654,296	1,690,799	14,455,211
b.	Depletion		1,897,425	2,100,605	2,575,618	2,630,321	2,524,290	2,589,531	20,744,130
c.	Lease Operating Expenses (LOE)		218,151	349,126	391,672	397,235	413,250	385,946	3,039,218
d.	Taxes (Ad-Valoren & Severance)		80,128	80,128	80,128	80,128	80,128	80,128	961,533
e.	G&A		25,000	25,000	25,000	25,000	25,000	25,000	300,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$4,727,572	$5,278,312	$6,087,105	$6,198,297	$6,057,675	$6,125,494	52,286,919

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Working capital balance has not been forecasted for inclusion in Average Rate Base but will be included in the true-up filings when actual balances are known.

Totals may not add due to rounding.

Florida Power & Light Company
Docket No. 140001-EI
Staff's 2nd Set of Interrogatories
Question No. 78
Attachment I / Staff's 2nd Set No. 78 Exhibit KO-6 Fuel Projection Filing (Updated).xlsx
Page 2 of 2

Q.

Please refer to pages 20 and 21, paragraph 42, of the petition. For 2015, provide an estimate of each type of recoverable cost.

A.

FPL is supplementing this response only by providing a copy of the updated Exhibit KO-6 that was filed as part of FPL's errata on November 5, 2014. Please see Attachment I to this supplemental response.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January ESTIMATED	February ESTIMATED	March ESTIMATED	April ESTIMATED	May ESTIMATED	June ESTIMATED	Six Month Amount
1.	Investments								
	a. Capital addition		$5,045,400	$19,260,000	$14,214,600	$19,260,000	$5,045,400	$19,260,000	$82,085,400
2.	Gas Reserve Investment / DD&A Base (A)	$68,446,271	73,491,671	92,751,671	106,966,271	126,226,271	131,271,671	150,531,671	n/a
3.	Less: Accumulated Depletion Reserve	$0	238,144	594,867	1,179,341	2,029,642	3,172,825	4,591,220	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$68,446,271	$73,253,527	$92,156,804	$105,786,930	$124,196,629	$128,098,846	$145,940,451	n/a
5.	Average Rate Base (D)		70,849,899	82,705,165	98,971,867	114,991,779	126,147,737	137,019,648	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		472,897	552,027	660,601	767,528	841,990	914,556	$4,209,597
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		87,096	101,669	121,666	141,359	155,073	168,438	$775,302
	Subtotal (Debt & Equity Return)		559,993	653,696	782,267	908,887	997,063	1,082,994	
7.	Investment and Operating Expenses								
	a. Transportation Costs		285,676	359,088	507,406	615,425	772,784	833,646	$3,374,026
	b. Depletion		238,144	356,723	584,474	850,301	1,143,183	1,418,395	$4,591,220
	c. Lease Operating Expenses (LOE)		47,592	103,946	121,077	169,423	201,640	240,162	$883,839
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	$480,766
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	$150,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$1,236,533	$1,578,581	$2,100,351	$2,649,165	$3,219,797	$3,680,324	$14,464,751

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Working capital balance has not been forecasted for inclusion in Average Rate Base but will be included in the true-up filings when actual balances are known.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July ESTIMATED	August ESTIMATED	September ESTIMATED	October ESTIMATED	November ESTIMATED	December ESTIMATED	Twelve Month Amount
1.	Investments								
a.	Capital addition		$16,276,500	$9,630,000	$2,522,700	$8,368,650	$3,438,450	$0	$122,321,700
2.	Gas Reserve Investment / DD&A Base (A)	$150,531,671	166,808,171	176,438,171	178,960,871	187,329,521	190,767,971	190,767,971	n/a
3.	Less: Accumulated Depletion Reserve	$4,591,220	6,271,949	8,224,436	10,639,750	13,222,515	15,746,805	18,336,336	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$145,940,451	$160,536,222	$168,213,735	$168,321,121	$174,107,006	$175,021,166	$172,431,635	n/a
5.	Average Rate Base (D)		153,238,336	164,374,978	168,267,428	171,214,063	174,564,086	173,726,400	n/a
6.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		1,022,809	1,097,142	1,123,123	1,142,791	1,165,151	1,159,560	10,920,174
b.	Debt Component (Line 5 x debt rate x 1/12) (C)		188,376	202,066	206,851	210,473	214,592	213,562	2,011,223
	Subtotal (Debt & Equity Return)		1,211,185	1,299,209	1,329,974	1,353,264	1,379,743	1,373,122	
7.	Investment and Operating Expenses								
a.	Transportation Costs		898,337	987,416	1,166,726	1,186,225	1,133,535	1,158,547	9,904,811
b.	Depletion		1,680,729	1,952,487	2,415,314	2,582,765	2,524,290	2,589,531	18,336,336
c.	Lease Operating Expenses (LOE)		218,151	349,126	391,672	397,235	413,250	385,946	3,039,218
d.	Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	961,533
e.	G&A		25,000	25,000	25,000	25,000	25,000	25,000	300,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$4,113,530	$4,693,365	$5,408,814	$5,624,617	$5,555,945	$5,612,274	45,473,295

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Simplified example omits the working capital items that would be included in the actual clause filings

Totals may not add due to rounding.

Exhibit KO-6 **as filed** totaled $52,473,402

1) Update made to WACC components Debt/Equity per FPSC Order No. PSC-12-0425-PAA-EU

As Filed	Debt	1.5658%
	Equity	4.9230%
As Updated	Debt	1.4751%
	Equity	4.8938%

2) Transportation costs were reduced.

Exhibit KO-6 is intended to reflect costs purely associated with GRCO. The transportation costs as reflected in the "as filed" exhibit contained approximately $4.550 million of transportation costs that will be incurred by FPL directly, not the GRCO.

Therefore Exhibit KO-6 was updated to reflect the reduction of transportation costs.

3) Version of Exhibit KO-6 provided as part of the response to OPC 3rd Set of Interrogatories No. 43 footnote (c) incorrectly reflected the debt component (WACC)
It should have shown 1.4751%, instead reflected 1.4151%. Note that this only affected the footnote, the calculation was correctly presented.

4) Exhibit KO-6, Page 2, line 5, missing the footnote pointing to note (D)

5) Depletion calculation was updated to reflect timing of investment made instead of assumption of all investment made at day 1.
Revised Exhibit KO-6 total $45,473,295

Q.

Please refer to page 23 of the testimony of witness Forrest. Line 19 mentions "benefits and responsibilities." Please identify the specific benefits and responsibilities FPL will be assuming under the PetroQuest Agreement.

A.

- FPL is obligated to participate in a minimum of 15 wells and up to 38 wells
- FPL must provide timely notice of consent or non-consent to PetroQuest for each proposed well
- FPL shall pay its working interest share plus the carry amount for each well in which it participates
- FPL shall pay its working interest share of the operating expenses incurred by PetroQuest
- FPL must provide notice to PetroQuest to take its share of gas in kind and arrange for the delivery of its gas from the wellhead
- FPL shall pay PetroQuest for FPL's portion of the royalty payments
- FPL shall cooperate with PetroQuest in the exchange of information and filing required under the Tax Partnership Agreement

In return, FPL's customers will receive the benefits of gas production from the Woodford Project wells. These benefits include long-term price stability over a period of time (30-plus years) that is not offered through the financial markets, as well as projected customer savings of approximately $107 million on a net present value basis over the life of the project, based on FPL's forecast of natural gas prices.

Q.

Please refer to page 28 of the testimony of witness Forrest, lines 18 through 23. Is the requirement that PetroQuest meet prescribed targets an opt-out clause? Please explain the response.

A.

Yes. Although FPL has a commitment to engage in a minimum number of wells (see comments below), FPL can opt out of those wells if (a) PetroQuest's average drilling costs exceed a prescribed cost threshold or (b) if PetroQuest is in violation of an Environmental or Safety law. Of course, this opt out right is in addition to FPL's right to "non-consent" or opt out of participation in any specific well as long as it meets its required minimum number of wells.

Please note that the minimum commitment described on page 28 of the testimony of witness Forrest, lines 18 through 23, relates to FPL's commitment to drill a minimum number of the wells proposed by PetroQuest in the Area of Mutual Interest ("AMI"). FPL may elect to "non-consent" or opt-out of participation in any proposed well, subject to the constraint that FPL and USG combined must participate in a minimum of 15 wells prior to December 31, 2015, provided that PetroQuest has proposed at least 15 wells. If PetroQuest proposes less than 15 wells prior to December 31, 2015, then the minimum number of participation wells is reduced to the number of wells proposed.

Q.

Please refer to pages 30 and 31 of the testimony of witness Forrest. Identify and describe the incremental costs for each of the three functions (accounting, technical services, and business management) that FPL proposes to include for recovery in the Fuel Clause.

A.

FPL's current estimate used in the model related to incremental costs expected to support the gas reserves activity is approximately $300,000 per year. Refer to FPL witness Ousdahl KO-6, line 7e; the type of costs reflected in that line are:

<u>Accounting:</u> Monthly accounting and reporting activities provided by the third-party outsource provider. Note that the cost of accounting will typically be in proportion to the number of wells as costs and activities are managed and recorded on a well by well basis.
<u>Technical Services</u>: Reserve engineering support for reporting purposes and economic analysis of drilling costs and expected production for proposed wells, to be provided by USG as well as third parties.
<u>Business Management</u>: Review and analysis of expenditures, operations and production related to the Woodford Project, to be provided by USG.

FPL is in the process of selecting providers, the services to outsource and/or obtain from the affiliate, USG. FPL has not yet completed the sourcing process.

Q.

Please refer to page 35 of witness Forrest's testimony, line 17 and continuing on to page 36, line 2. Can the fuel savings (cost of production below market prices) be demonstrated based on past experience for existing wells and then-current market prices?

A.

FPL has not previously participated in a gas reserves project so it cannot provide any details on past experience. However, FPL has analyzed a number of gas reserve projects, as is mentioned in witness Forrest's testimony, at page 18, line 15 and continuing through line 20 on page 19. Several of those opportunities, although not transacted upon for various reasons, would have been economic for FPL's customers from year one, similar to the Woodford Project. The Woodford Project itself, as is demonstrated in the economics presented to the Commission, is conservatively forecast to result in $107 million savings to FPL customers, with immediate savings in 2015. The effective price of gas for the Woodford Project is projected to be $3.48/mmBtu in 2015, while the 2015 NYMEX Henry Hub forecast (NYMEX HH is the forecast FPL used in its long term forecast for 2015) is $4.02/mmBtu. That provides for an estimate of over $8 million in customer savings in 2015 alone. To go one step further, as is explained in the testimony of FPL witnesses Taylor and Forrest, 10 percent is considered a reasonable sensitivity to the expected production level given all that is known about the Area of Mutual Interest where the 38 wells are to be drilled. In the event FPL receives 10 percent lower production than projected, FPL's customers can still expect to benefit by an estimated $3.5 million in 2015. In the event FPL receives 10 percent more production than projected, FPL's customers can expect to benefit by an estimated $12 million in 2015.

Q.

Please refer to page 9, lines 5 through 12, of the testimony of witness Forrest. Identify the other utilities that have invested in gas reserves. In each case, how are the cost of the investments recovered?

A.

Questar Gas is an investor owned utility that provides natural gas distribution service to approximately 900,000 customers in Utah, Wyoming, and Idaho. Questar Gas is a wholly owned subsidiary of Questar Corporation, which is publicly traded. Wexpro Corporation is an unregulated wholly owned subsidiary of Questar Corporation which develops natural gas wells to supply Questar Gas. The supply relationship is currently governed by the "Wexpro II Agreement", which has been approved by the Public Service Commissions of Utah and Wyoming. Questar Gas pays Wexpro the cost-of-service for the gas plus a 20% after-tax return and the "Wexpro II Agreement" allows for those costs to be recovered from Questar Gas' customers. According to a Questar Corporation June 23, 2014 investor presentation, the Wexpro/Questar Gas relationship has saved customers $1.2 billion since its inception in 1981. Currently, Wexpro supplies 59% of Questar Gas' needs.

NorthWestern Energy is an investor owned utility that serves approximately 673,000 gas and electric customers in the northwest quadrant of the United States. NorthWestern received approval from the Montana Public Service Commission that an investment in the Battle Creek gas reserves project was prudent and that they may recover costs associated with the acquisition and operation of gas reserves in their rate base. Before final approval for inclusion in rate base, the Commission previously agreed that the estimated annual revenue requirement associated with Battle Creek may be included as part of NorthWestern's monthly gas supply rates. This allowed NorthWestern to recover its revenue requirement in the interim before the next rate case when they would file for final approval for inclusion in rate base. NorthWestern has acquired additional gas reserves in the Bear Paw basin, and the associated revenue requirements are currently being recovered through the monthly gas supply rates until NorthWestern can petition the Commission for inclusion in rate base during the next rate case. In addition to the gas reserves assets, NorthWestern also acquired associated gathering and gas transmission assets as part of those transactions. The combined cost of service for the gas producing assets as well as the gas gathering and transmission assets are included in the revenue requirements that are recovered through either base rates or the monthly gas supply rates. To FPL's knowledge, NorthWestern has not publicly stated how the cost of production from its gas reserves compare to market prices for natural gas during its period of ownership.

NW Natural is an investor owned utility that supplies natural gas to 686,000 homes and businesses in Oregon and Washington. The Oregon Public Service Commission deemed NW Natural's acquisition of gas reserves assets located in the Jonah Field to be prudent and that they may recover the costs through their Purchased Gas Adjustment. The Purchased Gas Adjustment is an annual document filed with the Commission that supports the Company's request for rate changes, which appears to be similar to FPL's annual Fuel Clause Projection filing. To FPL's knowledge, NW Natural has not publicly stated how the cost of production from its gas reserves compare to market prices for natural gas during its period of ownership.

Public Gas Partners (PGP) is a non-profit gas agency formed to secure long-term wholesale natural gas supply for municipal end-users. PGP is comprised of six members: Florida Municipal Power Agency, Lower Alabama Gas District, Municipal Gas Authority of Georgia, Patriots Energy Group, The Southeast Alabama Gas District, and Tennessee Energy Acquisition Corporation. Although members are individually governed, through joint action and contracting with PGP, they can source long-term gas supplies. PGP utilizes wholly owned subsidiaries to own the gas reserves and manage the operations. Currently, PGP owns working interests in over 3,300 wells located across 16 states. To FPL's knowledge, PGP members have not publicly stated how the cost of production from their gas reserves compare to market prices for natural gas during their period of ownership.

The Southern California Public Power Authority (SCCPA) is a joint powers authority consisting of eleven municipal utilities and one irrigation district. A subset of their members; Anaheim, Burbank, Colton, Glendale, Los Angeles, Pasadena, and the Turlock Irrigation District, have participated in the acquisition of gas reserve properties. Each member's participation in the gas reserves investment is approved by the applicable city council or governing body. To FPL's knowledge, SCCPA members have not publicly stated how the cost of production from their gas reserves compare to market prices for natural gas during their period of ownership.

Q.

Please refer to page 44 of witness Forrest's testimony, line 20 through page 45, line 8. Was the NorthWestern Energy acquisition criteria approved by state regulators? If yes, identify each state commission, the order approving the criteria, and the date of approval.

A.

No, the criteria were submitted to the Montana Public Service Commission as part of NorthWestern's Biennial Procurement Plan in 2012. The procurement plan does not receive specific approval by the Commission, but it has the right to comment. The comments contained in Docket No. N2012.12.125 related to gas reserves and acquisition criteria are as follows: "The main factors that NorthWestern needs to evaluate are volumes, price, and term. Given that a large amount of capital will be required to purchase significant natural gas reserves, the Commission notes that such a transaction will be best presented to the Commission in the form of a stipulated agreement concerning the acquisition between NorthWestern and the Montana Consumer Counsel. Evaluation of the prudence of NWE's natural gas procurement activities will be based solely on information available to NWE at the time transactions were done. Using subsequent market price information constitutes the use of hindsight which has no place in the proper regulatory evaluation of the prudence of procuring natural gas. The Commission also notes that it does not have as a standard that a utility must always purchase a commodity at the bottom of a market cycle. The Commission expects NWE to purchase natural gas following the concepts contained in the 2012 Plan."

Q.

Please refer to page 44 of Witness Forrest's testimony, line 20 and continuing on to page 45, line 8. Are the benefits to customers that witness Forrest mention that are derived from North Western Energy having an established acquisition criteria for acquiring gas reserved properties similar to the benefits FPL's customers would derive from FPL proposed guidelines if these guidelines are approved by the Commission? If so, please describe these benefits and how customers actually benefit from each of the proposed guidelines.

A.

Both FPL and NorthWestern have suggested criteria that limit the size and scope of potential transactions, describe the need to provide customer savings, and define the potential geographical locations of reserves and their characteristics. These criteria are established upfront to allow the utility to pursue prudent investments in gas reserves in a timely fashion. Due to the physical nature of well depletion, most of the gas will be extracted towards the beginning of a well's lifetime. As such, in order to provide more stable fuel pricing that is estimated to result in customer savings in relation to expected market pricing, FPL must continue to be in a position to react to additional opportunities and transact when appropriate without being subject to any regulatory delay. Also, similar to the hedging guidelines, FPL's gas reserves guidelines will proactively set the direction of the program so that both FPL and the Commission are in support of the results.

Setting the size and scope provides customers the security that these transactions will gradually be blended in to current operations such that there is a seamless transition towards more long-term and less volatile supply. FPL acknowledges that in addition to reducing volatility, transactions should also be expected to generate customer savings based on the best available information at the time of the transaction. Finally, defining the location and characteristics of gas reserves limits potential investments to only well-established production areas with available transport to Florida while avoiding more exploratory plays, which in turn will help reduce the customers' risk profile.

Q.

Please refer to question 85 above. Is FPL aware of information or documentation showing the level of customer benefits associated with gas purchases from gas reserve properties which have state commission approved establish acquisition criteria? If so, please identify the information or documentation.

A.

FPL is only aware of a recent Questar investor presentation dated June 23, 2014 which states that their agreement with Wexpro has saved customers a cumulative $1.2 Billion since the program's inception in 1981.

Q.

Please refer to page 44 of witness Forrest's testimony, line 20 and continuing on to page 45, line 8. Was the gas purchased from the gas reserve properties deemed prudent for cost recovery by state regulators? If yes, please identify each state commission, the order deeming the investment in gas reserves prudent for cost recovery, and the date.

A.

The Montana Public Service Commission approved NorthWestern's acquisition of gas reserves as prudent in Docket D2012.3.25 – Final Order 7210b on November 16, 2012.

The Public Utility Commission of Oregon approved NW Natural's acquisition of gas reserves as prudent in Docket UG204 Order No. 11-140 on April 28, 2011.

The Public Service Commission of Utah approved Questar Gas' Wexpro II Agreement in DOCKET NO. 12-057-13 on March 28, 2013.

The Public Service Commission of Wyoming approved Questar Gas' Wexpro II Agreement in Docket No. 30010-123-GA-12 Record No. 13347 on October 16, 2013.

Q.

Please refer to page 46 of witness Forrest's testimony. Assuming the Commission approves FPL's request regarding the Woodford Project, what is the worst-case scenario that could result? For purposes of this response, if none of the proposed wells produced gas, how much money would FPL request be recovered through the Fuel Clause?

A.

The assumption posed in the question, that "none of the proposed wells produced gas," is not credible. There are several factors that provide confidence in the projections discussed in the petition for approval of the Woodford Project, including the well-defined Area of Mutual Interest ("AMI") that has 19 existing producing wells, along with extensive seismic data on the AMI geology. These factors contribute to effectively "de-risking" the area. However, production can vary from well-to-well across a field as a function of geology, fluid saturations, and completion techniques. Production variations of +/- 10% are not uncommon, but given the significant understanding of the AMI, the risk of a "dry-hole", producing zero gas, is extremely unlikely. However, in this extreme example, FPL would expect to request recovery of its entire investment, as we are entering the Woodford Project with the best information available, which projects $107MM in customer savings.

There are a couple of additional factors that should give comfort to the projections that have been provided. First, as drilling is done in a particular area, more is learned about the geology of that specific area. In the early stage of developing this part of the Woodford Shale, PetroQuest drilled one dry hole in 2011. The lateral in this well was drilled in an East-West orientation. Subsequent geologic study, along with seismic data, indicated all laterals should be drilled in a North-South orientation, which is now known to be the preferred orientation. Since the dry hole was drilled, which is 10.5 miles west of the AMI, all wells have been drilled in the North-South orientation and there have been no more dry holes. Another factor that should give the Commission comfort is that FPL will be the beneficiary of the early drilling that PetroQuest and USG will perform prior to any assignment of the Woodford Project to FPL. As currently forecasted, there will be 14 wells drilled before the assumed assignment date of January 1, 2015. Four of these wells will begin to produce gas in December 2014. Although the first 30 days initial production ("IP") is not a direct indicator of the long-term production of an individual well, IP tells us "directionally" how that well will perform over the long-run and should give the Commission comfort that there are no dry holes.

Q.

Please refer to page 12 of witness Ousdahl's testimony and continuing on to page 14, line 10. Also refer to Exhibit KO-1. Assuming the Commission approves FPL's request regarding the Woodford Project, what is the anticipated number of PDP wells, PUD wells, and probable wells at the time of transfer?

A.

As discussed in the testimony of FPL Witness Forrest, the PetroQuest Agreement contemplates that FPL will obtain rights in 38 wells located within the AMI. At the assumed time of transfer on January 1, 2015, FPL anticipates it will be acquiring rights to:

4 PDPs

22 PUDs

12 PRBs

Q.

Since production values and quantities are more certain for the PDP wells and PUD wells, and not certain for the probable wells, is the allocation of carry adjusted for these differences in certainty? Please explain the response.

A.

The allocation of carry is not adjusted for reserve category. It is the same for PDP, PUD and PRB wells. The agreement with PetroQuest, which is one of the standard structures in the industry, is that the carry is a method to earn acreage as wells are drilled rather than pay for that acreage up front. Given the intended function of the carry to earn acreage rights within the AMI where drilling is to occur, it would not be appropriate to tie it to the categorization of specific, individual wells within the AMI.

Production can vary from well-to-well across a field as a function of geology, fluid saturations, and completion techniques. Therefore, production variations of +/- 10% are not uncommon but there is no industry standard. In the early stage of developing this part of the Woodford Shale, PetroQuest drilled one dry hole in 2011. The lateral in this well was drilled in an East-West orientation and, therefore, was not in what we now know to be the preferred orientation. Subsequent geologic study, along with seismic data, indicates all laterals should be drilled in a North-South orientation. Since the dry hole was drilled, which is 10.5 miles west of the AMI, all wells have been drilled in the North-South orientation and there have been no more dry holes.

Although the 30 day initial production (IP) is not a direct indicator of EUR, it tells us "directionally" how the well will perform. In other words, a well with a low 30 day IP will usually not perform long-term at the same level as a well with a high 30 day IP. However, there are numerous reasons for exceptions.

Q.

On page 15 of witness Ousdahl's testimony, she notes that "USG will not be compensated for any gain that might occur as a result of market increases between the time of the initial purchase and the transfer to FPL." If the market for producing properties in the Woodford formation decreased, would that insulate USG from a loss? Please explain the response.

A.

No. FPL will pay net book value for the transaction, regardless of the then-current market price for gas. USG is entirely at risk for any losses they incur should the forward market decrease during the period when the Commission is considering FPL's petition. Similarly, if the forward price of natural gas is higher at the time of transfer, USG will be the beneficiary of any gains they may have achieved and FPL will still pay NBV to USG.

Q.

Both sections on pages 33 and 34 of witness Forrest's testimony and pages 17 and 18 of witness Ousdahl's testimony reference capital investment and capitalized costs. Please identify any instances when recovery of capital items through the fuel clause has not been limited to the amount of fuel savings generated in the recovery period.

A.

FPL has reviewed several orders approving recovery of proposed capital costs through the Fuel Clause in which the rationale expressed by the Commission for approval was that the total fuel savings over a multi-year analytical period exceeded the total cost of the project. Those orders do not express (and their rationale for approval appears inconsistent with) a requirement that recovery of capital costs in each year of the recovery period be limited to the amount of fuel savings generated in that year. Examples of such orders include Order No. PSC-95-1089-FOF-EI, Issued September 5, 1995 in Docket 950001-EI, allowing FPL's recovery of the cost of investment in rail cars which enabled FPL to lower the delivered price of fuel, where FPL projected that the $24,024,000 cost would save customers more than $24 million above the cost of the cars over a 15 year period; Order No. PSC-97-0359-FOF-EI, issued March 31,1997 in docket 970001-EI, allowing FPL's recovery of the cost of modifications to generating plants and fuel storage facilities to use low gravity fuel oil, where FPL's modifications were projected to produce an estimated savings of $19 million with a recovery amount of $2 million over a 3 year recovery period; Order No. PSC-12-0498-PAA-EI, issued September 27, 2012 in docket 120153-EI, allowing TECO's recovery of fuel conversion costs, where TECOs conversions were projected to cost $14.7 million, resulting in net fuel savings to customers of approximately $29.6 million through the requested five-year cost recovery period.

Q.

Are fuel savings guaranteed for the Woodford Project? Please explain the response.

A.

No. The savings explained in the petition and supporting testimony for the Woodford Project were based on the best information available at the time the transaction was entered. As explained in the testimony of FPL witness Forrest on page 38, lines 5-17, should market prices increase over the term of the Woodford Project, FPL's customers will save more than the estimated $107MM projected in the base case. Should prices decrease over the term, the savings will be lower, although customers will benefit from the lower prices across the rest of the procurement portfolio. Additionally, the proposed investment will provide long-term price stability for a portion of FPL's natural gas needs which helps accomplish the primary goal of FPL's hedging program. This investment allows FPL to replace a portion of its short-term financial hedging program with a longer-term physical hedge that will provide stable prices over the 30-plus years of Woodford Project production.

Q.

The stated purpose of the financial hedging program is to reduce fuel price volatility, not necessarily to generate fuel savings. Over the years, both gains and losses associated with the financial hedging program have been recorded to the Fuel Clause. Is it possible the costs of investing in gas reserves could exceed the value of gas received from this investment in a given year? Please explain this response.

A.

Yes. The Woodford Project provides an opportunity to effectively "lock-in" gas prices for the life of the wells (30-plus years) and thus provides a long-term hedge to FPL's fuel procurement portfolio. This reduces the volatility of FPL's procurement portfolio in a manner very similar to FPL's current financial hedging program. As stated in the proposed gas reserves guidelines, FPL is making the decision to enter the Woodford Project based on the best available information available at the time the agreement was entered. This information led to a projection of $107MM in customer savings. However, lower gas prices are certainly a possibility. As stated in the testimony of FPL witness Forrest, in the event the market price of gas falls below the effective price of gas of the Woodford Project, FPL's customers will enjoy the benefits of lower prices in the balance of the procurement portfolio.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 30 day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **12, 14-15, 20-38, 43-56, 72, 75-77, 79-80, 82-89, 91, 93-94** from **STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 12-94)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30 day of July, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF TEXAS)

COUNTY OF HARRIS)

I hereby certify that on this 29 day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Tim D. Taylor, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 90 from **STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (Nos. 12-94)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Tim D. Taylor

Tim D. Taylor

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of July, 2014.

Gia Faucheux

Notary Public
State of Texas, at Large

GIA M. FAUCHEUX
Notary Public, State of Texas
My Commission Expires
March 07, 2018

My Commission Expires: March 7, 2018

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 29 day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry J. Keith, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 92 from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 12-94) in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Terry J. Keith

Terry J. Keith

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of July, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
ANNETTE L. GIVENS
Notary Public - State of Florida
My Comm. Expires Mar 15, 2017
Commission # EE 854124

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 30th day of July, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **13, 16, 17-19, 39-42, 57-71, 73-74, 78, and 81** from **STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 12-94)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of July, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11-24-2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

45

FPL's Responses to Staff's Third Set of Interrogatories (Nos. 95-134)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 45
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Third Set of Interrogatories (Nos. 95-134)

Q.

On page 15, lines 5 through 10 of his testimony, witness Forrest discusses drilling and completion techniques and well stimulation methods that are involved in natural gas production from shale formations. Witness Taylor discusses horizontal drilling and completion techniques on page 10, lines 1 through 10 of his testimony. Witness Taylor also discusses technological advances in horizontal drilling and completion methods on page 18, lines 21 through 23. Is hydraulic fracturing a part of producing natural gas from shale formations? Please explain the response.

A.

Yes. While shale formations generally have enough porosity to store large volumes of hydrocarbons (oil and/or natural gas), they have very low permeability. In other words, the pore spaces are not connected in such a way that would allow the fluids to flow through the shale. In order to connect these pore spaces it is necessary to create fractures in the shale. This is done by hydraulic fracturing. All gas wells completed in shale formations are fracture stimulated. Without this completion technique there would be little, or no, gas production from shale reservoirs.

It is this completion technique that has virtually revolutionized the natural gas industry in recent years, leading to a huge expansion of available reserves and a dramatic lowering of natural gas prices. That dramatic lowering of gas prices and the addition of highly efficient natural gas fired combined cycle units replacing older, less efficient units has resulted in literally billions of dollars in savings to FPL's customers. FPL and its customers have greatly benefited from these developments in the natural gas exploration and development market, with an estimated 70% of the natural gas that FPL procures for its customers being produced from unconventional sources that use hydraulic fracturing. FPL and its customers are already taking advantage of this completion technique, and approving FPL's efforts to engage in limited long-term production provides a long-term hedge that benefits customers by reducing price volatility and further reducing forecasted costs.

Q.

It is staff's understanding that natural production from shale gas formations involves exploration, drilling, water use, chemicals use, hydraulic fracturing, and wastewater disposal. Does FPL agree that natural gas production from shale formations involves these functions? If no, please explain the response.

A.

FPL agrees that natural gas production from shale formations generally may involve exploration, drilling, water use, chemicals use, hydraulic fracturing and wastewater disposal. However, for the Woodford Project, exploration is not involved, as this is a development project in an area that has already been explored and developed. Of course, it is important to understand that much of the gas that FPL already purchases for the benefit of its customers involve these same activities. What the proposed transaction provides is the potential for long-term hedging that is currently not available for FPL's customers, with reduced price volatility and lower costs for FPL's customers.

Q.

On page 44 of his testimony, lines 2 through 6, witness Forrest discusses potential drilling/production risks. This is also discussed in paragraph 56 of the petition. Regarding investing in gas reserves in general and investing in the Woodford Project in particular, what analysis has FPL done regarding drilling/production risks?

A.

The drilling and production risks discussed on page 44 of witness Forrest's testimony specifically refer to the gas production volumetric risks associated with the Woodford Project. FPL employed Dr. Tim Taylor to develop type curves to determine the overall production projections. Dr. Taylor utilized his years of experience, the data from surrounding wells (19 PDPs that already exist in the Area of Mutual Interest) and PetroQuest's seismic data to understand the expected production profile. Further, Forrest A. Garb & Associates, Inc., ("FGA") an independent engineering and geology consulting firm that specializes in reservoir analysis, completed their own estimates which validate Dr. Taylor's analysis. The FGA report is included in the testimony of Dr. Taylor as Exhibit TT-10. The summary of these experts is that they have sufficient confidence in the results that have been presented. Dr. Taylor also uses +/- 10% as a reasonable sensitivity to his analysis of the expected production, which is provided as Exhibit TT-9 to his testimony.

Q.

What are the potential costs associated with these drilling/production risks?

A.

In the Base Fuel/Base Production Case, there are no "costs" to these risks. In the event of either Low Fuel or Low Production (or both), the "costs" are ultimately lower customer savings, as referenced in the table included on page 38 of witness Forrest's testimony. FPL's experts suggest that the reasonable range of production variation for this known and proven formation is plus or minus 10%. If the Base Fuel case is considered, a 10% decrease in the estimated production would result in a reduction of $34.3 million in customer savings from the Base Production case, but would still result in an overall savings of $72.6 million for FPL's customers. It should also be noted that the production sensitivity is also as much as 10% more than projected, which would increase projected customer savings from the transaction from $107 million to over $140 million.

There is also a potential for higher costs to be incurred than what was assumed in the analysis of the Woodford Project, but Dr. Taylor has used conservative cost estimates to help address this possibility. Specifically, Dr. Taylor began his analysis with the historical costs from previous wells for the Woodford-Arkoma region, as well as PetroQuest's more recent experience in drilling in the Woodford shale to estimate the costs for each well in the Woodford Project. This estimate, with PetroQuest's input, was then increased by 3% for each well to create a conservative estimate of the over cost of the drilling program. Only the actual costs incurred will be passed on as the effective costs of gas coming from the Woodford Project, but this conservative approach should cover higher than expected capital expenditures (CapEx"). High CapEx may occur as a result of an individual well that needs to be reworked/redrilled, re-completed (horizontal drilling and completion above the primary productive zone) or if the drilling costs are higher than the average. For example, if, for a specific well, production is unexpectedly lower than projected, PetroQuest may propose an incremental capital investment to "re-complete" a well. This proposal would only be made if there was high certainty that this endeavor would yield enough incremental gas to justify the incremental investment.

Q.

Please identify the potential liability associated with drilling/production risks FPL's customers would be exposed to as a result of FPL's proposed investment in the Woodford Project. Please explain your response.

A.

There are no liabilities associated with lower production volumes. The impact of lower production would be lower customer savings. See the response to Interrogatory No. 98 for the impact of a plus or minus 10% production volume swing from the production level projected in the Base Case. Dr. Taylor has described in his testimony that the risk of production volumes outside the 10% band is low due to the data that is available regarding the existing 19 PDPs in the Area of Mutual Interest, the seismic data that exists, and the experience of PetroQuest as an operator.

Q.

Has FPL evaluated risks associated with natural gas production from shale gas formations? Please explain the response.

A.

FPL has analyzed numerous transactions as we've investigated potential investments in gas reserves across different shales. Upon initial due diligence with any potential counterparty, SEC filings and investor presentations, that were publicly available at the time, were sourced from the specific counterparty's website and reviewed. FPL also considered information that was available on the Energy Information Administration's website at the time of review.

To the extent a transaction progressed to the point where confidential documents specific to a gas reserve deal were exchanged, FPL used these materials to construct financials models and further evaluate risks. This evaluation process was also supplemented by reports from independent engineering firms such as Laroche Petroleum Consultants and Forrest Garb, as well as research firms such as Wood Mackenzie. However, given that FPL did not execute an agreement on any of these previously considered transactions, FPL did not retain any related materials.

A more detailed response to specific potential risks are discussed in response to Interrogatories 102, 103, 108, 109, 113, and 114.

Q.

Has FPL evaluated risks unique to natural gas production from the Woodford formation?

A.

FPL is unaware of any risks that are unique to the Woodford formation.

Q.

There have been news reports of earthquake activity in Oklahoma and Ohio that may be associated with or caused by natural gas production from shale formations (exploration, drilling, water use, chemicals use, hydraulic fracturing, disposal of wastewater, and other activities).

a. Has FPL evaluated the risk that natural gas production from shale formations may be associated with or cause earthquakes? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of this risk was done.

b. Has FPL evaluated the risk that natural gas production from the Woodford shale formation may be associated with or cause earthquakes? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of this risk was done.

c. Has there been any earthquake activity in Oklahoma that may be associated with or caused by natural gas production from the Woodford shale formation? Please explain the response.

d. What potential liability is FPL exposed to by investing in the Woodford Project if it is later determined that the drilling, hydraulic fracturing, and/or shale gas production activity at the Woodford Project has contributed to earthquake activity in Oklahoma?

A.

a.) As the largest investor-owned utility consumer of natural gas in the United States, FPL is aware of the controversies surrounding natural gas production from shale formations including the claimed relationship between seismic activity and certain shale gas production techniques. The general risks associated with increased costs of shale gas production due to new regulations, liability and/or required modifications to production techniques if the claims are validated were not specifically evaluated with respect the proposed investment in the Woodford Project given that FPL already bears these risks as a major consumer of shale gas. As described in the testimony of FPL witness Forrest, approximately 70% of FPL's natural gas supply is sourced from shale. The possibility of a linkage to seismic activity and related risks are industry-wide and, as such, are borne throughout the natural gas industry, including both producers and consumers such as FPL. PetroQuest provided a good explanation of these risks in its most recent 10-K. As described in the testimony of FPL witness Forrest, the proposed investment in the Woodford Project is simply a hedge on price volatility for a cost that is passed through to FPL's customers. The proposed investment neither increases nor decreases the amount of natural gas consumed by FPL for its customers, rather, it merely hedges a portion of the cost and provides an opportunity to reduce the cost of gas compared to projected market prices. Accordingly, the proposed investment does not materially change the risk borne by FPL and its customers associated with a possible connection between shale gas production and seismic activity.

b.) No, while FPL is aware of news reports related to earthquake activity in Oklahoma we have not evaluated the risk that natural gas production from the Woodford shale formation may be associated with or cause earthquakes. Should additional regulatory measures be required or imposed affecting the Woodford Project, PetroQuest, as operator under the Drilling and Development Agreement ("DDA"), would be responsible for compliance with those Environmental and Safety Laws. Under the DDA and applicable operating agreements, FPL is not liable for the gross negligence or willful misconduct of PetroQuest or their affiliates with regard to their failure to comply with Environmental and Safety Laws.

c.) FPL is aware of news reports related to earthquake activity in Oklahoma, but does not wish to speculate on whether earthquake activity in Oklahoma may be associated with or caused by natural gas production from the Woodford shale formation. According to PetroQuest's most recent 10-K, "Recent seismic events have been observed in some areas (including Oklahoma, Ohio and Texas) where hydraulic fracturing has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection associated with use of hydraulic fracturing. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns."

d.) We are not aware of any existing or pending laws in Oklahoma specifically addressing liability associated with earthquake activities associated with drilling, hydraulic fracturing, or shale gas production activity. Any liability under existing laws would be based on violations of laws or regulations involving the operations generally and under common law principles of negligence and liability. All drilling and hydraulic fracturing will be performed by drilling contractors hired by PetroQuest pursuant to contracts which obligate the contractor to maintain insurance and to indemnify the working interest owners from claims associated with the contractor's negligence. Under the Drilling and Development Agreement and applicable operating agreements, PetroQuest, is liable for its gross negligence or willful misconduct in its role as operator. PetroQuest is also responsible for obtaining liability insurance on behalf of the project for liability associated with the ownership of the Woodford Project. Accordingly, if activities at the Woodford Project are found to have contributed to earthquake activity resulting in personal injury or property damage claims, depending on the proximate cause of any earthquake activity, there may be other entities and insurers responsible for paying the associated liability.

Finally, as described in FPL witness Ousdahl's testimony, FPL will hold its investment in the Woodford Project through a subsidiary company wholly owned by, and legally distinct from, FPL. One of the benefits of holding the investment in a subsidiary is that the any liabilities associated with the Woodford Project that are not otherwise covered through insurance or by PetroQuest, will be limited to the subsidiary entity. As such, even assuming a case for liability were to be properly established, FPL should not be exposed to liability beyond the extent of its investment in the Woodford Project through the subsidiary.

Q.

There have been news reports of possible contamination of groundwater and drinking water that may be associated with or caused by natural gas production from shale formations.

a. Has FPL evaluated the risk that natural gas production from shale formations may be associated with or cause groundwater contamination? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of this risk was done.

b. Has FPL evaluated the risk that natural gas production from the Woodford shale formation may be associated with or cause groundwater contamination? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of this risk was done.

c. Has there been any groundwater contamination in Oklahoma that may be associated with or caused by natural gas production from the Woodford shale formation? Please explain the response.

d. Is natural gas production for the Woodford Project specifically subject to or specifically affected by the Federal Safe Drinking Water Act? Please explain the response.

e. What potential liability is FPL exposed to by investing in the Woodford Project if it is later determined that drilling, hydraulic fracturing, and/or shale gas production activity at this site contributed to groundwater contamination?

f. How will PetroQuest dispose of wastewater associated with natural gas production for the Woodford Project?

g. Has FPL evaluated whether there is adequate capacity for wastewater disposal for the Woodford Project?

A.

a.) As a non-operating working interest owner, FPL has not performed any studies related to contamination of groundwater and drinking water in Oklahoma. However, the operator is in compliance with all local, state and federal regulations. There has been no groundwater or drinking water contamination in the area of the AMI and the operator is in compliance with the Federal Safe Drinking Water Act.

The operator runs surface casing to approximately 5,000 feet and cements it into place to isolate all subsurface freshwater zones. In addition, there are also two other rings of casing between any produced or injected fluids and these freshwater zones.

Produced water is disposed of in a saltwater disposal system. This water is disposed of in the Heartshorn Sandstone, which volumetric studies show has plenty of capacity to accept all the produced water from the AMI as well as from many other wells in the area.

b.) See response to Staff Interrogatory No. 103 a.

c.) See response to Staff Interrogatory No. 103 a.

d.) See response to Staff Interrogatory No. 103 a.

e.) All drilling and hydraulic fracturing will be performed by drilling contractors hired by PetroQuest pursuant to contracts which obligate the contractor to maintain insurance and to perform its activities in accordance with all applicable laws. PetroQuest is also responsible for obtaining liability insurance on behalf of the project for liability associated with the ownership of the Woodford Project. Under the DDA and applicable operating agreements, PetroQuest, is liable for its gross negligence or willful misconduct in its role as operator as is customary within the industry. Accordingly, if the operations at a well are found to have contributed to groundwater contamination, there may be other entities and insurers responsible for paying the associated liability.

In addition, as noted above, FPL will hold its investment in the Woodford Project through a subsidiary company wholly owned by, and legally distinct, from FPL. To the extent that another party or insurer isn't responsible and capable of paying the associated liability, FPL will not be exposed beyond its interest in the Woodford Project.

f.) See response to Staff Interrogatory No. 103 a.

g.) See response to Staff Interrogatory No. 103 a.

Q.

Has FPL evaluated the availability and quantity of water that is necessary for natural gas production for the Woodford Project, considering both current and expected production? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of water availability and use was done.

A.

As a non-operating working interest owner, FPL has not performed any studies related to the availability and quantity of water necessary in the Woodford Project. However, the operator, PetroQuest, has significant experience drilling in the vicinity of the Woodford Project and the knowledge of water resources available and has a permit from the Corps of Engineers to use water from Lake Eufaula, the largest capacity lake in Oklahoma.

Q.

Do emissions of natural gas and methane into the atmosphere occur as part of natural gas production from shale formations?

A.

Small amounts of methane can escape into the atmosphere during the flowback period when a well is initially brought on to production. However, after final hook-up of the well, the surface equipment is designed to capture 100% of produced natural gas. The EPA regulates emissions of natural gas and the operator required to comply with all environmental laws, and is in compliance with all regulations. Note, the average emissions rate of methane from natural gas production in shale formations is similar to the emissions rate in conventional wells. See FPL's response to Staff's 3rd Set of Interrogatories No. 106.

Q.

If the response to Interrogatory No. 105 is yes, how do emissions of natural gas and methane associated with natural gas production from shale formations compare to emissions of natural gas and methane associated with conventional production?

A.

According to data provided by the US DOE, the average methane leakage rate for conventional onshore wells is similar to unconventional wells. For conventional wells the rate is 3.1%, and for unconventional it is 3.4%. The small differences among the analyses done by the DOE are driven by data sources, assumptions, and scopes. In 2 out of the 3 studies reviewed by DOE, unconventional wells show a lower methane leakage rate than conventional onshore wells.

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Q.

Has FPL evaluated emissions of natural gas and methane associated with natural gas production from shale formations specifically for the Woodford Project? If yes, please explain the results of the evaluation and potential outcomes. If no, please explain why no evaluation of this risk was done.

A.

As a non-operating working interest owner, FPL has not performed any studies related to emissions of natural gas from shale formations in the Woodford Project. However, the operator is in compliance with all local, state and federal regulations. See FPL's responses to Staff's 3rd Set of Interrogatories Nos. 102(a) and 105.

Q.

Has FPL evaluated the risks and potential outcomes for emissions of natural gas and methane associated with natural gas production from shale formations? Please explain the response.

A.

As a non-operating working interest owner, FPL has not performed any studies related to the risks associated with emissions of natural gas from shale formations. However, the operator is in compliance with all local, state and federal regulations. See FPL's responses to Staff's 3rd Set of Interrogatories Nos. 102(a) and 105.

Q.

What potential liability is FPL exposed to by investing in the Woodford Project if it is later determined that drilling, hydraulic fracturing, and/or shale gas production activity at this site if an accident resulting in significant injury or loss of life occurs at one or more of the future wells in the Woodford Project?

A.

Any liability arising as a result of significant injury or loss of life at any of the Woodford Project wells would be based on violations of laws or regulations involving the operations generally and/or under common law principles of negligence and liability. All drilling and completion activities will be performed by drilling contractors hired by PetroQuest pursuant to contracts which typically will hold the contractor responsible for its activities and to assume responsibility for its employees, including any accidents that occur during the drilling operations, obligate the contractor to maintain insurance, and obligate the contractor to indemnify the working interest owners from claims associated with injury and loss of life to its employees and invitees. Under the Drilling and Development Agreement and applicable operating agreements, PetroQuest is liable for its gross negligence or willful misconduct in its role as operator as is customary within the industry. PetroQuest is also responsible for obtaining liability insurance on behalf of the project for liability associated with the ownership of the Woodford Project. Accordingly, depending on the proximate cause of the accident, there may be other entities and insurers responsible for paying the associated liability.

Finally, as described in the testimony of FPL witness Ousdahl, FPL will hold its investment in the Woodford Project through a subsidiary company wholly owned by, and legally distinct from, FPL. One of the benefits of holding the investment in a subsidiary is that the liabilities associated with the Woodford Project that are not otherwise covered through insurance or by PetroQuest, will be the responsibility of the subsidiary entity rather than FPL. As such, even assuming a case for liability were to be properly established, FPL should not be exposed to liability beyond the extent of its investment in the Woodford Project through the subsidiary.

Q.

What regulations (federal, state, and local) currently affect the Woodford Project, specifically regarding safety, the environment, economic regulations, and oil and gas production regulations?

A.

According to the most recent 10-K filed by PetroQuest, they are subject to, and abide by, the following regulations across all their drilling activities:

- the Comprehensive Environmental Response, Compensation and Liability Act, including the Superfund Amendments and Reauthorization Act of 1986, 42 U.S.C. § 9601 et seq.
- the Resource Conservation and Recovery Act, including the Hazardous and Solid Waste Amendments Act of 1984, 42 U.S.C. § 6901 et seq.
- the Federal Water Pollution Control Act, 33 U.S.C. § 1251 et seq.
- the Clean Air Act, 42 U.S.C. § 7401 et seq.
- the Hazardous Materials Transportation Act, 49 U.S.C. § 1471 et seq.
- the Toxic Substances Control Act, 15 U.S.C. §§ 2601 through 2629
- the Oil Pollution Act, 33 U.S.C. § 2701 et seq.
- the Emergency Planning and Community Right to Know Act, 42 U.S.C. § 11001 et seq.
- the Safe Drinking Water Act, 42 U.S.C. §§ 300f through 300j; the Rivers and Harbors Act of 1899, 33 U.S.C. § 401 et seq.
- the Occupational Safety and Health Act, 29 U.S.C. § 651 et seq.

Oklahoma oil and gas conservation is regulated by the Oklahoma Corporation Commission under title 165 chapter 10 of the Oklahoma Administrative code.

Q.

How will these regulations affect FPL if the Commission approves FPL's request for the Woodford Project?

A.

By virtue of its ongoing operation, FPL is already subject to many of these same regulations. Moreover, the gas exploration and production industry is already subject to these regulations, is currently producing gas pursuant to them and FPL purchases gas so produced (at market prices that reflect the costs of compliance). FPL will not have direct responsibility to adhere to the regulations for the Woodford Project as PetroQuest, as the operator, is responsible for abiding by all regulations posed on its operations. Currently, as stated in their most recent 10-K, PetroQuest is in compliance with the stated regulations. Any violation due to the gross negligence or willful misconduct of PetroQuest will be solely their responsibility as is customary in the industry.

Q.

What is the outlook for changes in regulations and future additional regulations - federal, state, and local - for the Woodford Project?

A.

As operator, PetroQuest is responsible for understanding and abiding by all regulations posed on its operations. As per PetroQuest's most recent 10-K, they are actively monitoring those federal, state, and local regulations that may affect their operations. In any case, FPL is unaware of any specific proposed changes in regulations that will impact the outlook for the Woodford Project. FPL expects that any such changes would also affect the gas exploration and production industry generally and the costs of compliance would be reflected in the market prices that FPL pays for gas.

Q.

What is FPL's assessment of the regulatory risks associated with the Woodford Project?

A.

As operator, PetroQuest is responsible for understanding and abiding by all regulations posed on its operations. As per PetroQuest's most recent 10-K, they are actively monitoring those federal, state, and local regulations that may affect their operations. As stated in the response to Interrogatory No. 112, FPL is unaware of any pending or anticipated changes in the regulations governing the Woodford Project that will impact the potential success of the endeavor.

Q.

If natural gas production in another shale formation in the U.S. was found to cause or contribute to earthquake activity, groundwater contamination, and/or greenhouse gases, could this be a risk for an FPL investment in the Woodford Project? Please explain the response and state whether FPL has evaluated this risk. If FPL has evaluated this risk, please explain and include the results of the evaluation.

A.

FPL has not specifically studied the risks mentioned. Should additional regulatory measures be required or imposed affecting the Woodford Project, PetroQuest, as operator under the Drilling and Development Agreement would be responsible for compliance. The incremental costs borne by the project would be felt throughout the industry and the costs associated with this additional compliance would be passed through to consumers, such as FPL, who purchases approximately 70% of its gas supply from unconventional sources like shale formations. See FPL's responses to Staff's 3rd Set of Interrogatories No. 102(a).

Q.

Please refer to the testimony of witness Forrest, page 28, lines 1 through 12. Also refer to Exhibit SF-6, page 1 (Operator) and page 2 (Drilling Elections).

a. Do the Operator and Drilling Elections section of the PetroQuest agreement protect FPL and its customers from risks associated with natural gas production from shale formations and the Woodford Project? Please explain the response.

b. Witness Forrest states on lines 7 through 9: This minimum commitment is subject to PetroQuest meeting mutually agreed upon targets on drilling costs, safety, and environmental compliance. Does this mean that PetroQuest bears all risks associated with natural gas production from the Woodford Project? Please explain the response.

A.

a) The Drilling and Development Agreement protects FPL and its customers from acts of gross negligence or willful misconduct on the part of PetroQuest. Otherwise, FPL is subject to the risks associated with being a non-operating working interest owner in any shale. Given that FPL currently sources approximately 70% of its natural gas supply from domestic shale production, FPL's customers are already exposed to the risks of natural gas production to the extent they will ultimately have an impact on the price of natural gas.

b) The section of Witness Forrest's testimony referenced in Question 115.b. refers to PetroQuest's capital expenditure targets and environmental and safety targets it must meet in order to maintain FPL's obligation to participate in at least 15 wells, and not the overall risks associated with the Woodford Project. Should PetroQuest be in breach of either of those targets, FPL has the right to non-consent to any future proposed well, without penalty, until such point that those breaches are cured.

Q.

Please refer to page 17, lines 12-13 of witness Taylor's testimony. What is an "economically significant" quantity of natural gas liquids (NGLs) or crude oil in a project the scope and scale of the Woodford Project?

A.

An "economically significant" quantity of natural gas liquids or crude oil in a project would be an amount large enough to affect the outcome of the economic analysis and, therefore, the decision on whether or not to invest in the project. In the case of the Woodford Project, it is not expected to contain any valuable hydrocarbons such as NGLs or oil; rather, the natural gas received from the project is projected to be economic on its own. Additionally, in the event NGLs or oil are expected to be present for a given project, they must first be separated from the natural gas. This separation occurs in a field facility or in a gas processing plant. The volume of NGLs or oil produced will also determine whether the expense of processing is even economically feasible. Finally, it is important to note there is no processing needed for the Woodford Project, whether it be for valuable hydrocarbons (NGLs or oil), or to process out contaminates (such as water and carbon dioxide).

Q.

Please refer to page 17, lines 14-15 of witness Taylor's testimony, which states in part that "NGLs currently trade at a premium to natural gas." How much is the current premium for NGLs compared to natural gas? Please explain your response.

A.

In general, NGLs sell for approximately 40% of the price of a barrel of crude oil, or $40/barrel of NGL. On a heating value basis, there are 6 Mcf (thousand cubic feet) of natural gas per barrel of oil. If natural gas is selling for $4/Mcf, that would amount to $24/equivalent barrel of oil. Therefore NGLs at $40/barrel are worth approximately 66% more than the equivalent volume of natural gas, when gas is trading at $4/Mcf. However, this issue does not come into play in the FPL deal with PetroQuest, as the natural gas in this area is "dry" and contains no NGLs.

Q.

If found, how will NGLs and oil from the Woodford Project be marketed and sold? Please explain your response.

A.

Although not expected, if NGLs and/or oil are discovered in the production output from Woodford Project wells, FPL will market and sell, or contract with a third party to market and sell, them through local or regional NGL and oil marketers or producers. All NGLs and oil produced from a given gas reserve project will be sold at market prices and the resulting revenues will be credited to the Fuel Clause to offset the production costs for which customers are responsible, thus lowering the effective cost of natural gas. The projected revenues from NGLs and oil produced from a gas reserve project will be taken into consideration when analyzing the economics of that project.

Q.

Please refer to page 41, lines 3-5 of witness Forrest's testimony, which states in part, "when analyzing future projects the value of NGLs and oil will be considered as well." Does this mean that no consideration was made regarding the value of NGLs and oil for the Woodford Project? Please explain your response.

A.

No. As stated in the response to Interrogatory No. 116, the Woodford Project is not expected to produce any NGLs or oil. If NGLs or oil were expected from the Woodford Project, their contribution to customer savings most certainly would have been evaluated.

Q.

If known, what is the estimated value of NGLs in the Woodford Project?

A.

See response to Staff Interrogatory Nos. 116 and 119. The base case economic evaluation assumes there are no NGLs associated with the Woodford Project, and hence no value has been attributed. This is consistent with both Witness Taylor's and Forrest A. Garb's analyses, which show no production of NGLs in the reserves estimates.

Q.

If known, what is the estimated value of crude oil in the Woodford Project?

A.

See responses to Staff Interrogatory Nos. 116 and 119. The base case economic evaluation assumes there is no oil associated with the Woodford Project, and hence no value has been attributed. This is consistent with both Witness Taylor's and Forrest A. Garbs analyses, which show no oil production in the reserves estimates.

Q.

Will FPL's ratepayers benefit in any way from the sale of NGLs and/or crude oil from FPL's investment in the Woodford Project? Please explain your response.

A.

If, contrary to the reserves estimates for the Woodford Project, NGLs and/or oil are produced, those quantities will be sold as described in response to Interrogatory No. 118. Any revenue received from such a sale will be directly credited to the Fuel Clause to reduce the cost of gas produced from the Woodford Project paid by FPL's customers.

Q.

Will FPL's investors benefit in any way from the sale of NGLs and/or crude oil from FPL's investment in the Woodford Project? Please explain your response.

A.

See response to Staff Interrogatory No. 122. If NGLs and/or oil are produced from the Woodford Project, any resulting revenue from those commodity sales will be used solely to offset the cost of gas production paid by FPL's customers. No benefit will be passed through to FPL's investors.

Q.

If the Commission approves FPL's request, will all tax benefits that accrue to FPL based on its investment in the Woodford Project inure to the benefit of FPL's customers? Please explain this response.

A.

Yes. All of the deferred income tax benefits which will be generated from the investment in the Woodford Project will be recorded as deferred income taxes and will be included in FPL's consolidated capital structure at zero cost. Additionally, note that currently the investment in the Woodford Project would not qualify for any tax credits.

Q.

If the Commission approves FPL's request, will any tax benefits that accrue to FPL based on its investment in the Woodford Project benefit (only) FPL management and shareholders? Please explain the response.

A.

No. See response to Staff's 3rd Set of Interrogatories No. 124.

Q.

How can FPL assure the Commission that the Forrest Garb report is truly independent?

A.

Forrest A. Garb & Associates is a consulting firm that performs reserve and economic valuations for a large number of clients, including oil and gas companies, banks, investment firms and others. They have been in business since 1988, and their ability to continue getting this type of business is based on their reputation. Their clients rely on unbiased reports for internal analyses. Many of Forrest A. Garb's clients are regulated by the Securities and Exchange Commission ("SEC") and under SEC regulation these entities cannot afford to use in disclosures to their investors reserve calculations or production estimates that are unreliable or biased. Similarly, FPL cannot afford to rely on an unreliable consulting firm when seeking regulatory approval in a prudence determination. Further, Forrest A. Garb's website touts their independence and adherence to a code of ethics that is expected in the industry.

Q.

Provide a list of regulated utilities that are involved in physical hedging projects similar to the Woodford Project.

A.

Please refer to Staff's 2nd Set of Interrogatories Numbers 83 and 87.

Q.

The Company's petition asks the Commission to approve guidelines for acquiring future gas reserve projects:

a. How will a larger scale of gas reserve projects affect FPL's business risk?

b. How will a larger scale of gas reserve projects affect FPL's required return on equity?

c. How will a larger scale of gas reserve projects affect FPL's bond rating?

d. How will a larger scale of gas reserve projects affect FPL's cost of debt?

A.

a. The impact, if any, of a larger scale of gas reserve projects on FPL's business risk is uncertain but is likely to depend both on the scale of the gas production activities relative to FPL's overall asset base, capital expenditure and cash flow profiles, as well as on the Commission's decision with respect to the guidelines and possibly other factors. For the immediately foreseeable future, because of the likely relatively small scale of gas production activities, FPL does not believe it will have a material adverse effect on its risk profile. FPL further believes that Commission approval of the guidelines will substantially ameliorate any negative impact on FPL's risk profile.

FPL expects to monitor the effect on its risk profile, if any, of introducing gas producing activities into its business mix over time. FPL expects that it will obtain feedback both directly and indirectly from investors and credit rating agencies that will assist in this ongoing evaluation. FPL further expects that it will be possible to identify indicators of any material adverse impact on its risk profile in advance, because the relative scale of the gas producing activities is likely to grow at a modest and very controllable rate.

b.-d. Please see response to subpart (a) above.

Q.

At what dollar amount of investment does FPL estimate gas reserve projects will affect FPL's business risk profile?

A.

Please refer to response provided to Staff's 3rd Set of Interrogatories No. 128.

Q.

Does FPL expect to increase its equity ratio to address the greater risk associated with gas reserve projects relative to regulated utility operations?

A.

Please refer to response provided to Staff's 3rd Set of Interrogatories No. 128.

Q.

At what dollar amount of investment does FPL estimate gas reserve projects will require FPL to increase its equity ratio to address the greater risk associated with gas reserve projects relative to regulated utility operations?

A.

Please refer to response provided to Staff's 3rd Set of Interrogatories No. 128.

Q.

Provide a list of the risks associated with the Woodford Project similar to the way the risks would be shown in the "Risk Factors" section of the Securities and Exchange Commission's 10-K report.

A.

The Risk Factors disclosures in Securities and Exchange Commission filings require companies to present possible risks to their business. The risks do not give any indication of likelihood of occurrence or magnitude of impact to the business. Below is an excerpt of the relevant risk factors contained in the 2013 combined Form 10-K for NextEra Energy, Inc. and FPL. As described in these forms, these are the factors that likely would include those risks that pertain to the Woodford Project.

Regulatory, Legislative and Legal Risks

NEE's and FPL's business, financial condition, results of operations and prospects may be materially adversely affected by the extensive regulation of their business.

The operations of NEE and FPL are subject to complex and comprehensive federal, state and other regulation. This extensive regulatory framework, portions of which are more specifically identified in the following risk factors, regulates, among other things and to varying degrees, NEE's and FPL's industries, businesses, rates and cost structures, operation of nuclear power facilities, construction and operation of generation, transmission and distribution facilities and natural gas and oil production, transmission and fuel transportation and storage facilities, acquisition, disposal, depreciation and amortization of facilities and other assets, decommissioning costs and funding, service reliability, wholesale and retail competition, and commodities trading and derivatives transactions. In their business planning and in the management of their operations, NEE and FPL must address the effects of regulation on their business and any inability or failure to do so adequately could have a material adverse effect on their business, financial condition, results of operations and prospects.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if they are unable to recover in a timely manner any significant amount of costs, a return on certain assets or an appropriate return on capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise.

FPL is a regulated entity subject to the jurisdiction of the FPSC over a wide range of business activities, including, among other items, the retail rates charged to its customers through base rates and cost recovery clauses, the terms and conditions of its services, procurement of electricity for its customers, issuance of securities, and aspects of the siting, construction and operation of its generating plants and transmission and distribution systems for the sale of electric energy. The FPSC has the authority to disallow recovery by FPL of costs that it considers excessive or imprudently incurred and to determine the level of return that FPL is permitted to earn on invested capital. The regulatory process, which may be adversely affected by the political, regulatory and economic environment in Florida and elsewhere, limits FPL's ability to increase earnings and does not provide any assurance as to achievement of authorized or other earnings levels. NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected if any material amount of costs, a return on certain assets or an appropriate return on capital cannot be recovered through base rates, cost recovery clauses, other regulatory mechanisms or otherwise. Lone Star, an indirect wholly-owned subsidiary of NEE that is a regulated electric transmission utility subject to the jurisdiction of the PUCT, is subject to similar risks.

Regulatory decisions that are important to NEE and FPL may be materially adversely affected by political, regulatory and economic factors.

The local and national political, regulatory and economic environment has had, and may in the future have, an adverse effect on FPSC decisions with negative consequences for FPL. These decisions may require, for example, FPL to cancel or delay planned development activities, to reduce or delay other planned capital expenditures or to pay for investments or otherwise incur costs that it may not be able to recover through rates, each of which could have a material adverse effect on the business, financial condition, results of operations and prospects of NEE and FPL. Lone Star is subject to similar risks.

NEE's and FPL's business, financial condition, results of operations and prospects could be materially adversely affected as a result of new or revised laws, regulations or interpretations or other regulatory initiatives.

NEE's and FPL's business is influenced by various legislative and regulatory initiatives, including, but not limited to, new or revised laws, regulations or interpretations or other regulatory initiatives regarding deregulation or restructuring of the energy industry, regulation of the commodities trading and derivatives markets, and environmental regulation, such as regulation of air emissions, regulation of water consumption and water discharges, and regulation of gas and oil infrastructure operations, as well as associated environmental permitting. Changes in the nature of the regulation of NEE's and FPL's business could have a material adverse effect on NEE's and FPL's results of operations. NEE and FPL are unable to predict future legislative or regulatory changes, initiatives or interpretations, although any such changes, initiatives or interpretations may increase costs and competitive pressures on NEE and FPL, which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

FPL has limited competition in the Florida market for retail electricity customers. Any changes in Florida law or regulation which introduce competition in the Florida retail electricity market could have a material adverse effect on FPL's business, financial condition, results of operations and prospects. There can be no assurance that FPL will be able to respond adequately to such regulatory changes, which could have a material adverse effect on FPL's business, financial condition, results of operations and prospects.

NEER is subject to FERC rules related to transmission that are designed to facilitate competition in the wholesale market on practically a nationwide basis by providing greater certainty, flexibility and more choices to wholesale power customers. NEE cannot predict the impact of changing FERC rules or the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond NEE's control. There can be no assurance that NEER will be able to respond adequately or sufficiently quickly to such rules and developments, or to any other changes that reverse or restrict the competitive restructuring of the energy industry in those jurisdictions in which such restructuring has occurred. Any of these events could have a material adverse effect on NEE's business, financial condition, results of operations and prospects.

NEE and FPL are subject to numerous environmental laws, regulations and other standards that may result in capital expenditures, increased operating costs and various liabilities, and may require NEE and FPL to limit or eliminate certain operations.

NEE and FPL are subject to domestic and foreign environmental laws and regulations, including, but not limited to, extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, climate change, emissions of greenhouse gases, including, but not limited to, CO_2, waste management, hazardous wastes, marine, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health (including, but not limited to, electric and magnetic fields from power lines and substations), safety and RPS, that could, among other things, prevent or delay the development of power generation, power or natural gas transmission, or other infrastructure projects, restrict the output of some existing facilities, limit the availability and use of some fuels required for the production of electricity, require additional pollution control equipment, and otherwise increase costs, increase capital expenditures and limit or eliminate certain operations.

There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations, and those costs could be even more significant in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. For example, among other potential or pending changes, the use of hydraulic fracturing or similar technologies to drill for natural gas and related compounds used by NEE's gas infrastructure business is currently being discussed for regulation at state and federal levels.

Violations of current or future laws, rules, regulations or other standards could expose NEE and FPL to regulatory and legal proceedings, disputes with, and legal challenges by, third parties, and potentially significant civil fines, criminal penalties and other sanctions. Proceedings could include, for example, litigation regarding property damage, personal injury, common law nuisance and enforcement by citizens or governmental authorities of environmental requirements such as air, water and soil quality standards.

Operational Risks

NEE's and FPL's business, financial condition, results of operations and prospects could suffer if NEE and FPL do not proceed with projects under development or are unable to complete the construction of, or capital improvements to, electric generation, transmission and distribution facilities, gas infrastructure facilities or other facilities on schedule or within budget.

NEE's and FPL's ability to complete construction of, and capital improvement projects for, their electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities on schedule and within budget may be adversely affected by escalating costs for materials and labor and regulatory compliance, inability to obtain or renew necessary licenses, rights-of-way, permits or other approvals on acceptable terms or on schedule, disputes involving contractors, labor organizations, land owners, governmental entities, environmental groups, Native American and aboriginal groups, and other third parties, negative publicity, transmission interconnection issues and other factors. If any development project or construction or capital improvement project is not completed, is delayed or is subject to cost overruns, certain associated costs may not be approved for recovery or recoverable through regulatory mechanisms that may otherwise be available, and NEE and FPL could become obligated to make delay or termination payments or become obligated for other damages under contracts, could experience the loss of tax credits or tax incentives, or delayed or diminished returns, and could be required to write-off all or a portion of their investment in the project. Any of these events could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

The operation and maintenance of NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities are subject to many operational risks, the consequences of which could have a material adverse effect on NEE's and FPL's business, financial condition, results of operations and prospects.

NEE's and FPL's electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities are subject to many operational risks. Operational risks could result in, among other things, lost revenues due to prolonged outages, increased expenses due to monetary penalties or fines for compliance failures, liability to third parties for property and personal injury damage, a failure to perform under applicable power sales agreements and associated loss of revenues from terminated agreements or liability for liquidated damages under continuing agreements, and replacement equipment costs or an obligation to purchase or generate replacement power at higher prices.

Uncertainties and risks inherent in operating and maintaining NEE's and FPL's facilities include, but are not limited to:

- risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned;
- failures in the availability, acquisition or transportation of fuel or other necessary supplies;
- the impact of unusual or adverse weather conditions and natural disasters, including, but not limited to, hurricanes, floods, earthquakes and droughts;

- performance below expected or contracted levels of output or efficiency;
- breakdown or failure, including, but not limited to, explosions, fires or other major events, of equipment, transmission and distribution lines or pipelines;
- availability of replacement equipment;
- risks of property damage or human injury from energized equipment, hazardous substances or explosions, fires or other events;
- availability of adequate water resources and ability to satisfy water intake and discharge requirements;
- inability to manage properly or mitigate known equipment defects in NEE's and FPL's facilities;
- use of new or unproven technology;
- risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation, and lack of available alternative fuel sources;
- increased competition due to, among other factors, new facilities, excess supply and shifting demand; and
- insufficient insurance, warranties or performance guarantees to cover any or all lost revenues or increased expenses from the foregoing.

If power transmission or natural gas, nuclear fuel or other commodity transportation facilities are unavailable or disrupted, FPL's and NEER's ability to sell and deliver power or natural gas may be limited.

FPL and NEER depend upon power transmission and natural gas, nuclear fuel and other commodity transportation facilities, many of which they do not own. Occurrences affecting the operation of these facilities that may or may not be beyond FPL's and NEER's control (such as severe weather or a generator or transmission facility outage, pipeline rupture, or sudden and significant increase or decrease in wind generation) may limit or halt the ability of FPL and NEER to sell and deliver power and natural gas, or to purchase necessary fuels and other commodities, which could materially adversely impact NEE's and FPL's business, financial condition, results of operations and prospects.

Q.

For sub-parts A through E below, please refer to page 35 of the testimony of witness Forrest and to Exhibit SF-1 regarding the assumptions made on the gas transportation for purposes of the economic evaluation.

a. What is the annual incremental transportation cost per MMBtu on the Enable Pipeline System for physical delivery of the gas from the Woodford Project?

b. What is the annual incremental transportation cost per MMBtu for FPL to move the gas from the Woodford Project based on FPL's existing agreement on the Southeast Supply Header pipeline?

c. Are there any other contributors to the incremental transportation cost for physical delivery of the gas from the Woodford Project? If so, please describe and provide the total annual incremental transportation cost per MMBtu.

d. Would FPL incur the incremental transportation cost for physical delivery of the gas from Woodford Project if the Commission denied FPL's Petition?

e. Are there any escalating factors used regarding the gas transportation cost? If so, please describe the factors and provide the factors for each year.

A.

a.) The estimated cost used in the model for firm transportation on the Enable Pipeline in 2015 is \$6.13 MM, or \$0.39 per Mcf (thousand cubic feet). This cost is comprised of two components; transportation equal to \$4.55 MM (\$0.29 per Mcf), and 2.83% fuel retention equal to \$1.58 MM (\$0.10 per Mcf). These costs represent the maximum posted tariff rates on the Enable Pipeline and are a conservative estimate of the actual costs that FPL will incur. These total firm transportation costs have been imbedded in the calculations that lead to the expected FPL customer savings of approximately \$107 million.

b.) There is no annual incremental transportation cost per MMBtu for FPL to move the gas from the Woodford Project based on FPL's existing agreement on the Southeast Supply Header pipeline. The Woodford Project will help FPL maintain its high utilization factor (84% from January 2012 through June 2014, and 94% for June-September of 2012 and 2013) on the Southeast Supply Header ("SESH") and will not impact its utilization of SESH. This high utilization factor on SESH will continue if the Woodford Project is approved. FPL intends to deliver the Woodford Project gas to Perryville where it will be delivered into SESH for delivery into either FGT or Gulfstream. The Woodford Project gas will simply replace a portion of the gas that FPL procures today at market prices at Perryville.

c.) FPL has not committed to procuring capacity on the Enable pipeline at this time. The economics shown as part of the PetroQuest petition include the transportation costs for the Enable pipeline as it represents the most conservative estimate, but FPL continues to pursue other transportation options that may provide improved economics. FPL believes that this is a very conservative approach because it may be possible for FPL to secure firm gas transportation service for a volume profile that more closely matches the projected production profile of the Woodford Project. This would effectively reduce the amount of unused transportation on the Enable Pipeline and reduce the incremental transportation cost to FPL customers. Additional cost savings would be realized if FPL, through negotiation with the pipeline company or with another third party that possesses transportation on Enable Pipeline, is able to secure a discount to the maximum rate on any or all of its firm transportation service requirements.

d.) No. FPL will not incur any incremental transportation cost for physical delivery of the gas from Woodford Project if the Commission denied FPL's Petition. The decision to enter into firm transportation is conditioned on the Commission's approval of FPL's request for the Woodford Project.

e.) No. There are no escalation factors used regarding gas transportation cost on the Enable Pipeline from the Woodford Project to the Southeast Supply Header pipeline.

Q.

For sub-parts A through E below, please refer to the redacted Exhibit TT-9 attached to witness Taylor's testimony regarding the source of inputs to the cash flow analysis and economic evaluation.

a. Describe the cost components that contribute to the net costs shown in column F in Exhibit TT-9 and explain whether the costs represent the combined working interest or the share for FPL/USG according to the PetroQuest Agreement.

b. Are there any escalating factors used regarding the net costs shown in column F in Exhibit TT-9? If so, please describe the factors and provide the factors for each year.

c. For each year shown in column A with new well(s) going into production, please provide the number of new well(s) going into production in that year.

d. Describe the difference between the gross volume and net volume shown in columns B and C and explain whether they are based on the combined working interest or the share for FPL/USG according to the PetroQuest Agreement.

e. For each year shown in column A, provide the annual production volume in Excel format if available.

A.

a. The costs shown in column F are the FPL/USG's share of monthly operating costs which include field supervision, repairs and maintenance, insurance, compression, communications, environmental and regulatory costs, lubricants and fuels, transportation, electricity, water disposal, charts/measurement, supplies, pipeline operating expenses, workovers, etc.

b. There are no escalating factors applied to the costs in column F.

c. Four wells will be completed in 2014, and 34 wells will be completed in 2015.

d. The gross volumes in column B represent the total amount of gas produced from the wells. The net volumes, shown in column C, are that portion of the gross volumes that will be owned by FPL and is the product of the gross volumes multiplied by FPL's net revenue interest in each well.

e. Spreadsheet attached.

	Gross Gas (MMcf)	Net Gas (MMcf)
2015	28,409	17,377
2016	30,669	18,722
2017	20,519	12,530
2018	15,776	9,636
2019	12,941	7,905
2020	11,062	6,757
2021	9,652	5,896
2022	8,604	5,256
2023	7,778	4,752
2024	7,128	4,355
2025	6,554	4,004
2026	6,087	3,719
2027	5,688	3,475
2028	5,353	3,270
2029	5,018	3,065
2030	4,717	2,882
2031	4,434	2,709
2032	4,179	2,553
2033	3,917	2,393
2034	3,683	2,250
2035	3,462	2,115
2036	3,263	1,993
2037	3,059	1,869
2038	2,875	1,757
2039	2,703	1,651
2040	2,547	1,556
2041	2,388	1,459
2042	2,245	1,371
2043	2,110	1,289
2044	1,989	1,215
2045	1,864	1,139
2046	1,753	1,071
2047	1,648	1,007
2048	1,553	949
2049	1,456	889
2050	1,368	836
2051	1,286	786
2052	1,212	741
2053	1,136	694
2054	1,068	653
2055	1,004	614
2056	947	578
2057	887	542
2058	834	510
2059	784	479
2060	739	452
2061	693	423
2062	651	398
2063	612	374
2064	291	178

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 5th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Joseph Balzano, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **128-129** from **STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 95-134)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Joseph Balzano

Joseph Balzano

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of August, 2014.

Kathy Pelly

Notary Public
State of Florida, at Large

My Commission Expires:

KATHY PELLY
Commission # EE 007342
Expires September 4, 2014
Bonded Thru Troy Fain Insurance 800-385-7019

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 7th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **124-125 and 130-132** from **STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 95-134)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of August, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11-24-2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072666
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 7TH day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **100, 109-113, 115, 118, 122, 123, 127, 133** from **STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 95-134)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of August, 2014.

Maritza Miranda-Wise
Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF TEXAS)

COUNTY OF HARRIS)

I hereby certify that on this 7 day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Tim D. Taylor, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number **95-99, 101-108, 114, 116-117, 119-121, 126, 134** from **STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 95-134)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Tim D. Taylor

Tim D. Taylor

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7 day of August, 2014.

GIA M. FAUCHEUX
Notary Public, State of Texas
My Commission Expires
March 07, 2018

Gia Faucheux

Notary Public
State of Texas, at Large

My Commission Expires: March 7, 2018

46

FPL's Responses to Staff's Fourth Set of Interrogatories (Nos. 135-139, 140 (CONFIDENTIAL), 141-144, 145 (CONFIDENTIAL), and 146-153), including the Supplemental Response to No. 145

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 46
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's
Fourth Set of Interrogatories (Nos. 135-139,

Q.

Please refer to page 25 and 26 of the testimony of witness Forrest. Please provide a detailed history of costs paid and market value and quantity of gas received for each year 2010 through 2014, inclusive, based on the USG agreement with PetroQuest.

A.

Staff has confirmed that FPL does not need to respond to this interrogatory.

Q.

When did the Energy and Marketing Trading Business Unit of FPL first develop the idea for FPL to invest in a gas reserve project?

A.

FPL continually focuses on new and creative ways to procure natural gas which provide both customer savings through reductions in our customer's fuel bills, as well as longer term physical delivery to take advantage of the historically low gas prices that have been experienced over the last few years. In 2011, the Energy and Marketing Trading Business Unit of FPL ("EMT") was made aware of a joint venture to develop gas reserves for service to Northwest Natural Gas Company, a gas LDC located in Oregon, and Encana Corporation, an oil and natural gas producer, which provides benefits to Northwest Natural's customers in the form of lower and more stable gas prices. For EMT, the Northwest Natural transaction was the impetus to begin looking at gas reserves as a potential source of low cost, stable supply for our customers.

Q.

When was the proposal to seek approval of an investment in gas reserves and a set of guidelines for future investments first presented to FPL's higher management?

A.

FPL's senior management has been updated on efforts by FPL since 2011 to negotiate with counterparties to secure positions in gas reserves, for the reasons and benefits explained at length in Mr. Forrest's testimony. As also described in Mr. Forrest's testimony, such counterparties were unwilling to enter into an agreement that required a significant delay while awaiting FPSC approval. For that reason, in late 2013 Mr. Forrest began discussing with FPL senior management the need for a set of gas reserve guidelines that would enable FPL to negotiate and transact on projects that would meet the parameters of FPSC-approved guidelines. Specific approvals for the proposal to enter into the investment in the Woodford Project, as well as the gas reserve guidelines for future investments, were first presented to FPL's senior management on June 13, 2014.

Q.

When was the proposal to seek approval of an investment in gas reserves and a set of guidelines for future investments first presented to FPL's Board of Directors?

A.

The concept of investment in an initial gas reserve project together with establishment of guidelines for future projects was first discussed with FPL's Board of Directors in March of 2014.

Q.

Please refer to the testimony of witness Forrest, page 46 and lines 11 through 19. How could FPL quickly curtail customer exposure to the gas reserve revenue requirement?

A.

The testimony of witness Forrest, page 46 and lines 11 through 19, describes FPL's ability to curtail future investments in gas reserves should gas prices fall and be expected to remain low in the future. If that were to occur, FPL would contractually be required to continue participation in wells to which it had previously consented and would continue to receive the associated production at stable gas prices. Due to the rapid depletion of gas production from gas reserve projects, the revenue requirements would fall until the end of the economic life of the wells and subsequent end of the gas reserve revenue requirements. For example, if at the end of the Woodford Project drilling program (estimated to be at the end of 2015), FPL decided to temporarily halt future investments in gas reserves due to projected low sustained gas prices, the gas reserve revenue requirements from the Woodford Project would fall by 50% from its peak by 2020 and FPL's customers would enjoy the benefits of substantial reductions in their electric bills due to the reduced cost for gas that FPL would acquire at those lower market prices.

Q.

Please refer to the testimony of witness Forrest, at page 28, line 15, and also page 33, line 4, to answer the following:

a. Is it correct that the $191 million estimate for capital expenditures under the PetroQuest Agreement (on page 28, line 15) is the maximum estimated investment amount for FPL, and $119 million (on page 33, line 4) is the minimum estimated investment amount? Please explain your response.

b. Assuming the $191 million estimate for capital expenditures (as stated on page 28, line 15), provide an E-10 Schedule that will show the bill impact for a residential customer in 2015 using 1,000 kilowatt-hours of electricity.

c. Assuming the $191 million estimate for capital expenditures (as stated on page 28, line 15), provide an E-10 Schedule that will show the bill impact for a residential customer in 2016 using 1,000 kilowatt-hours of electricity.

d. Assuming the $119 million estimate for capital expenditures (as stated on page 33, line 4), provide an E-10 Schedule that will show the bill impact for a residential customer in 2015 using 1,000 kilowatt-hours of electricity.

e. Assuming the $119 million estimate for capital expenditures (as stated on page 33, line 4), provide an E-10 Schedule that will show the bill impact for a residential customer in 2016 using 1,000 kilowatt-hours of electricity.

f. Exhibit SF-8, attached to the testimony of Sam Forrest, appears to show the results of FPL's economic evaluation based on the $191 million estimate for capital expenditures under the PetroQuest Agreement. Please provide a similar schedule based the $119 million estimate referred to on page 33, line 4.

A.

a. The $191 million as described in FPL witness Forrest page 28, line 15 is the estimate for capital expenditures at the maximum estimated investment amount for FPL. If FPL participates in all 38 wells and assuming that 3rd Parties "non-consent", then FPL pays $191 million in capital expenditures. The result of the third-party's non-consent is that FPL and PetroQuest acquire all third-party's working interest shares and pay proportionally according to the cost allocation defined in the Drilling and Development Agreement and outlined in Exhibit SF-6 (see section entitled "Development and Drilling Costs").

Our approach to calculating a minimum investment amount is based on FPL participating in the minimum required 15 wells as described in FPL's response to Staff's 2nd Set of Interrogatories No. 12 and further expounded upon in response to Staff's 2nd Set of Interrogatories Nos. 80 and No. 115, subpart b. This 15 well participation scenario yields a minimum estimated investment of $80.4 million under the assumption that FPL consents to participate in only 15 proposed wells and all third-party working interest owners "non-consent" or elect to not participate.

The $119 million amount described on page 33, line 4 of FPL witness Forrest's testimony (revised to $125 million as described in subpart (f) below) is based on FPL consenting to participate in all 38 proposed wells (not just the 15 well minimum) with the key differentiation being that all third-party working interest owners elect to participate rather than non-consent as assumed in the base case. When third-party working interest owners consent they have elected to pay their proportionate share of drilling and completion costs along with FPL and PetroQuest in return for their working interest share of production from the well(s). The inclusion of these third-party working interest owners investing alongside FPL and PetroQuest would have the effect of reducing FPL's overall investment requirement and consequentially the total savings available to FPL's customers.

b. Please see Attachment I, which provides Schedule E-10 based on FPL's proposed residential 1,000 kWh bill for 2015 as filed on September 15, 2014.

c. At this time, FPL has not calculated an estimated bill for 2016 that reflects fuel costs without capital expenditures related to the Gas Reserves Project. FPL has, however, calculated an estimated bill impact by comparing the total cost of natural gas volumes associated with $191 million of capital expenditures in the Gas Reserves Project to the total cost of an equivalent volume of natural gas at market prices. This calculation shows that including the Gas Reserves Project results in a bill impact of approximately $0.06 lower for a residential 1,000 kWh bill, based on 2016 projected kWh sales.

d. Attachment II provides an E-10 Schedule showing a 2015 residential 1,000 kWh bill based on FPL's proposed residential 1,000 kWh bill for 2015 as filed on September 15, 2014, with the exception of the fuel charge, which was calculated based on $125 million of Gas Reserves Project capital expenditures.

e. At this time, FPL has not calculated an estimated bill for 2016 that reflects fuel costs without capital expenditures related to the Gas Reserves Project. FPL has, however, calculated an estimated bill impact by comparing the total cost of natural gas volumes associated with $125 million of capital expenditures in the Gas Reserves Project to the total cost of an equivalent volume of natural gas at market prices. This calculation shows that including the Gas Reserves Project results in a bill impact of approximately $0.03 lower for a residential 1,000 kWh bill based on 2016 projected kWh sales.

f. Please refer to Attachment III. As stated in FPL's response to OPC's 5th Request for Production of Documents No. 33, the attachment reflects minor differences from the customer savings and capital expenditures shown for the sensitivity case discussed in FPL witness Forrest's testimony. The attachment shows $60 million in customer savings (rounded down to the nearest million), whereas Mr. Forrest's testimony shows $61 million; and the attachment shows capital expenditures of $125 million vs. $119 million stated in the aforementioned testimony.

FLORIDA POWER & LIGHT COMPANY

SCHEDULE: E10

ASSUMING $191 MILLION OF GAS RESERVES PROJECT CAPITAL EXPENDITURES

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	WITHOUT GAS RESERVES PROPOSED JAN 15 - DEC 15	WITH GAS RESERVES PROPOSED JAN 15 - DEC 15	DIFFERENCE $	DIFFERENCE %
BASE	$54.87	$54.87	$0.00	0.00%
FUEL	$30.96	$30.90	-$0.06	-0.19%
CONSERVATION	$1.89	$1.89	$0.00	0.00%
CAPACITY PAYMENT	$6.35	$6.35	$0.00	0.00%
ENVIRONMENTAL	$2.06	$2.06	$0.00	0.00%
STORM RESTORATION SURCHARGE (1)	$1.16	$1.16	$0.00	0.00%
SUBTOTAL	$97.29	$97.23	-$0.06	-0.06%
GROSS RECEIPTS TAX	$2.49	$2.49	$0.00	0.00%
TOTAL	**$99.78**	**$99.72**	-$0.06	-0.06%

(1) Reflects true-up adjustment in storm charges effective September 2, 2014.

FLORIDA POWER & LIGHT COMPANY
ASSUMING $125 MILLION OF GAS RESERVES PROJECT CAPITAL EXPENDITURES

SCHEDULE: E10

ESTIMATED FOR THE PERIOD OF: JANUARY 2015 THROUGH DECEMBER 2015

	WITHOUT GAS RESERVES PROPOSED JAN 15 - DEC 15	WITH GAS RESERVES PROPOSED JAN 15 - DEC 15	DIFFERENCE $	DIFFERENCE %
BASE	$54.87	$54.87	$0.00	0.00%
FUEL	$30.96	$30.94	-$0.02	-0.06%
CONSERVATION	$1.89	$1.89	$0.00	0.00%
CAPACITY PAYMENT	$6.35	$6.35	$0.00	0.00%
ENVIRONMENTAL	$2.06	$2.06	$0.00	0.00%
STORM RESTORATION SURCHARGE (1)	$1.16	$1.16	$0.00	0.00%
SUBTOTAL	$97.29	$97.27	-$0.02	-0.02%
GROSS RECEIPTS TAX	$2.49	$2.49	$0.00	0.00%
TOTAL	**$99.78**	**$99.76**	-$0.02	-0.02%

(1) Reflects true-up adjustment in storm charges effective September 2, 2014.

Results of FPL's Economic Evaluation - All Consent Case

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)
2015	9.3	[redacted]	[redacted]	[redacted]	[redacted]	$3.67	$4.02	$3.3	0.9302	$3.1
2016	10.9	[redacted]	[redacted]	[redacted]	[redacted]	$3.63	$4.30	$7.3	0.8649	$6.3
2017	7.2	[redacted]	[redacted]	[redacted]	[redacted]	$4.10	$4.70	$4.4	0.8043	$3.5
2018	5.5	[redacted]	[redacted]	[redacted]	[redacted]	$4.53	$5.74	$6.7	0.7480	$5.0
2019	4.5	[redacted]	[redacted]	[redacted]	[redacted]	$5.11	$5.89	$3.5	0.6956	$2.4
2020	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$4.89	$6.03	$4.4	0.6468	$2.9
2021	3.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.05	$6.13	$3.6	0.6015	$2.2
2022	3.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.19	$6.33	$3.4	0.5594	$1.9
2023	2.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.33	$6.63	$3.5	0.5202	$1.8
2024	2.5	[redacted]	[redacted]	[redacted]	[redacted]	$5.46	$7.03	$3.9	0.4837	$1.9
2025	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.47	$7.33	$4.2	0.4498	$1.9
2026	2.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.57	$7.63	$4.4	0.4183	$1.8
2027	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$7.93	$4.5	0.3890	$1.8
2028	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.72	$8.33	$4.9	0.3617	$1.8
2029	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.80	$8.63	$5.0	0.3364	$1.7
2030	1.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.86	$8.83	$4.9	0.3129	$1.5
2031	1.5	[redacted]	[redacted]	[redacted]	[redacted]	$5.95	$9.17	$5.0	0.2910	$1.4
2032	1.5	[redacted]	[redacted]	[redacted]	[redacted]	$6.02	$9.52	$5.1	0.2705	$1.4
2033	1.4	[redacted]	[redacted]	[redacted]	[redacted]	$6.12	$9.88	$5.1	0.2516	$1.3
2034	1.3	[redacted]	[redacted]	[redacted]	[redacted]	$6.22	$10.26	$5.2	0.2340	$1.2
2035	1.2	[redacted]	[redacted]	[redacted]	[redacted]	$6.32	$10.65	$5.2	0.2176	$1.1
2036	1.1	[redacted]	[redacted]	[redacted]	[redacted]	$6.42	$11.06	$5.3	0.2023	$1.1
2037-65	14.6	[redacted]	[redacted]	[redacted]	[redacted]	$8.66	$17.16	$124.4	0.0902	$11.2
Totals[1]	**87.4**	**$220.0**	**$125.4**	**$128.4**	**$473.8**			**$227.3**		**$60.3**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on the assets and return of financing costs.

(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital

Q.

Please refer to the testimony of witness Forrest, at page 39, lines 10-15 to answer the following:

a. Please identity the 3 most recent "subsequent decisions" that the Commission has made interpreting Order No. 14546, and state why FPL believes each listed Order is relevant or applicable to the fact pattern for the proposed recovery of this gas reserve project.

b. In Order No. PSC-12-0498-PAA-EI, page 5, and Order No. PSC-14-0309-PAA-EI, page 7, the Commission interpreted Order No. 14546, and allowed the petitioner to recover capital cost through the Fuel Clause, subject to the condition that cost recovery is capped at fuel savings, and that if there are no fuel savings, then the capital recovery is deferred to a future period. Is this condition relevant or applicable to this gas reserve project? Please explain your response.

c. Given that cost recovery was capped at fuel savings in the above-cited cases, should cost recovery for the Woodford project be limited at the concurrent market price of natural gas? Please explain.

d. In Order No. PSC-12-0498-PAA-EI, page 5, and PSC-14-0309-PAA-EI, page 7, the Commission interpreted Order No. 14546, and allowed the petitioner to recover capital cost through the Fuel Clause, subject to the condition that cost recovery is capped at fuel savings, and that if there are no fuel savings, then the capital recovery is deferred to a future period. Should this condition be incorporated into the Gas Reserve Guidelines (Exhibit SF-9) for future gas reserves projects? Please explain your response.

e. Given that cost recovery was capped at fuel savings in the above-cited cases, should cost recovery for the projects subject to the Gas Reserve Guidelines be limited to the concurrent market price of natural gas? Please explain.

A.

a. The three most recent orders that FPL has identified which address Order No. 14546 are PSC-12-0498-PAA-EI, PSC-13-0505-PAA-EI and PSC-14-0309-PAA-EI. Each is discussed briefly below:

- Order No. PSC-12-0498-PAA-EI. This order approved Fuel Clause recovery for the costs (including a return on and of capital expenditures) associated with converting from fuel oil and propane to natural gas for firing certain auxiliary boilers and furnaces at TECO's Polk Unit 1 ("Polk Fuel Conversion Project"). This decision is supportive of FPL's request to recover gas reserve project costs through the Fuel Clause because it continued the Commission's consistent precedent of allowing Fuel Clause recovery for types of costs that are not specifically identified for such recovery in Order No. 14546 when the utility demonstrates that the costs relate to a project that is projected to result in net fuel savings to customers. That is a significant part of the basis for FPL's request to recover gas reserve project costs through the Fuel Clause (the project also is a form of hedging, and the Commission permits hedging costs to be recovered through the Fuel Clause). TECO's petition for Fuel Clause recovery of the Polk Fuel Conversion Project costs agreed to limit each year's recovery of the project costs to the fuel savings resulting from the project in that year. This aspect of TECO's request is not consistent with FPL's request and is not required by the prior precedent applying Order No. 14546. As FPL discusses in its response to subpart (b) below, the fuel-savings cap that applies to recovery of the Polk Fuel Conversion Project is neither relevant nor applicable to FPL's request to recover gas reserve project costs through the Fuel Clause, for several reasons.

- Order No. PSC-13-0505-PAA-EI. This order approved Fuel Clause recovery for the gas transportation charges paid to the Sabal Trail and Florida Southeast Connection pipelines. The order is not directly relevant to FPL's request to recover gas reserve project costs through the Fuel Clause, because FPL will be paying gas transportation charges to third parties pursuant to long-term gas transportation contracts regulated by FERC. Fuel transportation charges are one of the categories of fuel-related costs that are specifically identifiable in Order No. 14546 as eligible for recovery through the Fuel Clause.

- Order No. PSC-14-0309-PAA-EI. This order approved Fuel Clause recovery for the costs (including a return on and of capital expenditures) associated with converting from distillate oil to natural gas for start-ups and flame stabilization at TECO's Big Bend Units 1-4 ("BB Fuel Conversion Project"). This decision is supportive of FPL's request to recover gas reserve project costs through the Fuel Clause because it continued the Commission's consistent precedent of allowing Fuel Clause recovery for types of costs that are not specifically identified for such recovery in Order No. 14546 when the utility demonstrates that the costs relate to a project that is projected to result in net fuel savings to customers. That is a significant part of the basis for FPL's request to recover gas reserve project costs through the Fuel Clause (the project also is a form of hedging, and the Commission permits hedging costs to be recovered through the Fuel Clause). TECO's petition for Fuel Clause recovery of the BB Fuel Conversion Project costs agreed to limit each year's recovery of the project costs to the fuel savings resulting from the project in that year. This aspect of TECO's request is not consistent with FPL's request and is not required by the prior precedent applying Order No. 14546. As FPL discusses in its response to subpart (b) below, the fuel-savings cap that applies to recovery of the BB Fuel Conversion Project is neither relevant nor applicable to FPL's request to recover gas reserve project costs through the Fuel Clause, for several reasons.

FPL notes that Commissioners commented on the annual fuel-savings cap at the agenda conference where the BB Fuel Conversion Project was approved, characterizing it as specific to the unique factors of TECO's particular project, without an expectation that other utilities would follow suit.

b. FPL does not believe that the annual fuel-savings cap imposed on recovery of the TECO fuel conversion projects in Order Nos. PSC-12-0498-PAA-EI and PSC-14-0309-PAA-EI is relevant or applicable to FPL's request to recover gas reserve project costs through the Fuel Clause, for several reasons:

- FPL does not believe that it would be equitable or consistent with the intent of Order No. 14546 to apply an annual fuel-savings cap to FPL's recovery of gas reserve project costs, because the cap would impose an asymmetric risk of recovery. FPL has reasonably projected that the Woodford Gas Reserves Project will result in approximately $107 million in fuel savings for customers over the project life, based upon the same forecast of natural gas prices that FPL used for its 2014 Ten Year Site Plan. Of course, actual natural gas prices may be higher or lower than forecast in a particular year throughout the project life. If they are higher, then fuel savings would be even greater than projected for that year. All of the additional savings would be passed through to customers, with FPL only recovering its actual annual costs for the gas reserve project. However, if natural gas prices were lower than projected such that there were no fuel savings for a year, then the fuel-savings cap would result in FPL not recovering all of its actual project costs for that year.

  This asymmetry would be a substantial disincentive to undertake gas reserve projects, even ones that are projected to generate large fuel savings for customers. As such, the asymmetry would be inconsistent with the Commission's intent in Order No. 14546 to remove disincentives to utilities taking advantage of innovative fuel-savings opportunities. As noted on page 7 of Order No. PSC-11-0080-PAA-EI, the stipulation approved by the Commission in Order No. 14546 provided for a policy "flexible enough to allow for recovery through fuel adjustment clauses of expenses normally recovered through base rates when utilities are in a position to take advantage of a cost-effective transaction, the costs of which were not recognized or anticipated in the level of costs used to establish the utility's base rates." The fuel-savings cap would work against this purpose.

- Imposing a fuel-savings cap would be logically inconsistent with one of the important benefits of a gas reserve project: providing a form of long-term hedge against volatility in natural gas market prices. When a hedge is used to mitigate market volatility, it is expected that the hedge price will remain relatively constant while market prices go up *and* down. This means that the hedge price can reasonably be expected to exceed market price at times, just as it is expected to fall below market price at others. Because of this reasonable expectation that prices under a well-designed hedge will occasionally exceed volatile market prices, a fuel-savings cap on recovery for hedging costs would virtually ensure under-recovery. This would be an illogical and punitive outcome. It also would be inconsistent with the Commission's established practice concerning the recovery of hedging costs through the Fuel Clause, whereby costs incurred consistent with a utility's approved hedging plan are recoverable without regard to whether they lead to savings or costs in a particular period.

- The relationship over time between fuel savings and costs to be recovered for the TECO fuel conversion projects appears to be quite different than what one expects with gas reserve projects, for two reasons.

  First, in FPL's experience there is a very high degree of uncertainty about the relationship over time between the prices for fuel oil and propane on the one hand, and natural gas on the other. Therefore, a project that is premised on fuel savings generated by switching fuels has an especially high degree of uncertainty as to the projections of what those fuel savings will be.

  Second, TECO is depreciating the investment in its fuel conversion projects over a short, fixed period of five years. TECO expects that the generating units at which the projects have been implemented will remain in service -- and the projects will continue to generate fuel savings -- for many years thereafter. *See, e.g.,* Polk Fuel Conversion Project petition (Document No. 03086-12), at p. 3; BB Fuel Conversion Project petition (Document No. 00696-14), at pp. 5-6. Thus, deferral of cost recovery as a result of the fuel-savings cap would impose little risk on TECO of ultimate non-recovery: TECO would just wait until the projects were fully depreciated and then use the "surplus" fuel savings thereafter to recoup in short order whatever amount had been deferred. In contrast, recovery of the gas reserve project investment occurs via depletion that is proportional to the volume of produced gas each year as a fraction of the total expected production volume. At the point when only a small portion of the gas reserve investment remains to be recovered, the volume of gas remaining to be produced will be small as well. Thus, if the market price of fuel were to be lower than forecast for the first several years of the project when most of the gas is produced, there never would be a period when FPL could reasonably expect to recoup deferred costs out of "surplus" fuel savings. Whereas the risk of ultimate non-recovery is essentially non-existent for TECO, it could be unacceptably large for FPL.

- Finally, in its petitions for both of the fuel conversion projects, TECO proposed to limit its annual recovery of project costs to that year's fuel savings, and the orders accepted the proposed limitation. Thus, FPL does not believe that it is accurate to characterize that condition as arising out of an interpretation of Order No. 14546; rather, it appears to FPL that the Commission simply approved TECO's proposal to impose the condition. As noted in response to subpart (a) above, Commissioners commented on this feature of TECO's petition at the agenda conference where the BB Fuel Conversion Project was approved, characterizing it as specific to the unique factors of TECO's particular project, without an expectation that other utilities would follow suit.

c. No. See response to subpart (b) above.

d. No. See response to subpart (b) above.

e. No. See response to subpart (b) above.

Q.

For purposes of the following interrogatory, please refer to the testimony of witness Ousdahl, page 18, line 17. How many "reservoir" or "field level" aggregations does FPL project for the entire Woodford Project?

A.

FPL plans to aggregate all of the individual wells and leases in the Woodford Project for depletion purposes into a single group (reservoir or field) as permitted under ASC 932-360-35-6 because they share common geological structural features.

Q.

What are the typical assets or costs that are included for capitalization under depletion accounting? What assets and costs associated with the Woodford Project does FPL project capitalizing and recovering through depletion?

A.

As discussed on pages 16-18 in the direct testimony of FPL witness Ousdahl, FPL intends to employ successful efforts accounting for the Woodford Project, and depletion is the form of depreciation that is recorded under successful efforts accounting. The typical costs that are capitalized under successful efforts accounting include the following:

1. Acquisition costs - incurred to acquire the rights to the natural gas
2. Exploration costs - incurred in examining specific areas for existence of proved natural gas reserves. This includes drilling exploratory wells, which are capitalized when reserves are discovered.
3. Development costs - incurred to obtain access to proved reserves and provide facilities for the extraction of natural gas. This includes the costs related to drilling and equipping wells.

FPL plans to capitalize similar-type costs in all of the above categories for the Woodford Project.

Q.

Please provide a generic example of how depletion accounting of a hydraulically fractured natural gas well is mathematically performed, including all inputs and calculations.

A.

Please refer to FPL's response provided to Staff's 4th Set of Interrogatories No. 145.

Q.

For purposes of the following interrogatory, please refer to the testimony of witness Ousdahl, page 25, lines 11-21. Please provide FPL's estimated annual depletion expense associated with the Woodford Project, by year, for the first three years of operation. Please show all calculation steps.

A.

Please refer to the Attachment I.

Documents responsive to Staff's Fourth Set of Interrogatories No. 145 are confidential in their entirety.

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Q.

For purposes of the following interrogatory, please refer to the testimony of witness Ousdahl, page 25, lines 11-21. Please provide FPL's estimated annual depletion expense associated with the Woodford Project, by year, for the first three years of operation. Please show all calculation steps.

A.

This supplemental response is to correct the depletion calculation provided in the original response. The original calculation was completed assuming that all capital expenditures during 2015 were made on day 1. The depletion calculation was amended to reflect the actual timing of the 2015 capital expenditures, thus slightly reducing the depletion amount. Note that this fine-tuning only applies to year 2015 because there are no further capital expenditures forecasted for the Woodford Project beyond 2015.

Attached is a confidential Excel file showing the depletion calculations for the full 50-year project analysis period (i.e., 2015-2065), with revisions only to the 2015 calculations. Also attached is a pdf file that shows the depletion calculations for the first three years of operation (i.e., 2015-2017), which is the time period requested in this interrogatory. As with the Excel file, only the 2015 depletion calculations have been revised. FPL has limited the pdf file to the first three years in order to make it easier for the parties to navigate.

Documents responsive to Staff's Fourth Set of Interrogatories No. 145 Supplemental are confidential in their entirety.

Q.

Refer to the testimony of witness Taylor, Exhibit TT-9 page 1. Please complete the following table below showing the annual probability over the next 10 years that the project will be economic to drill (i.e. the cost of the drilling for gas, or Column F / Column C, will be below the Henry Hub market price, column D). Please describe the method and assumptions that FPL used to calculate the probability that the cost of drilling for gas is below the Henry Hub market price.

A.

This interrogatory references the annual probability over the next 10 years that the Woodford Project will be economic to drill. It is important to understand the proposed Woodford Project proposes a drilling plan that will be complete by December 31, 2015, so looking at the probability in any individual year thereafter lacks practical relevance and is based on an inaccurate factual predicate that FPL could decide on a year-by-year basis whether or not to produce gas from the Woodford Project wells in that year. Further, within the 2015 drilling plan, FPL will utilize its non-consent rights to look at each well on an individual basis, rather than just making one overall determination of economics. For example, in January 2015 (assuming approval of the Woodford Project by the Commission and assignment to FPL from USG), FPL may evaluate a proposed well as being economic and consent to participate in the drilling of that individual well. It is assumed once this well is producing, it will remain operational until it is determined by the operator in accordance with the applicable Joint Operating Agreement that the long-term costs of operation of the well exceed the long-term revenues associated with operation. Wells are not like natural gas storage in that once a well is operational, it is not feasible to cycle it on and off due to the issues it may create with the structural integrity of the well. Once a well has been shut in, it would take a substantial amount of capital to rework the well and bring it back into operation. FPL's analysis has assumed, and will continue to assume, that the wells will operate for 50 years and then be permanently shut in. To continue the example, if later in 2015, projected prices for the entire life of a proposed well have fallen to a level that no longer makes economic sense to drill, FPL may non-consent to a well (or wells) if PetroQuest continues to propose wells under the drilling program, but this will not impact the wells that were consented to earlier in the year.

The mathematical exercise to look at the probability that the Woodford Project will be economic in any given year would be challenging, at best. More important, for the reasons discussed above, the exercise would not reflect the reality of how drilling and production decisions will be made for the Project. This decision making process isn't simply looking at whether the project is economic in 2015, and then 2016, and so on, because the well life is assumed to be 50 years - it is the cumulative impact over the 50 years that is important. Therefore, the relevant probability is the project's likelihood of being economic over its full lifetime, using the range of expected deviations in output and market prices known at the time that each of the wells is drilled. FPL recognizes there is implied volatility in the natural gas market that is a relevant proxy for calculating standard deviation. Utilizing the same implied volatility that was used in the analysis that was performed in response to Staff's 4th Set of Interrogatories No. 148, the probability of the project being economic over the 50-year analysis period is very high: 85.3%.

Year	Probability Drilling is Economic (%)
2015	N/A
2016	N/A
2017	N/A
2018	N/A
2019	N/A
2020	N/A
2021	N/A
2022	N/A
2023	N/A
2024	N/A

Q.

Please complete the following table below to provide an expected annual margin (drilling cost in $/mmbtu less gas price in $/mmbtu as referred to in interrogatory # 135) and an expected annual standard deviation ($/mmbtu) of margin from FPL's proposed gas reserve drilling program.

A.

COB 10/7/2013	Cost	FPL	Margin	StDev of Margin
Unit of Measure	$/mmBtu	$/mmBtu	$/mmBtu	$/mmBtu
2015	$ 3.48	$ 4.02	$ 0.54	$ 0.66
2016	$ 3.56	$ 4.30	$ 0.74	$ 1.03
2017	$ 4.00	$ 4.70	$ 0.71	$ 1.57
2018	$ 4.40	$ 5.74	$ 1.34	$ 2.24
2019	$ 4.96	$ 5.89	$ 0.92	$ 2.57
2020	$ 4.79	$ 6.03	$ 1.25	$ 2.86
2021	$ 4.94	$ 6.13	$ 1.19	$ 3.10
2022	$ 5.08	$ 6.33	$ 1.26	$ 3.36
2023	$ 5.21	$ 6.63	$ 1.42	$ 3.66
2024	$ 5.34	$ 7.03	$ 1.70	$ 4.01
2025	$ 5.24	$ 7.33	$ 2.09	$ 4.28

FPL utilized annual implied NYMEX volatility to calculate the standard deviation of the expected margin between estimated production costs and forecasted market price. As can be seen in the table above, there is a fairly high degree of volatility in the market, and the standard deviation of the margin widens over time. This is to be expected as this is a mathematical exercise with time to expiry one of the major drivers - the longer the time to expiry, the greater the standard deviation with all other parameters remaining constant. Please note that the great majority of the gas from the Woodford Project is projected to be produced in the early years, so that the yearly volumes to which these larger standard deviations would apply in later years would be relatively small.

This exercise illustrates effectively the value of the Woodford Project. As described in the testimony of FPL witness Forrest, if the price of gas in future periods is higher than that projected in the fuel price forecast supplied by FPL, FPL's customers will benefit from the savings associated with the Woodford Project gas. Conversely, if the price of gas in future periods is lower than that projected by FPL, FPL's customers can expect to benefit by FPL purchasing the balance of its fuel requirements at these lower market prices. Additionally, this exercise shows how the stable price of the Woodford Project gas provides a mitigant against long term price volatility. As with FPL's current financial hedging program, FPL is not trying to outguess the market, but rather attempting to reduce the volatility in the fuel bill. Not only will this transaction provide the aforementioned long-term price stability, but also FPL currently estimates that it will save customers an incremental $107 MM over the life of the project.

Q.

Refer to the "Sensitivity Cases for Customer Savings" exhibit on page 38 of witness Forrest's direct testimony. The matrix shows low, base, and high production levels and low, base, and high fuel price levels. Please complete the table below to provide probabilities for the life of the wells.

A.

Probabilities [of meeting or exceeding Customer Savings projected for each scenario]	**Low Fuel Price**	**Base Fuel Price**	**High Fuel Price**
Low Production Levels	88.4%	60.3%	27.7%
Medium Production Levels	82.7%	47.9%	16.5%
High Production Levels	73.1%	33.7%	9.0%

The percentage shown in each of the nine cells of the matrix represents the probability that customer savings will meet or exceed the level projected in the corresponding cell of the matrix on page 38 of Witness Forrest's testimony. Thus, for example, there is an 88.4% chance that customer savings will meet or exceed the "low fuel – low production" case in the upper left hand cell and a 9% chance of meeting or exceeding the customer savings in the "high fuel – high production" case in the lower right hand cell. The probabilities were calculated by running 10,000 simulations of outcomes with both price and production levels varied according to a normal distribution.

Please note that the probability of achieving the "Base Case" customer savings of $106.9 MM is slightly lower than 50% due to modeling of certain types of fixed costs, such as transportation costs, in blocks of capacity that do not perfectly follow the production levels in each simulation run. If those fixed costs could be perfectly correlated with the production levels for each simulation run, there would in fact be exactly a 50% probability of meeting or exceeding the base case level of customer savings.

Q.

The U.S. Department of Energy's Energy Information Administration (EIA) forecasted future Henry Hub gas prices in its Annual Energy Outlook 2014. The EIA link is http://www.eia.gov/forecasts/aeo/MT_naturalgas.cfm#natgas_pricefactor. The EIA's forecasts for Henry Hub gas are presented below next to the FPL Henry Hub Market Price Forecast from Exhibit SF-8 Pg 1 of 1. Please explain the reasons for the difference between the EIA gas price forecast, released in May 2014, and the FPL forecast.

A.

As described in the response to Staff's 2nd Set of Interrogatories, No. 21, FPL's long-term natural gas forecast utilizes the NYMEX forward curve, projections from The PIRA Energy Group (PIRA) and rates of escalation from the Department of Energy's (DOE) Energy Information Administration (EIA). FPL is not involved in determining specific forecasting methodologies and assumptions used by either PIRA or the EIA. PIRA typically provides a high level description of the changes that drive their updates and also hosts an annual conference in the fall of each year to further describe their forecasting assumptions. EIA provides a rather lengthy description of their forecasting approach (along with sensitivities) in their Annual Energy Outlook.

The single greatest factor leading to the differences in the forecasts shown in Staff's table above is that FPL's forecast reflects projected prices in nominal dollars, whereas the EIA forecast cited by Staff projects prices in real dollars. That is, the effects of inflation have been eliminated from the EIA real price forecast but are included in FPL's nominal price forecast. One would naturally expect prices stated in nominal terms to be increasingly higher through time than prices stated in real terms due to the cumulative compounding effects of inflation.

FPL's use of a nominal-dollar price forecast is consistent with the approach it uses in all economic analyses presented to this commission including the economic evaluation of the Woodford Project. To determine customer impacts expressed as cumulative present value of revenue requirements ("CPVRR"), FPL uses projections of revenue requirements in nominal dollars (i.e., stated in the year they are incurred) and discounts them using its weighted average cost of capital ("WACC") which is a nominal discount rate. This is common financial practice - nominal cash flows should be discounted at a nominal discount rate and vice versa for real cash flows. Without a lengthy discussion of the components that comprise FPL's weighted average cost of capital ("WACC"), suffice to say that the fundamental building block of both the debt and equity components of the WACC is market interest rates which are expressed in nominal terms. By calculating the net present value of the future nominal cash flows from the Woodford Project, the CPVRR calculation properly reflects the value of those revenue requirements in today's dollars, including removing the expected impact of inflation. It would be improper for FPL to utilize the EIA's projections of real gas prices shown in the table, and then discount the results using FPL's WACC. This would essentially remove the expected inflation twice and understate the savings to customers.

FPL has expanded Staff's table to include EIA's *nominal* prices from their 2014 Annual Energy Outlook for comparative purposes. The expanded table shows that the relative difference between FPL's forecasted natural gas prices and the EIA nominal curve is fairly small and in fact gets smaller over time.

Year	EIA Long Term Energy Outlook May 2014 Henry Hub Price Forecast **(PROVIDED BY STAFF - REAL)**	EIA Long Term Energy Outlook May 2014 Henry Hub Price Forecast **(PROVIDED BY FPL - NOMINAL)**	FPL Perryville market price forecast
2015	3.74	3.92	4.02
2016	4.14	4.41	4.30
2017	4.40	4.76	4.70
2018	4.80	5.27	5.74
2019	4.66	5.19	5.89
2020	4.38	4.95	6.03
2021	4.67	5.37	6.13
2022	4.82	5.64	6.33
2023	4.96	5.90	6.63
2024	5.12	6.20	7.03
2025	5.23	6.45	7.33
2026	5.36	6.72	7.63
2027	5.49	7.00	7.93
2028	5.59	7.26	8.33
2029	5.78	7.63	8.63
2030	6.03	8.12	8.83
2031	6.17	8.47	9.17

Year	EIA Long Term Energy Outlook May 2014 Henry Hub Price Forecast **(PROVIDED BY STAFF - REAL)**	EIA Long Term Energy Outlook May 2014 Henry Hub Price Forecast **(PROVIDED BY FPL - NOMINAL)**	FPL Perryville market price forecast
2032	6.36	8.90	9.52
2033	6.59	9.41	9.88
2034	6.74	9.83	10.26
2035	6.92	10.31	10.65
2036	7.18	10.93	11.06

One final note: The column in FPL's expanded table for the FPL forecast has been relabeled to "Perryville" from "Henry Hub." FPL provided a forecast for Perryville as this is the point the Woodford Project gas will be delivered as a replacement for market priced gas. The EIA forecast provided by Staff is for Henry Hub, which generally trades at a de minimis premium to Perryville.

Q.

Does FPL's natural gas price forecast on Exhibit SF-8 reflect the probability that natural gas, as LNG, will be exported from the United States? Please explain.

a. What number of LNG export terminals did the gas price forecast on SF-8 assume?

b. When are these export terminals expected to begin service?

c. What is the expected capacity of these export terminals?

d. Is the production of natural gas-based chemicals and fertilizers, such as methanol and ammonium nitrate, increasing in the U.S.? If yes, please explain how this affects the natural gas price forecast on SF-8.

A.

As described in the response to Staff's 2nd Set of Interrogatories, No. 21, FPL's natural gas price forecast is a blend of the NYMEX forward curve and a fundamental curve provided by PIRA, with EIA escalation utilized in the out years. FPL utilizes NYMEX in the front end of the curve to reflect the nature of a properly functioning free market - one that trades on supply and demand fundamentals and reflects the "perfect" nature of information in the short term. As the time horizon expands, the NYMEX tends to lose liquidity. In addition, the impact of longer term fundamentals tend to be downplayed by the market, because the market tends to only react to impacts on the longer term market when they become a reality.

FPL has not made any "external" adjustments to the NYMEX, PIRA or EIA data to address either LNG exports or the production of natural gas-based chemicals and fertilizers. In order to be responsive to this interrogatory, FPL asked PIRA for information about how, if at all, it considered these factors in developing its fundamental curve. The following information was provided by PIRA:

a. PIRA assumed six U.S. LNG export terminals in its reference case, 4 of which are located along the Gulf Coast and 2 which are located along the eastern seaboard.
b. PIRA assumed that the first LNG export terminal would be online in 2016 with all six in service by 2021.
c. The expected capacity of all six assumed LNG export terminals is 9 BCF/D. Forecasted exports assumed a 90% average annual load factor for the terminals, which equals 8.1 BCF/D.
d. Yes. Increases in natural gas-based production of methanol and ammonium nitrate were part of PIRA's industrial demand growth forecast. In that forecast, industrial demand growth was second only to LNG export growth.

Q.

Please refer to page 45 of witness Forrest's testimony, lines 18 through 21. Please explain the statement "future transactions may not present the level of savings the Woodford Project does"?

A.

The Woodford Project is expected to provide $107 MM in customer savings based on an investment of $191 MM. Per the proposed guidelines, all future projects will be projected to provide customer savings at the time the transaction is consummated. However, the relationship between projected savings and capital invested for future transactions may differ from that projected for the Woodford Project. Each negotiation is unique and presents unique economics based on a number of factors including the specific shale basin being produced, the potential existence of natural gas liquids, and availability and access to natural gas transportation to name a few.

Q.

Please refer to Exhibit SF-9, the proposed Gas Reserve Guidelines, Guideline 1.D. Why is it appropriate to have an upper limit on the aggregate amount invested in a particular calendar year and not have an upper limit on the cumulative amount invested in gas reserve projects?

A.

FPL has effectively put an upper limit on cumulative investment by providing caps on the percent of annual production that is supplied by gas reserves. By capping the total amount of gas that can be supplied by gas reserves, FPL is providing a boundary for the total size of the investment. FPL believes this limit on total supply from gas reserves provides the ability for a smooth blending with supply from the traditional open market purchases and avoids abrupt changes that may arrive from having to stop the program immediately due to an impending total spend cap. Additionally, Guideline 1.B proposes an annual update to the three year window provided for in Guideline 1.A, such that the Commission will have the ability to review the maximum volume to be supplied by gas reserves.

Q.

Please refer to Exhibit SF-9, the proposed Gas Reserve Guidelines. Why do these proposed guidelines not mention standards for counterparty creditworthiness and counterparty risks?

A.

As referenced in the response to Staff's 2nd Set of Interrogatories No. 34, it is not unusual for a company in the gas exploration and production business to have a below investment grade credit rating in spite of being well established and having a proven track record. Setting an initial standard for credit rating might prematurely eliminate a large portion of potential counterparties before any diligence has taken place. As such, FPL intends to perform the same evaluation referenced in the response to Staff's 2nd Set of Interrogatories No. 34 with respect to credit and counterparty risk for every potential transaction.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 15th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Melissa Linton, who is personally known to me, and she acknowledged before me that she provided the answer to and co-sponsored interrogatory number **140** from **STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 135-153)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Melissa Linton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 15th day of September, 2014.

N. Gregory

Notary Public
State of Florida, at Large

My Commission Expires:

2/20/2016

NICOLE ANDREA GREGORY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# EE173212
Expires 2/20/2016

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 10th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry J. Keith, who is personally known to me, and he acknowledged before me that he provided the answer to and co-sponsored interrogatory number **140** from **STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 135-153)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Terry J. Keith

Terry J. Keith

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10th day of September, 2014.

Carolyn J. Smith

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **142-144** and co-sponsored interrogatory number **145** from **STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 135-153)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of September, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11/24/2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12TH day of September, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **136-139, 146--153** and co-sponsored interrogatory number **140** from **STAFF'S FOURTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 135-153)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of September, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

47

FPL's Responses to Staff's Seventh Set of Interrogatories (Nos. 167-173)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 47
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Seventh Set of Interrogatories (Nos. 167-173)

Q.

Regarding the September 15, 2014 revisions to FPL petition and projection testimony, what specifically prompted this revision? Please state what variables/inputs changed.

A.

FPL's September 15, 2014 revision filing of the 2015 projected fuel costs with the Gas Reserves Project corrected the total system gas availability input into the production costing model. The previous filing had inadvertently added the projected output from the gas reserve project as incremental gas to the system.

Q.

Please refer to the testimony of FPL witness Ousdahl, page 25, lines 3 through 10, and to Exhibit KO-6. Also refer to the testimony of FPL witness Yupp, page 3 of September 15, 2014 testimony, lines 6 through 15. Also refer to FPL's response to OPC interrogatory 43 and FPL's response to staff interrogatory 78.

a. **Regarding the $47.7 million in projected 2015 costs related to the Woodford Gas Reserve project, provide a schedule like KO-6 that supports this amount.**
b. **What is the quantity of gas associated with the $47.7 million? Please state the answer in MCF and MMBtu.**
c. **What is the per MMBtu cost of this gas? As part of this response, please state the delivery point of this gas that matches with the projected transportation expense?**
d. **What is the per MMBtu cost of this gas delivered to FPL's Florida plants?**
e. **Regarding the $47.7 million in projected 2015 costs and projected transportation expense, how did FPL project the transportation expense? Include origin and delivery points and assumptions.**
f. **Regarding projected 2015 depletion expense for the Woodford project, how did FPL project the expense? Include assumptions on the number of wells and the quantity of gas estimated for the reserve.**
g. **Regarding projected 2015 lease operating expenses for the Woodford project, how did FPL project the expense? Include assumptions, allocations and methodology, and categories of expenses.**
h. **Regarding projected 2015 taxes for the Woodford project, how did FPL project the expense? Include assumptions, allocations and methodology, and types of taxes.**
i. **Regarding projected 2015 G&A expense for the Woodford project, how did FPL project the expense? Include assumptions.**

A.

a. Please see refer to "Attachment I" for the latest version of Exhibit KO-6.

b. The projected annual quantity of natural gas at the wellhead is 17,376,862 MCF (MMBtu). The projected annual quantity of natural gas delivered to FPL's plants is 15,138,189 MCF (MMBtu).

c. Exhibit SF-8 in the direct testimony of FPL witness Forrest shows an annual average cost of gas of $3.48/MMBtu delivered to the Perryville Hub in Louisiana. This value was calculated using the expenses shown on Exhibit KO-6 that was included in the direct testimony of FPL witness Ousdahl. As noted in FPL's response to Staff's 2nd Set of Interrogatories No. 78, FPL updated Exhibit KO-6 to revise the weighted average cost of capital ("WACC") applied to the net investment consistent with the Commission-approved methodology for calculating the WACC used in clause filings. With that revision, the 2015 annual average per MMBtu cost of this gas included in the revised 2015 Fuel Clause projection filing was $3.36/MMBtu. Consistent with Exhibit SF-8, this cost of gas represents delivery to the Perryville Hub in Louisiana.

d. The annual average per MMBtu cost of this gas delivered to FPL's plants is $3.47/MMBtu.

e. For clarification, the transportation costs shown on Line 7, subpart a of Attachment I, that is provided in response to part a of this Interrogatory, do not include long-haul transportation costs. The transportation costs shown in Attachment I represent the costs of the gathering system. Long-haul transportation costs to move the gas from the outlet of the gathering system to the Perryville Hub in Louisiana are included in FPL's total cost of gas shown on Schedule E3 of its revised filing with gas reserves. FPL assumed it would procure firm transportation on Enable Gas Transmission, LLC ("Enable Pipeline", formerly known as CenterPoint Energy Gas Transmission Company, LLC), to transport gas from the gathering system to the Perryville Hub in Louisiana. The projected 2015 transportation costs are based on securing sufficient firm transportation on the Enable Pipeline at the maximum posted transportation rate for the peak projected production volumes. The cost of long-haul transportation included in the revised filing with gas reserves is $4,550,400.

f. Please refer to FPL's response to Staff's 4th Set of Interrogatories No. 145. Regarding the underlying assumptions, the current drill schedule indicates 14 wells are expected to be drilled in 2014, with 4 being in production by year end. The remaining 24 wells will be drilled and completed in 2015. As described by witness Taylor in his testimony, the gross EUR for each well is estimated to be 6.6 Bcf.

g. FPL utilized the estimates for lease operating costs that were provided by PetroQuest, who is the operator. The specific assumptions are $2,300 per well per month plus an additional $2.11 per barrel of water disposal. The costs covered by the monthly charge include, but are not limited to chemicals, compression, contract labor, fuel, equipment repairs, vehicles, supplies, testing & measurement, and utilities.

h. Natural Gas Gross Production Tax (Severance Tax): Severance Taxes are calculated by multiplying the forecasted market value of gas production by the applicable Severance Tax rate. In Oklahoma, Severance Tax rates are applied to pre-7/1/2015 wells drilled at a rate of 1.095% for a period of 48 months. For wells drilled on or after 7/1/2015, the rate increases to 2.095% for a period of 36 months. After each of the aforementioned grace periods expires, the rate increases to 7.095%. Therefore, well production can be divided into one of three categories: 1) Before Rule Change – During Grace Period, 2) After Rule Change – During Grace Period, and 3) After Grace Period. Taking into account the differing start dates of each well, the annual weighted average Severance Tax rate was calculated as the sum of the product of monthly production and the applicable Severance Tax rate, divided by total annual production. The annual Severance Tax rate is then applied to the forecasted market value of gas production which is estimated as the forecasted price, multiplied by forecasted production.

State Franchise Tax: State Franchise Tax is calculated as $1.25/$1,000 of taxable capital employed in Oklahoma, capped at a maximum rate of $20,000/year. Total capital multiplied by the $1.25/$1,000 rate is greater than the $20,000 maximum rate in all years of the analysis. Therefore the project is assessed the $20,000 maximum State Franchise Tax in all years.

i. Please refer to FPL's response to Staff's 2nd Set of Interrogatories No. 81.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	January ESTIMATED	February ESTIMATED	March ESTIMATED	April ESTIMATED	May ESTIMATED	June ESTIMATED	Six Month Amount
1.	Investments								
	a. Capital addition		$5,045,400	$19,260,000	$14,214,600	$19,260,000	$5,045,400	$19,260,000	$82,085,400
2.	Gas Reserve Investment / DD&A Base (A)	$68,446,271	73,491,671	92,751,671	106,966,271	126,226,271	131,271,671	150,531,671	n/a
3.	Less: Accumulated Depletion Reserve	$0	377,307	971,330	1,901,685	3,106,386	4,682,419	6,426,341	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$68,446,271	$73,114,364	$91,780,341	$105,064,586	$123,119,885	$126,589,252	$144,105,330	n/a
5.	Average Rate Base (D)		70,780,318	82,447,352	98,422,463	114,092,236	124,854,569	135,347,291	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		472,433	550,306	656,934	761,524	833,358	903,393	$4,177,947
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		87,010	101,353	120,991	140,254	153,484	166,382	$769,473
	Subtotal (Debt & Equity Return)		559,443	651,658	777,924	901,777	986,842	1,069,776	
7.	Investment and Operating Expenses								
	a. Transportation Costs		285,676	359,088	507,406	615,425	772,784	833,646	$3,374,026
	b. Depletion		377,307	594,024	930,354	1,204,701	1,576,033	1,743,922	$6,426,341
	c. Lease Operating Expenses (LOE)		47,592	103,946	121,077	169,423	201,640	240,162	$883,839
	d. Taxes (Ad-Valorem, Severance & Franchise)		80,128	80,128	80,128	80,128	80,128	80,128	$480,766
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	$150,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$1,375,146	$1,813,844	$2,441,889	$2,996,455	$3,642,426	$3,992,633	$16,262,392

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Working capital balance has not been forecasted for inclusion in Average Rate Base but will be included in the true-up filings when actual balances are known.

Totals may not add due to rounding.

Florida Power & Light Company
Fuel and Purchased Power Recovery Clause
For the Period January through December 2015 - SUPPLEMENTAL SCHEDULE

Supplemental Schedule - Return on Capital Investments & Depletion
For Project: Gas Reserves Investment
(in Dollars)

Line		Beginning of Period Amount	July ESTIMATED	August ESTIMATED	September ESTIMATED	October ESTIMATED	November ESTIMATED	December ESTIMATED	Twelve Month Amount
1.	Investments								
	a. Capital addition		$16,276,500	$9,630,000	$2,522,700	$8,368,650	$3,438,450	$0	$122,321,700
2.	Gas Reserve Investment / DD&A Base (A)	$150,531,671	166,808,171	176,438,171	178,960,871	187,329,521	190,767,971	190,767,971	n/a
3.	Less: Accumulated Depletion Reserve	$6,426,341	8,323,765	10,424,370	12,999,989	15,630,310	18,154,600	20,744,130	n/a
									n/a
4.	Net Investment (Lines 2 - 3)	$144,105,330	$158,484,406	$166,013,801	$165,960,882	$171,699,211	$172,613,371	$170,023,841	n/a
5.	Average Rate Base		151,294,868	162,249,103	165,987,341	168,830,047	172,156,291	171,318,606	n/a
6.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,009,838	1,082,953	1,107,904	1,126,878	1,149,080	1,143,489	10,798,089
	b. Debt Component (Line 5 x debt rate x 1/12) (C)		185,987	199,453	204,048	207,543	211,632	210,602	1,988,738
	Subtotal (Debt & Equity Return)		1,195,824	1,282,406	1,311,953	1,334,421	1,360,712	1,354,091	
7.	Investment and Operating Expenses								
	a. Transportation Costs		898,337	987,416	1,166,726	1,186,225	1,133,535	1,158,547	9,904,811
	b. Depletion		1,897,425	2,100,605	2,575,618	2,630,321	2,524,290	2,589,531	20,744,130
	c. Lease Operating Expenses (LOE)		218,151	349,126	391,672	397,235	413,250	385,946	3,039,218
	d. Taxes (Ad-Valoren & Severance)		80,128	80,128	80,128	80,128	80,128	80,128	961,533
	e. G&A		25,000	25,000	25,000	25,000	25,000	25,000	300,000
8.	Total System Recoverable Expenses (Lines 6 & 7a-e)		$4,314,864	$4,824,680	$5,551,096	$5,653,330	$5,536,914	$5,593,243	47,736,519

Notes:

(A) Applicable beginning of period and end of period DD&A (Depreciation, Depletion & Amortization) base

(B) For purposes of this example the gross-up factor for taxes uses 0.6110, which reflects the Federal Income Tax Rate of 35% and Oklahoma State Tax rate of 6%.
The monthly Equity Component is 4.8938% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% return on equity, per FPSC Order No. PSC-12-0425-PAA-EU.

(C) For purposes of this example the debt component is 1.4751% based on the May 2014 Earnings Surveillance Report and reflects a 10.5% ROE, per FPSC Order No. PSC-12-0425-PAA-EU.

(D) Simplified example omits the working capital items that would be included in the actual clause filings

Totals may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
COST RECOVERY CLAUSES

Equity @ 10.50%

CAPITAL STRUCTURE AND COST RATES PER MAY 2014 EARNINGS SURVEILLANCE REPORT

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG_TERM_DEBT	7,260,190,891	29.609%	4.77%	1.41%	1.41%
SHORT_TERM_DEBT	303,811,216	1.239%	2.18%	0.03%	0.03%
PREFERRED_STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER_DEPOSITS	422,415,505	1.723%	2.04%	0.04%	0.04%
COMMON_EQUITY	11,427,411,916	46.604%	10.50%	4.89%	7.97%
DEFERRED_INCOME_TAX	5,104,824,995	20.819%	0.00%	0.00%	0.00%
INVESTMENT_TAX_CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	1,326,963	0.005%	8.27%	0.00%	0.00%
TOTAL	$24,519,981,486	100.00%		6.37%	9.44%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (a)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$7,260,190,891	38.85%	4.772%	1.854%	1.854%
PREFERRED STOCK	0	0.00%	0.000%	0.000%	0.000%
COMMON EQUITY	11,427,411,916	61.15%	10.500%	6.421%	10.453%
TOTAL	$18,687,602,807	100.00%		8.275%	12.307%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.4129%
SHORT TERM DEBT	0.0270%
CUSTOMER DEPOSITS	0.0352%
TAX CREDITS -WEIGHTED	0.0001%
TOTAL DEBT	**1.4751%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.8935%
TAX CREDITS -WEIGHTED	0.0003%
TOTAL EQUITY	**4.8938%**
TOTAL	6.3690%
PRE-TAX EQUITY	7.9671%
PRE-TAX TOTAL	9.4423%

Note:

(a) This capital structure applies only to Convertible Investment Tax Credit (C-ITC)

Q.

Please refer to the testimony of FPL witness Yupp, page 3 of September 15, 2014 testimony, lines 6 through 15.

a. **How did FPL project the $7 million in lower costs for 2015?**
b. **Originally, the projected savings for 2015 were $14 million and the revised amount is $7 million. What specifically caused this difference?**

A.

a. FPL projected the $7 million in lower costs of the Gas Reserves Project in 2015 by taking the differential between the projected fuel costs based on the production costing runs with and without the Gas Reserves Project.

b. The $7 million difference was caused by the error explained in Interrogatory No. 167.

Q.

Please refer to the September 15, 2014 revised filing and the E1 and E3 schedules with and without the Woodford gas reserve project.

a. **Considering the schedules with the Woodford project, the MWH system generation is higher and purchased power (E7 and E8) is lower. Please explain these differences.**
b. **Why did the cost and MWH for economy purchases (E9) remain the same for the with and without schedules?**

A.

a. FPL's production costing model output showed lower utilization of UPS (E7), SJRPP (E7) and QF (E8) purchases in the "with gas reserves" case. This decrease in power purchases resulted in higher system generation. It is reasonable to expect that lower system generation costs resulting from the availability of lower-cost gas caused the model to view system generation as slightly more attractive in the economic dispatch.

b. FPL's production costing model output showed slightly lower marginal costs in the "with gas reserves" case. This decrease in the marginal cost output of the model resulted in a lower "cost if generated" on Schedule E9. The small change in marginal costs, however, did not warrant changes to the projected volume of economy purchases or the prices at which FPL projected it could make economy purchases. Therefore, FPL did not adjust its projections for the cost and volume of economy purchases. Applying the slightly lower marginal costs did result in a small decrease in projected savings.

Q.

Please refer to the September 15, 2014 revised filing and the E1 and E6 schedules with and without the Woodford gas reserve project. Why is the fuel cost of economy sales lower with the gas reserve project but the MWH and gains from off-system sales remain the same?

A.

FPL's production costing model output showed slightly lower marginal costs in the with gas reserves case. This decrease in the marginal cost output of the model resulted in lower fuel costs for economy sales. However, the small change in marginal costs did not warrant changes to the projected volume of economy sales or to the projected gains on economy sales.

Q.

Please refer to TJK-7 and TJK-8 attached to September 15, 2014 testimony of FPL witness Keith. Refer to the with and without projected capacity payments schedule, line 9, column 14. Why is transmission of electricity by others higher with the gas reserves project than without?

A.

The "Transmission of Electricity by Others" line item in the revised filing represents the projected cost of unutilized Southern Company transmission service associated with FPL's UPS purchased power contracts. In the "with gas reserves" case, the production costing model output showed less utilization of UPS purchased power, resulting in a higher amount of unutilized transmission service.

Q.

Please refer to the testimony of FPL witness Forrest, page 36, lines 3 through 15. The cumulative NPV savings are $107 million. Given the September 15, 2014 revision to 2015 projected fuel costs, the projected 2015 savings from the Woodford project have decreased from $14 million to $7 million. Does the change for 2015 affect the $107 million cumulative NPV amount? Please explain.

A.

The decrease in the 2015 projected savings was due solely to an input error in FPL's production costing model related to the availability of natural gas to FPL's system (Please see the response to Interrogatory No. 167) that applied only to FPL's 2015 fuel filing. This correction does not impact the projected cumulative NPV savings of $107 million, the details of which are shown on Exhibit SF-8 in the direct testimony of FPL witness Forrest. For comparison, Exhibit SF-8 shows projected savings of the Woodford Gas Reserves Project in 2015 of $8.4 million ($7.8 million discounted to 2014). FPL's revision to its 2015 projected fuel costs shows projected savings of the Woodford Gas Reserves Project of $7 million. The difference for 2015 is due to the fact that the projected savings in the testimony of FPL witness Forrest are based on the October 7, 2013 fuel forecast while FPL's revision to its 2015 projected fuel costs is based on the July 28, 2014 fuel forecast.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI-DADE)

I hereby certify that on this 7th day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Daisy Iglesias, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 167 and 169 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 167-173) in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Daisy Iglesias

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 7th day of October, 2014.

Carolyn J Smith
Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA
CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2018
Commission # FF 122975

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Melissa Linton, who is personally known to me, and she acknowledged before me that she provided the answer to and co-sponsored interrogatory number 168 subpart (h) from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 167-173) in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Melissa Linton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11-24-2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 6th day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answer to and co-sponsored interrogatory number 168 subparts (a), (f) & (i) from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 167-173) in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of October, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11-24-2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 6TH day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to and co-sponsored interrogatory number 168 subparts (b) – (g) & (i) from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 167-173) in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2014.

Jacqueline S. Bussey
Notary Public
State of Florida, at Large

My Commission Expires:

JACQUELINE S. BUSSEY
MY COMMISSION # FF 103317
EXPIRES: July 18, 2018
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 170 through 173 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 167-173) in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Gerard J. Yupp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

48

FPL's Responses to Staff's Eighth Set of Interrogatories (Nos. 174-177)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 48
PARTY: STAFF
DESCRIPTION: FPL's Responses to Staff's Eighth Set of Interrogatories (Nos. 174-177)

Q.

(a) Please complete the table below to show FPL's high price sensitivity of the Perryville gas forecasts.

(b) Please refer to the second column in the table above entitled "Low Perryville Gas Price Forecast." Also, refer to exhibit DJL-2 of OPC witness Lawton's direct testimony. State whether the numbers are correct. If not, please provide the correct numbers.

(c) Please state the source used to derive the number for the low Perryville gas reserve price forecast.

A.

a)

Year	Low Perryville Gas Price Forecast	Base Perryville Gas Price Forecast	High Perryville Gas Price Forecast
2015	$3.14	$ 4.02	$4.91
2016	**$3.35**	$ 4.30	$5.24
2017	$3.67	$ 4.70	$5.73
2018	**$4.48**	$ 5.74	$6.99
2019	**$4.60**	$ 5.89	$7.17
2020	$4.71	$ 6.03	$7.35
2021	**$4.79**	$ 6.13	$7.47
2022	$4.95	$ 6.33	$7.72
2023	$5.18	$ 6.63	$8.08
2024	$5.50	$ 7.03	$8.57
2025	$5.73	$ 7.33	$8.93
2026	**$5.97**	$ 7.63	$9.29
2027	$6.20	$ 7.93	$9.66
2028	$6.51	$ 8.33	$10.15
2029	$6.75	$ 8.63	$10.51
2030	**$6.91**	$ 8.83	$10.75
2031	$7.17	$ 9.17	$11.16
2032	$7.45	$ 9.52	$11.59
2033	$7.73	$ 9.88	$12.03
2034	**$8.03**	$ 10.26	$12.49
2035	$8.33	$ 10.65	$12.96
2036	**$8.65**	$ 11.06	$13.46
2037-2065	$13.43	$ 17.16	$20.88

b) The table above is completed with the correct price forecasts (corrected values are in bold face). The low and high price forecasts are consistent with the responses provided to OPCs POD No. 34.

c) The low price forecast is derived by calculating one standard deviation of the day-to-day volatility of forward prices. The standard deviation is approximately 21.8%. The negative standard deviation is then multiplied by the base price forecast to get the low prices. Similarly, one positive standard deviation is multiplied by the base price forecast to get the high price sensitivity.

Q.

Please state whether FPL's low and high Perryville gas price sensitivities set forth in the table in interrogatory #174 were used to develop the information on page 38 of witness Forrest's direct testimony and in the response to Staff's Fourth Set of Interrogatories, No. 148. If not, please state the source of the information.

A.

Yes, those forecasts were used to create the table in Witness Forrest's direct testimony as well as the response to Staff Interrogatory #148 regarding the probability of outcomes.

Q.

Please explain the methodology used to develop FPL's low and high Perryville market price sensitivities.

A.

FPL adjusts the base price forecast for one standard deviation up or down to arrive at the high and low price forecasts, respectively. The standard deviation applied is derived from an 8-year historical running average for actual daily fluctuation in the forward price for natural gas. That data is annualized so it can be appropriately applied to FPL's corresponding annual natural gas price forecast.

Q.

Refer to FPL's response to Staff's Second Set of Interrogatories, No. 27. Please complete the table below.

A.

Year	FPL's Forecasted Cost of Gas Transportation, Woodford Shale, $/Mcf	FPL's System Average Forecasted Cost of Gas Transportation, $/Mcf
2015	$0.29	$1.07
2016	$0.27	$1.00
2017	$0.40	$1.35
2018	$0.53	$1.49
2019	$0.64	$1.49
2020	$0.29	$1.55
2021	$0.33	$1.61
2022	$0.37	$1.69
2023	$0.41	$1.83
2024	$0.45	$1.84
2025	$0.28	$1.78
2026	$0.30	$1.70
2027	$0.32	$1.83
2028	$0.34	$1.81
2029	$0.37	$1.70
2030	$0.39	$1.68
2031	$0.42	n/a
2032	$0.44	n/a
2033	$0.47	n/a
2034	$0.50	n/a
2035	$0.53	n/a
2036	$0.56	n/a
2037-2065	$1.57	n/a

FPL has completed the requested table based on the best information available. FPL does not regularly forecast a "system average cost of gas transportation" and, in fact, does not use such a metric for planning purposes. However, in order to be responsive to this interrogatory, FPL has calculated a yearly "system average cost" by totaling all demand charges under gas transportation contracts for a particular year and dividing that total by the forecasted gas requirements to operate its electric system in that year. FPL utilized the projected gas usage that was developed for the 2014 Nuclear Cost Recovery ("NCR") filing, which effectively has the same gas requirements as the Ten Year Site Plan through 2023 and continues thereafter. The NCR filing does not contain any assumptions about gas transportation costs that would be relevant past 2030 - after that point the resource plans that are compared for the filing are assumed to have the same gas requirements and therefore there is no need to continue forecasting gas transportation costs. As a consequence, FPL does not have a basis to complete the "system average cost of gas transportation" column beyond 2030.

FPL calculated the forecasted cost of gas transportation for the Woodford Project in a similar manner: dividing the annual demand charges for the gas transportation specifically attributable to the Woodford Project by the expected annual production from the project. Please note that only the demand charges were utilized to calculate the information provided in the table - all variable charges were excluded to give a more straightforward comparison. For this reason, the 2015 cost for the Woodford Project provided in this table is different than the response to Staff's Second Set of Interrogatories, No. 27, which included ($0.10 per Mcf) for fuel retention. It is important to note the forecasted gas transportation costs for the Woodford Project cannot be directly compared to FPL's "system average cost," because the former represents only the forecasted transportation demand charges to deliver the gas to the Perryville Hub as a point of receipt, whereas FPL's "system average cost" reflects all demand charges incurred to take gas from the various points of receipt and deliver it to FPL's generating units where it is consumed. The "system average cost" is inclusive of both upstream (SESH, Gulf South, Transco) and downstream (FGT, Gulfstream, Sabal Trail, FSC) pipelines.

Additionally, although the costs for gas transportation to support the Woodford Project are shown through 2065, they are heavily skewed by the last years of the analysis as the gas production tapers off. Again, FPL has been conservative in the approach to modeling gas transportation and has assumed approximately 10 MMcf/day of gas transportation capacity will remain under contract over the last 40 years of the analysis, when in fact less than 1 MMcf/day is being extracted over the last few years. As discussed in the response to Staff Interrogatory No. 53, FPL will pursue the best economic solution for its customers if this transaction is approved and is currently working with a few companies to determine the best approach to physically deliver the gas to Florida - there is no intention to manage the position as conservatively as it has been modeled, but feel this conservative approach is appropriate to test the Project's economics.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 30th day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to and co-sponsored interrogatory numbers 174-177 from **STAFF'S EIGHTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 174-177)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of October, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

49

FPL's Responses to OPC's Second Set of Interrogatories (Nos. 11-14, 16, and 17)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 49
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's
Second Set of Interrogatories (Nos. 11-14, 16,

Q.

This interrogatory relates to the prefiled testimony of Sam Forrest, at page 9, who states: "...there are multiple utilities across the U.S. investing in gas reserves..." Please identify the utilities to whom the witness refers in this part of his testimony; the type of utility business (gas, electric, combination) in which each is engaged; the corporate structure (affiliate, subsidiary, department, other) being employed by each utility identified in your answer to pursue the investment in gas reserves; the form or nature Goint venture, outright ownership, contractual relationship with producer, etc.) of the investment vehicle employed by each; the nature and extent of the investment in gas reserves of each; and the regulatory treatment, including standards and provisions/limitations on cost recovery, if applicable, that the pertinent regulatory authority has applied to requests for cost recovery submitted by each such utility. In your answer, identify any and all documents (including, but not limited to, orders of regulatory bodies) known to the witness that support the statement quoted within this interrogatory.

A.

Please refer to the responses for Staff Interrogatories Nos. 83 and 87.

Q.

This interrogatory relates to the relationship between the proposal contained in FPL's June 25, 2014 petition in the instant docket and the "asset optimization program" that the Commission approved as a pilot program in Order No. PSC-13-0023-S-EI. Under the terms of the "asset optimization program," and the terms of the proposal that is the subject of FPL's June 25, 2014 petition and related testimony and exhibits filed in Docket No. 140001-EI, would FPL, or the FPL subsidiary formed to participate in the joint venture with an affiliate of PetroQuest, or the PetroQuest affiliate have the ability to sell natural gas produced by the PetroQuest affiliate with capital supplied by the FPL subsidiary to entities other than FPL? If your answer is "yes," under what circumstances could such sales occur? Please explain your answer.

A.

First and foremost, FPL intends that the investment would be for the sole purpose of delivering the Woodford Project gas to Florida to serve its generating facilities. As such, the base case analysis assumes neither FPL, nor FPL's subsidiary nor PetroQuest would be selling the gas from the Woodford Project into the market.

The FPL subsidiary proposed by FPL in the June 25, 2014 petition will sell 100% of the gas received from the Woodford Project directly to FPL. The FPL subsidiary has no capability to make sales into the market, and it is not FPL's intent for its subsidiary to sell gas to any entity other than FPL.

FPL would maintain the flexibility to make sales of the gas from the Woodford Project into the market, if and only if circumstances arose where FPL could thereby lower the overall price of fuel for customers. Generally, such circumstances could arise when the relationship between the market prices at different delivery points and the cost of transportation between those delivery points made it possible to sell FPL's gas at an upstream delivery point and then buy replacement gas at a downstream delivery point for less than the transportation cost. If FPL entered into any such transactions, it would do so pursuant to its asset optimization program, such sales would only take place when there was the potential for generating additional savings for FPL's customers, and the benefits of such transactions would be credited directly to FPL's customers through the Fuel Clause.

Additionally, contractually through the Drilling and Development Agreement presented as Exhibit SF-4, FPL has the option of either taking the gas in kind or allowing PetroQuest (note there is no difference between PetroQuest or a PetroQuest affiliate in this discussion, so we will refer to both as "PetroQuest") to sell it. This option was meant to allow for the transition from USG to FPL should the Commission approve the assignment. During the interim period, USG plans to utilize the existing relationships PetroQuest has to sell the Woodford Project gas into the market. However, if the Commission approves FPL's petition for the Woodford Project, FPL intends to elect to take the gas in kind and will no longer have the ability to have PetroQuest market FPL's share of production. By exercising the one-time option to take the gas in kind, the Woodford Project gas will become part of FPL's larger procurement portfolio and the gas will be treated in the same manner as the rest of the portfolio. As discussed above, FPL may consider selling the Woodford Project gas that it has taken in kind, but only when the potential for generating additional savings for FPL's customers is available.

The decision to enter into the PetroQuest transaction was made independent of the incentive mechanism and under the assumption that FPL would accept the gas from the joint venture in kind and have it delivered to Florida. Consequently, the economics assume FPL receives the gas from its subsidiary and delivers the gas to Florida to serve FPL's customers, and there is no sale pursuant to FPL's asset optimization program. It is that analysis that results in projected savings to FPL's customers of $107 million. Of course, if there were optimization opportunities, the projected benefits would have been even greater than the $107 million that FPL calculated. As stated previously, while FPL's decision to enter into the gas reserve transaction was made independent of the incentive mechanism, FPL sees no reason not to allow the incentive mechanism to work to benefit FPL's customers in the gas reserve transactions.

Q.

This interrogatory relates to page 22 of the prefiled testimony of Sam Forrest. At line 3, Mr. Forrest states that"... USG already has substantial experience with a known partner (PetroQuest) that has produced good operating results." Please describe the nature and extent ofUSG's (or other subsidiaries or affiliates ofNextEra, Inc.) prior experience with PetroQuest and/or PetroQuest affiliates. Include in your answer data regarding the NextEra affiliates' (USG and others, if applicable) total investment in PetroQuest wells, total volume of gas received by USG (and/or other entities related to NextEra) in return for its (their, as applicable) capital investment, total profit, and realized return on investment for each of the years 2011-2013, inclusive, and 2014 to date.

A.

FPL objects to the request in this interrogatory for financial details about the original joint venture between USG and PetroQuest, because those details are confidential and not relevant to this proceeding. FPL, not USG, is the petitioner in this proceeding, and the requested information is not necessary "to ensure that a utility's ratepayers do not subsidize non-utility activities" as contemplated for Commission access to affiliate information under Section 366.093(1) of the Florida Statutes. Moreover, the detailed financial information sought by OPC in this interrogatory was not provided to FPL and was not the basis for Mr. Forrest's statement that PetroQuest has produced good operating results.

Without waiving its objections, FPL notes that USG's confidence in PetroQuest's good operational performance is evidenced by the facts that (1) USG is entering a new joint venture with PetroQuest for the development of wells outside the Woodford Project AMI; and (2) USG is willing to continue as a joint venturer with PetroQuest for the Woodford Project if the Commission does not approve FPL's petition.

Q.

This interrogatory relates to page 28 of the prefiled testimony of Sam Forrest. At line 15, Mr. Forrest states that FPL will have a total capital expenditure of approximately $191 million under the initial PetroQuest Agreement attached to Mr. Forrest's testimony. What maximum total capital expenditure does FPL contemplate investing in shale gas drilling and fracking production joint ventures if the Commission approves its petition in the form in which FPL submitted it? In your answer, provide the value of investment that corresponds to the highest level of participation in such ventures contemplated by FPL in its June 25, 2014 filing.

A.

The maximum investment contemplated by FPL in the Woodford Project is $191 million. This value corresponds to the highest level of participation by FPL in the Woodford Project joint venture. As stated in Witness Forrest's testimony on page 32 line 18 through page 33 line 2, for purposes of the evaluation, FPL has conservatively assumed that all working interest owners with such rights non-consent on all 38 proposed wells, such that FPL and PetroQuest would step into these other working interest owners' rights under the carry structure terms of the PetroQuest Agreement. This conservative assumption results in the highest level of projected capital expenditure by FPL.

The maximum total capital expenditure for FPL investments in gas reserves is limited by Guidelines I.A and I.D in the Proposed Transactional Guidelines (Exhibit SF-9). Guidelines I.A and I.D limit FPL's total investment using a volumetric limit (maximum volume from gas reserves as a percentage of FPL's average annual daily burn) and capital expenditure limit (aggregate annual investment in gas reserves), respectively. The investment limit guideline is not intended to represent a target, but rather intended to provide FPL with the flexibility to pursue and structure transactions that meet the development schedules and capital requirements of potential counterparties.

Q.

This interrogatory relates to page 31 of the prefiled testimony of Sam Forrest. At lines 4-5, he states, "Technical services will be provided by USG to FPL under established affiliate services terms." Please describe in detail the services to which the witness refers, the estimated amount of the costs of such services, and the "established affiliate services terms" that would be applicable to each. In your answer, please explain how FPL would or would not apply the Commission's cost allocation manual to the identified services under its proposal. Does FPL propose to recover such costs through the fuel and purchased power cost recovery clause? If your answer is "yes," do the quantitative estimates of benefits take these costs into account?

A.

The full scope of services that will be needed by FPL are still being identified as a part of determining the processes and activities that will be required to support its investments in gas producing activities. Some of those services are described in Staff 2nd Set of Interrogatories No. 81.

Once we have a discreet list of services and service providers, we will determine the appropriate means to charge those incurred costs. In the start up phase, it is likely that any time spent by affiliates in support of FPL will be charged on a direct bill basis at fully loaded cost. That method will insure that the affiliate charges incurred comply with the Commission's affiliate rules and with FPL's cost allocation manual.

All incremental costs incurred in direct support of the gas producing activities are eligible for recovery in the fuel clause. This support is incremental and necessary and therefore, will be recovered through the fuel clause.

Q.

This interrogatory relates to page 31 of the prefiled testimony of Sam Forrest. At lines 9-10, he states, "FPL proposes to include for recovery in the Fuel Clause any incremental costs that are incurred to manage these activities."

a. To what does the witness refer by the words "these activities"?

b. Identify and describe in detail the "incremental costs" to which the witness refers.

c. Please quantify the "incremental costs" and state whether they have been included in the "exploration and production costs" embedded in FPL's estimate of payments to its subsidiary when estimating the "economic benefits" of the PetroQuest transaction.

A.

a. The activities that FPL witness Forrest refers to are accounting, technical services and business management activities. Refer to response provided to Staff's 2nd Set of Interrogatories No. 81.

b. Refer to response provided to Staff's 2nd Set of Interrogatories No. 81.

c. As stated in Staff's 2nd Set of Interrogatories No. 81 and reflected in FPL witness Ousdahl Exhibit KO-6, line 7e, $300,000 is the best estimate of those costs available at this time. As stated, FPL is in the process of selecting providers and determining the services to outsource and/or obtain from the affiliate USG. This estimate was used in developing the economic benefits of the transaction and included in the financial assumptions.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 11 day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **15-17** from **OPC'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 11-17)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of August, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

JOANN RICHELSON
Notary Public - State of Florida
My Comm. Expires Dec 21, 2017
Commission # FF 74371

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 11TH day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **11-14** from **OPC'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 11-17)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of August, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

50

FPL's Responses to OPC's Third Set of Interrogatories (Nos. 37, 38-41, 45, 46, 47 and 50)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 50
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's Third Set of Interrogatories (Nos. 37, 38-41,

Q.

Please refer to the Results of FPL's Economic Evaluation provided at Exhibit SF-8.

a. Please provide a detailed breakdown of the projected operating expenses in Column (C) for each year, broken down between amounts that will be billed from PetroQuest as part of the Joint Venture and those that will be incurred by FPL or its subsidiary (such as those described on pages 31 and 32 of the direct testimony of Sam Forrest).
b. Column "D" is labeled "Depreciation" but, according to testimony, "Depletion" will be used. Please explain whether a depreciation rate or a depletion rate was used in calculating FPL's Economic Evaluation.
c. Please provide the detail of the data by year for column "E", Return Rate, showing the assumed return, cost rates for debt and equity, capital structure ratios, and assumed level of investment for which the return is earned.
d. Please provide a detailed breakdown of the items included in determining the Rate of Return in Column (E), by year and by individual items to which a return would be applied.
e. Please provide the return that is being applied on the assets in Column (E).
f. Please provide the basis for the estimate and all formulas and detail showing the calculation of Column "H" FPL Market Price Forecast.
g. Please refer to footnote (2). Please explain, in detail, how the "return of the financing costs" was determined and identify the amounts, by year, included in Column (E) associated with the "return of the financing costs."

A.

a. PetroQuest will bill the subsidiary for Lease Operating Expenses, severance tax and state franchise tax. Additionally, the subsidiary will be incurring the gathering costs as well as accounting, technical and business management incremental costs as stated in FPL's response to Staff's 2nd Interrogatories No. 81. FPL will incur directly all long-haul transportation costs, including both the incremental long-haul costs displayed in this response and the costs that it would have incurred anyway to deliver gas purchased in the market. See Attachment No. I.

b. In Column D of Exhibit SF-8, "Depreciation" is synonymous with depletion and is based on units of production.

c. In Attachment No. II, the table provides a build-up of the components of column "E", Return Rate. The column headings provide the relevant formulas for calculating the assumed return, cost rates for debt and equity, capital structure ratios, and assumed level of investment (rate base) upon which the return is earned.

d. Please refer to the table provided in response to OPC's 3rd Interrogatories No. 37(c). The return is calculated based on the average rate base for the respective period.

e. Please refer to the table provided in response to OPC's 3rd Interrogatories No. 37(c).

f. Please refer to the response provided for Staff's 2nd Interrogatories No. 21(a,c).

g. Please refer to the table provided for OPC 3rd Interrogatories No. 37(c). Within this response, refer to the "Financing Costs" column. This column represents the "return of the financing costs", namely interest expense. Interest expense is calculated by applying the debt ratio of [redacted] to the respective periods' average rate base, and then multiplying that by the assumed debt cost rate of [redacted].

Response to Question 37(a)
Operating Expense Breakdown

A	i	ii	iii	iv	v	vi	C = i + ii + iii + iv + v + vi
Year	Lease Operating Expense ($MM)	Gathering Costs ($MM)	Long-Haul Costs ($MM)	Business Management Fee ($MM)	Severance Tax ($MM)	State Franchise Tax ($MM)	Operating Expenses ($MM)
2015	[redacted]						
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							
2037-65							
Totals	[redacted]						$323.2

Response to Question 37(c)
Return Rate

A	i	ii = i x 40.4%	iii = ii x 5.1%	iv = i x 59.6%	v = iv x 10.5%	vi = v x (1/(1+38.9%)-1)	E = iii + v + vi
Year	Average Rate Base ($MM)	Average Debt Balance ($MM)	Financing Costs ($MM)	Average Equity Base ($MM)	After-Tax Equity Return on Assets ($MM)	Gross-up for Income Tax ($MM)	Return Rate ($MM)
2015	[redacted]						
2016							
2017							
2018							
2019							
2020							
2021							
2022							
2023							
2024							
2025							
2026							
2027							
2028							
2029							
2030							
2031							
2032							
2033							
2034							
2035							
2036							
2037-65[1]							
Totals			[redacted]				$195.5

(1) This amount represents the cumulative average rate base from 2037-65. The average rate base during this period declines according to units of production.

Q.

The Company indicated that it will utilize the successful efforts method of Ousdahl for the investment in the Woodford Gas Reserves Project. At page 23 of the Petition, at paragraph 50, the Company states: "Under the successful method of Ousdahl, depreciation is recorded in the form of "depletion," which is measured on a unit-of- production basis rather than on a remaining life or whole life basis."

a. Please explain, in detail, how the remaining undepreciated or "undepleted" balance is accounted for under the successful efforts method of Ousdahl in situations in which production suddenly ceases due to unforeseen events, such as (but not limited to) environmental issues, accidents, unfixable well problems, halt to drilling or extraction operations, natural disasters, etc. Additionally, please provide a citation to the Ousdahl Standards Codification that addressed how such undepreciated or undepleted costs should be accounted for under Generally Accepted Ousdahl Principles.

b. If it is determined that additional natural gas cannot be produced from a particular well and the full capital balance has not yet been fully depreciated or depleted, please explain in detail how FPL or its subsidiary would account for the undepreciated, undepleted, or otherwise unrecovered capital costs on its books?

c. If it is determined that additional natural gas cannot be produced from a particular well and the full capital balance has not yet been fully depreciated or depleted by FPL, would such unrecovered costs be incorporated in the fuel clause by FPL after it is determined that additional natural gas cannot be produced from the well? Please explain the response.

d. If it is determined that additional natural gas cannot be produced from a particular well and the full capital balance has not yet been fully depreciated or depleted by FPL, please explain in detail if such resulting loss would be a risk that is funded by FPL's shareholders, or if FPL would seek to recover the unrecovered or undepreciated/undepleted amount from ratepayers? If from ratepayers, please explain how such recovery would be achieved (i.e., flow through fuel clause, set up as a regulatory asset to incorporate in base rates, etc.).

e. If it is determined that additional natural gas cannot be produced from a particular well and the capital asset for tax purposes has not yet been fully depreciated or depleted for tax purposes, please explain in detail how FPL or its subsidiary would account for the income tax impacts of the loss or stranded cost on its books. Also, please describe the tax impacts under such scenario and explain how ratepayers would benefit from the tax loss.

A.

a. In the unlikely event that there is a sudden unforeseen cessation of production, the successful efforts method of accounting requires a review for potential impairment in accordance with Accounting Standards Codification (ASC) No. 932-360-35. The impairment analysis involves a comparison of the undiscounted cash flows to the net book value of the asset group. To the extent that the cash flows of the asset group exceed the net book value of the asset group, no impairment is recognized. FPL has defined the asset group for proved properties to be at the FPL entity level because all of the Company's assets are used to provide utility service (i.e., asset group would include all cash flows and assets and liabilities of FPL). Therefore, it is unlikely that FPL would recognize an impairment of the undepleted balance of the Woodford Project.

b. In the unlikely event that there is a sudden unforeseen cessation of production, FPL would consider the facts and circumstances associated with the event. If the unrecovered balance is limited to one or a few wells and given the relatively small investment that would likely be remaining once production had already begun, FPL would seek to recover the undepleted investment in the fuel clause in the current period. Alternatively, an analogy could be made to the Commission treatment for unrecovered investment in retired utility plant whereby its practice has been to consider the use of capital recovery schedules to amortize remaining unrecovered balance through rates. This could be applied if necessary to the clause recovery of any retired but unrecovered gas reserve investment. The Company believes the likelihood of these scenarios to be remote.

c. Refer to response in part b.

d. As discussed in the response to part b. above, FPL has many examples of retirement of assets before they are fully depreciated. Absent a finding of imprudence, the full return of the cost of the asset is recovered through rates. The Commission has discretion to determine the proper recovery period and has utilized capital recovery schedules in many cases to amortize those remaining costs into rates. The appropriate treatment for this investment would be no different.

e. If it is determined that a well could not produce any additional natural gas and there were remaining tax basis in the capital assets, the remaining balance of the capital asset would be written off for income tax purposes at the subsidiary. The difference between the book loss and the tax loss will be reflected in the tax computation and the deferred income taxes related to the book/tax timing difference will be reversed.

If it is determined that the remaining book investment in the well would be recovered under a capital recovery schedule for regulatory purposes, then the remaining tax basis in the asset would be deducted for income tax purposes and a timing difference and deferred income tax liability would be provided for the amount related to the regulatory asset. Since it is assumed that FPL would recover the undepleted investment for book purposes in the fuel clause, the total investment in the well would be recovered for book and tax purposes and all book/tax benefits of the loss would have been reflected in the subsidiary's tax provision.

Q.

The direct testimony of Kiim Ousdahl at page 15, lines 1 and 2, indicates that "In essence, FPL will be paying the market price for this transaction, as measured at the time of USG's initial purchase."

a. Please provide the current market value of the assets being transferred from USG to FPL or its subsidiary. Include all calculations and assumptions used in determining the current market value.
b. Please provide the projected market value of the assets being transferred from USG to FPL or its subsidiary at the anticipated time of transfer from USG. Include all calculations and assumptions used in determining the projected market value.
c. Please explain, in detail, if the projected market value at the anticipated time of transfer is greater than or less than the projected net book value for the interests that will be transferred at the time of purchase between USG and FPL or its subsidiary.
d. Please explain, in detail, if the current market value of the assets to be transferred from USG to FPL or its subsidiary is greater than or less than the current net book value of the assets.
e. Please describe, in detail, any research conducted by or for FPL, USG, NextEra Energy (or any subsidiary thereof) regarding the change in market value of the assets from the time of acquisition by USG and provide the results of such research.

A.

a. The concept as formulated in the cited excerpt of FPL witness Ousdahl's testimony is that the transfer at net book value equates to the market price of the investment at the time that USG initially entered into the transaction with PetroQuest plus any additional investment, less any depletion recognized through the date of transfer. The transfer at net book value puts FPL essentially in the same position as the initial purchaser (USG) at the time of the initial purchase. FPL is not proposing that the transfer from USG to FPL would occur based on the market price at the time of such transfer and, accordingly, does not have information on what that market price might be.

b.-e. See response to subpart a.

Q.

The direct testimony of Kim Ousdahl at page 15, lines 1 and 2, indicates that "In essence, FPL will be paying the market price for this transaction, as measured at the time of USG's initial purchase." Did USG attempt to sell its interest to any parties other than FPL? If the answer is no, please explain why not. If the answer is yes, please respond to the following:

a. Explain why USG attempted to sell its interest to a third party.
b. Provide the purchase price being sought by USG and identify how that price compared to USG's net book value at the time of the attempted sale.
c. Provide the purchase price offered by potential purchasers and how that offer compared to USG's net book value at the time of the attempted sale.
d. Explain why such efforts were not successful.

A.

No. This transaction was entered into by USG for the sole purpose of providing a backstop, or bridge, for FPL. As such, USG did not seek to sell its interest to any other party.

As FPL seeks approval of the Woodford Project from the Commission, USG will begin the drilling program with PetroQuest. If FPL receives Commission approval, the transaction will be assigned to FPL and FPL will continue the drilling program and FPL's customers will enjoy the benefits of lower fuel price volatility and customer savings. If the Commission does not approve the transfer, USG will continue the drilling program and will take the economic benefits for its own account.

Parts a-d are not applicable as USG did not attempt to sell its interest to a third party.

Q.

The direct testimony of Kim Ousdahl at page 19, lines 3 and 19, indicate that the reserve estimates must be updated annually and that the reports on the reserve estimates will be used "...to determine the subsequent year's depletion expense."

a. Does the Company agree that the subsequent year's depletion expense can change substantially based on the updated reserve estimates? If no, explain why not.
b. Does the Company agree that the annual updating of the depletion expense as a result of changes in the reserve estimates can cause volatility in the depletion expense on a per unit basis that is incorporated into the Fuel Adjustment Clause under the Company's proposed recovery method? If no, please explain why not.
c. Does the Company agree that, if the required annual analysis of the reserve results in a substantial decline in the estimated remaining reserves, a large increase in the annual depletion expense could result? If no, please explain, in detail, why not.

A.

a. A subsequent year's depletion expense can change based on the updated reserve estimates, but this change should not be substantial. As described in FPL witness Forrest's testimony, Page 38, Lines 1 through 5, a +/- 10% window on well production volumes is industry standard to capture potential variation in expected Economic Ultimate Recovery (EUR). Additionally, once a well comes online and the production rate is observed during the first year, any resulting update to the decline curve and EUR would be expectedly small and would recast the production profile for the remainder of the well's life. It is not expected that updating the decline curve for actual results would result in a substantial variation to the depletion expense given that actual production closely follows a stable logarithmic decline curve.

b. Please refer to response to subpart (a). The reserve estimate changes typically follow production volume changes such that the expense per unit may not be substantially different. If the reserve estimate changes are not accompanied by subsequent production volume changes in the later years then the cost per Mcf would change.

c. If there is a substantial decline in reserve estimates after the first five years, the depletion expense change nonetheless may not be significant as most of the production has already been delivered. However, if in the early years of production a substantial decline in remaining reserves was estimated, that change could result in a large percentage increase in the depletion expense for those producing wells. Since individual well costs are not significant, the dollar change in depletion would likely not be great even if the percentage basis would be.

Q.

In reference to Confidential Exhibit SF-9, at page 1 of 4, Guideline I.A, please provide the "Maximum Volume as a Percentage of Average Daily Burn" for 2015, 2016, and 2017 in terms of Mcf of gas quantities.

A.

The maximum gas quantity based on Guideline I.A is approximately [redacted] Mcf/day or [redacted] Bcf/year in 2015, [redacted] Mcf/day or [redacted] Bcf/year in 2016, and [redacted] Mcf/day or [redacted] Bcf/year in 2017. This is based on the projected gas usage as filed in FPL's most recent Ten Year Site Plan.

Florida Power & Light Company
Docket No. 140001-EI
OPC's 3rd Set of Interrogatories
Interrogatory No. 46
Page 1 of 1

Q.

In reference to Confidential Exhibit SF-9, at page 1 of 4, Guideline 1.A, given the high depletion rate of a well in its early years of production, please describe how many "producing" wells (and at what volumes of gas) FPL will need to attain in order to reach "Maximum Volume as a Percentage of Average Daily Burn" shown on this exhibit in 2015, 2016, 2017, and will that continue to increase in subsequent years?

A.

The Woodford Project represents 38 producing wells that are expected to produce approximately [redacted] Bcf (billion cubic feet) in 2015, [redacted] Bcf in 2016, [redacted] Bcf in 2017, and [redacted] Bcf in 2018. Based on these production rates the number of wells required to reach the maximum volume as a percentage of average daily burn using gas usage projection as filed in FPL's most recent Ten Year Site Plan is [redacted] wells in 2015, [redacted] wells in 2016 and [redacted] wells in 2017. If the percentage of the average daily burn is held at [redacted] in 2018, the number of wells will continue to increase due to depletion of the earlier wells. For 2018, the number of wells required to maintain [redacted] of the average daily burn increases to [redacted].

Q.

In reference to Confidential Exhibit SF-9, at page 2 of 4, Guideline 1.D, is the confidential dollar amount of investment in gas reserve projects limited to each calendar year such that there is no cumulative investment limit so long as each calendar year investment amount is within the guideline limitation, or is this a total limit on all investment at any point in time? As part of this response, please fully explain in detail how proposed Guideline l.D will work.

A.

The dollar amount of investment in gas reserve projects applies to each calendar year such that FPL may invest up to the "confidential dollar amount" in each year provided that FPL adheres to the other guidelines in Exhibit SF-9 including, but not limited to, the Maximum Volume as a Percentage of Average Daily Burn (Guideline I.A) for that year. Guideline I.D is not a cumulative investment over multiple years. FPL's aggregate investment obligation in gas reserves in any one calendar year is calculated by taking the sum of the investments for each individual project during that calendar year. Because of the natural depletion rate of shale-based gas production, it is understood that FPL will need to continue pursuing new gas reserve project opportunities to compensate for declining production from existing projects, as well as to expand the percentage of FPL's gas requirements that are hedged long-term.

FPL may invest in multiple gas reserve projects in a given year; however, FPL would be limited to the "confidential dollar amount" in aggregate across all gas reserve projects for that calendar year. For example, if FPL were involved in 3 gas reserve projects in 2016, each with a capital expenditure requirement of $50 million during calendar year 2016, the aggregate investment in gas reserve projects for calendar year 2016 would be $150 million. In this example it is assumed that the total 2016 spend of $150 million would be below the annual threshold, and thus permitted by the guidelines.

FPL could also enter into multi-year gas reserve drilling programs where the obligation to invest is spread across multiple years. For example, if FPL were involved in 2 separate multi-year gas reserve projects, one starting in 2015 and one starting in 2016, each with a capital expenditure profile of $100 million per year for a 3 year drilling program, the annual aggregate investment in gas reserve projects would be $100 million in 2015, $200 million in 2016, $200 million in 2017, and $100 million in 2018. In this example it is assumed that each year's total is below the annual threshold, and thus permitted by the guidelines.

In each example it is assumed that in addition to being below the annual investment threshold (Guideline I.D); the estimated output from gas reserves is below a maximum percentage of FPL's burn (Guideline I.A), FPL has submitted and the Commission has approved a volume threshold for 2018 (Guideline I.B), FPL is hedging within its annual Risk Management Plan guidelines (Guideline I.C), each project is estimated to provide customer savings at the time the transaction was entered (Guideline II.A), the projects are located onshore in well-established areas (Guideline III.A) with an available transportation path to Florida (Guideline III.B), the estimated output of the wells contains a minimum volume of methane (Guideline IV.A), and associated NGLs and oil are sold at market prices and credited back to customers (Guideline IV.B). Failure to meet all of the guidelines would limit FPL's ability to invest up to the "confidential dollar amount."

Q.

Assuming the Woodford Project goes forward as planned by FPL and GRCO and all wells projected to be developed are developed - what is the total anticipated capital investment by FPL and/or GRCO for the entire Woodford Project? Also provide how much of the total investment will be funded by debt and how much by equity.

A.

FPL projects the capital costs to total $190.8 million for the Woodford Project.

This investment will be financed incrementally with debt and equity at a ratio of approximately 40.4% debt and 59.6% equity.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 20TH day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **18-22, 24-25, 27-28, 33, 40, 42, 44-47, 49, 53-56, 59** and co-sponsored interrogatory number **41 and 50** from **OPC'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 18-59)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of August, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF TEXAS)

COUNTY OF HARRIS)

I hereby certify that on this 20 day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Tim D. Taylor, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number **23** from **OPC'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 18-59)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Tim D. Taylor

Tim D. Taylor

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20 day of August, 2014.

GIA M. FAUCHEUX
Notary Public, State of Texas
My Commission Expires
March 07, 2018

Gia Faucheux

Notary Public
State of Texas, at Large

My Commission Expires:

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 20th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Melissa Linton, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **36-37** from **OPC'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 18-59)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Melissa Linton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of August, 2014.

Janet Kelly
Notary Public
State of Florida, at Large

My Commission Expires: 11/24/2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 20th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers **26, 29-32, 34-35, 38-39, 43, 48, 50-52** and co-sponsored interrogatory numbers **41 and 50** from **OPC'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 18-59)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 20th day of August, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11/24/2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 19th day of August, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Joseph Balzano, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **57-58** from **OPC'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 18-59)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Joseph B. Balzano

Joseph Balzano

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of August, 2014.

Traci D. Goldwire

Notary Public
State of Florida, at Large

My Commission Expires:

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

51

FPL's Responses to OPC's Fifth Set of Interrogatories (Nos. 63 and 64)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 51
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's Fifth Set of Interrogatories (Nos. 63 and 64)

Q.

For the following please refer to FPL's response to Staff's 4th Set of Interrogatories, Interrogatory No. 141, subpart b, where FPL states the projected savings from the Woodford Gas Reserves Project are "based upon the same forecast of natural gas prices that FPL used for its 2014 Ten Year Site Plan." Please reconcile this response with the differences between FPL's natural gas market price forecast figures presented in Exhibit SF -8 in this docket and FPL's natural gas market price forecast figures on p. 62 of FPL's 2014 Ten Year Site Plan filed April 1, 2014 located at: http://www.psc.state.fl.us/library/FILINGS/ 14/01462-14/0 1462-1 4.pdf.

A.

The forecast utilized in the 2014 Ten Year Site Plan was the same forecast underlying exhibit SF-8 with the exception of two adjustments. First, the forecast used in SF-8 was adjusted down by $0.08/MMBtu to reflect the basis difference between Henry Hub and Perryville, which is where FPL will receive gas from the Woodford Project. Second, the annual forecast used in SF-8 was "production weighted" based on combining the monthly price forecast with monthly projected volumes produced from the Woodford Project to reflect the estimated value of the gas at the time it was extracted.

Q.

Please explain the differences between FPL's natural gas market price forecast figures presented in Exhibit SF-8 in this docket with the natural gas market price forecast figures presented in FPL's witness Sim's Exhibit SRS-7 in Docket 130199 filed April 2, 2014 located at: http://www.psc.state.fl.us/library/FILINGS/14/01476-14/01476-14.pdf.

A.

The forecast presented in Witness Sim's Exhibit SRS-7 is the same forecast that is utilized in the 2014 Ten Year Site Plan and is the same forecast underlying exhibit SF-8 with the exception of two adjustments. First, the forecast used in SF-8 was adjusted down by $0.08/MMBtu to reflect the basis difference between Henry Hub and Perryville, which is where FPL will receive gas from the Woodford Project. Second, the annual forecast used in SF-8 was "production weighted" based on combining the monthly price forecast with monthly projected volumes produced from the Woodford Project to reflect the estimated value of the gas at the time it was extracted.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 10TH day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **63-64** from **OPC'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 63-64)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10th day of October, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002858
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

52

FPL's Responses to OPC's Sixth Set of Interrogatories (No. 65) (CONFIDENTIAL)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 52
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's Sixth Set of Interrogatories (No. 65)

Q.

Please refer to Exhibit SF-8 provided with the testimony of FPL witness Forrest and the response to Staffs 7th Set of Interrogatories, Interrogatory No. 173.

a. Please provide a revised version of Exhibit SF -8 replacing the October 7, 2013 fuel forecast with the July 28, 2014 fuel forecast used in the referenced revision to the 2015 projected fuel costs. This should include a revision to all of the years utilized in SF-8 and not just to the 2015 projected fuel costs.

b. Please provide a revised version of Exhibit SF-8 replacing the October 7, 2013 fuel forecast with the Company's most recent fuel forecast if a new forecast has been prepared since the July 28, 2014 forecast identified in (a), above. This should include a revision to all of the years utilized in SF-8 and not just to the 2015 projected fuel costs.

A.

a. See Attachment I for the updated Exhibit SF-8 using the July 28, 2014 fuel forecast.

b. The latest fuel forecast is the July 28, 2014 fuel forecast, and the updated Exhibit SF-8 is attached in response to part (a) of this question.

Revised SF-8 Based on July 28, 2014 Fuel Forecast

Results of FPL's Economic Evaluation

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast 7/28/2014 ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)
2015	15.6	[redacted]				$3.48	$3.75	$4.2	0.9302	$3.9
2016	16.8					$3.56	$3.94	$6.4	0.8649	$5.5
2017	11.3					$4.00	$4.42	$4.8	0.8043	$3.9
2018	8.7					$4.40	$4.66	$2.3	0.7480	$1.7
2019	7.1					$4.96	$5.23	$1.9	0.6956	$1.3
2020	6.1					$4.79	$5.38	$3.6	0.6468	$2.3
2021	5.3					$4.94	$5.58	$3.4	0.6015	$2.0
2022	4.7					$5.08	$5.78	$3.3	0.5594	$1.8
2023	4.3					$5.21	$5.98	$3.3	0.5202	$1.7
2024	3.9					$5.34	$6.18	$3.3	0.4837	$1.6
2025	3.6					$5.24	$6.33	$3.9	0.4498	$1.8
2026	3.3					$5.32	$6.53	$4.0	0.4183	$1.7
2027	3.1					$5.39	$6.78	$4.3	0.3890	$1.7
2028	2.9					$5.46	$7.03	$4.6	0.3617	$1.7
2029	2.8					$5.52	$7.33	$5.0	0.3364	$1.7
2030	2.6					$5.58	$7.63	$5.3	0.3129	$1.7
2031	2.4					$5.65	$7.81	$5.3	0.2910	$1.5
2032	2.3					$5.71	$8.00	$5.2	0.2705	$1.4
2033	2.2					$5.80	$8.19	$5.2	0.2516	$1.3
2034	2.0					$5.88	$8.39	$5.1	0.2340	$1.2
2035	1.9					$5.97	$8.60	$5.0	0.2176	$1.1
2036	1.8					$6.05	$8.81	$4.9	0.2023	$1.0
2037-65	23.1					$7.88	$11.55	$84.6	0.1008	$8.5
Totals[1]	**137.8**	**$323.2**	**$190.8**	**$195.5**	**$709.4**			**$178.7**		**$51.9**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on the assets and return of financing costs.

(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 31 day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he co-sponsored the answer to interrogatory number **65** from **OPC'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 65)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 31 day of October, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of November, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Melissa Linton, who is personally known to me, and she acknowledged before me that she co-sponsored the answer to interrogatory number 65 from **OPC'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 65)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Melissa Linton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of November, 2014.

Janet Kelly
Notary Public
State of Florida, at Large

My Commission Expires: 11/24/2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

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FPL's Responses to OPC's Seventh Set of Interrogatories (Nos. 72, 75-78, 80-84, 87, and 89-103)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 53
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's Seventh Set of Interrogatories (Nos. 72,

Q.

In reference to the rebuttal testimony of Sam Forrest at page 4, lines 13-16:

a. **Given Mr. Forrest's assessment that the Woodford Project is "extremely beneficial to customers" and has a "high probability of achieving lower gas costs starting in year I (2015) and continuing thereafter," would Mr. Forrest recommend that FPL guarantee a minimum floor of benefits to consumers under the Woodford Project? If the answer is no, please fully explain the reasons for your answer.**
b. **In reference to the rebuttal testimony of Sam Forrest at page 5, lines 7-8, please explain in detail how the "market price risk for natural gas to customers is lower with this transaction than it is without it."**

A.

a. No.

b. As described by Witness Deason in his rebuttal testimony, guaranteeing customer benefits would be in contrast to the well established regulatory construct in Florida. FPL is proposing an investment in the Woodford Project as a means of providing a long-term stable price for natural gas that is also expected to result in a significant amount of customer savings. As with all other capital investments, the Commission will review the merits of the Woodford Project as it's proposed and determine whether the investment is prudent. There is no precedent that the determination of prudence must hinge upon a utility providing a guarantee to a level of customer benefit.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 6, lines 14-20:

a. **If Mr. Forrest considers the Woodford Project a physical hedge, please define the term physical hedge as he is using it in this section of his testimony?**
b. **In Mr. Forrest's opinion or based on his knowledge, is the output projection from the Woodford Project shown in his Direct Exhibit SF -8 guaranteed by FPL?**
c. **In Mr. Forrest's opinion or based on his knowledge, is the investment projection and subsequent return costs and depreciation requirements projection from the Woodford Project shown in his Direct Exhibit SF -8 guaranteed by FPL?**
d. **In Mr. Forrest's opinion or based on his knowledge, are the operating costs from the Woodford Project shown in his Direct Exhibit SF-8 guaranteed by FPL?**
e. **In Mr. Forrest's opinion or based on his knowledge, are any of the costs from the Woodford Project shown in his Direct Exhibit SF-8 guaranteed by FPL?**
f. **Does Mr. Forrest agree that it is correct that the Woodford Project is a physical hedge against market cost of natural gas so long as Woodford Project costs are below market gas prices? If not, why not?**
g. **If Mr. Forrest agrees that the future Woodford Project costs are unknown and the Woodford Project cost projections contained in Exhibit SF-8 are not being guaranteed by FPL, please fully explain how this physical hedge works and what exactly is being hedged.**
h. **Does Mr. Forrest acknowledge that future Woodford project output and/or costs could change substantially from year to year, causing Woodford unit costs to change substantially from year to year? Please fully explain your answer.**
i. **In Mr. Forrest's opinion or based on his knowledge, would FPL guarantee that there will be no substantial changes in year to year prices from the base case projected Woodford Project costs contained in Exhibit SF-8?**

A.

a. Hedging in its simplest form is taking some action to reduce specific risk. A physical hedge in the context of Mr. Forrest's testimony is procuring physical supply that offsets potential market price fluctuations. Please note that it is unnecessary for the cost of physical supply to be "guaranteed," as suggested in the remaining subparts of this interrogatory, in order for the physical supply to constitute an effective hedge. Rather, so long as potential variability in the cost of the physical supply is driven by different factors than the variability in market prices, then the physical supply can be an effective hedge against the market prices, as is the case with the Woodford Project.

b. No.

c. No.

d. No.

e. No.

f. No. Whether the effective price of gas delivered from the Woodford Project is higher or lower than market prices does not dictate whether it should be considered a hedge. Per the Commission's order (PSC-08-0667-PAA-EI) that established the Hedging Guidelines, hedges are not expected to reduce fuel costs.

g. A hedge is a transaction that simply looks to reduce risk. The Woodford Project will do that by decoupling the price FPL pays for gas from the market and tying it to the cost of production, a cost that is expected to be highly predictable given the experience of PetroQuest and the quality of the data reviewed to establish the projections. In effect, the Woodford Project will eliminate the impacts of the common drivers of fuel prices and create a stable-priced source of supply.

h. There is the potential for unit costs to change over time, but FPL believes that it is highly unlikely for those costs to change substantially.

i. No.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 10, lines 20-23:

a. **Please explain in detail precisely which inputs to the cost of gas from the Woodford Project are "largely fixed."**
b. **Will FPL guarantee that certain inputs to the cost of gas from the Woodford Project will remain fixed?**
c. **If the answer to part (b) is no, precisely what level of variance is allowed in the determination that the inputs to the cost of gas from the Woodford Project are "largely fixed?" Please explain in detail.**

A.

a. The single largest component of the effective cost of gas is the depletion expense, which accounts for approximately 25-30% of the effective cost of gas. Depletion expense is driven by the cost of drilling the well and the production profile of that well thereafter. Once the capital has been spent to drill the well, there is no further cost to impact depletion expense. Therefore, half of the depletion expense equation will be known immediately after a well is completed. In conjunction, as described by Witness Taylor and illustrated by exhibits TT-11 and TT-12, the output of a well is fairly predictable in the aggregate. It follows that the combination of a known number and a highly predictable well production profile will generate a cost that is largely fixed in terms of the likelihood it would deviate from the forecast amount. Additionally, the gathering and transportation costs, which account for another 20-25% of the effective cost of gas, are based on contracted rates. These too add to the certainty about the effective cost gas and reduce the likelihood the cost would deviate significantly from the forecasted amount.

b. No.

c. The question presumes a level of analysis that has not been undertaken and should not be undertaken. The Company has not established a precise level of variance used to determine whether inputs to the cost of gas are "largely fixed." The factual bases for the observation in Mr. Forrest's rebuttal testimony that inputs to the cost of gas from the Woodford Project are "largely fixed" is already addressed in response to subpart (a) above. All cost estimates are projected and subject to variance, although the costs being addressed here do not appear to have much potential for variance. The fundamental issue is not whether costs can or should be guaranteed; there are no guarantees in regulation. The fundamental issue is whether the projections of costs are reasonable and whether the risk of variances are reasonable. If so, then the transaction is prudent and should be approved, because it is a reasonable projected cost of providing service to customers. That is the standard for determining whether other projected costs of service should be recovered, and it should be the standard for these projected costs as well.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 12, lines 11-13:

a. **Please explain how much variance in the costs of the Woodford Project are allowed before the costs are no longer "fairly predictable."**
b. **Please explain "effective cost of gas" as used in this context.**

A.

a. As described in FPL's response to OPC's Seventh Set of Interrogatories No. 76, the single largest expense impacting the effective cost of gas is depletion expense. And as also described in that same response, depletion expense is fairly predictable given that it is driven by the cost of the well, which is known immediately after drilling is complete. The other component of depletion expense is the production profile of the well, which as Dr. Taylor describes, is highly predictable on average. The combination of a known number and a highly predictable well production profile would generate a cost that is, in turn, fairly predictable. Another major component of the effective cost of gas from the Woodford Project is the gathering and transportation expense. Given that this is based on contracted rates, it would follow that these costs are fairly predictable. As such, with each well proposal, FPL will utilize data on costs and performance from all other wells in the AMI to update, if necessary, the assumptions used to evaluate each successive opportunity. If FPL finds that the projected costs no longer indicate that a proposed well will provide customer savings, it will non-consent to the well.

b. The effective cost of gas represents the total cost to produce and transport the gas divided by the amount of gas produced. This yields the effective cost of gas to FPL's customers on a per unit basis.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 12, lines 13-15:

a. **Please identify the specific "risks inherent in the market" to which Mr. Forrest is referring.**
b. **In Mr. Forrest's opinion or based on his knowledge, will FPL guarantee that the Woodford Project "will reduce the volatility of future fuel costs for FPL' s customers"?**

A.

a. The risks referred to are those that create gas price volatility and can be both short-term and long-term. Short-term impacts can cause spikes in gas prices that last just a few days or weeks. For example, tropical disturbances in the Gulf of Mexico can disrupt supply and cause shortages and short-term market volatility in the name of higher prices. These higher prices may subside as soon as production has been restored. Longer term, as market fundamentals change, gas prices can and do fluctuate. The influx of shale, in combination with the economic downturn in the 2008 time frame, caused natural gas prices to plummet. This has been sustained over an extended period of time. As we look forward, production from unconventional sources is expected to continue, but demand is also expected to rise with LNG exports, implementation of the EPA's Clean Power Plan, and industrial growth. These are the types of risks referred to in Mr. Forrest's testimony.

b. There are no guarantees that any forecast will materialize. OPC witness Lawton is correct in his assertion that "all forecasts will be wrong." However, the stability of costs projected for the Woodford Project compared to the volatility in the forward market for natural gas prices, FPL has a high degree of confidence the Woodford Project will reduce volatility in the future costs for FPL's customers. As the Commission stated in the Hedging Guidelines final order, "the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers." FPL firmly believes the Woodford Project accomplishes that.

Q.

In reference to the rebuttal testimony of Sam Forrest at pages 12, lines 17 through page 15, lines 7 regarding forecasting:

a. **In FPL' s forecasts of natural gas market prices, does FPL account for variations in natural gas production costs? If yes, please explain in detail; if not, why not?**
b. **Is FPL relying on historical costs in its assumption that the costs of the Woodford Project are "fairly predictable?"**

A.

a. Yes. As described in FPL's responses to Staff's Second Set of Interrogatories No. 21 and Staff's Fourth Set of Interrogatories No. 150, FPL incorporates fundamental projections from PIRA Energy Group ("PIRA") into its forecast for natural gas market prices. At its core, PIRA's fundamental projections are based on expectations around supply and demand. Given that natural gas production costs are instrumental to calculating supply estimates, PIRA actively accounts for potential variations in production costs in developing their fundamental natural gas price forecast.

b. Yes. FPL reviewed the historical cost and performance of the existing wells in the Area of Mutual Interest to develop its projections.

Q.

Referring to the forecasts referenced on page 15, lines 1-7, in any previous proceeding before the Commission (excluding this one):

a. **What is the farthest point (in terms of number of years) into the future that FPL has forecasted the natural gas market price?**
b. **In which docket was this forecast submitted?**

A.

a. Prior to February 2013, FPL's long-term fuel forecast typically included forecasted natural gas prices through the year 2061. In February 2013, FPL modified its long-term fuel forecast to include forecasted natural gas prices through the year 2100, although no analyses used prices beyond the 2060 time frame.

b. Docket No. 070602-EI (Nuclear Uprates) and Docket No. 070650-EI (Turkey Point 6 and 7) utilized a forecast that extended through the year 2061.
Docket No. 130199-EI (DSM Goals) utilized a forecast that extended through the year 2100.
Docket No. 140009-EI (Nuclear Cost Recovery Clause) utilized a forecast that extended through the year 2100.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 17, lines 13-15, please compare, contrast, and explain the difference between the "EIA's forecast of nominal prices" and the "EIA real-price rates of escalation" forecast.

A.

The table below compares the EIA's forecast of nominal prices ("nominal dollars per million Btu") with EIA's forecast of real prices ("2012 dollars per million Btu"). The only difference between the two forecasts is the impact of inflation expressed in nominal vs. real terms. The two forecasts are shown here, along with the rates of escalation by year:

Henry Hub Spot Price				Henry Hub Spot Price		
(2012 dollars per million Btu)				(nominal dollars per million Btu)		
Year	Price	Growth Rate		Year	Price	Growth Rate
2012	2.75			**2012**	2.75	
2013	3.60	31.0%		**2013**	3.66	32.9%
2014	3.74	3.7%		**2014**	3.86	5.6%
2015	3.74	0.2%		**2015**	3.93	1.8%
2016	4.14	10.6%		**2016**	4.41	12.3%
2017	4.40	6.3%		**2017**	4.76	7.9%
2018	4.80	9.0%		**2018**	5.27	10.7%
2019	4.66	-2.9%		**2019**	5.19	-1.4%
2020	4.38	-6.1%		**2020**	4.96	-4.6%
2021	4.67	6.6%		**2021**	5.37	8.4%
2022	4.82	3.3%		**2022**	5.64	5.1%
2023	4.96	2.8%		**2023**	5.90	4.6%
2024	5.12	3.3%		**2024**	6.20	5.0%
2025	5.23	2.2%		**2025**	6.45	4.0%
2026	5.36	2.4%		**2026**	6.72	4.2%
2027	5.49	2.4%		**2027**	7.00	4.2%
2028	5.59	2.0%		**2028**	7.26	3.8%
2029	5.78	3.2%		**2029**	7.63	5.1%
2030	6.03	4.5%		**2030**	8.12	6.4%
2031	6.17	2.2%		**2031**	8.47	4.3%
2032	6.36	3.1%		**2032**	8.91	5.1%
2033	6.59	3.6%		**2033**	9.41	5.7%
2034	6.74	2.3%		**2034**	9.83	4.4%
2035	6.92	2.8%		**2035**	10.31	4.9%
2036	7.18	3.8%		**2036**	10.93	6.0%
2037	7.23	0.6%		**2037**	11.23	2.8%
2038	7.26	0.5%		**2038**	11.53	2.7%
2039	7.42	2.2%		**2039**	12.04	4.4%
2040	7.65	3.1%		**2040**	12.69	5.3%
	CAGR	**3.7%**			**CAGR**	**5.6%**

The inflationary difference between the two forecasts is 1.9%. In the early years of the forecast, the impacts of inflation are less dramatic; however, as the years pass, the impacts become quite dramatic, as there is over $5.00/mmBtu difference in 2040. One other point to make about the two forecasts provided here. Both demonstrate the significant volatility in the market from year to year. Looking at just the real price forecast, which again doesn't take into consideration the impacts of inflation, one can see an actual increase of 31% between 2012 and 2013, and projected increases of 10.6%, 9%, and 6.6%, and a decrease of 6.6% in other years. This simply points to the uncertainty of the market and the need for a longer term hedge that the Woodford Project provides.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 18, lines 13 - 23:

a. **Does Mr. Forrest believe that market natural gas prices will increase by 22% between 2017 and 2018? Please fully explain your answer.**
b. **Is Mr. Forrest asserting that Mr. Lawton's alternative natural gas market price forecast in his Schedule (DJL-4) column G shows a 10.7% increase in market prices between 2017 and 2018?**
c. **If the answer is anything but an unequivocal "no," then provide all data and calculations used in reaching your conclusion of a 10.7% increase.**

A.

a. The forecasting sources relied upon by FPL and Mr. Forrest do not specifically project a 22% increase between 2017 and 2018. Rather, as FPL has previously explained, the forecasted 22% increase between 2017 and 2018 reflects a transition in the elements of FPL's forecasting methodology around those years, toward an approach that relies more heavily on market fundamentals. The large percentage increase indicates that the forward curve prices for 2016 and 2017 may be somewhat undervalued relative to market fundamentals. If that were the case, then upward adjustments to the 2016 and 2017 forecasts would increase the projected savings from the Woodford Project. In any event, the transition between 2017 and 2018 is fairly irrelevant to the overall evaluation of this project. To illustrate, FPL lowered its 2018 forecast from $5.74 to $5.25. This creates a smoother transition year over year, with an 11.7% increase between 2017 and 2018 and actually lower than the 12.3% increase EIA's nominal forecast sees over that same period (as a note, OPC witness Lawton references EIA's *real price* forecast the same period which saw a 10.6% increase over the 2017-2018 period). By creating a smoother transition, the total projected customer savings only drops from $106.9MM to $103.7MM, a $3MM impact. Mr. Forrest's rebuttal testimony shows that the Woodford Project is estimated to generate substantial savings for customers over a wide range of gas price forecasts, including those proposed by the intervenor witnesses.

b. No. Mr. Forrest recognizes that Mr. Lawton has used EIA's rate of escalation to calculate his forecast of prices. The reference in Mr. Forrest's testimony is to the actual forecast that EIA provides and the year-over-year changes, not the compounded annual growth rate that Mr. Lawton utilized. In its 2014 Annual Energy Outlook, EIA has provided an excellent roadmap of how the supply and demand balance changes over time taking into consideration such factors as new gas production resources coming online, net imports of natural gas declining, net exports increasing with LNG and pipeline exports, and how consumption varies under a number of scenarios. This well thought out balance is then used to develop prices which vary year-by-year as the supply and demand balance changes. Mr. Lawton uses the effective average rate of escalation of these changes which is a consistent 3.7%. In fact, as can be seen in the table provide in response to Interrogatory 82, EIA's actual forecast for real prices varies year-over-year by as much as 10.6% and as little as (6.1%). The EIA forecast for nominal prices, which has an average rate of escalation of 5.6%, varies on a year-over-year basis by as much as 12.3% and as little as (4.6%). It is this actual nominal forecast that I am referring to in my testimony.

c. See the response to subpart (b) of this interrogatory.

Q.

In reference to the rebuttal testimony of Sam Forrest at page 21, line 17 through page 23, line 10:

a. **Does Mr. Forrest believe that the FPL response to Staff Interrogatory No. 75 is true and correct?**
b. **Is it Mr. Forrest's position that natural gas prices will never go as low as the NYMEX prices during the 2011 - 2013 period?**
c. **What is Mr. Forrest's estimate of the lowest possible NYMEX price over the next 50 years?**
d. **In Mr. Forrest's opinion or based on his knowledge, will FPL guarantee that the NYMEX price will never approach the 2011 - 2013 levels?**
e. **If the Woodford cost of production is decreasing (as discussed at page 22, lines 16-22), please explain why the Woodford unit costs shown in Exhibit SF-8 increase to $4.00 in 2017 and continue to increase thereafter.**

A.

a. Yes.

b. Neither Mr. Forrest nor anyone else is in a position to state definitively whether or not natural gas prices will ever go as low as the NYMEX prices during the 2011-2013 period.

c. Mr. Forrest does not have a personal prediction of prices, either high or low. Fundamentally, there are a lot of factors that drive prices at any given point in time, and especially in the short-term when mild weather, surplus gas storage, decreased demand, and increased supply can cause downward pressure on prices. Gas prices could certainly return to the low levels of 2011-2013 again, just as they could return to the high levels of 2008 under the right set of fundamental factors. As discussed previously, this uncertainty is what makes the hedging effect of gas reserve projects especially attractive.

d. No.

e. The table provided by Wood Mackenzie shows an analysis of the Henry Hub break-even price needed to cover production costs, gathering services, and natural gas transportation, along with a 10% rate of return at the wellhead. The natural gas transportation assumed in Wood Mackenzie's analysis is volumetrically "perfect" in that it matches the actual production. FPL's forecast of the Woodford Project effective cost in SF-8 also includes gathering and transportation costs to deliver the gas from the wellhead to the Perryville Hub. One of the primary drivers of the increase in effective unit costs over time is gas transportation. As is provided for in FPL's response to Staff's Second Set of Interrogatories No. 31, FPL has assumed that transport capacity must be reserved in "blocks" that can't be volumetrically synched with production. This creates a fixed cost that does not smoothly decrease as production naturally declines, thus increasing unit costs over time. FPL believes that this is a very conservative approach because it may be possible for FPL to secure firm gas transportation service for a volume profile that more closely matches the projected production profile of the Woodford Project. As is further discussed in FPL's response to Staff's Second Set of Interrogatories No. 53, FPL has not committed to procuring capacity in blocks on the Enable pipeline. FPL continues to pursue other transportation options that may provide improved economics. If FPL receives approval from the Commission for the Woodford Project, we will seek a gas transportation agreement that makes the most sense for our customers and which also closely mirrors the production profile of the Woodford Project, thus reducing the fixed costs over time.

Q.

For the next series of interrogatories, please reference to the rebuttal testimony of Sam Forrest at page 24, line 11 through page 26, line 3:

In reference to page 25, lines 16-21, can Mr. Forrest, FPL, or any of FPL's other witnesses guarantee that the Woodford Project cost will be less volatile than natural gas market cost?

A.

No, and FPL should not be held to such a standard. The proper standard is not whether FPL can guarantee a result; the proper standard is whether the transaction proposed is reasonable and prudent. The Woodford Project is reasonable and prudent for two primary reasons, neither of which is guaranteed, but both of which are highly probable. First, there is a high probability (85%) that the transaction will result in savings to FPL's customers. Second, there is a high probability that the Woodford Project's production costs, which are reasonably forecast to stay within a modest range, are likely to vary less than natural gas market prices, which are forecasted to remain volatile and also increase over time. So, with the best information available at the time the deal was negotiated and now subject to approval by the Commission, the Woodford Project has a high probability of serving customers' needs for both reduced volatility and natural gas price savings.

The Woodford project is just like FPL's other hedges in that it is being entered into to lower volatility and to reduce the impact on customers if natural gas price volatility is experienced. However, rather than a financial fixed price hedge, the Woodford Project provides physical supply that decouples the factors that determine the price of gas paid from those factors that drive market prices. FPL's customers are exposed to the market volatility of natural gas for as long as FPL burns it in its power plants, and given that FPL uses natural gas to generate over 65% of the electricity it provides to customers, FPL's customers' exposure to natural gas price volatility is significant. This transaction makes the first attempt to mitigate this long-term volatility by tying the cost of gas to production, rather than simply paying market prices over time - prices that have proven to swing dramatically.

Q.

In reference to the rebuttal testimony of Kim Ousdahl, page 5, lines 9 through 12, Ms. Ousdahl indicates that " ... FPL is proposing to use the FERC USOA natural gas chart of accounts in FPL' s consolidated financial statements as shown in the aforementioned exhibit." The referenced aforementioned exhibit is Exhibit K0-7.

a. **Please providing a listing of all of FPL's unconsolidated (i.e., FPL stand-alone, not consolidated) FERC accounts under either the FERC electric USOA or the FERC gas USOA that the acquisition of the gas reserves and the investment in the subsidiary, GRCO, will be recorded in. If the investment will be in any accounts other than FERC Account 123.1 - Investment in Subsidiaries, please explain in detail why.**
b. **Please provide a listing of all of FPL' s FERC accounts, as reported in the annual FERC Form 1 filed with the Florida Public Service Commission, the acquisition of the gas reserves and the investment in the subsidiary, GRCO, will be recorded in. If the investment will be in any accounts other than FERC Account 123.1 - Investment in Subsidiaries, please explain in detail why.**

A.

a. FPL's investment in GRCO will be reflected in FPL's unconsolidated financial statements in FERC Account 123.1 - Investment in Subsidiaries for the equity contribution and in FERC account 145 Notes Receivable from Associated Companies to reflect the debt contribution.

b. For purposes of the FERC Form 1, which is required to be presented on an unconsolidated basis, FPL will reflect the GRCO investment in FERC Account 123.1 - Investment in Subsidiaries and 145 Notes Receivable from Associated Companies to reflect the equity and debt contributions respectively and the earnings of the subsidiary, along with the earnings of other FPL wholly-owned regulated subsidiaries, will be recorded in Account No. 418.1 Equity in Earnings of Subsidiary Companies. It is important to note that FPL's MFRs and Earnings Surveillance Reports ("ESR") do not originate from the unconsolidated FPL FERC Form 1, but rather from FPL's consolidated financial statements which will include the FERC natural gas accounts reflected on KO-7.

Q.

In reference to the rebuttal testimony of Kim Ousdahl, page 5, lines 9 through I2, Ms. Ousdahl indicates that " ... FPL is proposing to use the FERC USOA natural gas chart of accounts in FPL' s consolidated financial statements as shown in the aforementioned exhibit." The referenced aforementioned exhibit is Exhibit K0-7.

a. **Please confirm that the "mapping" shown on Exhibit K0-7 will be used for purposes of providing consolidated financial statements only and will not be used for FPL' s stand-alone or unconsolidated financial statements.**
b. **Please confirm that the "mapping" shown on Exhibit K0-7 will not be used for purposes of FPL' s Annual Report to the Florida Public Service Commission, which includes the FERC Form I.**

A.

a - b. The mapping shown on Exhibit KO-7 depicts the FERC accounts that FPL plans to utilize for its consolidated financial statements, which form the starting point for the monthly Earnings Surveillance Report and MFRs to the FPSC. Once mapped, the gas reserves transactions will be recorded monthly and consolidated with FPL's results for SEC and FPSC reporting. When financial statements are presented on an unconsolidated basis as is required for FERC reporting, the results of subsidiary activity are reported in Accounts 123.1 Investments in Subsidiary, 145 Notes Receivable from Associated Companies to reflect the equity and debt contributions respectively and 418.1 Equity in Earnings of Subsidiary Companies.

Q.

The rebuttal testimony of Kim Ousdahl, page 5, lines 9 through 12, Ms. Ousdahl indicates that " ... FPL is proposing to use the FERC USOA natural gas chart of accounts in FPL's consolidated financial statements as shown in the aforementioned exhibit." The referenced aforementioned exhibit is Exhibit KO-7. With reference to Exhibit KO-7, please respond to the following:

a. **Which FERC Account 101 - Gas Plant in Service subaccounts (i.e., 300 through 399) will GRCO Account 22I - Proved Property Acquisition Costs be included in or "mapped to" in the FPL consolidated financial statements?**
b. **Which FERC Account 101 - Gas Plant in Service subaccounts (i.e., 300 through 399) will GRCO Account 233- Tangible Costs of Wells & Development Costs be included in or "mapped to" in the FPL consolidated financial statements?**
c. **Which FERC account will GRCO Account 219 - Impairment Allowance be included in or "mapped to" in the FPL consolidated financial statements?**
d. **Which FERC account will GRCO Account 761- Provision for Impairment of Oil and Gas Properties be included in or "mapped to" in the FPL consolidated financial statements?**

A.

a. FPL does not plan to use the FERC subaccounts for plant-in-service in its consolidated financial statements. As has been previously explained, the detailed ledger as shown in condensed form on Exhibit KO-7 will be used to record each transaction consistent with the industry chart of accounts. The mapping to the FERC natural gas chart of accounts will be on a condensed basis as would be the case for a subsidiary ledger vs. the general ledger. Industry account 221- Proved Property Acquisition Costs will be mapped to FERC account 101 - Plant-in-Service.

b. Industry account 233 - Tangible Costs of Wells & Development Costs will be mapped to FERC account 101 - Plant-in-Service.

c. If necessary, Industry account 219 - Impairment Allowance for Unproved Property will be mapped to FERC account 105.1 - Production Properties Held for Future Use.

d. If necessary, Industry account 761 - Provision for Impairment of Oil & Gas Properties will be mapped to FERC account 403 - Depreciation Expense.

Q.

The rebuttal testimony of Kim Ousdahl, page 5, lines 9 through 12, Ms. Ousdahl indicates that " ... FPL is proposing to use the FERC USOA natural gas chart of accounts in FPL's consolidated financial statements as shown in the aforementioned exhibit." The referenced aforementioned exhibit is Exhibit K0-7. The FERC USOA accounts for regulatory assets and regulatory liabilities are not shown in the mapping presented on Exhibit KO-7. Is it anticipated that any of the GRCO accounts may be mapped to the FERC USOA accounts for regulatory assets and regulatory liabilities? If yes, please describe, in detail, situations in which the GRCO accounts would be "mapped" to a FERC regulatory asset or FERC regulatory liability account.

A.

FPL does not anticipate recording any regulatory assets or liabilities at GRCO; however situations could arise in the future requiring use of those accounts. For instance, the Commission could require deferral and amortization of a cost which is properly expensed in the current period under GAAP and that scenario would require the use of a regulatory asset and amortization account.

Q.

At page 5, lines 17 - 18 of Ms. Ousdahl's rebuttal testimony, she states: "For FPL consolidation and financial reporting and ratemaking, the activity will be mapped to the USOA natural gas chart of accounts." Will the industry standard chart of accounts be "mapped to the USOA natural gas chart of accounts" for purposes of preparing the annual reports based on the FERC Form 1 filed with the Florida Public Service Commission? Please explain your response.

A.

Yes. Please refer to FPL's response to OPC's Seventh Set of Interrogatories No. 90.

Q.

If the investment in the natural gas reserves were made directly by FPL instead of through the subsidiary, GRCO, would FPL use the FERC USOA and the accounts prescribed thereunder in accounting for the original investment, subsequent investments in the gas reserves, and the operations of the gas reserves, or would it use the standard accounting utilized in the oil and gas production industry? Please explain your response.

A.

As holding the investment directly in FPL would not be the optimal structure, a thorough vetting of this approach has not been performed. However, it is likely that if the investment were held directly by FPL, the Company would utilize the standard industry chart of accounts to facilitate electronic mapping of the JIBs and the use of third-party support. The Company would map the standard industry chart of accounts to the FERC natural gas USOA consistent with what is shown on Exhibit KO-7.

Q.

At page 16 of her Direct Testimony, lines 9 through 10, Ms. Ousdahl states: "Neither the FERC Electric nor Natural Gas chart(s) of accounts is consistent with the standard accounting utilized in the oil and gas production industry." Considering that Ms. Ousdahl's rebuttal testimony indicates at page 5, lines 17 through 18, that "For FPL consolidation and financial reporting and ratemaking the activity will be mapped to the USOA natural gas chart of accounts" is the statement in Ms. Ousdahl's direct testimony that "Neither the FERC Electric nor Natural Gas chart(s) of account is consistent with the standard accounting utilized in the oil and gas production industry" accurate? Please explain your response.

A.

Yes, the statement is accurate. The petroleum industry standard commercial and accounting practices are unique to the exploration and production of petroleum hydrocarbons. However, the FERC natural gas chart of accounts ("COA") was developed for use by local natural gas distribution companies ("LDCs") and, as such, recognizes and accommodates exploration and production (E&P) activities. Because the USOA considers E&P activities, it can be mapped to industry transacted results, although there are certain detailed instructions in the gas USOA that will not be applicable to such transactions. For instance, Account 105.1 – Gas Plant Held for Future Use will be utilized for wells that have not yet been proved. The detailed instructions for account 105.1 require filing with the FERC to seek approval prior to recording the journal entries to remove the property from account 105.1 in the event of a sale of property that results in a gain of $100,000 or greater. This provision was clearly intended for gas utilities regulated under the Natural Gas Act and not for transactions such as the one currently being presented by FPL. In short, FPL is able to account for the transactions using the petroleum industry structures while still reporting that activity in the condensed natural gas USOA.

Q.

Ms. Ousdahl's rebuttal testimony indicates at page 5, lines 17 through 18, that "For FPL consolidation and financial reporting and ratemaking the activity will be mapped to the USOA natural gas chart of accounts."

a. **Is it Ms. Ousdahl's position that the "mapping" to the natural gas USOA will result in the amounts being reported on a FERC USOA basis for these activities being fully compliant with the detailed accounting instructions provided for in the FERC's Natural Gas Uniform System of Accounts? Please explain your response.**
b. **Is it Ms. Ousdahl' s opinion that the successful efforts method of accounting is fully compliant with the accounting instructions for natural gas utilities provided for in FERC's Natural Gas Uniform System of Account? Please explain your response.**
c. **Does the "FPL consolidation and financial reporting" have to be fully compliant with the FERC USOA system of accounts for either electric or gas utilities? Please explain your response.**

A.

a. Please see FPL's response to OPC's Seventh Set of Interrogatories No. 95. FPL is not a regulated gas utility (LDC) under the Natural Gas Act and would not be required to comply with the detailed accounting instructions associated with the FERC natural gas USOA. FPL proposes to utilize the FERC natural gas chart of accounts ("COA") in order to provide information in a familiar format for the FPSC that appropriately reports investments in gas reserves.

b. No. There are differences between the accounting prescribed by the successful efforts method and the FERC Natural Gas USOA. However, FPL believes that the FERC natural gas condensed COA can be used to record and report natural gas reserves activity accounted for under the successful efforts method.

c. Materially, yes; however, there can be differences. For instance, the FERC AFUDC calculation is slightly different in terms of its allocation method between debt and equity than that prescribed by the FPSC. FPL utilizes the FPSC methodology for both its FPSC and FERC reporting because the differences are immaterial and we work carefully to ensure compliance with each regulatory body's (FPSC, FERC and GAAP) rules. In the instant case, we believe all differences can be reasonably accommodated while still providing our regulators with transparent, consistent financial information.

Q.

Has FPL ever filed accounting records with the Florida Public Service Commission that were prepared under the regulatory accounting methods prescribed for in the FERC Natural Gas Uniform System of Accounts and the chart of accounts provided for within the FERC Natural Gas Uniform .System of Accounts? If yes, please describe the reasons causing the accounting records to be prepared under the FERC Natural Gas Uniform System of Accounts and identify the circumstances and dockets under which such information was filed with the Florida Public Service Commission.

A.

No. FPL has not previously invested directly in gas reserves or other gas-related assets that would warrant such accounting.

Florida Power & Light Company
Docket No. 140001-EI
OPC's 7th Set of Interrogatories
Interrogatory No. 98
Page 1 of 1

Q.

Has FPL ever filed accounting records with regulatory agencies other than the Florida Public Service Commission that were prepared under the regulatory accounting methods prescribed for in the FERC Natural Gas Uniform System of Accounts and the chart of accounts provided for within the FERC Natural Gas Uniform System of Accounts? If yes, please describe the reasons causing the accounting records to be prepared under the FERC Natural Gas Uniform System of Accounts, identify the regulatory agency such accounting records were provided to, and identify the circumstances and dockets under which such information was filed with the respective regulatory authorities.

A.

No.

Q.

Please refer to Ms. Ousdahl' s rebuttal testimony, at page 6, line 11 through page 7, line 10.

a. **Is it Ms. Ousdahl' s assertions that the investments in the gas reserves will be recorded as Plant in Service on FPL's stand-alone (i.e., unconsolidated) books?**
b. **Is it Ms. Ousdahl' s assertion that the investments in the gas reserves will be included in FERC Account 101 - Plant in Service in the annual report FPL is required to file with the Florida Public Service Commission on an annual basis (i.e., the FERC Form 1)?**
c. **Does Ms. Ousdahl agree that the investments made by FPL in its subsidiary (GRCO) for GRCO's use in acquiring the gas reserves will be recorded as an investment or as an investment in subsidiary on FPL' s stand-alone books? If no, please explain.**

A.

a. Please refer to FPL's response to OPC's Seventh Set Interrogatories No. 89.

b. Please refer to FPL's response to OPC's Seventh Set Interrogatories No. 89.

c. Yes. The gas reserves transactional activity will be recorded in the subsidiary ledger using industry accounts and then will be condensed and reported in the FPL general ledger using FERC natural gas chart of accounts ("COA"). When FPL produces financial statements on an unconsolidated basis, the activity recorded to these gas accounts is eliminated and cleared to equity in earnings of subsidiary FERC account 418.1 for income reporting and investment in subsidiary to FERC account 123.1 Investment in Subsidiary and 145 Notes Receivable from Associated Companies for balance sheet reporting. All of the appropriate accounts are used, the transactions are recorded and can be sampled and tested and audited, but that activity is not displayed on an unconsolidated financial statement.

Q.

At page 7, lines 11 through 13, of her rebuttal testimony, Ms. Ousdahl indicates that OPC witness Ramas asserts on pages 17 and 18 of her testimony that "The USOA and Generally Accepted Accounting Principles ("GAAP") accounting are mutually exclusive." Please identify specifically where Ms. Ramas asserts that the USOA and GAAP accounting are "mutually exclusive."

A.

Page 18 lines 21 through 28 and Page 23 lines 10 through 14.

Q.

Please refer to the rebuttal testimony of Ms. Ousdahl, page 9, lines 1 through 3.

a. **Is it Ms. Ousdahl's position that " ... depletion accounting, which by definition results in application of a new rate in each reporting period, is integrally woven ... " into the FERC electric USOA that FPL is required to use under Commission Rule 25-6.014? Please explain.**
b. **Is it Ms. Ousdahl' s position that FPL would be required by the Florida Public Service Commission rules to follow the FERC natural gas uniform system of accounts? Please explain.**

A.

a. No. Depletion is appropriately recorded under the FERC natural gas chart of accounts.

b. No. FPL is not a regulated gas utility and would not be required to comply with all of the detailed accounting instructions associated with the FERC natural gas USOA. FPL proposes to utilize the FERC natural gas USOA in order to provide information in a familiar format for the FPSC which accommodates its review of investments in gas reserves.

Q.

Please refer to Ms. Ousdahl's rebuttal testimony at page 10, lines 5 through 17. Do any of the joint ownership interests identified in this section (i.e., St. Johns River power Park and Scherer Unit 4) utilize the unique accounting provisions provided for under Accounting Standard Codification 932- Accounting for Oil and Gas Exploration?

A.

No. SJRPP and Scherer Unit 4 are not required to comply with Accounting Standards Codification No. 932. However, that fact is irrelevant to the reason Ms. Ousdahl referred to those two facilities. Each of them is the subject of a joint venture in which FPL holds an interest but is not the operator, similar to the situation that will exist with respect to Woodford Project. Ms. Ousdahl's reference to those facilities was in connection with her comments on the audit procedures used by the FPSC staff in auditing investments by FPL in joint ventures whose costs are recovered in whole or in part through adjustment clauses.

Q.

Please refer to page 14 of Ms. Ousdahl's rebuttal testimony, lines 5 through 8, in which Ms. Ousdahl indicates that "it is clear that the costs, at least at the outset, will be lower with the use of a third-party than what FPL would incur initially...", assuming the Commission approves the Woodford Project and the Guidelines which would allow FPL to annually invest up to $750 million in gas reserves projects.

a. **Please provide a detailed listing of all estimated costs that would be incurred by FPL to handle the gas reserves accounting, recordkeeping, and reporting internally instead of through the use of outside vendors.**
b. **Please indicate how many additional staff FPL anticipates it would need to retain in order to handle the gas reserves accounting, recordkeeping, and reporting internally.**
c. **Is it anticipated that any additional staff retained to handle the accounting, recordkeeping and reporting for the gas reserves internally, if eventually done internally, would be employed by FPL or by the subsidiary, GRCO? Please explain.**
d. **Please provide a listing of all positions, by title, the Company anticipates will be employed by the proposed subsidiary, GRCO, and indicate the current status of filling such positions.**
e. **Referring to FPL's response to (d) above, please include estimated salary range for each position, along with total estimated budget for employee salaries in the proposed GRCO subsidiary.**

A.

a-c. FPL does not have a detailed study of all of the costs that would be incurred internally because it properly chose to outsource this activity and thus a detailed study was not required. As part of the consideration to outsource the transactional accounting, FPL weighed the significant start-up costs and implementation lead time that would be required if FPL were to perform this work internally, including selecting and implementing an oil & gas accounting system as well as recruiting and hiring experienced JIB accountants. The third-party providers have the proper systems, experience and scalability to deliver the full scope of back-office services necessary to effectively participate as a non-operator in oil and gas production.

d-e. At this time, FPL does not anticipate hiring staff at GRCO.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 31 day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers **67** and **71-88**, and co-sponsored the answer to interrogatory number **66** from **OPC'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 66-116)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 31 day of October, 2014.

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF LEON)

I hereby certify that on this 6th day of November, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry Deason, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 104 through 116 from **OPC'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 66-116)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Terry Deason

Terry Deason

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of November, 2014.

Pam Keillor

Notary Public
State of Florida, at Large

My Commission Expires:

PAM KEILLOR
MY COMMISSION # EE 220745
EXPIRES: October 27, 2016
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 6th day of November, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she provided the answers to numbers 89 through 103 from **OPC'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 66-116)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Kim Ousdahl

Kim Ousdahl

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of November, 2014.

Janet Kelly

Notary Public
State of Florida, at Large

My Commission Expires: 11-24-2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

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FPL's Responses to OPC's Sixth Request for Production of Documents (Nos. 35, 36, and 37)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI   EXHIBIT: 54
PARTY: STAFF
DESCRIPTION: FPL's Responses to OPC's Sixth Request For Production of Documents

Q.

Please refer to the response to Staffs 7th Set of Interrogatories, Interrogatory No. 173.

Please provide the source documents used in projecting the July 28, 2014 fuel forecast.

A.

Documents responsive to this request are provided as Bates Nos. FCR-14-06432 through FCR-14-06507.

LONG-TERM FORECAST METHODOLOGY - GAS PRICE
July 28, 2014 - LYSTRA LOUTAN

LOW 79.10% HIGH 120.90%

MEDIUM PRICES | WITH NOx

SUNK DEMAND CHARGE FOR ALL CURRENT FIRM TRANSPORT AND STORAGE CONTRACTS THROUGH FGT PHASE VIII

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Jan-14	$4.54	$4.55	$4.55	$4.55	$5.21	$4.53	$5.18	$4.53	$4.41	$4.50	$29.3	$12.1	$4.9	$0.7	$0.8	[redacted]	[redacted]	$1.0
Feb-14	$5.73	$5.73	$5.75	$5.74	$6.40	$5.72	$6.36	$5.78	$5.56	$5.68	$26.5	$10.9	$4.5	$0.6	$0.8	[redacted]	[redacted]	$1.0
Mar-14	$5.00	$5.01	$5.06	$5.04	$5.71	$5.04	$5.68	$5.04	$4.86	$4.97	$29.4	$12.1	$4.9	$0.7	$0.8	[redacted]	[redacted]	$1.0
Apr-14	$4.72	$4.73	$4.81	$4.78	$5.49	$4.76	$5.46	$4.76	$4.58	$4.69	$30.2	$11.7	$4.8	$0.7	$0.8	[redacted]	[redacted]	$1.0
May-14	$4.94	$4.95	$5.01	$4.99	$5.71	$4.96	$5.93	$4.95	$4.80	$4.90	$32.6	$12.1	$4.9	$0.7	$0.8	[redacted]	[redacted]	$1.0
Jun-14	$4.76	$4.76	$4.79	$4.78	$5.50	$4.76	$5.70	$4.75	$4.62	$4.71	$30.8	$11.7	$4.4	$0.6	$0.8	[redacted]	[redacted]	$1.1
Jul-14	$4.53	$4.54	$4.58	$4.56	$5.29	$4.55	$5.49	$4.54	$4.40	$4.51	$31.8	$12.1	$4.5	$0.6	$0.8	[redacted]	[redacted]	$1.1
Aug-14	$3.86	$3.86	$3.88	$3.87	$4.56	$3.86	$4.77	$3.87	$3.75	$3.84	$31.8	$12.1	$4.5	$0.6	$0.8	[redacted]	[redacted]	$1.1
Sep-14	$3.87	$3.88	$3.89	$3.88	$4.57	$3.87	$4.78	$3.87	$3.77	$3.85	$30.8	$11.7	$4.4	$0.6	$0.8	[redacted]	[redacted]	$1.1
Oct-14	$3.88	$3.89	$3.90	$3.89	$4.58	$3.87	$4.79	$3.88	$3.78	$3.86	$30.7	$12.1	$4.9	$0.6	$0.8	[redacted]	[redacted]	$1.1
Nov-14	$3.93	$3.94	$3.94	$3.94	$4.61	$3.93	$4.82	$3.97	$3.83	$3.91	$27.9	$11.7	$4.8	$0.6	$0.0	[redacted]	[redacted]	$1.1
Dec-14	$4.02	$4.02	$4.03	$4.03	$4.70	$4.01	$4.91	$4.06	$3.91	$4.00	$28.9	$12.1	$4.9	$0.6	$0.0	[redacted]	[redacted]	$1.1
Jan-15	$4.10	$4.10	$4.11	$4.10	$4.77	$4.09	$4.98	$4.14	$3.98	$4.07	$28.9	$12.1	$4.9	$0.6	$0.0	[redacted]	[redacted]	$1.1
Feb-15	$4.09	$4.09	$4.10	$4.10	$4.77	$4.08	$4.97	$4.13	$3.98	$4.07	$26.1	$10.9	$4.5	$0.6	$0.0	[redacted]	[redacted]	$1.1
Mar-15	$4.02	$4.03	$4.03	$4.03	$4.70	$4.02	$4.91	$4.06	$3.91	$4.00	$28.9	$12.1	$4.9	$0.6	$0.0	[redacted]	[redacted]	$1.1
Apr-15	$3.81	$3.82	$3.81	$3.81	$4.56	$3.79	$4.77	$3.83	$3.71	$3.78	$30.1	$11.7	$4.8	$0.6	$2.0	[redacted]	[redacted]	$1.1
May-15	$3.81	$3.82	$3.80	$3.80	$4.56	$3.80	$4.77	$3.82	$3.70	$3.77	$32.2	$12.1	$4.5	$0.6	$2.1	[redacted]	[redacted]	$1.1
Jun-15	$3.84	$3.85	$3.84	$3.84	$4.60	$3.83	$4.80	$3.86	$3.74	$3.81	$31.2	$11.7	$4.4	$0.6	$2.0	[redacted]	[redacted]	$1.1
Jul-15	$3.88	$3.89	$3.87	$3.88	$4.63	$3.87	$4.84	$3.90	$3.77	$3.84	$32.2	$12.1	$4.5	$0.6	$2.1	[redacted]	[redacted]	$1.1
Aug-15	$3.89	$3.90	$3.88	$3.89	$4.64	$3.88	$4.85	$3.91	$3.78	$3.85	$32.2	$12.1	$4.5	$0.6	$2.1	[redacted]	[redacted]	$1.1
Sep-15	$3.88	$3.88	$3.87	$3.87	$4.63	$3.87	$4.84	$3.89	$3.77	$3.84	$31.2	$11.7	$4.4	$0.6	$2.0	[redacted]	[redacted]	$1.1
Oct-15	$3.89	$3.90	$3.87	$3.88	$4.65	$3.90	$4.86	$3.91	$3.79	$3.86	$31.1	$12.1	$4.9	$0.6	$2.1	[redacted]	[redacted]	$1.1
Nov-15	$3.97	$3.98	$3.96	$3.97	$4.65	$3.96	$4.86	$4.04	$3.86	$3.95	$28.4	$11.7	$4.8	$0.6	$1.2	[redacted]	[redacted]	$1.1
Dec-15	$4.15	$4.16	$4.15	$4.15	$4.83	$4.14	$5.04	$4.22	$4.04	$4.13	$29.3	$12.1	$4.9	$0.6	$1.2	[redacted]	[redacted]	$1.1
Jan-16	$4.29	$4.30	$4.29	$4.29	$4.97	$4.28	$5.17	$4.33	$4.17		$29.3	$12.1	$4.9	$0.6	$1.2	[redacted]	[redacted]	
Feb-16	$4.27	$4.28	$4.27	$4.27	$4.95	$4.26	$5.16	$4.31	$4.15		$27.4	$11.3	$4.6	$0.6	$1.1	[redacted]	[redacted]	
Mar-16	$4.21	$4.21	$4.21	$4.21	$4.89	$4.20	$5.09	$4.25	$4.09		$29.3	$12.1	$4.9	$0.6	$1.2	[redacted]	[redacted]	
Apr-16	$3.99	$3.99	$3.99	$3.99	$4.74	$3.96	$4.95	$4.00	$3.88		$30.1	$11.7	$4.8	$0.6	$2.0	[redacted]	[redacted]	
May-16	$4.00	$4.01	$4.01	$4.01	$4.75	$3.97	$4.96	$4.01	$3.89		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Jun-16	$4.03	$4.04	$4.04	$4.04	$4.78	$4.00	$4.99	$4.04	$3.92		$29.7	$11.7	$4.8	$0.4	$2.0	[redacted]	[redacted]	
Jul-16	$4.06	$4.06	$4.07	$4.07	$4.81	$4.03	$5.01	$4.07	$3.94		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Aug-16	$4.07	$4.07	$4.08	$4.08	$4.82	$4.04	$5.02	$4.08	$3.95		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Sep-16	$4.06	$4.07	$4.07	$4.07	$4.81	$4.03	$5.02	$4.07	$3.94		$29.7	$11.7	$4.8	$0.4	$2.0	[redacted]	[redacted]	
Oct-16	$4.08	$4.08	$4.07	$4.08	$4.83	$4.08	$5.04	$4.09	$3.97		$31.1	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Nov-16	$4.16	$4.16	$4.14	$4.15	$4.83	$4.14	$5.04	$4.22	$4.04		$28.4	$11.7	$4.8	$0.4	$1.2	[redacted]	[redacted]	
Dec-16	$4.33	$4.34	$4.32	$4.33	$5.01	$4.31	$5.21	$4.39	$4.21		$29.3	$12.1	$4.9	$0.4	$1.2	[redacted]	[redacted]	
Jan-17	$4.89	$4.90	$4.89	$4.89	$5.57	$4.87	$5.77	$4.91	$4.75		$29.3	$12.1	$4.9	$0.4	$1.2	[redacted]	[redacted]	
Feb-17	$4.57	$4.58	$4.57	$4.57	$5.25	$4.56	$5.45	$4.60	$4.45		$26.5	$10.9	$4.5	$0.3	$1.1	[redacted]	[redacted]	
Mar-17	$4.48	$4.48	$4.47	$4.48	$5.15	$4.46	$5.36	$4.50	$4.35		$29.3	$12.1	$4.9	$0.4	$1.2	[redacted]	[redacted]	
Apr-17	$4.54	$4.55	$4.56	$4.55	$5.30	$4.51	$5.50	$4.54	$4.42		$30.1	$11.7	$4.8	$0.4	$2.0	[redacted]	[redacted]	
May-17	$4.67	$4.68	$4.68	$4.68	$5.42	$4.63	$5.62	$4.66	$4.54		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Jun-17	$4.59	$4.60	$4.60	$4.60	$5.34	$4.55	$5.54	$4.59	$4.46		$29.7	$11.7	$4.8	$0.4	$2.0	[redacted]	[redacted]	
Jul-17	$4.79	$4.80	$4.80	$4.80	$5.54	$4.75	$5.74	$4.78	$4.65		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Aug-17	$4.42	$4.43	$4.43	$4.43	$5.17	$4.38	$5.37	$4.42	$4.29		$30.7	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Sep-17	$4.33	$4.34	$4.34	$4.34	$5.08	$4.29	$5.28	$4.33	$4.21		$29.7	$11.7	$4.8	$0.4	$2.0	[redacted]	[redacted]	
Oct-17	$4.52	$4.52	$4.51	$4.52	$5.27	$4.51	$5.47	$4.52	$4.39		$31.1	$12.1	$4.9	$0.4	$2.1	[redacted]	[redacted]	
Nov-17	$4.87	$4.88	$4.86	$4.87	$5.55	$4.85	$5.75	$4.91	$4.74		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-17	$4.86	$4.87	$4.85	$4.86	$5.54	$4.84	$5.74	$4.91	$4.73		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-18	$5.15	$5.16	$5.15	$5.15	$5.83	$5.12	$6.02	$5.16	$5.00		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-18	$4.82	$4.82	$4.82	$4.82	$5.49	$4.80	$5.69	$4.83	$4.68		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-18	$4.71	$4.72	$4.71	$4.71	$5.39	$4.69	$5.59	$4.73	$4.58		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-18	$4.79	$4.79	$4.81	$4.80	$5.54	$4.77	$5.74	$4.77	$4.65		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-18	$4.92	$4.92	$4.93	$4.93	$5.67	$4.90	$5.86	$4.90	$4.77		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-18	$4.84	$4.84	$4.86	$4.85	$5.59	$4.82	$5.78	$4.82	$4.70		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-18	$5.05	$5.05	$5.06	$5.06	$5.80	$5.03	$5.99	$5.03	$4.90		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-18	$4.65	$4.66	$4.67	$4.67	$5.41	$4.64	$5.60	$4.65	$4.52		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-18	$4.56	$4.57	$4.58	$4.57	$5.31	$4.55	$5.51	$4.55	$4.43		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-18	$4.76	$4.76	$4.78	$4.77	$5.51	$4.75	$5.71	$4.75	$4.62		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-18	$5.13	$5.14	$5.12	$5.13	$5.81	$5.10	$6.00	$5.16	$4.99		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-18	$5.12	$5.13	$5.11	$5.12	$5.80	$5.10	$5.99	$5.16	$4.98		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Jan-19	$5.77	$5.77	$5.77	$5.77	$6.45	$5.73	$6.63	$5.76	$5.60		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-19	$5.39	$5.40	$5.39	$5.40	$6.07	$5.36	$6.26	$5.39	$5.24		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-19	$5.28	$5.28	$5.28	$5.28	$5.96	$5.25	$6.15	$5.28	$5.13		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-19	$5.36	$5.36	$5.38	$5.38	$6.11	$5.34	$6.30	$5.33	$5.21		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-19	$5.51	$5.51	$5.52	$5.52	$6.26	$5.48	$6.44	$5.47	$5.35		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-19	$5.42	$5.42	$5.44	$5.43	$6.17	$5.39	$6.36	$5.38	$5.26		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-19	$5.65	$5.66	$5.67	$5.66	$6.40	$5.63	$6.59	$5.61	$5.49		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-19	$5.21	$5.22	$5.23	$5.23	$5.96	$5.19	$6.15	$5.19	$5.06		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-19	$5.10	$5.11	$5.12	$5.12	$5.85	$5.09	$6.05	$5.08	$4.96		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-19	$5.33	$5.33	$5.35	$5.34	$6.08	$5.31	$6.27	$5.30	$5.18		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-19	$5.75	$5.75	$5.74	$5.74	$6.43	$5.71	$6.61	$5.76	$5.58		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-19	$5.74	$5.74	$5.73	$5.73	$6.42	$5.70	$6.60	$5.75	$5.57		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-20	$5.93	$5.94	$5.93	$5.93	$6.61	$5.90	$6.79	$5.92	$5.76		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-20	$5.55	$5.55	$5.55	$5.55	$6.23	$5.52	$6.41	$5.54	$5.39		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-20	$5.43	$5.43	$5.43	$5.43	$6.11	$5.40	$6.30	$5.43	$5.27		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-20	$5.51	$5.52	$5.53	$5.53	$6.26	$5.49	$6.45	$5.48	$5.35		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-20	$5.66	$5.67	$5.68	$5.67	$6.41	$5.64	$6.60	$5.62	$5.50		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-20	$5.57	$5.58	$5.59	$5.58	$6.32	$5.55	$6.51	$5.53	$5.41		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-20	$5.81	$5.82	$5.83	$5.82	$6.56	$5.78	$6.74	$5.77	$5.64		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-20	$5.36	$5.37	$5.38	$5.37	$6.11	$5.34	$6.30	$5.33	$5.21		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-20	$5.25	$5.26	$5.27	$5.26	$6.00	$5.23	$6.19	$5.22	$5.10		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-20	$5.48	$5.49	$5.50	$5.50	$6.23	$5.46	$6.42	$5.45	$5.32		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-20	$5.91	$5.92	$5.90	$5.90	$6.59	$5.87	$6.77	$5.92	$5.74		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-20	$5.90	$5.91	$5.89	$5.90	$6.58	$5.86	$6.76	$5.91	$5.73		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-21	$6.15	$6.16	$6.15	$6.15	$6.83	$6.11	$7.01	$6.13	$5.97		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-21	$5.75	$5.76	$5.75	$5.75	$6.43	$5.72	$6.61	$5.74	$5.59		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-21	$5.63	$5.63	$5.63	$5.63	$6.31	$5.60	$6.49	$5.62	$5.47		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-21	$5.72	$5.72	$5.74	$5.73	$6.47	$5.69	$6.65	$5.67	$5.55		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-21	$5.87	$5.88	$5.89	$5.88	$6.62	$5.84	$6.80	$5.82	$5.70		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-21	$5.78	$5.78	$5.79	$5.79	$6.53	$5.75	$6.71	$5.73	$5.61		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-21	$6.02	$6.03	$6.04	$6.04	$6.78	$5.99	$6.95	$5.97	$5.85		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-21	$5.56	$5.57	$5.58	$5.57	$6.31	$5.53	$6.50	$5.52	$5.40		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-21	$5.44	$5.45	$5.46	$5.46	$6.19	$5.42	$6.38	$5.41	$5.28		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-21	$5.68	$5.69	$5.70	$5.70	$6.43	$5.66	$6.62	$5.64	$5.52		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-21	$6.13	$6.13	$6.12	$6.12	$6.81	$6.09	$6.99	$6.13	$5.95		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-21	$6.12	$6.12	$6.11	$6.11	$6.80	$6.08	$6.97	$6.12	$5.94		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-22	$6.37	$6.37	$6.37	$6.37	$7.05	$6.33	$7.22	$6.34	$6.18		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-22	$5.96	$5.96	$5.95	$5.96	$6.63	$5.92	$6.82	$5.94	$5.78		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-22	$5.83	$5.83	$5.83	$5.83	$6.51	$5.79	$6.69	$5.81	$5.66		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-22	$5.92	$5.92	$5.94	$5.93	$6.67	$5.89	$6.85	$5.87	$5.75		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-22	$6.08	$6.09	$6.10	$6.09	$6.83	$6.05	$7.01	$6.02	$5.90		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-22	$5.98	$5.99	$6.00	$5.99	$6.73	$5.95	$6.91	$5.93	$5.81		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-22	$6.24	$6.25	$6.26	$6.25	$6.99	$6.20	$7.17	$6.18	$6.05		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-22	$5.76	$5.76	$5.77	$5.77	$6.51	$5.73	$6.69	$5.71	$5.59		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-22	$5.63	$5.64	$5.65	$5.65	$6.39	$5.61	$6.57	$5.60	$5.47		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-22	$5.88	$5.89	$5.91	$5.90	$6.64	$5.86	$6.82	$5.84	$5.71		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-22	$6.35	$6.35	$6.33	$6.34	$7.02	$6.30	$7.20	$6.34	$6.16		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-22	$6.33	$6.34	$6.32	$6.33	$7.01	$6.29	$7.19	$6.33	$6.15		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-23	$6.59	$6.59	$6.59	$6.59	$7.26	$6.54	$7.44	$6.55	$6.39		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-23	$6.16	$6.16	$6.16	$6.16	$6.84	$6.12	$7.02	$6.14	$5.98		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-23	$6.03	$6.03	$6.03	$6.03	$6.71	$5.99	$6.89	$6.01	$5.85		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-23	$6.12	$6.13	$6.14	$6.14	$6.87	$6.09	$7.05	$6.07	$5.94		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-23	$6.29	$6.29	$6.30	$6.30	$7.04	$6.25	$7.21	$6.23	$6.10		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-23	$6.19	$6.19	$6.20	$6.20	$6.94	$6.15	$7.11	$6.13	$6.00		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-23	$6.45	$6.46	$6.47	$6.47	$7.20	$6.42	$7.38	$6.39	$6.26		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-23	$5.95	$5.96	$5.97	$5.97	$6.70	$5.92	$6.88	$5.90	$5.78		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-23	$5.83	$5.84	$5.85	$5.84	$6.58	$5.80	$6.76	$5.78	$5.66		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-23	$6.08	$6.09	$6.11	$6.10	$6.84	$6.06	$7.02	$6.03	$5.91		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-23	$6.56	$6.57	$6.55	$6.56	$7.24	$6.51	$7.41	$6.55	$6.37		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-23	$6.55	$6.56	$6.54	$6.55	$7.23	$6.50	$7.40	$6.54	$6.36		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-24	$6.80	$6.81	$6.80	$6.81	$7.48	$6.76	$7.65	$6.76	$6.61		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-24	$6.36	$6.37	$6.36	$6.36	$7.04	$6.32	$7.22	$6.33	$6.18		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-24	$6.23	$6.23	$6.23	$6.23	$6.91	$6.19	$7.08	$6.20	$6.05		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-24	$6.32	$6.33	$6.34	$6.34	$7.08	$6.29	$7.25	$6.26	$6.14		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-24	$6.49	$6.50	$6.51	$6.51	$7.25	$6.46	$7.42	$6.43	$6.30		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-24	$6.39	$6.40	$6.41	$6.40	$7.14	$6.35	$7.32	$6.33	$6.20		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-24	$6.67	$6.67	$6.68	$6.68	$7.42	$6.63	$7.59	$6.59	$6.47		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Aug-24	$6.15	$6.16	$6.17	$6.16	$6.90	$6.12	$7.08	$6.10	$5.97		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-24	$6.02	$6.03	$6.04	$6.03	$6.77	$5.99	$6.95	$5.97	$5.84		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-24	$6.29	$6.29	$6.31	$6.30	$7.04	$6.25	$7.22	$6.23	$6.10		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-24	$6.78	$6.79	$6.77	$6.77	$7.46	$6.73	$7.63	$6.76	$6.58		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-24	$6.77	$6.77	$6.76	$6.76	$7.45	$6.72	$7.62	$6.75	$6.57		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-25	$6.97	$6.97	$6.97	$6.97	$7.65	$6.92	$7.81	$6.92	$6.76		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-25	$6.52	$6.52	$6.52	$6.52	$7.20	$6.47	$7.37	$6.48	$6.33		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-25	$6.38	$6.38	$6.38	$6.38	$7.06	$6.33	$7.23	$6.35	$6.19		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-25	$6.48	$6.48	$6.50	$6.49	$7.23	$6.44	$7.40	$6.41	$6.29		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-25	$6.65	$6.66	$6.67	$6.66	$7.40	$6.61	$7.57	$6.58	$6.45		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-25	$6.54	$6.55	$6.56	$6.56	$7.29	$6.51	$7.47	$6.48	$6.35		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-25	$6.83	$6.83	$6.84	$6.84	$7.58	$6.78	$7.75	$6.75	$6.62		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-25	$6.30	$6.31	$6.32	$6.31	$7.05	$6.26	$7.22	$6.24	$6.11		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-25	$6.17	$6.17	$6.18	$6.18	$6.92	$6.13	$7.09	$6.11	$5.98		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-25	$6.44	$6.44	$6.46	$6.45	$7.19	$6.40	$7.36	$6.38	$6.25		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-25	$6.94	$6.95	$6.93	$6.94	$7.62	$6.89	$7.79	$6.92	$6.74		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-25	$6.93	$6.94	$6.92	$6.93	$7.61	$6.88	$7.78	$6.91	$6.73		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-26	$7.19	$7.19	$7.19	$7.19	$7.87	$7.13	$8.03	$7.13	$6.98		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-26	$6.72	$6.73	$6.72	$6.72	$7.40	$6.67	$7.57	$6.68	$6.52		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-26	$6.58	$6.58	$6.58	$6.58	$7.26	$6.53	$7.43	$6.54	$6.39		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-26	$6.68	$6.68	$6.70	$6.69	$7.43	$6.64	$7.60	$6.61	$6.48		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-26	$6.86	$6.87	$6.88	$6.87	$7.61	$6.82	$7.78	$6.78	$6.66		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-26	$6.75	$6.76	$6.77	$6.76	$7.50	$6.71	$7.67	$6.67	$6.55		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-26	$7.04	$7.05	$7.06	$7.05	$7.79	$7.00	$7.96	$6.96	$6.83		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-26	$6.50	$6.50	$6.51	$6.51	$7.25	$6.46	$7.42	$6.43	$6.30		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-26	$6.36	$6.37	$6.38	$6.37	$7.11	$6.32	$7.28	$6.30	$6.17		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-26	$6.64	$6.64	$6.66	$6.66	$7.39	$6.60	$7.56	$6.57	$6.45		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-26	$7.16	$7.17	$7.15	$7.16	$7.84	$7.10	$8.00	$7.13	$6.95		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-26	$7.15	$7.15	$7.14	$7.14	$7.83	$7.09	$7.99	$7.12	$6.94		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-27	$7.46	$7.46	$7.46	$7.46	$8.14	$7.40	$8.30	$7.40	$7.24		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-27	$6.98	$6.98	$6.98	$6.98	$7.65	$6.93	$7.82	$6.93	$6.77		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-27	$6.83	$6.83	$6.83	$6.83	$7.51	$6.78	$7.67	$6.78	$6.63		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-27	$6.93	$6.94	$6.95	$6.95	$7.68	$6.89	$7.85	$6.85	$6.73		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-27	$7.12	$7.13	$7.14	$7.13	$7.87	$7.07	$8.03	$7.03	$6.91		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-27	$7.00	$7.01	$7.02	$7.02	$7.76	$6.96	$7.92	$6.92	$6.80		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-27	$7.31	$7.31	$7.33	$7.32	$8.06	$7.26	$8.22	$7.22	$7.09		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-27	$6.74	$6.75	$6.76	$6.76	$7.49	$6.70	$7.66	$6.67	$6.54		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-27	$6.60	$6.61	$6.62	$6.61	$7.35	$6.56	$7.52	$6.53	$6.41		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-27	$6.89	$6.90	$6.91	$6.91	$7.64	$6.85	$7.81	$6.82	$6.69		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-27	$7.43	$7.44	$7.42	$7.43	$8.11	$7.37	$8.27	$7.39	$7.21		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-27	$7.42	$7.43	$7.41	$7.41	$8.10	$7.36	$8.26	$7.38	$7.20		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-28	$7.73	$7.74	$7.73	$7.73	$8.41	$7.67	$8.57	$7.66	$7.50		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-28	$7.23	$7.24	$7.23	$7.23	$7.91	$7.18	$8.07	$7.17	$7.02		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-28	$7.08	$7.08	$7.08	$7.08	$7.76	$7.02	$7.92	$7.02	$6.87		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-28	$7.19	$7.19	$7.21	$7.20	$7.94	$7.14	$8.10	$7.10	$6.97		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-28	$7.38	$7.39	$7.40	$7.39	$8.13	$7.33	$8.29	$7.28	$7.16		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-28	$7.26	$7.27	$7.28	$7.27	$8.01	$7.21	$8.17	$7.17	$7.05		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-28	$7.57	$7.58	$7.59	$7.59	$8.32	$7.52	$8.48	$7.47	$7.35		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-28	$6.99	$7.00	$7.01	$7.00	$7.74	$6.94	$7.91	$6.91	$6.78		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-28	$6.84	$6.85	$6.86	$6.86	$7.59	$6.80	$7.76	$6.77	$6.64		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-28	$7.14	$7.15	$7.17	$7.16	$7.90	$7.10	$8.06	$7.06	$6.93		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-28	$7.71	$7.71	$7.69	$7.70	$8.38	$7.64	$8.54	$7.66	$7.48		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-28	$7.69	$7.70	$7.68	$7.69	$8.37	$7.63	$8.53	$7.65	$7.46		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-29	$8.06	$8.06	$8.06	$8.06	$8.74	$7.99	$8.89	$7.98	$7.82		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-29	$7.54	$7.54	$7.54	$7.54	$8.22	$7.48	$8.38	$7.47	$7.32		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-29	$7.38	$7.38	$7.38	$7.38	$8.06	$7.32	$8.22	$7.31	$7.16		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-29	$7.49	$7.49	$7.51	$7.51	$8.24	$7.44	$8.40	$7.39	$7.27		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-29	$7.69	$7.70	$7.71	$7.71	$8.44	$7.64	$8.60	$7.59	$7.46		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-29	$7.57	$7.58	$7.59	$7.58	$8.32	$7.52	$8.48	$7.47	$7.34		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-29	$7.89	$7.90	$7.91	$7.91	$8.65	$7.84	$8.80	$7.79	$7.66		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-29	$7.28	$7.29	$7.30	$7.30	$8.04	$7.24	$8.20	$7.19	$7.07		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-29	$7.13	$7.14	$7.15	$7.14	$7.88	$7.09	$8.05	$7.05	$6.92		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-29	$7.45	$7.45	$7.47	$7.46	$8.20	$7.40	$8.36	$7.35	$7.23		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-29	$8.03	$8.04	$8.02	$8.03	$8.71	$7.96	$8.86	$7.97	$7.79		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-29	$8.02	$8.02	$8.01	$8.01	$8.70	$7.95	$8.85	$7.96	$7.78		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-30	$8.39	$8.39	$8.39	$8.39	$9.07	$8.32	$9.21	$8.29	$8.14		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-30	$7.84	$7.85	$7.84	$7.84	$8.52	$7.78	$8.68	$7.77	$7.61		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Mar-30	$7.68	$7.68	$7.68	$7.68	$8.36	$7.62	$8.51	$7.60	$7.45		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]		
Apr-30	$7.79	$7.80	$7.82	$7.81	$8.55	$7.74	$8.70	$7.69	$7.56		$30.1	$11.7	$4.8	$0.4	$1.3			
May-30	$8.00	$8.01	$8.02	$8.02	$8.76	$7.95	$8.91	$7.89	$7.77		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-30	$7.88	$7.88	$7.89	$7.89	$8.63	$7.82	$8.78	$7.77	$7.64		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-30	$8.21	$8.22	$8.23	$8.23	$8.97	$8.15	$9.11	$8.10	$7.97		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-30	$7.58	$7.59	$7.60	$7.59	$8.33	$7.53	$8.49	$7.48	$7.35		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-30	$7.42	$7.43	$7.44	$7.43	$8.17	$7.37	$8.33	$7.33	$7.20		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-30	$7.75	$7.75	$7.77	$7.76	$8.50	$7.70	$8.66	$7.65	$7.52		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-30	$8.36	$8.36	$8.35	$8.35	$9.04	$8.28	$9.18	$8.29	$8.11		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-30	$8.34	$8.35	$8.33	$8.34	$9.02	$8.27	$9.17	$8.28	$8.09		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-31	$8.59	$8.59	$8.59	$8.59	$9.27	$8.52	$9.41	$8.49	$8.33		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-31	$8.03	$8.04	$8.03	$8.03	$8.71	$7.97	$8.86	$7.95	$7.79		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-31	$7.86	$7.87	$7.86	$7.86	$8.54	$7.80	$8.69	$7.78	$7.63		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-31	$7.98	$7.99	$8.00	$8.00	$8.73	$7.93	$8.89	$7.87	$7.74		$30.1	$11.7	$4.8	$0.4	$1.3			
May-31	$8.20	$8.21	$8.22	$8.21	$8.95	$8.14	$9.10	$8.08	$7.95		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-31	$8.07	$8.07	$8.08	$8.08	$8.82	$8.01	$8.97	$7.95	$7.82		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-31	$8.41	$8.42	$8.43	$8.43	$9.16	$8.35	$9.31	$8.29	$8.16		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-31	$7.76	$7.77	$7.78	$7.78	$8.51	$7.71	$8.67	$7.66	$7.53		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-31	$7.60	$7.61	$7.62	$7.61	$8.35	$7.55	$8.51	$7.50	$7.37		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-31	$7.94	$7.94	$7.96	$7.95	$8.69	$7.88	$8.84	$7.83	$7.70		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-31	$8.56	$8.56	$8.55	$8.55	$9.24	$8.48	$9.38	$8.48	$8.30		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-31	$8.54	$8.55	$8.53	$8.54	$9.22	$8.47	$9.37	$8.47	$8.29		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-32	$8.80	$8.80	$8.80	$8.80	$9.47	$8.72	$9.62	$8.69	$8.53		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-32	$8.23	$8.23	$8.23	$8.23	$8.90	$8.16	$9.05	$8.14	$7.98		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-32	$8.05	$8.06	$8.05	$8.05	$8.73	$7.98	$8.88	$7.97	$7.81		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-32	$8.17	$8.18	$8.20	$8.19	$8.93	$8.11	$9.08	$8.06	$7.93		$30.1	$11.7	$4.8	$0.4	$1.3			
May-32	$8.39	$8.40	$8.41	$8.41	$9.15	$8.33	$9.29	$8.27	$8.14		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-32	$8.26	$8.27	$8.28	$8.27	$9.01	$8.20	$9.16	$8.14	$8.01		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-32	$8.62	$8.62	$8.63	$8.63	$9.37	$8.55	$9.51	$8.48	$8.36		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-32	$7.95	$7.96	$7.97	$7.96	$8.70	$7.89	$8.85	$7.84	$7.71		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-32	$7.78	$7.79	$7.80	$7.80	$8.53	$7.73	$8.69	$7.68	$7.55		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-32	$8.13	$8.13	$8.15	$8.14	$8.88	$8.07	$9.03	$8.01	$7.88		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-32	$8.77	$8.77	$8.75	$8.76	$9.44	$8.69	$9.59	$8.68	$8.50		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-32	$8.75	$8.75	$8.74	$8.74	$9.43	$8.67	$9.57	$8.67	$8.49		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-33	$9.01	$9.01	$9.01	$9.01	$9.69	$8.93	$9.82	$8.90	$8.74		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-33	$8.42	$8.43	$8.42	$8.43	$9.10	$8.35	$9.25	$8.33	$8.17		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-33	$8.24	$8.25	$8.24	$8.25	$8.92	$8.18	$9.07	$8.15	$8.00		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-33	$8.37	$8.38	$8.39	$8.39	$9.12	$8.31	$9.27	$8.25	$8.12		$30.1	$11.7	$4.8	$0.4	$1.3			
May-33	$8.60	$8.60	$8.61	$8.61	$9.35	$8.53	$9.49	$8.46	$8.34		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-33	$8.46	$8.47	$8.48	$8.47	$9.21	$8.39	$9.35	$8.33	$8.20		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-33	$8.82	$8.83	$8.84	$8.84	$9.57	$8.75	$9.71	$8.68	$8.56		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-33	$8.14	$8.15	$8.16	$8.15	$8.89	$8.08	$9.04	$8.02	$7.90		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-33	$7.97	$7.98	$7.99	$7.98	$8.72	$7.91	$8.87	$7.86	$7.73		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-33	$8.32	$8.33	$8.34	$8.34	$9.07	$8.26	$9.22	$8.20	$8.07		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-33	$8.98	$8.98	$8.96	$8.97	$9.65	$8.89	$9.79	$8.89	$8.71		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-33	$8.96	$8.96	$8.95	$8.95	$9.64	$8.88	$9.78	$8.88	$8.69		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-34	$9.22	$9.23	$9.22	$9.23	$9.90	$9.14	$10.04	$9.11	$8.95		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-34	$8.63	$8.63	$8.63	$8.63	$9.31	$8.55	$9.45	$8.53	$8.37		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-34	$8.44	$8.45	$8.44	$8.44	$9.12	$8.37	$9.27	$8.35	$8.19		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-34	$8.57	$8.58	$8.59	$8.59	$9.32	$8.51	$9.47	$8.44	$8.32		$30.1	$11.7	$4.8	$0.4	$1.3			
May-34	$8.80	$8.81	$8.82	$8.82	$9.55	$8.73	$9.69	$8.66	$8.54		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-34	$8.66	$8.67	$8.68	$8.67	$9.41	$8.59	$9.56	$8.53	$8.40		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-34	$9.03	$9.04	$9.05	$9.05	$9.79	$8.96	$9.92	$8.89	$8.76		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-34	$8.34	$8.34	$8.36	$8.35	$9.09	$8.27	$9.23	$8.21	$8.09		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-34	$8.16	$8.17	$8.18	$8.18	$8.91	$8.10	$9.06	$8.04	$7.92		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-34	$8.52	$8.53	$8.54	$8.54	$9.28	$8.46	$9.42	$8.40	$8.27		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-34	$9.19	$9.20	$9.18	$9.19	$9.87	$9.11	$10.01	$9.10	$8.92		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-34	$9.18	$9.18	$9.17	$9.17	$9.85	$9.09	$9.99	$9.08	$8.90		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-35	$9.45	$9.45	$9.45	$9.45	$10.12	$9.36	$10.26	$9.32	$9.16		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-35	$8.83	$8.84	$8.83	$8.84	$9.51	$8.76	$9.65	$8.73	$8.57		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-35	$8.65	$8.65	$8.65	$8.65	$9.32	$8.57	$9.47	$8.54	$8.39		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-35	$8.78	$8.78	$8.80	$8.79	$9.53	$8.71	$9.67	$8.64	$8.52		$30.1	$11.7	$4.8	$0.4	$1.3			
May-35	$9.02	$9.02	$9.03	$9.03	$9.77	$8.94	$9.90	$8.87	$8.74		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-35	$8.87	$8.88	$8.89	$8.88	$9.62	$8.80	$9.76	$8.73	$8.60		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-35	$9.25	$9.26	$9.27	$9.27	$10.00	$9.18	$10.14	$9.10	$8.97		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-35	$8.54	$8.54	$8.56	$8.55	$9.29	$8.47	$9.43	$8.41	$8.28		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-35	$8.36	$8.37	$8.38	$8.37	$9.11	$8.29	$9.26	$8.23	$8.11		$29.7	$11.7	$4.8	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Oct-35	$8.73	$8.73	$8.75	$8.74	$9.48	$8.66	$9.62	$8.59	$8.47		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-35	$9.41	$9.42	$9.40	$9.41	$10.09	$9.32	$10.22	$9.31	$9.13		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-35	$9.40	$9.40	$9.39	$9.39	$10.07	$9.31	$10.21	$9.30	$9.12		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-36	$9.67	$9.68	$9.67	$9.67	$10.35	$9.59	$10.48	$9.54	$9.38		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-36	$9.05	$9.05	$9.05	$9.05	$9.73	$8.97	$9.86	$8.93	$8.78		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-36	$8.85	$8.86	$8.85	$8.86	$9.53	$8.78	$9.67	$8.74	$8.59		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-36	$8.99	$8.99	$9.01	$9.01	$9.74	$8.92	$9.88	$8.85	$8.72		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-36	$9.23	$9.24	$9.25	$9.25	$9.98	$9.16	$10.12	$9.08	$8.95		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-36	$9.08	$9.09	$9.10	$9.10	$9.83	$9.01	$9.97	$8.94	$8.81		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-36	$9.47	$9.48	$9.49	$9.49	$10.23	$9.40	$10.36	$9.32	$9.19		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-36	$8.74	$8.75	$8.76	$8.76	$9.49	$8.67	$9.63	$8.61	$8.48		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-36	$8.56	$8.57	$8.58	$8.57	$9.31	$8.49	$9.45	$8.43	$8.30		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-36	$8.94	$8.94	$8.96	$8.95	$9.69	$8.87	$9.83	$8.80	$8.67		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-36	$9.64	$9.65	$9.63	$9.63	$10.32	$9.55	$10.45	$9.53	$9.35		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-36	$9.62	$9.63	$9.61	$9.62	$10.30	$9.53	$10.43	$9.52	$9.33		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-37	$9.91	$9.91	$9.91	$9.91	$10.59	$9.81	$10.71	$9.77	$9.61		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-37	$9.27	$9.27	$9.26	$9.27	$9.94	$9.18	$10.08	$9.14	$8.99		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-37	$9.07	$9.07	$9.07	$9.07	$9.75	$8.99	$9.88	$8.95	$8.80		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-37	$9.21	$9.21	$9.23	$9.22	$9.96	$9.13	$10.09	$9.06	$8.93		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-37	$9.45	$9.46	$9.47	$9.47	$10.21	$9.38	$10.34	$9.29	$9.17		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-37	$9.30	$9.31	$9.32	$9.32	$10.05	$9.23	$10.19	$9.15	$9.02		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-37	$9.70	$9.71	$9.72	$9.72	$10.45	$9.62	$10.58	$9.54	$9.41		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-37	$8.95	$8.96	$8.97	$8.97	$9.70	$8.88	$9.84	$8.81	$8.68		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-37	$8.76	$8.77	$8.78	$8.78	$9.52	$8.70	$9.66	$8.63	$8.50		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-37	$9.15	$9.16	$9.17	$9.17	$9.91	$9.08	$10.04	$9.01	$8.88		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-37	$9.87	$9.88	$9.86	$9.87	$10.55	$9.78	$10.68	$9.75	$9.58		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-37	$9.85	$9.86	$9.84	$9.85	$10.53	$9.76	$10.66	$9.74	$9.56		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-38	$10.15	$10.15	$10.14	$10.15	$10.82	$10.05	$10.95	$10.00	$9.84		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-38	$9.49	$9.49	$9.49	$9.49	$10.17	$9.40	$10.30	$9.36	$9.20		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-38	$9.29	$9.29	$9.28	$9.29	$9.96	$9.20	$10.10	$9.16	$9.01		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-38	$9.43	$9.43	$9.45	$9.44	$10.18	$9.35	$10.31	$9.27	$9.15		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-38	$9.68	$9.69	$9.70	$9.69	$10.43	$9.60	$10.56	$9.51	$9.39		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-38	$9.53	$9.53	$9.54	$9.54	$10.28	$9.45	$10.41	$9.36	$9.24		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-38	$9.94	$9.94	$9.96	$9.95	$10.69	$9.85	$10.81	$9.76	$9.64		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-38	$9.17	$9.18	$9.19	$9.18	$9.92	$9.09	$10.05	$9.02	$8.89		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-38	$8.98	$8.98	$8.99	$8.99	$9.73	$8.90	$9.87	$8.83	$8.71		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-38	$9.37	$9.38	$9.39	$9.39	$10.13	$9.30	$10.26	$9.22	$9.09		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-38	$10.11	$10.11	$10.10	$10.10	$10.79	$10.01	$10.91	$9.98	$9.81		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-38	$10.09	$10.10	$10.08	$10.09	$10.77	$9.99	$10.89	$9.97	$9.79		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-39	$10.39	$10.39	$10.39	$10.39	$11.07	$10.29	$11.19	$10.23	$10.08		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-39	$9.72	$9.72	$9.72	$9.72	$10.39	$9.63	$10.52	$9.58	$9.43		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-39	$9.51	$9.51	$9.51	$9.51	$10.19	$9.42	$10.32	$9.38	$9.22		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-39	$9.65	$9.66	$9.68	$9.67	$10.41	$9.57	$10.54	$9.49	$9.36		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-39	$9.91	$9.92	$9.93	$9.93	$10.67	$9.83	$10.79	$9.74	$9.61		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-39	$9.75	$9.76	$9.77	$9.77	$10.51	$9.67	$10.63	$9.59	$9.46		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-39	$10.18	$10.18	$10.19	$10.19	$10.93	$10.09	$11.05	$9.99	$9.87		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-39	$9.39	$9.40	$9.41	$9.40	$10.14	$9.31	$10.27	$9.23	$9.11		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-39	$9.19	$9.20	$9.21	$9.21	$9.94	$9.12	$10.08	$9.04	$8.92		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-39	$9.60	$9.60	$9.62	$9.61	$10.35	$9.52	$10.48	$9.44	$9.31		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-39	$10.35	$10.36	$10.34	$10.35	$11.03	$10.25	$11.15	$10.22	$10.04		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-39	$10.33	$10.34	$10.32	$10.33	$11.01	$10.23	$11.13	$10.21	$10.02		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-40	$10.64	$10.64	$10.64	$10.64	$11.32	$10.54	$11.43	$10.48	$10.32		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-40	$9.95	$9.96	$9.95	$9.95	$10.63	$9.86	$10.75	$9.81	$9.65		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-40	$9.74	$9.74	$9.74	$9.74	$10.42	$9.65	$10.55	$9.60	$9.45		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-40	$9.89	$9.89	$9.91	$9.90	$10.64	$9.80	$10.77	$9.72	$9.59		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-40	$10.15	$10.16	$10.17	$10.17	$10.90	$10.06	$11.03	$9.97	$9.85		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-40	$9.99	$10.00	$10.01	$10.00	$10.74	$9.90	$10.86	$9.81	$9.69		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-40	$10.42	$10.43	$10.44	$10.43	$11.17	$10.33	$11.29	$10.23	$10.10		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-40	$9.61	$9.62	$9.63	$9.63	$10.37	$9.53	$10.50	$9.45	$9.32		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-40	$9.41	$9.42	$9.43	$9.43	$10.16	$9.34	$10.30	$9.26	$9.13		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-40	$9.83	$9.83	$9.85	$9.85	$10.58	$9.75	$10.71	$9.66	$9.53		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-40	$10.60	$10.61	$10.59	$10.60	$11.28	$10.50	$11.40	$10.46	$10.28		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-40	$10.58	$10.59	$10.57	$10.58	$11.26	$10.48	$11.38	$10.45	$10.26		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-41	$10.90	$10.90	$10.89	$10.90	$11.57	$10.79	$11.69	$10.72	$10.57		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-41	$10.19	$10.20	$10.19	$10.19	$10.87	$10.09	$10.99	$10.04	$9.88		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-41	$9.97	$9.98	$9.97	$9.97	$10.65	$9.88	$10.78	$9.83	$9.67		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-41	$10.13	$10.13	$10.15	$10.14	$10.88	$10.04	$11.00	$9.95	$9.82		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACE MENT SUNK DEMAND CHARGE MM$
May-41	$10.40	$10.41	$10.42	$10.41	$11.15	$10.31	$11.27	$10.21	$10.08		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]		
Jun-41	$10.23	$10.24	$10.25	$10.24	$10.98	$10.14	$11.10	$10.05	$9.92		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-41	$10.67	$10.68	$10.69	$10.68	$11.42	$10.58	$11.54	$10.47	$10.35		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-41	$9.85	$9.85	$9.86	$9.86	$10.60	$9.76	$10.72	$9.68	$9.55		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-41	$9.64	$9.65	$9.66	$9.65	$10.39	$9.56	$10.52	$9.48	$9.35		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-41	$10.07	$10.07	$10.09	$10.08	$10.82	$9.98	$10.94	$9.89	$9.76		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-41	$10.86	$10.86	$10.85	$10.85	$11.54	$10.75	$11.65	$10.71	$10.53		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-41	$10.84	$10.84	$10.83	$10.83	$11.52	$10.73	$11.63	$10.69	$10.51		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-42	$11.16	$11.16	$11.16	$11.16	$11.84	$11.05	$11.94	$10.98	$10.82		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-42	$10.44	$10.44	$10.43	$10.44	$11.11	$10.34	$11.23	$10.28	$10.12		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-42	$10.21	$10.22	$10.21	$10.21	$10.89	$10.12	$11.01	$10.06	$9.91		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-42	$10.37	$10.37	$10.39	$10.38	$11.12	$10.28	$11.24	$10.18	$10.06		$30.1	$11.7	$4.8	$0.4	$1.3			
May-42	$10.65	$10.66	$10.67	$10.66	$11.40	$10.55	$11.51	$10.45	$10.32		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-42	$10.48	$10.48	$10.49	$10.49	$11.23	$10.38	$11.34	$10.29	$10.16		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-42	$10.93	$10.94	$10.95	$10.94	$11.68	$10.83	$11.79	$10.72	$10.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-42	$10.08	$10.09	$10.10	$10.10	$10.83	$10.00	$10.96	$9.91	$9.78		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-42	$9.87	$9.88	$9.89	$9.89	$10.62	$9.79	$10.75	$9.70	$9.57		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-42	$10.31	$10.31	$10.33	$10.32	$11.06	$10.22	$11.18	$10.13	$10.00		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-42	$11.12	$11.12	$11.11	$11.11	$11.80	$11.01	$11.91	$10.96	$10.78		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-42	$11.10	$11.10	$11.09	$11.09	$11.78	$10.99	$11.89	$10.95	$10.76		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-43	$11.43	$11.43	$11.43	$11.43	$12.10	$11.31	$12.21	$11.24	$11.08		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-43	$10.69	$10.69	$10.69	$10.69	$11.36	$10.58	$11.48	$10.52	$10.36		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-43	$10.46	$10.46	$10.46	$10.46	$11.14	$10.36	$11.26	$10.30	$10.14		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-43	$10.62	$10.62	$10.64	$10.63	$11.37	$10.52	$11.49	$10.42	$10.30		$30.1	$11.7	$4.8	$0.4	$1.3			
May-43	$10.90	$10.91	$10.92	$10.92	$11.65	$10.80	$11.77	$10.70	$10.57		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-43	$10.73	$10.74	$10.75	$10.74	$11.48	$10.63	$11.59	$10.53	$10.40		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-43	$11.19	$11.20	$11.21	$11.20	$11.94	$11.09	$12.05	$10.98	$10.85		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-43	$10.33	$10.33	$10.34	$10.34	$11.08	$10.24	$11.20	$10.14	$10.01		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-43	$10.11	$10.12	$10.13	$10.12	$10.86	$10.02	$10.98	$9.93	$9.80		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-43	$10.56	$10.56	$10.58	$10.57	$11.31	$10.46	$11.43	$10.37	$10.24		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-43	$11.39	$11.39	$11.37	$11.38	$12.06	$11.27	$12.17	$11.22	$11.04		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-43	$11.37	$11.37	$11.36	$11.36	$12.04	$11.25	$12.15	$11.21	$11.02		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-44	$11.70	$11.71	$11.70	$11.70	$12.38	$11.58	$12.48	$11.50	$11.35		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-44	$10.94	$10.95	$10.94	$10.94	$11.62	$10.84	$11.73	$10.77	$10.61		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-44	$10.71	$10.72	$10.71	$10.71	$11.39	$10.61	$11.50	$10.54	$10.39		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-44	$10.87	$10.88	$10.89	$10.89	$11.63	$10.78	$11.74	$10.67	$10.55		$30.1	$11.7	$4.8	$0.4	$1.3			
May-44	$11.17	$11.17	$11.18	$11.18	$11.92	$11.06	$12.02	$10.95	$10.83		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-44	$10.99	$10.99	$11.00	$11.00	$11.74	$10.89	$11.85	$10.78	$10.65		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-44	$11.46	$11.47	$11.48	$11.47	$12.21	$11.35	$12.31	$11.24	$11.11		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-44	$10.57	$10.58	$10.59	$10.59	$11.33	$10.48	$11.44	$10.38	$10.25		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-44	$10.35	$10.36	$10.37	$10.37	$11.10	$10.26	$11.22	$10.17	$10.04		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-44	$10.81	$10.82	$10.83	$10.83	$11.56	$10.72	$11.68	$10.61	$10.48		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-44	$11.66	$11.66	$11.65	$11.65	$12.34	$11.54	$12.44	$11.49	$11.31		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-44	$11.64	$11.64	$11.63	$11.63	$12.32	$11.52	$12.42	$11.47	$11.29		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-45	$11.98	$11.99	$11.98	$11.98	$12.66	$11.86	$12.76	$11.78	$11.62		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-45	$11.21	$11.21	$11.21	$11.21	$11.89	$11.10	$11.99	$11.03	$10.87		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-45	$10.97	$10.97	$10.97	$10.97	$11.65	$10.86	$11.76	$10.79	$10.64		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-45	$11.14	$11.14	$11.16	$11.15	$11.89	$11.03	$12.00	$10.92	$10.80		$30.1	$11.7	$4.8	$0.4	$1.3			
May-45	$11.43	$11.44	$11.45	$11.45	$12.19	$11.33	$12.29	$11.21	$11.09		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-45	$11.25	$11.26	$11.27	$11.26	$12.00	$11.15	$12.11	$11.04	$10.91		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-45	$11.74	$11.74	$11.75	$11.75	$12.49	$11.63	$12.59	$11.51	$11.38		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-45	$10.83	$10.84	$10.85	$10.84	$11.58	$10.73	$11.69	$10.63	$10.50		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-45	$10.60	$10.61	$10.62	$10.61	$11.35	$10.51	$11.47	$10.41	$10.28		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-45	$11.07	$11.08	$11.09	$11.09	$11.82	$10.97	$11.93	$10.86	$10.74		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-45	$11.94	$11.95	$11.93	$11.93	$12.62	$11.82	$12.72	$11.76	$11.58		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-45	$11.92	$11.92	$11.91	$11.91	$12.60	$11.80	$12.70	$11.74	$11.56		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-46	$12.27	$12.28	$12.27	$12.27	$12.95	$12.15	$13.04	$12.06	$11.90		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-46	$11.48	$11.48	$11.48	$11.48	$12.15	$11.36	$12.26	$11.29	$11.13		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-46	$11.23	$11.24	$11.23	$11.23	$11.91	$11.12	$12.02	$11.05	$10.89		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-46	$11.40	$11.41	$11.42	$11.42	$12.16	$11.30	$12.26	$11.18	$11.06		$30.1	$11.7	$4.8	$0.4	$1.3			
May-46	$11.71	$11.72	$11.73	$11.72	$12.46	$11.60	$12.56	$11.48	$11.35		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-46	$11.52	$11.53	$11.54	$11.53	$12.27	$11.41	$12.37	$11.30	$11.17		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-46	$12.02	$12.03	$12.04	$12.03	$12.77	$11.90	$12.86	$11.78	$11.65		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-46	$11.09	$11.10	$11.11	$11.10	$11.84	$10.99	$11.95	$10.88	$10.75		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-46	$10.86	$10.86	$10.88	$10.87	$11.61	$10.76	$11.72	$10.65	$10.53		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-46	$11.34	$11.34	$11.36	$11.35	$12.09	$11.23	$12.19	$11.12	$10.99		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-46	$12.23	$12.23	$12.22	$12.22	$12.91	$12.10	$13.00	$12.04	$11.86		$28.4	$11.7	$4.8	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Dec-46	$12.21	$12.21	$12.20	$12.20	$12.88	$12.08	$12.98	$12.02	$11.84		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]		
Jan-47	$12.57	$12.57	$12.57	$12.57	$13.24	$12.44	$13.33	$12.34	$12.18		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-47	$11.75	$11.76	$11.75	$11.75	$12.43	$11.63	$12.53	$11.55	$11.40		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-47	$11.50	$11.51	$11.50	$11.50	$12.18	$11.39	$12.28	$11.31	$11.15		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-47	$11.68	$11.68	$11.70	$11.69	$12.43	$11.57	$12.53	$11.45	$11.32		$30.1	$11.7	$4.8	$0.4	$1.3			
May-47	$11.99	$12.00	$12.01	$12.00	$12.74	$11.88	$12.84	$11.75	$11.63		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-47	$11.80	$11.81	$11.82	$11.81	$12.55	$11.69	$12.65	$11.57	$11.44		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-47	$12.31	$12.31	$12.33	$12.32	$13.06	$12.19	$13.15	$12.06	$11.93		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-47	$11.36	$11.36	$11.37	$11.37	$12.11	$11.25	$12.21	$11.14	$11.01		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-47	$11.12	$11.13	$11.14	$11.13	$11.87	$11.02	$11.98	$10.91	$10.78		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-47	$11.61	$11.61	$11.63	$11.63	$12.36	$11.50	$12.46	$11.39	$11.26		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-47	$12.52	$12.53	$12.51	$12.52	$13.20	$12.39	$13.29	$12.32	$12.14		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-47	$12.50	$12.50	$12.49	$12.49	$13.18	$12.37	$13.27	$12.30	$12.12		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-48	$12.87	$12.87	$12.87	$12.87	$13.55	$12.73	$13.63	$12.64	$12.48		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-48	$12.04	$12.04	$12.03	$12.04	$12.71	$11.91	$12.81	$11.83	$11.67		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-48	$11.78	$11.78	$11.78	$11.78	$12.46	$11.66	$12.56	$11.58	$11.42		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-48	$11.96	$11.96	$11.98	$11.97	$12.71	$11.85	$12.81	$11.72	$11.60		$30.1	$11.7	$4.8	$0.4	$1.3			
May-48	$12.28	$12.29	$12.30	$12.29	$13.03	$12.16	$13.12	$12.03	$11.91		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-48	$12.08	$12.09	$12.10	$12.10	$12.83	$11.97	$12.93	$11.84	$11.71		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-48	$12.60	$12.61	$12.62	$12.62	$13.35	$12.48	$13.44	$12.35	$12.22		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-48	$11.63	$11.64	$11.65	$11.64	$12.38	$11.52	$12.48	$11.40	$11.27		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-48	$11.38	$11.39	$11.40	$11.40	$12.14	$11.28	$12.24	$11.17	$11.04		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-48	$11.89	$11.89	$11.91	$11.90	$12.64	$11.78	$12.74	$11.66	$11.53		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-48	$12.82	$12.83	$12.81	$12.82	$13.50	$12.69	$13.59	$12.61	$12.43		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-48	$12.80	$12.80	$12.79	$12.79	$13.48	$12.67	$13.56	$12.60	$12.41		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-49	$13.18	$13.18	$13.18	$13.18	$13.86	$13.04	$13.94	$12.94	$12.78		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-49	$12.32	$12.33	$12.32	$12.33	$13.00	$12.20	$13.10	$12.11	$11.95		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-49	$12.06	$12.07	$12.06	$12.06	$12.74	$11.94	$12.84	$11.85	$11.70		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-49	$12.25	$12.25	$12.27	$12.26	$13.00	$12.13	$13.09	$12.00	$11.87		$30.1	$11.7	$4.8	$0.4	$1.3			
May-49	$12.58	$12.58	$12.59	$12.59	$13.33	$12.45	$13.41	$12.32	$12.19		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-49	$12.37	$12.38	$12.39	$12.39	$13.12	$12.25	$13.21	$12.12	$12.00		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-49	$12.91	$12.91	$12.92	$12.92	$13.66	$12.78	$13.74	$12.64	$12.51		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-49	$11.91	$11.92	$11.93	$11.92	$12.66	$11.80	$12.76	$11.67	$11.55		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-49	$11.66	$11.67	$11.68	$11.67	$12.41	$11.55	$12.51	$11.43	$11.30		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-49	$12.17	$12.18	$12.20	$12.19	$12.93	$12.06	$13.02	$11.93	$11.81		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-49	$13.13	$13.14	$13.12	$13.13	$13.81	$12.99	$13.89	$12.91	$12.73		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-49	$13.11	$13.11	$13.10	$13.10	$13.79	$12.97	$13.87	$12.89	$12.71		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-50	$13.49	$13.50	$13.49	$13.50	$14.17	$13.35	$14.25	$13.24	$13.08		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-50	$12.62	$12.63	$12.62	$12.62	$13.30	$12.49	$13.39	$12.40	$12.24		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-50	$12.35	$12.36	$12.35	$12.35	$13.03	$12.23	$13.12	$12.13	$11.98		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-50	$12.54	$12.55	$12.56	$12.56	$13.29	$12.42	$13.38	$12.29	$12.16		$30.1	$11.7	$4.8	$0.4	$1.3			
May-50	$12.88	$12.89	$12.90	$12.89	$13.63	$12.75	$13.71	$12.61	$12.48		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-50	$12.67	$12.68	$12.69	$12.68	$13.42	$12.55	$13.51	$12.41	$12.28		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-50	$13.22	$13.22	$13.23	$13.23	$13.97	$13.09	$14.05	$12.94	$12.81		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-50	$12.19	$12.20	$12.21	$12.21	$12.95	$12.08	$13.04	$11.95	$11.82		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-50	$11.94	$11.95	$11.96	$11.95	$12.69	$11.83	$12.79	$11.70	$11.58		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-50	$12.47	$12.47	$12.49	$12.48	$13.22	$12.35	$13.31	$12.22	$12.09		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-50	$13.45	$13.45	$13.44	$13.44	$14.13	$13.30	$14.20	$13.22	$13.04		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-50	$13.42	$13.43	$13.41	$13.42	$14.10	$13.28	$14.18	$13.20	$13.01		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-51	$13.82	$13.82	$13.82	$13.82	$14.50	$13.67	$14.57	$13.56	$13.40		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-51	$12.93	$12.93	$12.92	$12.93	$13.60	$12.79	$13.69	$12.69	$12.53		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-51	$12.65	$12.65	$12.65	$12.65	$13.33	$12.52	$13.42	$12.42	$12.27		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-51	$12.84	$12.85	$12.86	$12.86	$13.60	$12.72	$13.68	$12.58	$12.45		$30.1	$11.7	$4.8	$0.4	$1.3			
May-51	$13.19	$13.20	$13.21	$13.20	$13.94	$13.06	$14.02	$12.91	$12.78		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-51	$12.98	$12.98	$12.99	$12.99	$13.73	$12.85	$13.81	$12.71	$12.58		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-51	$13.53	$13.54	$13.55	$13.55	$14.29	$13.40	$14.36	$13.25	$13.12		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-51	$12.49	$12.50	$12.51	$12.50	$13.24	$12.37	$13.33	$12.24	$12.11		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-51	$12.23	$12.23	$12.25	$12.24	$12.98	$12.11	$13.07	$11.98	$11.85		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-51	$12.77	$12.77	$12.79	$12.78	$13.52	$12.65	$13.61	$12.51	$12.38		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-51	$13.77	$13.78	$13.76	$13.77	$14.45	$13.62	$14.52	$13.53	$13.35		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-51	$13.75	$13.75	$13.74	$13.74	$14.42	$13.60	$14.50	$13.51	$13.33		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-52	$14.15	$14.16	$14.15	$14.15	$14.83	$14.00	$14.90	$13.88	$13.72		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-52	$13.24	$13.24	$13.24	$13.24	$13.91	$13.10	$13.99	$12.99	$12.83		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-52	$12.95	$12.96	$12.95	$12.95	$13.63	$12.82	$13.72	$12.72	$12.56		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-52	$13.15	$13.16	$13.17	$13.17	$13.90	$13.02	$13.98	$12.88	$12.75		$30.1	$11.7	$4.8	$0.4	$1.3			
May-52	$13.50	$13.51	$13.52	$13.52	$14.26	$13.37	$14.33	$13.22	$13.09		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-52	$13.29	$13.30	$13.31	$13.30	$14.04	$13.16	$14.12	$13.01	$12.88		$29.7	$11.7	$4.8	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Jul-52	$13.86	$13.87	$13.88	$13.87	$14.61	$13.72	$14.68	$13.56	$13.43		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-52	$12.79	$12.80	$12.81	$12.80	$13.54	$12.66	$13.62	$12.53	$12.40		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-52	$12.52	$12.53	$12.54	$12.53	$13.27	$12.40	$13.36	$12.27	$12.14		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-52	$13.07	$13.08	$13.10	$13.09	$13.83	$12.95	$13.91	$12.81	$12.68		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-52	$14.10	$14.11	$14.09	$14.10	$14.78	$13.95	$14.85	$13.85	$13.67		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-52	$14.08	$14.08	$14.07	$14.07	$14.75	$13.92	$14.82	$13.83	$13.65		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-53	$14.49	$14.50	$14.49	$14.49	$15.17	$14.34	$15.23	$14.21	$14.05		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-53	$13.55	$13.56	$13.55	$13.56	$14.23	$13.41	$14.31	$13.30	$13.14		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-53	$13.27	$13.27	$13.26	$13.27	$13.94	$13.13	$14.02	$13.02	$12.86		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-53	$13.47	$13.47	$13.49	$13.48	$14.22	$13.33	$14.30	$13.18	$13.06		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-53	$13.83	$13.84	$13.85	$13.84	$14.58	$13.69	$14.65	$13.53	$13.41		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-53	$13.61	$13.61	$13.63	$13.62	$14.36	$13.47	$14.43	$13.32	$13.19		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-53	$14.19	$14.20	$14.21	$14.21	$14.94	$14.05	$15.01	$13.89	$13.76		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-53	$13.10	$13.10	$13.12	$13.11	$13.85	$12.97	$13.93	$12.82	$12.70		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-53	$12.82	$12.83	$12.84	$12.84	$13.57	$12.70	$13.66	$12.56	$12.43		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-53	$13.39	$13.39	$13.41	$13.41	$14.14	$13.26	$14.22	$13.11	$12.98		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-53	$14.44	$14.45	$14.43	$14.44	$15.12	$14.28	$15.18	$14.18	$14.00		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-53	$14.42	$14.42	$14.41	$14.41	$15.09	$14.26	$15.16	$14.16	$13.97		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-54	$14.84	$14.85	$14.84	$14.84	$15.52	$14.68	$15.58	$14.55	$14.39		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-54	$13.88	$13.89	$13.88	$13.88	$14.56	$13.73	$14.63	$13.62	$13.46		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-54	$13.58	$13.59	$13.58	$13.59	$14.26	$13.44	$14.34	$13.33	$13.17		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-54	$13.79	$13.80	$13.81	$13.81	$14.54	$13.65	$14.62	$13.50	$13.37		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-54	$14.16	$14.17	$14.18	$14.18	$14.91	$14.02	$14.98	$13.86	$13.73		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-54	$13.93	$13.94	$13.95	$13.95	$14.69	$13.79	$14.75	$13.64	$13.51		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-54	$14.53	$14.54	$14.55	$14.55	$15.29	$14.39	$15.35	$14.22	$14.09		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-54	$13.41	$13.42	$13.43	$13.42	$14.16	$13.28	$14.24	$13.13	$13.00		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-54	$13.13	$13.14	$13.15	$13.14	$13.88	$13.00	$13.96	$12.86	$12.73		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-54	$13.71	$13.72	$13.73	$13.73	$14.46	$13.58	$14.54	$13.42	$13.29		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-54	$14.79	$14.79	$14.78	$14.78	$15.47	$14.63	$15.53	$14.52	$14.34		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-54	$14.76	$14.77	$14.75	$14.76	$15.44	$14.60	$15.50	$14.50	$14.31		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-55	$15.20	$15.20	$15.20	$15.20	$15.88	$15.03	$15.93	$14.89	$14.73		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-55	$14.21	$14.22	$14.21	$14.22	$14.89	$14.06	$14.96	$13.94	$13.78		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-55	$13.91	$13.92	$13.91	$13.91	$14.59	$13.76	$14.66	$13.64	$13.49		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-55	$14.12	$14.13	$14.14	$14.14	$14.88	$13.98	$14.94	$13.82	$13.69		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-55	$14.50	$14.51	$14.52	$14.52	$15.25	$14.35	$15.31	$14.19	$14.06		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-55	$14.27	$14.28	$14.29	$14.28	$15.02	$14.12	$15.08	$13.96	$13.83		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-55	$14.88	$14.89	$14.90	$14.90	$15.63	$14.73	$15.69	$14.56	$14.43		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-55	$13.73	$13.74	$13.75	$13.75	$14.48	$13.60	$14.56	$13.44	$13.31		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-55	$13.45	$13.45	$13.46	$13.46	$14.20	$13.31	$14.27	$13.16	$13.03		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-55	$14.04	$14.05	$14.06	$14.06	$14.79	$13.90	$14.86	$13.74	$13.61		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-55	$15.14	$15.15	$15.13	$15.14	$15.82	$14.98	$15.88	$14.86	$14.68		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-55	$15.12	$15.12	$15.11	$15.11	$15.80	$14.95	$15.85	$14.84	$14.65		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-56	$15.56	$15.57	$15.56	$15.56	$16.24	$15.39	$16.29	$15.25	$15.09		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-56	$14.56	$14.56	$14.56	$14.56	$15.23	$14.40	$15.30	$14.27	$14.11		$27.4	$11.3	$4.6	$0.3	$1.2	[redacted]	[redacted]	
Mar-56	$14.25	$14.25	$14.24	$14.25	$14.92	$14.09	$14.99	$13.97	$13.81		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-56	$14.46	$14.47	$14.48	$14.48	$15.22	$14.32	$15.28	$14.15	$14.02		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-56	$14.85	$14.86	$14.87	$14.86	$15.60	$14.70	$15.66	$14.52	$14.40		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-56	$14.61	$14.62	$14.63	$14.63	$15.36	$14.46	$15.42	$14.29	$14.16		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-56	$15.24	$15.25	$15.26	$15.26	$15.99	$15.08	$16.04	$14.90	$14.77		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-56	$14.06	$14.07	$14.08	$14.08	$14.82	$13.92	$14.88	$13.76	$13.63		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-56	$13.77	$13.78	$13.79	$13.78	$14.52	$13.63	$14.59	$13.48	$13.35		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-56	$14.38	$14.38	$14.40	$14.40	$15.13	$14.23	$15.19	$14.07	$13.94		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-56	$15.51	$15.51	$15.50	$15.50	$16.19	$15.34	$16.24	$15.22	$15.03		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-56	$15.48	$15.49	$15.47	$15.48	$16.16	$15.31	$16.21	$15.19	$15.01		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-57	$15.94	$15.94	$15.94	$15.94	$16.62	$15.76	$16.66	$15.61	$15.45		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-57	$14.91	$14.91	$14.91	$14.91	$15.58	$14.74	$15.64	$14.61	$14.45		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-57	$14.59	$14.59	$14.59	$14.59	$15.27	$14.43	$15.33	$14.30	$14.14		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-57	$14.81	$14.82	$14.83	$14.83	$15.56	$14.66	$15.62	$14.49	$14.36		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-57	$15.21	$15.22	$15.23	$15.22	$15.96	$15.05	$16.01	$14.87	$14.74		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-57	$14.96	$14.97	$14.98	$14.98	$15.71	$14.81	$15.77	$14.63	$14.50		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-57	$15.61	$15.62	$15.63	$15.62	$16.36	$15.44	$16.40	$15.26	$15.13		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-57	$14.40	$14.41	$14.42	$14.42	$15.15	$14.26	$15.22	$14.09	$13.96		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-57	$14.10	$14.11	$14.12	$14.11	$14.85	$13.96	$14.92	$13.80	$13.67		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-57	$14.73	$14.73	$14.75	$14.74	$15.48	$14.58	$15.54	$14.40	$14.27		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-57	$15.88	$15.89	$15.87	$15.88	$16.56	$15.70	$16.60	$15.58	$15.40		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-57	$15.85	$15.86	$15.84	$15.85	$16.53	$15.68	$16.57	$15.55	$15.37		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-58	$16.32	$16.33	$16.32	$16.32	$17.00	$16.14	$17.04	$15.98	$15.82		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Feb-58	$15.26	$15.27	$15.26	**$15.27**	$15.94	$15.10	$15.99	$14.96	$14.80		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]		
Mar-58	$14.94	$14.94	$14.94	**$14.94**	$15.62	$14.78	$15.67	$14.64	$14.48		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-58	$15.17	$15.17	$15.19	**$15.18**	$15.92	$15.01	$15.97	$14.83	$14.70		$30.1	$11.7	$4.8	$0.4	$1.3			
May-58	$15.57	$15.58	$15.59	**$15.59**	$16.33	$15.41	$16.37	$15.22	$15.10		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-58	$15.32	$15.33	$15.34	**$15.34**	$16.07	$15.16	$16.12	$14.98	$14.85		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-58	$15.98	$15.99	$16.00	**$16.00**	$16.73	$15.81	$16.78	$15.62	$15.49		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-58	$14.75	$14.76	$14.77	**$14.76**	$15.50	$14.60	$15.56	$14.43	$14.30		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-58	$14.44	$14.45	$14.46	**$14.45**	$15.19	$14.29	$15.25	$14.13	$14.00		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-58	$15.08	$15.08	$15.10	**$15.10**	$15.83	$14.92	$15.89	$14.75	$14.62		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-58	$16.26	$16.27	$16.25	**$16.26**	$16.94	$16.08	$16.98	$15.95	$15.77		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-58	$16.23	$16.24	$16.22	**$16.23**	$16.91	$16.05	$16.95	$15.92	$15.74		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-59	$16.71	$16.72	$16.71	**$16.71**	$17.39	$16.53	$17.42	$16.36	$16.20		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-59	$15.63	$15.64	$15.63	**$15.63**	$16.31	$15.46	$16.36	$15.31	$15.15		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-59	$15.30	$15.30	$15.30	**$15.30**	$15.98	$15.13	$16.03	$14.99	$14.83		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-59	$15.53	$15.54	$15.55	**$15.55**	$16.28	$15.37	$16.33	$15.18	$15.06		$30.1	$11.7	$4.8	$0.4	$1.3			
May-59	$15.95	$15.96	$15.97	**$15.96**	$16.70	$15.78	$16.74	$15.59	$15.46		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-59	$15.69	$15.70	$15.71	**$15.71**	$16.44	$15.53	$16.49	$15.34	$15.21		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-59	$16.37	$16.38	$16.39	**$16.38**	$17.12	$16.19	$17.15	$15.99	$15.86		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-59	$15.10	$15.11	$15.12	**$15.12**	$15.85	$14.95	$15.91	$14.77	$14.64		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-59	$14.79	$14.79	$14.81	**$14.80**	$15.54	$14.63	$15.59	$14.46	$14.33		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-59	$15.44	$15.45	$15.46	**$15.46**	$16.19	$15.28	$16.24	$15.10	$14.97		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-59	$16.66	$16.66	$16.64	**$16.65**	$17.33	$16.47	$17.37	$16.33	$16.14		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-59	$16.62	$16.63	$16.61	**$16.62**	$17.30	$16.44	$17.34	$16.30	$16.11		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-60	$17.12	$17.12	$17.12	**$17.12**	$17.79	$16.92	$17.82	$16.75	$16.59		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-60	$16.01	$16.01	$16.01	**$16.01**	$16.69	$15.83	$16.73	$15.68	$15.52		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-60	$15.67	$15.67	$15.67	**$15.67**	$16.35	$15.49	$16.39	$15.34	$15.19		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-60	$15.91	$15.91	$15.93	**$15.92**	$16.66	$15.74	$16.70	$15.55	$15.42		$30.1	$11.7	$4.8	$0.4	$1.3			
May-60	$16.33	$16.34	$16.35	**$16.35**	$17.08	$16.16	$17.12	$15.96	$15.83		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-60	$16.07	$16.08	$16.09	**$16.08**	$16.82	$15.90	$16.86	$15.70	$15.57		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-60	$16.76	$16.77	$16.78	**$16.78**	$17.51	$16.58	$17.54	$16.38	$16.24		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-60	$15.47	$15.47	$15.49	**$15.48**	$16.22	$15.30	$16.27	$15.12	$14.99		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-60	$15.14	$15.15	$15.16	**$15.16**	$15.89	$14.98	$15.95	$14.81	$14.68		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-60	$15.81	$15.82	$15.84	**$15.83**	$16.57	$15.65	$16.61	$15.46	$15.33		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-60	$17.06	$17.06	$17.04	**$17.05**	$17.73	$16.86	$17.76	$16.71	$16.53		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-60	$17.02	$17.03	$17.01	**$17.02**	$17.70	$16.83	$17.73	$16.69	$16.50		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-61	$17.53	$17.53	$17.53	**$17.53**	$18.21	$17.33	$18.23	$17.15	$16.99		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-61	$16.39	$16.40	$16.39	**$16.39**	$17.07	$16.21	$17.11	$16.05	$15.89		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-61	$16.04	$16.05	$16.04	**$16.04**	$16.72	$15.87	$16.76	$15.71	$15.55		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-61	$16.29	$16.29	$16.31	**$16.30**	$17.04	$16.12	$17.08	$15.92	$15.79		$30.1	$11.7	$4.8	$0.4	$1.3			
May-61	$16.73	$16.73	$16.74	**$16.74**	$17.48	$16.54	$17.51	$16.34	$16.21		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-61	$16.46	$16.46	$16.47	**$16.47**	$17.21	$16.28	$17.24	$16.08	$15.95		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-61	$17.16	$17.17	$17.18	**$17.18**	$17.92	$16.98	$17.94	$16.77	$16.64		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-61	$15.84	$15.85	$15.86	**$15.85**	$16.59	$15.67	$16.63	$15.48	$15.35		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-61	$15.51	$15.51	$15.53	**$15.52**	$16.26	$15.34	$16.30	$15.16	$15.03		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-61	$16.19	$16.20	$16.22	**$16.21**	$16.95	$16.02	$16.98	$15.83	$15.70		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-61	$17.47	$17.47	$17.45	**$17.46**	$18.14	$17.26	$18.16	$17.11	$16.93		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-61	$17.43	$17.44	$17.42	**$17.43**	$18.11	$17.23	$18.13	$17.09	$16.90		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-62	$17.95	$17.95	$17.95	**$17.95**	$18.63	$17.74	$18.64	$17.56	$17.40		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-62	$16.79	$16.79	$16.79	**$16.79**	$17.47	$16.60	$17.50	$16.43	$16.27		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-62	$16.43	$16.43	$16.43	**$16.43**	$17.11	$16.25	$17.14	$16.08	$15.93		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-62	$16.68	$16.68	$16.70	**$16.70**	$17.43	$16.50	$17.46	$16.30	$16.17		$30.1	$11.7	$4.8	$0.4	$1.3			
May-62	$17.13	$17.14	$17.15	**$17.14**	$17.88	$16.94	$17.90	$16.73	$16.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-62	$16.85	$16.86	$16.87	**$16.87**	$17.60	$16.67	$17.63	$16.46	$16.33		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-62	$17.58	$17.59	$17.60	**$17.59**	$18.33	$17.39	$18.35	$17.17	$17.03		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-62	$16.22	$16.23	$16.24	**$16.23**	$16.97	$16.05	$17.01	$15.85	$15.72		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-62	$15.88	$15.89	$15.90	**$15.89**	$16.63	$15.71	$16.67	$15.52	$15.39		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-62	$16.58	$16.59	$16.61	**$16.60**	$17.34	$16.41	$17.37	$16.20	$16.07		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-62	$17.89	$17.89	$17.87	**$17.88**	$18.56	$17.68	$18.58	$17.52	$17.34		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-62	$17.85	$17.86	$17.84	**$17.85**	$18.53	$17.65	$18.55	$17.49	$17.30		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-63	$18.38	$18.39	$18.38	**$18.38**	$19.06	$18.17	$19.07	$17.98	$17.81		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-63	$17.19	$17.20	$17.19	**$17.19**	$17.87	$17.00	$17.89	$16.82	$16.66		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-63	$16.82	$16.83	$16.82	**$16.83**	$17.50	$16.64	$17.53	$16.47	$16.31		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-63	$17.08	$17.09	$17.10	**$17.10**	$17.83	$16.90	$17.86	$16.69	$16.56		$30.1	$11.7	$4.8	$0.4	$1.3			
May-63	$17.54	$17.55	$17.56	**$17.55**	$18.29	$17.35	$18.31	$17.13	$17.00		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-63	$17.26	$17.26	$17.28	**$17.27**	$18.01	$17.07	$18.03	$16.85	$16.72		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-63	$18.00	$18.01	$18.02	**$18.01**	$18.75	$17.80	$18.76	$17.58	$17.44		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-63	$16.61	$16.62	$16.63	**$16.62**	$17.36	$16.43	$17.39	$16.23	$16.10		$30.7	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Sep-63	$16.26	$16.27	$16.28	$16.27	$17.01	$16.09	$17.05	$15.89	$15.76		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]		
Oct-63	$16.98	$16.99	$17.00	$17.00	$17.73	$16.80	$17.76	$16.59	$16.46		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-63	$18.32	$18.32	$18.30	$18.31	$18.99	$18.10	$19.00	$17.94	$17.75		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-63	$18.28	$18.29	$18.27	$18.28	$18.96	$18.07	$18.97	$17.91	$17.72		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-64	$18.82	$18.83	$18.82	$18.82	$19.50	$18.61	$19.50	$18.40	$18.24		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-64	$17.60	$17.61	$17.60	$17.61	$18.28	$17.41	$18.30	$17.22	$17.06		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-64	$17.23	$17.23	$17.23	$17.23	$17.91	$17.03	$17.93	$16.86	$16.70		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-64	$17.49	$17.50	$17.51	$17.51	$18.24	$17.30	$18.26	$17.08	$16.95		$30.1	$11.7	$4.8	$0.4	$1.3			
May-64	$17.96	$17.97	$17.98	$17.97	$18.71	$17.76	$18.72	$17.54	$17.41		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-64	$17.67	$17.68	$17.69	$17.69	$18.42	$17.48	$18.44	$17.26	$17.13		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-64	$18.43	$18.44	$18.45	$18.45	$19.18	$18.23	$19.19	$17.99	$17.86		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-64	$17.01	$17.02	$17.03	$17.02	$17.76	$16.83	$17.79	$16.62	$16.48		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-64	$16.65	$16.66	$16.67	$16.67	$17.40	$16.47	$17.43	$16.27	$16.14		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-64	$17.39	$17.40	$17.41	$17.41	$18.14	$17.20	$18.16	$16.99	$16.86		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-64	$18.76	$18.76	$18.74	$18.75	$19.43	$18.54	$19.44	$18.36	$18.18		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-64	$18.72	$18.73	$18.71	$18.72	$19.40	$18.51	$19.40	$18.33	$18.15		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-65	$19.28	$19.28	$19.27	$19.28	$19.95	$19.05	$19.95	$18.84	$18.68		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-65	$18.03	$18.03	$18.03	$18.03	$18.71	$17.82	$18.72	$17.63	$17.47		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-65	$17.64	$17.65	$17.64	$17.64	$18.32	$17.44	$18.34	$17.26	$17.10		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-65	$17.91	$17.92	$17.93	$17.93	$18.67	$17.72	$18.68	$17.49	$17.36		$30.1	$11.7	$4.8	$0.4	$1.3			
May-65	$18.39	$18.40	$18.41	$18.41	$19.14	$18.19	$19.15	$17.95	$17.82		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-65	$18.10	$18.10	$18.12	$18.11	$18.85	$17.90	$18.86	$17.67	$17.54		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-65	$18.88	$18.88	$18.89	$18.89	$19.63	$18.67	$19.63	$18.42	$18.29		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-65	$17.42	$17.43	$17.44	$17.43	$18.17	$17.23	$18.19	$17.01	$16.88		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-65	$17.05	$17.06	$17.07	$17.07	$17.80	$16.87	$17.83	$16.66	$16.53		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-65	$17.81	$17.81	$17.83	$17.82	$18.56	$17.62	$18.58	$17.39	$17.26		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-65	$19.21	$19.21	$19.20	$19.20	$19.89	$18.98	$19.88	$18.80	$18.62		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-65	$19.17	$19.18	$19.16	$19.17	$19.85	$18.95	$19.85	$18.77	$18.58		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-66	$19.74	$19.74	$19.74	$19.74	$20.42	$19.51	$20.41	$19.29	$19.13		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-66	$18.46	$18.47	$18.46	$18.46	$19.14	$18.25	$19.15	$18.05	$17.89		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-66	$18.07	$18.07	$18.07	$18.07	$18.75	$17.86	$18.76	$17.67	$17.51		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-66	$18.34	$18.35	$18.36	$18.36	$19.10	$18.14	$19.10	$17.91	$17.78		$30.1	$11.7	$4.8	$0.4	$1.3			
May-66	$18.83	$18.84	$18.85	$18.85	$19.59	$18.63	$19.59	$18.38	$18.25		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-66	$18.53	$18.54	$18.55	$18.55	$19.28	$18.33	$19.29	$18.09	$17.96		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-66	$19.33	$19.34	$19.35	$19.34	$20.08	$19.11	$20.07	$18.86	$18.73		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-66	$17.84	$17.84	$17.86	$17.85	$18.59	$17.64	$18.60	$17.42	$17.29		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-66	$17.46	$17.47	$17.48	$17.48	$18.21	$17.27	$18.23	$17.05	$16.92		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-66	$18.24	$18.24	$18.26	$18.25	$18.99	$18.04	$19.00	$17.81	$17.68		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-66	$19.67	$19.67	$19.66	$19.66	$20.35	$19.44	$20.34	$19.25	$19.06		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-66	$19.63	$19.64	$19.62	$19.63	$20.31	$19.40	$20.30	$19.22	$19.03		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-67	$20.21	$20.22	$20.21	$20.21	$20.89	$19.98	$20.87	$19.75	$19.59		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-67	$18.91	$18.91	$18.90	$18.91	$19.58	$18.69	$19.58	$18.48	$18.32		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-67	$18.50	$18.51	$18.50	$18.50	$19.18	$18.29	$19.19	$18.09	$17.93		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-67	$18.78	$18.79	$18.81	$18.80	$19.54	$18.58	$19.54	$18.34	$18.21		$30.1	$11.7	$4.8	$0.4	$1.3			
May-67	$19.29	$19.30	$19.31	$19.30	$20.04	$19.07	$20.03	$18.82	$18.69		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-67	$18.98	$18.99	$19.00	$18.99	$19.73	$18.77	$19.73	$18.52	$18.39		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-67	$19.79	$19.80	$19.81	$19.81	$20.55	$19.57	$20.53	$19.31	$19.18		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-67	$18.27	$18.27	$18.28	$18.28	$19.02	$18.06	$19.03	$17.83	$17.70		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-67	$17.88	$17.89	$17.90	$17.90	$18.63	$17.69	$18.65	$17.46	$17.33		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-67	$18.68	$18.68	$18.70	$18.69	$19.43	$18.47	$19.43	$18.23	$18.10		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-67	$20.14	$20.15	$20.13	$20.14	$20.82	$19.90	$20.80	$19.70	$19.52		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-67	$20.11	$20.11	$20.10	$20.10	$20.78	$19.87	$20.77	$19.67	$19.49		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-68	$20.70	$20.70	$20.70	$20.70	$21.38	$20.46	$21.35	$20.22	$20.06		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-68	$19.36	$19.37	$19.36	$19.36	$20.04	$19.14	$20.03	$18.92	$18.76		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-68	$18.95	$18.95	$18.95	$18.95	$19.63	$18.73	$19.63	$18.52	$18.36		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-68	$19.24	$19.24	$19.26	$19.25	$19.99	$19.02	$19.98	$18.77	$18.64		$30.1	$11.7	$4.8	$0.4	$1.3			
May-68	$19.75	$19.76	$19.77	$19.76	$20.50	$19.53	$20.49	$19.27	$19.14		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-68	$19.43	$19.44	$19.45	$19.45	$20.18	$19.22	$20.18	$18.96	$18.83		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-68	$20.27	$20.28	$20.29	$20.28	$21.02	$20.04	$21.00	$19.78	$19.64		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-68	$18.70	$18.71	$18.72	$18.72	$19.46	$18.50	$19.46	$18.26	$18.13		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-68	$18.31	$18.32	$18.33	$18.33	$19.06	$18.11	$19.07	$17.88	$17.75		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-68	$19.12	$19.13	$19.15	$19.14	$19.88	$18.91	$19.87	$18.67	$18.53		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-68	$20.63	$20.63	$20.62	$20.62	$21.31	$20.38	$21.28	$20.17	$19.99		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-68	$20.59	$20.59	$20.58	$20.58	$21.27	$20.35	$21.24	$20.14	$19.95		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-69	$21.20	$21.20	$21.20	$21.20	$21.88	$20.95	$21.84	$20.70	$20.54		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-69	$19.83	$19.83	$19.83	$19.83	$20.50	$19.60	$20.49	$19.38	$19.21		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-69	$19.40	$19.41	$19.40	$19.40	$20.08	$19.18	$20.08	$18.96	$18.80		$29.3	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Apr-69	$19.70	$19.70	$19.72	**$19.71**	$20.45	$19.48	$20.44	$19.22	$19.09		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]		
May-69	$20.23	$20.23	$20.24	**$20.24**	$20.98	$20.00	$20.96	$19.73	$19.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-69	$19.90	$19.91	$19.92	**$19.91**	$20.65	$19.68	$20.64	$19.42	$19.28		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-69	$20.76	$20.77	$20.78	**$20.77**	$21.51	$20.52	$21.48	$20.25	$20.11		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-69	$19.15	$19.16	$19.17	**$19.17**	$19.91	$18.94	$19.90	$18.69	$18.56		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-69	$18.75	$18.76	$18.77	**$18.77**	$19.50	$18.55	$19.51	$18.30	$18.17		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-69	$19.58	$19.59	$19.61	**$19.60**	$20.34	$19.37	$20.33	$19.11	$18.98		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-69	$21.12	$21.13	$21.11	**$21.12**	$21.80	$20.87	$21.77	$20.65	$20.47		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-69	$21.08	$21.09	$21.07	**$21.08**	$21.76	$20.83	$21.73	$20.62	$20.43		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-70	$21.71	$21.71	$21.71	**$21.71**	$22.39	$21.45	$22.35	$21.20	$21.04		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-70	$20.30	$20.31	$20.30	**$20.30**	$20.98	$20.07	$20.96	$19.84	$19.68		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-70	$19.87	$19.87	$19.87	**$19.87**	$20.55	$19.64	$20.54	$19.42	$19.26		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-70	$20.17	$20.18	$20.19	**$20.19**	$20.93	$19.95	$20.91	$19.68	$19.55		$30.1	$11.7	$4.8	$0.4	$1.3			
May-70	$20.71	$20.72	$20.73	**$20.73**	$21.46	$20.48	$21.44	$20.20	$20.07		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-70	$20.38	$20.39	$20.40	**$20.39**	$21.13	$20.15	$21.11	$19.88	$19.75		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-70	$21.26	$21.27	$21.28	**$21.27**	$22.01	$21.01	$21.97	$20.73	$20.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-70	$19.62	$19.62	$19.63	**$19.63**	$20.37	$19.40	$20.36	$19.14	$19.01		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-70	$19.20	$19.21	$19.22	**$19.22**	$19.96	$18.99	$19.95	$18.74	$18.61		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-70	$20.06	$20.06	$20.08	**$20.07**	$20.81	$19.83	$20.79	$19.57	$19.44		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-70	$21.63	$21.64	$21.62	**$21.62**	$22.31	$21.37	$22.27	$21.15	$20.96		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-70	$21.59	$21.60	$21.58	**$21.59**	$22.27	$21.33	$22.23	$21.11	$20.92		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-71	$22.23	$22.23	$22.23	**$22.23**	$22.91	$21.96	$22.86	$21.70	$21.54		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-71	$20.79	$20.80	$20.79	**$20.79**	$21.47	$20.55	$21.44	$20.31	$20.15		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-71	$20.35	$20.35	$20.35	**$20.35**	$21.03	$20.11	$21.01	$19.88	$19.72		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-71	$20.66	$20.66	$20.68	**$20.67**	$21.41	$20.42	$21.39	$20.15	$20.02		$30.1	$11.7	$4.8	$0.4	$1.3			
May-71	$21.21	$21.22	$21.23	**$21.22**	$21.96	$20.97	$21.93	$20.68	$20.55		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-71	$20.87	$20.88	$20.89	**$20.88**	$21.62	$20.63	$21.59	$20.35	$20.22		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-71	$21.77	$21.78	$21.79	**$21.78**	$22.52	$21.52	$22.48	$21.23	$21.09		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-71	$20.09	$20.09	$20.11	**$20.10**	$20.84	$19.86	$20.82	$19.60	$19.46		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-71	$19.67	$19.67	$19.68	**$19.68**	$20.42	$19.45	$20.41	$19.19	$19.06		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-71	$20.54	$20.54	$20.56	**$20.55**	$21.29	$20.31	$21.27	$20.04	$19.90		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-71	$22.15	$22.16	$22.14	**$22.14**	$22.83	$21.88	$22.78	$21.65	$21.47		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-71	$22.11	$22.12	$22.10	**$22.11**	$22.79	$21.85	$22.74	$21.62	$21.43		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-72	$22.76	$22.77	$22.76	**$22.76**	$23.44	$22.49	$23.39	$22.22	$22.06		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-72	$21.29	$21.30	$21.29	**$21.29**	$21.97	$21.04	$21.94	$20.79	$20.63		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-72	$20.84	$20.84	$20.84	**$20.84**	$21.52	$20.59	$21.49	$20.35	$20.19		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-72	$21.15	$21.16	$21.18	**$21.17**	$21.91	$20.91	$21.88	$20.63	$20.50		$30.1	$11.7	$4.8	$0.4	$1.3			
May-72	$21.72	$21.73	$21.74	**$21.73**	$22.47	$21.47	$22.43	$21.18	$21.05		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-72	$21.37	$21.38	$21.39	**$21.38**	$22.12	$21.13	$22.09	$20.84	$20.71		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-72	$22.29	$22.30	$22.31	**$22.31**	$23.04	$22.03	$22.99	$21.73	$21.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-72	$20.57	$20.58	$20.59	**$20.58**	$21.32	$20.34	$21.30	$20.07	$19.93		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-72	$20.14	$20.15	$20.16	**$20.15**	$20.89	$19.91	$20.87	$19.65	$19.51		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-72	$21.03	$21.04	$21.05	**$21.05**	$21.78	$20.79	$21.75	$20.51	$20.38		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-72	$22.68	$22.69	$22.67	**$22.68**	$23.36	$22.41	$23.31	$22.17	$21.98		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-72	$22.64	$22.65	$22.63	**$22.64**	$23.32	$22.37	$23.27	$22.13	$21.94		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-73	$23.31	$23.32	$23.31	**$23.31**	$23.99	$23.03	$23.93	$22.75	$22.59		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-73	$21.80	$21.81	$21.80	**$21.80**	$22.48	$21.54	$22.44	$21.29	$21.13		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-73	$21.34	$21.34	$21.34	**$21.34**	$22.02	$21.09	$21.98	$20.84	$20.68		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-73	$21.66	$21.67	$21.68	**$21.68**	$22.42	$21.42	$22.38	$21.12	$20.99		$30.1	$11.7	$4.8	$0.4	$1.3			
May-73	$22.24	$22.25	$22.26	**$22.26**	$22.99	$21.99	$22.95	$21.68	$21.55		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-73	$21.89	$21.89	$21.90	**$21.90**	$22.64	$21.63	$22.59	$21.34	$21.21		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-73	$22.83	$22.84	$22.85	**$22.84**	$23.58	$22.56	$23.52	$22.25	$22.12		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-73	$21.06	$21.07	$21.08	**$21.08**	$21.82	$20.82	$21.78	$20.54	$20.41		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-73	$20.62	$20.63	$20.64	**$20.64**	$21.37	$20.39	$21.35	$20.12	$19.98		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-73	$21.54	$21.54	$21.56	**$21.55**	$22.29	$21.29	$22.25	$21.00	$20.87		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-73	$23.23	$23.23	$23.22	**$23.22**	$23.91	$22.95	$23.85	$22.69	$22.51		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-73	$23.19	$23.19	$23.18	**$23.18**	$23.86	$22.91	$23.81	$22.66	$22.47		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-74	$23.87	$23.88	$23.87	**$23.87**	$24.55	$23.58	$24.48	$23.29	$23.13		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-74	$22.33	$22.33	$22.33	**$22.33**	$23.01	$22.06	$22.96	$21.80	$21.64		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-74	$21.85	$21.86	$21.85	**$21.85**	$22.53	$21.59	$22.49	$21.34	$21.18		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-74	$22.18	$22.19	$22.21	**$22.20**	$22.94	$21.93	$22.89	$21.63	$21.50		$30.1	$11.7	$4.8	$0.4	$1.3			
May-74	$22.78	$22.79	$22.80	**$22.79**	$23.53	$22.51	$23.47	$22.20	$22.07		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-74	$22.41	$22.42	$22.43	**$22.42**	$23.16	$22.15	$23.11	$21.85	$21.72		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-74	$23.38	$23.38	$23.40	**$23.39**	$24.13	$23.10	$24.06	$22.78	$22.65		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-74	$21.57	$21.58	$21.59	**$21.58**	$22.32	$21.32	$22.28	$21.03	$20.90		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-74	$21.12	$21.13	$21.14	**$21.13**	$21.87	$20.88	$21.84	$20.60	$20.46		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-74	$22.06	$22.06	$22.08	**$22.07**	$22.81	$21.80	$22.76	$21.51	$21.37		$31.1	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACE MENT SUNK DEMAND CHARGE MM$
Nov-74	$23.79	$23.79	$23.78	**$23.78**	$24.47	$23.50	$24.40	$23.24	$23.05		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]		
Dec-74	$23.74	$23.75	$23.73	**$23.74**	$24.42	$23.46	$24.36	$23.20	$23.01		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-75	$24.44	$24.45	$24.44	**$24.45**	$25.12	$24.15	$25.05	$23.85	$23.69		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-75	$22.86	$22.87	$22.86	**$22.86**	$23.54	$22.59	$23.49	$22.32	$22.16		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-75	$22.38	$22.38	$22.38	**$22.38**	$23.05	$22.11	$23.01	$21.84	$21.68		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-75	$22.72	$22.72	$22.74	**$22.73**	$23.47	$22.46	$23.42	$22.15	$22.01		$30.1	$11.7	$4.8	$0.4	$1.3			
May-75	$23.33	$23.33	$23.34	**$23.34**	$24.08	$23.05	$24.01	$22.73	$22.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-75	$22.95	$22.96	$22.97	**$22.96**	$23.70	$22.68	$23.64	$22.37	$22.24		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-75	$23.94	$23.95	$23.96	**$23.95**	$24.69	$23.66	$24.62	$23.33	$23.19		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-75	$22.09	$22.10	$22.11	**$22.10**	$22.84	$21.83	$22.80	$21.54	$21.40		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-75	$21.63	$21.63	$21.65	**$21.64**	$22.38	$21.38	$22.34	$21.09	$20.96		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-75	$22.59	$22.59	$22.61	**$22.60**	$23.34	$22.33	$23.29	$22.02	$21.89		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-75	$24.36	$24.36	$24.35	**$24.35**	$25.04	$24.06	$24.96	$23.79	$23.60		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-75	$24.31	$24.32	$24.31	**$24.31**	$24.99	$24.02	$24.92	$23.75	$23.56		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-76	$25.03	$25.04	$25.03	**$25.03**	$25.71	$24.73	$25.63	$24.42	$24.26		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-76	$23.41	$23.42	$23.41	**$23.41**	$24.09	$23.13	$24.03	$22.85	$22.69		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-76	$22.91	$22.92	$22.91	**$22.92**	$23.59	$22.64	$23.54	$22.37	$22.20		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-76	$23.26	$23.27	$23.28	**$23.28**	$24.02	$22.99	$23.96	$22.67	$22.54		$30.1	$11.7	$4.8	$0.4	$1.3			
May-76	$23.89	$23.89	$23.90	**$23.90**	$24.64	$23.61	$24.57	$23.28	$23.14		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-76	$23.50	$23.51	$23.52	**$23.52**	$24.25	$23.23	$24.19	$22.90	$22.77		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-76	$24.51	$24.52	$24.53	**$24.53**	$25.26	$24.23	$25.19	$23.89	$23.75		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-76	$22.62	$22.63	$22.64	**$22.63**	$23.37	$22.36	$23.32	$22.05	$21.92		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-76	$22.15	$22.15	$22.17	**$22.16**	$22.90	$21.89	$22.85	$21.59	$21.46		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-76	$23.13	$23.13	$23.15	**$23.14**	$23.88	$22.86	$23.82	$22.55	$22.41		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-76	$24.94	$24.95	$24.93	**$24.94**	$25.62	$24.64	$25.54	$24.36	$24.17		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-76	$24.90	$24.90	$24.89	**$24.89**	$25.58	$24.60	$25.49	$24.32	$24.13		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-77	$25.63	$25.64	$25.63	**$25.64**	$26.31	$25.32	$26.22	$25.00	$24.84		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-77	$23.98	$23.98	$23.98	**$23.98**	$24.65	$23.69	$24.58	$23.40	$23.23		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-77	$23.47	$23.47	$23.46	**$23.47**	$24.14	$23.18	$24.08	$22.90	$22.74		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-77	$23.82	$23.83	$23.84	**$23.84**	$24.58	$23.55	$24.51	$23.22	$23.08		$30.1	$11.7	$4.8	$0.4	$1.3			
May-77	$24.46	$24.47	$24.48	**$24.47**	$25.21	$24.17	$25.13	$23.83	$23.70		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-77	$24.07	$24.07	$24.09	**$24.08**	$24.82	$23.78	$24.75	$23.45	$23.32		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-77	$25.10	$25.11	$25.12	**$25.12**	$25.85	$24.81	$25.77	$24.46	$24.32		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-77	$23.16	$23.17	$23.18	**$23.18**	$23.92	$22.89	$23.86	$22.58	$22.44		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-77	$22.68	$22.69	$22.70	**$22.69**	$23.43	$22.42	$23.38	$22.11	$21.97		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-77	$23.68	$23.69	$23.71	**$23.70**	$24.44	$23.41	$24.37	$23.08	$22.95		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-77	$25.54	$25.55	$25.53	**$25.54**	$26.22	$25.23	$26.13	$24.94	$24.75		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-77	$25.50	$25.50	$25.49	**$25.49**	$26.18	$25.19	$26.09	$24.90	$24.71		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-78	$26.25	$26.26	$26.25	**$26.25**	$26.93	$25.93	$26.83	$25.60	$25.44		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-78	$24.55	$24.56	$24.55	**$24.55**	$25.23	$24.26	$25.15	$23.95	$23.79		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-78	$24.03	$24.03	$24.03	**$24.03**	$24.71	$23.74	$24.64	$23.45	$23.28		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-78	$24.40	$24.40	$24.42	**$24.41**	$25.15	$24.11	$25.07	$23.77	$23.64		$30.1	$11.7	$4.8	$0.4	$1.3			
May-78	$25.05	$25.06	$25.07	**$25.06**	$25.80	$24.75	$25.71	$24.40	$24.27		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-78	$24.65	$24.65	$24.66	**$24.66**	$25.40	$24.36	$25.32	$24.01	$23.88		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-78	$25.71	$25.71	$25.73	**$25.72**	$26.46	$25.40	$26.36	$25.04	$24.91		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-78	$23.72	$23.73	$23.74	**$23.73**	$24.47	$23.44	$24.40	$23.12	$22.98		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-78	$23.22	$23.23	$23.24	**$23.24**	$23.98	$22.95	$23.91	$22.64	$22.50		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-78	$24.25	$24.26	$24.28	**$24.27**	$25.01	$23.97	$24.93	$23.64	$23.50		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-78	$26.16	$26.16	$26.15	**$26.15**	$26.84	$25.84	$26.74	$25.53	$25.35		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-78	$26.11	$26.12	$26.10	**$26.11**	$26.79	$25.79	$26.69	$25.49	$25.30		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-79	$26.88	$26.89	$26.88	**$26.88**	$27.56	$26.55	$27.45	$26.21	$26.05		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-79	$25.14	$25.15	$25.14	**$25.14**	$25.82	$24.84	$25.74	$24.53	$24.36		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-79	$24.61	$24.61	$24.61	**$24.61**	$25.29	$24.31	$25.21	$24.01	$23.84		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-79	$24.98	$24.99	$25.00	**$25.00**	$25.73	$24.69	$25.65	$24.34	$24.21		$30.1	$11.7	$4.8	$0.4	$1.3			
May-79	$25.65	$25.66	$25.67	**$25.66**	$26.40	$25.35	$26.31	$24.99	$24.85		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-79	$25.24	$25.25	$25.26	**$25.25**	$25.99	$24.94	$25.90	$24.59	$24.45		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-79	$26.32	$26.33	$26.34	**$26.34**	$27.08	$26.01	$26.97	$25.64	$25.50		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-79	$24.29	$24.30	$24.31	**$24.31**	$25.04	$24.01	$24.97	$23.67	$23.54		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-79	$23.78	$23.79	$23.80	**$23.80**	$24.53	$23.50	$24.46	$23.18	$23.04		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-79	$24.84	$24.84	$24.86	**$24.85**	$25.59	$24.55	$25.51	$24.20	$24.07		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-79	$26.79	$26.79	$26.78	**$26.78**	$27.47	$26.46	$27.36	$26.14	$25.96		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-79	$26.74	$26.74	$26.73	**$26.73**	$27.42	$26.41	$27.31	$26.10	$25.91		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-80	$27.53	$27.53	$27.53	**$27.53**	$28.21	$27.19	$28.09	$26.84	$26.67		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-80	$25.75	$25.75	$25.75	**$25.75**	$26.43	$25.43	$26.33	$25.11	$24.95		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-80	$25.20	$25.20	$25.20	**$25.20**	$25.88	$24.89	$25.79	$24.58	$24.42		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-80	$25.58	$25.59	$25.60	**$25.60**	$26.34	$25.28	$26.24	$24.92	$24.79		$30.1	$11.7	$4.8	$0.4	$1.3			
May-80	$26.27	$26.28	$26.29	**$26.28**	$27.02	$25.95	$26.92	$25.58	$25.45		$30.7	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Jun-80	$25.84	$25.85	$25.86	**$25.86**	$26.60	$25.54	$26.50	$25.17	$25.04		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]		
Jul-80	$26.96	$26.97	$26.98	**$26.97**	$27.71	$26.63	$27.60	$26.25	$26.12		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-80	$24.88	$24.88	$24.89	**$24.89**	$25.63	$24.58	$25.54	$24.24	$24.10		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-80	$24.35	$24.36	$24.37	**$24.37**	$25.11	$24.07	$25.03	$23.73	$23.60		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-80	$25.43	$25.44	$25.46	**$25.45**	$26.19	$25.13	$26.10	$24.78	$24.64		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-80	$27.43	$27.44	$27.42	**$27.43**	$28.11	$27.09	$27.99	$26.77	$26.58		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-80	$27.38	$27.39	$27.37	**$27.38**	$28.06	$27.04	$27.94	$26.72	$26.53		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-81	$28.19	$28.20	$28.19	**$28.19**	$28.87	$27.84	$28.74	$27.48	$27.31		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-81	$26.37	$26.37	$26.37	**$26.37**	$27.04	$26.04	$26.94	$25.71	$25.55		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-81	$25.80	$25.81	$25.80	**$25.81**	$26.48	$25.49	$26.39	$25.17	$25.00		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-81	$26.20	$26.20	$26.22	**$26.21**	$26.95	$25.89	$26.85	$25.52	$25.38		$30.1	$11.7	$4.8	$0.4	$1.3			
May-81	$26.90	$26.91	$26.92	**$26.91**	$27.65	$26.58	$27.54	$26.19	$26.06		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-81	$26.47	$26.47	$26.48	**$26.48**	$27.22	$26.15	$27.11	$25.78	$25.64		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-81	$27.61	$27.61	$27.62	**$27.62**	$28.36	$27.27	$28.23	$26.88	$26.74		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-81	$25.47	$25.48	$25.49	**$25.49**	$26.22	$25.17	$26.13	$24.82	$24.68		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-81	$24.94	$24.95	$24.96	**$24.95**	$25.69	$24.65	$25.61	$24.30	$24.16		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-81	$26.05	$26.05	$26.07	**$26.06**	$26.80	$25.74	$26.70	$25.37	$25.24		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-81	$28.09	$28.10	$28.08	**$28.09**	$28.77	$27.74	$28.64	$27.41	$27.22		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-81	$28.04	$28.05	$28.03	**$28.04**	$28.72	$27.69	$28.59	$27.36	$27.17		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-82	$28.87	$28.87	$28.87	**$28.87**	$29.55	$28.51	$29.41	$28.14	$27.97		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-82	$27.00	$27.01	$27.00	**$27.00**	$27.68	$26.67	$27.57	$26.33	$26.16		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-82	$26.43	$26.43	$26.42	**$26.43**	$27.10	$26.10	$27.00	$25.77	$25.60		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-82	$26.83	$26.83	$26.85	**$26.84**	$27.58	$26.51	$27.47	$26.13	$25.99		$30.1	$11.7	$4.8	$0.4	$1.3			
May-82	$27.55	$27.55	$27.56	**$27.56**	$28.30	$27.21	$28.18	$26.82	$26.69		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-82	$27.10	$27.11	$27.12	**$27.12**	$27.85	$26.78	$27.74	$26.39	$26.26		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-82	$28.27	$28.28	$28.29	**$28.28**	$29.02	$27.93	$28.89	$27.52	$27.39		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-82	$26.09	$26.09	$26.10	**$26.10**	$26.84	$25.78	$26.74	$25.41	$25.27		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-82	$25.54	$25.55	$25.56	**$25.55**	$26.29	$25.24	$26.20	$24.88	$24.74		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-82	$26.67	$26.68	$26.69	**$26.69**	$27.42	$26.36	$27.32	$25.98	$25.84		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-82	$28.77	$28.77	$28.76	**$28.76**	$29.45	$28.41	$29.31	$28.06	$27.87		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-82	$28.71	$28.72	$28.70	**$28.71**	$29.39	$28.36	$29.26	$28.01	$27.82		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-83	$29.56	$29.57	$29.56	**$29.56**	$30.24	$29.20	$30.09	$28.81	$28.64		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-83	$27.65	$27.65	$27.65	**$27.65**	$28.33	$27.31	$28.21	$26.95	$26.79		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-83	$27.06	$27.07	$27.06	**$27.06**	$27.74	$26.73	$27.63	$26.38	$26.22		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-83	$27.47	$27.48	$27.49	**$27.49**	$28.23	$27.14	$28.11	$26.75	$26.62		$30.1	$11.7	$4.8	$0.4	$1.3			
May-83	$28.21	$28.22	$28.23	**$28.22**	$28.96	$27.87	$28.83	$27.46	$27.33		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-83	$27.75	$27.76	$27.77	**$27.77**	$28.50	$27.42	$28.38	$27.02	$26.89		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-83	$28.95	$28.96	$28.97	**$28.96**	$29.70	$28.60	$29.56	$28.18	$28.05		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-83	$26.71	$26.72	$26.73	**$26.73**	$27.46	$26.39	$27.35	$26.02	$25.88		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-83	$26.15	$26.16	$26.17	**$26.17**	$26.90	$25.84	$26.80	$25.47	$25.34		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-83	$27.31	$27.32	$27.34	**$27.33**	$28.07	$26.99	$27.95	$26.60	$26.46		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-83	$29.46	$29.46	$29.45	**$29.45**	$30.14	$29.09	$29.99	$28.73	$28.54		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-83	$29.40	$29.41	$29.39	**$29.40**	$30.08	$29.04	$29.94	$28.68	$28.49		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-84	$30.27	$30.28	$30.27	**$30.27**	$30.95	$29.90	$30.79	$29.50	$29.33		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-84	$28.31	$28.32	$28.31	**$28.32**	$28.99	$27.97	$28.86	$27.60	$27.43		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-84	$27.71	$27.72	$27.71	**$27.71**	$28.39	$27.37	$28.27	$27.01	$26.85		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-84	$28.13	$28.14	$28.15	**$28.15**	$28.89	$27.80	$28.76	$27.39	$27.26		$30.1	$11.7	$4.8	$0.4	$1.3			
May-84	$28.89	$28.89	$28.90	**$28.90**	$29.64	$28.54	$29.50	$28.12	$27.98		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-84	$28.42	$28.43	$28.44	**$28.43**	$29.17	$28.08	$29.04	$27.67	$27.53		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-84	$29.64	$29.65	$29.66	**$29.66**	$30.40	$29.28	$30.25	$28.86	$28.72		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-84	$27.36	$27.36	$27.37	**$27.37**	$28.11	$27.03	$27.99	$26.64	$26.50		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-84	$26.78	$26.79	$26.80	**$26.80**	$27.53	$26.46	$27.42	$26.08	$25.95		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-84	$27.97	$27.98	$27.99	**$27.99**	$28.72	$27.64	$28.60	$27.24	$27.10		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-84	$30.17	$30.17	$30.15	**$30.16**	$30.84	$29.79	$30.69	$29.42	$29.23		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-84	$30.11	$30.12	$30.10	**$30.11**	$30.79	$29.74	$30.63	$29.37	$29.17		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-85	$31.00	$31.01	$31.00	**$31.00**	$31.68	$30.61	$31.51	$30.20	$30.03		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-85	$29.00	$29.00	$28.99	**$29.00**	$29.67	$28.64	$29.53	$28.26	$28.09		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-85	$28.38	$28.38	$28.38	**$28.38**	$29.06	$28.03	$28.92	$27.66	$27.49		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-85	$28.81	$28.81	$28.83	**$28.82**	$29.56	$28.46	$29.42	$28.05	$27.91		$30.1	$11.7	$4.8	$0.4	$1.3			
May-85	$29.58	$29.59	$29.60	**$29.59**	$30.33	$29.22	$30.18	$28.79	$28.66		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-85	$29.10	$29.11	$29.12	**$29.12**	$29.86	$28.75	$29.71	$28.33	$28.20		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-85	$30.36	$30.36	$30.38	**$30.37**	$31.11	$29.99	$30.95	$29.55	$29.41		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-85	$28.01	$28.02	$28.03	**$28.03**	$28.76	$27.68	$28.64	$27.28	$27.14		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-85	$27.43	$27.43	$27.44	**$27.44**	$28.18	$27.10	$28.06	$26.71	$26.57		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-85	$28.64	$28.65	$28.66	**$28.66**	$29.40	$28.30	$29.26	$27.89	$27.75		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-85	$30.89	$30.90	$30.88	**$30.89**	$31.57	$30.50	$31.40	$30.12	$29.93		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-85	$30.84	$30.84	$30.83	**$30.83**	$31.51	$30.45	$31.35	$30.07	$29.87		$29.3	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Jan-86	$31.75	$31.75	$31.74	$31.75	$32.42	$31.35	$32.25	$30.92	$30.76		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]		
Feb-86	$29.69	$29.70	$29.69	$29.69	$30.37	$29.32	$30.22	$28.93	$28.77		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-86	$29.06	$29.06	$29.06	$29.06	$29.74	$28.70	$29.60	$28.32	$28.16		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-86	$29.50	$29.51	$29.52	$29.52	$30.25	$29.15	$30.11	$28.72	$28.58		$30.1	$11.7	$4.8	$0.4	$1.3			
May-86	$30.29	$30.30	$30.31	$30.30	$31.04	$29.92	$30.88	$29.48	$29.35		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-86	$29.80	$29.81	$29.82	$29.82	$30.55	$29.44	$30.40	$29.01	$28.87		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-86	$31.09	$31.09	$31.11	$31.10	$31.84	$30.71	$31.67	$30.25	$30.12		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-86	$28.69	$28.69	$28.70	$28.70	$29.44	$28.34	$29.30	$27.93	$27.79		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-86	$28.08	$28.09	$28.10	$28.10	$28.84	$27.75	$28.71	$27.35	$27.21		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-86	$29.33	$29.34	$29.35	$29.35	$30.08	$28.98	$29.94	$28.55	$28.42		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-86	$31.63	$31.64	$31.62	$31.63	$32.31	$31.24	$32.14	$30.84	$30.65		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-86	$31.58	$31.58	$31.57	$31.57	$32.26	$31.18	$32.08	$30.79	$30.59		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-87	$32.51	$32.51	$32.51	$32.51	$33.19	$32.10	$33.00	$31.66	$31.49		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-87	$30.41	$30.41	$30.41	$30.41	$31.08	$30.03	$30.92	$29.63	$29.46		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-87	$29.76	$29.76	$29.76	$29.76	$30.44	$29.39	$30.29	$29.00	$28.83		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-87	$30.21	$30.22	$30.23	$30.23	$30.96	$29.84	$30.81	$29.41	$29.27		$30.1	$11.7	$4.8	$0.4	$1.3			
May-87	$31.02	$31.03	$31.04	$31.03	$31.77	$30.64	$31.60	$30.19	$30.05		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-87	$30.52	$30.53	$30.54	$30.53	$31.27	$30.15	$31.11	$29.70	$29.57		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-87	$31.83	$31.84	$31.85	$31.85	$32.59	$31.44	$32.40	$30.98	$30.84		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-87	$29.38	$29.38	$29.39	$29.39	$30.13	$29.02	$29.98	$28.60	$28.46		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-87	$28.76	$28.77	$28.78	$28.77	$29.51	$28.41	$29.37	$28.00	$27.86		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-87	$30.04	$30.04	$30.06	$30.05	$30.79	$29.67	$30.63	$29.24	$29.10		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-87	$32.39	$32.40	$32.38	$32.39	$33.07	$31.99	$32.89	$31.57	$31.38		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-87	$32.34	$32.34	$32.33	$32.33	$33.01	$31.93	$32.83	$31.52	$31.33		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-88	$33.29	$33.30	$33.29	$33.29	$33.97	$32.87	$33.77	$32.42	$32.25		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-88	$31.14	$31.14	$31.14	$31.14	$31.82	$30.75	$31.65	$30.33	$30.17		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-88	$30.47	$30.48	$30.47	$30.47	$31.15	$30.09	$30.99	$29.69	$29.52		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-88	$30.94	$30.94	$30.96	$30.95	$31.69	$30.56	$31.52	$30.11	$29.97		$30.1	$11.7	$4.8	$0.4	$1.3			
May-88	$31.76	$31.77	$31.78	$31.78	$32.52	$31.37	$32.34	$30.91	$30.77		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-88	$31.25	$31.26	$31.27	$31.27	$32.00	$30.87	$31.83	$30.41	$30.28		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-88	$32.60	$32.61	$32.62	$32.61	$33.35	$32.20	$33.16	$31.72	$31.58		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-88	$30.08	$30.09	$30.10	$30.10	$30.83	$29.72	$30.68	$29.28	$29.14		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-88	$29.45	$29.46	$29.47	$29.47	$30.20	$29.09	$30.05	$28.67	$28.53		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-88	$30.76	$30.76	$30.78	$30.77	$31.51	$30.38	$31.35	$29.94	$29.80		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-88	$33.17	$33.18	$33.16	$33.17	$33.85	$32.75	$33.65	$32.33	$32.14		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-88	$33.11	$33.12	$33.10	$33.11	$33.79	$32.70	$33.59	$32.28	$32.08		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-89	$34.09	$34.10	$34.09	$34.09	$34.77	$33.66	$34.56	$33.19	$33.03		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-89	$31.89	$31.89	$31.88	$31.89	$32.56	$31.49	$32.38	$31.06	$30.89		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-89	$31.21	$31.21	$31.21	$31.21	$31.88	$30.82	$31.71	$30.40	$30.23		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-89	$31.68	$31.69	$31.70	$31.70	$32.43	$31.29	$32.26	$30.83	$30.69		$30.1	$11.7	$4.8	$0.4	$1.3			
May-89	$32.53	$32.54	$32.55	$32.54	$33.28	$32.13	$33.09	$31.65	$31.51		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-89	$32.01	$32.01	$32.02	$32.02	$32.76	$31.61	$32.57	$31.14	$31.01		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-89	$33.38	$33.39	$33.40	$33.40	$34.13	$32.97	$33.93	$32.48	$32.34		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-89	$30.80	$30.81	$30.82	$30.82	$31.56	$30.43	$31.39	$29.98	$29.84		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-89	$30.16	$30.17	$30.18	$30.17	$30.91	$29.79	$30.75	$29.35	$29.22		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-89	$31.50	$31.50	$31.52	$31.51	$32.25	$31.11	$32.07	$30.65	$30.52		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-89	$33.97	$33.98	$33.96	$33.97	$34.65	$33.54	$34.44	$33.10	$32.91		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-89	$33.91	$33.91	$33.90	$33.90	$34.59	$33.48	$34.38	$33.05	$32.85		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-90	$34.91	$34.91	$34.91	$34.91	$35.59	$34.47	$35.37	$33.99	$33.82		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-90	$32.65	$32.66	$32.65	$32.65	$33.33	$32.24	$33.14	$31.80	$31.63		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-90	$31.96	$31.96	$31.96	$31.96	$32.63	$31.56	$32.45	$31.13	$30.96		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-90	$32.44	$32.45	$32.46	$32.46	$33.20	$32.05	$33.01	$31.57	$31.43		$30.1	$11.7	$4.8	$0.4	$1.3			
May-90	$33.31	$33.32	$33.33	$33.32	$34.06	$32.90	$33.86	$32.41	$32.27		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-90	$32.77	$32.78	$32.79	$32.79	$33.53	$32.37	$33.33	$31.89	$31.75		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-90	$34.19	$34.19	$34.20	$34.20	$34.94	$33.76	$34.72	$33.26	$33.12		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-90	$31.55	$31.55	$31.56	$31.56	$32.30	$31.16	$32.12	$30.70	$30.56		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-90	$30.88	$30.89	$30.90	$30.90	$31.64	$30.51	$31.47	$30.06	$29.92		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-90	$32.25	$32.26	$32.28	$32.27	$33.01	$31.86	$32.82	$31.39	$31.25		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-90	$34.79	$34.79	$34.78	$34.78	$35.47	$34.35	$35.25	$33.89	$33.70		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-90	$34.72	$34.73	$34.71	$34.72	$35.40	$34.28	$35.18	$33.84	$33.64		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-91	$35.75	$35.75	$35.75	$35.75	$36.43	$35.30	$36.19	$34.80	$34.63		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-91	$33.44	$33.44	$33.44	$33.44	$34.12	$33.02	$33.91	$32.56	$32.39		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-91	$32.72	$32.73	$32.72	$32.73	$33.40	$32.31	$33.21	$31.87	$31.70		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-91	$33.22	$33.23	$33.24	$33.24	$33.98	$32.81	$33.78	$32.32	$32.19		$30.1	$11.7	$4.8	$0.4	$1.3			
May-91	$34.11	$34.12	$34.13	$34.12	$34.86	$33.69	$34.65	$33.18	$33.04		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-91	$33.56	$33.57	$33.58	$33.58	$34.31	$33.15	$34.11	$32.65	$32.51		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-91	$35.01	$35.01	$35.03	$35.02	$35.76	$34.57	$35.53	$34.05	$33.91		$30.7	$12.1	$4.9	$0.4	$1.3			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACE MENT SUNK DEMAND CHARGE MM$
Aug-91	$32.30	$32.31	$32.32	$32.32	$33.05	$31.91	$32.87	$31.43	$31.29		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]		
Sep-91	$31.63	$31.63	$31.65	$31.64	$32.38	$31.24	$32.20	$30.78	$30.64		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-91	$33.03	$33.04	$33.05	$33.05	$33.78	$32.62	$33.59	$32.14	$32.00		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-91	$35.62	$35.63	$35.61	$35.62	$36.30	$35.17	$36.07	$34.70	$34.51		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-91	$35.56	$35.56	$35.55	$35.55	$36.24	$35.11	$36.01	$34.64	$34.45		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-92	$36.61	$36.61	$36.61	$36.61	$37.29	$36.14	$37.04	$35.63	$35.46		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-92	$34.24	$34.25	$34.24	$34.24	$34.92	$33.81	$34.71	$33.34	$33.17		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-92	$33.51	$33.52	$33.51	$33.51	$34.19	$33.09	$33.99	$32.63	$32.47		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-92	$34.02	$34.03	$34.04	$34.04	$34.77	$33.60	$34.56	$33.10	$32.96		$30.1	$11.7	$4.8	$0.4	$1.3			
May-92	$34.93	$34.94	$34.95	$34.94	$35.68	$34.50	$35.46	$33.98	$33.84		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-92	$34.37	$34.38	$34.39	$34.38	$35.12	$33.94	$34.90	$33.43	$33.29		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-92	$35.85	$35.86	$35.87	$35.86	$36.60	$35.40	$36.36	$34.87	$34.73		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-92	$33.08	$33.09	$33.10	$33.09	$33.83	$32.67	$33.63	$32.18	$32.05		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-92	$32.39	$32.39	$32.41	$32.40	$33.14	$31.99	$32.95	$31.51	$31.37		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-92	$33.82	$33.83	$33.85	$33.84	$34.58	$33.41	$34.37	$32.91	$32.77		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-92	$36.48	$36.49	$36.47	$36.47	$37.16	$36.01	$36.91	$35.53	$35.34		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-92	$36.41	$36.42	$36.40	$36.41	$37.09	$35.95	$36.85	$35.47	$35.28		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-93	$37.49	$37.49	$37.49	$37.49	$38.17	$37.01	$37.91	$36.49	$36.32		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-93	$35.06	$35.07	$35.06	$35.06	$35.74	$34.62	$35.52	$34.14	$33.97		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-93	$34.32	$34.32	$34.32	$34.32	$35.00	$33.88	$34.78	$33.41	$33.25		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-93	$34.84	$34.84	$34.86	$34.85	$35.59	$34.41	$35.37	$33.89	$33.75		$30.1	$11.7	$4.8	$0.4	$1.3			
May-93	$35.77	$35.78	$35.79	$35.78	$36.52	$35.32	$36.29	$34.79	$34.65		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-93	$35.19	$35.20	$35.21	$35.21	$35.95	$34.76	$35.72	$34.23	$34.09		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-93	$36.71	$36.72	$36.73	$36.72	$37.46	$36.25	$37.21	$35.70	$35.56		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-93	$33.88	$33.88	$33.89	$33.89	$34.63	$33.46	$34.42	$32.96	$32.82		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-93	$33.17	$33.17	$33.18	$33.18	$33.92	$32.76	$33.72	$32.27	$32.13		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-93	$34.64	$34.64	$34.66	$34.65	$35.39	$34.21	$35.17	$33.70	$33.56		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-93	$37.36	$37.36	$37.35	$37.35	$38.04	$36.88	$37.78	$36.38	$36.19		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-93	$37.29	$37.29	$37.28	$37.28	$37.97	$36.81	$37.71	$36.32	$36.12		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-94	$38.39	$38.39	$38.39	$38.39	$39.07	$37.90	$38.80	$37.36	$37.19		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-94	$35.91	$35.91	$35.91	$35.91	$36.59	$35.45	$36.35	$34.95	$34.79		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-94	$35.14	$35.15	$35.14	$35.14	$35.82	$34.70	$35.59	$34.21	$34.04		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-94	$35.68	$35.68	$35.70	$35.69	$36.43	$35.23	$36.20	$34.70	$34.56		$30.1	$11.7	$4.8	$0.4	$1.3			
May-94	$36.63	$36.64	$36.65	$36.64	$37.38	$36.17	$37.13	$35.62	$35.48		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-94	$36.04	$36.05	$36.06	$36.05	$36.79	$35.59	$36.55	$35.05	$34.91		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-94	$37.59	$37.60	$37.61	$37.61	$38.34	$37.12	$38.08	$36.56	$36.42		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-94	$34.69	$34.70	$34.71	$34.70	$35.44	$34.26	$35.22	$33.74	$33.60		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-94	$33.96	$33.97	$33.98	$33.98	$34.71	$33.54	$34.50	$33.04	$32.90		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-94	$35.47	$35.47	$35.49	$35.49	$36.22	$35.03	$35.99	$34.50	$34.36		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-94	$38.26	$38.26	$38.24	$38.25	$38.93	$37.76	$38.66	$37.25	$37.06		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-94	$38.19	$38.19	$38.18	$38.18	$38.86	$37.70	$38.60	$37.19	$36.99		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-95	$39.31	$39.32	$39.31	$39.31	$39.99	$38.81	$39.71	$38.25	$38.08		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-95	$36.77	$36.77	$36.77	$36.77	$37.45	$36.30	$37.20	$35.79	$35.62		$26.5	$10.9	$4.5	$0.3	$1.2			
Mar-95	$35.99	$35.99	$35.99	$35.99	$36.67	$35.53	$36.43	$35.03	$34.86		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-95	$36.53	$36.54	$36.56	$36.55	$37.29	$36.08	$37.04	$35.53	$35.39		$30.1	$11.7	$4.8	$0.4	$1.3			
May-95	$37.51	$37.52	$37.53	$37.52	$38.26	$37.04	$38.00	$36.47	$36.34		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-95	$36.91	$36.92	$36.93	$36.92	$37.66	$36.45	$37.41	$35.89	$35.75		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-95	$38.50	$38.50	$38.51	$38.51	$39.25	$38.01	$38.97	$37.43	$37.29		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-95	$35.52	$35.53	$35.54	$35.54	$36.27	$35.08	$36.04	$34.55	$34.41		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-95	$34.78	$34.79	$34.80	$34.79	$35.53	$34.35	$35.31	$33.83	$33.69		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-95	$36.32	$36.33	$36.34	$36.34	$37.08	$35.87	$36.83	$35.33	$35.19		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-95	$39.17	$39.18	$39.16	$39.17	$39.85	$38.67	$39.57	$38.14	$37.95		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-95	$39.10	$39.11	$39.09	$39.10	$39.78	$38.60	$39.50	$38.08	$37.88		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-96	$40.26	$40.26	$40.26	$40.26	$40.94	$39.74	$40.64	$39.17	$39.00		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-96	$37.65	$37.66	$37.65	$37.65	$38.33	$37.17	$38.07	$36.65	$36.48		$27.4	$11.3	$4.6	$0.3	$1.2			
Mar-96	$36.85	$36.86	$36.85	$36.85	$37.53	$36.38	$37.28	$35.87	$35.70		$29.3	$12.1	$4.9	$0.4	$1.3			
Apr-96	$37.41	$37.42	$37.43	$37.43	$38.17	$36.95	$37.91	$36.38	$36.24		$30.1	$11.7	$4.8	$0.4	$1.3			
May-96	$38.41	$38.42	$38.43	$38.43	$39.16	$37.93	$38.89	$37.35	$37.21		$30.7	$12.1	$4.9	$0.4	$1.3			
Jun-96	$37.79	$37.80	$37.81	$37.81	$38.55	$37.32	$38.28	$36.75	$36.61		$29.7	$11.7	$4.8	$0.4	$1.3			
Jul-96	$39.42	$39.43	$39.44	$39.43	$40.17	$38.93	$39.89	$38.33	$38.19		$30.7	$12.1	$4.9	$0.4	$1.3			
Aug-96	$36.38	$36.39	$36.40	$36.39	$37.13	$35.92	$36.88	$35.38	$35.24		$30.7	$12.1	$4.9	$0.4	$1.3			
Sep-96	$35.61	$35.62	$35.63	$35.63	$36.37	$35.17	$36.13	$34.64	$34.50		$29.7	$11.7	$4.8	$0.4	$1.3			
Oct-96	$37.20	$37.20	$37.22	$37.21	$37.95	$36.73	$37.69	$36.17	$36.03		$31.1	$12.1	$4.9	$0.4	$1.3			
Nov-96	$40.12	$40.12	$40.10	$40.11	$40.79	$39.60	$40.50	$39.05	$38.86		$28.4	$11.7	$4.8	$0.4	$1.3			
Dec-96	$40.04	$40.05	$40.03	$40.04	$40.72	$39.53	$40.43	$38.99	$38.79		$29.3	$12.1	$4.9	$0.4	$1.3			
Jan-97	$41.22	$41.23	$41.22	$41.23	$41.90	$40.70	$41.59	$40.11	$39.93		$29.3	$12.1	$4.9	$0.4	$1.3			
Feb-97	$38.56	$38.56	$38.56	$38.56	$39.24	$38.07	$38.96	$37.52	$37.35		$26.5	$10.9	$4.5	$0.3	$1.2			

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
Mar-97	$37.74	$37.74	$37.74	$37.74	$38.42	$37.26	$38.15	$36.73	$36.56		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-97	$38.31	$38.32	$38.33	$38.33	$39.06	$37.83	$38.79	$37.25	$37.11		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-97	$39.34	$39.34	$39.35	$39.35	$40.09	$38.84	$39.80	$38.24	$38.10		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-97	$38.70	$38.71	$38.72	$38.72	$39.45	$38.22	$39.18	$37.63	$37.49		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-97	$40.37	$40.38	$40.39	$40.38	$41.12	$39.86	$40.82	$39.25	$39.10		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-97	$37.25	$37.26	$37.27	$37.27	$38.00	$36.79	$37.75	$36.23	$36.09		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-97	$36.47	$36.48	$36.49	$36.48	$37.22	$36.02	$36.98	$35.47	$35.33		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-97	$38.09	$38.09	$38.11	$38.11	$38.84	$37.61	$38.57	$37.04	$36.90		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-97	$41.08	$41.09	$41.07	$41.07	$41.76	$40.55	$41.45	$39.99	$39.80		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-97	$41.01	$41.01	$41.00	$41.00	$41.68	$40.48	$41.38	$39.92	$39.72		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-98	$42.22	$42.22	$42.22	$42.22	$42.89	$41.67	$42.57	$41.07	$40.89		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-98	$39.49	$39.49	$39.49	$39.49	$40.16	$38.98	$39.88	$38.42	$38.25		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-98	$38.64	$38.65	$38.64	$38.65	$39.32	$38.15	$39.05	$37.60	$37.44		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-98	$39.23	$39.24	$39.25	$39.25	$39.99	$38.74	$39.70	$38.15	$38.01		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-98	$40.28	$40.29	$40.30	$40.29	$41.03	$39.77	$40.73	$39.16	$39.02		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-98	$39.63	$39.64	$39.65	$39.65	$40.38	$39.13	$40.09	$38.53	$38.39		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-98	$41.34	$41.35	$41.36	$41.35	$42.09	$40.82	$41.78	$40.19	$40.04		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-98	$38.15	$38.15	$38.17	$38.16	$38.90	$37.67	$38.63	$37.09	$36.95		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-98	$37.35	$37.36	$37.37	$37.36	$38.10	$36.88	$37.84	$36.32	$36.18		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-98	$39.00	$39.01	$39.03	$39.02	$39.76	$38.52	$39.48	$37.93	$37.78		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-98	$42.07	$42.07	$42.06	$42.06	$42.75	$41.52	$42.42	$40.95	$40.75		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-98	$41.99	$42.00	$41.98	$41.99	$42.67	$41.45	$42.35	$40.88	$40.68		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-99	$43.23	$43.24	$43.23	$43.23	$43.91	$42.67	$43.57	$42.05	$41.88		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-99	$40.43	$40.44	$40.43	$40.44	$41.11	$39.92	$40.81	$39.34	$39.17		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-99	$39.57	$39.58	$39.57	$39.57	$40.25	$39.07	$39.96	$38.50	$38.34		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-99	$40.18	$40.18	$40.20	$40.19	$40.93	$39.67	$40.63	$39.06	$38.92		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-99	$41.25	$41.26	$41.27	$41.26	$42.00	$40.73	$41.69	$40.10	$39.96		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-99	$40.59	$40.59	$40.60	$40.60	$41.34	$40.07	$41.03	$39.45	$39.31		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-99	$42.33	$42.34	$42.35	$42.35	$43.08	$41.80	$42.76	$41.15	$41.01		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-99	$39.06	$39.07	$39.08	$39.08	$39.81	$38.57	$39.53	$37.98	$37.84		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-99	$38.25	$38.25	$38.26	$38.26	$39.00	$37.77	$38.73	$37.19	$37.05		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-99	$39.94	$39.95	$39.96	$39.96	$40.70	$39.44	$40.40	$38.84	$38.69		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-99	$43.08	$43.08	$43.07	$43.07	$43.76	$42.52	$43.42	$41.93	$41.73		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-99	$43.00	$43.01	$42.99	$43.00	$43.68	$42.44	$43.34	$41.85	$41.65		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jan-00	$44.27	$44.27	$44.27	$44.27	$44.95	$43.70	$44.59	$43.06	$42.88		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Feb-00	$41.41	$41.41	$41.41	$41.41	$42.09	$40.88	$41.77	$40.28	$40.11		$26.5	$10.9	$4.5	$0.3	$1.2	[redacted]	[redacted]	
Mar-00	$40.52	$40.53	$40.52	$40.53	$41.20	$40.01	$40.90	$39.43	$39.26		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Apr-00	$41.14	$41.15	$41.16	$41.16	$41.89	$40.62	$41.58	$39.99	$39.85		$30.1	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
May-00	$42.24	$42.25	$42.26	$42.25	$42.99	$41.70	$42.67	$41.06	$40.92		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Jun-00	$41.56	$41.57	$41.58	$41.57	$42.31	$41.03	$42.00	$40.40	$40.26		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Jul-00	$43.35	$43.36	$43.37	$43.36	$44.10	$42.80	$43.76	$42.13	$41.99		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Aug-00	$40.00	$40.01	$40.02	$40.02	$40.75	$39.50	$40.46	$38.89	$38.75		$30.7	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Sep-00	$39.16	$39.17	$39.18	$39.18	$39.92	$38.67	$39.63	$38.08	$37.94		$29.7	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Oct-00	$40.90	$40.91	$40.92	$40.92	$41.66	$40.39	$41.35	$39.77	$39.62		$31.1	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
Nov-00	$44.11	$44.12	$44.10	$44.11	$44.79	$43.54	$44.44	$42.93	$42.73		$28.4	$11.7	$4.8	$0.4	$1.3	[redacted]	[redacted]	
Dec-00	$44.03	$44.04	$44.02	$44.03	$44.71	$43.46	$44.36	$42.86	$42.66		$29.3	$12.1	$4.9	$0.4	$1.3	[redacted]	[redacted]	
2014	$4.48	$4.49	$4.51	$4.51	$5.19	$4.49	$5.32		$4.35	$4.45	$360.6	$142.0	$56.5	$7.7	$7.9	[redacted]	[redacted]	$12.6
2015	$3.94	$3.95	$3.94	$3.94	$4.67	$3.94	$4.87		$3.84	$3.91	$361.8	$142.0	$56.1	$7.2	$16.9	[redacted]	[redacted]	$12.8
2016	$4.13	$4.13	$4.13	$4.13	$4.85	$4.11	$5.06		$4.01		$356.5	$142.4	$58.4	$5.4	$20.5	[redacted]	[redacted]	
2017	$4.63	$4.63	$4.63	$4.63	$5.35	$4.60	$5.55	$4.64	$4.50		$355.5	$142.0	$58.2	$4.4	$20.6	[redacted]	[redacted]	
2018	$4.87	$4.88	$4.88	$4.88	$5.60	$4.86	$5.79	$4.88	$4.74		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2019	$5.46	$5.46	$5.47	$5.47	$6.18	$5.43	$6.37	$5.44	$5.30		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2020	$5.61	$5.62	$5.62	$5.62	$6.33	$5.59	$6.52	$5.59	$5.45		$356.5	$142.4	$58.4	$4.4	$15.3	[redacted]	[redacted]	
2021	$5.82	$5.83	$5.83	$5.83	$6.54	$5.79	$6.72	$5.79	$5.65		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2022	$6.03	$6.03	$6.04	$6.03	$6.75	$5.99	$6.93	$5.99	$5.85		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2023	$6.23	$6.24	$6.24	$6.24	$6.95	$6.20	$7.13	$6.19	$6.05		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2024	$6.44	$6.45	$6.45	$6.45	$7.16	$6.40	$7.33	$6.39	$6.25		$356.5	$142.4	$58.4	$4.4	$15.3	[redacted]	[redacted]	
2025	$6.59	$6.60	$6.60	$6.60	$7.32	$6.55	$7.49	$6.54	$6.40		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2026	$6.80	$6.81	$6.81	$6.81	$7.52	$6.76	$7.69	$6.74	$6.60		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2027	$7.06	$7.07	$7.07	$7.07	$7.78	$7.01	$7.95	$6.99	$6.85		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2028	$7.32	$7.32	$7.33	$7.33	$8.04	$7.27	$8.20	$7.24	$7.10		$356.5	$142.4	$58.4	$4.4	$15.3	[redacted]	[redacted]	
2029	$7.63	$7.63	$7.64	$7.63	$8.35	$7.57	$8.51	$7.54	$7.40		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2030	$7.94	$7.94	$7.95	$7.94	$8.66	$7.88	$8.81	$7.84	$7.70		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2031	$8.13	$8.13	$8.14	$8.14	$8.85	$8.07	$9.00	$8.03	$7.89		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	
2032	$8.32	$8.33	$8.33	$8.33	$9.04	$8.26	$9.19	$8.22	$8.08		$356.5	$142.4	$58.4	$4.4	$15.3	[redacted]	[redacted]	
2033	$8.52	$8.53	$8.53	$8.53	$9.25	$8.46	$9.39	$8.41	$8.27		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]	[redacted]	

MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	WEIGHTED AVERAGE Z3 FGT FIRM $/MMBTU	WEIGHTED AVERAGE FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	WEIGHTED AVERAGE GULFSTREAM FIRM $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	FSC FIRM FROM SABAL TRAIL $/MMBTU	HENRY HUB $/MMBTU	UPS REPLACEMENT DISPATCH PRICE $/MMBTU	FGT MM$	GULFSTREAM MM$	SESH MM$	TRANSCO 4A MM$	GULF SOUTH MM$	SABAL TRAIL & FSC MM$	BAY GAS STORAGE DEMAND CHARGE MM$	UPS REPLACEMENT SUNK DEMAND CHARGE MM$
2034	$8.73	$8.74	$8.74	$8.74	$9.45	$8.66	$9.59	$8.61	$8.47		$355.5	$142.0	$58.2	$4.4	$15.2	[redacted]		
2035	$8.94	$8.95	$8.95	$8.95	$9.66	$8.87	$9.80	$8.81	$8.67		$355.5	$142.0	$58.2	$4.4	$15.2			
2036	$9.15	$9.16	$9.16	$9.16	$9.88	$9.08	$10.01	$9.02	$8.88		$356.5	$142.4	$58.4	$4.4	$15.3			
2037	$9.38	$9.38	$9.38	$9.38	$10.10	$9.29	$10.23	$9.24	$9.09		$355.5	$142.0	$58.2	$4.4	$15.2			
2038	$9.60	$9.61	$9.61	$9.61	$10.32	$9.52	$10.45	$9.46	$9.31		$355.5	$142.0	$58.2	$4.4	$15.2			
2039	$9.83	$9.84	$9.84	$9.84	$10.55	$9.74	$10.68	$9.68	$9.54		$355.5	$142.0	$58.2	$4.4	$15.2			
2040	$10.07	$10.07	$10.08	$10.08	$10.79	$9.98	$10.91	$9.91	$9.76		$356.5	$142.4	$58.4	$4.4	$15.3			
2041	$10.31	$10.32	$10.32	$10.32	$11.03	$10.22	$11.15	$10.14	$10.00		$355.5	$142.0	$58.2	$4.4	$15.2			
2042	$10.56	$10.56	$10.57	$10.57	$11.28	$10.46	$11.40	$10.38	$10.24		$355.5	$142.0	$58.2	$4.4	$15.2			
2043	$10.81	$10.82	$10.82	$10.82	$11.53	$10.71	$11.65	$10.63	$10.49		$355.5	$142.0	$58.2	$4.4	$15.2			
2044	$11.07	$11.08	$11.08	$11.08	$11.79	$10.97	$11.90	$10.88	$10.74		$356.5	$142.4	$58.4	$4.4	$15.3			
2045	$11.34	$11.35	$11.35	$11.35	$12.06	$11.23	$12.17	$11.14	$11.00		$355.5	$142.0	$58.2	$4.4	$15.2			
2046	$11.61	$11.62	$11.62	$11.62	$12.33	$11.50	$12.43	$11.40	$11.26		$355.5	$142.0	$58.2	$4.4	$15.2			
2047	$11.89	$11.90	$11.90	$11.90	$12.61	$11.78	$12.71	$11.67	$11.53		$355.5	$142.0	$58.2	$4.4	$15.2			
2048	$12.18	$12.18	$12.19	$12.19	$12.90	$12.06	$12.99	$11.95	$11.81		$356.5	$142.4	$58.4	$4.4	$15.3			
2049	$12.47	$12.48	$12.48	$12.48	$13.19	$12.35	$13.28	$12.24	$12.09		$355.5	$142.0	$58.2	$4.4	$15.2			
2050	$12.77	$12.78	$12.78	$12.78	$13.49	$12.64	$13.58	$12.53	$12.38		$355.5	$142.0	$58.2	$4.4	$15.2			
2051	$13.08	$13.08	$13.09	$13.09	$13.80	$12.95	$13.88	$12.82	$12.68		$355.5	$142.0	$58.2	$4.4	$15.2			
2052	$13.39	$13.40	$13.40	$13.40	$14.11	$13.26	$14.19	$13.13	$12.98		$356.5	$142.4	$58.4	$4.4	$15.3			
2053	$13.71	$13.72	$13.72	$13.72	$14.44	$13.57	$14.51	$13.44	$13.30		$355.5	$142.0	$58.2	$4.4	$15.2			
2054	$14.04	$14.05	$14.05	$14.05	$14.77	$13.90	$14.83	$13.76	$13.61		$355.5	$142.0	$58.2	$4.4	$15.2			
2055	$14.38	$14.39	$14.39	$14.39	$15.10	$14.23	$15.17	$14.09	$13.94		$355.5	$142.0	$58.2	$4.4	$15.2			
2056	$14.73	$14.73	$14.74	$14.74	$15.45	$14.57	$15.51	$14.42	$14.28		$356.5	$142.4	$58.4	$4.4	$15.3			
2057	$15.08	$15.09	$15.09	$15.09	$15.80	$14.92	$15.86	$14.77	$14.62		$355.5	$142.0	$58.2	$4.4	$15.2			
2058	$15.45	$15.45	$15.45	$15.45	$16.17	$15.28	$16.21	$15.12	$14.97		$355.5	$142.0	$58.2	$4.4	$15.2			
2059	$15.82	$15.82	$15.83	$15.82	$16.54	$15.65	$16.58	$15.48	$15.33		$355.5	$142.0	$58.2	$4.4	$15.2			
2060	$16.20	$16.20	$16.21	$16.20	$16.92	$16.02	$16.96	$15.85	$15.70		$356.5	$142.4	$58.4	$4.4	$15.3			
2061	$16.59	$16.59	$16.60	$16.59	$17.31	$16.41	$17.34	$16.22	$16.08		$355.5	$142.0	$58.2	$4.4	$15.2			
2062	$16.99	$16.99	$16.99	$16.99	$17.71	$16.80	$17.73	$16.61	$16.46		$355.5	$142.0	$58.2	$4.4	$15.2			
2063	$17.39	$17.40	$17.40	$17.40	$18.11	$17.20	$18.14	$17.00	$16.86		$355.5	$142.0	$58.2	$4.4	$15.2			
2064	$17.81	$17.82	$17.82	$17.82	$18.53	$17.61	$18.55	$17.41	$17.26		$356.5	$142.4	$58.4	$4.4	$15.3			
2065	$18.24	$18.25	$18.25	$18.25	$18.96	$18.04	$18.97	$17.83	$17.68		$355.5	$142.0	$58.2	$4.4	$15.2			
2066	$18.68	$18.69	$18.69	$18.69	$19.40	$18.47	$19.40	$18.25	$18.10		$355.5	$142.0	$58.2	$4.4	$15.2			
2067	$19.13	$19.13	$19.14	$19.14	$19.85	$18.91	$19.85	$18.69	$18.54		$355.5	$142.0	$58.2	$4.4	$15.2			
2068	$19.59	$19.59	$19.60	$19.60	$20.31	$19.37	$20.30	$19.13	$18.98		$356.5	$142.4	$58.4	$4.4	$15.3			
2069	$20.06	$20.07	$20.07	$20.07	$20.78	$19.83	$20.76	$19.59	$19.44		$355.5	$142.0	$58.2	$4.4	$15.2			
2070	$20.54	$20.55	$20.55	$20.55	$21.26	$20.31	$21.24	$20.05	$19.91		$355.5	$142.0	$58.2	$4.4	$15.2			
2071	$21.04	$21.04	$21.04	$21.04	$21.76	$20.79	$21.73	$20.53	$20.38		$355.5	$142.0	$58.2	$4.4	$15.2			
2072	$21.54	$21.55	$21.55	$21.55	$22.26	$21.29	$22.23	$21.02	$20.87		$356.5	$142.4	$58.4	$4.4	$15.3			
2073	$22.06	$22.07	$22.07	$22.07	$22.78	$21.80	$22.74	$21.52	$21.38		$355.5	$142.0	$58.2	$4.4	$15.2			
2074	$22.59	$22.60	$22.60	$22.60	$23.31	$22.32	$23.26	$22.04	$21.89		$355.5	$142.0	$58.2	$4.4	$15.2			
2075	$23.13	$23.14	$23.14	$23.14	$23.85	$22.86	$23.79	$22.56	$22.41		$355.5	$142.0	$58.2	$4.4	$15.2			
2076	$23.69	$23.70	$23.70	$23.70	$24.41	$23.41	$24.34	$23.10	$22.95		$356.5	$142.4	$58.4	$4.4	$15.3			
2077	$24.26	$24.26	$24.27	$24.27	$24.98	$23.97	$24.90	$23.66	$23.51		$355.5	$142.0	$58.2	$4.4	$15.2			
2078	$24.84	$24.85	$24.85	$24.85	$25.56	$24.55	$25.48	$24.22	$24.07		$355.5	$142.0	$58.2	$4.4	$15.2			
2079	$25.44	$25.45	$25.45	$25.45	$26.16	$25.13	$26.07	$24.80	$24.65		$355.5	$142.0	$58.2	$4.4	$15.2			
2080	$26.05	$26.06	$26.06	$26.06	$26.77	$25.74	$26.67	$25.39	$25.24		$356.5	$142.4	$58.4	$4.4	$15.3			
2081	$26.68	$26.68	$26.69	$26.68	$27.40	$26.35	$27.29	$26.00	$25.85		$355.5	$142.0	$58.2	$4.4	$15.2			
2082	$27.32	$27.32	$27.33	$27.33	$28.04	$26.99	$27.92	$26.62	$26.47		$355.5	$142.0	$58.2	$4.4	$15.2			
2083	$27.97	$27.98	$27.98	$27.98	$28.70	$27.63	$28.57	$27.26	$27.10		$355.5	$142.0	$58.2	$4.4	$15.2			
2084	$28.65	$28.65	$28.66	$28.65	$29.37	$28.30	$29.23	$27.91	$27.75		$356.5	$142.4	$58.4	$4.4	$15.3			
2085	$29.34	$29.34	$29.35	$29.34	$30.06	$28.98	$29.91	$28.57	$28.42		$355.5	$142.0	$58.2	$4.4	$15.2			
2086	$30.04	$30.05	$30.05	$30.05	$30.76	$29.67	$30.61	$29.26	$29.10		$355.5	$142.0	$58.2	$4.4	$15.2			
2087	$30.76	$30.77	$30.77	$30.77	$31.48	$30.38	$31.32	$29.96	$29.80		$355.5	$142.0	$58.2	$4.4	$15.2			
2088	$31.50	$31.51	$31.51	$31.51	$32.22	$31.11	$32.05	$30.67	$30.52		$356.5	$142.4	$58.4	$4.4	$15.3			
2089	$32.26	$32.27	$32.27	$32.27	$32.98	$31.86	$32.79	$31.41	$31.25		$355.5	$142.0	$58.2	$4.4	$15.2			
2090	$33.04	$33.04	$33.04	$33.04	$33.76	$32.62	$33.56	$32.16	$32.00		$355.5	$142.0	$58.2	$4.4	$15.2			
2091	$33.83	$33.84	$33.84	$33.84	$34.55	$33.41	$34.34	$32.93	$32.77		$355.5	$142.0	$58.2	$4.4	$15.2			
2092	$34.64	$34.65	$34.65	$34.65	$35.36	$34.21	$35.14	$33.72	$33.56		$356.5	$142.4	$58.4	$4.4	$15.3			
2093	$35.48	$35.48	$35.49	$35.48	$36.20	$35.03	$35.97	$34.52	$34.37		$355.5	$142.0	$58.2	$4.4	$15.2			
2094	$36.33	$36.33	$36.34	$36.34	$37.05	$35.87	$36.81	$35.35	$35.19		$355.5	$142.0	$58.2	$4.4	$15.2			
2095	$37.20	$37.21	$37.21	$37.21	$37.92	$36.73	$37.67	$36.19	$36.04		$355.5	$142.0	$58.2	$4.4	$15.2			
2096	$38.10	$38.10	$38.11	$38.10	$38.82	$37.61	$38.55	$37.06	$36.90		$356.5	$142.4	$58.4	$4.4	$15.3			
2097	$39.01	$39.02	$39.02	$39.02	$39.73	$38.52	$39.45	$37.95	$37.79		$355.5	$142.0	$58.2	$4.4	$15.2			
2098	$39.95	$39.96	$39.96	$39.96	$40.67	$39.44	$40.38	$38.86	$38.70		$355.5	$142.0	$58.2	$4.4	$15.2			
2099	$40.91	$40.92	$40.92	$40.92	$41.63	$40.39	$41.32	$39.79	$39.63		$355.5	$142.0	$58.2	$4.4	$15.2			
2100	$41.89	$41.90	$41.90	$41.90	$42.61	$41.36	$42.29	$40.74	$40.58		$355.5	$142.0	$58.2	$4.4	$15.2			

LONG-TERM FORECAST METHODOLOGY - CAPACITY
July 28, 2014 - LYSTRA LOUTAN

FGT FIRM BY ZONE

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jan-14	31	123	298	729	1150	100		695	50
Feb-14	30	123	298	729	1150	100		695	50
Mar-14	31	123	298	729	1150	100		695	50
Apr-14	30	141	268	830	1239	100		695	50
May-14	31	194	267	862	1324	75		695	50
Jun-14	30	194	267	862	1324	50		695	50
Jul-14	31	194	267	862	1324	50		695	0
Aug-14	31	194	267	862	1324	50		695	0
Sep-14	30	194	267	862	1324	50		695	0
Oct-14	31	132	277	830	1239	75		695	0
Nov-14	30	123	298	729	1150	100		695	50
Dec-14	31	123	298	729	1150	100		695	50
Jan-15	31	123	298	729	1150	100		695	50
Feb-15	28	123	298	729	1150	100		695	50
Mar-15	31	123	298	729	1150	100		695	50
Apr-15	30	141	268	830	1239	100		695	50
May-15	31	194	267	862	1324	75		695	50
Jun-15	30	194	267	862	1324	50		695	50
Jul-15	31	194	267	862	1324	50		695	0
Aug-15	31	194	267	862	1324	50		695	0
Sep-15	30	194	267	862	1324	50		695	0
Oct-15	31	132	277	830	1239	75		695	0
Nov-15	30	123	298	729	1150	100		695	50
Dec-15	31	123	298	729	1150	100		695	50
Jan-16	31	123	298	729	1150	100		695	50
Feb-16	29	123	298	729	1150	100		695	50
Mar-16	31	123	298	729	1150	100		695	50
Apr-16	30	141	268	830	1239	100		695	50
May-16	31	194	267	812	1274	75		695	50
Jun-16	30	194	267	812	1274	50		695	50
Jul-16	31	194	267	812	1274	50		695	0
Aug-16	31	194	267	812	1274	50		695	0
Sep-16	30	194	267	812	1274	50		695	0
Oct-16	31	132	277	830	1239	75		695	0
Nov-16	30	123	298	729	1150	100		695	50
Dec-16	31	123	298	729	1150	100		695	50
Jan-17	31	123	298	729	1150	100		695	50
Feb-17	28	123	298	729	1150	100		695	50
Mar-17	31	123	298	729	1150	100		695	50
Apr-17	30	141	268	830	1239	100		695	50
May-17	31	194	267	812	1274	75	400	695	50
Jun-17	30	194	267	812	1274	50	400	695	50
Jul-17	31	194	267	812	1274	50	400	695	0
Aug-17	31	194	267	812	1274	50	400	695	0
Sep-17	30	194	267	812	1274	50	400	695	0
Oct-17	31	132	277	830	1239	75	400	695	0
Nov-17	30	123	298	729	1150	100	400	695	50
Dec-17	31	123	298	729	1150	100	400	695	50
Jan-18	31	123	298	729	1150	100	400	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-18	28	123	298	729	1150	100	**400**	695	50
Mar-18	31	123	298	729	1150	100	**400**	695	50
Apr-18	30	141	268	830	1239	100	**400**	695	50
May-18	31	194	267	812	1274	75	**400**	695	50
Jun-18	30	194	267	812	1274	50	**400**	695	50
Jul-18	31	194	267	812	1274	50	**400**	695	0
Aug-18	31	194	267	812	1274	50	**400**	695	0
Sep-18	30	194	267	812	1274	50	**400**	695	0
Oct-18	31	132	277	830	1239	75	**400**	695	0
Nov-18	30	123	298	729	1150	100	**400**	695	50
Dec-18	31	123	298	729	1150	100	**400**	695	50
Jan-19	31	123	298	729	1150	100	**400**	695	50
Feb-19	28	123	298	729	1150	100	**400**	695	50
Mar-19	31	123	298	729	1150	100	**400**	695	50
Apr-19	30	141	268	830	1239	100	**400**	695	50
May-19	31	194	267	812	1274	75	**400**	695	50
Jun-19	30	194	267	812	1274	50	**400**	695	50
Jul-19	31	194	267	812	1274	50	**400**	695	0
Aug-19	31	194	267	812	1274	50	**400**	695	0
Sep-19	30	194	267	812	1274	50	**400**	695	0
Oct-19	31	132	277	830	1239	75	**400**	695	0
Nov-19	30	123	298	729	1150	100	**400**	695	50
Dec-19	31	123	298	729	1150	100	**400**	695	50
Jan-20	31	123	298	729	1150	100	**400**	695	50
Feb-20	29	123	298	729	1150	100	**400**	695	50
Mar-20	31	123	298	729	1150	100	**400**	695	50
Apr-20	30	141	268	830	1239	100	**400**	695	50
May-20	31	194	267	812	1274	75	**600**	695	50
Jun-20	30	194	267	812	1274	50	**600**	695	50
Jul-20	31	194	267	812	1274	50	**600**	695	0
Aug-20	31	194	267	812	1274	50	**600**	695	0
Sep-20	30	194	267	812	1274	50	**600**	695	0
Oct-20	31	132	277	830	1239	75	**600**	695	0
Nov-20	30	123	298	729	1150	100	**600**	695	50
Dec-20	31	123	298	729	1150	100	**600**	695	50
Jan-21	31	123	298	729	1150	100	**600**	695	50
Feb-21	28	123	298	729	1150	100	**600**	695	50
Mar-21	31	123	298	729	1150	100	**600**	695	50
Apr-21	30	141	268	830	1239	100	**600**	695	50
May-21	31	194	267	812	1274	75	**600**	695	50
Jun-21	30	194	267	812	1274	50	**600**	695	50
Jul-21	31	194	267	812	1274	50	**600**	695	0
Aug-21	31	194	267	812	1274	50	**600**	695	0
Sep-21	30	194	267	812	1274	50	**600**	695	0
Oct-21	31	132	277	830	1239	75	**600**	695	0
Nov-21	30	123	298	729	1150	100	**600**	695	50
Dec-21	31	123	298	729	1150	100	**600**	695	50
Jan-22	31	123	298	729	1150	100	**600**	695	50
Feb-22	28	123	298	729	1150	100	**600**	695	50
Mar-22	31	123	298	729	1150	100	**600**	695	50
Apr-22	30	141	268	830	1239	100	**600**	695	50
May-22	31	194	267	812	1274	75	**600**	695	50
Jun-22	30	194	267	812	1274	50	**600**	695	50
Jul-22	31	194	267	812	1274	50	**600**	695	0
Aug-22	31	194	267	812	1274	50	**600**	695	0
Sep-22	30	194	267	812	1274	50	**600**	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-22	31	132	277	830	1239	75	600	695	0
Nov-22	30	123	298	729	1150	100	600	695	50
Dec-22	31	123	298	729	1150	100	600	695	50
Jan-23	31	123	298	729	1150	100	600	695	50
Feb-23	28	123	298	729	1150	100	600	695	50
Mar-23	31	123	298	729	1150	100	600	695	50
Apr-23	30	141	268	830	1239	100	600	695	50
May-23	31	194	267	812	1274	75	600	695	50
Jun-23	30	194	267	812	1274	50	600	695	50
Jul-23	31	194	267	812	1274	50	600	695	0
Aug-23	31	194	267	812	1274	50	600	695	0
Sep-23	30	194	267	812	1274	50	600	695	0
Oct-23	31	132	277	830	1239	75	600	695	0
Nov-23	30	123	298	729	1150	100	600	695	50
Dec-23	31	123	298	729	1150	100	600	695	50
Jan-24	31	123	298	729	1150	100	600	695	50
Feb-24	29	123	298	729	1150	100	600	695	50
Mar-24	31	123	298	729	1150	100	600	695	50
Apr-24	30	141	268	830	1239	100	600	695	50
May-24	31	194	267	812	1274	75	600	695	50
Jun-24	30	194	267	812	1274	50	600	695	50
Jul-24	31	194	267	812	1274	50	600	695	0
Aug-24	31	194	267	812	1274	50	600	695	0
Sep-24	30	194	267	812	1274	50	600	695	0
Oct-24	31	132	277	830	1239	75	600	695	0
Nov-24	30	123	298	729	1150	100	600	695	50
Dec-24	31	123	298	729	1150	100	600	695	50
Jan-25	31	123	298	729	1150	100	600	695	50
Feb-25	28	123	298	729	1150	100	600	695	50
Mar-25	31	123	298	729	1150	100	600	695	50
Apr-25	30	141	268	830	1239	100	600	695	50
May-25	31	194	267	812	1274	75	600	695	50
Jun-25	30	194	267	812	1274	50	600	695	50
Jul-25	31	194	267	812	1274	50	600	695	0
Aug-25	31	194	267	812	1274	50	600	695	0
Sep-25	30	194	267	812	1274	50	600	695	0
Oct-25	31	132	277	830	1239	75	600	695	0
Nov-25	30	123	298	729	1150	100	600	695	50
Dec-25	31	123	298	729	1150	100	600	695	50
Jan-26	31	123	298	729	1150	100	600	695	50
Feb-26	28	123	298	729	1150	100	600	695	50
Mar-26	31	123	298	729	1150	100	600	695	50
Apr-26	30	141	268	830	1239	100	600	695	50
May-26	31	194	267	812	1274	75	600	695	50
Jun-26	30	194	267	812	1274	50	600	695	50
Jul-26	31	194	267	812	1274	50	600	695	0
Aug-26	31	194	267	812	1274	50	600	695	0
Sep-26	30	194	267	812	1274	50	600	695	0
Oct-26	31	132	277	830	1239	75	600	695	0
Nov-26	30	123	298	729	1150	100	600	695	50
Dec-26	31	123	298	729	1150	100	600	695	50
Jan-27	31	123	298	729	1150	100	600	695	50
Feb-27	28	123	298	729	1150	100	600	695	50
Mar-27	31	123	298	729	1150	100	600	695	50
Apr-27	30	141	268	830	1239	100	600	695	50
May-27	31	194	267	812	1274	75	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-27	30	194	267	812	1274	50	600	695	50
Jul-27	31	194	267	812	1274	50	600	695	0
Aug-27	31	194	267	812	1274	50	600	695	0
Sep-27	30	194	267	812	1274	50	600	695	0
Oct-27	31	132	277	830	1239	75	600	695	0
Nov-27	30	123	298	729	1150	100	600	695	50
Dec-27	31	123	298	729	1150	100	600	695	50
Jan-28	31	123	298	729	1150	100	600	695	50
Feb-28	29	123	298	729	1150	100	600	695	50
Mar-28	31	123	298	729	1150	100	600	695	50
Apr-28	30	141	268	830	1239	100	600	695	50
May-28	31	194	267	812	1274	75	600	695	50
Jun-28	30	194	267	812	1274	50	600	695	50
Jul-28	31	194	267	812	1274	50	600	695	0
Aug-28	31	194	267	812	1274	50	600	695	0
Sep-28	30	194	267	812	1274	50	600	695	0
Oct-28	31	132	277	830	1239	75	600	695	0
Nov-28	30	123	298	729	1150	100	600	695	50
Dec-28	31	123	298	729	1150	100	600	695	50
Jan-29	31	123	298	729	1150	100	600	695	50
Feb-29	28	123	298	729	1150	100	600	695	50
Mar-29	31	123	298	729	1150	100	600	695	50
Apr-29	30	141	268	830	1239	100	600	695	50
May-29	31	194	267	812	1274	75	600	695	50
Jun-29	30	194	267	812	1274	50	600	695	50
Jul-29	31	194	267	812	1274	50	600	695	0
Aug-29	31	194	267	812	1274	50	600	695	0
Sep-29	30	194	267	812	1274	50	600	695	0
Oct-29	31	132	277	830	1239	75	600	695	0
Nov-29	30	123	298	729	1150	100	600	695	50
Dec-29	31	123	298	729	1150	100	600	695	50
Jan-30	31	123	298	729	1150	100	600	695	50
Feb-30	28	123	298	729	1150	100	600	695	50
Mar-30	31	123	298	729	1150	100	600	695	50
Apr-30	30	141	268	830	1239	100	600	695	50
May-30	31	194	267	812	1274	75	600	695	50
Jun-30	30	194	267	812	1274	50	600	695	50
Jul-30	31	194	267	812	1274	50	600	695	0
Aug-30	31	194	267	812	1274	50	600	695	0
Sep-30	30	194	267	812	1274	50	600	695	0
Oct-30	31	132	277	830	1239	75	600	695	0
Nov-30	30	123	298	729	1150	100	600	695	50
Dec-30	31	123	298	729	1150	100	600	695	50
Jan-31	31	123	298	729	1150	100	600	695	50
Feb-31	28	123	298	729	1150	100	600	695	50
Mar-31	31	123	298	729	1150	100	600	695	50
Apr-31	30	141	268	830	1239	100	600	695	50
May-31	31	194	267	812	1274	75	600	695	50
Jun-31	30	194	267	812	1274	50	600	695	50
Jul-31	31	194	267	812	1274	50	600	695	0
Aug-31	31	194	267	812	1274	50	600	695	0
Sep-31	30	194	267	812	1274	50	600	695	0
Oct-31	31	132	277	830	1239	75	600	695	0
Nov-31	30	123	298	729	1150	100	600	695	50
Dec-31	31	123	298	729	1150	100	600	695	50
Jan-32	31	123	298	729	1150	100	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-32	29	123	298	729	1150	100	600	695	50
Mar-32	31	123	298	729	1150	100	600	695	50
Apr-32	30	141	268	830	1239	100	600	695	50
May-32	31	194	267	812	1274	75	600	695	50
Jun-32	30	194	267	812	1274	50	600	695	50
Jul-32	31	194	267	812	1274	50	600	695	0
Aug-32	31	194	267	812	1274	50	600	695	0
Sep-32	30	194	267	812	1274	50	600	695	0
Oct-32	31	132	277	830	1239	75	600	695	0
Nov-32	30	123	298	729	1150	100	600	695	50
Dec-32	31	123	298	729	1150	100	600	695	50
Jan-33	31	123	298	729	1150	100	600	695	50
Feb-33	28	123	298	729	1150	100	600	695	50
Mar-33	31	123	298	729	1150	100	600	695	50
Apr-33	30	141	268	830	1239	100	600	695	50
May-33	31	194	267	812	1274	75	600	695	50
Jun-33	30	194	267	812	1274	50	600	695	50
Jul-33	31	194	267	812	1274	50	600	695	0
Aug-33	31	194	267	812	1274	50	600	695	0
Sep-33	30	194	267	812	1274	50	600	695	0
Oct-33	31	132	277	830	1239	75	600	695	0
Nov-33	30	123	298	729	1150	100	600	695	50
Dec-33	31	123	298	729	1150	100	600	695	50
Jan-34	31	123	298	729	1150	100	600	695	50
Feb-34	28	123	298	729	1150	100	600	695	50
Mar-34	31	123	298	729	1150	100	600	695	50
Apr-34	30	141	268	830	1239	100	600	695	50
May-34	31	194	267	812	1274	75	600	695	50
Jun-34	30	194	267	812	1274	50	600	695	50
Jul-34	31	194	267	812	1274	50	600	695	0
Aug-34	31	194	267	812	1274	50	600	695	0
Sep-34	30	194	267	812	1274	50	600	695	0
Oct-34	31	132	277	830	1239	75	600	695	0
Nov-34	30	123	298	729	1150	100	600	695	50
Dec-34	31	123	298	729	1150	100	600	695	50
Jan-35	31	123	298	729	1150	100	600	695	50
Feb-35	28	123	298	729	1150	100	600	695	50
Mar-35	31	123	298	729	1150	100	600	695	50
Apr-35	30	141	268	830	1239	100	600	695	50
May-35	31	194	267	812	1274	75	600	695	50
Jun-35	30	194	267	812	1274	50	600	695	50
Jul-35	31	194	267	812	1274	50	600	695	0
Aug-35	31	194	267	812	1274	50	600	695	0
Sep-35	30	194	267	812	1274	50	600	695	0
Oct-35	31	132	277	830	1239	75	600	695	0
Nov-35	30	123	298	729	1150	100	600	695	50
Dec-35	31	123	298	729	1150	100	600	695	50
Jan-36	31	123	298	729	1150	100	600	695	50
Feb-36	29	123	298	729	1150	100	600	695	50
Mar-36	31	123	298	729	1150	100	600	695	50
Apr-36	30	141	268	830	1239	100	600	695	50
May-36	31	194	267	812	1274	75	600	695	50
Jun-36	30	194	267	812	1274	50	600	695	50
Jul-36	31	194	267	812	1274	50	600	695	0
Aug-36	31	194	267	812	1274	50	600	695	0
Sep-36	30	194	267	812	1274	50	600	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-36	31	132	277	830	1239	75	**600**	695	0
Nov-36	30	123	298	729	1150	100	**600**	695	50
Dec-36	31	123	298	729	1150	100	**600**	695	50
Jan-37	31	123	298	729	1150	100	**600**	695	50
Feb-37	28	123	298	729	1150	100	**600**	695	50
Mar-37	31	123	298	729	1150	100	**600**	695	50
Apr-37	30	141	268	830	1239	100	**600**	695	50
May-37	31	194	267	812	1274	75	**600**	695	50
Jun-37	30	194	267	812	1274	50	**600**	695	50
Jul-37	31	194	267	812	1274	50	**600**	695	0
Aug-37	31	194	267	812	1274	50	**600**	695	0
Sep-37	30	194	267	812	1274	50	**600**	695	0
Oct-37	31	132	277	830	1239	75	**600**	695	0
Nov-37	30	123	298	729	1150	100	**600**	695	50
Dec-37	31	123	298	729	1150	100	**600**	695	50
Jan-38	31	123	298	729	1150	100	**600**	695	50
Feb-38	28	123	298	729	1150	100	**600**	695	50
Mar-38	31	123	298	729	1150	100	**600**	695	50
Apr-38	30	141	268	830	1239	100	**600**	695	50
May-38	31	194	267	812	1274	75	**600**	695	50
Jun-38	30	194	267	812	1274	50	**600**	695	50
Jul-38	31	194	267	812	1274	50	**600**	695	0
Aug-38	31	194	267	812	1274	50	**600**	695	0
Sep-38	30	194	267	812	1274	50	**600**	695	0
Oct-38	31	132	277	830	1239	75	**600**	695	0
Nov-38	30	123	298	729	1150	100	**600**	695	50
Dec-38	31	123	298	729	1150	100	**600**	695	50
Jan-39	31	123	298	729	1150	100	**600**	695	50
Feb-39	28	123	298	729	1150	100	**600**	695	50
Mar-39	31	123	298	729	1150	100	**600**	695	50
Apr-39	30	141	268	830	1239	100	**600**	695	50
May-39	31	194	267	812	1274	75	**600**	695	50
Jun-39	30	194	267	812	1274	50	**600**	695	50
Jul-39	31	194	267	812	1274	50	**600**	695	0
Aug-39	31	194	267	812	1274	50	**600**	695	0
Sep-39	30	194	267	812	1274	50	**600**	695	0
Oct-39	31	132	277	830	1239	75	**600**	695	0
Nov-39	30	123	298	729	1150	100	**600**	695	50
Dec-39	31	123	298	729	1150	100	**600**	695	50
Jan-40	31	123	298	729	1150	100	**600**	695	50
Feb-40	29	123	298	729	1150	100	**600**	695	50
Mar-40	31	123	298	729	1150	100	**600**	695	50
Apr-40	30	141	268	830	1239	100	**600**	695	50
May-40	31	194	267	812	1274	75	**600**	695	50
Jun-40	30	194	267	812	1274	50	**600**	695	50
Jul-40	31	194	267	812	1274	50	**600**	695	0
Aug-40	31	194	267	812	1274	50	**600**	695	0
Sep-40	30	194	267	812	1274	50	**600**	695	0
Oct-40	31	132	277	830	1239	75	**600**	695	0
Nov-40	30	123	298	729	1150	100	**600**	695	50
Dec-40	31	123	298	729	1150	100	**600**	695	50
Jan-41	31	123	298	729	1150	100	**600**	695	50
Feb-41	28	123	298	729	1150	100	**600**	695	50
Mar-41	31	123	298	729	1150	100	**600**	695	50
Apr-41	30	141	268	830	1239	100	**600**	695	50
May-41	31	194	267	812	1274	75	**600**	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-41	30	194	267	812	1274	50	600	695	50
Jul-41	31	194	267	812	1274	50	600	695	0
Aug-41	31	194	267	812	1274	50	600	695	0
Sep-41	30	194	267	812	1274	50	600	695	0
Oct-41	31	132	277	830	1239	75	600	695	0
Nov-41	30	123	298	729	1150	100	600	695	50
Dec-41	31	123	298	729	1150	100	600	695	50
Jan-42	31	123	298	729	1150	100	600	695	50
Feb-42	28	123	298	729	1150	100	600	695	50
Mar-42	31	123	298	729	1150	100	600	695	50
Apr-42	30	141	268	830	1239	100	600	695	50
May-42	31	194	267	812	1274	75	600	695	50
Jun-42	30	194	267	812	1274	50	600	695	50
Jul-42	31	194	267	812	1274	50	600	695	0
Aug-42	31	194	267	812	1274	50	600	695	0
Sep-42	30	194	267	812	1274	50	600	695	0
Oct-42	31	132	277	830	1239	75	600	695	0
Nov-42	30	123	298	729	1150	100	600	695	50
Dec-42	31	123	298	729	1150	100	600	695	50
Jan-43	31	123	298	729	1150	100	600	695	50
Feb-43	28	123	298	729	1150	100	600	695	50
Mar-43	31	123	298	729	1150	100	600	695	50
Apr-43	30	141	268	830	1239	100	600	695	50
May-43	31	194	267	812	1274	75	600	695	50
Jun-43	30	194	267	812	1274	50	600	695	50
Jul-43	31	194	267	812	1274	50	600	695	0
Aug-43	31	194	267	812	1274	50	600	695	0
Sep-43	30	194	267	812	1274	50	600	695	0
Oct-43	31	132	277	830	1239	75	600	695	0
Nov-43	30	123	298	729	1150	100	600	695	50
Dec-43	31	123	298	729	1150	100	600	695	50
Jan-44	31	123	298	729	1150	100	600	695	50
Feb-44	29	123	298	729	1150	100	600	695	50
Mar-44	31	123	298	729	1150	100	600	695	50
Apr-44	30	141	268	830	1239	100	600	695	50
May-44	31	194	267	812	1274	75	600	695	50
Jun-44	30	194	267	812	1274	50	600	695	50
Jul-44	31	194	267	812	1274	50	600	695	0
Aug-44	31	194	267	812	1274	50	600	695	0
Sep-44	30	194	267	812	1274	50	600	695	0
Oct-44	31	132	277	830	1239	75	600	695	0
Nov-44	30	123	298	729	1150	100	600	695	50
Dec-44	31	123	298	729	1150	100	600	695	50
Jan-45	31	123	298	729	1150	100	600	695	50
Feb-45	28	123	298	729	1150	100	600	695	50
Mar-45	31	123	298	729	1150	100	600	695	50
Apr-45	30	141	268	830	1239	100	600	695	50
May-45	31	194	267	812	1274	75	600	695	50
Jun-45	30	194	267	812	1274	50	600	695	50
Jul-45	31	194	267	812	1274	50	600	695	0
Aug-45	31	194	267	812	1274	50	600	695	0
Sep-45	30	194	267	812	1274	50	600	695	0
Oct-45	31	132	277	830	1239	75	600	695	0
Nov-45	30	123	298	729	1150	100	600	695	50
Dec-45	31	123	298	729	1150	100	600	695	50
Jan-46	31	123	298	729	1150	100	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-46	28	123	298	729	1150	100	600	695	50
Mar-46	31	123	298	729	1150	100	600	695	50
Apr-46	30	141	268	830	1239	100	600	695	50
May-46	31	194	267	812	1274	75	600	695	50
Jun-46	30	194	267	812	1274	50	600	695	50
Jul-46	31	194	267	812	1274	50	600	695	0
Aug-46	31	194	267	812	1274	50	600	695	0
Sep-46	30	194	267	812	1274	50	600	695	0
Oct-46	31	132	277	830	1239	75	600	695	0
Nov-46	30	123	298	729	1150	100	600	695	50
Dec-46	31	123	298	729	1150	100	600	695	50
Jan-47	31	123	298	729	1150	100	600	695	50
Feb-47	28	123	298	729	1150	100	600	695	50
Mar-47	31	123	298	729	1150	100	600	695	50
Apr-47	30	141	268	830	1239	100	600	695	50
May-47	31	194	267	812	1274	75	600	695	50
Jun-47	30	194	267	812	1274	50	600	695	50
Jul-47	31	194	267	812	1274	50	600	695	0
Aug-47	31	194	267	812	1274	50	600	695	0
Sep-47	30	194	267	812	1274	50	600	695	0
Oct-47	31	132	277	830	1239	75	600	695	0
Nov-47	30	123	298	729	1150	100	600	695	50
Dec-47	31	123	298	729	1150	100	600	695	50
Jan-48	31	123	298	729	1150	100	600	695	50
Feb-48	29	123	298	729	1150	100	600	695	50
Mar-48	31	123	298	729	1150	100	600	695	50
Apr-48	30	141	268	830	1239	100	600	695	50
May-48	31	194	267	812	1274	75	600	695	50
Jun-48	30	194	267	812	1274	50	600	695	50
Jul-48	31	194	267	812	1274	50	600	695	0
Aug-48	31	194	267	812	1274	50	600	695	0
Sep-48	30	194	267	812	1274	50	600	695	0
Oct-48	31	132	277	830	1239	75	600	695	0
Nov-48	30	123	298	729	1150	100	600	695	50
Dec-48	31	123	298	729	1150	100	600	695	50
Jan-49	31	123	298	729	1150	100	600	695	50
Feb-49	28	123	298	729	1150	100	600	695	50
Mar-49	31	123	298	729	1150	100	600	695	50
Apr-49	30	141	268	830	1239	100	600	695	50
May-49	31	194	267	812	1274	75	600	695	50
Jun-49	30	194	267	812	1274	50	600	695	50
Jul-49	31	194	267	812	1274	50	600	695	0
Aug-49	31	194	267	812	1274	50	600	695	0
Sep-49	30	194	267	812	1274	50	600	695	0
Oct-49	31	132	277	830	1239	75	600	695	0
Nov-49	30	123	298	729	1150	100	600	695	50
Dec-49	31	123	298	729	1150	100	600	695	50
Jan-50	31	123	298	729	1150	100	600	695	50
Feb-50	28	123	298	729	1150	100	600	695	50
Mar-50	31	123	298	729	1150	100	600	695	50
Apr-50	30	141	268	830	1239	100	600	695	50
May-50	31	194	267	812	1274	75	600	695	50
Jun-50	30	194	267	812	1274	50	600	695	50
Jul-50	31	194	267	812	1274	50	600	695	0
Aug-50	31	194	267	812	1274	50	600	695	0
Sep-50	30	194	267	812	1274	50	600	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-50	31	132	277	830	1239	75	**600**	695	0
Nov-50	30	123	298	729	1150	100	**600**	695	50
Dec-50	31	123	298	729	1150	100	**600**	695	50
Jan-51	31	123	298	729	1150	100	**600**	695	50
Feb-51	28	123	298	729	1150	100	**600**	695	50
Mar-51	31	123	298	729	1150	100	**600**	695	50
Apr-51	30	141	268	830	1239	100	**600**	695	50
May-51	31	194	267	812	1274	75	**600**	695	50
Jun-51	30	194	267	812	1274	50	**600**	695	50
Jul-51	31	194	267	812	1274	50	**600**	695	0
Aug-51	31	194	267	812	1274	50	**600**	695	0
Sep-51	30	194	267	812	1274	50	**600**	695	0
Oct-51	31	132	277	830	1239	75	**600**	695	0
Nov-51	30	123	298	729	1150	100	**600**	695	50
Dec-51	31	123	298	729	1150	100	**600**	695	50
Jan-52	31	123	298	729	1150	100	**600**	695	50
Feb-52	29	123	298	729	1150	100	**600**	695	50
Mar-52	31	123	298	729	1150	100	**600**	695	50
Apr-52	30	141	268	830	1239	100	**600**	695	50
May-52	31	194	267	812	1274	75	**600**	695	50
Jun-52	30	194	267	812	1274	50	**600**	695	50
Jul-52	31	194	267	812	1274	50	**600**	695	0
Aug-52	31	194	267	812	1274	50	**600**	695	0
Sep-52	30	194	267	812	1274	50	**600**	695	0
Oct-52	31	132	277	830	1239	75	**600**	695	0
Nov-52	30	123	298	729	1150	100	**600**	695	50
Dec-52	31	123	298	729	1150	100	**600**	695	50
Jan-53	31	123	298	729	1150	100	**600**	695	50
Feb-53	28	123	298	729	1150	100	**600**	695	50
Mar-53	31	123	298	729	1150	100	**600**	695	50
Apr-53	30	141	268	830	1239	100	**600**	695	50
May-53	31	194	267	812	1274	75	**600**	695	50
Jun-53	30	194	267	812	1274	50	**600**	695	50
Jul-53	31	194	267	812	1274	50	**600**	695	0
Aug-53	31	194	267	812	1274	50	**600**	695	0
Sep-53	30	194	267	812	1274	50	**600**	695	0
Oct-53	31	132	277	830	1239	75	**600**	695	0
Nov-53	30	123	298	729	1150	100	**600**	695	50
Dec-53	31	123	298	729	1150	100	**600**	695	50
Jan-54	31	123	298	729	1150	100	**600**	695	50
Feb-54	28	123	298	729	1150	100	**600**	695	50
Mar-54	31	123	298	729	1150	100	**600**	695	50
Apr-54	30	141	268	830	1239	100	**600**	695	50
May-54	31	194	267	812	1274	75	**600**	695	50
Jun-54	30	194	267	812	1274	50	**600**	695	50
Jul-54	31	194	267	812	1274	50	**600**	695	0
Aug-54	31	194	267	812	1274	50	**600**	695	0
Sep-54	30	194	267	812	1274	50	**600**	695	0
Oct-54	31	132	277	830	1239	75	**600**	695	0
Nov-54	30	123	298	729	1150	100	**600**	695	50
Dec-54	31	123	298	729	1150	100	**600**	695	50
Jan-55	31	123	298	729	1150	100	**600**	695	50
Feb-55	28	123	298	729	1150	100	**600**	695	50
Mar-55	31	123	298	729	1150	100	**600**	695	50
Apr-55	30	141	268	830	1239	100	**600**	695	50
May-55	31	194	267	812	1274	75	**600**	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-55	30	194	267	812	1274	50	600	695	50
Jul-55	31	194	267	812	1274	50	600	695	0
Aug-55	31	194	267	812	1274	50	600	695	0
Sep-55	30	194	267	812	1274	50	600	695	0
Oct-55	31	132	277	830	1239	75	600	695	0
Nov-55	30	123	298	729	1150	100	600	695	50
Dec-55	31	123	298	729	1150	100	600	695	50
Jan-56	31	123	298	729	1150	100	600	695	50
Feb-56	29	123	298	729	1150	100	600	695	50
Mar-56	31	123	298	729	1150	100	600	695	50
Apr-56	30	141	268	830	1239	100	600	695	50
May-56	31	194	267	812	1274	75	600	695	50
Jun-56	30	194	267	812	1274	50	600	695	50
Jul-56	31	194	267	812	1274	50	600	695	0
Aug-56	31	194	267	812	1274	50	600	695	0
Sep-56	30	194	267	812	1274	50	600	695	0
Oct-56	31	132	277	830	1239	75	600	695	0
Nov-56	30	123	298	729	1150	100	600	695	50
Dec-56	31	123	298	729	1150	100	600	695	50
Jan-57	31	123	298	729	1150	100	600	695	50
Feb-57	28	123	298	729	1150	100	600	695	50
Mar-57	31	123	298	729	1150	100	600	695	50
Apr-57	30	141	268	830	1239	100	600	695	50
May-57	31	194	267	812	1274	75	600	695	50
Jun-57	30	194	267	812	1274	50	600	695	50
Jul-57	31	194	267	812	1274	50	600	695	0
Aug-57	31	194	267	812	1274	50	600	695	0
Sep-57	30	194	267	812	1274	50	600	695	0
Oct-57	31	132	277	830	1239	75	600	695	0
Nov-57	30	123	298	729	1150	100	600	695	50
Dec-57	31	123	298	729	1150	100	600	695	50
Jan-58	31	123	298	729	1150	100	600	695	50
Feb-58	28	123	298	729	1150	100	600	695	50
Mar-58	31	123	298	729	1150	100	600	695	50
Apr-58	30	141	268	830	1239	100	600	695	50
May-58	31	194	267	812	1274	75	600	695	50
Jun-58	30	194	267	812	1274	50	600	695	50
Jul-58	31	194	267	812	1274	50	600	695	0
Aug-58	31	194	267	812	1274	50	600	695	0
Sep-58	30	194	267	812	1274	50	600	695	0
Oct-58	31	132	277	830	1239	75	600	695	0
Nov-58	30	123	298	729	1150	100	600	695	50
Dec-58	31	123	298	729	1150	100	600	695	50
Jan-59	31	123	298	729	1150	100	600	695	50
Feb-59	28	123	298	729	1150	100	600	695	50
Mar-59	31	123	298	729	1150	100	600	695	50
Apr-59	30	141	268	830	1239	100	600	695	50
May-59	31	194	267	812	1274	75	600	695	50
Jun-59	30	194	267	812	1274	50	600	695	50
Jul-59	31	194	267	812	1274	50	600	695	0
Aug-59	31	194	267	812	1274	50	600	695	0
Sep-59	30	194	267	812	1274	50	600	695	0
Oct-59	31	132	277	830	1239	75	600	695	0
Nov-59	30	123	298	729	1150	100	600	695	50
Dec-59	31	123	298	729	1150	100	600	695	50
Jan-60	31	123	298	729	1150	100	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-60	29	123	298	729	1150	100	600	695	50
Mar-60	31	123	298	729	1150	100	600	695	50
Apr-60	30	141	268	830	1239	100	600	695	50
May-60	31	194	267	812	1274	75	600	695	50
Jun-60	30	194	267	812	1274	50	600	695	50
Jul-60	31	194	267	812	1274	50	600	695	0
Aug-60	31	194	267	812	1274	50	600	695	0
Sep-60	30	194	267	812	1274	50	600	695	0
Oct-60	31	132	277	830	1239	75	600	695	0
Nov-60	30	123	298	729	1150	100	600	695	50
Dec-60	31	123	298	729	1150	100	600	695	50
Jan-61	31	123	298	729	1150	100	600	695	50
Feb-61	28	123	298	729	1150	100	600	695	50
Mar-61	31	123	298	729	1150	100	600	695	50
Apr-61	30	141	268	830	1239	100	600	695	50
May-61	31	194	267	812	1274	75	600	695	50
Jun-61	30	194	267	812	1274	50	600	695	50
Jul-61	31	194	267	812	1274	50	600	695	0
Aug-61	31	194	267	812	1274	50	600	695	0
Sep-61	30	194	267	812	1274	50	600	695	0
Oct-61	31	132	277	830	1239	75	600	695	0
Nov-61	30	123	298	729	1150	100	600	695	50
Dec-61	31	123	298	729	1150	100	600	695	50
Jan-62	31	123	298	729	1150	100	600	695	50
Feb-62	28	123	298	729	1150	100	600	695	50
Mar-62	31	123	298	729	1150	100	600	695	50
Apr-62	30	141	268	830	1239	100	600	695	50
May-62	31	194	267	812	1274	75	600	695	50
Jun-62	30	194	267	812	1274	50	600	695	50
Jul-62	31	194	267	812	1274	50	600	695	0
Aug-62	31	194	267	812	1274	50	600	695	0
Sep-62	30	194	267	812	1274	50	600	695	0
Oct-62	31	132	277	830	1239	75	600	695	0
Nov-62	30	123	298	729	1150	100	600	695	50
Dec-62	31	123	298	729	1150	100	600	695	50
Jan-63	31	123	298	729	1150	100	600	695	50
Feb-63	28	123	298	729	1150	100	600	695	50
Mar-63	31	123	298	729	1150	100	600	695	50
Apr-63	30	141	268	830	1239	100	600	695	50
May-63	31	194	267	812	1274	75	600	695	50
Jun-63	30	194	267	812	1274	50	600	695	50
Jul-63	31	194	267	812	1274	50	600	695	0
Aug-63	31	194	267	812	1274	50	600	695	0
Sep-63	30	194	267	812	1274	50	600	695	0
Oct-63	31	132	277	830	1239	75	600	695	0
Nov-63	30	123	298	729	1150	100	600	695	50
Dec-63	31	123	298	729	1150	100	600	695	50
Jan-64	31	123	298	729	1150	100	600	695	50
Feb-64	29	123	298	729	1150	100	600	695	50
Mar-64	31	123	298	729	1150	100	600	695	50
Apr-64	30	141	268	830	1239	100	600	695	50
May-64	31	194	267	812	1274	75	600	695	50
Jun-64	30	194	267	812	1274	50	600	695	50
Jul-64	31	194	267	812	1274	50	600	695	0
Aug-64	31	194	267	812	1274	50	600	695	0
Sep-64	30	194	267	812	1274	50	600	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-64	31	132	277	830	1239	75	600	695	0
Nov-64	30	123	298	729	1150	100	600	695	50
Dec-64	31	123	298	729	1150	100	600	695	50
Jan-65	31	123	298	729	1150	100	600	695	50
Feb-65	28	123	298	729	1150	100	600	695	50
Mar-65	31	123	298	729	1150	100	600	695	50
Apr-65	30	141	268	830	1239	100	600	695	50
May-65	31	194	267	812	1274	75	600	695	50
Jun-65	30	194	267	812	1274	50	600	695	50
Jul-65	31	194	267	812	1274	50	600	695	0
Aug-65	31	194	267	812	1274	50	600	695	0
Sep-65	30	194	267	812	1274	50	600	695	0
Oct-65	31	132	277	830	1239	75	600	695	0
Nov-65	30	123	298	729	1150	100	600	695	50
Dec-65	31	123	298	729	1150	100	600	695	50
Jan-66	31	123	298	729	1150	100	600	695	50
Feb-66	28	123	298	729	1150	100	600	695	50
Mar-66	31	123	298	729	1150	100	600	695	50
Apr-66	30	141	268	830	1239	100	600	695	50
May-66	31	194	267	812	1274	75	600	695	50
Jun-66	30	194	267	812	1274	50	600	695	50
Jul-66	31	194	267	812	1274	50	600	695	0
Aug-66	31	194	267	812	1274	50	600	695	0
Sep-66	30	194	267	812	1274	50	600	695	0
Oct-66	31	132	277	830	1239	75	600	695	0
Nov-66	30	123	298	729	1150	100	600	695	50
Dec-66	31	123	298	729	1150	100	600	695	50
Jan-67	31	123	298	729	1150	100	600	695	50
Feb-67	28	123	298	729	1150	100	600	695	50
Mar-67	31	123	298	729	1150	100	600	695	50
Apr-67	30	141	268	830	1239	100	600	695	50
May-67	31	194	267	812	1274	75	600	695	50
Jun-67	30	194	267	812	1274	50	600	695	50
Jul-67	31	194	267	812	1274	50	600	695	0
Aug-67	31	194	267	812	1274	50	600	695	0
Sep-67	30	194	267	812	1274	50	600	695	0
Oct-67	31	132	277	830	1239	75	600	695	0
Nov-67	30	123	298	729	1150	100	600	695	50
Dec-67	31	123	298	729	1150	100	600	695	50
Jan-68	31	123	298	729	1150	100	600	695	50
Feb-68	29	123	298	729	1150	100	600	695	50
Mar-68	31	123	298	729	1150	100	600	695	50
Apr-68	30	141	268	830	1239	100	600	695	50
May-68	31	194	267	812	1274	75	600	695	50
Jun-68	30	194	267	812	1274	50	600	695	50
Jul-68	31	194	267	812	1274	50	600	695	0
Aug-68	31	194	267	812	1274	50	600	695	0
Sep-68	30	194	267	812	1274	50	600	695	0
Oct-68	31	132	277	830	1239	75	600	695	0
Nov-68	30	123	298	729	1150	100	600	695	50
Dec-68	31	123	298	729	1150	100	600	695	50
Jan-69	31	123	298	729	1150	100	600	695	50
Feb-69	28	123	298	729	1150	100	600	695	50
Mar-69	31	123	298	729	1150	100	600	695	50
Apr-69	30	141	268	830	1239	100	600	695	50
May-69	31	194	267	812	1274	75	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-69	30	194	267	812	1274	50	600	695	50
Jul-69	31	194	267	812	1274	50	600	695	0
Aug-69	31	194	267	812	1274	50	600	695	0
Sep-69	30	194	267	812	1274	50	600	695	0
Oct-69	31	132	277	830	1239	75	600	695	0
Nov-69	30	123	298	729	1150	100	600	695	50
Dec-69	31	123	298	729	1150	100	600	695	50
Jan-70	31	123	298	729	1150	100	600	695	50
Feb-70	28	123	298	729	1150	100	600	695	50
Mar-70	31	123	298	729	1150	100	600	695	50
Apr-70	30	141	268	830	1239	100	600	695	50
May-70	31	194	267	812	1274	75	600	695	50
Jun-70	30	194	267	812	1274	50	600	695	50
Jul-70	31	194	267	812	1274	50	600	695	0
Aug-70	31	194	267	812	1274	50	600	695	0
Sep-70	30	194	267	812	1274	50	600	695	0
Oct-70	31	132	277	830	1239	75	600	695	0
Nov-70	30	123	298	729	1150	100	600	695	50
Dec-70	31	123	298	729	1150	100	600	695	50
Jan-71	31	123	298	729	1150	100	600	695	50
Feb-71	28	123	298	729	1150	100	600	695	50
Mar-71	31	123	298	729	1150	100	600	695	50
Apr-71	30	141	268	830	1239	100	600	695	50
May-71	31	194	267	812	1274	75	600	695	50
Jun-71	30	194	267	812	1274	50	600	695	50
Jul-71	31	194	267	812	1274	50	600	695	0
Aug-71	31	194	267	812	1274	50	600	695	0
Sep-71	30	194	267	812	1274	50	600	695	0
Oct-71	31	132	277	830	1239	75	600	695	0
Nov-71	30	123	298	729	1150	100	600	695	50
Dec-71	31	123	298	729	1150	100	600	695	50
Jan-72	31	123	298	729	1150	100	600	695	50
Feb-72	29	123	298	729	1150	100	600	695	50
Mar-72	31	123	298	729	1150	100	600	695	50
Apr-72	30	141	268	830	1239	100	600	695	50
May-72	31	194	267	812	1274	75	600	695	50
Jun-72	30	194	267	812	1274	50	600	695	50
Jul-72	31	194	267	812	1274	50	600	695	0
Aug-72	31	194	267	812	1274	50	600	695	0
Sep-72	30	194	267	812	1274	50	600	695	0
Oct-72	31	132	277	830	1239	75	600	695	0
Nov-72	30	123	298	729	1150	100	600	695	50
Dec-72	31	123	298	729	1150	100	600	695	50
Jan-73	31	123	298	729	1150	100	600	695	50
Feb-73	28	123	298	729	1150	100	600	695	50
Mar-73	31	123	298	729	1150	100	600	695	50
Apr-73	30	141	268	830	1239	100	600	695	50
May-73	31	194	267	812	1274	75	600	695	50
Jun-73	30	194	267	812	1274	50	600	695	50
Jul-73	31	194	267	812	1274	50	600	695	0
Aug-73	31	194	267	812	1274	50	600	695	0
Sep-73	30	194	267	812	1274	50	600	695	0
Oct-73	31	132	277	830	1239	75	600	695	0
Nov-73	30	123	298	729	1150	100	600	695	50
Dec-73	31	123	298	729	1150	100	600	695	50
Jan-74	31	123	298	729	1150	100	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-74	28	123	298	729	1150	100	600	695	50
Mar-74	31	123	298	729	1150	100	600	695	50
Apr-74	30	141	268	830	1239	100	600	695	50
May-74	31	194	267	812	1274	75	600	695	50
Jun-74	30	194	267	812	1274	50	600	695	50
Jul-74	31	194	267	812	1274	50	600	695	0
Aug-74	31	194	267	812	1274	50	600	695	0
Sep-74	30	194	267	812	1274	50	600	695	0
Oct-74	31	132	277	830	1239	75	600	695	0
Nov-74	30	123	298	729	1150	100	600	695	50
Dec-74	31	123	298	729	1150	100	600	695	50
Jan-75	31	123	298	729	1150	100	600	695	50
Feb-75	28	123	298	729	1150	100	600	695	50
Mar-75	31	123	298	729	1150	100	600	695	50
Apr-75	30	141	268	830	1239	100	600	695	50
May-75	31	194	267	812	1274	75	600	695	50
Jun-75	30	194	267	812	1274	50	600	695	50
Jul-75	31	194	267	812	1274	50	600	695	0
Aug-75	31	194	267	812	1274	50	600	695	0
Sep-75	30	194	267	812	1274	50	600	695	0
Oct-75	31	132	277	830	1239	75	600	695	0
Nov-75	30	123	298	729	1150	100	600	695	50
Dec-75	31	123	298	729	1150	100	600	695	50
Jan-76	31	123	298	729	1150	100	600	695	50
Feb-76	29	123	298	729	1150	100	600	695	50
Mar-76	31	123	298	729	1150	100	600	695	50
Apr-76	30	141	268	830	1239	100	600	695	50
May-76	31	194	267	812	1274	75	600	695	50
Jun-76	30	194	267	812	1274	50	600	695	50
Jul-76	31	194	267	812	1274	50	600	695	0
Aug-76	31	194	267	812	1274	50	600	695	0
Sep-76	30	194	267	812	1274	50	600	695	0
Oct-76	31	132	277	830	1239	75	600	695	0
Nov-76	30	123	298	729	1150	100	600	695	50
Dec-76	31	123	298	729	1150	100	600	695	50
Jan-77	31	123	298	729	1150	100	600	695	50
Feb-77	28	123	298	729	1150	100	600	695	50
Mar-77	31	123	298	729	1150	100	600	695	50
Apr-77	30	141	268	830	1239	100	600	695	50
May-77	31	194	267	812	1274	75	600	695	50
Jun-77	30	194	267	812	1274	50	600	695	50
Jul-77	31	194	267	812	1274	50	600	695	0
Aug-77	31	194	267	812	1274	50	600	695	0
Sep-77	30	194	267	812	1274	50	600	695	0
Oct-77	31	132	277	830	1239	75	600	695	0
Nov-77	30	123	298	729	1150	100	600	695	50
Dec-77	31	123	298	729	1150	100	600	695	50
Jan-78	31	123	298	729	1150	100	600	695	50
Feb-78	28	123	298	729	1150	100	600	695	50
Mar-78	31	123	298	729	1150	100	600	695	50
Apr-78	30	141	268	830	1239	100	600	695	50
May-78	31	194	267	812	1274	75	600	695	50
Jun-78	30	194	267	812	1274	50	600	695	50
Jul-78	31	194	267	812	1274	50	600	695	0
Aug-78	31	194	267	812	1274	50	600	695	0
Sep-78	30	194	267	812	1274	50	600	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-78	31	132	277	830	1239	75	600	695	0
Nov-78	30	123	298	729	1150	100	600	695	50
Dec-78	31	123	298	729	1150	100	600	695	50
Jan-79	31	123	298	729	1150	100	600	695	50
Feb-79	28	123	298	729	1150	100	600	695	50
Mar-79	31	123	298	729	1150	100	600	695	50
Apr-79	30	141	268	830	1239	100	600	695	50
May-79	31	194	267	812	1274	75	600	695	50
Jun-79	30	194	267	812	1274	50	600	695	50
Jul-79	31	194	267	812	1274	50	600	695	0
Aug-79	31	194	267	812	1274	50	600	695	0
Sep-79	30	194	267	812	1274	50	600	695	0
Oct-79	31	132	277	830	1239	75	600	695	0
Nov-79	30	123	298	729	1150	100	600	695	50
Dec-79	31	123	298	729	1150	100	600	695	50
Jan-80	31	123	298	729	1150	100	600	695	50
Feb-80	29	123	298	729	1150	100	600	695	50
Mar-80	31	123	298	729	1150	100	600	695	50
Apr-80	30	141	268	830	1239	100	600	695	50
May-80	31	194	267	812	1274	75	600	695	50
Jun-80	30	194	267	812	1274	50	600	695	50
Jul-80	31	194	267	812	1274	50	600	695	0
Aug-80	31	194	267	812	1274	50	600	695	0
Sep-80	30	194	267	812	1274	50	600	695	0
Oct-80	31	132	277	830	1239	75	600	695	0
Nov-80	30	123	298	729	1150	100	600	695	50
Dec-80	31	123	298	729	1150	100	600	695	50
Jan-81	31	123	298	729	1150	100	600	695	50
Feb-81	28	123	298	729	1150	100	600	695	50
Mar-81	31	123	298	729	1150	100	600	695	50
Apr-81	30	141	268	830	1239	100	600	695	50
May-81	31	194	267	812	1274	75	600	695	50
Jun-81	30	194	267	812	1274	50	600	695	50
Jul-81	31	194	267	812	1274	50	600	695	0
Aug-81	31	194	267	812	1274	50	600	695	0
Sep-81	30	194	267	812	1274	50	600	695	0
Oct-81	31	132	277	830	1239	75	600	695	0
Nov-81	30	123	298	729	1150	100	600	695	50
Dec-81	31	123	298	729	1150	100	600	695	50
Jan-82	31	123	298	729	1150	100	600	695	50
Feb-82	28	123	298	729	1150	100	600	695	50
Mar-82	31	123	298	729	1150	100	600	695	50
Apr-82	30	141	268	830	1239	100	600	695	50
May-82	31	194	267	812	1274	75	600	695	50
Jun-82	30	194	267	812	1274	50	600	695	50
Jul-82	31	194	267	812	1274	50	600	695	0
Aug-82	31	194	267	812	1274	50	600	695	0
Sep-82	30	194	267	812	1274	50	600	695	0
Oct-82	31	132	277	830	1239	75	600	695	0
Nov-82	30	123	298	729	1150	100	600	695	50
Dec-82	31	123	298	729	1150	100	600	695	50
Jan-83	31	123	298	729	1150	100	600	695	50
Feb-83	28	123	298	729	1150	100	600	695	50
Mar-83	31	123	298	729	1150	100	600	695	50
Apr-83	30	141	268	830	1239	100	600	695	50
May-83	31	194	267	812	1274	75	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-83	30	194	267	812	1274	50	**600**	695	50
Jul-83	31	194	267	812	1274	50	**600**	695	0
Aug-83	31	194	267	812	1274	50	**600**	695	0
Sep-83	30	194	267	812	1274	50	**600**	695	0
Oct-83	31	132	277	830	1239	75	**600**	695	0
Nov-83	30	123	298	729	1150	100	**600**	695	50
Dec-83	31	123	298	729	1150	100	**600**	695	50
Jan-84	31	123	298	729	1150	100	**600**	695	50
Feb-84	29	123	298	729	1150	100	**600**	695	50
Mar-84	31	123	298	729	1150	100	**600**	695	50
Apr-84	30	141	268	830	1239	100	**600**	695	50
May-84	31	194	267	812	1274	75	**600**	695	50
Jun-84	30	194	267	812	1274	50	**600**	695	50
Jul-84	31	194	267	812	1274	50	**600**	695	0
Aug-84	31	194	267	812	1274	50	**600**	695	0
Sep-84	30	194	267	812	1274	50	**600**	695	0
Oct-84	31	132	277	830	1239	75	**600**	695	0
Nov-84	30	123	298	729	1150	100	**600**	695	50
Dec-84	31	123	298	729	1150	100	**600**	695	50
Jan-85	31	123	298	729	1150	100	**600**	695	50
Feb-85	28	123	298	729	1150	100	**600**	695	50
Mar-85	31	123	298	729	1150	100	**600**	695	50
Apr-85	30	141	268	830	1239	100	**600**	695	50
May-85	31	194	267	812	1274	75	**600**	695	50
Jun-85	30	194	267	812	1274	50	**600**	695	50
Jul-85	31	194	267	812	1274	50	**600**	695	0
Aug-85	31	194	267	812	1274	50	**600**	695	0
Sep-85	30	194	267	812	1274	50	**600**	695	0
Oct-85	31	132	277	830	1239	75	**600**	695	0
Nov-85	30	123	298	729	1150	100	**600**	695	50
Dec-85	31	123	298	729	1150	100	**600**	695	50
Jan-86	31	123	298	729	1150	100	**600**	695	50
Feb-86	28	123	298	729	1150	100	**600**	695	50
Mar-86	31	123	298	729	1150	100	**600**	695	50
Apr-86	30	141	268	830	1239	100	**600**	695	50
May-86	31	194	267	812	1274	75	**600**	695	50
Jun-86	30	194	267	812	1274	50	**600**	695	50
Jul-86	31	194	267	812	1274	50	**600**	695	0
Aug-86	31	194	267	812	1274	50	**600**	695	0
Sep-86	30	194	267	812	1274	50	**600**	695	0
Oct-86	31	132	277	830	1239	75	**600**	695	0
Nov-86	30	123	298	729	1150	100	**600**	695	50
Dec-86	31	123	298	729	1150	100	**600**	695	50
Jan-87	31	123	298	729	1150	100	**600**	695	50
Feb-87	28	123	298	729	1150	100	**600**	695	50
Mar-87	31	123	298	729	1150	100	**600**	695	50
Apr-87	30	141	268	830	1239	100	**600**	695	50
May-87	31	194	267	812	1274	75	**600**	695	50
Jun-87	30	194	267	812	1274	50	**600**	695	50
Jul-87	31	194	267	812	1274	50	**600**	695	0
Aug-87	31	194	267	812	1274	50	**600**	695	0
Sep-87	30	194	267	812	1274	50	**600**	695	0
Oct-87	31	132	277	830	1239	75	**600**	695	0
Nov-87	30	123	298	729	1150	100	**600**	695	50
Dec-87	31	123	298	729	1150	100	**600**	695	50
Jan-88	31	123	298	729	1150	100	**600**	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Feb-88	29	123	298	729	1150	100	**600**	695	50
Mar-88	31	123	298	729	1150	100	**600**	695	50
Apr-88	30	141	268	830	1239	100	**600**	695	50
May-88	31	194	267	812	1274	75	**600**	695	50
Jun-88	30	194	267	812	1274	50	**600**	695	50
Jul-88	31	194	267	812	1274	50	**600**	695	0
Aug-88	31	194	267	812	1274	50	**600**	695	0
Sep-88	30	194	267	812	1274	50	**600**	695	0
Oct-88	31	132	277	830	1239	75	**600**	695	0
Nov-88	30	123	298	729	1150	100	**600**	695	50
Dec-88	31	123	298	729	1150	100	**600**	695	50
Jan-89	31	123	298	729	1150	100	**600**	695	50
Feb-89	28	123	298	729	1150	100	**600**	695	50
Mar-89	31	123	298	729	1150	100	**600**	695	50
Apr-89	30	141	268	830	1239	100	**600**	695	50
May-89	31	194	267	812	1274	75	**600**	695	50
Jun-89	30	194	267	812	1274	50	**600**	695	50
Jul-89	31	194	267	812	1274	50	**600**	695	0
Aug-89	31	194	267	812	1274	50	**600**	695	0
Sep-89	30	194	267	812	1274	50	**600**	695	0
Oct-89	31	132	277	830	1239	75	**600**	695	0
Nov-89	30	123	298	729	1150	100	**600**	695	50
Dec-89	31	123	298	729	1150	100	**600**	695	50
Jan-90	31	123	298	729	1150	100	**600**	695	50
Feb-90	28	123	298	729	1150	100	**600**	695	50
Mar-90	31	123	298	729	1150	100	**600**	695	50
Apr-90	30	141	268	830	1239	100	**600**	695	50
May-90	31	194	267	812	1274	75	**600**	695	50
Jun-90	30	194	267	812	1274	50	**600**	695	50
Jul-90	31	194	267	812	1274	50	**600**	695	0
Aug-90	31	194	267	812	1274	50	**600**	695	0
Sep-90	30	194	267	812	1274	50	**600**	695	0
Oct-90	31	132	277	830	1239	75	**600**	695	0
Nov-90	30	123	298	729	1150	100	**600**	695	50
Dec-90	31	123	298	729	1150	100	**600**	695	50
Jan-91	31	123	298	729	1150	100	**600**	695	50
Feb-91	28	123	298	729	1150	100	**600**	695	50
Mar-91	31	123	298	729	1150	100	**600**	695	50
Apr-91	30	141	268	830	1239	100	**600**	695	50
May-91	31	194	267	812	1274	75	**600**	695	50
Jun-91	30	194	267	812	1274	50	**600**	695	50
Jul-91	31	194	267	812	1274	50	**600**	695	0
Aug-91	31	194	267	812	1274	50	**600**	695	0
Sep-91	30	194	267	812	1274	50	**600**	695	0
Oct-91	31	132	277	830	1239	75	**600**	695	0
Nov-91	30	123	298	729	1150	100	**600**	695	50
Dec-91	31	123	298	729	1150	100	**600**	695	50
Jan-92	31	123	298	729	1150	100	**600**	695	50
Feb-92	29	123	298	729	1150	100	**600**	695	50
Mar-92	31	123	298	729	1150	100	**600**	695	50
Apr-92	30	141	268	830	1239	100	**600**	695	50
May-92	31	194	267	812	1274	75	**600**	695	50
Jun-92	30	194	267	812	1274	50	**600**	695	50
Jul-92	31	194	267	812	1274	50	**600**	695	0
Aug-92	31	194	267	812	1274	50	**600**	695	0
Sep-92	30	194	267	812	1274	50	**600**	695	0

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Oct-92	31	132	277	830	1239	75	600	695	0
Nov-92	30	123	298	729	1150	100	600	695	50
Dec-92	31	123	298	729	1150	100	600	695	50
Jan-93	31	123	298	729	1150	100	600	695	50
Feb-93	28	123	298	729	1150	100	600	695	50
Mar-93	31	123	298	729	1150	100	600	695	50
Apr-93	30	141	268	830	1239	100	600	695	50
May-93	31	194	267	812	1274	75	600	695	50
Jun-93	30	194	267	812	1274	50	600	695	50
Jul-93	31	194	267	812	1274	50	600	695	0
Aug-93	31	194	267	812	1274	50	600	695	0
Sep-93	30	194	267	812	1274	50	600	695	0
Oct-93	31	132	277	830	1239	75	600	695	0
Nov-93	30	123	298	729	1150	100	600	695	50
Dec-93	31	123	298	729	1150	100	600	695	50
Jan-94	31	123	298	729	1150	100	600	695	50
Feb-94	28	123	298	729	1150	100	600	695	50
Mar-94	31	123	298	729	1150	100	600	695	50
Apr-94	30	141	268	830	1239	100	600	695	50
May-94	31	194	267	812	1274	75	600	695	50
Jun-94	30	194	267	812	1274	50	600	695	50
Jul-94	31	194	267	812	1274	50	600	695	0
Aug-94	31	194	267	812	1274	50	600	695	0
Sep-94	30	194	267	812	1274	50	600	695	0
Oct-94	31	132	277	830	1239	75	600	695	0
Nov-94	30	123	298	729	1150	100	600	695	50
Dec-94	31	123	298	729	1150	100	600	695	50
Jan-95	31	123	298	729	1150	100	600	695	50
Feb-95	28	123	298	729	1150	100	600	695	50
Mar-95	31	123	298	729	1150	100	600	695	50
Apr-95	30	141	268	830	1239	100	600	695	50
May-95	31	194	267	812	1274	75	600	695	50
Jun-95	30	194	267	812	1274	50	600	695	50
Jul-95	31	194	267	812	1274	50	600	695	0
Aug-95	31	194	267	812	1274	50	600	695	0
Sep-95	30	194	267	812	1274	50	600	695	0
Oct-95	31	132	277	830	1239	75	600	695	0
Nov-95	30	123	298	729	1150	100	600	695	50
Dec-95	31	123	298	729	1150	100	600	695	50
Jan-96	31	123	298	729	1150	100	600	695	50
Feb-96	29	123	298	729	1150	100	600	695	50
Mar-96	31	123	298	729	1150	100	600	695	50
Apr-96	30	141	268	830	1239	100	600	695	50
May-96	31	194	267	812	1274	75	600	695	50
Jun-96	30	194	267	812	1274	50	600	695	50
Jul-96	31	194	267	812	1274	50	600	695	0
Aug-96	31	194	267	812	1274	50	600	695	0
Sep-96	30	194	267	812	1274	50	600	695	0
Oct-96	31	132	277	830	1239	75	600	695	0
Nov-96	30	123	298	729	1150	100	600	695	50
Dec-96	31	123	298	729	1150	100	600	695	50
Jan-97	31	123	298	729	1150	100	600	695	50
Feb-97	28	123	298	729	1150	100	600	695	50
Mar-97	31	123	298	729	1150	100	600	695	50
Apr-97	30	141	268	830	1239	100	600	695	50
May-97	31	194	267	812	1274	75	600	695	50

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
Jun-97	30	194	267	812	1274	50	600	695	50
Jul-97	31	194	267	812	1274	50	600	695	0
Aug-97	31	194	267	812	1274	50	600	695	0
Sep-97	30	194	267	812	1274	50	600	695	0
Oct-97	31	132	277	830	1239	75	600	695	0
Nov-97	30	123	298	729	1150	100	600	695	50
Dec-97	31	123	298	729	1150	100	600	695	50
Jan-98	31	123	298	729	1150	100	600	695	50
Feb-98	28	123	298	729	1150	100	600	695	50
Mar-98	31	123	298	729	1150	100	600	695	50
Apr-98	30	141	268	830	1239	100	600	695	50
May-98	31	194	267	812	1274	75	600	695	50
Jun-98	30	194	267	812	1274	50	600	695	50
Jul-98	31	194	267	812	1274	50	600	695	0
Aug-98	31	194	267	812	1274	50	600	695	0
Sep-98	30	194	267	812	1274	50	600	695	0
Oct-98	31	132	277	830	1239	75	600	695	0
Nov-98	30	123	298	729	1150	100	600	695	50
Dec-98	31	123	298	729	1150	100	600	695	50
Jan-99	31	123	298	729	1150	100	600	695	50
Feb-99	28	123	298	729	1150	100	600	695	50
Mar-99	31	123	298	729	1150	100	600	695	50
Apr-99	30	141	268	830	1239	100	600	695	50
May-99	31	194	267	812	1274	75	600	695	50
Jun-99	30	194	267	812	1274	50	600	695	50
Jul-99	31	194	267	812	1274	50	600	695	0
Aug-99	31	194	267	812	1274	50	600	695	0
Sep-99	30	194	267	812	1274	50	600	695	0
Oct-99	31	132	277	830	1239	75	600	695	0
Nov-99	30	123	298	729	1150	100	600	695	50
Dec-99	31	123	298	729	1150	100	600	695	50
Jan-00	31	123	298	729	1150	100	600	695	50
Feb-00	28	123	298	729	1150	100	600	695	50
Mar-00	31	123	298	729	1150	100	600	695	50
Apr-00	30	141	268	830	1239	100	600	695	50
May-00	31	194	267	812	1274	75	600	695	50
Jun-00	30	194	267	812	1274	50	600	695	50
Jul-00	31	194	267	812	1274	50	600	695	0
Aug-00	31	194	267	812	1274	50	600	695	0
Sep-00	30	194	267	812	1274	50	600	695	0
Oct-00	31	132	277	830	1239	75	600	695	0
Nov-00	30	123	298	729	1150	100	600	695	50
Dec-00	31	123	298	729	1150	100	600	695	50
2014	365	155	281	802	1,237	79		695	33
2015	365	155	281	802	1,237	79		695	33
2016	366	155	281	781	1,217	79		695	33
2017	365	155	281	781	1,217	79	400	695	33
2018	365	155	281	781	1,217	79	400	695	33
2019	365	155	281	781	1,217	79	400	695	33
2020	366	155	281	781	1,217	79	533	695	33
2021	365	155	281	781	1,217	79	600	695	33
2022	365	155	281	781	1,217	79	600	695	33
2023	365	155	281	781	1,217	79	600	695	33
2024	366	155	281	781	1,217	79	600	695	33
2025	365	155	281	781	1,217	79	600	695	33
2026	365	155	281	781	1,217	79	600	695	33

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
2027	365	155	281	781	1,217	79	600	695	33
2028	366	155	281	781	1,217	79	600	695	33
2029	365	155	281	781	1,217	79	600	695	33
2030	365	155	281	781	1,217	79	600	695	33
2031	365	155	281	781	1,217	79	600	695	33
2032	366	155	281	781	1,217	79	600	695	33
2033	365	155	281	781	1,217	79	600	695	33
2034	365	155	281	781	1,217	79	600	695	33
2035	365	155	281	781	1,217	79	600	695	33
2036	366	155	281	781	1,217	79	600	695	33
2037	365	155	281	781	1,217	79	600	695	33
2038	365	155	281	781	1217	79	600	695	33
2039	365	155	281	781	1217	79	600	695	33
2040	366	155	281	781	1217	79	600	695	33
2041	365	155	281	781	1217	79	600	695	33
2042	365	155	281	781	1217	79	600	695	33
2043	365	155	281	781	1217	79	600	695	33
2044	366	155	281	781	1217	79	600	695	33
2045	365	155	281	781	1217	79	600	695	33
2046	365	155	281	781	1217	79	600	695	33
2047	365	155	281	781	1217	79	600	695	33
2048	366	155	281	781	1217	79	600	695	33
2049	365	155	281	781	1217	79	600	695	33
2050	365	155	281	781	1217	79	600	695	33
2051	365	155	281	781	1217	79	600	695	33
2052	366	155	281	781	1217	79	600	695	33
2053	365	155	281	781	1217	79	600	695	33
2054	365	155	281	781	1217	79	600	695	33
2055	365	155	281	781	1217	79	600	695	33
2056	366	155	281	781	1217	79	600	695	33
2057	365	155	281	781	1217	79	600	695	33
2058	365	155	281	781	1217	79	600	695	33
2059	365	155	281	781	1217	79	600	695	33
2060	366	155	281	781	1217	79	600	695	33
2061	365	155	281	781	1217	79	600	695	33
2062	365	155	281	781	1217	79	600	695	33
2063	365	155	281	781	1217	79	600	695	33
2064	366	155	281	781	1217	79	600	695	33
2065	365	155	281	781	1217	79	600	695	33
2066	365	155	281	781	1217	79	600	695	33
2067	365	155	281	781	1217	79	600	695	33
2068	366	155	281	781	1217	79	600	695	33
2069	365	155	281	781	1217	79	600	695	33
2070	365	155	281	781	1217	79	600	695	33
2071	365	155	281	781	1217	79	600	695	33
2072	366	155	281	781	1217	79	600	695	33
2073	365	155	281	781	1217	79	600	695	33
2074	365	155	281	781	1217	79	600	695	33
2075	365	155	281	781	1217	79	600	695	33
2076	366	155	281	781	1217	79	600	695	33
2077	365	155	281	781	1217	79	600	695	33
2078	365	155	281	781	1217	79	600	695	33
2079	365	155	281	781	1217	79	600	695	33
2080	366	155	281	781	1217	79	600	695	33
2081	365	155	281	781	1217	79	600	695	33
2082	365	155	281	781	1217	79	600	695	33
2083	365	155	281	781	1217	79	600	695	33
2084	366	155	281	781	1217	79	600	695	33
2085	365	155	281	781	1217	79	600	695	33

MONTH	DAYS	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	TOTAL FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	SABAL TRAIL PIPELINE MMCF/DAY	TOTAL GULFSTREAM FIRM MMCF/DAY	GULFSTREAM NON-FIRM & NON-FIRM BACKHAUL MMCF/DAY
2086	365	155	281	781	1217	79	600	695	33
2087	365	155	281	781	1217	79	600	695	33
2088	366	155	281	781	1217	79	600	695	33
2089	365	155	281	781	1217	79	600	695	33
2090	365	155	281	781	1217	79	600	695	33
2091	365	155	281	781	1217	79	600	695	33
2092	366	155	281	781	1217	79	600	695	33
2093	365	155	281	781	1217	79	600	695	33
2094	365	155	281	781	1217	79	600	695	33
2095	365	155	281	781	1217	79	600	695	33
2096	366	155	281	781	1217	79	600	695	33
2097	365	155	281	781	1217	79	600	695	33
2098	365	155	281	781	1217	79	600	695	33
2099	365	155	281	781	1217	79	600	695	33
2100	365	155	281	781	1217	79	600	695	33

LONG-TERM FORECAST METHODOLOGY - OIL PRICE
July 28, 2014 - LYSTRA LOUTAN

MEDIUM PRICES | WITH SO2 & NOx

	LOW	74%	HIGH	126%
	RESIDUAL		DISTILLATE	
MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jan-14	$16.44	$16.29	$24.23	$98.77
Feb-14	$17.46	$17.32	$24.36	$94.99
Mar-14	$17.57	$17.42	$23.30	$102.92
Apr-14	$16.61	$16.46	$22.81	$99.43
May-14	$16.42	$16.27	$23.13	$102.13
Jun-14	$16.22	$16.08	$23.11	$102.44
Jul-14	$16.39	$16.23	$23.40	$107.26
Aug-14	$15.59	$15.43	$22.80	$104.42
Sep-14	$15.48	$15.32	$22.86	$101.67
Oct-14	$15.41	$15.25	$22.93	$100.32
Nov-14	$15.35	$15.19	$23.00	$99.43
Dec-14	$15.29	$15.13	$23.07	$98.66
Jan-15	$15.29	$15.14	$23.13	$98.01
Feb-15	$15.29	$15.14	$23.11	$97.38
Mar-15	$15.29	$15.14	$23.03	$96.80
Apr-15	$15.29	$15.13	$22.94	$96.23
May-15	$15.29	$15.13	$22.85	$95.74
Jun-15	$15.29	$15.13	$22.77	$95.31
Jul-15	$15.10	$14.94	$22.73	$94.79
Aug-15	$15.10	$14.94	$22.72	$94.33
Sep-15	$15.10	$14.94	$22.71	$93.95
Oct-15	$15.10	$14.94	$22.70	$93.61
Nov-15	$15.10	$14.94	$22.70	$93.32
Dec-15	$15.10	$14.94	$22.69	$93.04
Jan-16	$14.45	$14.29	$22.66	$92.60
Feb-16	$14.48	$14.32	$22.61	$92.18
Mar-16	$14.51	$14.36	$22.51	$91.82
Apr-16	$14.54	$14.39	$22.39	$91.49
May-16	$14.58	$14.42	$22.30	$91.23
Jun-16	$14.62	$14.46	$22.22	$91.05
Jul-16	$14.47	$14.31	$22.20	$90.75
Aug-16	$14.51	$14.35	$22.18	$90.53
Sep-16	$14.54	$14.38	$22.17	$90.37
Oct-16	$14.57	$14.42	$22.15	$90.24
Nov-16	$14.60	$14.45	$22.12	$90.14
Dec-16	$14.63	$14.48	$22.09	$90.06
Jan-17	$14.18	$14.03	$21.46	$88.33
Feb-17	$14.50	$14.35	$22.15	$90.43
Mar-17	$15.35	$15.19	$23.22	$95.94
Apr-17	$15.95	$15.79	$23.84	$99.85
May-17	$16.31	$16.16	$23.59	$102.24
Jun-17	$16.36	$16.21	$23.79	$102.56
Jul-17	$16.36	$16.20	$24.15	$102.53
Aug-17	$16.74	$16.58	$23.92	$104.99

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Sep-17	$16.09	$15.94	$23.80	$100.80
Oct-17	$15.58	$15.42	$23.50	$97.45
Nov-17	$15.25	$15.09	$23.40	$95.30
Dec-17	$15.02	$14.87	$22.64	$93.80
Jan-18	$14.19	$14.04	$21.88	$89.61
Feb-18	$14.51	$14.36	$22.58	$91.74
Mar-18	$15.36	$15.20	$23.68	$97.32
Apr-18	$15.96	$15.80	$24.31	$101.29
May-18	$16.33	$16.17	$24.06	$103.72
Jun-18	$16.37	$16.22	$24.27	$104.05
Jul-18	$16.37	$16.21	$24.63	$104.01
Aug-18	$16.75	$16.59	$24.39	$106.50
Sep-18	$16.10	$15.95	$24.28	$102.26
Oct-18	$15.59	$15.43	$23.97	$98.86
Nov-18	$15.26	$15.10	$23.86	$96.67
Dec-18	$15.03	$14.87	$23.09	$95.16
Jan-19	$15.67	$15.51	$23.35	$100.50
Feb-19	$16.03	$15.87	$24.10	$102.89
Mar-19	$16.96	$16.81	$25.28	$109.15
Apr-19	$17.63	$17.47	$25.96	$113.60
May-19	$18.04	$17.88	$25.69	$116.33
Jun-19	$18.09	$17.94	$25.91	$116.69
Jul-19	$18.09	$17.93	$26.31	$116.66
Aug-19	$18.50	$18.35	$26.05	$119.45
Sep-19	$17.79	$17.64	$25.92	$114.69
Oct-19	$17.22	$17.07	$25.59	$110.88
Nov-19	$16.86	$16.70	$25.48	$108.42
Dec-19	$16.60	$16.45	$24.65	$106.73
Jan-20	$16.24	$16.09	$24.02	$103.07
Feb-20	$16.61	$16.46	$24.80	$105.52
Mar-20	$17.59	$17.43	$26.01	$111.95
Apr-20	$18.28	$18.12	$26.71	$116.51
May-20	$18.70	$18.54	$26.44	$119.30
Jun-20	$18.76	$18.60	$26.66	$119.68
Jul-20	$18.75	$18.59	$27.07	$119.64
Aug-20	$19.18	$19.03	$26.80	$122.51
Sep-20	$18.44	$18.29	$26.67	$117.62
Oct-20	$17.85	$17.70	$26.33	$113.72
Nov-20	$17.47	$17.32	$26.22	$111.20
Dec-20	$17.21	$17.05	$25.36	$109.46
Jan-21	$16.38	$16.22	$24.24	$102.96
Feb-21	$16.75	$16.59	$25.02	$105.40
Mar-21	$17.73	$17.58	$26.25	$111.82
Apr-21	$18.43	$18.27	$26.96	$116.38
May-21	$18.85	$18.70	$26.68	$119.17
Jun-21	$18.91	$18.76	$26.91	$119.54
Jul-21	$18.91	$18.75	$27.32	$119.51
Aug-21	$19.34	$19.19	$27.04	$122.37
Sep-21	$18.60	$18.44	$26.92	$117.49
Oct-21	$18.00	$17.85	$26.57	$113.59
Nov-21	$17.62	$17.46	$26.46	$111.07

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Dec-21	$17.35	$17.20	$25.59	$109.33
Jan-22	$16.29	$16.13	$24.63	$103.25
Feb-22	$16.66	$16.50	$25.43	$105.71
Mar-22	$17.63	$17.48	$26.68	$112.14
Apr-22	$18.33	$18.17	$27.40	$116.72
May-22	$18.75	$18.59	$27.12	$119.51
Jun-22	$18.81	$18.65	$27.35	$119.89
Jul-22	$18.80	$18.65	$27.77	$119.85
Aug-22	$19.24	$19.08	$27.49	$122.72
Sep-22	$18.50	$18.34	$27.36	$117.83
Oct-22	$17.90	$17.75	$27.01	$113.92
Nov-22	$17.52	$17.36	$26.89	$111.40
Dec-22	$17.26	$17.10	$26.01	$109.65
Jan-23	$16.97	$16.82	$25.63	$107.51
Feb-23	$17.36	$17.20	$26.46	$110.07
Mar-23	$18.38	$18.22	$27.77	$116.77
Apr-23	$19.10	$18.95	$28.52	$121.53
May-23	$19.54	$19.39	$28.22	$124.44
Jun-23	$19.60	$19.45	$28.46	$124.84
Jul-23	$19.60	$19.44	$28.90	$124.80
Aug-23	$20.05	$19.90	$28.61	$127.78
Sep-23	$19.28	$19.12	$28.48	$122.69
Oct-23	$18.66	$18.50	$28.11	$118.62
Nov-23	$18.26	$18.10	$27.99	$115.99
Dec-23	$17.98	$17.83	$27.06	$114.17
Jan-24	$17.73	$17.57	$26.57	$111.95
Feb-24	$18.13	$17.98	$27.44	$114.61
Mar-24	$19.20	$19.04	$28.80	$121.59
Apr-24	$19.95	$19.80	$29.58	$126.55
May-24	$20.42	$20.26	$29.27	$129.58
Jun-24	$20.48	$20.32	$29.52	$129.99
Jul-24	$20.47	$20.32	$29.98	$129.95
Aug-24	$20.95	$20.79	$29.68	$133.06
Sep-24	$20.14	$19.98	$29.53	$127.75
Oct-24	$19.49	$19.33	$29.16	$123.51
Nov-24	$19.07	$18.92	$29.02	$120.78
Dec-24	$18.79	$18.63	$28.06	$118.88
Jan-25	$18.60	$18.44	$27.47	$116.55
Feb-25	$19.02	$18.87	$28.37	$119.32
Mar-25	$20.14	$19.99	$29.78	$126.58
Apr-25	$20.94	$20.78	$30.59	$131.75
May-25	$21.43	$21.27	$30.27	$134.90
Jun-25	$21.49	$21.33	$30.53	$135.33
Jul-25	$21.48	$21.33	$31.00	$135.28
Aug-25	$21.98	$21.83	$30.69	$138.52
Sep-25	$21.13	$20.98	$30.54	$133.00
Oct-25	$20.45	$20.30	$30.15	$128.58
Nov-25	$20.01	$19.86	$30.01	$125.74
Dec-25	$19.71	$19.55	$29.02	$123.77
Jan-26	$19.33	$19.17	$28.48	$121.36
Feb-26	$19.77	$19.62	$29.41	$124.24

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Mar-26	$20.94	$20.78	$30.88	$131.80
Apr-26	$21.77	$21.61	$31.72	$137.18
May-26	$22.27	$22.12	$31.39	$140.46
Jun-26	$22.34	$22.18	$31.66	$140.91
Jul-26	$22.33	$22.18	$32.15	$140.86
Aug-26	$22.85	$22.70	$31.83	$144.24
Sep-26	$21.97	$21.81	$31.67	$138.49
Oct-26	$21.26	$21.10	$31.26	$133.89
Nov-26	$20.80	$20.65	$31.12	$130.92
Dec-26	$20.49	$20.33	$30.09	$128.87
Jan-27	$20.10	$19.94	$29.44	$126.34
Feb-27	$20.56	$20.40	$30.41	$129.34
Mar-27	$21.77	$21.62	$31.93	$137.22
Apr-27	$22.64	$22.48	$32.80	$142.82
May-27	$23.16	$23.01	$32.46	$146.24
Jun-27	$23.23	$23.08	$32.74	$146.70
Jul-27	$23.23	$23.07	$33.25	$146.65
Aug-27	$23.77	$23.61	$32.91	$150.16
Sep-27	$22.85	$22.69	$32.75	$144.18
Oct-27	$22.11	$21.95	$32.33	$139.39
Nov-27	$21.63	$21.48	$32.18	$136.30
Dec-27	$21.30	$21.15	$31.11	$134.17
Jan-28	$20.87	$20.72	$30.41	$131.53
Feb-28	$21.35	$21.20	$31.41	$134.66
Mar-28	$22.61	$22.46	$32.98	$142.86
Apr-28	$23.51	$23.35	$33.88	$148.69
May-28	$24.06	$23.90	$33.53	$152.25
Jun-28	$24.13	$23.97	$33.82	$152.73
Jul-28	$24.12	$23.97	$34.34	$152.68
Aug-28	$24.69	$24.53	$33.99	$156.33
Sep-28	$23.73	$23.57	$33.83	$150.10
Oct-28	$22.96	$22.80	$33.39	$145.12
Nov-28	$22.47	$22.31	$33.24	$141.91
Dec-28	$22.13	$21.97	$32.13	$139.68
Jan-29	$21.72	$21.56	$31.40	$136.94
Feb-29	$22.22	$22.06	$32.44	$140.19
Mar-29	$23.54	$23.38	$34.07	$148.73
Apr-29	$24.47	$24.31	$35.00	$154.80
May-29	$25.04	$24.88	$34.63	$158.50
Jun-29	$25.12	$24.96	$34.93	$159.00
Jul-29	$25.11	$24.95	$35.48	$158.95
Aug-29	$25.69	$25.54	$35.12	$162.76
Sep-29	$24.70	$24.54	$34.95	$156.27
Oct-29	$23.90	$23.74	$34.50	$151.08
Nov-29	$23.38	$23.23	$34.34	$147.74
Dec-29	$23.03	$22.87	$33.19	$145.42
Jan-30	$22.61	$22.45	$32.44	$142.58
Feb-30	$23.13	$22.97	$33.52	$145.97
Mar-30	$24.50	$24.34	$35.20	$154.86
Apr-30	$25.47	$25.31	$36.17	$161.17
May-30	$26.06	$25.91	$35.79	$165.03

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jun-30	$26.15	$25.99	$36.10	$165.55
Jul-30	$26.14	$25.98	$36.66	$165.50
Aug-30	$26.75	$26.59	$36.29	$169.46
Sep-30	$25.71	$25.55	$36.11	$162.71
Oct-30	$24.87	$24.72	$35.64	$157.30
Nov-30	$24.34	$24.18	$35.48	$153.82
Dec-30	$23.97	$23.81	$34.29	$151.41
Jan-31	$22.99	$22.84	$32.92	$145.11
Feb-31	$23.53	$23.37	$34.01	$148.55
Mar-31	$24.92	$24.76	$35.72	$157.60
Apr-31	$25.91	$25.75	$36.71	$164.03
May-31	$26.51	$26.36	$36.32	$167.96
Jun-31	$26.60	$26.44	$36.63	$168.49
Jul-31	$26.59	$26.43	$37.21	$168.43
Aug-31	$27.21	$27.05	$36.83	$172.47
Sep-31	$26.15	$25.99	$36.65	$165.59
Oct-31	$25.30	$25.15	$36.17	$160.09
Nov-31	$24.76	$24.60	$36.01	$156.55
Dec-31	$24.38	$24.22	$34.80	$154.10
Jan-32	$23.39	$23.23	$33.41	$147.68
Feb-32	$23.93	$23.77	$34.52	$151.18
Mar-32	$25.35	$25.19	$36.25	$160.39
Apr-32	$26.36	$26.20	$37.25	$166.93
May-32	$26.97	$26.81	$36.86	$170.93
Jun-32	$27.05	$26.90	$37.18	$171.47
Jul-32	$27.05	$26.89	$37.76	$171.42
Aug-32	$27.68	$27.52	$37.38	$175.52
Sep-32	$26.60	$26.44	$37.20	$168.53
Oct-32	$25.74	$25.58	$36.71	$162.93
Nov-32	$25.18	$25.03	$36.54	$159.32
Dec-32	$24.80	$24.64	$35.32	$156.83
Jan-33	$23.79	$23.63	$33.90	$150.29
Feb-33	$24.34	$24.18	$35.03	$153.86
Mar-33	$25.78	$25.63	$36.79	$163.23
Apr-33	$26.81	$26.65	$37.81	$169.89
May-33	$27.44	$27.28	$37.41	$173.96
Jun-33	$27.52	$27.36	$37.73	$174.51
Jul-33	$27.51	$27.36	$38.32	$174.45
Aug-33	$28.16	$28.00	$37.93	$178.63
Sep-33	$27.06	$26.90	$37.75	$171.51
Oct-33	$26.18	$26.03	$37.26	$165.81
Nov-33	$25.62	$25.46	$37.09	$162.14
Dec-33	$25.23	$25.07	$35.84	$159.60
Jan-34	$24.20	$24.04	$34.40	$152.96
Feb-34	$24.76	$24.60	$35.55	$156.59
Mar-34	$26.23	$26.07	$37.34	$166.13
Apr-34	$27.27	$27.12	$38.37	$172.90
May-34	$27.91	$27.75	$37.96	$177.04
Jun-34	$28.00	$27.84	$38.29	$177.60
Jul-34	$27.99	$27.83	$38.89	$177.55
Aug-34	$28.64	$28.49	$38.50	$181.80

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Sep-34	$27.53	$27.37	$38.31	$174.55
Oct-34	$26.63	$26.48	$37.81	$168.75
Nov-34	$26.06	$25.90	$37.64	$165.02
Dec-34	$25.66	$25.50	$36.37	$162.43
Jan-35	$24.62	$24.46	$34.91	$155.67
Feb-35	$25.19	$25.03	$36.08	$159.36
Mar-35	$26.68	$26.52	$37.89	$169.07
Apr-35	$27.74	$27.59	$38.94	$175.97
May-35	$28.39	$28.23	$38.53	$180.18
Jun-35	$28.48	$28.32	$38.87	$180.75
Jul-35	$28.47	$28.31	$39.47	$180.69
Aug-35	$29.14	$28.98	$39.07	$185.02
Sep-35	$28.00	$27.84	$38.88	$177.64
Oct-35	$27.09	$26.94	$38.37	$171.74
Nov-35	$26.51	$26.35	$38.20	$167.94
Dec-35	$26.10	$25.95	$36.91	$165.31
Jan-36	$25.04	$24.88	$35.43	$158.42
Feb-36	$25.62	$25.46	$36.61	$162.19
Mar-36	$27.14	$26.98	$38.46	$172.06
Apr-36	$28.22	$28.06	$39.52	$179.08
May-36	$28.88	$28.72	$39.10	$183.37
Jun-36	$28.97	$28.81	$39.45	$183.95
Jul-36	$28.96	$28.81	$40.06	$183.89
Aug-36	$29.64	$29.48	$39.65	$188.30
Sep-36	$28.48	$28.33	$39.46	$180.79
Oct-36	$27.56	$27.40	$38.95	$174.79
Nov-36	$26.96	$26.81	$38.77	$170.92
Dec-36	$26.55	$26.39	$37.46	$168.24
Jan-37	$25.47	$25.31	$35.96	$161.23
Feb-37	$26.06	$25.90	$37.16	$165.06
Mar-37	$27.61	$27.45	$39.03	$175.11
Apr-37	$28.71	$28.55	$40.11	$182.26
May-37	$29.38	$29.22	$39.69	$186.62
Jun-37	$29.47	$29.31	$40.03	$187.21
Jul-37	$29.46	$29.31	$40.66	$187.15
Aug-37	$30.15	$30.00	$40.25	$191.63
Sep-37	$28.98	$28.82	$40.05	$184.00
Oct-37	$28.03	$27.88	$39.53	$177.88
Nov-37	$27.43	$27.27	$39.35	$173.94
Dec-37	$27.01	$26.85	$38.02	$171.22
Jan-38	$25.91	$25.75	$36.49	$164.09
Feb-38	$26.51	$26.35	$37.71	$167.98
Mar-38	$28.08	$27.93	$39.61	$178.22
Apr-38	$29.20	$29.05	$40.71	$185.49
May-38	$29.89	$29.73	$40.28	$189.93
Jun-38	$29.98	$29.82	$40.63	$190.53
Jul-38	$29.97	$29.81	$41.27	$190.47
Aug-38	$30.67	$30.52	$40.85	$195.03
Sep-38	$29.48	$29.32	$40.65	$187.26
Oct-38	$28.52	$28.36	$40.12	$181.03
Nov-38	$27.90	$27.75	$39.93	$177.03

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Dec-38	$27.47	$27.32	$38.59	$174.25
Jan-39	$26.36	$26.20	$37.03	$167.00
Feb-39	$26.97	$26.81	$38.27	$170.96
Mar-39	$28.57	$28.41	$40.21	$181.37
Apr-39	$29.71	$29.55	$41.32	$188.77
May-39	$30.40	$30.25	$40.88	$193.29
Jun-39	$30.50	$30.34	$41.24	$193.90
Jul-39	$30.49	$30.33	$41.89	$193.84
Aug-39	$31.20	$31.05	$41.46	$198.48
Sep-39	$29.99	$29.83	$41.26	$190.57
Oct-39	$29.01	$28.85	$40.72	$184.24
Nov-39	$28.38	$28.23	$40.53	$180.16
Dec-39	$27.95	$27.79	$39.16	$177.34
Jan-40	$26.81	$26.65	$37.58	$169.95
Feb-40	$27.43	$27.28	$38.84	$173.99
Mar-40	$29.06	$28.91	$40.81	$184.59
Apr-40	$30.22	$30.07	$41.94	$192.12
May-40	$30.93	$30.77	$41.49	$196.72
Jun-40	$31.03	$30.87	$41.86	$197.34
Jul-40	$31.02	$30.86	$42.51	$197.28
Aug-40	$31.74	$31.59	$42.08	$202.00
Sep-40	$30.50	$30.35	$41.87	$193.95
Oct-40	$29.51	$29.36	$41.33	$187.51
Nov-40	$28.87	$28.72	$41.14	$183.36
Dec-40	$28.43	$28.27	$39.75	$180.48
Jan-41	$27.27	$27.12	$38.14	$172.97
Feb-41	$27.90	$27.75	$39.42	$177.07
Mar-41	$29.56	$29.41	$41.42	$187.86
Apr-41	$30.74	$30.59	$42.57	$195.52
May-41	$31.47	$31.31	$42.11	$200.20
Jun-41	$31.56	$31.41	$42.48	$200.84
Jul-41	$31.55	$31.40	$43.15	$200.77
Aug-41	$32.29	$32.14	$42.71	$205.58
Sep-41	$31.03	$30.88	$42.50	$197.39
Oct-41	$30.02	$29.87	$41.94	$190.83
Nov-41	$29.37	$29.22	$41.75	$186.60
Dec-41	$28.92	$28.77	$40.34	$183.68
Jan-42	$27.74	$27.59	$38.71	$176.03
Feb-42	$28.39	$28.23	$40.01	$180.21
Mar-42	$30.08	$29.92	$42.04	$191.19
Apr-42	$31.28	$31.12	$43.21	$198.98
May-42	$32.01	$31.85	$42.74	$203.75
Jun-42	$32.11	$31.95	$43.12	$204.39
Jul-42	$32.10	$31.94	$43.80	$204.33
Aug-42	$32.85	$32.70	$43.35	$209.22
Sep-42	$31.57	$31.41	$43.14	$200.88
Oct-42	$30.54	$30.39	$42.57	$194.21
Nov-42	$29.88	$29.72	$42.38	$189.91
Dec-42	$29.42	$29.27	$40.94	$186.94
Jan-43	$28.22	$28.07	$39.29	$179.15
Feb-43	$28.88	$28.72	$40.61	$183.40

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Mar-43	$30.60	$30.44	$42.67	$194.57
Apr-43	$31.82	$31.66	$43.85	$202.51
May-43	$32.56	$32.41	$43.38	$207.36
Jun-43	$32.67	$32.51	$43.77	$208.02
Jul-43	$32.65	$32.50	$44.46	$207.95
Aug-43	$33.42	$33.27	$44.00	$212.93
Sep-43	$32.12	$31.96	$43.79	$204.44
Oct-43	$31.07	$30.91	$43.21	$197.65
Nov-43	$30.40	$30.24	$43.01	$193.27
Dec-43	$29.93	$29.77	$41.55	$190.25
Jan-44	$28.71	$28.55	$39.88	$182.32
Feb-44	$29.38	$29.22	$41.21	$186.65
Mar-44	$31.13	$30.97	$43.31	$198.02
Apr-44	$32.37	$32.21	$44.51	$206.10
May-44	$33.13	$32.97	$44.04	$211.03
Jun-44	$33.23	$33.07	$44.42	$211.70
Jul-44	$33.22	$33.06	$45.12	$211.63
Aug-44	$34.00	$33.84	$44.66	$216.70
Sep-44	$32.67	$32.51	$44.44	$208.06
Oct-44	$31.61	$31.45	$43.86	$201.15
Nov-44	$30.92	$30.77	$43.66	$196.70
Dec-44	$30.45	$30.29	$42.18	$193.62
Jan-45	$29.20	$29.05	$40.47	$185.55
Feb-45	$29.88	$29.73	$41.83	$189.96
Mar-45	$31.66	$31.51	$43.96	$201.53
Apr-45	$32.93	$32.77	$45.18	$209.75
May-45	$33.70	$33.55	$44.70	$214.77
Jun-45	$33.81	$33.65	$45.09	$215.45
Jul-45	$33.80	$33.64	$45.80	$215.38
Aug-45	$34.59	$34.43	$45.33	$220.54
Sep-45	$33.24	$33.08	$45.11	$211.75
Oct-45	$32.15	$32.00	$44.52	$204.72
Nov-45	$31.46	$31.30	$44.31	$200.18
Dec-45	$30.97	$30.82	$42.81	$197.05
Jan-46	$29.71	$29.55	$41.08	$188.84
Feb-46	$30.40	$30.24	$42.46	$193.33
Mar-46	$32.21	$32.06	$44.62	$205.10
Apr-46	$33.50	$33.34	$45.86	$213.47
May-46	$34.29	$34.13	$45.37	$218.58
Jun-46	$34.39	$34.24	$45.77	$219.27
Jul-46	$34.38	$34.23	$46.49	$219.20
Aug-46	$35.19	$35.03	$46.01	$224.45
Sep-46	$33.81	$33.66	$45.79	$215.50
Oct-46	$32.71	$32.55	$45.18	$208.34
Nov-46	$32.00	$31.84	$44.98	$203.73
Dec-46	$31.51	$31.35	$43.45	$200.54
Jan-47	$30.22	$30.07	$41.69	$192.19
Feb-47	$30.93	$30.77	$43.09	$196.75
Mar-47	$32.77	$32.61	$45.29	$208.73
Apr-47	$34.08	$33.92	$46.55	$217.25
May-47	$34.88	$34.72	$46.05	$222.45

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jun-47	$34.99	$34.83	$46.46	$223.15
Jul-47	$34.98	$34.82	$47.19	$223.08
Aug-47	$35.80	$35.64	$46.71	$228.42
Sep-47	$34.40	$34.24	$46.48	$219.32
Oct-47	$33.28	$33.12	$45.86	$212.03
Nov-47	$32.56	$32.40	$45.65	$207.34
Dec-47	$32.06	$31.90	$44.10	$204.09
Jan-48	$30.75	$30.59	$42.32	$195.59
Feb-48	$31.46	$31.30	$43.74	$200.24
Mar-48	$33.34	$33.18	$45.97	$212.43
Apr-48	$34.67	$34.51	$47.25	$221.10
May-48	$35.49	$35.33	$46.74	$226.39
Jun-48	$35.60	$35.44	$47.16	$227.11
Jul-48	$35.58	$35.43	$47.90	$227.04
Aug-48	$36.42	$36.26	$47.41	$232.47
Sep-48	$35.00	$34.84	$47.18	$223.21
Oct-48	$33.85	$33.70	$46.55	$215.79
Nov-48	$33.12	$32.96	$46.34	$211.01
Dec-48	$32.61	$32.45	$44.76	$207.71
Jan-49	$31.28	$31.12	$42.95	$199.06
Feb-49	$32.00	$31.85	$44.40	$203.78
Mar-49	$33.91	$33.76	$46.66	$216.20
Apr-49	$35.27	$35.12	$47.96	$225.01
May-49	$36.10	$35.94	$47.45	$230.40
Jun-49	$36.21	$36.06	$47.87	$231.13
Jul-49	$36.20	$36.05	$48.62	$231.06
Aug-49	$37.05	$36.90	$48.12	$236.59
Sep-49	$35.60	$35.45	$47.89	$227.16
Oct-49	$34.44	$34.28	$47.25	$219.61
Nov-49	$33.69	$33.54	$47.04	$214.75
Dec-49	$33.18	$33.02	$45.44	$211.39
Jan-50	$31.82	$31.66	$43.59	$202.58
Feb-50	$32.56	$32.40	$45.06	$207.40
Mar-50	$34.50	$34.35	$47.36	$220.03
Apr-50	$35.88	$35.73	$48.68	$229.00
May-50	$36.73	$36.57	$48.16	$234.49
Jun-50	$36.84	$36.69	$48.59	$235.23
Jul-50	$36.83	$36.67	$49.36	$235.15
Aug-50	$37.70	$37.54	$48.85	$240.78
Sep-50	$36.22	$36.06	$48.61	$231.19
Oct-50	$35.04	$34.88	$47.97	$223.51
Nov-50	$34.28	$34.12	$47.75	$218.56
Dec-50	$33.75	$33.59	$46.12	$215.14
Jan-51	$32.37	$32.21	$44.25	$206.17
Feb-51	$33.12	$32.97	$45.74	$211.07
Mar-51	$35.10	$34.94	$48.07	$223.93
Apr-51	$36.51	$36.35	$49.42	$233.06
May-51	$37.36	$37.21	$48.89	$238.64
Jun-51	$37.48	$37.32	$49.32	$239.39
Jul-51	$37.47	$37.31	$50.10	$239.32
Aug-51	$38.35	$38.19	$49.59	$245.05

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Sep-51	$36.85	$36.69	$49.34	$235.28
Oct-51	$35.65	$35.49	$48.69	$227.47
Nov-51	$34.87	$34.71	$48.46	$222.43
Dec-51	$34.33	$34.18	$46.81	$218.95
Jan-52	$32.93	$32.77	$44.91	$209.83
Feb-52	$33.70	$33.54	$46.43	$214.81
Mar-52	$35.71	$35.55	$48.80	$227.89
Apr-52	$37.14	$36.98	$50.16	$237.19
May-52	$38.01	$37.86	$49.62	$242.87
Jun-52	$38.13	$37.98	$50.06	$243.64
Jul-52	$38.12	$37.96	$50.86	$243.56
Aug-52	$39.02	$38.86	$50.33	$249.39
Sep-52	$37.49	$37.33	$50.09	$239.45
Oct-52	$36.26	$36.11	$49.42	$231.50
Nov-52	$35.48	$35.32	$49.20	$226.37
Dec-52	$34.93	$34.77	$47.52	$222.83
Jan-53	$33.50	$33.34	$45.59	$213.55
Feb-53	$34.28	$34.12	$47.13	$218.62
Mar-53	$36.33	$36.17	$49.53	$231.93
Apr-53	$37.78	$37.63	$50.92	$241.39
May-53	$38.67	$38.52	$50.37	$247.17
Jun-53	$38.79	$38.64	$50.82	$247.95
Jul-53	$38.78	$38.63	$51.63	$247.87
Aug-53	$39.70	$39.54	$51.09	$253.81
Sep-53	$38.14	$37.98	$50.84	$243.69
Oct-53	$36.89	$36.74	$50.17	$235.60
Nov-53	$36.09	$35.93	$49.94	$230.38
Dec-53	$35.54	$35.38	$48.23	$226.77
Jan-54	$34.08	$33.92	$46.27	$217.33
Feb-54	$34.87	$34.72	$47.84	$222.49
Mar-54	$36.96	$36.80	$50.28	$236.04
Apr-54	$38.44	$38.28	$51.69	$245.67
May-54	$39.35	$39.19	$51.13	$251.55
Jun-54	$39.47	$39.31	$51.59	$252.35
Jul-54	$39.46	$39.30	$52.41	$252.27
Aug-54	$40.39	$40.23	$51.87	$258.31
Sep-54	$38.80	$38.65	$51.61	$248.01
Oct-54	$37.53	$37.38	$50.93	$239.77
Nov-54	$36.72	$36.56	$50.69	$234.46
Dec-54	$36.15	$36.00	$48.96	$230.79
Jan-55	$34.67	$34.52	$46.97	$221.18
Feb-55	$35.48	$35.32	$48.56	$226.43
Mar-55	$37.60	$37.44	$51.04	$240.22
Apr-55	$39.11	$38.95	$52.47	$250.02
May-55	$40.03	$39.87	$51.91	$256.01
Jun-55	$40.15	$40.00	$52.37	$256.82
Jul-55	$40.14	$39.99	$53.20	$256.74
Aug-55	$41.09	$40.93	$52.65	$262.88
Sep-55	$39.48	$39.32	$52.39	$252.41
Oct-55	$38.19	$38.03	$51.70	$244.02
Nov-55	$37.35	$37.20	$51.46	$238.62

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Dec-55	$36.78	$36.62	$49.70	$234.88
Jan-56	$35.27	$35.12	$47.68	$225.10
Feb-56	$36.09	$35.94	$49.29	$230.44
Mar-56	$38.25	$38.10	$51.81	$244.48
Apr-56	$39.79	$39.63	$53.27	$254.45
May-56	$40.73	$40.57	$52.69	$260.54
Jun-56	$40.85	$40.70	$53.16	$261.37
Jul-56	$40.84	$40.68	$54.00	$261.28
Aug-56	$41.80	$41.65	$53.45	$267.54
Sep-56	$40.16	$40.01	$53.18	$256.88
Oct-56	$38.85	$38.69	$52.48	$248.34
Nov-56	$38.00	$37.85	$52.24	$242.85
Dec-56	$37.42	$37.26	$50.45	$239.04
Jan-57	$35.88	$35.73	$48.39	$229.09
Feb-57	$36.72	$36.57	$50.03	$234.53
Mar-57	$38.92	$38.76	$52.60	$248.81
Apr-57	$40.48	$40.32	$54.07	$258.96
May-57	$41.43	$41.28	$53.49	$265.16
Jun-57	$41.56	$41.41	$53.96	$266.00
Jul-57	$41.55	$41.39	$54.82	$265.91
Aug-57	$42.53	$42.37	$54.26	$272.28
Sep-57	$40.86	$40.70	$53.99	$261.43
Oct-57	$39.52	$39.37	$53.27	$252.74
Nov-57	$38.66	$38.51	$53.03	$247.15
Dec-57	$38.07	$37.91	$51.21	$243.28
Jan-58	$36.51	$36.35	$49.12	$233.15
Feb-58	$37.36	$37.20	$50.79	$238.68
Mar-58	$39.59	$39.44	$53.39	$253.22
Apr-58	$41.18	$41.03	$54.89	$263.55
May-58	$42.15	$42.00	$54.30	$269.86
Jun-58	$42.29	$42.13	$54.78	$270.71
Jul-58	$42.27	$42.12	$55.65	$270.63
Aug-58	$43.27	$43.11	$55.08	$277.10
Sep-58	$41.57	$41.41	$54.81	$266.06
Oct-58	$40.21	$40.05	$54.08	$257.22
Nov-58	$39.33	$39.18	$53.83	$251.53
Dec-58	$38.73	$38.57	$51.99	$247.59
Jan-59	$37.14	$36.98	$49.87	$237.28
Feb-59	$38.01	$37.85	$51.55	$242.91
Mar-59	$40.28	$40.13	$54.20	$257.70
Apr-59	$41.90	$41.74	$55.72	$268.22
May-59	$42.89	$42.73	$55.12	$274.64
Jun-59	$43.02	$42.87	$55.61	$275.51
Jul-59	$43.01	$42.85	$56.50	$275.42
Aug-59	$44.02	$43.87	$55.91	$282.01
Sep-59	$42.29	$42.14	$55.64	$270.78
Oct-59	$40.91	$40.75	$54.90	$261.78
Nov-59	$40.02	$39.86	$54.64	$255.98
Dec-59	$39.40	$39.25	$52.77	$251.98
Jan-60	$37.79	$37.63	$50.62	$241.48
Feb-60	$38.67	$38.51	$52.33	$247.21

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Mar-60	$40.98	$40.83	$55.02	$262.27
Apr-60	$42.63	$42.47	$56.57	$272.97
May-60	$43.63	$43.48	$55.96	$279.51
Jun-60	$43.77	$43.61	$56.45	$280.39
Jul-60	$43.76	$43.60	$57.35	$280.30
Aug-60	$44.79	$44.63	$56.76	$287.01
Sep-60	$43.03	$42.87	$56.48	$275.57
Oct-60	$41.62	$41.47	$55.73	$266.42
Nov-60	$40.71	$40.56	$55.47	$260.52
Dec-60	$40.09	$39.93	$53.57	$256.44
Jan-61	$38.44	$38.29	$51.38	$245.76
Feb-61	$39.34	$39.18	$53.13	$251.59
Mar-61	$41.70	$41.54	$55.85	$266.92
Apr-61	$43.37	$43.21	$57.43	$277.81
May-61	$44.39	$44.24	$56.80	$284.46
Jun-61	$44.53	$44.38	$57.31	$285.36
Jul-61	$44.52	$44.36	$58.22	$285.27
Aug-61	$45.57	$45.41	$57.62	$292.10
Sep-61	$43.78	$43.62	$57.34	$280.46
Oct-61	$42.35	$42.19	$56.57	$271.14
Nov-61	$41.42	$41.27	$56.31	$265.14
Dec-61	$40.78	$40.63	$54.38	$260.98
Jan-62	$39.11	$38.95	$52.16	$250.11
Feb-62	$40.02	$39.87	$53.93	$256.05
Mar-62	$42.42	$42.27	$56.70	$271.65
Apr-62	$44.13	$43.97	$58.30	$282.73
May-62	$45.17	$45.01	$57.67	$289.50
Jun-62	$45.31	$45.15	$58.18	$290.41
Jul-62	$45.29	$45.14	$59.11	$290.32
Aug-62	$46.36	$46.21	$58.50	$297.27
Sep-62	$44.54	$44.38	$58.21	$285.43
Oct-62	$43.08	$42.93	$57.43	$275.94
Nov-62	$42.14	$41.99	$57.17	$269.83
Dec-62	$41.49	$41.34	$55.20	$265.61
Jan-63	$39.79	$39.63	$52.95	$254.54
Feb-63	$40.72	$40.56	$54.75	$260.59
Mar-63	$43.16	$43.00	$57.56	$276.46
Apr-63	$44.89	$44.74	$59.18	$287.74
May-63	$45.95	$45.80	$58.54	$294.63
Jun-63	$46.10	$45.94	$59.06	$295.56
Jul-63	$46.08	$45.93	$60.01	$295.46
Aug-63	$47.17	$47.01	$59.38	$302.54
Sep-63	$45.32	$45.16	$59.09	$290.48
Oct-63	$43.83	$43.68	$58.30	$280.83
Nov-63	$42.88	$42.72	$58.03	$274.61
Dec-63	$42.21	$42.06	$56.04	$270.31
Jan-64	$40.48	$40.32	$53.75	$259.05
Feb-64	$41.43	$41.27	$55.58	$265.21
Mar-64	$43.91	$43.75	$58.44	$281.36
Apr-64	$45.68	$45.52	$60.08	$292.83
May-64	$46.75	$46.60	$59.43	$299.85

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jun-64	$46.90	$46.74	$59.96	$300.80
Jul-64	$46.89	$46.73	$60.92	$300.70
Aug-64	$47.99	$47.84	$60.29	$307.90
Sep-64	$46.11	$45.95	$59.99	$295.63
Oct-64	$44.59	$44.44	$59.19	$285.81
Nov-64	$43.62	$43.47	$58.91	$279.48
Dec-64	$42.95	$42.79	$56.89	$275.10
Jan-65	$41.18	$41.03	$54.56	$263.64
Feb-65	$42.15	$41.99	$56.42	$269.90
Mar-65	$44.68	$44.52	$59.32	$286.34
Apr-65	$46.47	$46.31	$61.00	$298.02
May-65	$47.57	$47.41	$60.33	$305.16
Jun-65	$47.72	$47.56	$60.87	$306.13
Jul-65	$47.70	$47.55	$61.84	$306.03
Aug-65	$48.83	$48.67	$61.20	$313.35
Sep-65	$46.91	$46.75	$60.90	$300.87
Oct-65	$45.37	$45.22	$60.09	$290.87
Nov-65	$44.38	$44.23	$59.81	$284.43
Dec-65	$43.70	$43.54	$57.75	$279.98
Jan-66	$41.90	$41.74	$55.39	$268.32
Feb-66	$42.88	$42.72	$57.27	$274.69
Mar-66	$45.45	$45.30	$60.22	$291.42
Apr-66	$47.28	$47.12	$61.92	$303.30
May-66	$48.40	$48.24	$61.25	$310.57
Jun-66	$48.55	$48.39	$61.80	$311.55
Jul-66	$48.53	$48.38	$62.79	$311.45
Aug-66	$49.68	$49.52	$62.13	$318.91
Sep-66	$47.73	$47.57	$61.83	$306.20
Oct-66	$46.16	$46.01	$61.00	$296.02
Nov-66	$45.15	$45.00	$60.72	$289.47
Dec-66	$44.46	$44.30	$58.63	$284.94
Jan-67	$42.63	$42.47	$56.23	$273.07
Feb-67	$43.63	$43.47	$58.14	$279.55
Mar-67	$46.24	$46.09	$61.14	$296.58
Apr-67	$48.10	$47.95	$62.87	$308.68
May-67	$49.24	$49.09	$62.18	$316.07
Jun-67	$49.40	$49.24	$62.74	$317.07
Jul-67	$49.38	$49.22	$63.74	$316.97
Aug-67	$50.55	$50.39	$63.08	$324.56
Sep-67	$48.56	$48.40	$62.77	$311.62
Oct-67	$46.97	$46.81	$61.93	$301.27
Nov-67	$45.94	$45.78	$61.64	$294.60
Dec-67	$45.23	$45.07	$59.52	$289.99
Jan-68	$43.37	$43.22	$57.08	$277.91
Feb-68	$44.39	$44.23	$59.03	$284.51
Mar-68	$47.05	$46.89	$62.07	$301.83
Apr-68	$48.94	$48.79	$63.82	$314.15
May-68	$50.10	$49.94	$63.13	$321.67
Jun-68	$50.26	$50.10	$63.69	$322.69
Jul-68	$50.24	$50.08	$64.71	$322.58
Aug-68	$51.43	$51.27	$64.04	$330.31

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Sep-68	$49.40	$49.25	$63.72	$317.14
Oct-68	$47.78	$47.63	$62.87	$306.61
Nov-68	$46.74	$46.58	$62.58	$299.82
Dec-68	$46.02	$45.86	$60.43	$295.13
Jan-69	$44.13	$43.97	$57.95	$282.83
Feb-69	$45.16	$45.00	$59.92	$289.55
Mar-69	$47.87	$47.71	$63.01	$307.18
Apr-69	$49.80	$49.64	$64.80	$319.71
May-69	$50.97	$50.82	$64.09	$327.37
Jun-69	$51.13	$50.98	$64.66	$328.40
Jul-69	$51.12	$50.96	$65.70	$328.30
Aug-69	$52.33	$52.17	$65.02	$336.16
Sep-69	$50.27	$50.11	$64.69	$322.76
Oct-69	$48.62	$48.46	$63.83	$312.04
Nov-69	$47.56	$47.40	$63.53	$305.13
Dec-69	$46.82	$46.66	$61.35	$300.35
Jan-70	$44.90	$44.74	$58.83	$287.84
Feb-70	$45.95	$45.79	$60.83	$294.68
Mar-70	$48.70	$48.55	$63.97	$312.63
Apr-70	$50.67	$50.51	$65.78	$325.38
May-70	$51.86	$51.71	$65.07	$333.17
Jun-70	$52.03	$51.87	$65.65	$334.22
Jul-70	$52.01	$51.85	$66.70	$334.12
Aug-70	$53.24	$53.08	$66.01	$342.12
Sep-70	$51.14	$50.99	$65.68	$328.48
Oct-70	$49.46	$49.31	$64.80	$317.57
Nov-70	$48.38	$48.23	$64.50	$310.54
Dec-70	$47.64	$47.48	$62.28	$305.68
Jan-71	$45.68	$45.52	$59.72	$292.94
Feb-71	$46.75	$46.59	$61.76	$299.90
Mar-71	$49.55	$49.40	$64.95	$318.16
Apr-71	$51.55	$51.39	$66.79	$331.14
May-71	$52.77	$52.61	$66.06	$339.07
Jun-71	$52.93	$52.78	$66.65	$340.14
Jul-71	$52.92	$52.76	$67.72	$340.04
Aug-71	$54.17	$54.01	$67.01	$348.18
Sep-71	$52.03	$51.88	$66.68	$334.30
Oct-71	$50.33	$50.17	$65.79	$323.20
Nov-71	$49.23	$49.07	$65.48	$316.04
Dec-71	$48.47	$48.31	$63.23	$311.09
Jan-72	$46.47	$46.32	$60.63	$298.13
Feb-72	$47.56	$47.40	$62.70	$305.21
Mar-72	$50.42	$50.26	$65.94	$323.80
Apr-72	$52.45	$52.29	$67.80	$337.01
May-72	$53.69	$53.53	$67.07	$345.08
Jun-72	$53.86	$53.70	$67.67	$346.17
Jul-72	$53.84	$53.68	$68.75	$346.06
Aug-72	$55.11	$54.96	$68.04	$354.35
Sep-72	$52.94	$52.79	$67.70	$340.23
Oct-72	$51.21	$51.05	$66.79	$328.92
Nov-72	$50.09	$49.93	$66.48	$321.64

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Dec-72	$49.31	$49.16	$64.19	$316.60
Jan-73	$47.28	$47.13	$61.55	$303.42
Feb-73	$48.39	$48.23	$63.65	$310.62
Mar-73	$51.30	$51.14	$66.94	$329.54
Apr-73	$53.36	$53.21	$68.84	$342.98
May-73	$54.63	$54.47	$68.09	$351.19
Jun-73	$54.80	$54.64	$68.70	$352.30
Jul-73	$54.78	$54.62	$69.80	$352.19
Aug-73	$56.08	$55.92	$69.07	$360.62
Sep-73	$53.87	$53.71	$68.73	$346.25
Oct-73	$52.10	$51.94	$67.81	$334.75
Nov-73	$50.96	$50.80	$67.49	$327.34
Dec-73	$50.17	$50.02	$65.17	$322.21
Jan-74	$48.11	$47.95	$62.49	$308.79
Feb-74	$49.23	$49.08	$64.62	$316.12
Mar-74	$52.19	$52.04	$67.97	$335.38
Apr-74	$54.30	$54.14	$69.89	$349.06
May-74	$55.58	$55.42	$69.13	$357.42
Jun-74	$55.75	$55.60	$69.75	$358.55
Jul-74	$55.74	$55.58	$70.87	$358.43
Aug-74	$57.06	$56.90	$70.13	$367.01
Sep-74	$54.81	$54.65	$69.78	$352.39
Oct-74	$53.01	$52.85	$68.85	$340.68
Nov-74	$51.85	$51.69	$68.52	$333.14
Dec-74	$51.05	$50.89	$66.16	$327.92
Jan-75	$48.94	$48.79	$63.44	$314.26
Feb-75	$50.09	$49.94	$65.61	$321.72
Mar-75	$53.10	$52.95	$69.00	$341.32
Apr-75	$55.24	$55.09	$70.96	$355.24
May-75	$56.55	$56.39	$70.19	$363.75
Jun-75	$56.73	$56.57	$70.81	$364.90
Jul-75	$56.71	$56.55	$71.95	$364.78
Aug-75	$58.05	$57.90	$71.20	$373.52
Sep-75	$55.76	$55.61	$70.85	$358.63
Oct-75	$53.93	$53.78	$69.90	$346.72
Nov-75	$52.75	$52.60	$69.57	$339.04
Dec-75	$51.94	$51.78	$67.17	$333.73
Jan-76	$49.80	$49.64	$64.41	$319.83
Feb-76	$50.97	$50.81	$66.61	$327.43
Mar-76	$54.03	$53.87	$70.06	$347.37
Apr-76	$56.21	$56.05	$72.04	$361.54
May-76	$57.54	$57.38	$71.26	$370.19
Jun-76	$57.72	$57.56	$71.90	$371.36
Jul-76	$57.70	$57.54	$73.05	$371.25
Aug-76	$59.07	$58.91	$72.29	$380.14
Sep-76	$56.74	$56.58	$71.93	$364.99
Oct-76	$54.87	$54.72	$70.96	$352.86
Nov-76	$53.67	$53.52	$70.63	$345.05
Dec-76	$52.84	$52.69	$68.19	$339.65
Jan-77	$50.67	$50.51	$65.39	$325.50
Feb-77	$51.85	$51.70	$67.62	$333.23

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Mar-77	$54.97	$54.82	$71.13	$353.52
Apr-77	$57.19	$57.03	$73.14	$367.94
May-77	$58.54	$58.39	$72.35	$376.75
Jun-77	$58.73	$58.57	$73.00	$377.94
Jul-77	$58.71	$58.55	$74.17	$377.82
Aug-77	$60.10	$59.94	$73.39	$386.87
Sep-77	$57.73	$57.57	$73.03	$371.45
Oct-77	$55.83	$55.68	$72.05	$359.11
Nov-77	$54.61	$54.45	$71.71	$351.16
Dec-77	$53.77	$53.61	$69.24	$345.66
Jan-78	$51.55	$51.39	$66.38	$331.26
Feb-78	$52.76	$52.60	$68.66	$339.13
Mar-78	$55.93	$55.78	$72.21	$359.79
Apr-78	$58.19	$58.03	$74.26	$374.46
May-78	$59.57	$59.41	$73.45	$383.43
Jun-78	$59.75	$59.60	$74.11	$384.64
Jul-78	$59.73	$59.58	$75.30	$384.52
Aug-78	$61.15	$60.99	$74.52	$393.73
Sep-78	$58.74	$58.58	$74.15	$378.03
Oct-78	$56.81	$56.65	$73.15	$365.47
Nov-78	$55.56	$55.41	$72.81	$357.38
Dec-78	$54.70	$54.55	$70.29	$351.79
Jan-79	$52.45	$52.29	$67.40	$337.13
Feb-79	$53.68	$53.52	$69.70	$345.14
Mar-79	$56.91	$56.75	$73.32	$366.16
Apr-79	$59.21	$59.05	$75.40	$381.10
May-79	$60.61	$60.45	$74.58	$390.22
Jun-79	$60.80	$60.64	$75.25	$391.46
Jul-79	$60.78	$60.62	$76.45	$391.33
Aug-79	$62.22	$62.06	$75.66	$400.70
Sep-79	$59.76	$59.61	$75.28	$384.73
Oct-79	$57.80	$57.64	$74.27	$371.95
Nov-79	$56.53	$56.38	$73.92	$363.72
Dec-79	$55.66	$55.50	$71.37	$358.02
Jan-80	$53.37	$53.21	$68.42	$343.11
Feb-80	$54.62	$54.46	$70.77	$351.25
Mar-80	$57.90	$57.75	$74.44	$372.65
Apr-80	$60.24	$60.08	$76.55	$387.85
May-80	$61.67	$61.51	$75.72	$397.14
Jun-80	$61.86	$61.70	$76.40	$398.39
Jul-80	$61.84	$61.68	$77.63	$398.27
Aug-80	$63.31	$63.15	$76.81	$407.80
Sep-80	$60.81	$60.65	$76.43	$391.55
Oct-80	$58.81	$58.65	$75.41	$378.54
Nov-80	$57.52	$57.37	$75.05	$370.16
Dec-80	$56.63	$56.48	$72.46	$364.36
Jan-81	$54.30	$54.14	$69.47	$349.19
Feb-81	$55.57	$55.41	$71.85	$357.48
Mar-81	$58.92	$58.76	$75.58	$379.25
Apr-81	$61.29	$61.14	$77.73	$394.72
May-81	$62.75	$62.59	$76.88	$404.17

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jun-81	$62.94	$62.79	$77.57	$405.45
Jul-81	$62.92	$62.77	$78.81	$405.32
Aug-81	$64.41	$64.26	$77.99	$415.03
Sep-81	$61.87	$61.72	$77.60	$398.49
Oct-81	$59.84	$59.68	$76.56	$385.25
Nov-81	$58.53	$58.37	$76.20	$376.72
Dec-81	$57.62	$57.46	$73.57	$370.82
Jan-82	$55.24	$55.09	$70.53	$355.37
Feb-82	$56.54	$56.38	$72.95	$363.81
Mar-82	$59.95	$59.79	$76.74	$385.97
Apr-82	$62.36	$62.21	$78.92	$401.71
May-82	$63.84	$63.69	$78.05	$411.33
Jun-82	$64.04	$63.89	$78.76	$412.63
Jul-82	$64.02	$63.87	$80.02	$412.50
Aug-82	$65.54	$65.38	$79.19	$422.38
Sep-82	$62.95	$62.80	$78.79	$405.55
Oct-82	$60.88	$60.73	$77.73	$392.07
Nov-82	$59.55	$59.39	$77.37	$383.39
Dec-82	$58.63	$58.47	$74.69	$377.39
Jan-83	$56.21	$56.05	$71.61	$361.67
Feb-83	$57.53	$57.37	$74.06	$370.26
Mar-83	$60.99	$60.84	$77.91	$392.81
Apr-83	$63.45	$63.30	$80.13	$408.83
May-83	$64.96	$64.80	$79.25	$418.62
Jun-83	$65.16	$65.01	$79.96	$419.95
Jul-83	$65.14	$64.99	$81.25	$419.81
Aug-83	$66.69	$66.53	$80.40	$429.86
Sep-83	$64.05	$63.90	$80.00	$412.73
Oct-83	$61.95	$61.79	$78.92	$399.02
Nov-83	$60.59	$60.43	$78.55	$390.19
Dec-83	$59.65	$59.50	$75.83	$384.08
Jan-84	$57.19	$57.03	$72.70	$368.08
Feb-84	$58.53	$58.38	$75.20	$376.82
Mar-84	$62.06	$61.90	$79.10	$399.77
Apr-84	$64.56	$64.41	$81.35	$416.08
May-84	$66.10	$65.94	$80.47	$426.04
Jun-84	$66.30	$66.15	$81.19	$427.39
Jul-84	$66.28	$66.13	$82.50	$427.25
Aug-84	$67.85	$67.70	$81.63	$437.48
Sep-84	$65.17	$65.02	$81.23	$420.05
Oct-84	$63.03	$62.87	$80.13	$406.09
Nov-84	$61.65	$61.49	$79.76	$397.10
Dec-84	$60.69	$60.54	$77.00	$390.88
Jan-85	$58.19	$58.03	$73.81	$374.60
Feb-85	$59.56	$59.40	$76.35	$383.49
Mar-85	$63.14	$62.99	$80.32	$406.85
Apr-85	$65.69	$65.54	$82.60	$423.45
May-85	$67.25	$67.10	$81.70	$433.59
Jun-85	$67.46	$67.31	$82.43	$434.96
Jul-85	$67.44	$67.28	$83.76	$434.82
Aug-85	$69.04	$68.88	$82.89	$445.23

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Sep-85	$66.31	$66.16	$82.47	$427.49
Oct-85	$64.13	$63.98	$81.36	$413.28
Nov-85	$62.73	$62.57	$80.98	$404.14
Dec-85	$61.76	$61.60	$78.17	$397.81
Jan-86	$59.21	$59.05	$74.94	$381.24
Feb-86	$60.60	$60.44	$77.52	$390.29
Mar-86	$64.25	$64.09	$81.55	$414.06
Apr-86	$66.84	$66.69	$83.87	$430.95
May-86	$68.43	$68.27	$82.95	$441.27
Jun-86	$68.64	$68.49	$83.70	$442.67
Jul-86	$68.62	$68.47	$85.05	$442.52
Aug-86	$70.25	$70.09	$84.16	$453.12
Sep-86	$67.48	$67.32	$83.74	$435.06
Oct-86	$65.25	$65.10	$82.61	$420.61
Nov-86	$63.82	$63.67	$82.22	$411.30
Dec-86	$62.83	$62.68	$79.37	$404.86
Jan-87	$60.24	$60.09	$76.09	$387.99
Feb-87	$61.66	$61.50	$78.71	$397.20
Mar-87	$65.37	$65.22	$82.80	$421.40
Apr-87	$68.01	$67.86	$85.16	$438.59
May-87	$69.63	$69.47	$84.23	$449.09
Jun-87	$69.84	$69.69	$84.98	$450.51
Jul-87	$69.82	$69.67	$86.35	$450.37
Aug-87	$71.48	$71.32	$85.45	$461.15
Sep-87	$68.66	$68.50	$85.02	$442.77
Oct-87	$66.40	$66.24	$83.88	$428.06
Nov-87	$64.94	$64.78	$83.48	$418.58
Dec-87	$63.93	$63.78	$80.59	$412.03
Jan-88	$61.29	$61.14	$77.26	$394.87
Feb-88	$62.73	$62.58	$79.91	$404.24
Mar-88	$66.52	$66.36	$84.07	$428.86
Apr-88	$69.20	$69.05	$86.46	$446.36
May-88	$70.84	$70.69	$85.52	$457.04
Jun-88	$71.07	$70.91	$86.29	$458.49
Jul-88	$71.04	$70.89	$87.68	$458.34
Aug-88	$72.73	$72.57	$86.76	$469.32
Sep-88	$69.86	$69.70	$86.33	$450.62
Oct-88	$67.56	$67.40	$85.17	$435.64
Nov-88	$66.08	$65.92	$84.77	$426.00
Dec-88	$65.05	$64.90	$81.83	$419.33
Jan-89	$62.37	$62.21	$78.44	$401.86
Feb-89	$63.83	$63.68	$81.14	$411.40
Mar-89	$67.68	$67.52	$85.36	$436.46
Apr-89	$70.41	$70.26	$87.79	$454.26
May-89	$72.09	$71.93	$86.83	$465.14
Jun-89	$72.31	$72.16	$87.61	$466.61
Jul-89	$72.29	$72.13	$89.03	$466.47
Aug-89	$74.00	$73.85	$88.09	$477.63
Sep-89	$71.08	$70.92	$87.65	$458.60
Oct-89	$68.74	$68.58	$86.47	$443.36
Nov-89	$67.23	$67.08	$86.07	$433.55

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Dec-89	$66.19	$66.03	$83.08	$426.76
Jan-90	$63.46	$63.30	$79.64	$408.98
Feb-90	$64.95	$64.79	$82.38	$418.69
Mar-90	$68.86	$68.71	$86.67	$444.19
Apr-90	$71.65	$71.49	$89.14	$462.31
May-90	$73.35	$73.19	$88.17	$473.38
Jun-90	$73.58	$73.42	$88.96	$474.88
Jul-90	$73.55	$73.40	$90.40	$474.73
Aug-90	$75.30	$75.14	$89.45	$486.10
Sep-90	$72.32	$72.17	$89.00	$466.73
Oct-90	$69.94	$69.79	$87.80	$451.22
Nov-90	$68.41	$68.25	$87.39	$441.23
Dec-90	$67.35	$67.19	$84.36	$434.32
Jan-91	$64.57	$64.41	$80.86	$416.23
Feb-91	$66.08	$65.93	$83.65	$426.11
Mar-91	$70.07	$69.91	$88.00	$452.06
Apr-91	$72.90	$72.75	$90.51	$470.50
May-91	$74.63	$74.48	$89.52	$481.77
Jun-91	$74.87	$74.71	$90.33	$483.30
Jul-91	$74.84	$74.69	$91.79	$483.14
Aug-91	$76.62	$76.46	$90.82	$494.71
Sep-91	$73.59	$73.44	$90.37	$474.99
Oct-91	$71.17	$71.01	$89.15	$459.21
Nov-91	$69.61	$69.45	$88.73	$449.05
Dec-91	$68.53	$68.37	$85.65	$442.02
Jan-92	$65.70	$65.54	$82.10	$423.60
Feb-92	$67.24	$67.08	$84.93	$433.66
Mar-92	$71.30	$71.14	$89.36	$460.07
Apr-92	$74.18	$74.02	$91.90	$478.84
May-92	$75.94	$75.78	$90.90	$490.31
Jun-92	$76.18	$76.02	$91.72	$491.86
Jul-92	$76.15	$76.00	$93.20	$491.70
Aug-92	$77.96	$77.81	$92.22	$503.47
Sep-92	$74.88	$74.72	$91.76	$483.41
Oct-92	$72.41	$72.26	$90.52	$467.35
Nov-92	$70.82	$70.67	$90.10	$457.00
Dec-92	$69.73	$69.57	$86.97	$449.85
Jan-93	$66.85	$66.69	$83.36	$431.11
Feb-93	$68.42	$68.26	$86.23	$441.35
Mar-93	$72.54	$72.39	$90.73	$468.23
Apr-93	$75.48	$75.32	$93.32	$487.33
May-93	$77.27	$77.11	$92.30	$498.99
Jun-93	$77.51	$77.36	$93.13	$500.57
Jul-93	$77.49	$77.33	$94.63	$500.41
Aug-93	$79.33	$79.17	$93.64	$512.40
Sep-93	$76.19	$76.04	$93.17	$491.98
Oct-93	$73.68	$73.53	$91.91	$475.63
Nov-93	$72.06	$71.91	$91.48	$465.10
Dec-93	$70.95	$70.79	$88.30	$457.82
Jan-94	$68.01	$67.86	$84.64	$438.75
Feb-94	$69.61	$69.46	$87.56	$449.17

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Mar-94	$73.82	$73.66	$92.12	$476.52
Apr-94	$76.80	$76.64	$94.75	$495.96
May-94	$78.62	$78.47	$93.72	$507.84
Jun-94	$78.87	$78.71	$94.56	$509.44
Jul-94	$78.85	$78.69	$96.09	$509.28
Aug-94	$80.72	$80.56	$95.08	$521.47
Sep-94	$77.53	$77.37	$94.60	$500.69
Oct-94	$74.97	$74.82	$93.33	$484.06
Nov-94	$73.33	$73.17	$92.89	$473.34
Dec-94	$72.19	$72.03	$89.66	$465.93
Jan-95	$69.21	$69.05	$85.94	$446.52
Feb-95	$70.83	$70.68	$88.90	$457.12
Mar-95	$75.11	$74.95	$93.54	$484.97
Apr-95	$78.15	$77.99	$96.21	$504.75
May-95	$80.00	$79.84	$95.16	$516.83
Jun-95	$80.25	$80.10	$96.02	$518.47
Jul-95	$80.23	$80.07	$97.57	$518.30
Aug-95	$82.13	$81.98	$96.54	$530.71
Sep-95	$78.88	$78.73	$96.06	$509.56
Oct-95	$76.29	$76.13	$94.76	$492.63
Nov-95	$74.61	$74.45	$94.32	$481.73
Dec-95	$73.45	$73.30	$91.04	$474.18
Jan-96	$70.42	$70.26	$87.26	$454.43
Feb-96	$72.07	$71.92	$90.27	$465.22
Mar-96	$76.42	$76.27	$94.98	$493.56
Apr-96	$79.51	$79.36	$97.69	$513.69
May-96	$81.40	$81.25	$96.62	$525.99
Jun-96	$81.66	$81.50	$97.50	$527.66
Jul-96	$81.63	$81.48	$99.07	$527.49
Aug-96	$83.57	$83.42	$98.03	$540.12
Sep-96	$80.27	$80.11	$97.54	$518.59
Oct-96	$77.62	$77.47	$96.22	$501.36
Nov-96	$75.92	$75.76	$95.77	$490.26
Dec-96	$74.74	$74.58	$92.44	$482.59
Jan-97	$71.65	$71.49	$88.60	$462.48
Feb-97	$73.34	$73.18	$91.66	$473.47
Mar-97	$77.76	$77.61	$96.44	$502.30
Apr-97	$80.91	$80.75	$99.20	$522.79
May-97	$82.83	$82.67	$98.11	$535.31
Jun-97	$83.09	$82.93	$99.00	$537.00
Jul-97	$83.06	$82.91	$100.60	$536.83
Aug-97	$85.04	$84.88	$99.54	$549.69
Sep-97	$81.67	$81.52	$99.04	$527.78
Oct-97	$78.98	$78.83	$97.70	$510.25
Nov-97	$77.25	$77.09	$97.24	$498.95
Dec-97	$76.05	$75.89	$93.86	$491.14
Jan-98	$72.90	$72.75	$89.96	$470.68
Feb-98	$74.62	$74.46	$93.07	$481.85
Mar-98	$79.13	$78.97	$97.93	$511.20
Apr-98	$82.33	$82.17	$100.73	$532.05
May-98	$84.28	$84.13	$99.62	$544.80

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
Jun-98	$84.55	$84.39	$100.52	$546.52
Jul-98	$84.52	$84.36	$102.15	$546.35
Aug-98	$86.53	$86.37	$101.07	$559.43
Sep-98	$83.11	$82.95	$100.57	$537.13
Oct-98	$80.37	$80.21	$99.21	$519.29
Nov-98	$78.60	$78.45	$98.74	$507.79
Dec-98	$77.38	$77.22	$95.30	$499.84
Jan-99	$74.18	$74.02	$91.35	$479.02
Feb-99	$75.93	$75.77	$94.50	$490.39
Mar-99	$80.51	$80.36	$99.44	$520.26
Apr-99	$83.77	$83.61	$102.28	$541.48
May-99	$85.76	$85.60	$101.16	$554.45
Jun-99	$86.03	$85.87	$102.07	$556.20
Jul-99	$86.00	$85.85	$103.72	$556.03
Aug-99	$88.05	$87.89	$102.63	$569.34
Sep-99	$84.56	$84.41	$102.12	$546.65
Oct-99	$81.77	$81.62	$100.74	$528.49
Nov-99	$79.98	$79.82	$100.26	$516.79
Dec-99	$78.74	$78.58	$96.77	$508.69
Jan-00	$75.48	$75.32	$92.75	$487.51
Feb-00	$77.26	$77.10	$95.95	$499.08
Mar-00	$81.92	$81.77	$100.97	$529.48
Apr-00	$85.24	$85.08	$103.86	$551.08
May-00	$87.26	$87.11	$102.72	$564.27
Jun-00	$87.54	$87.38	$103.65	$566.06
Jul-00	$87.51	$87.35	$105.32	$565.88
Aug-00	$89.59	$89.43	$104.22	$579.43
Sep-00	$86.05	$85.89	$103.69	$556.33
Oct-00	$83.21	$83.05	$102.29	$537.85
Nov-00	$81.38	$81.22	$101.81	$525.94
Dec-00	$80.12	$79.96	$98.26	$517.71
2014	$16.18	$16.03	$23.25	$101.04
2015	$15.19	$15.04	$22.84	$95.21
2016	$14.54	$14.39	$22.30	$91.04
2017	$15.64	$15.49	$23.29	$97.85
2018	$15.65	$15.50	$23.75	$99.27
2019	$17.29	$17.13	$25.36	$111.33
2020	$17.92	$17.77	$26.09	$114.18
2021	$18.07	$17.92	$26.33	$114.05
2022	$17.97	$17.82	$26.76	$114.38
2023	$18.73	$18.58	$27.85	$119.10
2024	$19.57	$19.41	$28.88	$124.01
2025	$20.53	$20.38	$29.87	$129.11
2026	$21.34	$21.19	$30.97	$134.44
2027	$22.20	$22.04	$32.03	$139.96
2028	$23.05	$22.90	$33.08	$145.71
2029	$23.99	$23.84	$34.17	$151.70
2030	$24.97	$24.82	$35.31	$157.95
2031	$25.40	$25.25	$35.83	$160.75
2032	$25.84	$25.68	$36.36	$163.59

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
2033	$26.29	$26.13	$36.90	$166.49
2034	$26.74	$26.58	$37.45	$169.44
2035	$27.20	$27.04	$38.01	$172.44
2036	$27.67	$27.51	$38.58	$175.50
2037	$28.15	$27.99	$39.15	$178.61
2038	$28.63	$28.48	$39.74	$181.77
2039	$29.13	$28.97	$40.33	$185.00
2040	$29.63	$29.47	$40.93	$188.27
2041	$30.14	$29.99	$41.55	$191.61
2042	$30.66	$30.51	$42.17	$195.00
2043	$31.19	$31.04	$42.80	$198.46
2044	$31.73	$31.58	$43.44	$201.97
2045	$32.28	$32.13	$44.09	$205.55
2046	$32.84	$32.69	$44.75	$209.20
2047	$33.41	$33.25	$45.43	$212.90
2048	$33.99	$33.83	$46.11	$216.67
2049	$34.58	$34.42	$46.80	$220.51
2050	$35.18	$35.02	$47.51	$224.42
2051	$35.79	$35.63	$48.22	$228.40
2052	$36.41	$36.25	$48.95	$232.44
2053	$37.04	$36.89	$49.69	$236.56
2054	$37.68	$37.53	$50.44	$240.75
2055	$38.34	$38.18	$51.20	$245.02
2056	$39.01	$38.85	$51.97	$249.36
2057	$39.68	$39.53	$52.76	$253.78
2058	$40.37	$40.22	$53.56	$258.27
2059	$41.07	$40.92	$54.37	$262.85
2060	$41.79	$41.63	$55.19	$267.51
2061	$42.52	$42.36	$56.03	$272.25
2062	$43.26	$43.10	$56.88	$277.07
2063	$44.01	$43.85	$57.74	$281.98
2064	$44.77	$44.62	$58.62	$286.98
2065	$45.55	$45.40	$59.51	$292.06
2066	$46.35	$46.19	$60.41	$297.24
2067	$47.16	$47.00	$61.33	$302.50
2068	$47.98	$47.82	$62.26	$307.86
2069	$48.81	$48.66	$63.21	$313.32
2070	$49.66	$49.51	$64.18	$318.87
2071	$50.53	$50.37	$65.15	$324.52
2072	$51.41	$51.26	$66.15	$330.27
2073	$52.31	$52.15	$67.15	$336.12
2074	$53.22	$53.07	$68.18	$342.07
2075	$54.15	$53.99	$69.22	$348.14
2076	$55.10	$54.94	$70.28	$354.30
2077	$56.06	$55.90	$71.35	$360.58
2078	$57.04	$56.88	$72.44	$366.97
2079	$58.03	$57.88	$73.55	$373.47
2080	$59.05	$58.89	$74.67	$380.09
2081	$60.08	$59.92	$75.82	$386.82
2082	$61.13	$60.97	$76.98	$393.68
2083	$62.20	$62.04	$78.16	$400.65

MONTH	MARTIN RESIDUAL $/MMBTU	MANATEE / TURKEY POINT RESIDUAL $/MMBTU	ALL PLANTS DISTILLATE $/MMBTU	WTI $/BBL.
2084	$63.29	$63.13	$79.35	$407.75
2085	$64.39	$64.24	$80.57	$414.98
2086	$65.52	$65.36	$81.81	$422.33
2087	$66.67	$66.51	$83.06	$429.81
2088	$67.83	$67.68	$84.34	$437.43
2089	$69.02	$68.86	$85.63	$445.18
2090	$70.23	$70.07	$86.95	$453.06
2091	$71.46	$71.30	$88.28	$461.09
2092	$72.71	$72.55	$89.64	$469.26
2093	$73.98	$73.82	$91.02	$477.58
2094	$75.28	$75.12	$92.42	$486.04
2095	$76.59	$76.44	$93.84	$494.65
2096	$77.94	$77.78	$95.28	$503.41
2097	$79.30	$79.15	$96.75	$512.33
2098	$80.69	$80.54	$98.24	$521.41
2099	$82.11	$81.95	$99.75	$530.65
2100	$83.55	$83.39	$101.29	$540.05

July 28, 2014 - LYSTRA LOUTAN

LOW 85.10% HIGH 114.90% MEDIUM PRICES

MONTH	PLANT SCHERER UNIT 4 WEIGHTED AVERAGE WITHOUT SO2 & NOx $/MMBTU	PLANT SCHERER UNIT 4 DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	PLANT SCHERER UNIT 4 DISPATCH PRICE WITH SO2 & NOx $/MMBTU	ST. JOHNS RIVER POWER PARK WEIGHTED AVERAGE WITHOUT SO2 & NOx $/MMBTU	ST. JOHNS RIVER POWER PARK DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	ST. JOHNS RIVER POWER PARK DISPATCH PRICE WITH SO2 & NOx $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	ICL DISPATCH PRICE WITH SO2 & NOx $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	CEDAR BAY DISPATCH PRICE WITH SO2 & NOx $/MMBTU
Jan-14	[redacted]									
Feb-14										
Mar-14										
Apr-14										
May-14										
Jun-14										
Jul-14										
Aug-14										
Sep-14										
Oct-14										
Nov-14										
Dec-14										
Jan-15										
Feb-15										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Jan-20	[redacted]									
Feb-20										
Mar-20										
Apr-20										
May-20										
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Jul-26										

	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Aug-26	[redacted]									
Sep-26										
Oct-26										
Nov-26										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Mar-33	[redacted]									
Apr-33										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Oct-39	[redacted]									
Nov-39										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
May-46	[redacted]									
Jun-46										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
MONTH	WEIGHTED AVERAGE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITH SO2 & NOx $/MMBTU	WEIGHTED AVERAGE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITH SO2 & NOx $/MMBTU	DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITH SO2 & NOx $/MMBTU	DISPATCH PRICE WITHOUT SO2 & NOx $/MMBTU	DISPATCH PRICE WITH SO2 & NOx $/MMBTU
Dec-52	[redacted]									
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Jul-59	[redacted]									
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Feb-66	[redacted]									
Mar-66										
Apr-66										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Sep-72	[redacted]									
Oct-72	[redacted]									
Nov-72	[redacted]									
Dec-72	[redacted]									
Jan-73	[redacted]									
Feb-73	[redacted]									
Mar-73	[redacted]									
Apr-73	[redacted]									
May-73	[redacted]									
Jun-73	[redacted]									
Jul-73	[redacted]									
Aug-73	[redacted]									
Sep-73	[redacted]									
Oct-73	[redacted]									
Nov-73	[redacted]									
Dec-73	[redacted]									
Jan-74	[redacted]									
Feb-74	[redacted]									
Mar-74	[redacted]									
Apr-74	[redacted]									
May-74	[redacted]									
Jun-74	[redacted]									
Jul-74	[redacted]									
Aug-74	[redacted]									
Sep-74	[redacted]									
Oct-74	[redacted]									
Nov-74	[redacted]									
Dec-74	[redacted]									
Jan-75	[redacted]									
Feb-75	[redacted]									
Mar-75	[redacted]									
Apr-75	[redacted]									
May-75	[redacted]									
Jun-75	[redacted]									
Jul-75	[redacted]									
Aug-75	[redacted]									
Sep-75	[redacted]									
Oct-75	[redacted]									
Nov-75	[redacted]									
Dec-75	[redacted]									
Jan-76	[redacted]									
Feb-76	[redacted]									
Mar-76	[redacted]									
Apr-76	[redacted]									
May-76	[redacted]									
Jun-76	[redacted]									
Jul-76	[redacted]									
Aug-76	[redacted]									
Sep-76	[redacted]									
Oct-76	[redacted]									
Nov-76	[redacted]									
Dec-76	[redacted]									
Jan-77	[redacted]									
Feb-77	[redacted]									
Mar-77	[redacted]									
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May-77	[redacted]									
Jun-77	[redacted]									
Jul-77	[redacted]									
Aug-77	[redacted]									
Sep-77	[redacted]									
Oct-77	[redacted]									
Nov-77	[redacted]									
Dec-77	[redacted]									
Jan-78	[redacted]									
Feb-78	[redacted]									
Mar-78	[redacted]									
Apr-78	[redacted]									
May-78	[redacted]									
Jun-78	[redacted]									
Jul-78	[redacted]									
Aug-78	[redacted]									
Sep-78	[redacted]									
Oct-78	[redacted]									
Nov-78	[redacted]									
Dec-78	[redacted]									
Jan-79	[redacted]									
Feb-79	[redacted]									
Mar-79	[redacted]									

	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Apr-79	[redacted]									
May-79										
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Nov-85	[redacted]									
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
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MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
Jan-99	[redacted]									
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	PLANT SCHERER UNIT 4			ST. JOHNS RIVER POWER PARK			ICL		CEDAR BAY	
	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	WEIGHTED AVERAGE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITH SO2 & NOx
MONTH	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
2068	[redacted]									
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Q.

Please provide all electronic workpapers used in calculating the revised versions of Exhibit SF-8 requested in OPC Interrogatory No. 65(a) with all formulas intact.

A.

Attached are the respective supporting documents used in the response to OPC Interrogatory No. 65 (a).

- PetroQuest Gas Reserve Analysis 6-19-2014 (FINAL VERSION) Support for SF-8 with 20140728 Fuel Curve.xlsx: This updated model reflects the resulting customer savings ($51.9 MM) resulting from adjusting the base pricing on the FPL Market Price tab.
    - Updated fuel curve is included in the model in the FPL Market Price tab
    - For a detailed breakdown of the projected Operating Expenses, Depreciation, Return Rate, and Rate of Return, in Columns (C-E) of the revised Exhibit SF-8, please refer to OPC Int. 3rd Set 37 (a-g)
- Woodford Dry - Drill Schedule (Non-Consent).xlsx: This file was used to assist in the preparation of the upfront acquisition costs and capital costs. It provides a detailed breakdown by month, by well type, and timing of drilling and production.

Documents responsive to this request are provided as Bates Nos. FCR-14-06122 through FCR-14-06431.

Revised SF-8 Based on July 28, 2014 Fuel Forecast
Results of FPL's Economic Evaluation

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate[2] ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast 7/28/2014 ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)
2015	15.6	[redacted]				$3.48	$3.75	$4.2	0.9302	$3.9
2016	16.8					$3.56	$3.94	$6.4	0.8649	$5.5
2017	11.3					$4.00	$4.42	$4.8	0.8043	$3.9
2018	8.7					$4.40	$4.66	$2.3	0.7480	$1.7
2019	7.1					$4.96	$5.23	$1.9	0.6956	$1.3
2020	6.1					$4.79	$5.38	$3.6	0.6468	$2.3
2021	5.3					$4.94	$5.58	$3.4	0.6015	$2.0
2022	4.7					$5.08	$5.78	$3.3	0.5594	$1.8
2023	4.3					$5.21	$5.98	$3.3	0.5202	$1.7
2024	3.9					$5.34	$6.18	$3.3	0.4837	$1.6
2025	3.6					$5.24	$6.33	$3.9	0.4498	$1.8
2026	3.3					$5.32	$6.53	$4.0	0.4183	$1.7
2027	3.1					$5.39	$6.78	$4.3	0.3890	$1.7
2028	2.9					$5.46	$7.03	$4.6	0.3617	$1.7
2029	2.8					$5.52	$7.33	$5.0	0.3364	$1.7
2030	2.6					$5.58	$7.63	$5.3	0.3129	$1.7
2031	2.4					$5.65	$7.81	$5.3	0.2910	$1.5
2032	2.3					$5.71	$8.00	$5.2	0.2705	$1.4
2033	2.2					$5.80	$8.19	$5.2	0.2516	$1.3
2034	2.0					$5.88	$8.39	$5.1	0.2340	$1.2
2035	1.9					$5.97	$8.60	$5.0	0.2176	$1.1
2036	1.8					$6.05	$8.81	$4.9	0.2023	$1.0
2037-65	23.1					$7.88	$11.55	$84.6	0.1008	$8.5
Totals[1]	**137.8**	**$323.2**	**$190.8**	**$195.5**	**$709.4**			**$178.7**		**$51.9**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on the assets and return of financing costs.

(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital

FCR-14-06122

Florida Power & Light Company
Docket No. 140001-EI
OPC's 6th Request for POD's
Attachment I / Request No. 36
Pages 2 through 310

Documents responsive to OPC's Sixth Request for POD's No. 36 (Bates Nos. FCR-14-06123 through FCR-14-06431) are confidential in their entirety.

Q.

Please refer to OPC Interrogatory No. 65(b). Please provide the source documents supporting the most recent fuel forecast used in responding to this interrogatory as well as all electronic workpapers used in calculating the revised versions of Exhibit SF -8.

A.

Refer to the response and attachments in OPC 6th POD No. 36.

Scott A. Goorland
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5633
(561) 691-7135 (Facsimile)
scott.goorland@fpl.com

November 26, 2014

--VIA UPS OVERNIGHT DELIVERY--

VERITEXT – Production Department
One Biscayne Tower, Suite 2250
Two South Biscayne Boulevard
Miami, Florida 33131

Re: Docket No. 140001-EI – In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor
Job # 1967081

To: Veritext – Production Department

Pursuant to instructions from Zipporah Gibbs, I am enclosing the late-filed exhibit for Sam Forrest Volume 2 Deposition.

Additionally, I am enclosing the original errata sheets and signed affidavits from witness depositions of Sam Forrest, Kim Ousdahl, and Dr. Tim Taylor. The Errata Sheet for witness, Terry Deason is a PDF copy. It will be replaced with the original under separate cover.

All documents have been scanned and electronically sent to litsup-fla@veritext.com. Please contact me if you have any questions. Thank you for your assistance.

Sincerely

for

Scott A. Goorland
Principal Attorney

Attachments

cc: Zipporah Gibbs, zgibbs@veritext.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 55
PARTY: STAFF
DESCRIPTION: Deposition of Sam Forrest, 11/14/14 (CONFIDENTIAL), including late-

This late-filed exhibit responds to a request by the Office of Public Counsel for three variants to the matrix of customer savings under sensitivity cases that appears on page 38 of Mr. Forrest's direct testimony, to reflect the following changes in assumptions:

- Change Case 1 -- Changing the range of variability in gas production volume from +/- 10% to +/- 20%, but using the same October 2013 fuel forecast;
- Change Case 2 -- Using FPL's July 2014 fuel forecast instead of its October 2013 fuel forecast, but using the +/- 10% range of variability in gas production volume; and
- Change Case 3 -- Using FPL's July 2014 fuel forecast and a +/- 20% range of variability in gas production volume

The results for the three requested change cases as well as the original table are attached. FPL has several observations about the requested change cases:

- Each of the change cases shows significant base case customer savings ($106.9 MM NPV in Change Case 1 and $51.9 MM in Change Cases 2 and 3). These are the most likely outcomes for customers in each Change Case and are extremely favorable.
- The difference between the October 2013 and July 2014 fuel forecasts illustrates the price volatility that the Woodford Project would mitigate. Decoupling a portion of FPL's fuel purchases from market prices would create a more stably priced source of natural gas for the benefit of FPL's customers.
- Picking a fuel price forecast with lower fuel prices, as OPC has done, and then subjecting it to the same full range of downward fuel price volatility effectively double counts the potential "downside exposure." In other words, the variability that exists between the October 2013 and July 2014 fuel forecasts is accounted for in the 20.9% reduction in fuel prices used for the "low fuel price" sensitivities. Picking a lower fuel forecast as the starting point and then applying the same 20.9% reduction can result in exceptionally low values for the "low fuel price" sensitivity case.
- Finally, while FPL consented to run change cases using a +/- 20% range of variability in gas production volume, FPL does not believe that this range is realistic or relevant. As described by FPL witness Taylor in his direct testimony, the AMI has an established production history with a robust amount of operational performance data. Given this extensive base of production history and knowledge, Dr. Taylor expects that the aggregate volume of gas produced from the wells in the Woodford Project will not vary outside a +/- 10% band. While it is possible that the output of a single well could vary by +/- 20%, the variability for the Woodford Project in the aggregate should not exceed +/- 10%.

Pricing and Production Sensitivities[(1) / (2)]

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($38.2)	$39.1	$116.4
Base Production	$10.3	**$106.9**	$203.5
High Production	$59.8	$175.7	$291.7

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: October 2013

Pricing and Production Sensitivities(1) / (2)

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($50.7)	$23.1	$97.0
Base Production	($30.0)	**$51.9**	$134.0
High Production	($10.2)	$79.9	$170.2

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Pricing and Production Sensitivities(1) / (2)

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($70.5)	($4.9)	$60.8
Base Production	($30.0)	**$51.9**	$134.0
High Production	$11.4	$109.7	$208.3

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Pricing and Production Sensitivities[(1) / (2)]

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($14.4)	$72.6	$159.5
Base Production	$10.3	**$106.9**	$203.5
High Production	$34.1	$140.4	$246.7

Notes
For illustrative purposes, the following sensitivities were assumed:
(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.
(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.
(3) Fuel curve date: October 2013

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON
SEE ATTACHMENT		

I, Sam A. Forrest, do hereby certify that I have read the foregoing transcript of my deposition, given on Nov 13 & 14, 2014, and that together with any additions or corrections made herein, it is true and correct.

Deponent

The foregoing instrument was acknowledged before me this 26 day of November, 2014, by Sam A. Forrest, who is personally known to me or has produced ____________ as identification and who did not take an oath.

Notary Signature

LEEANN R. BREHM
Commission # FF 092442
Expires February 12, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

NOTARY PUBLIC, State of Florida

Commission Number

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON
43 / 23	Change "invented" to "vetted"	Transcription Error
63 / 10	Insert em dash "--" between "if" and "USG"	Transcription Error
77 / 8	Change "SFA" to "SF-8"	Transcription Error
77 / 14	Change "cap X" to "CAP EX"	Transcription Error
109 / 2	Change "bore" to "bear"	Transcription Error
110 / 20	Insert "billion" between "two" and "cubic"	Transcription Error
111 / 15	Change "after" to "halfway through"	Transcription Error
112 / 23 and 112 / 24	Change "Northwest" to "Northwestern"	Transcription Error
124 / 11	Change "Four Star" to "Forrest A. Garb"	Transcription Error
127 / 7	Change "they were" to "that we're"	Transcription Error
136 / 5	Change "FIGA" to "FIPUG"	Transcription Error
137 / 8	Change "are" to "aren't"	Transcription Error
137 / 22-23	Should read "...out as far as four or five years..."	Transcription Error
140 / 3	Change "proven" to "prudent"	Transcription Error
142 / 10	Change "really" to "originally"	Transcription Error
158 / 14	Change "SFA" to "SF-8"	Transcription Error
173 / 14	Replace "and" with "in"	Transcription Error
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183 / 23	Replace "Formal" with "Form of"	Transcription Error
214 / 22	Replace "opt" with "point"	Transcription Error
219 / 22	Replace "lower" with "longer"	Transcription Error
226 / 10, 19 and 20	Replace "SFA" with "SF-8"	Transcription Error
228 / 17	Replace "predict" with "protect"	Transcription Error
228 / 25	Replace "than" with "on"	Transcription Error
229 / 2	Replace "enterprises" with "prices"	Transcription Error
233 / 11-12	Replace "a BTU" with "an MMBtu"	Transcription Error
235 / 1	Replace "production" with "consumption"	Transcription Error
235 / 12	Replace "L & G" with "LNG"	Transcription Error
238 / 25	Replace "hire" with "higher"	Transcription Error
246 / 3	Replace "was" with "is"	Transcription Error
246 / 23	Replace "a navel" with "enable"	Transcription Error
247 / 2	Replace "percent" with "cents"	Transcription Error
247 / 4	Replace "anyway" with "that way"	Transcription Error
253 / 24	Should read "...I would call a promote or up front..."	Transcription Error
253 / 25	Replace "made" with "paid"	Transcription Error
266 / 7	Replace "170" with "107"	Transcription Error
267 / 20	Replace "transition" with "transportation"	Transcription Error

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Deposition of Sam Forrest (CONFIDENTIAL) 11/14/14, including late-filed Exhibit #1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FILED: October 25, 2014

IN RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

_________________________________/

Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida
November 13, 2014
2:10 p.m. - 6:15 p.m.

CONFIDENTIAL DEPOSITION OF SAM FORREST

VOLUME 1

Taken on behalf of the Alice Teslicko before Alice J. Teslicko, RMR, Notary Public in and for the State of Florida at Large, pursuant to a Notice of Taking Deposition in the above cause.

APPEARANCES:

FOR THE OFFICE OF PUBLIC COUNSEL:

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APPEARANCES - CONTINUED

Also Present:

Andrew Maurey - Florida Public Service Commission

Kurt Howard - FPL

Richard Ross - FPL

Appearing Telephonically:

Erik Sayler - Office of Public Counsel

Tarik Noriega - Office of Public Counsel

Patty Christensen - Office of Public Counsel

Donna Ramas - Office of Public Counsel

Florida Public Service Commission Staff

Inna Weintraub - FPL

Kory Dubin - FPL

Jay Beaupre - FPL

Dan Lawton - FPL

Scott Goorland, Esq. - FPL

- - -

I N D E X

EXHIBITS

(None marked)

Thereupon:

SAM FORREST

was called as a witness and having been first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE COURT REPORTER: Would everyone in the room please state your appearances for the record.

MR. REHWINKEL: This is Charles Rehwinkel with the Office of Public Counsel.

MR. TRUITT: John Truitt with the Office of Public Counsel.

MR. MOYLE: Jon Moyle, Florida Industrial Power Users Group.

MR. GUYTON: Charlie Guyton on behalf of Florida Power & Light Company.

MR. HOWARD: Kurt Howard, Florida Power & Light.

MR. ROSS: Rich Ross, Florida Power & Light.

THE COURT REPORTER: On the phone, please, would you announce?

MR. SAYLER: Erik Sayler, Office of Public Counsel.

MR. NORIEGA: Tarik Noriega, Office of Public Counsel.

MR. HOFFMAN: Ken Hoffman, Florida Power & Light.

MS. BARRERA: Martha Barrera and Andrew Maurey for the Public Service Commission.

MR. REHWINKEL: Are there two more on the phone?

A VOICE: Commission staff in Tallahassee.

MR. REHWINKEL: Is there anyone else on the phone?

MR. DUBIN: Kory Dubin for Florida Power & Light.

MR. TRUITT: Couple of preliminary housekeeping matters because we're on the record, just to make sure.

This is all confidential. So if there's any beeps on the phone, we're going to stop immediately and ask you to identify yourself. If a person doesn't identify themselves after we hear a beep, we're kind of forced to hang up and restart again. We want to make sure we don't breach the confidentiality.

Also, Mr. Guyton, I would assume that we're going to go under the same agreement that all objections except as to form will be reserved until the hearing. That's what we've been doing so far.

MR. GUYTON: Yes.

MR. TRUITT: With that, we'll go ahead and start.

DIRECT EXAMINATION

BY MR. TRUITT:

Q. Good afternoon, Mr. Forrest. How are you?

A. Afternoon, fine.

MR. GUYTON: And I assume that we have not waived reading or signing.

MR. TRUITT: Correct.

Q. Mr. Forrest, do you understand that I intend to rely on the answers in this deposition today during the cross examination at the hearing on this matter?

A. Yes.

Q. You had caused to be filed direct and rebuttal testimony, including exhibits, in this docket; is that correct?

A. I did, yes.

Q. At this time do you have any changes to any of your direct testimony or the attached exhibits to that?

A. We filed an errata, but beyond that, no.

Q. To the errata sheet on November 5th, 2014?

A. With those items, yes.

Q. Any changes to the rebuttal in those exhibits?

A. No.

Q. First I want to start with a threshold question. Do you think that whether -- the question whether the gas reserves investment case is within the Commission's jurisdiction, is a purely legal question?

MR. GUYTON: Are you asking him for a legal conclusion?

MR. REHWINKEL: No, I'm asking his personal opinion.

A. I think that I would answer yes, within the respects of whether it falls within Order 14546.

Q. The same question, the gas reserves investment case, do you believe that it could fall within the Commission's jurisdiction based on policy of the Commission?

A. I'm not an attorney. I'd rather leave that to the attorneys.

Q. To start, in your direct testimony on Page 39 you mention the Woodford project is eligible under the fuel clause according to Order 14546 and subsequent orders; is that correct?

A. That's correct.

Q. Did you read Order 14546 and all the

subsequent orders you referred to in that part of the testimony?

A. I have read parts of 14546 and the subsequent orders, yes.

Q. In reading 14546 and the subsequent did you reach the conclusion --

MR. REHWINKEL: Did someone join the call?

MR. LAWTON: Yeah, Dan Lawton.

MR. REHWINKEL: Who joined the call?

MR. GOORLAND: Hi, it's Scott Goorland joining, with FPL.

MR. REHWINKEL: Thank you.

BY MR. TRUITT:

Q. Upon reading the order and the subsequent orders, where you state in the testimony that it's eligible for recovery in the Fuel Clause, did you reach that conclusion on your own based on your reading of the orders?

A. With discussion with attorneys. I wouldn't say I reached this entirely on my own. I certainly relied upon attorneys and regulatory experts to help.

MR. REHWINKEL: Who was that that joined the call?

MR. BUTLER: John Butler.

MR. NORIEGA: Charles, this is Tarik Noriega again. The lady that just spoke, I couldn't hear a word she said.

MR. REHWINKEL: That was the court reporter. It was off-the-record conversation.

MR. NORIEGA: Okay. Thank you.

BY MR. TRUITT:

Q. Mr. Forrest, would you acknowledge that there are risks in investing in gas reserves?

A. Yes, I would.

Q. In the context of investing in gas reserves generally -- not necessarily in this project, but what you've learned over reviewing this project and anything else encompassed outside that -- in your opinion, what are the risks of investing in gas reserves?

A. I guess I would start with a more generic context that there are -- depending upon the type of opportunity, there are different risks inherent in a particular transaction. There is everything from, you know, exploration activities, you know, different types of exploration, whether it's offshore versus onshore.

Those would have different risk profiles in terms of the ability to extract gas and potential opportunities surrounding that.

I think as you get into the specifics of the project that's being presented here, where you get into an area that has existing wells, a lot of good seismic data, you tend to de-risk some of that.

I mean, there's still risks associated with, you know, production and the amount of production you might get, but you know, the more you know about a given area, the less risky they are.

So you could go anywhere from what I'll describe as exploration down to more of just a production or almost a true development opportunity.

Q. With respect to the Woodford project, as you just stated, it narrows down when you know more about the information. So with the Woodford project as our focus on this question, what are the main risks of investing in gas reserves in this project?

A. Variations in production, certainly. There are certainly risks around the cost associated with drilling, both of which we think we have a very good understanding of.

Again, as I mentioned, there's sort of been a de-risking of the properties based on the fact that there are a number of wells that exist in an area, but there is some risk of variation. Certainly Dr. Taylor has a much better grasp of those issues than I do, and I would defer specific conversations to him, but generally speaking.

Q. I'm trying to look at the big picture. So you mentioned production risk or costs of drilling. What about a regulatory risk in the actual area where you're drilling?

I'm not talking about in Florida here. I'm talking about there, since it's governed by a different state agency. Do you incorporate regulatory risk when you're looking at a project like this?

A. We certainly looked at what Petroquest has filed in some of their SEC disclosures, looked at other documents to determine whether we believe there was any risks associated with the Woodford Shale. We're not aware of any. We didn't discover any.

Certainly Petroquest hasn't identified what we believe are any regulatory risks that we thought were alarming to us.

Q. We'll pause for a second for the helicopter.

A. Sure.

Q. As part of the regulatory risk, some would term it a subset of that environmental risk, which could be incorporated under regulatory as well.

Did you guys specifically look at possible environmental risks which would encompass future possible increased environmental regulations or the current environmental regulatory landscape in the area, those types of risks, is that incorporated as well in your analysis?

A. There was some of that. Again, we didn't do any specific environmental surveys or investigations with respect to the properties. Again, we relied very much on Petroquest as well as our own affiliate to identify any potential risks. We're not aware of any.

You know, as you talk about environmental risks per se, you know, some of those risks are more what I would consider to be industry-wide kind of issues. If we're dealing with -- whether it's Oklahoma with respect to hydraulic fracturing or horizontal drilling or disposal of waste water, those are, I believe, probably issues that are not quite granular enough down to the Woodford project itself, but are probably more of a state-wide type issue such that, you know, if something was to be implemented, you're probably talking about something that's going to impact the industry across an entire state or even at a federal level.

I think that's much more remote. But at a state level you're talking about something that's going to impact all activities in the state, as opposed to just something that's so specific to one of these 38 wells.

Q. Okay. You mentioned that a lot of the information you got in terms of the analysis of this was information from Petroquest or USG.

Would you say that the bulk of the information you reviewed in your analysis to analyze the risks in this Woodford project came from USG and Petroquest and not any other source?

MR. GUYTON: Excuse me, are you still talking about environmental risks here, where he answered that question, or was that broader?

MR. TRUITT: I'm talking about the broader risk from previously.

MR. GUYTON: I just wanted to make sure.

A. No, we did a fair amount of our own due diligence with respect to PetroQuest as a counter party.

If we're talking about regulatory risk, we certainly talked to our regulatory folks internally that are more involved on a national level. So we did our own due diligence beyond just a conversation with PetroQuest and USG, certainly.

Q. I'm going to shift gears a little bit and ask you to look at a response by Staff, Interrogatory

Number 83. Do you have that with you?
A. I'm sure I do.
Q. It's in that second set of interrogatories, if that helps narrow it down.
A. Okay.
Q. Just to put the context, the discussions regarding other utilities that have invested in gas reserves and their response goes through five different named entities.
So my question is, in the research putting this together or at any point up until today did you discover any other utilities that you didn't specifically mention here or is this the complete list as you know it in response to that question?
A. To my knowledge, I believe this is the list. We're talking about entities that have actually done the investment and gone through some type of either regulatory approval or board approval.
These are the ones that I'm aware of. There may be others.
Q. Okay. And then if we flip over to Staff Interrogatory Number 87, there's a question going down that same line where it says:
"Please identify each State Commission order deeming the investment in gas reserves prudent for

cost recovery and the date."

There's a list of four orders there. So again, I'm just going to ask to clarify if that was a complete list.

A. Again, to the best of my knowledge it is.

Q. In these four orders that are listed in Interrogatory Number 87 -- so we're looking at orders from, just to be clear on the record, Montana Public Service Commission, Oregon Public Utility Commission, Public Service Commission of Utah, and the Public Service Commission of Wyoming, correct?

A. Correct.

Q. The utilities that are involved in those orders, do you know what kind of utilities those are?

A. Northwestern Natural is a gas LDC. I believe, again, subject to check, it's covering parts of Oregon and Washington.

Questar is, again, a gas LDC that covers parts of Utah, Wyoming, and potentially Colorado. Again, I would need to check. The Northwestern Energy is a combined gas LDC and electric utility.

Q. Do you know with regards to the Northwestern, though it's a combined utility, do you know if that order allows them to burn the gas they got to power the electric plant or is it simply the delivery of gas to end use consumers?

A. I'm not sure. I don't know that I recall.

Q. And then just to put in the context, what kind of a utility is FPL?

A. We are an investor-owned utility serving electric customers.

Q. I'm going to set those rogs away. We're not going to come back to those.

A. Okay.

Q. I'd like you to go to your direct testimony on Page 12, Line 18. "I'm giving a definition of price risk."

A. You said 12, Line 18?

Q. Yes, sir. Okay, see that?

A. Yes.

Q. Can you tell me what your source is for that definition?

A. I don't know that it was -- that's my personal definition.

Q. Is that a definition that FPL as a whole would operate under or is that strictly your --

A. That's my response to the question. I'm not sure whether FPL would operate on that.

Q. And then there's testimony talking about the hedging properties of the Woodford project and the guidelines.

So regarding FPL's current hedging program, could you please explain to me which pieces of your currently approved hedging programs are fixed and explain to me which pieces are variable, such as costs or quantity, that nature, that big broad picture type view?

A. Yes. Our current hedging program effectively hedges gas prices say 12 to 24 months in advance, but what we're effectively doing is hedging sort of one year in advance.

So the reason for the 12 to 24 months is because as we step into a new year -- so as an example, as we step into 2015, assuming we have Commission approval of our risk management plan, we'll start hedging in 2016 and we'll hedge all the way out through the end of 2016.

So at that point we're effectively hedging 24 months in advance. Once you get to the end of 2015, now you're sort of like 12 months, right?

So that's the nature of our program, is it's a very short term in nature. We use almost, I'd say exclusively, over-the-counter swaps. They're fixed price swaps. So we are paying a fixed price in exchange for a floating price, and the way that would work with our existing -- if it's helpful to have an example of what we would do -- as an example, if we were going to buy a physical supply in January of 2015, that physical supply would typically have a floating price that would be established the week prior to entering into 2015.

So if gas prices go up, we pay a higher price for that physical gas. If gas prices go down, we pay a lower price for that physical gas.

The swap, how the financial piece of this works, the hedging program ties in, is we go to another counter party, typically a financial institution, and we would pay them a fixed price established today in exchange for a floating price that would be established again that week prior to January.

So if the two months matched up we would effectively have received a floating price, paid a floating price, and then also paid a fixed price; meaning we ultimately locked in the price for that volume of gas.

So that's how our program works today. I would describe it simply as kind of a dollar cost averaging. Every day we come in and we layer a few more hedges.

We do have a little bit of flexibility in terms of how we do that from a timing perspective. Nothing prescribes that we have to buy this much gas today. So we have a little bit of flexibility within a month, depending on what circumstances may be existing in the marketplace at a given time.

If we have a hurricane in the Gulf of Mexico, it's probably not the greatest time to be hedging. So we're paying attention to what's happening to prices. It's just, again, layering in.

So we got a very prescribed hedge at [redacted] percent of our volumes for a given year and within that [redacted] percent, again, we sort of layer it in as the year goes by. So that's the hedging program we have today.

The variability is sort of the timing of when you are purchasing those hedges, the fixed price piece of it. That's the product we're using. We're using a fixed price swap.

Q. Okay. Now, just to clarify what is a rather simplistic question, but I'm going to put it on the record anyway, when you pay whatever the dollar is for the amount of gas, isn't the amount of gas fixed to that price?

Say it's $5 for X amount. If you don't pay,

$5 you don't get varying amounts?

A. No, it's for a fixed price quantity, that's right.

Q. Now, looking at the Woodford project alone, are the production costs fixed?

A. Fixed in that they're a hundred percent known, no. I think they're very well understood with the information we do have, but they are not fixed in the sense that a swap is fixed, if you will.

Q. If the proposed guidelines were passed and future projects were invested in -- I'm assuming they would be similar to the lines of Woodford project, that's the point of guidelines -- would those production costs -- do the guidelines fixed production costs in any of those?

A. I can't speak to what future transactions may look like.

Q. I guess I'll clarify. Is there anything in the guidelines that would fix production costs in any future investments?

A. Not inherently, no.

Q. In the analysis of the Woodford project, you know, you just stated production costs weren't a hundred percent guaranteed, but you guys were fairly sure of the range.

What are the variables in your analysis that you saw change these production costs? What were the big factors you saw moving them?

A. That's probably a question best answered by Dr. Taylor. He's got years of experience with that.

Q. Now, by your testimony, you're clearly recommending acceptance of the Woodford project and the proposed guideline. Is that an accurate statement?

A. That's correct.

Q. Now, at what level of variance -- and I'm looking at a percentage-wise kind of figure here -- from the currently anticipated production costs would it cause you to stop recommending acceptance of the Woodford project?

For example, production costs go up 10 percent, you say no. 15 percent, no. That's what I'm looking at.

A. Again, I think Dr. Taylor is a better resource for the response, but from our perspective we're going to analyze -- and maybe I should caveat how I respond to the question so that we're all clear.

If I was looking at an individual well -- are you talking about a particular project or --

Q. I'm looking overall at the Woodford project, in terms of your high level review of the project.

A. Sure. So with respect to the Woodford project itself, if we're analyzing an individual well to determine whether we want to consent or not consent into that well, if costs have been increasing, the rights that we have within the contract obviously would allow us to non-consent to a given well if cash price -- or excuse me, if the production costs have grown to a level that we're no longer comfortable with or it no longer shows as being economical against the forward curve. We could non-consent to that.

If there's [redacted] we would be let out of kind of the non-consent, if you will, in terms of maintaining this obligation to have 15 minimum wells.

So there are some constructs built into the contract which allow us some leeway in terms of Petroquest managing this contract appropriately.

With respect to the overall project, you know, as we view it today under a number of different scenarios, we view this as being beneficial for customers. The first couple of wells that have been proposed actually have come in at a lower cost, at least on a proposed basis, than what was originally proposed in the initial evaluation.

So we feel pretty confident that things are headed in a good direction with respect to the cost situation.

Q. Okay. Now, then just to clarify, you don't have an internal rule per se that says we see production costs, in the hypothetical, a hundred. If it goes up 10 percent or more, we're done. You're going to evaluate it on a case-by-case basis.

Is my interpretation of your answer correct, it will be on a case-by-case basis?

A. Well, we haven't taken possession of the contract today, so we haven't developed necessarily any rules or how we're going to approach the market place necessarily. This is, you know, probably two or three months in the making.

I will say that there's a lot of factors that go into an individual decision on, you know, whether you consent to a well or not. If gas prices have gone lower, but costs have gone lower, it would be part of the analysis to say, you know, is it still economic for our customers.

If costs have gone higher, but gas prices have gone up to $8, you know, again, that may still be a more expensive well, but it still may be incredibly beneficial for customers to drill that well.

So I don't think there's a black and white response to the question. It has to be really done on a case-by-case basis to understand the circumstances at the time the decision is made.

Q. Do you anticipate under the proposed guideline -- is FPL going to restrict itself to looking at projects where it has the consent/non-consent options like it does under Woodford or is that not an absolute requirement?

A. [redacted]

I don't think any two transactions will be identical. It's two counter parties negotiating, and so there are no guarantees in that, but [redacted]

Q. In the Woodford project again as a whole, are the production levels of natural gas fixed or guaranteed in any way?

A. The production levels?

Q. Yes.

A. No, they are not.

Q. Under the proposed guidelines, outside of the total daily earned percentage, is there any other requirement that would limit or guarantee production levels, fixed or guaranteed, for future projects?

A. No.

Q. In terms of looking at Woodford project -- and again, the predicate to this is you recommend acceptance of the Woodford project as it stands right now -- do you have, in your opinion or either internally FPL have, any of those categories, a level of variance percentage-wise from the currently anticipated production where you would determine that no, this project is not a good project?

I understand where you run your matrix and things like that. Again, I'm looking at do you have a hard stop anywhere, essentially?

A. Again, no, we don't.

Again, we haven't taken possession of the transaction, so all our procedures evolve. But again, I will say as we look at each individual well as they are proposed, we'll be making a decision based on the information that we have at that time.

So it's, again, not a black and white answer without having all the circumstances presented.

Q. Okay. In the Woodford project as it stands, are the customer savings fixed or guaranteed in any way?

A. No, they are not.

Q. Under the proposed guidelines is there anything in the guidelines -- again, I'm talking about requirements in the guidelines themselves -- that would guarantee customer savings or fix them at a certain level?

A. No, they're not, but I'm not sure where in any of the transactions we propose to the Commission where there have been guaranteed savings, whether that's a power plant or anything else.

We present the information with the best information we have available and the decisions are made. The Commission decides whether it's a prudent, reasonable decision and we move forward.

So no, there's no guarantees in this.

Q. Okay. This is going to be my last variance percentage-wise question, so I know you might be tired of that.

Again, the Woodford project, recommending acceptance currently based on everything you've looked at, do you have a level of variance percentage-wise from the currently anticipated customer savings where you would stop recommending acceptance of the Woodford project?

Do you have a hard stop in that category?

A. No, I do not.

Q. Is it FPL's position that as long as customers are saving some amount, then the project should be approved?

A. That would be our position.

I think there's other benefits that go along with this beyond just customer savings. I know there was an extreme example presented where if we were looking at one dollar of customer savings, would we go forward with that.

Obviously that's a very unique and specific example that was presented. Obviously our intent would be to look for opportunities that have a much greater level of savings.

You can't ignore the hedging benefits of some of these transactions, such that if the forward curve were to fall to a level where production costs in the forward curve were essentially equal with one another for a 50-year period, that's a terrific day for our customers in terms of, you know, being able to lock in a very long term supply at a very low level for an extended period of time. We certainly would evaluate that as to the benefits for our customers.

Again, if that one dollar, if you will, if that was the example again that was presented, I think it's still worthy of assessing whether that is a worthwhile transaction just based on the true hedge benefits and the fact that this is going to be an extremely low source of supply for a very, very long time.

I will say that the transactions that we have evaluated to date have been nowhere near that kind of level. They're all presenting very, very substantial savings. So I think it's a bit of an extreme example, at least in today's environment.

Q. Okay, that's fair enough.

In the Woodford project as it stands, is the return that FPL shareholders are going to get investment fixed?

A. Is it fixed?

Q. Is it a fixed percentage?

A. If it's approved the Fuel Clause will be allowed to earn I guess their authorized return of equity of 10 and a half percent.

It certainly isn't fixed in the sense that there's no guarantees to that. There are risks that are associated with it, but --

Q. What are those risks?

A. You know, you look at our SEC disclosure, there's a number of risks that are identified within that document that are probably pertinent to the Woodford project or other potential investments in gas reserves, which include a potential increase in the cost of debt, you know, future rate cases, a decrease in the return on equity. You've got, you know, a potential disallowance for any costs that were deemed imprudent by the Commission.

So there are risks associated with them.

Q. Now, if Woodford is approved -- and I know there's a proposed drilling schedule, so I'm going to assume that's the drilling schedule I'm working with in terms of this question.

A. Okay.

Q. Is FPL locked in going forward with drilling all wells on the drilling schedule?

A. No.

Q. Does that have to do with the consent/non-consent issue that you discussed earlier?

A. Yes, it does.

Q. Now, if the guidelines are approved as they stand, is there any term in the guidelines that would lock FPL in and make you go forward with drilling all the wells?

I'm just talking about if there were a term in the guidelines that if you invest in a project under those guidelines, is there a term there that says, okay, since you invested in it you got to drill all the wells in it?

A. No, there's not.

Q. Now, in the world as it exists now, without the gas reserves investment in FPL's contract for fuel to burn, to provide electricity, specifically natural gas, if you have a deal with a supplier -- you buy gas from a supplier that supplies you gas -- if, for example, he raised his part of the contract, you know, does not supply the amount of gas you contracted from him, what are FPL's remedies in that situation?

A. In the event of a -- is he selling you fixed price, variable price?

Q. Fixed.

A. In a fixed price contract, depending upon the nature of the relationship with the counter party and what collateral sort of agreement has been developed, if you're talking about a financial institution and it's just fixed price gas and an over-the-counter swap, it's not physical, there's going to be a posting of collateral and I will hold onto that collateral in exchange for his nonperformance.

On the physical side of the business, it depends. Naturally, if he's selling me fixed price gas, typically it's a very, very short term transaction. We don't buy fixed price physical gas on a longer term basis, just because of the credit requirements of dealing with smaller entities and you know, in some cases what would be a less than investment grade counter party.

We would hold payment for that gas, for whatever gas we may owe him at that point, in exchange for settlement of the terms.

Q. Now, for longer terms, which I guess would involve a variable price, say gas is not delivered according to the contract, what would be different in that scenario?

A. In that particular scenario I probably haven't taken much risk. If I could buy -- it's a pretty liquid market in most places, so to the extent that a counter party does not deliver gas to me, I can go to another counter party and have them deliver gas probably for the same price or if there's any type of price differential I may seek remedy from the first counter party that's no longer delivering.

If they're doing it under a force majeure, then that's within their rights, to stop delivery as a result of that.

Q. Now, in both the fixed situation and the variable situation, which have some similarities, what are the risks to FPL's customers if someone doesn't deliver gas?

A. To the extent it was a fixed price transaction, the risks would be that I have to go acquire higher priced gas and then try and resolve my legal issues with the first counter party.

So there's a potential for higher priced gas being passed on to the counter party or to our customers, excuse me.

Q. In that instance would FPL's customers pay for the gas twice? Would they pay for it once, then it wasn't delivered, and then pay for it again when you have to go buy the higher price?

A. We pay in arrears, so no.

Q. When you were -- again, on the risk and fuel concept here, when you were preparing your testimony and rebuttal, what were you keeping in the forefront as current risks that FPL's customers face regarding fuel?

When you were preparing this and explaining why this was a good deal, what in your opinion did you see as the current risks for FPL's customers regarding fuel?

A. Well, I think the primary risk that they -- I'll break it into two pieces.

I think there's the physical risk that exists today, which is in the event of a shortage of supply, in the event of some type of pipeline disruption, in the event of some other type of issue in the delivery system that prohibits us from getting the gas we need, we do have alternative fuels like residual fuel oil and distillate fuel oil that we can burn, which is a much higher priced product. So our customers in that event have the risk of price as an impact.

If those outages last long enough, obviously they are, you know, potentially facing a shortfall of generation, if we run out of the distillate fuel oil, and then you're looking at potential rolling of feeders to disrupt customers.

That's obviously an extreme example, but there is that risk. It's one of the reasons that the new pipeline being developed. You know, it's going to help offset that risk.

The other type of risk they deal with is the fact that gas prices can and do move up and down over time. We're hedging out right now through the end of 2015. Again, we've hedged about [redacted] percent of our supply for 2015. Our customers are in pretty good shape. So if gas prices increase, we have a good percentage of the fuel hedged and so they've got protection. But if gas prices increase in '16 and '17 and '18, there is no protection for them.

So, you know, as you look at what's happening with gas prices over time, our customers have a hundred percent exposure to whatever those prices do in the long run, and so with that we approach the Woodford project and projects like it, as we have looked at this for the last couple of years, with the intent of trying to diversify our price portfolio away from just market prices that tend to fluctuate, in some cases extreme, and decouple that and tie it closer to the cost of production.

Q. So that was the current risk FPL's customers face regarding fuel. Again, when you were preparing the testimony both for direct and rebuttal for this Woodford project, did you realize there could be additional risks FPL's customers would face if the Woodford project was accepted?

Did you in your analysis determine if there were any additional risks that customers don't face now?

A. Well, we discussed earlier the potential for variations in production, which again, we believe are fairly well contained based on the information that we have, and there are the risks of potential cost issues.

Again, early indications are that the costs are coming in cheaper than what we expected, but yes, certainly we were aware that there are risks. We felt we had a good understanding of what they were and that decoupling from the market risk at least for a portion of your portfolio was a prudent decision to make in terms of diversifying the portfolio over time.

Q. And then it's FPL's position that the proposed hedging benefits and proposed customer savings outweigh those additional risks that may be incorporated?

A. Absolutely.

Q. Now, are FPL's shareholders at risk if funds are invested in the Woodford project, but expected quantities of gas are not extracted under that specific scenario?

A. Beyond the risk that I talked about earlier, no.

Q. Okay. Now, are FPL's shareholders at risk, for example, if you have a situation where funds are invested in the Woodford project and a well turns out to be completely dry? Not just lower production, but nothing?

A. I guess to the extent that the decision to enter that well was being prudent by the Commission, then no.

Q. I'm going to shift gears and I'm going to assume that in terms of looking at the Woodford project and the proposed guidelines, you probably had discussions with people or you, yourself looked at different materials about the natural gas industry as a whole, kind of a high level.

A. Yes.

Q. Okay. So I'm going to ask you if you're familiar with a few of them. Are you familiar with Natural Gas Intelligence?

A. I'm familiar with the document, yes, or the publication.

Q. How are you familiar? Like what's your understanding of what it is, etc?

A. I get an occasional article from them. I'm not a subscriber to Natural Gas Intelligence, but I do get an occasional article forwarded.

Q. Do the people in your business unit review Natural Gas Intelligence on a regular basis, that you know of?

A. I don't know. We have a number of subscriptions to different publications and I'm not sure what every individual is reviewing.

Q. In terms of -- you said you had occasional articles. In terms of preparing testimony in rebuttal and reviewing documents in the Woodford project, did you rely on anything from Natural Gas Intelligence at any point in time, that you can recall?

A. Not that I can recall. I can't say that I didn't read an article or something, but I don't remember quoting it, necessarily.

Q. Do you recognize Natural Gas Intelligence material as authoritative and accurate sources of information in the field of natural gas?

A. I'm not a judge of that.

Q. And that's fine.

A. Their articles are informative when I read them, but whether they're authoritative or not --

Q. Are you familiar with Baker Hughes Services?

A. I'm familiar with Baker Hughes, yes.

Q. How so?

A. I know that they've published rig counts with respect to the activity in certain drilling areas.

Q. Have you ever relied on information from Baker Hughes such as that in drilling rig counts?

A. I personally have not, no.

Q. Has anyone in your unit relied on it?

A. I do know there are individuals in my group that do pay attention to the rig counts. How they may rely on that information, I'm not --

Q. Again, same type question; in preparing direct, rebuttal, and reviewing everything for this Woodford project, at any point in time did you see any papers or anything like that that relied on Baker Hughes information?

A. Not that I know of.

Q. Okay. Now, in this petition specifically for the Woodford project, what were the main reasons -- I guess I'll just say what were the reasons why FPL chose Petroquest?

A. Chose Petroquest? I'll start -- I'll tell a story.

I started back in 2011. We looked at a number of different opportunities over the last several years in an effort to sort of further this idea of investing in gas reserves.

We first heard about a transaction back in 2011 that piqued our interest in terms of a way to diversify our portfolio and so we began to have discussions with a number of counter parties. Those counter parties ranged in size from, you know, we'll call it [redacted] at the top and you know, very small -- you know, [redacted] and other smaller players at the bottom and several in between.

Some of those counter parties we had very constructive conversations with, exchanged a lot of information back and forth. A lot of data was provided.

We did some analysis on it, determined ultimately that the transaction wasn't feasible or we had a third party petroleum engineering firm review the reserve information and maybe there was a disconnect and how that worked. We also had a number of counter parties that just weren't willing to go through this regulatory process and wait for the regulatory lag.

Our affiliate, U.S. Gas -- I'll just call them USG, because I believe that's what they're referred to in the testimony -- USG has had a relationship with Petroquest I believe since the 2010 time frame. We have relied upon USG and their expertise to help us out in some of these areas and have had conversations with them and we used Dr. Tim Taylor to analyze several of the transactions.

As a result of some of those conversations, the idea around the particular area within the existing relationship between PetroQuest and USG was identified as a potential drilling opportunity for us, and so it was ultimately U.S. Gas that identified the opportunity just based on, you know, knowing, again, what it was that we were searching for and some of the opportunities that we had identified.

Q. You started your answer with -- you said "we". I'm wondering who is the "we" in that statement, when you were saying "we had looked around," etc.

Who's the "we" there?

A. Energy Marketing and Trading Business Unit.

So I've got -- so I manage Energy Marketing and Trading. Within that group I've got four or five individuals that are focused on longer term natural gas procurement and interfacing with natural gas companies.

So you know, at various times any one of those individuals could have been having a conversation, again, with anybody from [redacted] on down about potential opportunities for gas reserves.

Q. But it was just your unit? In that story the "we" was your --

A. Right, energy Marketing and Trading.

Q. So in terms of the "we", to use a bad analogy, you are essentially the top dog of that "we" that was going around talking to other groups?

A. I think it was a great analogy.

Q. It doesn't read well in the record.

A. No, that's accurate.

Q. When did FPL first consider the Woodford project?

I'm speaking about FPL specifically, not USG. When did it come on FPL's radar, so to speak?

A. I don't know that I can recall a specific time frame. Earlier this year, in probably the late first quarter time frame, give or take. I can't remember specifically when it was.

I'm sorry, we're talking about the Petroquest?

Q. Yes, the Petroquest Woodford project

specifically, as it's presented in this petition.

A. I've been aware of the relationship between USG and Petroquest for sometime, but with respect to how it would play into this opportunity, the Woodford project as we're calling it, I would suggest probably sometime late Q1, but that's subject to change.

Q. So roughly spring of 2014?

A. Yeah. Again, subject to check.

Q. I know you said the date wasn't exact, but maybe you can give me a time frame on this question as well.

How long did it take FPL to review the Woodford project and reach a conclusion that FPL would propose this project to the Commission?

How long did it take from when you decided you were going to look into this before you decided, yeah, we need to file a petition? How long did that review take?

A. Again, very much subject to check, several weeks.

Q. Now, I know you don't have an exact time frame, so I'm going to ask you a generalized question.

Since you did the review and invented this project and recommended approval, what factors were really affecting the amount of time required to vet this project?

Like when you were actually digging into the meat of the Woodford project, what did you discover took the most time to vet? What is the thing that slows this process down?

A. Okay. So there's one individual item. Certainly the development of the information that's provided by Dr. Taylor is part of that process and then he develops his type curve, he develops his estimates of production.

He provided that to FPL and then we ran that through our own model with respect to how that would impact customers, in terms of you got to -- you got production, you got the forecasted prices, you've got an effective cost after we develop our own revenue requirements, and then developing all the economic analysis behind that.

So I would say the economic analysis probably was one of the longer processes in that, just because there's a fair amount of back and forth, having Forrest Garb run their own analysis to validate the assumptions that were made and then going through the approval process from there.

Q. Okay. So I want to make sure I characterize your answer fairly.

The analysis of the data itself is the most time consuming part of the process; would you say that's a fair statement?

And by analysis I mean the actual crunching of numbers and then looking at the results. I'm trying to exclude that from the gathering of the data itself, if that makes sense.

A. Sure. It depends on -- I'll back up from the Woodford project and say there have been certain situations where the longest step in the entire process was just waiting for data to be transferred from the counter party.

Q. Right, and I meant in this one.

A. In this particular transaction I can't remember necessarily how long it took Petroquest and USG to put their data together to present to us and then have Dr. Taylor begin to analyze that.

But that was probably one of the longer steps in the process, just from the time the data was gathered, going through Dr. Taylor's analysis, then providing that to Florida Power & Light for our finance team to then develop the model that produced what customer savings ultimately were.

Then in the meantime you had a lot of things happening in parallel with respect to analyzing PetroQuest as a counter party, starting to put together some of the internal approval documents, and understanding how all of that was going to fit into a package.

Q. Now, in the spring of 2014, specifically May 5th, FPL had undertaken a selection process not unlike the selection process you discuss in your direct testimony on Pages 18 and 19, but had tentatively settled on a company that was not Petroquest; is that correct?

This is not your testimony. I'm just talking about as an example.

A. That's correct.

Q. Now, isn't it also correct that you met with OPC, Office of Public Counsel, to give us a preview of the upcoming filing that was to be with another company as your partner and to get Office of Public Counsel's feedback?

Is that also correct?

A. That's correct.

Q. Now, when you filed the petition, which was less than 60 days after meeting, it was PetroQuest, not the previous discussion.

A. That's right.

Q. Why did FPL change partners?

A. We would have very happily have gone to the Commission with the -- the company was [redacted]. We would have happily gone to the Commission with [redacted], but at very last minute -- and I do mean at the last minute -- at their board approval one board member was unwilling to vote for the transaction and started to gain some consensus on the board.

I wasn't there, so I'm not sure how it occurred, but they decided not to sign the agreement with us and I mean, it stopped immediately thereafter.

Q. Now, you just said you weren't there. Did you get briefed on what happened? Did you have any understanding at all?

A. Just a very quick briefing that there was a particular board member that was not supportive of the transaction, and that was that.

Q. Was it [redacted] who was the board member who was not supportive of the proposal; do you know that?

A. I don't believe it was [redacted].

Q. With [redacted], had you begun to prepare draft testimony, exhibits, a Forrest A. Garb type analysis? Did you have that in the works at the time that fell through?

A. I'd have to go back and check my records in terms of the timing of all of that. We had put together some very high level thoughts around how a petition and how a supporting discovery -- or excuse me, supporting testimony would look, but I'm not sure where we stood in that process.

Q. Given [redacted] as an example, why should the Commission not have a concern that there could be an excessive risk in the stability of the exploration and production partners that FPL chooses or even the situation itself?

So given that predicate, it was almost through the door, we didn't make it through the door and switched to another one, why should the Commission not have a concern that that could happen frequently?

A. Well, I guess I would say that I don't think that decisions made at the boards are necessarily -- you know, are only with smaller companies. They happen with bigger companies all the time.

I think that perhaps the [redacted] transaction not happening may have been a good thing, may have been a blessing in disguise, for all we know. But you know, the truth of the matter is once the transaction is approved and we're all committed, then we're moving forward.

I'm not sure there's a risk that the Commission should have with respect to that type of thing happening after the fact, and in fact, if it does, we do have step-in rights and other remedies within the contract to insert a new operator should something happen there.

So there are rights within the contract that we have negotiated that give us the protection that we need in order to ensure that the agreement moves forward.

Q. Now, is [redacted] still a potential FPL investment partner?

A. I would say no. I can't say that definitively, but I would say not at this point.

Q. Does NextEra have any active working investments with [redacted] now through USG or those affiliate cousin type -- and I know yesterday we looked at the org chart and called them "cousins."

So using that term, does NextEra have any working investments with [redacted] through USG or those types of cousins?

A. I'm not aware of any.

Q. If you don't know, that's fine.

A. I'm not aware of any.

Q. I think you touched on it as part of another answer earlier, but I'm going to go ahead and ask it so it's in its own separate category here.

To your knowledge, how long has Petroquest been drilling in Woodford?

A. I don't know definitively what that is.

Q. I think earlier you mentioned 2010.

A. 2010, I know -- I believe that's --

MR. TRUITT: Wait. Who joined the call, please?

MS. RAMAS: Hi, this is Donna Ramas. I just called in.

MR. TRUITT: Thank you, Donna.

THE WITNESS: The 2010 reference was with respect to the relationship between USG and Petroquest. I don't know how long Petroquest had been drilling prior to that.

I know Petroquest has been an entity going concern since 1985, but I believe back then their efforts were more offshore and shallow water stuff as opposed to, you know, their movement onshore. I don't know when that occurred.

BY MR. TRUITT:

Q. I'm looking at your direct testimony on Page 20, Line 10. You had stated in response to a question: "Petroquest is a well known and highly regarded independent oil and natural gas company."

Do you see that part?

A. I do.

Q. So what factors led you in your testimony here to call Petroquest "well known and highly regarded"?

A. Again, the reputation that they hold internally with respect to the words that were spoken to them about USG goes a long ways toward that conversation. Also, the research that we did with them just in respect to the work they're doing in the Woodford -- and they are one of the more active drillers there -- is what led us to that.

Q. If I said that Petroquest has been drilling in the Woodford since 2003 -- so we're looking at roughly a decade, 11 years -- would you call that a long history of drilling in the Woodford, given your knowledge of gas exploration and stuff you've learned here?

A. I would say with respect to the Woodford, it seems like a long period of time.

Q. Regarding Petroquest specifically, do you know what Petroquest's percentage of being on time on drilling projects is?

A. I personally do not know.

Q. Do you not know at this time or did you ever encounter that kind of information in your analysis and didn't commit it to memory or have you never encountered information regarding that ever?
A. I personally have not had that.
Q. Do you know Petroquest's percentage for completing wells on time?
A. I do not know.
Q. Do you know PetroQuest's percentage for completing jobs in or under budget?
A. I personally do not know that.
Q. I'd like to look at the drilling plan you have as part of your Exhibit SF-4.
A. Okay.
Q. It's listed as Exhibit D. It's technically Pages 60 and 61 of Exhibit SF-4.
A. I have it.
Q. So we've got two charts here, rig one and rig two?
A. Correct.
Q. We have some drill dates. For example, I'm looking at the one for rig one. It's got a drill date, first line, of [redacted] with a completion date of [redacted] and then it goes into other data that tells us when it's rigging.

Is Petroquest on schedule for these two drilling development plans?

A. No, they are not.

Q. Let's just look at -- we'll do one at a time. So I'll do the one on Page 60 first. I guess I'm just going to go down line by line.

Are they on time with the drill date of [redacted]? Were they on time with that one, the first one?

A. I don't believe so.

Q. You don't believe so, okay. I guess I could ask it this way, because I want to be clear on the record.

A. Sure.

Q. In theory, up until today [redacted] wells should have been spudded or started drilling; would you agree with that?

A. That's correct.

Q. Of those [redacted], how many have been started?

A. I believe the answer is [redacted].

Q. [redacted], okay. Do you know which [redacted]?

A. I specifically do not.

Q. So [redacted] out of the [redacted]?

A. Correct.

Q. Now I'm looking at the one on Page 61.

So again, looking at that chart, we've got [redacted] that should have started drilling by today or should have been spudded?

A. Right.

Q. What do you have on those [redacted]; are those on time?

A. They have not started [redacted]. They have not acquired a rig, which I guess I would suggest both in the case of Page 60 and Page 61, [redacted] is due to the fact they're looking for a rig that meets their needs, rather than just going out and acquiring any old rig to go out and start drilling.

They want to make sure they got something that meets their needs in terms of being able to meet efficiently, in stepping through this, in a fashion that is to their standard.

There's some other -- in the case of the delay on rig one, there was also some land issues that they were taking care of which caused a couple-week delay, to my knowledge.

Q. In terms of land issues, could you please tell us any details that you know about whatever caused that delay with land issues?

A. My understanding was it was resolved. I don't have any specifics on it. Again, that would be a question for Dr. Taylor.

Q. Do you know of any other NextEra companies that have DDAs with Petroquest besides USG?

A. I'm not aware of any, no.

Q. In terms of the DDA that you present as part of your testimony, does that contain the same terms as the original when it was entered into in 2010?

Is that kind of a copy of the same terms or do you know if the terms are different?

A. I don't have access to that document.

Q. Okay. I'm going to apologize, but we're going to kind of have a dictionary session of questions. So I'm going to ask about certain terms and if you understand or know the meaning of them.

A. Sure.

Q. Are you familiar with the phrase "royalty terms" in the context of oil and gas leases?

A. I'm familiar with it.

Q. What your understanding of "royalty terms"?

A. It's essentially -- again, I'm not an expert in the oil and gas industry per se in terms of production and drilling.

Q. Right.

A. But it's payment to lease and landholders for their rights to particular minerals within the property.

Q. Are you familiar with the phrase "overriding royalties" in the same context?

A. No, I'm not.

Q. Under the leases encompassed by the DDA -- which there's a large list on Exhibit B starting on Page 35 of Exhibit SF-4. Do you know the section I'm talking about?

MR. MOYLE: Exhibit D as in "dog"?

MR. TRUITT: Exhibit B, as in "bravo". It starts on Pages 35 and 78 in Exhibit SF-4.

BY MR. TRUITT:

Q. Are you there?

A. I'm there.

Q. So generally speaking, this large list here -- are you familiar with the royalty terms or overriding royalty terms in any of these leases?

A. I am not.

Q. Is there anyone in your unit that's familiar with those terms?

A. Potentially. I can't say for sure.

Q. In your discussions, when the DDA came up in those discussions did you ever hear what a standard royalty term is for an oil and gas lease in this area, like what is the market standard for a royalty term?

A. I did not, but the folks that negotiated this for me probably did, yes.

Q. Are you familiar with the phrase "shut-in royalty terms" in this context of oil and gas leases?

A. No.

Q. Are you familiar with any phrases involving that shut-in? Sometimes they call it "shutting costs, shutting payments", etc? Are you familiar with any of that?

A. I'm familiar with the --

Q. The shut-in concept? In your own words, what do you understand that to mean?

A. Effectively shutting in a well to either -- on a temporary basis to allow for some condition, whether it's a rework, to restore the well to a productive level, or on a permanent basis shutting it down.

Q. Are you aware that quite frequently in oil and gas leases there are extra payments that have to go to mineral rights owners if wells are shut in?

A. No, I'm not.

Q. Again, back to this large list of leases in SF-4. Are the mineral rights in the AMI all leased or does PetroQuest own any of the mineral rights outright, fee simple?

A. I don't know that. I would defer to Dr. Taylor.

Q. Now, in terms of the negotiations of this DDA itself, was Dr. Taylor essentially sitting at the table and negotiating the terms of this or was a negotiation going on and then he was asked for input outside the process?

I'm trying to see how he fit in.

A. My understanding is the latter. He was, to my knowledge, not at the table during the negotiations.

Q. He played more of a consultant role rather than an active participant; would that be a fair --

A. I think that's a fair description.

Q. Now, again, another term. I apologize.

A. Sure.

Q. "Primary term" in the context of oil and gas leases, are you familiar with that phrase, "primary term"?

A. No.

Q. Have you ever heard any discussion that a primary term is the part of a lease where drilling must commence within a certain time frame or the lease expires? In other words, goes back to the owner?

A. I'm familiar with the concept, not as a primary term.

Q. Are you familiar with the phrase "secondary term"?

A. (Shakes head.)

Q. Okay. Again, in going through this did you ever hear a discussion about secondary term being once production starts, that's the period that the lease will stay because production is occurring. But if production stops, the lease can revert back to an owner?

Did you hear any discussions about that?

A. I'm familiar with that.

Q. When looking at these leases and evaluating this project, do you know what the primary terms are in any of these leases?

A. I personally do not know, no.

Q. Do you know what any of the secondary terms are?

A. I do not personally, no.

Q. Do you know if any of these leases are conditioned on specific production levels?

A. I do not know.

Q. Are you familiar with the Surface Damages

Act in Oklahoma?

A. No, I am not.

Q. Have you ever heard that term tossed around in a discussion? Maybe you're not familiar with it, but have you ever heard the term?

A. No.

Q. Do you know if all of these leases -- I guess I'll set the predicate.

There's a law in Oklahoma that requires drillers to set up bonds and payments for anticipated surface damage, the Surface Damage Act. There's a bunch of requirements to it, but that's the big picture. Generally speaking, permits usually aren't issued until those Surface Damage Act requirements are met.

Do you know if the Surface Damage Act requirements are met for all these leases?

A. I personally do not know.

Q. Do you know if any of the areas in the AMI, either sections or the AMI as a whole, is subject to a pooling or unitization order?

A. I'm familiar with what pooling orders are. I'm not sure whether they apply in the case of the 19 sections or the 19 drilling units.

Q. What's your understanding of a pooling or unitization order?

And I understand the terms are used generally interchangeably, there's minor differences, but whatever you've got I'm happy to hear.

A. So a pooling order as I know it would be effectively, just to use an example, if you had an area with 10,000 acres in it and you had a landowner with 50 acres who was unwilling to sell his property rights, you can petition to in this case the State of Oklahoma to obtain pooling rights, which would give you the rights to not drill on his property, but to essentially drill through his property and he would be compensated for his mineral rights.

But it stops individual land owners from blocking larger develop type opportunities, and that's obviously a lay explanation.

Q. You've got a pretty good grasp on it, probably I know a lot of us had to learn what pooling unitizations orders are, because we don't have them in Florida.

In terms of that and that understanding, which is a pretty good understanding, in your opinion why do you think they would have pooling orders?

If you'd said we had a hold-out, so why do you think that would be a concern?

A. Again, from my understanding, which again is, a very lay understanding of it, they've been around for decades and were meant to further development opportunities where you may have an individual landowner or landowners who may try to block potential development of these types of opportunities.

Q. Did anyone in FPL verify the terms of leases for the Woodford project?

And I can go through the different terms I'm talking about individually, but what I'm talking about is those royalty terms, shut-in royalty or payments, primary terms, secondary terms, and any of those categories that are in every gas and oil mineral lease.

Did anybody in FPL go through all of them that are in this chart?

A. I did not specifically ask anybody on my team to go through all of them. I know that we worked directly with USG during the process. Members of my team helped negotiate the terms of this agreement.

So there may be members of my team that have gone through it.

Q. Well, then I'll ask you this question. Are you comfortable with saying that FPL employees vetted the terms of all the leases attached to SF-4?

A. Not with a hundred percent surety, no.

Q. Did you rely on any of the vetting that USG may have done?

A. Absolutely.

Q. Do you know where USG got the information from? Do you know if they personally vetted all the information or if they again took it from another party?

A. I don't know if USG does have a land group within their team and -- or whether they vetted them internally or they outsourced that activity. I can't speak to that.

Q. Now, that was a question regarding the terms. This question is regarding the title chain of minerals, which is a quite tricky legal chain of title trace.

Did anyone at FPL verify the title chain for the minerals themselves for these leases?

A. My response would be the same as it was before.

Q. So I'm going to walk through it, just so the record is clear. So you can't say that FPL employees vetted one hundred percent of the title chain of the minerals?

A. Correct.

Q. And you relied on some information from USG for the title chain verification?

A. That's correct.

Q. And it's also correct that USG may have gotten that information from another third party or done it themselves, but you're unclear?

A. Correct, I'm not sure whether they outsourced that or did it themselves.

MR. MOYLE: It's called what?

MR. TRUITT: The title chain of minerals. They split it from the land.

BY MR. TRUITT:

Q. Now, on the DDA itself -- and there's a lot of terms and I understand a lot of that is kind of form language in the industry and there's terms of art and things of that nature.

I'm specifically looking at suppose Petroquest proposes a well and FPL consents. So we're in the idea of we're moving forward on this well, you and PetroQuest. I'm leaving all the other owners out, I'm saying all the other non-consenters. I'm looking at you two.

A. Right.

Q. And then Petroquest decides I don't want to drill. Under the terms of the DDA or as FPL, you wanted them to drill and you thought they were drilling, now they're not, what are FPL's remedies?

A. [redacted]

Q. [redacted]

[redacted]

A. [redacted]

[redacted]

Q. [redacted]

A. I did not.

Q. I'd like you to take a look -- you had a matrix on Page 38 of your direct testimony, the high-low matrix, the little nine-box matrix.

A. Correct.

Q. We're going to have kind of a pile of questions around this. I'm going to suggest we take maybe a five-minute break now, because once we start I kind of want to get through all of that without stopping.

Is that okay with you?

A. Sure.

(Whereupon a recess was taken.)

BY MR. TRUITT:

Q. Okay, Mr. Forrest. Again, we're talking about -- lots of these questions are going to focus on this matrix on Page 38.

Now, I know the first page with data on it on your errata sheet applies to a lot of the testimony floating back and forth between this. So do you have a copy of your errata sheet?

A. I absolutely do not, no.

Q. I'll give you my copy just to make sure, because some of those numbers are changing.

A. Okay.

Q. I don't want to have to bounce back and forth with the transcript from this to insert the errata sheet at a later date, so I want to try and make sure it reads easily.

A. That's fine.

Q. So again, with this matrix on 38 in mind, back on Page 36, Line 14 -- sorry, we'll switch out the extra for mine.

A. Okay.

Q. On Page 36, Line 14 you discuss, "The distinction between the sensitivity assumed all other working interest owners' consent."

In that instance the customer savings dropped to $61 million; is that correct?

A. Yeah, the errata would have it be $60 million, yes.

Q. Now, looking at this matrix on Page 38, the way I read it, this matrix is saying all other owners did not consent, which requires the highest Cap X; is that correct?

A. That's correct.

Q. What is that matrix going to look like if all the other owners do consent? Obviously that middle number is going down to the $60 million, is that correct, the number right in the middle?

A. That's correct.

Q. What are the other ones going to be?

A. I don't have that information in front of me. I don't know that I've seen that analysis.

Q. Did you ever run that?

A. I can't say for certain whether we did or we didn't. I would say that I didn't see the information, if we did. So I'm not sure whether we did or we didn't.

It should be fairly linear in terms of the scale, if you will. If you have $191 million and it delivers a $107 million in savings, if you scale that back, the customer savings will shrink on a kind of commensurate level on a pro rata basis. I don't know if it would absolutely apply in terms of this lower level of investment, but it's going to be in a sort of similar order of magnitude to what the table shows there.

But I have not seen the answer to the question. I haven't seen another nine-box that was done with that there.

Q. In relation to that matrix, right above it on Page 38 you state a high case estimated production is up 10 percent, low case estimated production is down 10 percent.

Then what does it say there in the testimony? It says "based on Witness Taylor". The 10 percent figure was why you did that?

A. That's correct.

Q. And it says, let's see -- "As discussed by FPL Witness Taylor." Can you point to me where in his testimony he said the 10 percent is the industry standard"?

I can give you time to look, but I would like to know where that is.

A. I guess you're suggesting it's not in there. It would be in the response to discovery, would have been where he stated it. So I don't know that I could find it in his testimony.

Q. Did you do any other variation on this matrix, like say a plus/minus 20 percent, instead of 10 percent?

A. I did not, no.

Q. Now, the 10 percent change, you said it was probably somewhere in response to discovery, it was not in his testimony?

A. Correct.

Q. Would you say that a 20 percent variation in production is a significant variation?

A. A significant? I would defer to Dr. Taylor in terms of what he believes is significant or insignificant. I'm not one to judge the production levels.

Q. That's fair enough.

You described that if you ran this with a different all owners consent scenario, it should be a fairly linear relationship that you should be able to get to.

A. I don't know if this is one-to-one, but it should have a similar --

Q. Going on that predicate, because you understand more of the math cells that went into this than I do, if you did all other owners consent -- so now we're down to that $60 million projected savings hypothetical -- would it still be only one in nine scenarios where customers lose money or are there more chances that they would lose money?

A. I would have to run the numbers to be able to definitively tell you that.

Q. Okay. But you didn't do that as part of the analysis?

A. No, I did not, no. No, I did not.

Q. You have a gut reaction on whether it would be or not?

A. I think it's going to be one in nine, but that's a gut reaction, without the benefit of the math.

Q. So I guess if I vary that, that was the consent owner's variation?

A. Correct.

Q. Say I vary the production numbers, say I go to 20 percent or whatever we defer to Dr. Taylor as being significant or not, whatever that is.

A. Yes.

Q. Under the production variation would it change -- still you think only one in nine is going to have a loss of money or do you think that would affect how many situations they could lose money?

A. Are you suggesting, just so I'm clear, that the low production case would be minus 20?

Q. Yes.

A. And the high production case would be plus 20?

Q. Yes.

A. I haven't seen the analysis on them. My guess would be it would still be one and nine. The low production, low fuel would be lower. The high fuel, high production case would be significantly higher, and I believe it would still be one in nine, but that's just a gut reaction.

Q. If you hadn't run it before, I want to try and explore here what the relationship is.

A. I have not run it before.

Q. Now, in previous Petroquest projects in the AMI -- so for example with USG since 2010 -- what's the rate at which other working interest owners have consented?

A. I don't have that information.

Q. Did you ever encounter that data in your review of this and just can't recall it at this moment?

A. Individuals on my team had conversations with Petroquest with respect to who the other interest owners were. I don't know that there were any indications as to what their likelihood of consent was.

Q. Okay. Did the -- I understand here you did all non-consents was the largest cap X?

A. That's correct.

Q. In terms of the actual project if it moves forward, is FPL operating under the assumption that all will non-consent or actually looking at the project you assume that some will consent?

A. I don't know that we have an opinion as to what they're going to do.

Q. That's what I'm just asking, if you've made a prediction.

A. Again, we've been given at a very high level who a few of the interest owners are. I don't have an indication one way or the other whether they'll participate or not. At least I don't.

Again, my team is interfacing with USG and Petroquest, so I'm just not familiar with what that potential answer might be.

Q. In terms of the interfacing with Petroquest and USG, have either one of those insinuated or hinted at or suggested a consent non-consent ratio?

A. Not to my knowledge.

Q. Now, looking at this matrix, if all the working owners consent and we have customer savings going from 106.9 to $60 million, it drops 43 percent; is that correct?

I noticed you brought a calculator, so I apologize.

A. I'll trust your math.

Q. That's scary. So that's what I was going to say. I knew everybody in the room would agree to that. I think I did it with 61 because I didn't have the errata yet.

A. You verified that math?

Yes, good.

Q. So we have a 43 percent drop if we change from all non-consent to all consent in savings. Would that 43 percent apply to all those boxes? Is that linear relationship an accurate saving?

A. I don't think it's -- I'd have to do the math to see, go back and look at the original table.

Q. What's making you say you're not sure? I'm trying to understand how all these work. So if you can explain to me why you're concerned with that assumption, that would be good.

A. Just trying to understand the relationship between, say like a base fuel, high production kind of case, where you've got more gas at the base case forecast -- I mean, it's going to be close to 40 percent, I imagine.

Q. You think it will be close. Like, if I use 40 percent, could I get a rough ballpark figure? Do you think I'd be at least close?

A. Subject to check, I think that's close.

Q. Okay, that will work.

I'm also going to have you look, in conjunction with this matrix, the revised Exhibit SF-8, which was in response to OPC Interrogatory Number 65.

Do you have that?

A. I do.

Q. Now, for the matrix you did on Page 38, the fuel cost or forecast in fuel prices was from when? Your direct testimony, what was your forecast price? When was that done?

A. That was October 7th, I believe, of 2013, which was the forecast that was used for our 10-year site plan for the nuclear cost recovery DSM. So it was a consistent forecast through those dockets.

Q. Was that forecast modified in any way from the October 2013 forecast to when it was used here?

A. I do not believe, no.

Q. Now, this revised Exhibit SF-8, it states that that's a forecast based on July 28, 2014, is when that forecast was done; is that correct?

A. That's correct, yes.

Q. How often do you redo your fuel forecast?

A. As requested.

Q. I understand that in this instance, but I'm just saying as a general rule?

A. What I'm saying is as a resource planning team requests new forecasts, you would provide one to them. We do a monthly update of our short term forecast, which is utilized for hedging and for other things in the short term, but longer term forecasts are basically as requested by our resource planning group.

This was a forecast that was done in support of our 2015 fuel filing.

Q. Okay. Now, in terms of short term, so the record is clear, how long is the short term when you're talking about that forecast?

A. I'm not sure how far out it goes from a time frame perspective, but like our hedging program again is for 2015, so it's covering certainly that period of time.

But this forecast was one that was done as a result of or a request for a new forecast in support of our 2015 fuel filing and a few other things that were happening.

Q. Okay. Now, other than those types of requests, what other -- are there any other factors in the market or items that change outside FPL's box that cause you to redo these long term forecasts?

A. Periodic updates from PIRA, PIRA Energy Group, as well as the Energy Information Administration, when they come out with their annual forecasts. Their energy outlook would be the new inputs to drive a new forecast as well.

Q. The EIA, Energy Information Administration, when they come out with annual reports, do you automatically update your forecast then?

A. Not necessarily, no.

Q. So it doesn't always correspond that when the EIA kicks out something new, FPL redoes it?

A. That's correct.

Q. Now, looking at the revised SFA based on the July forecast, it shows that the discounted customer savings go down to $51.9 million; is that correct?

A. That's correct.

Q. Now, my first question, to make sure we're on the same page again, that's assuming all other owners non-consent. So it's the largest cap X?

A. That is my opinion, yes.

Q. Because I noticed all the technically confidential yellow lines or yellow box doesn't change, is that correct, from the previous forecast?

A. That's correct, I believe so.

Q. So the revenue requirement, return rate, depreciation, operating expenses, etc, and annual production all stay the same. So what are the drivers that push down the discounted customer savings under the revised forecast? What did it?

A. In the revised fuel forecast we had updated obviously the NYMEX curve in the short term. That would have been updated. It would have extended the NYMEX for one year.

So if you go back to 2013, it does two years of NYMEX, so it would have been '14 and '15. Now it's '15 and '16, so it would have shifted because we're into a new calendar year.

We would have received -- I believe we would have utilized the new escalation factors driven by the EIA forecast and I'm assuming -- this is an assumption on my part -- that we would have received a PIRA update as well in there, potentially.

Q. So essentially in simple terms, the long range cost of natural gas went down quite a bit, is that correct, based on between the two forecasts?

A. That's correct.

Q. Now, if it changed from customer savings of $106.9 million to $51.9 million, that's a 51 percent reduction, correct?

I want to make sure I get the numbers right, because I want to kind of go through the same exercise, if you want to do it.

A. Okay, sure.

Q. I got two math numbers correct today, so I'll stop while I'm ahead.

So in the matrix on Page 38, that $51.9 million is going to plug into the central spot, base fuel, base production?

A. That's correct.

Q. Now, again, when we say 51 percent, can I do the 51 percent with the other numbers?

A. Again, I'd like to run the math, but it seems like a reasonable assumption. But it's -- without having run the math, I can't validate it.

Q. Would you say -- like the other one, you said it could be in the ballpark. Would you say this could be in the ballpark as well?

A. Sure.

Q. So the record is clear, what would your concerns be about applying that as an across-the-board rule?

A. Just without running the math I can't validate it.

Q. Okay. So I'm going to ask this just to clarify. Say we propose a 20 percent variance in production in the new revised SF-8. Did you guys run any matrix of that?

Actually, strike that. I didn't ask, did you run a matrix with the revised SF-8?

A. Not to my knowledge, no.

Q. Well, previously on this matrix when I talked about production levels changing, you stated that without running the math you believed it was your prediction that still in only one scenario customers would lose money. Other numbers might go down, but in theory there's only one losing?

A. Correct.

Q. With the new fuel forecast are you stating that you still think in only one scenario of the nine the customers would lose money?

A. So if I use -- just to make sure I'm following your logic, you're going to use the 51.9 as the base fuel base production?

Q. Correct. I'm going to rerun the matrix with your revised SF-8, keeping everything else constant.

A. Right.

Q. Do you believe it's only going to be, again, one scenario of customers lose money?

A. Again, without running the math it would be difficult for me to say. There's a potential, I guess, that the base production low fuel could potentially drop below that level, but I don't have the math. It's hard for me to say.

Q. Do you think when the Commission considers this, it would be appropriate to place in front of them the matrix with FPL's most current gas price forecast?

A. I think that's appropriate. I'm not sure that's for me to say.

Q. Okay. Do you have an opinion on it?

A. An opinion? I'm happy to update the table.

Q. Would you give us a late filed exhibit if it was an updated table? Could you guys do that?

A. That would be up to the attorneys.

MR. TRUITT: Can we go off the record for a second?

(Discussion off the record.)

MR. TRUITT: Regarding the matrix on Page 38, OPC would request three new variations of that matrix. The first variation would be using the fuel price forecast in that matrix and the non-consent scenario, adjusting the high-low fuel production by 20 percent.

The second variation would be using the new revised July 28th, 2014 fuel forecast, the new Exhibit SF-8, and running that with a non-consent owner and 10 percent to a variation.

And the third version would be the matrix with the new SF-8 non-consent, owner's non-consent and fuel high-low range is

20 percent.

MR. HOWARD: Production.

MR. TRUITT: Production, correct. Sorry.

MR. MOYLE: And would you extend the courtesy, if you do this, communicate with all the parties as to how this gets sorted out, please?

MR. GUYTON: Yes. I need to consult with my client and I want to do it outside of the deposition.

MR. TRUITT: Of course.

MR. GUYTON: So just to preserve my ability to do that, I'm going to object to it at this point and then if we modify that position, we'll let you know. But I want to make sure I preserve the ability to object.

MR. TRUITT: Of course, thank you.

MR. MOYLE: And I'll preserve my ability to object as well. Let's see what it says.

MR. REHWINKEL: So it's one late filed or three? That's what you're asking, okay. So it's late filed Deposition Exhibit 1 and we should probably give it Page 38 matrix with --

MR. TRUITT: Three variations as stated.

MR. GUYTON: So it's one exhibit with three schedules, as opposed to three different exhibits.

MR. TRUITT: Correct. Thank you.

BY MR. TRUITT:

Q. Now, back to the questions.

Is it correct to say that FPL's estimated cost savings to customers over the duration of the Woodford project assumes that one hundred percent of the wells proposed or contemplated under the DDA, I should say, are drilled, that they're successful, and that they contain within the range of reserve predicted?

A. That's correct.

Q. So all those qualifiers that I stated; specifically that all the ones contemplated are drilled, all of them are successful, and all of them are contained the reserve, all of those standards must be met to reach the predicted savings?

A. Yes.

Q. Now, in terms of -- we discussed earlier the changes when you revise your natural gas forecasts. Are there other outside trigger events -- I know you mentioned the new PIRA energy update or the EIA data or something like that.

I'm looking in terms of the market itself.

What are triggering events in the market that might cause you to revise this?

A. I'm not aware of any.

Q. I guess I'll restate it.

A. Yes, please.

Q. Has there ever been historically an event in the market that caused you to revise your fuel price forecasts?

A. Not that I can recall.

Q. Hurricane disruption in the Gulf maybe as an example?

A. That would have predated me. I started in 2007. I'm not sure there's been anything as disruptive as say Katrina, and Rita subsequent to that, if I can knock on wood.

Q. Another kind of a clarification question.

In your response to OPC's sixth request for PODs, you included a chart as well. There's a big giant chart. Do you have those requests with you?

A. I do not believe I have any PODs with me, I apologize.

Q. It's OPC's sixth request for PODs Attachment One and request number 35, and it's Pages 1 through 76.

I'm going to flip to -- there's a term in particular in one of them that I'll hand you my copy to look at and I'm wondering what it means.

So on Page 66 -- I'm going to read it, because I have it in front of me, into the record so I don't state something incorrectly. Let's see -- sorry, give me a second.

At the top on Page 66 it specifically says: "0.0 percent goal, seek to NGL percent of oil to CPVRR break even."

I'm going to hand this to you, because I want you to explain to me what that means. That was the response that you guys sent. I'm looking for the meaning of that phrase right there, if you could, please.

A. I don't know. This is not my -- I didn't build this spreadsheet, so I'm not sure what the note would imply.

Q. Have you ever seen anything like that before in some of your other spreadsheets, like hazard a guess even?

A. No, I can't even hazard a guess.

Q. Okay, thank you.

Now, what benefit is USG getting for giving the deal with PetroQuest to FPL?

A. For the period in which they're holding it they have the benefit of whatever gas production comes until such time that the Commission would approve it or assign it to FPL. So during this interim period the transaction is for their benefit solely.

At such time that the Commission sees fit to approve the transaction, they're not receiving any type of compensation for that other than just basically the payment of net book value, whatever they have invested in the transaction. So their capital expenditure is less than whatever depletion.

So whatever gas they receive would be their compensation, so net book value. So no benefit for holding it.

Q. Okay. Now, in terms of transferring it, if it's approved and it's transferred over to FPL, is USG getting a benefit for that transfer itself?

A. No.

Q. Now, in regards to the Woodford production, in your testimony you refer to Dr. Taylor's testimony a few times. Did you -- I'm sorry, strike that.

Did you rely on Dr. Taylor's reserve estimates in putting together your testimony?

A. That's correct.

Q. Did you review the type curves that Dr. Taylor included as Exhibits TT-11 and TT-12 to his rebuttal testimony?

A. I reviewed them, yes. I'm certainly not an expert in that area.

Q. I'm just asking if you saw them.

A. I saw them, yes.

Q. Do you have a copy of them with you?

A. I believe so. Bear with me a second.

Q. There were only two exhibits that he had attached to his rebuttal.

A. Yes, okay.

Q. I know reserve estimates require a rather complex mathematical calculation and I'm going on the premise that this graphical representation is kind of simplifying all the numbers that went into this; is that correct?

A. I'm fine with that assumption. It's the same one I would make.

Q. And that's what I'm working on here.

Now, when in this process did you see these two type curves?

A. I would have seen these, I believe, during a discussion of Dr. Taylor's rebuttal testimony.

Q. How long before filing it would that have been?

A. I'm not exactly sure. I would say maybe a week or two.

Q. Now, again, to make sure we're on the same page, I know you're looking at a black and white version, as I am, correct?

A. Yes.

Q. So we have a lighter set of lines and a darker set of lines, correct?

A. Yes.

Q. And the lighter lines, according to the chart, you would agree, are supposed to represent the production of individual existing PetroQuest wells in the AMI?

A. Yes.

Q. And would you agree the dark line, the type curve is Dr. Taylor's prediction of what the reserves are going to be in the other wells; is that correct?

A. Yes, I believe that prediction is a mathematical best fit line based on the average.

Q. Right. I didn't mean prediction in a derogatory sense. His best estimate, I'll put it that way.

A. Yes.

Q. Now, we have here zero through year 25 at the bottom of that chart; is that correct?

A. That's correct.

Q. So the light lines are covering actual production of individual existing wells.

When you look at this chart, what is your understanding of how many years of actual production data we have or you had to rely upon?

A. Well, Dr. Taylor would have been the one that would have relied upon it. My understanding is there would be -- again subject to check -- four or five years or so of actual data from it.

Again, subject to check. I'm not sure of the exact life of those wells.

Q. Now, why do you think it would be four to five years of production data?

A. I'm assuming 17 of the wells were drilled as part of the original agreement -- I believe again subject to check -- between Petroquest and USG, which started in 2010.

Q. So you're basing it on the assumption of the time frame when USG Petroquest started, not some other information you have; is that an accurate statement?

A. Again, yeah, subject to check.

Q. When you looked at the [redacted] project earlier in here, did you rely only on four to five years of production data in that one?

A. I didn't see any of the data with respect to the [redacted] transaction, at least to this level of detail, so I'm not sure what was being relied upon.

We actually utilized another petroleum engineering company called LaRoche to do the initial analysis, if I remember correctly, and then Dr. Taylor was involved as well, but I'm not sure exactly what history of data was used or the quality of data that was.

Q. Now, in your testimony on Page 33 of your direct you mentioned that FPL retained Forrest A. Garb & Associates to do a confirmatory analysis of Dr. Taylor's data, is that correct, starting on Line 9?

A. I'm sorry, what page are we on?

Q. 33, Line 9, in that answer.

A. Yes.

Q. Was it your decision to use Forrest A. Garb & Associates to analyze the data?

A. It was not my decision, no.

Q. Whose decision was it to pick Forrest A. Garb?

A. It was at the recommendation of USG, given Forrest Garb's experience in the Woodford.

Q. Did FPL consider any other entities or did they go with USG's recommendation?

A. No, we went with USG's recommendation.

Q. Did you ever consider any other entities, though?

A. We may have discussed other entities.

Again, we got experience with LaRoche, as an example, but went with Forrest Garb, again, because of USG's relationship and understanding of their level of analysis within the Woodford.

Q. When was Forrest A. Garb & Associates engaged to perform analyses for FPL?

A. I believe that -- does Dr. Taylor's direct have it?

Q. He does. I wasn't asking about that one yet. I was just asking when historically was Forrest A. Garb first engaged to perform any analyses?

A. Sometime around this time frame.

Q. Now I'm going to skip to his. It's TT-10. Do you have that?

A. I believe so. Yes, I have it.

Q. If we go to the first page of it, would you agree the title page says "Estimated Reserves and Future Net Revenue as of July 1st, 2014," the very first page of the exhibit?

There's kind of a cover page that's stamped "Confidential".

A. Yes, I see that.

Q. And then on the first page, where it gets into the actual letter accompanying the report, it says June 18, 2014 at the top.

Do you see that?

A. I see that.

Q. So in terms of this analysis, when did FPL engage Forrest A. Garb to perform this analysis itself?

A. Around this time frame. I don't know, don't remember the specific date.

Q. Rough estimate, a month before the petition was filed?

Because I'm looking at June 18th, the petition was filed June 25th. I'm trying to find out how far before June 18th.

A. It would have been a week or two probably prior to that, which was pretty consistent with how we saw other relationships.

As we dealt with LaRoche we could provide something to them and they could turn it around in a week or two. It was pretty standard.

Q. Okay. Now, in your testimony again on Page 33 you stated that you guys -- FPL engaged Forrest A. Garb & Associates to provide independent confirmatory analysis.

Do you see that section?

A. Yes.

Q. And that they performed a formal reserve evaluation which included an evaluation of reserves and future net revenues.

Do you see that?

A. Yes.

Q. In preparing that portion of your testimony at that time, your mindset, what was your understanding of what materials Forrest A. Garb & Associates used to perform that analysis?

A. They would have provided inputs from USG based on the existing wells that sat within the area of mutual interest. So the 19 wells that are there, 17 of which were USG's and another two that were outside of that Petroquest/USG relationship, and other information that would have been provided by Dr. Taylor.

Q. Okay.

A. Which, again, was standard for how we had relationships with other folks. We provided information that we had.

Q. So it was your understanding at the time that Forrest A. Garb & Associates was provided information either by FPL or by USG or by USG from Petroquest. Essentially, that's the three locations the information could have come from; am I correct in that statement?

A. That's a safe assumption, I think.

Q. Now I'm going to have you look at TT-10, if you would, please.

A. Sure.

Q. And it's Attachment D, delta, one. It's Page 26 of 30. There's a numbered list of general comments that you frequently see with engineering type analysis.

A. Okay.

Q. Let me ask you look at Number 5, and if you could read that section into the record, please?

A. "Extent and character of ownership. Oil and gas prices, production data, direct operating costs, required capital expenditures, and other data furnished have been accepted as represented. No independent well tests, property inspections, or audits of operating expenses were conducted by our staff in conjunction with the study."

Q. Now, I understand it's attached to Dr. Taylor's testimony, but in terms of your reviewing his testimony and you'd stated that, you know, FPL asked Forrest A. Garb & Associates to do this and it seems you relied on it, at least somewhat bolstered by Dr. Taylor --

A. Sure.

Q. -- in terms of your knowledge, is that a correct statement?

A. To the best of my knowledge, I'm assuming this is correct.

Q. That's why I'm asking. I'm just asking to the best of your knowledge.

A. Again, the information flow was basically from Dr. Taylor back and forth. I negotiated the contract with Forrest A. Garb & Associates to get them started. Dr. Taylor provided whatever information was utilized for them.

Q. Now, the way I'm interpreting this is again like we went through before, all the data came from either FPL, USG, or Petroquest.

Am I correct in stating that that sentence is telling us that Forrest A. Garb didn't independently go get data themselves, they were given data from the parties involved?

A. Yeah, you'd have to discuss that with Dr. Taylor. It's what the statement says, but --

Q. Okay. When you reviewed that were you aware of the qualification of that statement?

Did you understand that Forrest A. Garb & Associates was reviewing this and supporting Dr. Taylor's testimony based on information that Dr. Taylor gave them?

A. Yes, I was aware of that.

Q. Is that an industry standard thing?

A. I can't say that I know what the industry standard is, in all honesty.

Q. Okay. There's a couple of times in direct and rebuttal, I'll just state as an example in your direct testimony -- there's 34, line 6, for example, where you state, "Then minimal production processing and gathering costs would be incurred over the remaining 30-plus year economic life."

Do you see where I am at in your testimony?

A. Yes.

Q. That "30-plus" phrase occurs in different smatterings throughout direct and rebuttal.

A. Correct.

Q. I understand when you say 30-plus years in the direct and rebuttal, but the revised SF-8 and the productions are going out 50 years.

A. Correct.

Q. Why say 30 years in the written testimony and project lots of charts and everything else out 50 years? What's the difference?

A. Nothing magical about it. 30-plus could lead to 50.

Q. I understand.

A. There wasn't anything specific about stating it that way.

Q. Okay. I was trying to see if there was -- so there was no internal reasoning for giving the chart with the hard numbers clearly stopping at 50, but then in the written going to 30-plus, other than 30-plus can include 50; is that an accurate statement?

A. No, that is an inaccurate statement.

Dr. Taylor's analysis shows that these wells were economic for a period of 50 or so years. That's why the analysis runs that far. Again, sort of the decision as to how long those wells will last is something that will be determined over time.

Q. Right.

A. Again, there was -- 30-plus was kind of meant to create some of the fact that in the back end of this thing you're going to be making the decision as to whether to shut a well in or whether to continue in operation.

Q. Okay.

A. So we're committing to the full 50 versus --

Q. So it's accurate to say that the 30-plus year statement used in the testimony is a way of adding a buffer for unknowns. Would that be an accurate representation?

A. That wasn't the intent of it, no.

Q. Not the intent, all right.

I want to switch topics to hedging. You mentioned hedging in both direct and rebuttal. In the scope of your direct and rebuttal, what is your definition of hedging.

As you sit here today, give me your definition of hedging.

A. So in it's simplest form it's taking some action to reduce a risk or risks.

Q. Now, as a subset of that there's hedging activities, would you agree? Hedging is the concept and hedging activity is the physical things you can do?

A. Right.

Q. So sitting here today, again, what would be your definition of hedging activities?

A. Again, taking some action to reduce whatever risk it is you're seeking to mitigate.

Q. To reach that definition and in preparation of your direct and rebuttal, did you review any specific orders for the definition of hedging?

Orders of the Commission, I'm sorry. I want to clarify that.

A. I did review the 2002 hedging order from the Commission, as well as the 2008, but I didn't pull a definition from those documents. But I did review those orders with respect to hedging.

Q. Do you know if one of those documents actually gives a definition for hedging?

A. I don't know.

Q. Do you know if one of those documents gives a definition for hedging activities?

A. I know there are some statements given that include -- it's not an all inclusive list, but it does discuss some of the activities, yes.

Q. I guess just to clarify, you don't know if there's a specific part in the order that says "a hedging activity is defined as" --

A. I don't know.

Q. Okay. Again, with respect to the concept of hedging as you were incorporating it in your direct and your rebuttal, what are the key factors of hedging activities?

Like what is the key, if you could summarize

it down? What do you think the key points are?
A. Just generically in a hedging activity? It's taking some action to mitigate some other risk or to mitigate a risk.
I'm not sure there are key points. There's a lot of ways to look at hedging.
Q. Okay. I guess I'll go through and see if you agree with me. We could try that.
A. Sure.
Q. Would you agree or disagree that a key point of hedging activities is keeping certain items such as costs fixed?
A. I don't -- no, I don't agree with that.
Q. Would you agree or disagree with me that one of the key points or key factors of hedging is ensuring volatility is removed?
A. I wouldn't agree that it's removed. I would --
Q. Mitigated, I'll use that.
A. Yes, it's mitigated.
Q. All right. Would you agree or disagree that one of the key points of hedging activities involves financial or physical transactions?
A. With respect to mitigating price risk, yes.
Q. Let's see. When you're talking in your

testimony on Page 9 and 10, kind of your introductory section there, you discuss a few previous orders. You touch on a few previous orders. You touch on Order 14546, the genesis of the Fuel Clause docket, and then you also mention Order 11-0080.

Do you see that section of your testimony?

A. You're on Page --

Q. Nine, I'm sorry, starting at Line 19.

A. Yes.

Q. Now, in terms of that portion of your testimony and the discussion of those orders, I know it goes on to Page 10. You specifically mention a Martin gas pipeline; is that correct?

A. Correct.

Q. And I know there's other places in the testimony. Wouldn't you agree there's a mention of rail cars --

A. That's correct.

Q. -- resulting in lower cost? Okay.

And there's also a mention of physical modifications to a plant allowing burning cheaper fuel; is that correct?

A. Correct.

Q. Now, in the Martin gas pipeline lateral, that was something to lower the cost of fuel, but all it did was carry the fuel, right? There wasn't a drilling rig attached to the end of it or anything like that?

A. That's correct.

Q. Now, the rail cars, all they did was carry coal, correct?

A. Correct.

Q. And the physical modification to the plant, that was an actual physical item on the utility plant at the site that allowed you to burn the fuel; is that correct?

A. My understanding, yes.

Q. Now, is it your testimony that those items that I just described -- the Martin pipeline that carries fuel, rail cars that carry fuel, and the physical modification to a plant that generates electricity -- are analogous to the gas reserves?

A. Analogous? I don't know that I would say they're analogous. I would say that they were things that -- they were actions taken by the utility to help reduce fuel costs, which is one of the things that's contemplated by Order 14546, is taking action to recover fuel related costs that result in fuel savings for customers.

None of those are related with one another, nor is gas reserves necessarily related to any of those, but it certainly does reduce fuel costs.

Q. So would you agree with me that the touchstone there is the lowered cost of fuel or fuel savings?

A. It is certainly one of the key components of it, yes.

Q. Now, we haven't really discussed too much guidelines for Exhibit SF-9, your Exhibit SF-9, the guidelines. Just kind of as a whole I have some general questions on it.

Did you develop the guidelines in Exhibit SF-9?

A. I was part of the development of that.

Q. Were they solely created by your team, your unit?

A. No, they were not.

Q. What are the groups outside that unit that had any input in the creation and the guidelines of SF-9?

A. Most likely finance, as well as folks from senior management.

Q. Anybody outside FPL?

A. No.

Q. Now, under the guidelines for proposed projects, what incentive in the guidelines creates -- or what in the guidelines would create an incentive for FPL to maximize customer savings?

A. What within the guidelines would --

Q. Create an incentive for FPL to maximize customer savings. Can you point me to somewhere in there that says this term is going to incentivize me to maximize customer savings?

A. I don't know if that term appears in the guidelines necessarily. We certainly are pursuing opportunities that would maximize customer savings.

Q. I understand that's the intent. I'm just trying to see if we're looking at a framework. I'm trying to see if the framework has its own mechanism inside of it that mandates that.

A. No, there's no mandate. Again, because to mandate customer savings may potentially force you away from one of the benefits, which is the hedging benefits.

Q. Okay.

A. So we get to that sort of scenario I drew earlier, where if gas prices were to continue to fall in the back end, then you could find a transaction that would allow you to lock in gas prices for an extremely long period of time at a very low price.

That's a very good day for customers and it may not necessarily represent maximum customer savings per se.

Q. Now, in the linkage between the customer savings and hedging qualities, as you just discussed, the savings could go up or down and there might be an issue where the savings aren't the best, but the hedging might make it worthwhile; is that right?

A. Very similar to the current hedging program, yes.

Q. So in your opinion, which is the overriding principle, hedging or customer savings? Which one is --

A. I don't know that there's an overriding principle between the two of them.

Again, we see both as a significant benefit to customers. The reduction of long term volatility, which the current shorter term financial hedging program does not offer, is certainly a significant -- of significant importance to our customers, we believe, and customer savings certainly, and that's why they're both included.

That's why the notion that customer savings have to be present, it wasn't just presented as this is a long term hedge. The guidelines do reference the fact that there has to be customer savings present in order to transact.

Q. Now, if the guidelines were approved, what's FPL's plan at looking forward at investing? Do you plan on staying in the Woodford, do you plan on expanding in the United States?

A. No, part of the guidelines themselves under Section 3 of the guidelines under "Supply Diversity" discusses that we're going to be onshore. We're looking for proven plays. We're looking for areas where we can get gas transportation economically delivered into our system such that we can burn the gas in our power plants.

We've identified some of the states where we'll be looking within Guideline 3B --

Q. Right.

A. -- as potential opportunities. But you know, would we be in North Dakota drilling for oil? No, I don't see that as, you know, sort of germane to what it is that we're trying to do here, which is again, ultimately trying to find a physical source of supply for our power plants.

So it's going to be somewhere within the sort of mid continent, as it's referred to, and the southeast of the United States, up into potentially the Marcellus, where there is the physical capacity to be able to deliver that gas down to Florida.

MR. MOYLE: Would you mark that, please.

Q. Now, overall with drilling -- and I know we had a shorter conversation about the Oklahoma Commerce Commission and some of the regulations and things that we talked about, regulatory risks -- just to be clear, I'm going to wind up talking about the regulatory scheme. I should be wrapping up shortly here, so I'm going to plow through this.

Did you look at any of the rules regulations, or laws regarding drilling in Oklahoma?

A. I did not, no.

Q. Did anyone brief you on it? Like did you have someone from your team come down and sit down and tell you the high points about it or no?

A. No, I did not.

Q. Are you aware that when a drilling permit is issued, are you aware of any time frame that attaches to that permit; that it may expire by a certain time or anything of that nature?

A. Generally speaking, not with respect to Oklahoma, but I'm aware that certain permits do expire if they are not drilled upon or some action is taken within a certain period of time.

Q. But you don't know if that's the case with Oklahoma?

A. I do not.

Q. Besides rules and regulations, did you review any press releases or documents regarding the Oklahoma Commerce's position related to fracking, disposal wells, and seismic activity?

A. I have not, no.

Q. Have you had anyone brief you on that topic?

A. I have not.

Q. Are you aware that there's discussions in the academic community about whether or not there is a link between fracking injection wells and seismic activity?

A. I am aware there are people lining up on both sides of that discussion with respect to what the potential impacts may or may not be.

The way I view it, again, this is a relatively small drilling program, 38 wells to be drilled between now and 2015. Those are much broader issues than obviously the 38 wells that we're talking about here. I think it would be very challenging to show that there are any direct links between just these wells and some activity out there that may trigger seismic activity.

The broader issue for us is that we already bore much of that risk. 70 percent of the portfolio that we have is driven by shale or unconventional gas drilling and so to the extent that there is a moratorium or some type of issue that is laid down by the Oklahoma Commission that either imposes a higher cost or a moratorium on it, there's going to be an impact.

Again, you're talking about a relatively small state, if you will, from a drilling perspective. There's -- approximately three or so percent of all of the shale gas that comes out of this country comes out of Oklahoma.

So if it was removed, it would be replaced by something else, but there's going to be a price impact in that, and whether it's discernable or not, it's difficult for us to say.

So we're certainly aware those are issues. We recognize that those issues are industry-wide, not specific to this opportunity, and that by participating in this opportunity we don't believe we're any more or less exposed to those issues.

Q. Are you aware that there's a moratorium in Oklahoma that they can't do any injection well for 1,600 square miles?

A. I am not aware.

Q. I mean Arkansas, I'm sorry.

A. I'm aware that there's an issue in Arkansas.

Q. Now, you just said that if there's a moratorium or something like that, then we're already facing those risks.

Isn't it different that if you're drilling and relying on gas to come out of an area and there's a moratorium and you don't get that gas that you've invested there, versus just having to pay a prior price on the open market, wouldn't you agree that there's a difference in those two scenarios?

A. There is some difference, but I'll explain.

To the extent that -- let's say there's a moratorium on the injection of the waste water from hydraulic fracturing and it causes natural gas prices to increase a nickel -- and again, I don't know whether that's realistic or what it is -- but just to kind of put things in context, you're going to remove two cubic feet of gas out of the market every single day as a result of slowing down or stopping what's coming out of some of the shale plays in Oklahoma.

A nickel on our portfolio is $30 million on an annual basis. It's a big impact. Small changes are relatively big in our portfolio, just given the amount of gas that we buy.

When we look at an opportunity like the Woodford project or other projects out there, the potential for I think stopping something that's happening at that particular site as opposed to a broader set of sites we think is very, very remote. But if there is a moratorium as a result of some action taken by the Oklahoma Commission or others that stops it, to the extent that we've already got flowing gas, it shouldn't stop that gas from flowing.

Those activities are finished and we pay as we go in terms of the drilling opportunity. So we pay half of it up front. In terms of an individual well, we pay the other half when it's finished. So if it stops after the drilling program, we'll have only paid for 19 wells and we'll be the beneficiary of the gas flowing from those wells.

Q. In terms of your analysis, did you incorporate anything in your analysis regarding increased costs linked to seismic activity?

A. No, we did not.

Q. Was that an internal decision not to or did either USG or Petroquest have input in that decision?

For example, did they say, "It's not a big deal in Oklahoma, you don't need to consider it", or did you make that decision internally?

A. We had discussions with Petroquest with respect to any concerns they may have, but the decision as to how we would treat that economically or not was made by FPL.

MR. TRUITT: Can we go off the record, please?

If we can take a five minute break real quick just to make sure we don't have any followup and then I'll be done, okay.

MR. GUYTON: Okay.

(Whereupon a recess was taken.)

BY MR. TRUITT:

Q. I've got a couple of clean up questions, nothing new.

A. Okay.

Q. Earlier we were discussing those other utilities and the orders in other jurisdictions that allowed gas reserves to be passed.

Do you know if the Northwest Utility, which is the one that has both natural gas and electric -- do you know the one I'm talking about?

A. Northwest Energy.

Q. Northwest Energy, I'm sorry.

Do you know if in that case whether the cost in investing in gas reserves can be passed on to electric utility customers as well?

A. I don't know for a fact. I'd be speculating. I don't know. I have to check.

Q. Now, in terms of the Woodford project, did FPL propose the Woodford project to NextEra or did NextEra propose it to FPL?

A. It was proposed by NextEra. They're the ones that brought the opportunity.

Q. Earlier you stated FPL began looking for transactions in 2011. Do you recall that?

A. We were made aware of the -- I believe it was the Northwest Natural transaction back in the 2011 time frame. I wouldn't say that we actively started pursuing anything until sometime thereafter.

So whether it was in '11 or '12, it was in that time frame. So we've been looking for these opportunities for a couple of years.

Q. So you've been looking since '11 or '12. I'd ask to narrow that down a little bit. How well can you narrow it down?

A. Probably not very well. In the '11 or '12 time frame, early '12, late '11.

Q. You didn't look before that order came out, would you say that?

A. Yeah, we were unaware of sort of the opportunities prior to that.

MR. TRUITT: Okay, I appreciate your time. Sorry about bouncing around, but thank you. We're done.

MS. BARRERA: Are you going to ask anything?

MR. GUYTON: I'll wait till everybody is done. So by all means, go ahead, Martha.

CROSS EXAMINATION

BY MS. BARRERA:

Q. Mr. Forrest, I'm Martha Barrera. We met before. I represent Commission Staff. I have a few questions. If you can't -- if you don't understand what I'm asking, just let me know and I'll ask Staff to explain it to me so I can explain it to you.

A. Okay.

Q. Okay. Regarding fuel price hedging, does FPL agree that a long term fixed price supply contract for natural gas provides a physical hedge against gas price volatility?

A. I'm going to ask you to repeat that just a little bit.

Q. Does FPL agree that a long term fixed price supply contract for natural gas provides a physical hedge against gas price volatility?

A. So it's a physical transaction? I do agree that it does provide a long term physical hedge. I do agree with that. I would say that they are -- long term fixed price physical contracts are something that we have not seen in the marketplace.

We have had discussions with counter parties about those types of activities. They are just not something that's readily available. Part of the issue is you have the larger players -- again, I've used [redacted] a couple of times. They're a very large part of our portfolio. [redacted] is somebody that takes prices as they come, so they don't hedge themselves. They don't lock in long term -- my understanding -- long term fixed price contracts.

That's somebody that I would be comfortable with doing a longer term transaction like that with, because they're a great credit counter party.

If you were to look at small players in the marketplace, even somebody of the size of Petroquest to do a long term physical transaction, there is a significant amount of collateral risk in that type of a transaction, in that I've got somebody who has committed to sell me gas at a fixed price over a long term period of time, but I've got to ensure that they are going to be there for the entire point of that delivery.

So that raises the issue of credit and how credit is supported, and smaller companies like that, they just can't afford the collateral requirements that it would require.

Q. And for the Woodford gas reserve project the cost of production would be the price FPL pays for gas?

A. For the Woodford project we effectively are going to calculate revenue requirements. So we'll invest a hundred and -- let's call it within the non-consent case. So in the base case that we presented roughly $191 million of capital. We'll calculate the revenue requirements based on that $191 million.

So based on the depreciation schedule it's roughly, subject to check, somewhere in the neighborhood of about [redacted] or so percent of the overall capital as kind of the first year revenue requirement. So something around [redacted] or $[redacted] million are the first year revenue requirements.

The way that we would calculate the effective cost of that gas would be to look at the amount of gas we're receiving, divided by our revenue requirements. That would give you an effective cost of gas.

So in the case of -- if you look at SF -- sorry, SF-8, if you have that in front of you, I'll kind of walk you through that math.

Q. Yes, I have it.

A. You appear to have the redacted version of that.

Q. Yes, because they don't trust me.

A. I'll walk you through the first line there.

So in the case of annual production, there's 15.6 billion cubic feet of gas to be delivered in year one. Step over to column F, which is the revenue requirement of $[redacted] million, those are the revenue requirements, which is all the operating expenses, the depreciation, return of and return on capital, all right. So you come up with a $[redacted] million revenue requirement in year one.

You take [redacted] -- you would take the $[redacted] million number, you would divide that by the 15.6 billion cubic feet, and that gives you $3.48 as an effective cost, which is Column G.

So when we talk about what's the cost, what we've done is calculated an effective cost. The real cost is the revenue requirement.

Is that clear?

Q. Yes. And the same analysis would be true for the gas reserve projects covered under the guidelines?

A. That is correct, yes.

Q. Is the cost of production from a gas reserve project fixed or can it vary?

A. There can be some variation to it. That variation would be dependent upon obviously production costs, the amount of production that you receive.

So again, if we go back to that same example that I was giving you before and let's say that instead of 15.6 billion cubic feet that you see there in Column B, let's say that in year one it produced 16 billion cubic feet, but all other things being equal, your effective cost would go down by just a little bit, right, because you're dividing now the $[redacted] million revenue requirement by 16 billion cubic feet, which gives you something probably closer to $3.46 or $3.45, wherever that number ends up being.

So there's some potential for a little bit of variation in this, but it's a very stable -- again, understanding the quality of data that we have that was used to assess the Woodford project -- a very good understanding of what the potential costs are.

Again, the costs are actually coming in on the first couple of wells at a less expensive level than was originally projected and so there's some potential that the effective costs could be even lower than what was originally projected.

Q. And for -- you may not have the answer to this, I don't know, but for the Woodford gas reserve project does FPL know the cost of production for certain year-to-year out into the future?

A. For certain? Again, I think with that same level of variability that I discussed earlier. You're going to see potentially some level of variation.

What's different about the out years is once you've drilled the well you have a good portion of your known expenses already fixed at that point. So once you've drilled a well and you know the cost of that well, then it's about depreciating those costs over time. So the variation from that point would then be the amount of production that you're actually getting.

The cost side of it then is fairly well fixed. You could have a little bit of variation in some of the operating expenses, but again, these are very, very small minor variations that you might see in the outer years.

Q. If the Commission rules not to grant FPL's petition, is it true that USG will retain all rights, benefits, and responsibilities of the Petroquest joint venture?

A. That is correct.

Q. And is it correct to say that if the Commission rules not to grant FPL's proposal, USG will bear all the costs and risks associated with the Petroquest venture?

A. That is correct.

Q. This is a hypothetical which I tried before.

If FPL and it customers were to share 50-50 the Woodford project gains and losses between the production costs and the market price of gas and share 50-50 the cost of the return on the investment above the line, would that provide FPL with an incentive to maximize the benefits to be shared with customers?

A. That was a mouthful.

Q. I know. It's hard for me to say.

A. I'm not sure. It would be difficult for me to answer that without thinking about it a little bit.

I'm not in a position anyway to commit one way or the other whether that was something that --

there are various structures that do exist out there on these types of transactions. One of the ones that was mentioned earlier as a transaction is where there's actually a subsidiary that supplies gas to the parent effectively at a cost of service, plus they receive a premium over the utility's return on equity. It's a very different model, but there are different models that exist.

I just haven't had a chance to think about even whether we would -- whether that would incent us or not. I would have to really think about it. I'm not sure how the 50-50 sharing would work on that type of mechanism.

Q. Fair enough --

MR. MOYLE: Sleep on it.

MR. GUYTON: Please, don't make him go home and worry about this tonight.

BY MS. BARRERA:

Q. Well, you haven't thought about it, but in effect, would it be a feasible alternative to FPL's proposal to do a 50-50 share between, you know, risks and liabilities and benefits?

A. Again, I'm just not in a position to say today.

Q. Okay. If you can go to Page 21 of your testimony.

A. Yes, ma'am. Okay, you're talking about direct?

Q. Excuse me one second. Yes, direct, I'm sorry.

Forget that. Strike that.

If you could go to Page 18 of your direct testimony, Lines 22 to 23 and then continuing on to Page 19, Lines 1 and 2. Where it states that:

"Several counter parties were not interested in a joint venture under the terms FPL required to assure savings for FPL customers or were unwilling to wait the time necessary to complete the regulatory process," can you please explain the specific terms FPL required to assure savings for FPL customers?

A. Certainly.

So the Woodford project is probably a good example and we can talk a little bit about how that may apply to other counter parties we were discussing.

So in the Woodford project we're paying effectively [redacted] of the costs to receive [redacted] of the working interest or of the gas. So that [redacted] delta, so the [redacted] to [redacted], that [redacted] delta is considered a carry.

That carry is very common in these types of transactions and it's meant to compensate the operator -- in this case Petroquest -- for the actions that they have taken to date. They've acquired the land, they have the expertise, they have further techniques to improve the efficiencies of the drilling activities. They've gone out and hired the talent, they've gone out and acquired the rig. So they're being compensated for everything that they have done to date, as well as to incent them to participate in this process.

Negotiating carry is a very common and standard part of this entire process when somebody like a Florida Power & Light as a non-operator, if you will, is trying to get involved with somebody that's going to operate the activity.

So carry that to some of the other conversations that we had with counter parties. In a lot of cases we may have required a much lower carry, and perhaps it was not a [redacted] cost for [redacted] of the working interest and maybe it was more like [redacted] cost for [redacted] of the working interest, and the math just didn't work for both sides, so they wanted a higher premium. They were looking for [redacted] or [redacted] or whatever the number might be for a [redacted] working interest on our part, and from our perspective it didn't produce the customer savings.

So when I talk about the ultimate terms that we're trying to negotiate, it was around that carry and some of the terms that would impact ultimately our economics and the counter party's economics. So we just couldn't come to an agreement.

In other cases we may have come to an agreement and then brought in a third party independent evaluator like a LaRoche or a Four Star or somebody to evaluate it, and when they began to look at the company's type curves and their seismic data and that kind of stuff it just didn't prove out. It just wasn't -- you know, we just couldn't get comfortable with the data they had provided.

So those are sort of some of the things that we saw along the way as we were negotiating some of these terms. But primarily it was the issue of carry and what the counter parties' expectations were versus what we were willing to pay in order to ensure a meaningful level of customer savings.

Q. Are the customer savings guaranteed under FPL's proposal for its investments in the gas reserve projects?

A. Are they guaranteed? No, they're not guaranteed. They're projected, is what they are, which is very similar to any other time that we're in front of the Commission with a particular project.

A petition for a power plant, you know, we'll demonstrate, again using a nine box or whatever it might be, sort of different sensitivities around it and demonstrate what we believe to be the expected customer savings. But those aren't guaranteed and we're not guaranteeing these either.

Again, this is a petition for approval of an individual project.

Q. Can you please turn to Page 9 of your direct testimony.

A. Yes.

Q. On Lines 9 to 12 you say that, "Due to the size of the investment and the length of the commitment required, FPL believes it must seek a prudent determination from the Commission before proceeding."

You go on to state that, "FPL cannot justify undertaking such a sizable financial commitment without assurance from the Commission."

From the customer's perspective, would the recovery of the cost of the proposed investments in the gas reserve projects through the Fuel Clause also represent a sizable financial commitment over a lengthy period of time?

A. Repeat the last part of the question.

Q. From a customer's perspective, would the recovery of the cost of the proposed investments through the Fuel Clause also represent a sizable financial commitment over a long period of time?

A. Yeah, again, using the Woodford project as a great example -- and if we can go to SF-8 you can see that the revenue requirements are going to continue for that period in which we're still receiving gas.

So you're going to start off with a production profile that is very heavy on the front end. So you're getting a lot of gas in the front end and that gas is going to taper off over time. That gas supply may last, you know, 40, 50, 60 years, and so we would be expecting to recover those costs throughout that entire period from our customers.

You know, the thought around why we're seeking the prudence determination partly is driven by 14546 and the fact that it asks you to come in front of the Commission, you know, for -- basically petitioning them for recovery through the Fuel Clause. But you know, part of it too is just it's a fairly sizable transaction.

It's the first time, in my understanding, that the Commission has looked at anything like gas reserves. Not that they haven't looked at unique things like rail cars and other things before that we mentioned earlier, but this has been a lot of work and there's a reason that, you know, they were in front of the Commission with the petition. This has obviously gone through a lot of work and a lot of counter parties, you know, parts. So that's why we're here.

Q. And if the savings to customers are not guaranteed, can you explain how the customers' interests are protected under the proposal?

A. Well, again, we have an obligation to make prudent decisions in terms of how we approach the business and you know, our efforts here are to put the best information in front of the Commission that we have and then the Commission makes a decision based on whether those costs are reasonable and prudent and we move forward.

The notion of guaranteed fuel savings, again, is something that's just -- that I'm not aware of that the Commission has required of other things.

Again, we're looking at this as just

basically the acquisition of fuel at the end of the day. That's what we're doing. We just happen to be buying it at the well head as opposed to being able to buy it from a marketer or producer or somebody else. So it's the acquisition of fuel. You know, when we buy fuel we don't -- you know, we don't guarantee any savings associated with that.

So again, this is no different than any other petition or determination that we've put in front of the Commission.

Q. Okay. And can you turn to Page 23 of your direct testimony.

A. Yes.

Q. On Lines 18 to 20 you state that, "The Petroquest agreement is structured such that USG may assign all of its benefits and responsibilities under the agreement to FPL."

When you speak of benefits, are you referring to a percentage of the physical gas or if not, what are those benefits?

A. The benefits are the entire transaction, is what it is.

So at the time, if the Commission sees fit to approve the transaction, that entire transaction, all of it is coming our way. So we'll have the benefit of customer savings and the benefit of the hedging activities that we believe that this serves. Nothing will remain behind with USG.

So we're going to get our -- let's assume that there is flowing gas out of some of the wells when we actually get approval and take assignment. We'll get that flowing gas, so we'll get those wells that are actually in operation. We'll get those wells that are at some level of drilling. They've been spudded or they've been encased or whatever it might be, and then you've got the potential for drilling future wells.

All of those benefits come to us, a hundred percent of it, and in exchange for that we're going to pay USG the net book value. So essentially just the cost that they have in it, nothing more and nothing less.

Q. And when you speak of responsibilities, what are you referring to?

A. Responsibilities to look at it on a well-by-well basis, making prudent decisions as to whether to consent to a particular well or not, you know, participating as a partner with -- it's not a true partnership, but I'm going to call it a partner in Petroquest; participating with them to ensure that, you know, decisions are made in terms of how we handle the gas and then ultimately for us the responsibilities will be -- our intent is to take the gas in kind.

USG, under the way the contract is currently constructed, is going to sell that gas along with Petroquest and just receive the benefits of whatever price they get. Our intent is to take the gas in kind.

So there is a provision within the contract which will allow us to convert from selling the gas to actually taking the physical gas. We'll have an obligation to then take that physical gas and deliver it into our system and manage it accordingly as part of the broader part of our procurement portfolio.

There's also the issues around making sure that royalty payments are made to the other working interest owners, and so on.

Q. Do the responsibilities include any other legal or other liabilities that may arise out of the production of natural gas associated with FPL's working interest?

A. It potentially -- yes, liabilities in the sense of making payments, certainly. So we'll inherit whatever costs from any drilling activities that have occurred. If any legal issues have arisen, we would step into those legal issues.

I will say that there are insurance policies that Petroquest will have as an operator that they will utilize. So in the event of, you know, God forbid, say a bodily injury occurs at one of the sites, they actually do have insurance policies to help recover costs associated with whatever those might be or there's an umbrella policy that they will own as well.

So while we do step into the legal rights, we feel that those risks are fairly well mitigated.

Q. That leads very nicely into my next question. Assuming something goes wrong related to the production of the gas, if PetroQuest and/or FPL is sued as a result, would FPL be contractually insulated from bearing any liability?

A. FPL would, yes. Holding this as a subsidiary would isolate FPL from that.

So the limit of the exposure would be up to the level of investment that we've made through the subsidiary, through this partnership.

Now, again, there's a lot of mitigating factors to all of that. If it's due to the gross negligence or willful misconduct of Petroquest, that's on their dime. But, you know, if there's an issue that's occurred, again, there's insurance policies that will go to offset whatever potential costs are.

But yeah, ultimately the costs or the liability is kept at the subsidiary and sheltered from the parent.

Q. Would the customers be also insulated the same way that FPL would be?

A. Well --

Q. The liability.

A. This is a question for Kim Ousdahl, obviously. I'm getting way outside of my comfort zone with respect to accounting.

But because it's consolidated reporting, there's a potential impact of customers in that way. Not necessarily that anybody could come after FPL for anything above and beyond the initial investment, but there's -- you know, whatever costs were incurred would be felt by the customers.

Now, again, there's the issue of a prudence determination from the Commission in terms of whatever costs are incurred, so --

Q. Is it your testimony that if the Commission approves FPL's petition as filed, that FPL can assure the Commission that it will not attempt to recover through the Fuel Clause the costs of any liability that may arise from any activities associated with FPL's working interest in Woodford or any other gas reserve project?

A. I would probably leave that to the attorneys to respond to.

Q. Please turn to Page 42 of your direct testimony.

A. Yes.

Q. On Lines 6 to 10 you stated that, "Most counter parties have been unwilling to wait for the standard regulatory approval timing in order to execute an agreement."

What's your definition of the standard regulatory approval timing, the length of time we're talking about?

A. Well, the time from the filing of a petition through Commission approval. So however long that would standardly take.

Q. How many months would that be, do you know?

A. Let's say from the time that we filed this in June -- and we're going to hearing in December, so we're talking six plus months.

Q. You also stated that FPL could not depend on

USG or any other entity to stand in until the regulatory process was completed. Why not?

A. It's just not within their business model.

You know, this is -- for them, they are actively pursuing other opportunities for their own gain. So in the NextEra's 10-K they mention a number of places where they are actively drilling today or are part of a partnership. They don't actually drill themselves, but they're a nonoperating partner in a couple of different plays. They're involved in plays in -- again, according to the 10-K -- North Dakota, Wyoming. They're pursuing opportunities, you know, for their own benefit.

We had a willing counter party in Petroquest. We had USG, who had experience with them. There was an area of mutual interest between the two of them that was not being drilled and so, you know, you had economics that apparently worked for USG in the long run.

If they do happen -- if we don't get approval and they do happen to own it for a long time, they were willing to work the transaction forever, with the benefits that would come with that. But we just can't rely on that occurring. Again, that was sort of like all planets aligning in order to make it happen.

Additionally, this is in its simplest form just a free option. They are owning the transaction right now while we go through this approval process. Should we get approval, they are going to transition over at net book value. So they haven't been paid anything for that time while they were owning it.

So it's not part of their business model and I can't imagine it's part of anybody else's either.

Q. I think you answered this -- yeah, I think you answered it. Never mind.

Can you turn to Page 43 of your direct testimony, and on Lines 14 to 15 you refer to a set of initial guidelines in 2002 and then expanding and refining those guidelines in 2008.

Is this testimony based on your interpretation of any particular Commission orders?

A. Yes.

Q. And to make your life easier, are you referring to --

A. Thank you.

Q. -- Order Number 02-1484, which was issued in 2002?

A. Yes.

Q. And 08-0667 issued in 2008?
A. That's correct.
Q. Okay. And would you agree that the 2002 order was issued following a settlement reached between each of the four major IOUs, OPC, and FIGA?
A. To the best of my knowledge, I believe that's correct.
Q. And prudence didn't automatically attach with financial hedging activities when they were first proposed in 2002; is that correct?
A. I'll have to defer. I'm not sure what you're asking me.
Q. Well, did the Commission preapprove or pre-find prudence when they first --
A. Oh, no.
Q. And does this statement mean that prudence -- oh, wait.
Financial hedging involves investments of much shorter duration than the physical hedging investments contemplated in the new guidelines; is that correct?
A. That is certainly true. We have our hedging program and I'm aware that there are others that are also hedging; you know, that the IOUs are hedging as well, and have just a little bit of knowledge of some

of the things that they're doing.

Our hedging program, again, sort of given the size of our overall portfolio, is specific to very short term periods of time. So right now, as I said earlier, we're hedging just through 2015 and starting in January we'll begin to hedge 2016.

It's very much driven by liquidity issues. There just are a lot of trades available beyond sort of that time frame. There's tremendous balance sheet requirements to support meaningful hedging going beyond just a couple of years.

This transaction certainly -- the Woodford project certainly is a much longer form of hedge and what we're asking the Commission to do is recognize that there's value in long term hedging in their approving the transaction.

Q. Does FPL have experience with entering into long term physical hedging activities?

A. Long term, no.

Q. Physical?

A. Physical? I mean, we do longer term physical procurement. We've done transactions out as four or five years, but those were at market prices.

As I explained earlier how prices get set when you have a floating price, so as you enter each month, if I do a five-year transaction with you, say the 2015 through 2019 time frame, each month will get set individually on the week prior to the start of that month. So it's a floating price throughout time. So as gas prices rise, so does the price of that contract. As gas prices fall, so does the price of that contract.

So we're familiar with long term physical procurement, but none of those have been fixed price. None of those have had sort of a fixed price notion to them, no.

Q. Okay. If neither FPL nor the Commission has any experience with long term physical hedging activities and the Commission has had six years of transactional experience before entering guidelines for short term financial hedging activities, why would it be necessary for the Commission to consider guidelines with prudence attached at this point in time?

A. Well, the guidelines are being proposed in a manner very similar to the 2008 hedging guidelines, in my opinion. Back in 2008, you know, we presented -- FPL presented guidelines to the Commission with respect to the hedging guidelines to sort of -- pardon the analogy -- talk about, you know, what the fairway is and what the rough is. It didn't -- it wasn't necessarily -- it didn't absolve us of any of our responsibilities. It wasn't a pre-prudence determination. There's nothing about that that's pre-prudence.

You know, it's basically telling the Commission this is what we plan to do by filing a risk management plan, and the Commission has an opportunity to review that and make comments. If they approve the plan, then we go execute on that plan.

That doesn't necessarily mean that we have a hundred percent recovery of costs just as a result of taking those activities. The Commission still has the opportunity to come in and audit -- which they do every year -- our hedging program and to ensure that we've done exactly what it is that we say we're doing.

I was going to say, this is the same type of activity. So with respect to the guidelines for gas reserves, again, it's defining kind of what the fairway is and what the rough is so that we all have an understanding of the types of transactions that we can go pursue, and you know, again, just because we transacted within those boundaries doesn't necessarily grant us a prudence or a guarantee of return. There is still the activity of us having to demonstrate that we've been proven in our actions. We're not absolved of anything just by virtue of having the guidelines.

So we pursued them really to try and give us the opportunity to pursue these types of transactions for the benefit of our customers solely and we felt like having to go through the process that we're going through here in advance of transacting, knowing that very few counter parties are willing to wait, if any, these are just going to come few and far between and we just see that there's too much opportunity for significant customer savings through these type of transactions.

That was the rationale behind the guidelines.

Q. Please turn to Page 44 of your direct testimony. Are you there?

A. Yes, ma'am.

Q. On lines 3 to 6 you state that, "The Commission should acknowledge that there are potential drilling/production risks with pursuing gas assets and as long as the transaction was within the guidelines, it could not be deemed imprudent based on the results."

Is this correct?

A. Yes.

Q. Does this statement mean that prudence attaches at the time of the investment, if the investment is made within the guidelines?

A. No. As I mentioned earlier, just transacting within the guidelines doesn't absolve us of anything. We would very much expect to be -- you know, have full scrutiny through the Fuel Clause at the end of the proceeding for any transaction that we had executed upon, and just because we have transacted within the guidelines doesn't mean that the actions we took within those individual transactions were prudent. We would still expect to be reviewed for prudence.

Q. So you're not suggesting that by adopting these guidelines the Commission would abdicate its authority to determine the prudence of the transaction?

A. Not in any way.

Q. Can you identify the specific drilling production risks with pursuing gas assets that you're referring to?

A. Well, again, probably the easiest way to talk about just one or two of them would be potentially drilling a well that doesn't perform to the level that it was originally projected. Nothing necessarily imprudent about that activity, but for whatever reason it didn't perform to the level that it was projected to. You have an underperforming well.

Now, again, if you talk about the Woodford project, there's 38 wells. On average, you would still hope to be right at that same sort of on-average production level that was really projected, but you may have one individual well that is underperforming.

Similarly, you may have cost overruns on a particular well. Again, the first couple of wells that we've seen have been proposed at levels lower than what were originally projected, but you may have one well for whatever reason that required a little bit of rework and so it has some cost overruns associated with it. There are risks in that level.

Now, again, as Dr. Taylor will attest to, you know, there's kind of a -- plus or minus 10 percent is a pretty good boundary for understanding production. That's on a well-by-well basis and really on a kind of play-by-play basis which is with the 38 wells that we're talking about.

So those are the types of risks that we're really referring to.

Q. And there could be other risks; this is not an exhaustive list?

A. It's not exhaustive at all, no, ma'am.

Q. Are there any additional costs above and beyond the investment in normal operation and maintenance expenses FPL has identified associated with the proposed project that FPL may seek to recover through the Fuel Clause?

A. Say the first part of your question again, please.

Q. Are there additional costs above and beyond investment and normal operation and maintenance expenses that FPL has identified associated with the proposed Woodford project investment?

Are these additional costs -- has FPL identified any additional costs that they may seek to recover through the Fuel Clause?

A. Not beyond what is in the testimony of the witnesses. And everything is embedded in the economics that I've presented, so no additional costs beyond that.

Q. If you can turn to Exhibit SF-9, Page 2.

A. Yes.

Q. Okay. Under the "ii" bullet, it's understood that FPL may seek fuel costs recovery for a project that deviates from one or more of the guidelines or upon a showing that the project nonetheless is expected to benefit FPL customers?

A. And where do I see that, I'm sorry?

Q. It's Page 4 of Exhibit --

A. Oh, I'm sorry.

Q. It's not Page 4.

MR. MOYLE: It's your guideline document, last page.

THE WITNESS: The last page? Yes, I have it now.

MS. BARRERA: All right, strike that. Let me start again.

BY MS. BARRERA:

Q. Okay. Please turn to Exhibit SF-9 on Page 2.

A. Got it.

Q. Okay. And under guideline ID it states that: "FPL will not obligate itself to invest more than a certain amount in the aggregate on gas reserve projects over the course of any one calendar year without stating the absolute amount if what is the relevant percentage of capital versus expense in this amount."

A. I would have to check. Subject to check, I don't know.

Q. Can you get that into a late filed exhibit?

A. So just to make sure I understand your question, ask it again for me, please.

Q. All right. The guideline ID states that: "FPL would not obligate itself to invest more than a certain amount in the aggregate on gas reserve projects over the course of any one calendar year."

A. Right.

Q. What is the relative percentage of capital versus expense in that amount?

A. So if I can partially answer your question, the $750 million is a capital amount. That is meant to be capital. Now, obviously we're not asking for recovery of $750 million in one year. There's revenue requirements associated that would be calculated based on that.

So if you used the Woodford project as an example, you're probably talking, you know, [redacted] -- bear with the math, it's just a sort of a rough example -- but [redacted] million of revenue requirements in that first year.

Now, you have customer savings above and beyond those revenue requirements. Customer savings would be after the return of this revenue requirement. But the expenses themselves are a separate line item beyond the 750 million, if I'm understanding your question correctly.

Q. Okay. Now, if you go to Page 4 of Exhibit SF-9 --

A. I'm sorry, if I could finish up?

Q. Sure.

A. Again, if you have the un-redacted version --

MR. MOYLE: Of the guidelines?

THE WITNESS: I'm sorry, of SF-8.

MR. GUYTON: It's the document I gave you.

BY MS. BARRERA:

Q. Yes, I do.

A. You can see a separate column there for the operating expenses.

Q. Yes.

A. That's partially other expenses in there, if I'm not mistaken. That's subject to check, but I believe that those are in addition to capital.

Q. That would be different from the capital?

A. Correct, subject to check. I want to verify that.

Q. So on Exhibit SF-9 on Page 4 it says: "FPL may seek fuel costs recovery for a project that deviates from one or more of the guidelines upon a showing that the project nonetheless is expected to benefit FPL customers."

A. Correct.

Q. And is it your testimony that FPL may seek a case-by-case determination from the Commission for certain gas reserve projects in the future?

A. That's correct. To be clear, we would petition the Commission specifically for approval of a transaction that fell outside these guidelines.

(Discussion off the record.)

BY MS. BARRERA:

Q. In the fuel cost proceeding the cost of capital on capital investments is trued up each year, such that the utility earns its midpoint ROE on these investments; is that correct?

A. Yes.

Q. And would you agree then that prudent capital investments recovered through the Fuel Clause are guaranteed to earn the midpoint ROE?

A. I'll probably defer to the lawyers to discuss the idea of a guarantee on that, but we would be allowed to earn our authorized midpoint, if you will. Whether that's guaranteed or not is --

Q. But you expect to get that midpoint?

A. Correct, assuming that we're prudent in our actions, yes.

Q. Can you turn to Page 46, Lines 17 to 19 of your direct testimony.

A. 17 to 19?

Q. Yes. You state that, "Gas reserve projects offer customers an unparalleled opportunity for substantial savings and certainty in the face of a volatile gas market."

A. Yes.

Q. Is it correct to say that FPL will not knowingly enter into an imprudent investment?

A. Knowingly enter into an imprudent investment? I would say we would not enter into an imprudent investment.

Q. Would it also be fair to say that gas reserve projects also offer FPL an unparalleled opportunity for a guaranteed return on its investment in gas reserve projects in the face of a volatile gas market?

MR. GUYTON: I'm sorry, you changed the question from earlier. Earlier you talked about prudent investments. This time you didn't add the qualifier.

Did you mean to say "prudent investment" or did you --

MS. BARRERA: Yes, I'm sorry.

BY MS. BARRERA:

Q. Gas reserve projects -- okay, well, one second. Let me just --

A. Sure.

Q. Would it also be fair to say that gas reserve projects also offer FPL an unparalleled opportunity for a midpoint ROE on its prudent investment in gas reserve projects in the face of a volatile gas market?

A. I guess the word "unparalleled" would give me a little bit of pause, just because when I look at it with respect to the opportunity for customers in terms of substantial savings as well as volatility mitigation, these types of opportunities -- and again, there have been a handful of them done around the country -- offer a very unique opportunity that we can't find elsewhere in the marketplace for customers to see a long term fuel savings when we would otherwise be buying gas at market prices.

We have decoupled prices that will pay for fuel away from market and tied it to the cost of production, which is what offers the significant savings. That's the word "unparalleled" that I would use.

In terms of the unparalleled opportunity with respect to FPL's investment, I think unparalleled is kind of a -- I don't know if -- it's a strange word to put in there. We have -- I don't know that this investment for us is any different than another investment with respect to Fuel Clause recovery. But certainly from a base rate perspective and earning within the authorized range, I'm not sure "unparalleled" is the word that I would utilize there.

Q. Earlier today Mr. Deason was unsure that the $750 million was an annual amount or a cumulative amount. Do you know if this is annual or cumulative?

A. It's an annual amount and the reason that we define it at the level that we did -- again, we buy a significant amount of fuel. We're buying three and a half plus billion dollars worth of fuel every year, so we just deal with rather large capital numbers anyway when we deal with this kind of stuff.

But the reason that we went with that type of level was to give us a flexibility to be able to negotiate contracts that may be for the benefit of customers that would otherwise be hamstrung by a much lower cap, right? So we're pursuing these opportunities and it's just meant to give us flexibility.

We are by no means targeting $750 million of investment every year as a result of this type of thing. It's just meant to give us the flexibility to be able to construct some of these things to be able, you know, to maximize customer benefits.

Again, it's not meant to be a target. It is a cap such that we have some flexibility within how we would transact.

MS. BARRERA: Okay, off the record.

(Discussion off the record.)

BY MS. BARRERA:

Q. Earlier today you said you had to think about a 50-50 split. Can you make a late filed exhibit with your opinion of a 50-50 split?

A. Charlie? I think I'd want to understand much better what you're asking, because I'm not sure I necessarily follow the example.

MS. BARRERA: Let's go off the record.

(Discussion off the record.)

THE WITNESS: So I can respond to that?

MR. MOYLE: Just so we're clear, you're

responding to the 50-50 question?

THE WITNESS: I'm responding to the 50-50 question, that's right.

My initial reaction to that is that is a different risk profile than the utility currently has and I would expect that there would be a higher -- if it was going to be I guess solely for the benefit of FPL, such that there wasn't any kind of recovery whatsoever other than what we were able to achieve in the marketplace, I'm not sure that's a business model that FPL wants to participate in. We already have USG, who is doing that very thing on behalf of the company. I'm not sure that we would pursue that type of opportunity.

Again, I'm speaking solely off the cuff here, so we can talk about it.

BY MS. BARRERA:

Q. So you don't think the 50-50 split would be a good idea as a business model?

A. Again, I just don't think that's -- that's my initial reaction. We can certainly talk about it. That's not the type of business that FPL necessarily wants to get into.

Q. Can you please turn to Page 27 of your rebuttal testimony. It's 27 of your rebuttal testimony, Lines 13 to 17.

A. Okay.

Q. There you state that, "The carry serves to compensate Petroquest for a series of expenses it's incurred and tasks it has undertaken associated with Woodford."

Does any and all liability that may arise out of drilling and production of gas assets at the Woodford project also reside with Petroquest?

A. They would be shared among the working interest owners. So maybe you could explain the liabilities and risks that you're referring to.

MS. BARRERA: Off the record.

(Discussion off the record.)

BY MS. BARRERA:

Q. So I'll just go to this next question.

Can you foresee any contingency that would motivate it to request recovery through the Fuel Clause of costs above and beyond its identified investment and O&M cost associated with the projects?

A. No, we don't foresee any -- again, to sort of your original question there, Petroquest as the operator has a duty and obligation to the working interest owners to basically operate in a manner, you know, fitting of the responsibility.

You know, to the extent that there are any issues, risks, liabilities that may be incurred, whether that's a lawsuit -- again, there are insurance policies that they are required to carry as the operator on behalf of the working interest owners. So to the extent that any of those costs are covered by the insurance, nothing would be carried forward. So I feel like we're fairly well protected.

Again, anything that is willful misconduct or gross negligence on their part is entirely on them as well.

We don't foresee anything at this time, but you know, I can't say that it would never happen.

Q. Would the customers be exposed to that liability, as opposed to FPL?

A. Again, I would probably have to defer to the attorneys in terms of how that would be interpreted.

Q. Can you turn to Page 32 of your rebuttal testimony.

A. Yes.

Q. And on Lines 11 to 12 you state that, "FPL will pursue projects only where fuel savings are expected to exceed the project's revenue requirements." Is this correct?

A. That's correct.

Q. Earlier you testified that fuel savings for FPL customers are not guaranteed. Would you agree that fuel savings for FPL customers are dependent on the actual outcome of the drilling production activities?

A. Yes, in combination with whatever happens with the forward price of natural gas.

Again, we have a high degree of confidence through Dr. Taylor that we've done a good job of assessing what the cost of future production of the drilling program is. We've made our best projections of what forward prices will be and have estimated customer savings. But those savings aren't guaranteed.

Again, if forward prices fall below the level of production, those savings could go away.

Q. And would you agree that FPL will earn its midpoint ROE on these gas reserve projects independent of the outcome of the drilling production activities?

A. Assuming their actions were prudent, of course, yes, I would.

I would say too, though, that to the extent that gas prices do fall, that is a very, very good outcome for our customers. Maybe not so much for the individual project here, the Woodford project, but to the extent that gas prices fall below the levels that are projected, that is a very good outcome for customers. Having to buy as much gas as we do at considerably lower prices, that is a good day for customers.

Q. Is your pursuing a working interest in the Woodford project -- wait, excuse me one second.

Is pursuing a working interest in the Woodford project too risky for FPL?

A. I don't believe it is, no. If I could -- with respect to how it's proposed, no, we do not believe so.

Q. How about on its own account?

A. I would say that that's not our business model.

Q. If it's too risky for -- well, if it's too risky for FPL, would it be too risky for -- assuming it's too risky for FPL, would it be too risky for the customers?

A. No, I don't believe so. I don't believe so.

Again, I think we have a very good grasp of the opportunity. We believe it does provide both the benefits of customer savings as well as long term fuel price mitigation in terms of the volatility inherent in the marketplace.

It's a different proposition for customers than it is for us to go out and drill on our own behalf and try to earn a return based on, you know, what we're able to do with that gas in the marketplace. This is a source of physical supply for our customers that projects to be considerably cheaper than what the forward curve currently says that it is.

Q. Is it correct that FPL's most recent long range natural gas price forecast was prepared on July 28, 2014?

A. I believe that's correct, yes.

Q. And is it correct that the July 28th natural gas price forecast replaces the October 7th forecast?

A. It is an update to that forecast, yes.

Q. When will FPL next revise its long range natural gas price forecast?

A. I can't say for sure. We'll determine at some point when the right time to update that forecast is based on sort of the upcoming filings of the 10-year site plan and of future dockets as -- you know, we'll select a time frame to develop that forecast and then we'll utilize that for a series of dockets going forward.

So I'm not sure when that will be.

Q. So that you wouldn't be doing a new forecast prior to the end of these proceedings?

A. It's possible. It's possible, I can't say for sure.

Q. Is it correct that FPL's July 28th natural gas price forecast was lower than its October 7, 2013 fuel forecast?

A. That is correct.

Q. And what were the reasons for the decline in the natural gas forecast on July 28th?

A. If you could give me just a moment, I will get a couple of things for you.

What was the updated SFA, does anyone remember that? I don't have that.

Q. If you look at OPC ROG 65 -- you want a copy?

A. No, I have it. Thank you.

I see a few changes that occurred during the period were that the -- so our forecast methodology we've explained a few times, but it bears repeating.

We use the NYMEX. So that the forward curve, if you will, for the first two years of the evaluation period, we then blended that with PIRA.

PIRA produces a nominal price forecast.

We blended the NYMEX with PIRA for a two-year period and then utilized NYMEX -- I'm sorry, utilized PIRA for the remainder of their forecast; which in the case of October, the October forecast went out to 2030. From that point forward we then use a rate of escalation as calculated by the EIA, the Energy Information Administration.

That's kind of methodology we've used now for many, many years. I think 2007 was kind of when that was first implemented.

So we updated with the NYMEX curve -- so this is an example. The first year forecast 2015 was $4.02 back in October. That price dropped to $3.75 as of the July update, okay.

Q. Okay.

A. So like you just saw, a drop of approximately 25 cents just in year one alone, which is when you're getting a fair amount of gas. So the customer savings that year dropped from on a discount -- actually, I was looking at it nominally -- from a nominal basis of $8.4 million down to $4.2 million. So that 25 cents had a fairly substantial impact just because of the volume of gas.

We then had again a new PIRA forecast that I believe was implemented, as well as we would have had EIA's new updated rate of escalation at that point. So really, every piece was updated as a result of that.

Now, there's a fair amount of volatility in all those numbers. As of yesterday the new 2015 curve had gone from $3.75 back in July back up to $3.98, which adds all that value back in.

So there's a lot of volatility in this marketplace and it moves around a lot, but we have a the point in time selected and then implemented based on that individual point in time.

Q. Do you plan to revise your direct and rebuttal testimony regarding your customer savings estimate based on this updated natural gas price forecast?

A. I think there will be some discussion as to the requested exhibits from OPC earlier which would do that. I'm not sure that our plans would be to update that testimony, but again, I'll defer to the attorneys.

Q. So we'll just wait for you to let us know if you're going to be doing it. That would be covered in the exhibits that OPC requested.

A. I believe so, but again, I'm going to defer to counsel.

MR. GUYTON: I think that's separate from the exhibits that they requested. If we decide to not object and give it to them, we may or may not revise testimony.

THE WITNESS: That's right.

MR. GUYTON: Typically, intervenors would be crawling all over us about providing revised forecasts this far after the direct testimony. They're two separate issues.

MS. BARRERA: All right. That's all the questions I have. Thank you very much.

THE WITNESS: All right. Thank you.

MR. MOYLE: Couple housekeeping things, off the record.

(Discussion off the record.)

MR. REHWINKEL: Just for the record, we're adjourning tonight and we will resume tomorrow at 8 a.m. in the same room. Same number, same call in.

(Whereupon, the taking of the deposition was adjourned at 6:15 p.m., to be continued on Friday, November 14, 2014 at 8 a.m.)

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CERTIFICATE OF OATH

I, Alice J. Teslicko, RMR, a Notary Public for the State of Florida at large, do hereby certify that the witness, Sam Forrest, appeared personally before me and was duly sworn.

Signed and sealed this 19th day of November, 2014.

____

Alice J. Teslicko, RMR

Commission No. EE031095
My Commission Expires:
December 14, 2014

CERTIFICATE

STATE OF FLORIDA)
) ss.
COUNTY OF PALM BEACH)

I, ALICE TESLICKO, RMR, a Registered Merit Reporter and Notary Public for the State of Florida at Large, do hereby certify that I reported the deposition of Sam Forrest, a witness called by the Office of Public Counsel in the above-styled cause; and that the foregoing pages constitute a true and correct transcription of my shorthand report of the deposition of said witness.

I further certify that I am not an attorney or counsel of any of the parties, nor a relative or employee of counsel connected with the action, nor financially interested in the action.

WITNESS my hand and official seal in the City of Hobe Sound, County of Martin, State of Florida, this 19th day of November, 2014.

____
Alice J. Teslicko, RMR

My commission expires:
December 14, 2014
Commission No. EE310095

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

SAM FORREST

SUBSCRIBED AND SWORN before and to me
this ____ day of _________, ____.

____

NOTARY PUBLIC

My Commission expires:

ERRATA SHEET

PAGE/LINE CHANGE/CORRECTION REASON

I, ____________________, do hereby certify that I have read the foregoing transcript of my deposition, given on _________________, and that together with any additions or corrections made herein, it is true and correct.

____

Deponent

The foregoing instrument was acknowledged before me this _____ day of ___________, 2014, by ______________________, who is personally known to me or has produced ____________________ as identification and who did not take an oath.

____

Notary Signature

NOTARY PUBLIC, State of Florida

____

Commission Number

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FILED: October 25, 2014

IN RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR

_________________________________/

Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida
November 14, 2014
8:05 a.m. - 10:50 a.m.

CONFIDENTIAL DEPOSITION OF SAM FORREST

VOLUME 2

Taken on behalf of the Alice Teslicko before Alice J. Teslicko, RMR, Notary Public in and for the State of Florida at Large, pursuant to a Notice of Taking Deposition in the above cause.

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Donna Ramas - Office of Public Counsel

Florida Public Service Commission Staff

Kory Dubin - FPL

Jay Beaupre - FPL

Scott Goorland, Esq. - FPL

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I N D E X

EXHIBITS

(None marked)

MR. MOYLE: For the record, this is the continuation of the deposition of Mr. Forrest, and I think everyone made appearances yesterday.

PSC staff has indicated that it's okay to proceed and that PSC counsel will be here shortly. South Florida has drawbridges and apparently they encountered one. Let's move on.

THE COURT REPORTER: Let me remind you that you are still under oath, sir.

CROSS EXAMINATION

BY MR. MOYLE:

Q. Good morning, Mr. Forrest.

A. Good morning.

Q. Tell me what you did to prepare for your deposition, if you would.

A. In terms of preparation, just reviewed discovery, reread through all of the testimony that had been filed.

Q. My recollection is you and I spoke under oath previously. Is that your recollection?

A. Yes.

Q. And that was in a hedging docket or relating to hedging, I believe?

A. Related to hedging.

Q. Did you go review that deposition in

preparation for anything related to this case?

A. I did not, no.

Q. Do you have that deposition?

A. I do not.

Q. I'm going to ask you some questions about what we talked about then, but just as sort of a foundational matter, has anything material changed with respect to FPL's hedging program since we talked about it at your deposition?

A. In terms of what has changed, I don't remember the exact timing of the deposition itself. Do you recall the date when that occurred?

Q. A few years, ago, I think.

A. It was a few years ago, I agree.

We stopped hedging fuel oil, is one material change, just given the amount of fuel oil that we are burning now. I mean, back in the 2005, '06, '07 time frame we were burning several million barrels of residual fuel oil. We were hedging at pretty significant levels at that time.

As our use of fuel oil has decreased over time, we slowly but surely just kind of weaned off the hedging program with respect to the fuel oil, to where we're not hedging it at all.

That would probably be the most substantive change that we have implemented, I would guess.

Q. And with respect to how that program is operated, the objective is to try to shave peaks and valleys with respect to price; is that fair?

A. We're focused on reducing volatility in the consumer's fuel bill. Again, it is not meant to outguess the market. It is not meant to out-time the market. We just, as I think I described it yesterday, dollar cost average, so we're coming in every day and making decisions to continue to hedge for the following year; and again, it's just meant to reduce the volatility of the bill again.

Whether those hedges are in the money or out of the money, so to speak, really is kind of irrelevant to the overall goal of making sure that they are reducing volatility.

Q. And what you described at your deposition and briefly just now is different than how some people invest in the natural gas markets, right?

You talked a little bet yesterday about financial hedges and mentioned some names of some companies that engage in trades in the market.

You would agree that certain entities engage in hedges in order to take advantage of which way they think the market is going to go?

MR. GUYTON: Object to the form of the question. I believe we got probably got two, if not three in that question.

BY MR. MOYLE:

Q. Did you understand the question?

A. I think I could address part of it and if I miss your overall question, then feel free to ask it again.

Q. Sure.

A. But people hedge for different reasons, if that's what you're asking, and yes, I do agree with that. I think there are people that -- for us, we're attempting to hedge solely for the purpose of reducing volatility and the customer's fuel bill.

There are others that aren't -- that don't have a customer profile or aren't responsible for serving the electrical needs of customers and trying to, you know, provide some stability to that bill. There are others that are out there that are hedging for purposes of locking in gains on a particular position.

So there's a lot of reasons why people hedge in the marketplace. I would agree with that comment.

Q. And the Commission has a policy,

you understand, with respect to hedging; that you're not supposed to take speculative positions and load up one way or the other based on which way you think the market is going, correct?

A. I generally agree that the Commission has suggested that you're to hedge within your existing position and not beyond that; existing position being your expected gas burns or your expected oil burns, as it would be.

Q. So let's talk a little bit about your testimony and your role as a witness in this case.

I read your testimony as being a fact witness. You're the guy/big dog at FPL responsible, most knowledgeable for the Woodford project; is that fair?

A. I'm certainly representing the Woodford project on behalf of Florida Power & Light. Whether I'm the most knowledgeable person on that will remain to be seen. But I certainly am representing the project on behalf of the company, yes.

Q. And in fact, there are two witnesses that are FPL employees in this case, you and Ms. Ousdahl, right?

A. That's correct.

Q. And Ms. Ousdahl, as if I understand her testimony, she's commenting and focusing on accounting for rate-making purposes, right?

A. Correct.

Q. And you have a broader scope of testimony. You're kind of covering the project in total; is that right?

A. Correct.

Q. But you're not covering it as an expert in any field that you claim, correct?

A. With respect to oil and gas exploration and production, I certainly am not an expert in that and don't claim to be. I have a lot of experience in the commodities market, but I certainly -- with respect to exploration, production, I would not claim myself as an expert in that by any stretch.

Q. So just so the record is clear, there's nothing -- you're a fact witness in this case, not an expert witness, correct?

A. I would say I'm a fact witness with respect to presenting the drilling and development agreement. Several things in here I am a fact witness, but you know with respect to the management of our risk profile at FPL, I would consider myself to be a bit of an expert on that.

Q. With respect to managing FPL's risk profile or just managing the risk profile in general?

A. With respect to the fuels that we purchase, the commodities.

Q. You had mentioned in that answer that the agreement that you're sponsoring, the D -- is it the DDA?

A. The DDA, yes.

Q. And why are you sponsoring that?

A. We felt it was important to present the DDA as part of the discovery process and for all to review to see what it was that we had signed up for.

Ultimately Florida Power & Light will -- assuming the Commission approves the transaction, will take assignment of that agreement and so it will be managed out of my group.

Q. Are you comfortable discussing that agreement?

A. At some level, yes.

Q. There's nobody else with any better knowledge of that agreement that FPL has put forward in the case, correct?

A. I don't believe so, no. Certain parts of it there may be, but in general I think I'm probably the right witness for that.

Q. Petroquest is a material player in this project, you would agree with that, correct?

A. Yes.

Q. And there's no witness from Petroquest that's going to testify or appear or that's been made available to ask questions of, correct?

A. No.

Q. Same question with respect to USG?

A. Other than Dr. Taylor?

Q. We'll look at his deposition, but I don't think he suggested he was affiliated with USG. Maybe he did.

But do you have an understanding as to Dr. Taylor, what company he works for?

A. He works for U.S. Gas, as I said. They go under a number of different sort of titles, but I think in my testimony I referred to the exact name of the company, if you'd like that.

Q. I'm going to ask you a lot questions and hopefully we'll have a conversation about risk and allocation of risk.

A. Okay.

Q. You brought up the drilling and development agreement and yesterday you were talking about some liabilities. Staff asked you questions about liabilities and how those might be addressed, and I want to kind of pursue that line of questioning a little bit, if I could.

A. Okay.

Q. So if I could refer you to the drilling and development agreement, which is your Exhibit SF-4, and I believe it's confidential.

But tell me when you're there, if you would.

A. I'm there.

Q. On Page 9 of 78 --

A. I'm there.

Q. -- there's a definition of "non-drilling cost".

A. Correct.

Q. Is it your understanding that -- and I'll just use the term "FPL" for this part of the conversation. When I say "FPL", just assume that it means the wholly owned subsidiary that you're participating for me.

Is it your understanding that FPL is responsible for non-drilling costs?

A. For our portion of the working interest.

Q. You are responsible, is your understanding?

A. Again, we're talking about the consolidation of FPL and the subsidiary as one --

Q. Right.

A. -- as referring to FPL as one entity, yes.

Q. We can call it -- just to make the record clear, let's just agree to call it New Co., okay?

A. New Co.?

Q. NewCo, it means "new company". You call it Gas Reserve Co. It's the same thing. It's the contemplation of a single purpose LLC that will be a wholly owned subsidiary of FPL, right?

A. Just to be clear, though, there are certain costs here, the gathering costs, if you will, which are those costs to move the gas from the well head to a transportation line. That would be handled at the subsidiary level and the transportation costs would be handled at the Florida Power & Light level.

So it might be easier to talk about just all of us together as FPL, since it's all consolidated.

Q. Well, I don't want to jumble it. So I think what you're saying is that you already have firm fuel transportation costs arrangements in place via FPL, right?

A. Not for this transaction, no.

Q. Not for this transaction?

A. No, we do not. We won't commit to any firm transportation costs until such time as the Commission approves the transaction. Otherwise those assets are not necessary for our portfolio.

MR. GUYTON: John, if we don't want to confuse it, can we call it what we called it in the testimony, as opposed to New Co.? I mean, it's GRCO.

MR. MOYLE: It's just in my head I stumble with it.

BY MR. MOYLE:

Q. Just call it -- GRCO?

A. GRCO.

Q. GRCO.

A. I didn't choose it.

Q. GRCO.

A. Gas Reserves Company, yes.

Q. Are there any costs that you're aware of associated with the project that are not going to flow through to GRCO, based on the percentage of ownership that GRCO will receive upon the completion of the assignment?

A. Not that I'm aware of, subject to check.

Again, those costs will get consolidated up to FPL, but for our portion of the working interest those costs would flow through GRCO into FPL. But again, just to be clear, there are certain costs that won't flow through GRCO that will just be handled directly by FPL.

Q. Are ratepayers going to be asked to cover those costs?

A. Yes.

Q. So it may be a different path to the same place?

A. That's right. That's what I was ultimately trying to say, was whether you call it one entity or two entities, those costs are ultimately being passed to customers.

Q. So a specific question with respect to non-drilling costs, it's your testimony that non-drilling costs are or will be the responsibility of the new company that will be formed and will be passed through to ratepayers in the percentage share that is owned by the new company; is that correct?

A. That's correct, yes.

Q. And this includes things like personal injury, certain property damage, environmental damage, or contamination. Those are all potential costs, correct, according to the non-drilling costs as defined on Page 9 of the exhibit?

A. That is correct. So to the extent that it wasn't as a result of PetroQuest's willful misconduct or gross negligence and to the extent that those costs aren't covered by an insurance policy.

So in the case of say personal injury, PetroQuest will have an insurance policy, an individual personal injury policy as well as an umbrella policy that will cover all of the working interest owner rights.

So to the extent that the costs aren't covered through those insurance policies, then yes, they would be passed through.

Q. You would agree the insurance arrangements are set forth in the agreement, correct?

A. The policies themselves which are required are set forth in the agreement. The actual policies themselves I have not seen.

Q. Okay. So on Page 18 of 78 of this document --

A. Correct.

Q. [redacted] would you read into the record that provision, please?

A. Sure. [redacted]

[redacted]

Q. Okay. Where is the applicable operating agreement?

A. They are -- the applicable operating agreement is an attachment to this document that is negotiated between the operator and non-operator to govern operations through drilling and then, you know, for however long is gas is flowing through the operations of that.

Then it does define the joint operating agreement -- does define what types of insurance are required. So it's negotiated after this document.

Q. Would you show it to me, where it is in your agreement in SF-4, please?

A. It is not included in this document.

Q. So the applicable operating agreement is not part of this document?

A. I'll defer to my attorneys. It is. I'm not sure why it's not included here.

Q. Because what I found was on Page 78 of 78, Exhibit G, there's a place that says "Formal operating agreement, see attachment."

A. Right.

Q. And I don't have an attachment to my exhibit and I assume you don't either, correct?

A. I don't in my document.

Q. You would agree -- I mean, we're talking about liabilities and how these liabilities are going to be handled and the liabilities are going to be put on ratepayers.

Your testimony is, "hey, don't worry, insurance covers it," and I was hoping to ask questions about, well, what's the limits of liability and you know, dig into that so I kind of understood as part of -- I'll call it ratepayer due diligence as part of asking questions. But I guess you would agree that I'm not able to do that today with respect to looking at the operating agreement, correct?

A. Not without the JOA, no.

Q. And the JOA is the Joint Operating Agreement?

A. The Joint Operating Agreement, yes.

MR. GUYTON: John, are you suggesting that you've asked for it in discovery and we haven't provided it?

MR. MOYLE: I mean, discovery speaks for itself. I'm just asking him questions about it. He's referenced it in the agreement, says it was attached. It's not attached.

It seems to me it would be a material document that -- you know, it's your case. So is it somewhere that I missed it?

MR. GUYTON: I thought you were suggesting that you asked for it and it wasn't provided.

MR. MOYLE: No, I'm asking him about his testimony talking about insurance, rev provisions referenced in the agreement. The agreement is not around.

MR. BUTLER: Let's go off the record for a moment.

MR. MOYLE: You know what, let's not, John. I mean, we're time pressed here. Let me just move on. We can figure it out later. We can talk about it later.

MR. BUTLER: I believe we can make it available to you if you want to ask questions. If you don't, it's your call.

MR. MOYLE: Well, I'm prepared, I've got time constraints. Let me just move on. We can deal with it later.

MR. BUTLER: Fair enough. It's your call.

MR. GUYTON: Before you start -- go back on the record -- we've offered to make, if we can find it, the agreement available to you. You declined, correct?

MR. MOYLE: No, I haven't. The record speaks for itself. You know, I prepared for the deposition. He has a hard stop at a certain time. I don't want to spend the time, you know, going through a document now, unless you want to agree to make him available next week where I can go through the document and see what it says and ask him questions about it next week.

Would you agree to that?

MR. GUYTON: No, but we will search for the document, if you desire.

MR. MOYLE: I'm good. It's your case, you referenced document, it's not attached. I think we'll move on.

MS. BARRERA: Can we go off the record?

MR. MOYLE: I think we're still on.

MS. BARRERA: Right now we just want to clarify. From what I understand -- I haven't reviewed it -- the agreement was referenced in the exhibit. It said it was attached as Exhibit G and it wasn't attached. Is that what you're saying?

MR. MOYLE: That's my understanding of the witness' testimony.

MS. BARRERA: We would like a copy. So if you want to get copies, you know, by the end of the deposition, that would be good, but Staff would like a copy.

BY MR. MOYLE:

Q. Do you know how many pages this document is?

A. Well, subject to check, I would guess 50 to 60 pages.

Again, it looks very much like the DDA itself, but it survives the DDA. So once the drilling is finished the Joint Operating Agreement survives that document and details maybe the very same things.

The DDA would always supersede the Joint Operating Agreement where there is any conflict, but the JOA itself between the two parties, us and Petroquest -- or in this case where USG has it, between USG and Petroquest -- defines, again, maybe in the terms you referenced, in terms of bodily injury, you know, automotive protection, an umbrella policy. Those actual coverages are actually listed in there.

Q. And in other portions of the agreement there's a section that references leases and it says

"See Attached," but there are no leases attached, correct?

A. The leases are attached. It's Exhibit B on Page 35.

Q. So that's a list of the leases, correct?

A. That is correct.

Q. If you go to Page 70 of 78, just read into the record what's set forth on Page 70 to 78.

A. "Leases attached."

Q. Are there any leases attached?

A. They are not. That is the partial assignment of oil and gas leases, which is a document which is signed between the parties as acreage is acquired. So those would be attached as this document is signed.

It's not something that's signed today. It's signed as the acreage is basically earned. This is a form of an agreement that would be utilized as we go forward.

So you drill a particular area, you earn acreage. The assignment of acreage is then assigned from one party to another and the lease is actually attached to that.

So that Exhibit A is an exhibit to the form of this agreement. The leases that you see in

Exhibit B are the actual leases that we're discussing.

Q. As part of due diligence, has anybody that you know looked at the underlying leases that are in place with landowners whose property are going to be looked to?

A. Absolutely.

Q. Who's done that?

A. It's sort of a number of different entities have been engaged in that. USG itself, along with Florida Power & Light by their side, but USG hired a firm called Moffitt and Associates, which was used to perform title due diligence on the Petroquest acquisition.

Moffitt, they reviewed all the title data that was provided by Petroquest. They provided documentation showing the extensive title research that they did do.

In a case of --

Q. "That they did do." Who, Petroquest?

A. No, that Moffitt did on behalf of NextEra or on behalf of USG.

Again, we were there by their side. They were the ones that were owning the transaction initially, so they were the ones paying for that due diligence.

USG also has a land department themselves. They have several land men that they have on staff, but they outsourced it to a group called Moffitt.

They also hired -- Petroquest hired a law firm to render opinions around title and drill sites, supplemental title opinions, a number of different issues related to drilling on particular lands. Anything that needed to be cured was cured by that law firm and then Moffitt ultimately reviewed all of those on behalf of USG.

So there was a pretty extensive title research that was done on behalf of the company. Again, we participated in that process through USG.

Q. Has anybody made any representations or warranties specifically to you, FPL, or its subsidiary with respect to the title?

A. Well, Petroquest has made reps and warranties through the purchase and sale agreement that is currently owned by USG and ultimately would be assigned to FPL.

So they have made reps and warranties that there are no violations that they're aware of or there are no land issues that they're aware of that can't be cured.

Q. And USG and FPL, they looked at a lot of Petroquest data to make judgments as to whether to go forward with the project, correct?

A. We did, absolutely, but we also utilized third party experts to help analyze that data as well.

Q. Do you believe Petroquest made any reps and warranties with respect to the quality of the data that they provided to you?

A. They made reps and warranties with respect to their compliance with laws, regulations, their title search and so on, but that's why we hired third party experts to go ahead and validate what it is that they provided.

Q. Did the third party experts independently look at the results coming out of the Petroquest wells?

A. Not these particular experts, but we did have a third party, Forrest Garb, analyze the data that was provided by Petroquest as a result of the operations of the 19 wells that are part of the area of mutual interest that we're talking about, and so they did analyze that data.

Q. Who from Forrest Garb is going to testify about the report that they did before the PSC to answer questions about the analysis that they did and the reports that they did?

A. The Forrest Garb report -- nobody, in short answer to your question, nobody from Forrest Garb is testifying here. They provided the report and their report is an attachment to Dr. Taylor's testimony, and he's more than capable of representing the data that's analyzed there.

Q. You're aware of this drilling agreement and a lot of the testimony says that this project is being done for the benefit of the ratepayers, correct?

A. For the benefit of our customers, yes.

Q. This agreement says there's no third party beneficiaries under this agreement. Would you agree with that or disagree with it or don't have a view on it?

A. If you could point me to that?

Q. Sure. It's Page -- I have it at Page 30 of 78, Section 10.11, "Third Party Beneficiaries".

"Nothing contained in this agreement shall entitle anyone other than PQ and USG and their successors and permit assigns to any claim, cause of action, remedy or right of any kind whatsoever, provided that only a party will have the right to enforce the provisions of this agreement on its own behalf."

A. I agree with that. I believe what that suggests is there's no other parties to this agreement. Doesn't mean that at the point at which FPL has taken assignment of it, that the benefits of the gas coming out of the ground will certainly be FPL's customers.

FPL's customers are not a party to the agreement, but they certainly will be a beneficiary in the sense that they're going to receive lower cost gas at a very stable price.

Q. I mean, that's one of the big points of this, correct? It's intended that they would be a beneficiary of this arrangement, right?

A. But they're not a party to it.

Q. I understand. I'm just testing your understanding of the arrangement.

A. I'm not an attorney, so I would defer sort of the definition of how this is being read to an attorney.

Q. No, I gotcha, and I'm not asking you for your legal opinion. I'm just asking -- you're the guy on this and just, you know, is it your understanding that the ratepayers are intended to be a beneficiary of this project?

A. Absolutely.

Q. What is your understanding of why you guys have a separate tax agreement for this project?

A. I would refer the questions on the tax agreement to Ms. Ousdahl. I mean --

Q. You have a cursory understanding?

A. It's a potential benefit in terms of how taxes are accrued with respect to any benefits that might come through the agreement from a tax perspective. It creates a partnership between us and Petroquest so we can both share in the benefits of those tax benefits.

Q. I'm a lawyer and read through this agreement. I'm trying to understand it so I can make judgments as to how it impacts my clients and there's some portions I found a little challenging.

A. Okay.

Q. But I'm assuming you all have a little more familiarity with it, so I'm going to ask you about a couple of the provisions. If you don't know, you can say I don't know.

A. Okay.

Q. So this provision on Page 10 of 78 called "The post earn-out well," it says -- and I'll read it into the record -- "Post earn-out well means with respect to a first well drilling unit, any commitment well following the third commitment well drilled in such first well drilling unit, and with respect to an existing drilling well unit, any commitment well following the second commitment well drilled in such existing drilling unit."

Could you explain your understanding of that to me, please?

A. I can. So on page -- I think sort of graphic sort of depiction of the property itself might be helpful. So go to Page 34.

Q. Right.

A. So on Page 34 you see defined in the black outline there a -- that's basically the 19 sections that are the area of mutual interest. This is the area in which the wells are going to be drilled, and you can see that if you start at the top left corner there, it's 18, 17, 16, 15, and so on. Those are the 19 sections that are being referred to in the area of mutual interest.

Q. Okay.

A. So a first well drilling unit is a unit -- a drilling unit and section are the same thing, just to keep things clean. In the lower right-hand corner you see drilling units 26 and 27.

Q. Represented by those little circles?

A. No, they're represented just by the square itself. It's a 640-acre parcel of land. One mile square, basically. Those two drilling units or those two sections do not have wells drilled on them today. There are no wells there. So those are first well drilling units.

Once a drilling unit or a section has three wells drilled on it, all of the acreage within that drilling unit will have been earned by currently NextEra, but once we take assignment of it, FPL.

So it takes three wells to earn all of the acreage in a particular drilling unit. So you have a one mile square unit, you drill three wells on it. Once it's got three wells on it, then we've earned all the acreage and the rights therein.

So in some cases there are wells drilled. So if you look in area 28, you'll see sort of a hand drawn line on the left-hand side of that box. That line drawn there is a well that has already been drilled. So that is a commitment well that is already in place.

Q. How is the commitment well depicted?

A. It's just a hand drawn line, sort of the left quarter of the section itself. I can show you if it will help.

Q. I'm not sure mine has a hand drawn line on it. If it does, I can't understand it.

A. So this is 26, which is a first well drill unit, no wells drilled. 27 is a first well drilled unit, no wells drilled.

28, you can see this line right here that is drawn? That is a well that is existing today. So if you count from the left, there's one, two, three, four -- there's 19 wells that have already been drilled in this area. Those are the 19 wells that have been referred to. In your case, kind of the red lines are wells that have been drilled today.

Q. And your document has a couple of additional notations on it, 27, 28?

A. Yeah, I just wrote notes on there that say those are the first two well drill units, meaning no wells drilled today.

So if you go back to what is a first post earn-out well, once three wells have been drilled on a particular section, anything beyond that -- a fourth well would be a post earn-out well. So we've already earned all the acreage.

So if a fourth well was drilled -- which currently none are contemplated, just to be clear, we're looking to drill 38 wells -- but once all the acreage has been earned in a particular section, a fourth well would be considered to be a post earn-out well. You've already earned all the acreage.

That's the simple definition. Very long winded, but the simple definition of what that is. It's the fourth well drilled on a property or on a drilling unit once all the acreage has been earned.

You have to earn your way into the acreage.

Q. And if you don't?

A. You don't have the rights to it.

Q. Does that happen sometimes in this business?

A. If you don't drill, you're not earning the acreage. So yes, it does happen.

But in this particular case, if we assume that we drill all 38 wells, we will have earned all the acreage for the Woodford piece of this property on the 19 sections.

Q. So let me take you to Page 65 of 78 of this, and toward the bottom there's language in big caps. Do you see that?

A. Yes, sir.

Q. I'll just read an excerpt of it. It says, "In addition, there are no warranties or representations, expressed or implied. As to the accuracy or completeness of any data, information or materials heretofore or hereafter furnished in connection with the assets as to the quality or quantity of possible hydrocarbon reserves, if any, attributable to interests herein assigned or the ability of the assets to produce hydrocarbons."

Is that your understanding of the status of affairs between Petroquest and FPL? It actually would be PetroQuest and USG via assignment FPL.

A. Yes, it is. I'm certainly not an attorney and every time you put something in all caps I would defer to an attorney.

But the gist is do your due diligence. That's -- they're not repping to anything that is being sold here with respect to joining as a working interest owner. Do your due diligence to understand what it is that you're buying your way into.

They provided seismic data. We've done a third party analysis by Forrest Garb. We've had Dr. Taylor assess all that data. We've had other third party experts in terms of title research and that type of stuff, but this is essentially saying do your research, do your due diligence.

Q. Do you have an understanding with respect to what reclamation obligations exist under Oklahoma law?

A. I do not.

Q. And on the next page, 66 of 78, at the end of the bold type it talks about "together with all plugging obligations with respect to the assigned well bore interest and reclamation obligations under Oklahoma law with respect to the assigned lease interest."

So I guess it follows, given that you're not familiar with it, that to the extent that those represent costs that could be incurred in the future, you're not aware of what the order of magnitude of such costs are, correct?

A. I personally am not, but we've got experts that certainly do this for a living and I'm assuming that they understand what those costs are and have accounted for them.

Q. So if they testify to it, it should be somewhere in the testimony and then if they did, I guess --

A. I'm sure you could ask Dr. Taylor when he's on the stand.

Q. Same question with respect to plugging obligations?

A. Same response.

Q. So if there's a dispute over this agreement, it's going to be litigated in Texas; is that right?

I mean, if the document says that, as I'll represent to you that it does?

A. Yes.

Q. Page 31 of 78 -- before I get to that, you had said yesterday there was an opt-out -- not an opt-out, but you used a term to represent that you thought you had the ability to come in and take over the project if they didn't perform yesterday.

A. We have the right to replace PetroQuest as an operator if they are not performing, yes.

Q. What was that term, the term associated with that, a term of art? So you have the right to replace them, you think?

A. Step-in rights.

Q. Step-in rights. Could you show me where those step-in rights are?

A. It's been a while since I have read the agreement start to finish, but -- and I'm not sure if it's in the Joint Operating Agreement, which you don't have, which we covered.

Q. I'll tell you, yesterday -- I read it last night. I read the agreement and I didn't see anything that said you have the right to step in and take over.

So I don't want to waste our time if you think it's in the agreement that I don't have. Is that what you're saying?

A. I'm not sure if it's in this agreement or in the JOA, but if you look at say bankruptcy as an example, if there's a bankruptcy issue, there's the right to replace Petroquest as an operator.

Obviously, there's a lot of issues that go into that with respect to the Bankruptcy Court and so on, being a trustee in the process, but there are rights to replace Petroquest as an operator.

Q. The 10.17 is specific performance and I assume that's not what you're referring to, correct, on Page 31 of 78?

A. That's correct.

Q. And then on 10.16, where it says "Right of Competition", there's the use of the term "fiduciary duty," in that section. It says, "Except as expressly set forth herein, no party nor its affiliate shall have any duty, including any fiduciary duty, to the other party and its affiliates."

I read this provision as saying you could do other deals. You didn't have an obligation to PetroQuest to give them first looks at deals.

A. That's correct.

Q. Is that your understanding?

A. That's my understanding.

Q. And with respect to a fiduciary duty, do you have an understanding of fiduciary duty, and if so, what is that understanding?

A. Not in a legal sense, no.

Q. In any sense? I mean, have you negotiated contracts that have that term in it?

A. I have. Again, I would defer to the lawyer to figure out what that legally means.

Q. And I'm just trying to understand not legally, because lawyers can argue over that, but if you have an understanding as an executive with respect to a fiduciary duty.

A. Making decisions that are financially responsible for the parties you represent.

Q. And who are the parties that you represent?

A. Our customers.

Q. Anybody else?

A. Well, ultimately shareholders.

Q. I appreciated your willingness to accept the term "top dog" yesterday when you were asked that question by Staff, and sometimes I fall into less than lawyerly speak.

I'm going to use a term similar to top dog, but kind of -- I'll call it "paper pushing" or "paper flow", and what I'm trying to capture there is we'll talk about the respective roles of what people do in this deal, and I want to reference you to Page 17 of 78, and this is Section 4.2, "Certain Reports Notifications."

You would agree that this sets forth a number of documents, pieces of paper, information that FPL or its New Co. subsidiary are to receive pursuant to this agreement; is that right?

A. That's correct.

Q. Looks like a considerable amount of paper to me, would you agree?

A. Certainly looks like a lot of paper.

Q. So let's kind of just step back and see if I understand this deal in accordance with how you understand this deal.

Can we have that conversation?

A. Sure.

Q. All right. What do you see as the benefits of this deal to Petroquest, the upside and the downside with respect to this arrangement?

A. It's difficult for myself to be in their shoes to sort of assess that, but outsider looking in, they receive a premium in terms of the carry that we discussed yesterday. So they're receiving a bit of a premium and want to compensate them for the work that's been done to develop the property, the risk that they've taken for the land work they've done, or any previous drilling that they've done on the site to enhance drilling opportunities.

So they've received the carry and they will essentially get [redacted] of the working interests in the property in exchange for essentially [redacted] of the costs.

So for them this is an opportunity for them to drill acreage that they already have that they may not have otherwise focused on as a result of the premium that's being paid. So for them it's just a further expansion of their business, allows them to allocate their capital in other places that may have interest to them as well.

So from their perspective this is right in line with their business model. They are a gas operator.

Q. Would it be fair to say it may help them finance the operations?

A. It may help them finance these operations, as well as others, by being able to deploy their capital elsewhere.

Q. Does it potentially help insulate them from some market risk as well?

A. I'm not sure how that would work and I'm not sure what market you're referring to.

Q. The open market for natural gas.

A. I don't see how that would -- how this transaction would insulate them from that risk.

Q. Let's talk about that.

So with respect to the arrangement, the contractual arrangement that we've been talking about, if I understand it -- and you have looked at it and you say, well, ratepayers are going to save money, then you give them a green light and off they go, I don't understand that there's a regular periodic check with the market component of that arrangement.

I understand it that you're kind of saying, hey, look, we want to fix -- we can fix our costs based on what we perceive as today's level. We want to fix them and lock them in; i.e. the hedge, right?

A. That's correct.

Q. So if that's correct, then there's not a market force necessarily that's being exerted in that relationship except for the initial look-see as to how that market looks, as to whether it will save ratepayers money on a projected basis, correct?

A. I'm not sure I follow that entire question.

Q. We'll try to take it in steps.

A. Okay.

Q. So let's just say the USG piece -- or what you're proposing is that you look at the deal and if it looks like it's going to save ratepayers money, then you go forward, correct?

A. That's correct.

Q. And if a year from now the market for natural gas is one-tenth of today's price, let's assume that, Petroquest is still going to go forward with the wells that are part of this agreement, right?

A. Not necessarily.

Q. Because you have your opt-out provision?

A. They have the right to propose wells. So if gas prices -- it's a pretty extreme example. So let's say that gas prices are trading for -- just round numbers, let's say it's trading at $4.00 today and you say one-tenth of that --

Q. 40 cents.

A. -- 40 cents. I will as a side note say that's a tremendous day for our customers, given a 90 percent reduction in their fuel bill would be a very good day for everybody.

Q. But completely unrelated to this.

A. Unrelated to this, certainly. I completely agree, but I don't want to miss the chance to talk about what a great day that would be.

Q. My aunt gave me a big inheritance. I mean, it was a great day, but it may not have much to do with what we're talking about, right?

A. This is probably a little more related.

With respect to that, though, if gas prices drop to 40 cents, first off, I don't know if Petroquest would propose any wells, given that they're facing, you know, a loss on day one when the gas is produced.

Again, you know, I know you're going to get to the SEC document from Petroquest eventually. They do have a very short term hedging program. So I think it would probably depend to a certain degree on what the forward curve looked like after gas prices dropped to 40 cents.

If they dropped to 40 cents in January of 2015 and they returned to $4.00 in the back end of 2015, they may well propose wells if they see that as an opportunity for them to continue to make money in the back end.

So they may propose a well, they may not. It really depends on all the market factors and not just what's happening tomorrow, but what's happening for the rest of the term.

For us, again, if they propose a well in a market when gas prices are at 40 cents, we're going to go through an exercise that looks at what is our projection of forward, of the forward curve, so what is our projection of forward prices.

Again, if the entire curve has dropped to a level at that, we would probably non-consent to that well. If I have the opportunity to buy 40-cent gas, why would I buy it for $3.50 as an effective cost from this?

So we're going to make a prudent decision based on the information available to us when the well is proposed.

Q. Let's just say this 40-cent event happens halfway through this deal. How many wells are contemplated? 38, is that right?

A. There's 38 wells.

Q. So let's use 40 for the purposes of discussion and 20 of them have been done or 19. Just approximately half of them have been done and then it goes to one-tenth. It's at 40 cents.

With respect to this deal, has Petroquest suffered in that scenario? Have they lost any money?

MR. GUYTON: I really don't want to object. I just want to make sure that I understand the

question. You said "halfway through the deal."
Do you mean that by time, or do you mean by --
MR. MOYLE: Yes -- no, no, by operation, by drilling. They put money in, they've invested capital, they have 19 of the 38 wells in operation.
BY MR. MOYLE:
Q. Let's say you spent $10 million on those 19 wells, just so we can talk about it.
A. So if I can keep going with your example, just so I have all the facts, that 40-cent gas, is that one month of the forward curve or is that the next 20 years?
Q. It's two years.
A. It's two years. They've probably lost money, yes.
Q. With respect to this field. We're isolating only on this deal.
A. And I'm only speaking to this deal.
I would say it largely depends on what they have done prior to the drilling of those 19 wells. If they hedged in a market when it was at $4.00 to $5.00, then they should be protected against what forward prices do.
If they haven't hedged their portfolio and

they're just taking gas prices as they come, they will have lost money, absolutely.

Q. And that's because they're exposed to market risk on their share, right?

A. Yeah. If they're producing gas at $3.00 or whatever their effective cost is themselves and selling gas at 40 cents, that's a losing proposition.

But if they've hedged that gas at $4.00, then they're producing at $3.00 and they're selling for $4.00, effectively making a dollar.

Q. Okay. How does that fact pattern look with respect to the New Co. wholly owned subsidiary? Do they make money, lose money, indifferent?

A. So for us we're different, in that when you look at Petroquest as an example, they are producing gas and hedging that gas to try and lock in some value. For us, we are producing gas and it is the hedge. We already have a short position, in that we have to buy gas every single day.

The gas coming out of the ground with the PetroQuest transaction is the hedge against that short position, right? So it's a little bit different. We're on opposite sides of this equation in terms of hedging. They view the financial market as the hedge. We view the physical piece of this as the hedge to our short position.

Now, that doesn't really change. Ultimately the bottom line when it comes to -- if we have, you know, invested our $10 million and we have our 19 wells and gas prices all of a sudden plummet to 40 cents -- which I appreciate the example. I will say that's an extreme example.

Q. I admit it.

A. That's not happening in our lifetime, I'm sure.

Q. But it helps to understand.

A. Sure. Then this particular transaction will have not provided any customer benefit other than the hedging value that it has, but it will have lost money at least in the first two years during this period when you're talking about.

But again, we're talking about doing a very small portion of the overall portfolio through these types of transactions. The other 98 percent of our portfolio that we're buying at 40 cents is a savings of a couple of billion dollars for our customers.

Q. It's my aunt with the inheritance, the other 98 percent, to just talk in short term.

But I want you to focus on the financial ramifications and implications for the New Co.

A. Sure.

Q. It's my understanding that if it goes to 40 cents they don't lose any money, because essentially the cost, whatever those costs are that they've paid to PetroQuest are going to be paid for by ratepayers, assuming they're prudent, correct?

A. Assuming they're prudent we'll have a right to earn at the midpoint of our ROE range, correct.

Q. So not only do you not lose money, you actually make money, because you're earning on the $10 million investment, right?

A. That is correct.

Q. And if they say -- well, if Petroquest says, "You know what, these wells, man, 40-cent gas, you know, we're going to have to park these for two years," that $10 million is just considered plant held for future use and sits there and earns the ROE on it as long as it sits there, correct?

A. I'm not sure what the accounting treatment would be, so I can't speak to that piece of it.

Q. Okay. So now we've talked about how 40-cent gas impacts the New Co. and I think you touched on it in the previous answer.

You said 40-cent gas is not good for customers within the confines of this deal, correct, because they would lose money within the confines of this deal on a pure financial basis, right?

A. That's correct.

Q. Acknowledging there's some value in hedge that you would contend and there's value in what I call, you know, the aunt inheritance, which is the gas market as a whole has come down and you save money on your other gas, right?

A. Yeah, again, in your example they have saved $2 billion on fuel elsewhere, but yes.

Q. Right.

A. Which is $20 on a customer bill, somewhere in that range.

Q. Isn't FPL really acting as a conduit for risk in this case in terms of passing through risk to the ratepayers?

I mean, just the way we talked about that pass-through, liabilities are passed through. Isn't this just sort of a -- you know, when you really look at it, a conduit-type relationship?

A. I don't know that I agree with that. I mean, the first opt to the liability and the risk issue, there are a number of mitigants to those risks.

Q. I understand, insurance and things like that, that you can do some things.

A. I don't want to downplay that.

Q. But there's nothing that you're aware of, no liability that could flow into the New Co. that isn't stopped at the New Co. and is not necessarily passed through to the ratepayers unless the New Co. was acting willfully and wantonly and intentionally, correct?

A. Well, that would be at the Petroquest level.

Q. For the New Co.?

A. Well, if it happens at the New Co. level, then I'm assuming that the Commission is going to deem that we've acted imprudently and it's not going to get passed through. It doesn't absolve us of our obligation to act prudently in our decisions as well as in our operations. So there's nothing that absolves us just through the very investment.

I guess I would say I don't see how this differs from building a power plant. You know, we project fuel savings when we build a power plant and if two years from now the price of gas goes to $10.00 and the price of oil goes to $20.00, the decision was made with the best information available at the time, and yet had we left the oil facility there -- use Canaveral as a good example of that -- had we left Canaveral there with the ability to burn oil, there would have been significant savings had it continued to burn oil compared to what the price of gas was. But I mean, we're not being second-guessed based on that.

Q. I understand.

A. It's the same type of investment. It's investing for the benefit of the customers based on the information that we have at the time.

Q. And you're aware all your customers are saying we don't want this deal, right?

A. I am not what aware of that.

Q. Are you aware of any customers that say, "This is a great deal, we want this"?

A. Individually?

Q. Yes.

A. I've talked to a few customers who think it's a terrific idea.

Q. Who are they?

A. By name?

Q. Yeah.

A. I think it's kind of a -- I think it's kind of a silly question.

Mitch Davidson is a customer of ours who things it's a terrific idea. There are people out there that do understand the value of it and seem to think it makes perfect sense. However, I recognize that you all represent the consumers of Florida and we represent them as customers and feel like we're doing what's in the best interest of those customers.

Q. When you went to Tallahassee -- there was testimony yesterday that you went to Tallahassee and met with some people about this project.

When was it, in the spring?

A. I don't remember the exact time frame, but earlier this spring, yes.

Q. And who did you meet with?

A. With the Office of Public Counsel.

Q. Anybody else?

A. No.

Q. At any point in time you haven't met with anybody about this project in Tallahassee or talked to anybody in Tallahassee, communicated in any way, you or anybody from FPL, other than the OPC?

A. I can only speak for myself.

Q. Or if you have information. I mean, if somebody from FPL is going to have a meeting with somebody; for example, the head of the state's energy office --

A. I'm not aware of what conversations they may have had.

Q. So you just don't know one way or the other?
A. I don't.
Q. You touched on this a little bit yesterday. In your testimony you had referenced some orders and offered the view that you think that this is something that you think could be recovered in accord with Commission policy.
I was unclear. Did you review and read all of the orders that relate to fuel cost recovery?
A. All of them, no. I reviewed some of them.
Q. And you said yesterday you reviewed portions of them; is that right?
A. Yes, correct.
Q. So back to the conversation we had about the respective risk of the parties. If I understood our conversation, Petroquest is subject to some market risk in this deal, right?
A. Correct.
Q. The subsidiary is not, correct?
A. Again, I'm going to consolidate the subsidiary and FPL together, just because we're going to consolidate our reporting.
FPL --
Q. Market risk?
A. -- is not exposed to market risk per se, in

the sense that gas prices go up and down.

Q. And the customers are exposed to some market risk, right?

A. They are exposed to market risk today regardless.

Q. Right. And in the conversation yesterday about long term hedges, I thought you said, hey, you can only do long term hedges on an index basis; is that right?

A. I wouldn't consider that -- I wouldn't consider that a hedge per se. It's long term physical procurement.

Q. Okay.

A. So just to give you a sense of our procurement portfolio, we procure what I'll call a base load source of supply. We typically will go out two or three years to acquire what I'll describe again as a base load supply. That base load supply is all done at market prices; meaning as gas prices go up, so goes the price that we pay. As gas prices go down, so goes the price we pay.

The reason we do go out on a lower term basis as opposed to just buying it daily is that it allows us to build up a portfolio. We're buying a significant amount of gas on a daily basis. We probably buy an average of somewhere between 1.5 to 1.6 billion cubic feet of gas every single day. That's how much we're burning.

So we'll go out and we'll buy a base load portion of supply in areas that are a little less liquid or in areas where we have a good supplier that we know will be there for the long run. So we will, you know, buy that longer term and then we start to layer in what I'll call monthly and seasonal hedges.

So as our load fluctuates throughout the year we'll start to layer in some of the other months to try and create a little bit of a shape to it. Then we leave the last little bit of it for the daily operations and that takes care of the daily swing. We get a rain shower, our gas burns can change significantly. All right.

So all of that is physical supply, all done at market prices, none of which I would consider to be either a financial or physical hedge per se. It's all being done at market. So no matter what the market does, that's again all costs that are being passed through to our customers.

Q. So if I wanted to buy a long term supply of gas at a fixed price, could I do that?

A. I'm not aware of anybody that's offering it.

We have had conversations previously with counter parties that are not interested in doing it, if we're talking about physical supply.

Q. Right.

A. So if I wanted to buy a long term physical supply position from you at a fixed price, say five years or ten years or whatever that number is, there are very few counter parties out there --

Q. [redacted], we talked about yesterday.

A. [redacted] is somebody that --

Q. Maybe can do it. But also --

A. They can do it, but they have no interest in doing it.

Q. Same question, you were asked about hedges. You said, hey -- as I understood your answer you said people don't do long term hedges at fixed price because of the credit consequences of it, right?

A. Yeah. So to break it into the two components of it, you have a physical fixed price hedge and the financial fixed price hedge.

On the physical side of the marketplace the counter parties that might be willing to do it are counter parties that I would not be comfortable with from a credit profile perspective. You're talking about in some cases a non-investment grade entity.

The level of credit support that they would need to provide to us in support of that transaction would be so burdensome to them that they couldn't afford it.

Q. Sure, and let me just interrupt you.

The reason is, as I assume it -- I just want you to confirm it -- is that you're exposed to market risk for a long period of time in that arrangement; isn't that right?

A. That's correct.

Q. Isn't that what makes this difficult?

A. Yeah, I am exposed to their financial performance over time. I'm exposed to them being there to honor it, right? So I've got kind of a going concern issue with them.

If for whatever reason they disappear, I'm out whatever that price was that they were providing to me, and if it was in the money, our customers will have suffered the loss on that transaction. But there's purely, more importantly, the collateral requirements required of that company.

So then we look at the financial side of it. So looking at financial hedges, you know, the short term -- as I addressed in my rebuttal testimony, the short term NYMEX market is very liquid on the front end. So the first year there are tremendous number of trades being done on a daily basis.

Q. In large part because there's less risk associated with that, right? It's not so far beyond the horizon. You have a better sense of what the price is going to be a year, two years, as compared to ten years.

A. There's a certain piece of that, but a lot of it too is just there are a lot of people involved in the daily market that are trading the stuff. I'll call them day traders. A lot of guys have hedge funds and they essentially trade for their own accounts on a speculative basis. So it creates a lot of liquidity there. You have a lot of different industries that are using natural gas as hedges as sort of the short term volatility that occurs in the marketplace.

Again, last week, you look at the December contract, December went up 55 cents last week just over the course of a week. There's A tremendous amount of volatility that happens in the short term and so you get people that will hedge just to ensure that they have a stable budget, if you will, with respect to the costs that they're paying.

You go out beyond just the short term and there's a tremendous lack of liquidity in the number of trades that occur out there. Again, the size of the portfolio that we're trying to hedge gets to the point where you're asking for a real level of support from a balance sheet speculative that's not available. But we can't support the level that would require over a long term period.

So you got the liquidity issues, the lack of trades happening out there, in addition to the balance sheet requirements.

Q. But would it be correct to say that a large component you're describing as to why there's not long term fixed products out there is there's a high level of risk out there?

A. The other issue I would point out too is when you look at hedging over time, if gas prices rise over time and I'm hedging at that market price, all I'm doing is hedging at a higher market price.

That was one of the benefits we saw in the Woodford project and other gas reserve projects, is you decouple the hedging process to what is happening in the marketplace. So if I keep hedging at that higher price, here I've decoupled from that and I'm hedging at the cost of production. So I've completely decoupled myself away from what's happening in the marketplace.

Q. The current hedging program, you, FPL, don't make money on the hedging program?

A. That's correct.

Q. And in this hedging arrangement you do make money because of what we've talked about, in terms of the ability to earn a return on the investments, right?

A. Yes, we would.

Q. So that's better for FPL from a shareholder standpoint purely with respect to how you hedge, correct?

A. That's not how we viewed it or why we viewed it that way, but that is the difference.

Q. It's also true that this arrangement, you in effect are betting on the market in this arrangement, in that it's projected that ratepayers will do really well if natural gas climbs, correct, and they don't do very well if natural gas falls.

We saw that in your revised exhibit yesterday. They do less well if the price from natural gas falls, they do better if the price of natural gas rises. This deal is in effect premised on a bet that natural gas prices are going to go up.

A. Who's gaining on that? I missed the first part of the question.

Q. The ratepayers, the ratepayers.

A. Well, I guess I would maybe disagree with a couple of premises there. One is we're not betting on anything. We're not, you know --

Q. My term.

MR. GUYTON: If he could finish his answer.

A. We're not betting on anything. We provided a forecast of forward prices and certainly those forward prices can and are quite volatile. So you can see in the updated SFA that we provided, gas prices have come down quite a bit. That's all has to do with the volatility in the marketplace, which is the very thing that the hedge provides protection against.

In the event -- and I don't want to dismiss this and I know that you talked about your aunt and her inheritance -- but when gas prices fall, that is a very, very good day for our customers, right?

Looking again at the Woodford project when it was originally filed with the SFA, and what the updated SFA looks like, they went from $107 million down to 52 or $53 million, whatever the number was. All that means is that if gas prices have fallen, the rest of the portfolio has seen a tremendous gain for our customers.

Again, we're not betting on gas prices

going up and down. I know they're going to go up or down. That's just inherent in the marketplace. But anytime gas prices fall, that is a very good day for our customers. We buy a lot of gas.

Q. Is this a true statement; with respect to the hedging program as approved by the PSC, are you indifferent to which way the market goes?

A. Specific to the hedging program, yes. We place hedges --

Q. We don't need to go back through it. I understand.

A. Okay.

Q. And same question with respect to this --

A. It's a hedge, yes.

Q. But are you similarly indifferent as to which way the market goes?

A. Yes. Again, it performs the same sort of service that the short term financial hedge does. It just does it over time.

Again, you're trying to provide protection against rising prices or falling prices for that matter, given that you're trying to create just a little bit of stability to the bill over time.

Q. See, I didn't think you were indifferent in this proposal, because I thought that you think that the prices of natural gas are going to go up and when they go up, that's going to result in ratepayer savings.

So I thought your answer when I asked you the indifferent question, you would have said no, actually we think ratepayers do better if prices go up.

A. That's not what you asked me. But in answer to that question, they absolutely do better if gas prices go up. I'm not predicting gas prices, never have suggested that I could.

We do provide a forecast and that forecast I think by all accounts -- you know, including the forecasts that were submitted by the intervener witnesses, the EIA's nominal forecast -- all those show prices rising over time. That's what we're trying to predict against.

I'm not predicting that gas prices go up, I'm not suggesting they're going down. I know they'll be volatile and there will be periods when it goes up and down.

But in reference to your last question, yeah, customers do better if gas prices rise on this particular transaction. But conversely to my earlier comments, they do a whole lot worse than the rest of the portfolio. This provides a little bit of protection in the event that gas enterprises do go up.

Q. I'm going to ask you one or two more questions and then we'll take a break. We've been going for about an hour and a half.

A. Okay.

Q. I asked Mr. Deason a real direct question and I'll ask you the same question with respect to whether ratepayers will save money/realize savings with this proposal. Will they?

A. There's an 85 percent chance based on the forecast that we provided that they will.

Q. So he answered it no. He said he can't answer it, to say that they absolutely will.

A. I can't guarantee you that they will either.

Q. Because it depends on what the market does?

A. That's exactly right. Based on the analysis that we ran and the sensitivities that we ran, we're showing an 85 percent chance that they'll save money in this particular instance.

Q. Do you know how that 85 percent -- how they came up with that?

A. You'll get off my area of expertise here quickly, because I'm certainly not an analyst, but effectively they look at our high and low band sensitives on fuel, which is based on the forward volatility of the marketplace. So we have a high band forecast and a low band forecast, as well as the base forecast, and we had the plus or minus 10 percent sensitivities which were run on production.

Again, I don't know how they do this. These guys are a lot smarter than I am. They run a series of Monte Carlo simulations. So they run basically 10,000 simulations just to show in every one of those situations, in every scenario using those volatility factors, in 85 percent of the cases it showed positive customer benefits in terms of savings.

Q. Do you find it ironic that that data is derived through the use of a device called a Monte Carlo model.

A. I didn't name it, so I don't know why it would be ironic.

Q. I mean, you know a lot of gambling goes on in Monte Carlo.

A. I do, I do.

Q. Who did this analysis for you?

A. People on my team.

Q. Financial?

A. Financial analysts on my team.

Q. So who's the best person to talk to about all the financial stuff, you?

A. Probably me, yes.

Q. How confident are you in that 85 percent number?

A. How confident am I? Again, it's a series of sensitivity analysis. Again, I'm not guaranteeing that 85 percent. We feel confident that based on the information we had available to us, that 85 percent chance that our customers save money, I'd feel good about it. It's a solid analysis.

Q. Have you ever heard the saying the most certain thing associated with a forecast is that it will be wrong?

A. Oh, I'm certain of that.

Q. You would agree with that?

A. Sure.

MR. MOYLE: Let's take five minutes, take a pretty tight five minutes. I'm trying to get you out of here with enough time to do other business.

THE WITNESS: Great, thank you.

(Whereupon a recess was taken.)

BY MR. MOYLE:

Q. So to kind of continue talking about risk and allocation of risk, we've talked about the difficulties associated with this market in terms of its volatility, right?

A. Yes.

Q. And the attendant difficulties with doing things on a long term basis with respect to -- on a fixed price with respect to hedges or physical fuel supply, right?

A. Correct.

Q. So tell me why I'm wrong if I look at it that this deal this way. You in effect are coming to the ratepayers and saying "hey, we got a deal for you. We want to fix a price for you for natural gas on a long term basis and expose you to that risk."

That's what I understand is in effect being done, because you're saying hey, we're going to do this for production cost and we think these productions costs are pretty static and aren't going to move a lot, which to my thinking is fixed price.

Tell me if you disagree with that observation.

A. I do disagree with it, and perhaps going back to the hedging side of things would be a good place to start and then kind of explain why I think it's different.

So if we do a fixed price physical transaction with some counter party, whoever that might be -- again, with the caveat that we haven't found any in the marketplace available and I'm not sure I would do one anyway with a counter party that might be willing to do one, just because of the credit risk. We have added a tremendous amount of risk to the portfolio.

If I did a transaction with you at $4.00 a BTU for a 10-year period and gas prices go to $7.00, you're going to be posting a tremendous amount of collateral to me as a result of that to protect my position, because I'm way into the money and I've got no assurance that you'll be able to deliver that. I mean, you're probably talking about an entity that is a B rated entity. There's a tremendous amount of exposure on that.

Again, I don't think that anybody is willing to offer that, but that's the corollary. The risk is counter party risk in this particular case.

What we are offering our customers is saying let's go to 2016, because in 2015 we've hedged about [redacted] of our overall order flow. So our customers are fairly protected with the vast majority of the market risk that exists. There's still that other [redacted] of the market that can obviously go up and down and will go up and down. 2016 and beyond they're completely exposed to the marketplace.

So for 50 years -- I mean, as far as you can see we're going to be buying natural gas in some form. Over the near term it tends to ramp up. So we're probably projecting about probably 600 billion cubic feet by the end of the decade. They are exposed to every single market move that happens during that period for all of that gas.

Q. "They" being ratepayers?

A. "They" being our customers. They are completely exposed to whatever happens and that's from now until forever, until we stop buying natural gas sometime in the future.

Q. I'm sorry?

A. I was going to say, this is an opportunity for just a small fraction of that.

Again, remember, at the very peak of this production profile it's about 2.7 percent of our daily needs. It ramps up pretty quickly again because of the depletion of the wells. But at the absolute max it's about 2.7 percent of our daily production and then it starts to taper off.

We're talking about a very small transaction at least for this first transaction, the Woodford project, to start to lock in some pricing. That stops the exposure to what could happen in the marketplace.

I mean, you look at even the EIA, who has a really well thought out energy outlook, and their forecast takes into consideration additional production plays coming online. It takes into consideration, you know, slowing down of imports from Canada, exports into Mexico, L & G exports and industrial complexes continues to grow. They take all these things into consideration and they're forecasting prices that are increasing over time and actually get fairly high in, you know, the outer years.

For this small transaction it locks in a little bit of a price that takes away the volatility into that marketplace. We're not asking our customers to take risk in this transaction. We're asking our customers to allow them to just take a little bit of risk off the table. We've completely decoupled the price away from what's happening in the marketplace.

Q. Is the proposition that I articulated unreasonable, in your judgment?

A. Articulate it again.

Q. In terms of ratepayers. I'm representing ratepayers. In effect, we see this deal as locking in a price for ratepayers based on production cost; is that fair?

A. That's what we're trying to do, yes.

Q. And that's projected to remain relatively stable, right?

A. Correct.

Q. So doesn't that in effect look like a long term commitment to a particular price that the ratepayers will pay?

A. That's the idea, yes.

Q. And that is the same risk that we've been talking about that in the market it doesn't appear a lot of people will step up to because of risk, agreed, locking into a fixed price over a long time?

A. I agree that the reason that the transactions aren't happening in the marketplace is one of the components is counter party risk.

This is FPL standing behind it. So they already have a fair amount of risk to us. We're not asking them to take any more or any less with respect to FPL.

Q. But the ratepayers can't go out to a bank and say, "Hey, this risk is getting thrust on us and you know, we need you to back it." I mean, it's just a regulatory scheme where the ratepayers will be there for it on a go-forward basis, right?

A. Yeah, I just don't view it in that kind of a risk profile.

Q. So let me run some facts by you, see if I can get you to agree or disagree with them in a general context.

A. Okay.

Q. Right now FPL is long in power?

A. Long in power?

Q. Yes.

A. We have generation with -- call it a reserve margin in the 20 percent range.

Q. Continued cycling would be the best evidence of it. I mean, with the expansions at Canaveral, Riviera, Port Everglades --

A. Correct.

Q. -- you're in good shape. You're not in need.

A. For the time being we are, yes.

Q. And that's in the next years, correct, you're in pretty good shape?

A. Correct.

Q. You also agree that those expansions, the ones I just mentioned, the repowerings, that those were significant capital investments for FPL?

A. That's correct.

Q. Roughly a billion dollars each?

A. I'll give you that.

Q. And from a shareholder perspective, the additional billion represents some growth of FPL, correct?

A. Growth of FPL. Rate base, yes.

Q. And that's typically a positive thing for investors, correct, all other things being equal?

A. All other things being equal, I agree it's a great thing for customers as well, but yes.

Q. Commissioner Deason has some reference in his testimony about -- I kind of shorthand it as it's better to earn 10 and a half percent on a million dollars as opposed to 10 percent on a hundred dollars.

You would agree with that, right?

A. I would agree generally, yes.

Q. And that construct sort of translates over to a regulated environment; that to the extent you're able to earn a return at a hire rate base, the more dollars are earned?

A. Assuming prudent actions are taken, yes.

Q. So the repowerings are finished. There are no more repowerings on the horizon, correct?

A. Canaveral and Riviera units are online. Everglades comes online in 2016. I'm not aware of any modernization beyond that.

Q. The nuclear project with its capital is not scheduled to come online for a number of years, correct, if it does come online?

A. That's my understanding, yes.

Q. You said this deal represented two and a half or 2.39 of your annual fuel -- or of your daily fuel. What was that number, in response to a previous question?

A. Subject to check, it's 2.7 percent and I believe that's sort of the early January 2016 time frame, when production hits its absolute peak. It's about 2.7 percent of our overall daily natural gas requirements.

Q. In your guidelines you'd you say you'd like to take this program up to potentially 25 percent?

A. That's the cap that we've proposed.

Q. So what would that number look like? What would that number be if you just took the cost associated --

A. When you say the number -- I'm not sure I'm following when you say "the number".

MR. GUYTON: Are you asking in terms of burn?

MR. MOYLE: No, I'm sorry, I'm not clear.

BY MR. MOYLE:

Q. Let's just look at the guidelines real quick.

A. Okay.

Q. It's on page one.

A. Okay.

Q. The 2017, you're saying maximum volume as a result of average daily burn is 25 percent, right?

A. 2017, that's correct.

Q. So does that mean that these type of projects that you're suggesting, that up to 25 percent of them be put in place to provide gas, that would be the equivalent of 25 percent of FPL's need for gas?

A. What those percentages are, what they represent is the maximum amount of gas contributed from a gas reserves project as a percentage of your daily burn.

So using the example I gave you with our own, on the Woodford project, 2.7 percent in January of '16, the maximum that we would allow is 15 percent in 2015, and I will tell you that with a $750 million cap we can't get to that level. But we wanted to get some flexibility, because you never know how these deals might be constructed.

Q. So how does the $750 million cap interrelate to this percentage?

You said you couldn't get to that number because of the $750 million cap. Which one would govern if you were saying you know what, I got a limitation of 15 percent, I got a limitation to 750, you know what, I'm going to use the 15 percent limitation and exceed the 750? Could you do that?

A. I don't believe we could, subject to check.

We did respond to this very question, I think it's OPC's interrogatory number 45, where the calculations were actually done. I think they asked in both cases, both utilizing this percentage of daily burn as well as the $750 million, they kind asked how does that equate to consumption from FPL's perspective.

So the answer is there in 45 and 46.

Q. Again, I understand your testimony about why you're doing this, but let's just say I'm an investor now. Can I look at this and say, you know what, this is a pretty good potential arrangement for me as an investor, because I don't think FPL is going to be building any more large capital power plants, investing in their rate base, growing their rate base through power plant investments. How are they going to grow the company?

Well, they have a creative idea to get in the oil and gas business through these reserve projects, up to $750 million a year, which based on last year's numbers represents I think about 25 percent of your capital spend for 2013.

If I were an investor, would I be looking at things incorrectly with that analysis?

MR. GUYTON: Object to the question, asking him to speculate as to an investor.

I just want to lodge the objection.

A. So in terms of -- and again, I'm certainly not part of the investor relations team, so I haven't been in discussions with how investors and/or analysts have reacted to this Woodford project proposal and the guidelines.

Again, I think it would be viewed favorable in a lot of senses in that, yeah, it's an investment opportunity much like any other investment opportunity that we might have. But again, I think they would also view it in a very positive sense from a customer perspective in terms of the potential savings it might offer.

Q. Am I correct about the -- do you have information about the capital spend for FPL for 2013?

A. I don't know those numbers at all.

Q. The SEC reports would have that or discussions with investors that Mr. Dewhurst or somebody would have?

A. Probably, yeah.

Q. Are you aware of any other capital spends on the horizon on a recurring basis that would be in this magnitude for new projects?

A. I am aware of continued development of the Everglades project. I know we are currently assessing what our next generation need is. Post that, there's obviously infrastructure with hurricane hardening or storm hardening, if you will.

There's other proposals on the horizon. I'm not privy to what all those potential development opportunities are. Again, I represent sort of the fuel side of the business.

Q. So do you have -- like if I asked you if investors were briefed on the reserve project as a matter of course, would you have information about that or know about that or would that mean anything to you?

A. I'm aware there have been some discussions held with investors and with analysts with respect to this. I've seen just a couple of really quick blushes, but I have not seen any -- necessarily a response or specific information that's been shared or how any of them have responded.

Q. You've seen nothing that suggests this is a bad deal for investors?

A. I have not seen that, no.

Q. And you have seen stuff that says this would be a positive deal for investors?

A. I have seen a few analyst comments that view it as kind of a wait and see, let's see how the Commission review it. But it is generally spoken of in a favorable sense.

Q. In your rebuttal -- and to save you time, I'll refer you to pages, but just for purposes of kind of walking you through it, you don't disagree, do you, that the cost of production with respect to Petroquest exceeded the market price for the past three years?

A. For Petroquest, I don't know that I said that in the rebuttal.

Q. 22, line 3 of the rebuttal. You state on line 2, "While it is correct that the breakeven cost of production was above the average market price for the 2010 to 2013 time period" --

A. I'm sorry, I hate to interrupt. Which line did you say you were on?

Q. I'm on line two of Page 22 of your rebuttal testimony.

A. I'm there.

Q. I'm trying to understand. So the testimony is that the breakeven cost of production was above the average market price for the last three years; is that right?

MR. GUYTON: This is a new question or you're still asking about Petroquest?

MR. MOYLE: New question.

A. Specific to Petroquest or just in general?

Q. Well, how did you make that statement, is that in what general or to PetroQuest?

A. This is in general. So I'm looking at the Woodford Shale. So maybe you can address your comment in a general sense, because I wasn't referring to Petroquest. I don't have their information.

Q. My bad.

A. So the analysis that we ran, the table that was provided in -- actually, it was provided by intervenors that we responded to. Understand that there wasn't a lot of data available.

So Wood McKenzie, who was a very experienced energy research firm that we rely upon at a corporate level, and most energy companies do, provided what they called a breakeven analysis of pricing in the Woodford and what they did was look at the well head and then equated that to the Henry Hub, which is kind of the normal benchmark people use for natural gas costs.

So they equated sort of a breakeven analysis at the well head versus Henry Hub and included a 10 percent rate of return and the gathering and transportation charges to get to the Henry Hub to sort of equate that.

It is a very different analysis than how most companies would actually look at what their breakeven costs are for an individual project. So it wasn't apples and oranges or apples and tuna fish, but it was a comparison just to show you a breakeven price at the Henry Hub.

In reality Petroquest, as an example, sells their gas basically at what's called a navel east, which is located right at the end of their gathering system. So they're not incurring the transportation charges to move the gas down, which can be anywhere from 40 to 70 percent. So those costs have transferred out because they're not selling it anyway.

You also have to take into consideration that they may be willing to earn less than a 10 percent rate of return in the short term for the betterment of their long term business. There are very few businesses I know that can sell things at a loss for an extended period. I just can't believe an industry could do that, especially the oil and gas industry.

So the table that was provided is a bit of an apples and oranges comparison, because they're not selling their gas at the Henry Hub. They are selling their gas much further upstream and saving all those charges to do that.

So I think it's very challenging to look at the costs that were provided in that table and say they were selling below market charges.

Q. Page 8, line 15, you're talking about Mr. Pollock there and you say his map depicts a total savings to FPL's customers of .03 per month over the life of the Woodford project.

You don't disagree with that calculation, do you? Just yes or no, if you can.

A. No.

Q. Do you agree with the calculation of Mr. Pollock?

A. You said you don't disagree with it. I don't disagree with it.

Q. Okay. I didn't ask that very clearly.

And given the most recent forecast that number would come down, correct, if he were to redo that calculation based on the forecast you guys gave me last night?

A. I'd have to go back and look at his analysis, whether he used our forward curve or whether he used his own. I don't remember.

Q. On line 25 -- I'm sorry, Page 25, line 11, you're talking about the SEC filing and I know you just said you don't deal with your investor relations people, but you're providing some testimony about SEC filings here, correct?

A. Yeah, certainly I don't deal with our SEC -- I'm not part of the investor relations team, but I certainly do discuss with them from time to time.

Q. Are you one of the officers subject to the Sarbanes-Oxley requirements?

A. Yes.

Q. So you have a pretty good knowledge about making material statements to investors and others in operations?

A. Correct.

Q. So you are commenting with respect to some information that was contained in SEC filings and you say that you believe it's the practice to warn investors of all known risks, regardless of how remote.

A. Correct.

Q. Is it your understanding that the SEC requires companies to disclose remote risk?

A. I think the comment is being made --

Q. If you could go yes or no and then tell me.

A. Is there a threshold?

Q. Yeah.

A. I do not know if there's a threshold per se. My comment was meant large or remote meaning we're not trying to determine an order of magnitude of the risk itself. It's being presented as a risk, and whether that is a risk that we face every day or one of the risks that's inherent in the business.

Q. I just want to explore this. An asteroid, you know, hitting Florida is probably remote?

A. Seems remote, yes.

Q. You don't think that SEC filings need to see that there could be an asteroid that could hit one of your power plants?

A. I'm not aware of any that do, no.

Q. So with respect to risks that are disclosed, you would agree that there's a higher bar than a remote improbable risk, correct?

A. If we're using asteroids as the benchmark for remote, I agree.

Q. Use whatever you're comfortable with using. I want to understand what you understand to be the requirement to disclose risk.

A. Again, I don't report the risk to our investors. I leave that to the experts, certainly. But it is meant to suggest the risks that are inherent in the business that our investors face every day.

Again, it's not meant to discuss how large or small remote may be replaced with small. It's not meant to indicate how large or small those risks are, but those risks that they are exposed to.

Q. And you agree they would be a meaningful disclosure if they're contained in SEC filings; meaningful, material?

A. Sure, absolutely.

Q. So the Petroquest report, the court reporter has a copy of it that I'd ask her to give to you.

You don't have any reason to disagree, do you, with respect to the risk that Petroquest has identified in this annual report?

A. I don't have any reason to disagree with it.

Q. As part of your due diligence, did FPL independently go and evaluate all the risks associated with this Petroquest project?

A. We certainly did our due diligence with respect to the project itself, yes.

Q. Is there a document that you came up with that says "Due Diligence"?

A. I'm not aware of a document, no. I don't know that a document was created.

Q. There are a lot of documents associated with this transaction. Do you have a sense as to with respect to due diligence reports, when lawyers are hired to do due diligence, do they typically come up with a written product for the client to review; do you know?

A. They may or may not. I have seen due diligence reports. I did not see one for this. I can't say that one doesn't exist, but I certainly didn't see one for this.

Q. When you reviewed them, in what context have you reviewed due diligence reports?

A. With respect to potential acquisition, looking at whether environmental risks were assessed for certain things. Depends on the nature of the transaction.

Q. I assume we can agree that they're informative, meaningful, and useful?

A. They certainly can be.

Q. There wasn't one that you were aware of in this case?

A. I'm not aware of one.

Q. Assume your request gets granted and it's a hundred percent your way and we're having this conversation a couple of years from now, and I think you made a bad investment and I think you gave away you know, too much.

Q. Do you anticipate that you would be the one saying, "No, John, I didn't and here's what happened in the negotiation" or would you be saying, "You know, I'm not really the person. We got the information and you'll have to talk to them about why they negotiated this. We think it's fair, a fair deal, and here's the paperwork associated with it?"

Do you have a contemplation on that?

A. I assume if I'm in the same position I am today, it would be me.

Q. So I read this annual report to suggest that the USG deal that they had previously with Petroquest was a better deal than the deal that is in front of the Commission now.

Do you have an understanding of that?

A. I do not. I'm not aware of the nature -- I understand they had a transaction. I don't know what the specific details of their transaction are.

Q. If it was a better deal, like if they had provided USG a better deal than they had provided FPL/ratepayers, would that concern you in any way?

A. Would it concern me? No, times change, certainly.

Q. So it just would have been part of the negotiations?

A. Yeah, I mean, if we negotiated side by side and they wound up with a better deal, that might be bothersome. But if they negotiated a deal four years ago, certainly times change and there are a lot of factors that would go into that.

My understanding, again, having read through the Petroquest disclosures, is that their agreement contemplated what I would call up front as opposed to a carry. So they actually made money up front as opposed to paying a carry over time.

We're earning our acreage as we go, so the carry that we're paying is as we enter each particular well. We are earning the acreage as we go. So we're paying a carry in that sense.

Whereas my understanding -- and again, I could be mistaken, but as I read the Petroquest disclosure documents, it appears that USG paid a promote. So they paid money up front for the right to retain acreage before it ever started.

That's a very, very different structure, one that's just fine, but one that is --

Q. So I think you may be wrong.

A. Okay, I could be.

Q. So go to Page 5, first fall paragraph.

A. Uh-huh.

Q. It says, "Under the amended JDA, the phase two drilling carry was expanded to provide for development in both the Mississippi Lime and Woodford Shale plays, whereby we will pay 25 percent of the costs to drill" --

A. I'm sorry, I'm not following you. You are on --

Q. Page five.

A. Page five.

Q. First full paragraph. It starts "as a result".

A. Yes.

Q. Toward the end.

A. Okay.

Q. "We will pay 25 percent of the costs to drill and receive a 50 percent ownership."

A. Right.

Q. Isn't that the carry? Isn't that a carry concept or am I wrong?

A. That is a carry concept. It doesn't mean you can't have a promote up front as well. Again, I could be wrong in terms of the promote. As I said, I have not read their agreement.

But yeah, you are correct in saying that they're paying 25 percent of the cost to drill, which obviously they're getting a carry as well. But again, there's lot of types of agreements.

You could pay a promote, you could pay a carry, you could pay a combination thereof. You could pay a higher carry over time and earn your way into a 50-50 proposition.

But again, like I said, I would suggest to my earlier comment that the agreement was negotiated back in 2010, four years later. Certainly times have changed. You know, liquids and oil have become more valuable. So you know, you're just trying to negotiate a deal that works for both parties.

Q. In this arrangement the NGLs and the oil are going to be sold at market and the monies get credited to the Fuel Clause; is that right?

MR. GUYTON: Excuse me, "this arrangement", are you talking about the earlier PetroQuest --

MR. MOYLE: No, the Woodford deal.

A. The Woodford project as proposed does not have any meaningful oils or liquids, to the extent that you would want to process those out and sell those in the market. We do not contemplate -- and Dr. Taylor can certainly go into this in more detail, but there are no oils and NGLs contemplated in the Woodford project itself.

Q. What happens if you extract those, something unexpected happens and you end up with them?

A. Again I would defer to Dr. Taylor, but I would be very, very surprised if any of those are discovered, given sort of the seismic data that we have, as well as the 19 wells that we have that are not producing any NGLs or any oil.

Again, Dr. Taylor is much more versed at this than I am. Even if you extracted just a very small amount of let's say natural gas liquids, it needs to be at a meaningful enough level that it actually makes sense to go through the process and the expense of doing that and tying in a processing facility.

So I would suggest the Woodford project will not be producing any.

Q. But any other projects that you want to go into, it is contemplated?

A. It's possible, it's possible. It certainly would be something that if we found a potential joint venture or a partnership or just an agreement, a working interest with somebody that is producing oils and natural gas liquids, that we wouldn't shy away from that, let's say, you know, per the guidelines.

The reason I say that is, you know, while our primary and sole focus is to bring natural gas all the way to Florida, that's the reason we're entering into these transactions, they do have value. Those other products do have value and if they could potentially buy down the effective cost of gas, then we would do that.

Now, while the guidelines dictate we want the predominant amount of that sort of hydrocarbon stream to be methane or natural gas, if there were oil and natural gas products, it would certainly be for the benefit of the customers.

Q. So the customers would either benefit or not benefit, depending on what the market price for oil is in that context, right?

We're going in the future, there's a project, it gets 51 percent gas, we know what happens with that. 49 percent oil, you take the oil and you sell it in the market, whatever the number you get is -- if it's below the production cost, above the production costs, it doesn't matter, it just gets credited to fuel cost?

A. That's correct.

Q. And actually that's contemplated in your guideline IBB, right, all NGLs and oil produced from a gas reserve project will be sold at market prices?

A. That's correct.

Q. So doesn't that put ratepayers at some risk with respect to future market prices for oil, because they're going to have to pick up the production cost, right?

A. Pick up their production cost? It would be included as part of the production of the project, whatever that is.

I mean, if you want to use the Woodford

project as an example, if it was producing natural gas liquids, those natural gas liquids would be produced along with the methane or the natural gas would be sent to a processing facility and sold in the open market.

So the cost of the processing would be included, but the benefit of the sales price would certainly be credited back to customers.

There is some potential exposure to a little bit of volatility and what is the price for oil, but --

Q. A little bit of volatility on oil?

A. Not today it's not. It's $80 every day, but I completely agree, there's volatility in the forward market for oil. I'm not suggesting anything to the contrary.

Yeah, there is some exposure to oil prices, but again, to the extent that there is value in those products they would absolutely buy down the cost of gas.

Q. So on this Petroquest annual report, just flipping briefly, if you'd go to Page 5.

A. Yes.

Q. There's a sentence in here -- this is in the letter that the CEO writes to the shareholders on

Page 5. He says, "These are the areas in which we will focus our 2014 Woodford drilling program, as we plan to drill between 30 to 50 liquids-rich wells using multi pad drilling sites", and he goes on and talks about funding.

Do you have an understanding as to liquids-rich wells? I thought we're talking about dry wells with the Woodford project and he's saying liquid-rich wells.

A. I didn't see specifically where the sentence was that you were reading. But in general, yes, I understand liquids-rich wells.

Again, I think Dr. Taylor can probably give you a better idea where the cut off between a dry well and a liquid well is sort of considered. But as a lay person sort of speaking to it, you know, the point at which it makes economic sense to start extracting the NGLs and processing those for sale, the Woodford itself is divided up into different regions, where you might have dry gas and you might have natural gas liquids and oil, and in fact, my understanding again of the joint venture that is currently between U.S. Gas and Petroquest is they are focused on an area that is wet, as it were, in that they're drilling for natural gas liquids.

So right in the same area there's an area of production that is a wet play per se.

Q. So do you have an understanding as to what the play is with Woodford? Is it wet, dry? I mean, is it that --

A. Well, in the particular area that we're in, the very specific area that we're in, the 19 drilling units or 19 section is a dry play. There are no oils or natural gas liquids or oil that we're aware of or that we expect to extract. But in that same general vicinity there are -- you know, there are certain formations that are producing natural gas liquids and even oil.

Q. Petroquest -- you said at one point I think in your testimony that -- you comment on the revenues, right?

Let me flip you to Page F-13 -- I'm sorry, F-3 toward the back of the report. It's their consolidated statement of operations.

A. F-3, okay.

Q. I think you had said 182. That was the revenue number. You see that, right on the top of the page of revenue?

A. Yes.

Q. Are you skilled in financial analysis?

A. I would consider myself a lay person in terms of it, yes.

Q. Well, we'll be talking on the same level. I always like to go to the bottom line, the net income statement, which is on F-4, and it shows for 2013 they were at $14 million; is that right?

A. Net income I show as 8.9. Is that what you're -- you're on F-3. I show their net income as --

Q. I'm flipping over to the next page.

A. I'm sorry.

Q. Kind of the bottom line, right toward the end.

A. Sure.

Q. There's a line that says "Comprehensive Income (Loss)".

A. Yes.

Q. Above that there's a line that says Net Income (Loss)", so 2013, $14,000,000?

A. Correct.

Q. And that compares to your revenue number of 182?

A. Correct.

Q. So that return is single digit?

A. Correct.

Q. Is that typical? Do you know what kind of returns are in this business? I mean, they look for double digit returns, single digit returns?

A. I can't speak to the rest of their operations in '13 which would derive why or what their ultimate targets are. I know I just looked at their most recent 10-Q that just came out this week and their net income is considerably higher than that for 2014.

Q. 2012 looked like a bad year, because they lost 132.

A. It looks like a bad year. Again, I don't know what they were doing in terms of operations. Looks like it was primarily driven by a write-down.

Q. Did you review this kind of information before filing your testimony?

A. I did some cursory review of some of their documents. Members of my team certainly did a much more thorough review, including our financial and treasury departments.

Q. Back to your rebuttal. I'm hopping around a little bit, so I apologize.

But when we're talking about this plan on a go-forward basis, my understanding of your guidelines is you can do $750 million a year as a cap, and I understand what you said yesterday is hey, we just want some flexibility.

A. Right.

Q. But if you take a worst case scenario, if that's what it could be, that's additive, right? So it's 750 in year one, 750 in year two, 750 in year three, and those amounts continue on for a long period of time, right?

A. That's correct. Well, obviously the long period of time piece of it is up to the Commission, but the idea is that, yeah, they would be additive. So 750 in year one and $750 million in year two.

Again, that wasn't meant at all to be a target, but just enough to provide the flexibility that we need to enter into certain types of transactions.

One of the things to keep in mind is the way -- and I think SF-8 in my testimony or SF-9, excuse me, if you look at the production profile of these types of projects --

Q. It's all at the front end, right?

A. SF-7, excuse me. So it declines quickly. Not all of them are made equal. So you've got some that deplete over a shorter period of time, some that deplete over a longer period of time. Some of these are similar in nature, in that they do deplete. In order to create a consistent level of production coming from these types of deals, you have to invest.

One of the things I mentioned in my direct testimony was, you know, what happens if gas prices drop below a certain level. Well, we've just stopped doing these types of deals. They deplete naturally very quickly and you could replace them with market price gas.

You know, if gas prices get as they are projected to increase, you would continue to layer these transactions to create a level of production that remains somewhat consistent over time, which requires you to continue to invest just because of the depletion.

Q. Let me flip you to your direct testimony, Page 45, starting on line 18.

A. One second.

Q. Tell me when you're there.

A. Okay.

Q. You state, "While future transactions may not present the level of savings the Woodford project does, the proposed guidelines will ensure that future gas reserve projects are also projected to deliver net savings," correct?

A. That's correct.

Q. So the phrase about "future transactions may not present a level of savings," why did you put that in there?

A. We weren't trying to create -- the Woodford project itself at $191 million of investment with a $170 million of projected savings --

Q. Now 50.

A. Now 50, but at the time it was written, projected somewhere in the neighborhood of a little north of 50 percent of the overall capital investment, returning customer savings at a very meaningful level.

That's a pretty pretty strong return for customers. We can't guarantee that all transactions will look that way. Every one of these negotiations is separate. They're going to have different expectations. The production profiles are going to be different. We may be talking about liquids versus natural gas as a small component. So maybe customer savings on a kind of a per dollar investment are higher and maybe they're lower, but they're still significant.

Again, you know, as we look at the updated analysis that shows $52 million in savings, I would still consider that to be significant, you know, by comparison. I mean, this is $52 million after all costs have been returned, including FPL's investment. That is still a very, very meaningful level of customer savings.

That's the rationale behind it, is that not all deals are created equal in terms of how you negotiate with a counter party and what the opportunity is.

Q. In your testimony you had talked about your efforts to try to address natural gas as part of a strategy; you know, hedging program, stable trail, gas reserves, and you referenced it as being a step.

Are there other steps contemplated beyond this?

A. No, I think that we've --

Q. You can just say "no". If it's no, that's fine.

A. I'm not aware of other steps, but it's part of a portfolio. We constantly look at storage, we constantly look at transition, we constantly look at gas supply. We're looking at new ways of enhancing the optimization that we're currently functioning under to continue to bring customer savings.

It's all part of the grander scheme in terms of how we're going to, you know, develop a robust supply of natural gas to serve customers.

Q. Was this your idea, in terms of the gas reserve project?

A. I don't know that I could attribute it to any one individual. It's just something that we just started looking into it after we heard about the transaction back in '11.

Q. I've been trying all week to find out who gets credit or blame for it.

A. You can certainly give me credit for it if it goes well, how about that?

But no, I wouldn't say that, again, it was any individual's idea.

Q. You got it from that filing?

A. Yeah, that was where the idea originally -- that's the genesis for it.

Q. And just to be clear, you weren't aware of that filing as it was going through and tracked it, correct?

A. No, I wouldn't say that. I wouldn't say that. We saw it when the announcement was made after it was approved and began to research it at that point.

There may be others in my group that had heard about it before then, but I was made aware of it after it was approved.

MR. MOYLE: I have a hard stop, so thank you for your time. I have some questions I'm going to save for you when I get to see you in Tallahassee in a few weeks.

But thanks for your patience. I have been a little pressing just because of another obligation that I have, so I want to stay on the record just for a minute and I have to duck out in a second.

In some preliminary discussions about how these depos we're going to go and confidentiality, Mr. Rehwinkel suggested that this would be the only deposition that would have confidentiality attached to it and the other two would be clean.

I think I may have taken action to make the first depo less than completely clean with the introduction of a handwritten exhibit, Exhibit A to the deposition of Mr. Taylor, and upon reflection I don't feel a need to continue to have that exhibit and would ask that it be returned back to FPL, if that's okay with you guys.

MR. GUYTON: We have no objection.

MR. TRUITT: You're withdrawing it?

MR. MOYLE: Yeah, I'm withdrawing it. So just so we're clear, if you would take that confidential exhibit and give it back to Mr. Forrest for his save handling, I would appreciate it.

THE WITNESS: I'll give it to Charles, since I don't have any idea what it is.

MR. GUYTON: John, thank you for that.

MR. MOYLE: Thank you. I have nothing further. And I apologize, I know you have some redirect.

MR. GUYTON: Yeah, I do, but I'd like to make sure that I've got it organized. If we can take a minute or two, I don't think I've got more than five or ten minutes. Is that going to create a problem for you?

MR. MOYLE: Yeah, it is. I'll just manage through it.

Let me just say this. To the extent you're going to try to put that document in, the operating document, I would object to that. It's a meaningful document. He described it earlier as 60 to 80 pages. I haven't seen it. You know, trial is coming up in a couple of weeks.

So I would object to any efforts to try to put that in through the deposition. All the PSC prehearing order rules are pretty clear on when you file stuff.

Any other things I should object to, Charlie?

MR. GUYTON: Not that I can think of.

MR. MOYLE: Thank you, excuse me.

THE WITNESS: Thank you, sir.

MR. GUYTON: I do need a couple of minutes before we start.

(Whereupon a recess was taken.)

CROSS EXAMINATION

BY MR. GUYTON:

Q. I really only have a few questions that I want to ask you on redirect.

You were asked yesterday by counsel for OPC about the drilling schedule for the initial wells in the Woodford project. Do you recall that line of cross?

A. Yes.

Q. Is the Petroquest current drilling schedule and performance under it a matter of concern to FPL?

A. No, not in any way.

They are being quite diligent in their

pursuit of a second drilling rig that meets their needs. There is no concern on our part that, you know, we are falling behind schedule per se. You know, we're a couple of weeks behind where we expected to be when the schedule was set out back in June of this year. Certainly schedule changes can occur, but we're not concerned that we've fallen behind, so to speak. I guess the gas will be there when we drill it, so there's no concerns.

Q. Yesterday you were asked about FPL's verification of leases associated with the AMI and this morning you were also asked about it. In that response you referred to a firm by the name of Moffitt?

A. That's correct.

Q. Can you spell that and give the full name as you understand it?

A. Yes. As I understand it, it's Moffitt and Associates. First name is M-O-F-F-I-T-T and Associates.

They're the ones that we -- I say "we", that NextEra through U.S. Gas hired. They were retained by USG to perform title due diligence for the Petroquest transaction and then they did in fact reviewe all title data that had been provided by

Petroquest, and there was an extensive title search done both through independent land men as well as through the Moffitt organization, in addition to the title research that included the royalty and mineral rights there.

Q. Did it include the title chain of mineral verification?

A. That's correct.

Q. You were also asked by counsel for OPC if you had looked at the laws in Oklahoma regarding drilling operations to be undertaken.

Do you recall that line?

A. I do, yes.

Q. I believe you responded that you have not taken a look at those. Has someone within the FPL and USG organizations taken a look at those logs?

A. Yes. I cannot attest to the fact that they read them A to Z, but I can attest that they certainly were reviewed by both internal counsel and external counsel, as far as I'm aware.

We have attorneys in our Houston office, who are a U.S. Gas affiliate, that have certainly reviewed those laws and the regulations associated with drilling activities in Oklahoma and are well aware of them, yes.

In addition to that, Petroquest has represented through reps and warranties that they too are aware of those laws and you know, there's no violations or any non-compliance with any of those laws.

Q. You were also asked by counsel about PetroQuest's 10-Q and specifically the financial pages, F-3 and F-4.

Do you recall that line of questioning?

A. I do, yes.

Q. And you were asked to draw comparison between $182 million of revenue and $14 million of net operating income. Do you recall that?

A. I do.

Q. Does that provide any measure of a return on investment?

A. I am not aware of any metric of net income over revenue providing a meaningful level of representation. Nowhere in there do you get the level of investment. So a return on investment calculation is impossible with those two numbers.

So no, I'm not aware of that.

Q. Are there any other observations that you draw from your review of those pages of the PetroQuest 10K?

A. No. Obviously in 2012 they dealt with a writeoff of some sort, which I'm not familiar with. Their 2013 performance certainly grew from there and 2014 year-to-date has continued to grow.

So they as a company are continuing to perform, you know, better year over year.

MR. GUYTON: Excuse me, if we can go off the record.

(Discussion off the record.)

A few house cleaning matters, but I do want to do it on the record so that we're all aware of it.

Office of Public Counsel requested a late filed exhibit consisting of three different schedules. We will provide those schedules as requested. So I will withdraw my objection.

MR. TRUITT: Thank you.

MR. REHWINKEL: Do you have a time frame in mind?

MR. GUYTON: It will be sometime next week.

MR. REHWINKEL: That's fine.

MR. GUYTON: My guess is towards the latter part of the week, but it will be next week.

MR. GUYTON: Staff had asked for the operating agreement. We will provide a copy of that. John's objected to it being an exhibit to the deposition. I'm not going to move to attach it as an exhibit, but it will be provided to any party that is willing to take it. We'll even offer it to John. You can choose whether or not to have it.

I think we may just have it here and if we do, we'll hand it out to you before we leave.

MR. TRUITT: We won't refuse it.

MR. GUYTON: I would be surprised if you did.

I'll state for the record it was an oversight. It was intended to be handed out and quite frankly, we discovered late that it wasn't.

I don't know of any other housekeeping matters.

MR. REHWINKEL: We have one. We worked out that the transcript will be sent directly to FPL. We would ask that when you do that, if you would at the same time email the parties.

MR. BUTLER: Trust but verify.

MR. REHWINKEL: Just so we know that it's there. If you would email the parties and let us know that you had sent it to them, without sending a copy to us.

THE COURT REPORTER: Okay.

MR. BUTLER: That makes sense.

MS. BARRERA: Just to let you know, you'll have the comprehensive exhibit list. Theresa is going to send it out at noon today.

MR. REHWINKEL: Okay.

MS. BARRERA: And we hope it will all be stipulated.

MR. GUYTON: I think that's all. I assume we can excuse Mr. Forrest?

MR. REHWINKEL: Yes.

MS. BARRERA: Thank you, Mr. Forrest.

THE WITNESS: You're welcome.

(Whereupon, the taking of the deposition was concluded at 10:50 a.m.)

- - -

CERTIFICATE OF OATH

I, Alice J. Teslicko, RMR, a Notary Public for the State of Florida at large, do hereby certify that the witness, Sam Forrest, appeared personally before me and was duly sworn.

Signed and sealed this 19th day of November, 2014.

____

Alice J. Teslicko, RMR

Commission No. EE031095
My Commission Expires:
December 14, 2014

CERTIFICATE

STATE OF FLORIDA)
) ss.
COUNTY OF PALM BEACH)

I, ALICE TESLICKO, RMR, a Registered Merit Reporter and Notary Public for the State of Florida at Large, do hereby certify that I reported the deposition of Sam Forrest, a witness called by the Office of Public Counsel in the above-styled cause; and that the foregoing pages constitute a true and correct transcription of my shorthand report of the deposition of said witness.

I further certify that I am not an attorney or counsel of any of the parties, nor a relative or employee of counsel connected with the action, nor financially interested in the action.

WITNESS my hand and official seal in the City of Hobe Sound, County of Martin, State of Florida, this 19th day of November, 2014.

____

Alice J. Teslicko, RMR

My commission expires:
December 14, 2014
Commission No. EE310095

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

SAM FORREST

SUBSCRIBED AND SWORN before and to me
this ____ day of _________, ____.

____

NOTARY PUBLIC

My Commission expires:

ERRATA SHEET

PAGE/LINE CHANGE/CORRECTION REASON

I, ____________________, do hereby certify that I have read the foregoing transcript of my deposition, given on _________________, and that together with any additions or corrections made herein, it is true and correct.

____

Deponent

The foregoing instrument was acknowledged before me this _____ day of ____________, 2014, by ______________________, who is personally known to me or has produced _____________________ as identification and who did not take an oath.

____

Notary Signature

NOTARY PUBLIC, State of Florida

____

Commission Number

This late-filed exhibit responds to a request by the Office of Public Counsel for three variants to the matrix of customer savings under sensitivity cases that appears on page 38 of Mr. Forrest's direct testimony, to reflect the following changes in assumptions:

- Change Case 1 -- Changing the range of variability in gas production volume from +/- 10% to +/- 20%, but using the same October 2013 fuel forecast;
- Change Case 2 -- Using FPL's July 2014 fuel forecast instead of its October 2013 fuel forecast, but using the +/- 10% range of variability in gas production volume; and
- Change Case 3 -- Using FPL's July 2014 fuel forecast and a +/- 20% range of variability in gas production volume

The results for the three requested change cases as well as the original table are attached. FPL has several observations about the requested change cases:

- Each of the change cases shows significant base case customer savings ($106.9 MM NPV in Change Case 1 and $51.9 MM in Change Cases 2 and 3). These are the most likely outcomes for customers in each Change Case and are extremely favorable.
- The difference between the October 2013 and July 2014 fuel forecasts illustrates the price volatility that the Woodford Project would mitigate. Decoupling a portion of FPL's fuel purchases from market prices would create a more stably priced source of natural gas for the benefit of FPL's customers.
- Picking a fuel price forecast with lower fuel prices, as OPC has done, and then subjecting it to the same full range of downward fuel price volatility effectively double counts the potential "downside exposure." In other words, the variability that exists between the October 2013 and July 2014 fuel forecasts is accounted for in the 20.9% reduction in fuel prices used for the "low fuel price" sensitivities. Picking a lower fuel forecast as the starting point and then applying the same 20.9% reduction can result in exceptionally low values for the "low fuel price" sensitivity case.
- Finally, while FPL consented to run change cases using a +/- 20% range of variability in gas production volume, FPL does not believe that this range is realistic or relevant. As described by FPL witness Taylor in his direct testimony, the AMI has an established production history with a robust amount of operational performance data. Given this extensive base of production history and knowledge, Dr. Taylor expects that the aggregate volume of gas produced from the wells in the Woodford Project will not vary outside a +/- 10% band. While it is possible that the output of a single well could vary by +/- 20%, the variability for the Woodford Project in the aggregate should not exceed +/- 10%.

Pricing and Production Sensitivities[1]/[2]

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($38.2)	$39.1	$116.4
Base Production	$10.3	**$106.9**	$203.5
High Production	$59.8	$175.7	$291.7

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: October 2013

Florida Power & Light Company
Docket No. 140001-EI
Forrest Late Filed Deposition Exhibit 1
Three Variations on Customer Fuel Savings Sensitivity Matrix
Attachment 1, "Change Case 1"
Page 1 of 1

Pricing and Production Sensitivities[(1) / (2)]

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($50.7)	$23.1	$97.0
Base Production	($30.0)	**$51.9**	$134.0
High Production	($10.2)	$79.9	$170.2

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Pricing and Production Sensitivities[(1) / (2)]

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($70.5)	($4.9)	$60.8
Base Production	($30.0)	**$51.9**	$134.0
High Production	$11.4	$109.7	$208.3

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Florida Power & Light Company
Docket No. 140001-EI
Forrest Late Filed Deposition Exhibit 1
Three Variations on Customer Fuel Savings Sensitivity Matrix
Attachment 3, "Change Case 3"
Page 1 of 1

Pricing and Production Sensitivities[(1) / (2)]

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($14.4)	$72.6	$159.5
Base Production	$10.3	**$106.9**	$203.5
High Production	$34.1	$140.4	$246.7

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: October 2013

Florida Power & Light Company
Docket No. 140001-EI
Forrest Late Filed Deposition Exhibit 1
Three Variations on Customer Fuel Savings Sensitivity Matrix
Attachment 4, "Original Matrix"
Page 1 of 1

FPL

Scott A. Goorland
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5633
(561) 691-7135 (Facsimile)
scott.goorland@fpl.com

November 26, 2014

--VIA UPS OVERNIGHT DELIVERY--

VERITEXT – Production Department
One Biscayne Tower, Suite 2250
Two South Biscayne Boulevard
Miami, Florida 33131

Re: Docket No. 140001-EI – In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor
Job # 1967081

To: Veritext – Production Department

Pursuant to instructions from Zipporah Gibbs, I am enclosing the late-filed exhibit for Sam Forrest Volume 2 Deposition.

Additionally, I am enclosing the original errata sheets and signed affidavits from witness depositions of Sam Forrest, Kim Ousdahl, and Dr. Tim Taylor. The Errata Sheet for witness, Terry Deason is a PDF copy. It will be replaced with the original under separate cover.

All documents have been scanned and electronically sent to litsup-fla@veritext.com. Please contact me if you have any questions. Thank you for your assistance.

Sincerely

for

Scott A. Goorland
Principal Attorney

Attachments

cc: Zipporah Gibbs, zgibbs@veritext.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 56
PARTY: STAFF
DESCRIPTION: Deposition of Kim Ousdahl, 11/12/14, including late-filed exhibits #1 and 2

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON
See attached		

I, Kimberly Ousdahl, do hereby certify that I have read the foregoing transcript of my deposition, given on November 12, 2014, and that together with any additions or corrections made herein, it is true and correct.

Kim Ousdahl

Deponent

The foregoing instrument was acknowledged before me this 25th day of November, 2014, by Kimberly Ousdahl, who is personally known to me or has produced ____________________ as identification and who did not take an oath.

Janet Kelly

Notary Signature

NOTARY PUBLIC, State of Florida

____

Commission Number

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

FLORIDA NOTARY ASSOCIATION SINCE 1975

Page	Line	Remove	Replace	Reason for change
Page 4	Line 5	"Truitt"	"Rehwinkel"	Corrected Wording
Page 13	Line 14	"account"	"accounting"	Corrected Wording
Page 15	Line 3	"account"	"accounting"	Corrected Wording
Page 16	Line 8	"is"	"in"	Corrected Wording
Page 25	Line 19	strike "to"		Corrected Wording
Page 32	Line 16	"not"	"net"	Corrected Wording
Page 34	Line 22	"costs"	"clause"	Corrected Wording
Page 36	Line 20	"so"	"and"	Corrected Wording
Page 37	Line 10	"in my"	"that might"	Corrected Wording
Page 37	Line 21	"agreed"	"analyzed"	Corrected Wording
Page 38	Line 18	after "reserve" add "engineer"		Corrected Wording
Page 42	Line 9	add "charging in" after "not"		Corrected Wording
Page 42	Line 22	add "base" before "rates"		Corrected Wording
Page 42	Line 22	"set"	"setting"	Corrected Wording
Page 43	Line 2	"them"	"in"	Corrected Wording
Page 46	Line 14	"opting"	"opti"	Corrected Wording
Page 46	Line 18	"opting"	"opti"	Corrected Wording
Page 47	Line 17	"in"	"it"	Corrected Wording
Page 48	Line 2	"lines"	"items"	Corrected Wording
Page 49	Line 7	insert "we" between "audit" and "performed"		Corrected Wording
Page 49	Line 14	"share"	"Scherer"	Corrected Wording
Page 49	Line 23	"plot"	"amount"	Corrected Wording
Page 51	Line 1	"quip"	"CWIP"	Corrected Wording
Page 51	Line 1,2	"A, B, C"	"AFUDC"	Corrected Wording
Page 51	Line 6	"cost"	"clause"	Corrected Wording
Page 51	Line 8	"cost"	"clause"	Corrected Wording
Page 51	Line 20	add "in" after "investment"		Corrected Wording
Page 51	Line 25	"in"	"on"	Corrected Wording
Page 54	Line 5	"prepaid"	"prepared"	Corrected Wording
Page 54	Line 10	"reparation"	"preperation"	Corrected Wording
Page 57	Line 12	"covered"	"recovered"	Corrected Wording
Page 59	Line 13	"Care"	"CAIR"	Corrected Wording
Page 59	Line 16	"Care"	"CAIR"	Corrected Wording
Page 60	Line 12	"Care"	"CAIR"	Corrected Wording
Page 60	Line 15	add "in" between "have" and "rate"		Corrected Wording
Page 60	Line 18	"Care"	"CAIR"	Corrected Wording
Page 65	Line 23, 24	add quotes around "The fact that the Commission"		Corrected Wording
Page 67	Line 6	"that's"	"that are"	Corrected Wording
Page 69	Line 1	"depreciation"	"depletion"	Corrected Wording
Page 71	Line 2	"reserving"	"reserves"	Corrected Wording
Page 72	Line 21	"plan"	"plant"	Corrected Wording
Page 72	Line 23	"purchaser"	"purchase or"	Corrected Wording
Page 73	Line 15, 16	"AFPC"	"AFUDC"	Corrected Wording
Page 89	Line 22	add "of" after "return"		Corrected Wording
Page 94	Line 17	"on"	"interim"	Corrected Wording

Page 106	Line 25	add "production" between "gas" and "prices"		Corrected Wording
Page 107	Line 1	add "be" after "would"		Corrected Wording
Page 109	Line 9	"PD"	"PV"	Corrected Wording
Page 109	Line 19	"voided"	"avoided"	Corrected Wording
Page 110	Line 12	"outside"	"outsized"	Corrected Wording
Page 121	Line 22	"the"	"this"	Corrected Wording
Page 121	Line 22	"had"	"has"	Corrected Wording
Page 123	Line 21	"MCI"	"MCF"	Corrected Wording
Page 126	Line 14	"parts"	"part"	Corrected Wording
Page 129	Line 19	add "date" between "transaction" and "is"		Corrected Wording
Page 130	Line 9, 10	"swops"	"swaps"	Corrected Wording
Page 132	Line 13	"acquisition"	"access"	Corrected Wording
Page 149	Line 21	"ARP"	AFE"	Corrected Wording
Page 152	Line 16	"shift"	"ship"	Corrected Wording

56

Deposition of Kim Ousdahl 11/12/14, including late-filed Exhibits #1 and 2

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FILED: October 25, 2014

IN RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR
_____________________________________/

Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida
November 12, 2014
1:20 p.m. - 5:25 p.m.

DEPOSITION OF KIMBERLY OUSDAHL

Taken on behalf of the Alice Teslicko before Alice J. Teslicko, RMR, Notary Public in and for the State of Florida at Large, pursuant to a Notice of Taking Deposition in the above cause.

APPEARANCES:

FOR THE OFFICE OF PUBLIC COUNSEL:

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APPEARANCES - CONTINUED

Also Present:

Andrew Maurey - Florida Public Service Commission

Loretta Duran - FPL

Richard Ross - FPL

Appearing Telephonically:

Erik Sayler - Office of Public Counsel

Tarik Noriega - Office of Public Counsel

Donna Ramas - Office of Public Counsel

Florida Public Service Commission Staff

Inna Weintraub - FPL

Jay Beaupre - FPL

Ellen Joseph - FPL

Sol Stamm - FPL

Ken Hoffman - FPL

- - -

I N D E X

EXHIBITS

Thereupon:

KIMBERLY OUSDAHL

was called as a witness and having been first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

THE COURT REPORTER: Would everyone in the room please state your appearances for the record.

MR. REHWINKEL: This is Charles Rehwinkel with the Office of Public Counsel.

MR. TRUITT: John Truitt with the Office of Public Counsel.

MR. MOYLE: John Moyle, Moyle Law Firm, for the Florida Industrial Powers Users Group.

MR. GOORLAND: Scott Goorland, counsel for Florida Power & Light.

MR. BUTLER: John Butler, counsel for FPL.

MS. DURAN: Loretta Duran, regulatory accounting, FP&L.

MS. OUSDAHL: Kim Ousdahl with Florida Power & Light.

MR. MOWREY: Andrew Maurey, staff, Florida Public Service Commission.

MS. BARRERA: Martha Barrera, PSC attorney.

MR. BUTLER: And on the phone?

THE COURT REPORTER: On the phone, would you just announce your appearances again, please?

MR. STAFF: Commission staff is on the line.

MS. RAMAS: Donna Ramas is on the line, listening on behalf of OPC.

MR. SAYLER: Erik Sayler, Office of Public Counsel.

MR. NORIEGA: Tarik Noriega, Office of Public Counsel.

MS. WEINTRAUB: Inna Weintraub, Jay Beaupre, Ellen Joseph, Sol Stamm, and Ken Hoffman, FPL.

MR. REHWINKEL: Anyone else? Thank you.

BY MR. REHWINKEL:

Q. Good afternoon, Ms. Ousdahl.

A. Good afternoon.

Q. My name is Charles Rehwinkel. As you know, I'm with the Office of Public Counsel.

MR. REHWINKEL: Before we get started, Mr. Butler, I assume that we will utilize the standard agreement of all objections except as to form will be reserved?

MR. BUTLER: Yes.

MR. REHWINKEL: And you will not waive reading and signing?

MR. BUTLER: That's right.

MR. REHWINKEL: It is not my intent to ask questions about confidential information today at all, but should we get into an area that would require that, we will consult off the record and work out a process.

But I don't think we'll get into that today.

MR. BUTLER: Okay.

BY MR. REHWINKEL:

Q. Ms. Ousdahl, I'm going to ask you first about your direct testimony. Do you have that with you?

A. I do.

Q. And I may ask you questions about Ms. Ramas' testimony. Do you have a copy of her testimony with you or available to you?

MS. DURAN: I have it.

A. Yes.

Q. Do you understand that I'm going to ask you questions about your testimony, your direct and rebuttal testimony in this docket, and that I expect to be able to rely on answers you give me here today in cross examination of you at the hearing?

A. Yes, I do.

Q. Will you also agree with me that unless the context requires otherwise, that when I ask you a question about a question and/or answer that's contained in your prefiled testimony, that I'm asking for you to answer based on the knowledge that you had at the time you prepared and submitted that testimony?

A. Okay.

Q. Do you have any changes or corrections to make to your testimony or exhibits?

A. We did file a limited errata and none beyond that.

Q. So the errata that you filed I think within the past week or so --

A. Yes, very recently.

Q. -- those are the only changes or corrections that you have?

A. Yep, yes.

Q. So does that mean as of today that you are not aware of anything material that requires a modification, correction, or change to your testimony?

A. That's correct.

Q. I see on Page 3 of your direct testimony that you're a CPA licensed in the State of Texas?

A. I am.

Q. Does that mean that you are not licensed in Florida?

A. That's correct.

Q. I noticed you state that you are a member of the Florida Institute of CPAs?

A. I am.

Q. Is there any -- is there a reciprocity arrangement between Texas and Florida that you're operating under?

A. I don't know. I don't practice public accounting.

Q. I understand.

Would you agree with me that it is important not to contort, misuse or misconstrue the language of a Commission order in providing testimony to the Commission?

A. Yes, I would agree with that statement.

Q. Would you also agree with me that it is important not to contort, misuse or misconstrue the language of another witness' testimony in providing testimony to the Commission?

A. Yes, I agree.

Q. Let's turn to Page 5, Line 20, of your direct and if I could ask you what you mean when you state that "USG will not gain from this transfer," on Lines 5 and 6 there?

A. We have formulated this transaction of net book value so that FPL could be placed in the position of original purchaser. So U.S. Gas is foregoing the benefits and/or the risk, right, that they would have had by giving us this option. They are not going to be in the driver's seat on whether or not we're able to purchase the properties ultimately.

So that's what I mean by saying they won't gain. They have provided a benefit for FPL on behalf of its customers by stepping into the transaction originally.

Q. Does that mean that FPL will not be transferring any benefits to NextEra shareholders through the transaction?

A. Are you talking about on the day of transfer?

Q. Yes.

A. FPL's shareholders will bear the cost of the investment on the date of transfer. On the date of transfer we will be financing and because there won't be immediate rate relief, FPL shareholders will be supporting the financing of that investment.

Q. Now, I asked about NextEra shareholders. Are you considering FPL shareholders and NextEra shareholders to be the same?

A. No, I should not. Ultimately, our shareholders at FPL are NextEra.

Q. My question to you was, will FPL be transferring any benefits to NextEra shareholders through the transaction?

A. No. They will be paying that book value, that cost at the date of transfer.

Q. Do you know whether NextEra will allocate any costs to USG Woodford, or what will become GRCO, that would be assumed by FPL GRCO upon transfer?

A. Let me see if I understand that question. I think you're asking me are there other costs beyond the incremental investments that might be allocated by U.S. Gas to us at date of transfer?

Is that what you're asking?

Q. Well let me ask it this way. Before you were sitting in that chair there was Mr. Taylor.

A. Dr. Taylor.

Q. Dr. Taylor, yes, who works for NextEra -- I forget. He works for a subsidiary of NextEra?

A. Correct.

Q. On the nonregulated side.

Will be there people like him or services provided by entities like that that will allocate costs to the subsidiary, that will be a wholly owned subsidiary of FPL, prior to the transfer, such that FPL customers will bear that cost in the future?

A. The answer to that is no.

So if you look at my KO-2, which was our estimate at the time we filed the testimony of the net book values that would be transferred, those are all third party costs and no affiliate costs are being allocated.

I think somewhere in this testimony, and I can't recall where, we actually state that each party bore its own costs while we were in the process of doing due diligence on the acquisition.

Q. So if I look at KO-5, page one, I see on the account 900, G&A expenses line, $300,000. That's an estimate, I assume?

A. Yes, that is.

Q. None of those costs are allocated by an affiliate?

A. No, that's a different question.

Q. Okay.

A. So I understood and tried to make sure I understood the first question, which is in the cost at date of transfer are there any allocated costs from U.S. Gas or another affiliate.

The answer to that is no. When we look forward at the first year of operation and beyond, and we've obviously had testimony on this too, Sam Forrest and the EMT team will be relying on some of the commercial expertise of the U.S. Gas folks and there will ultimately be allocated expenses associated with the time and support they provide commercially to FPL.

Q. Okay. I understand the difference. One is in 2014 and one is after the transfer in 2015?

A. The cost investments we're acquiring have no affiliate costs, all third party costs.

Q. On Page 6, Lines 7 through 13, you state that you intend to use one of the several well established third party providers of accounting and recordkeeping services in order to maintain oversight control for the project -- over the account for the project?

A. That's correct.

Q. Have you selected one as of today?

A. We have not.

Q. Is it a matter of waiting to see what the outcome of the PSC docket is?

A. Well, it has been a challenge to try to find the sweet spot between advancing this process, but not going so far that we commit dollars beyond what we would need to. It's been a big challenge.

We're in the last stages of a rigorous due diligence process with two firms that are the short list and we have a couple issues that are still remaining that we're working on.

Q. Okay. So as I said, I wouldn't ask for confidential information. I won't ask you about the names of those firms. Will these firms do any work for any other FPL affiliate?

A. Not today, and I wouldn't anticipate that they would.

I think we've also responded to interrogatories stating that U.S. Gas performs its accounting in-house.

Q. Do you know how many third parties FPL --

A. You know, I'm sorry. Let me clarify that.

One of these firms -- both of these firms have a division under the umbrella of the firm that performs systems consultations and implementations of systems, and U.S. Gas has secured services on a system that they've implemented previously that's through a division of one of the firms on our short list.

So there could be that connection, but not the services that we are securing specifically.

Q. That was my question, whether the same functions that you would contract for would be

provided for any other nonregulated --
A. Right, not the back office transaction account. That's correct.
Q. Okay, thank you.
Can you tell me how many -- this is one third party which would do the accounting and recordkeeping. Are there any other third parties that you know of that FPL will contract with, whether by name or function?
A. Well, we'll have to have a reserve valuation each year and I don't know which firm we will select, but that will be done externally.
Q. What about legal services?
A. To the extent we have future acquisitions, I'm sure there would be legal involved. I know some of that is performed in-house. You know, I can't answer that specifically.
Q. Can you turn to the MOU that's attached to your testimony? And this is KO-1, Page 1 of 3, Paragraph C.
In the last two lines of that paragraph it references that, "Each party is engaged and paid for third party consultants, including external legal counsel, for the purpose of due diligence and negotiations on the project."

A. That's referring to this transaction, yes.

Q. So will FPL have third party external legal counsel provide services to this project on a going-forward basis?

A. I don't know specifically. I was thinking about the need to potentially have external legal counsel as we do further acquisitions, right? Because that's when you need outside legal, is the contracting process, the process of the conveyance.

I do not know the answer to that on an ongoing basis.

Q. Can you tell me what third party consultants is that is referred to here?

A. The ones I know about, we had external counsel and we had a firm performing the reserve valuation. I don't know of any others.

Q. Who was the firm that did the reserve valuation?

A. Forrest Garb.

Q. So that's what's attached. That work product is what's referred to here and that's attached to Mr. Taylor's testimony. Is that what you're saying?

A. Those are the two that I'm aware of.

Q. On Page 6 --

A. Six of my testimony?

Q. Well, actually, before I go to that, Forrest A. Garb, do you know whether they provide the same type of services for NextEra and the other nonregulated affiliates?

A. I do not.

Q. You're unaware of whether they do or not?

A. Right. I never asked.

Q. Let me ask you questions about your knowledge. I'm not looking for information about the operating results of non-FPL affiliates that are in the investment and oil and gas reserves, and I'd like to see if I can come up with an agreement with you on a kind of convention.

There are functional equivalents of what would be GRCO, G-R-C-O, within the NextEra organization that would perform the same type of investment, nonoperating functions; is that right?

Is that your understanding?

A. To some extent. There are some significant differences in that they are engaged in deploying at-risk capital, so they buy and sell in and out of positions.

It's very different for FPL. We'll invest based on a set of facts in that position and we'll produce the properties throughout. So our commercial needs will be very different.

Q. What I'd like to do is ask you about what is OPC's third request for PODs, request number four, and it's an org chart for the FPL organization.

I have a few copies. I don't know if I'm going to make this an exhibit or not.

Do you have that document with you?

A. Yes, I do.

Q. Just if we could just walk through this real quickly, on Bates 14-649, which is the highest level of the org chart, you have NextEra Energy, Inc. and two of its subsidiaries are Florida Power & Light and NextEra Energy Capital Holdings.

Would you agree with that?

A. Yes.

Q. And if I go to chart B, I see that NextEra Energy Capital Holdings has a subsidiary called NextEra Energy Resources, LLC?

A. Yes.

Q. If I go to the reference Chart D, we see NextEra Energy Resources, LLC has a subsidiary called NextEra Energy Project Management, LLC, which I think from reading his testimony, that's where Mr. Taylor is housed.

Would you agree with that?

A. I don't know.

Q. But then I go and there's a NextEra Energy Power Marketing, LLC that has a subsidiary called USG Energy Gas Producer Holdings, LLC.

Do you see that?

A. I do.

Q. And then if I go to the reference chart F-2, I see that USG Energy Gas Producer Holdings, LLC has a subsidiary called WGSP Gas Producing, LLC, which has a subsidiary -- which has a subsidiary called USG Properties Woodford I, LLC.

Do you see that?

A. Yes, I do.

Q. Now, that last entity I read, that's what will become GRCO upon transfer; is that right?

A. Well, we're not buying stock in the entity. They could have other investments. We're taking those specific assets that we discussed.

Q. That's the entity that was referenced in the MOU and the DEA; is that right?

A. The holder of those assets. Again, we're not purchasing the entity.

Q. I understand, but that's the entity that --

A. Holds those assets.

Q. -- where you will transfer assets from, to FPL's created subsidiary?

A. That's correct.

Q. Regardless of what they do, would you agree that there are entities that perform similar, but not identical functions of oil and gas exploration investors that are not the ones listed on -- that we have identified here?

A. In addition to?

Q. Yes.

A. Yes.

Q. For instance, if I look to the next page on chart F-3, which is Bates 14667, there is something called USG Properties Woodford Holdings, LLC.

Do you know what's different about that entity than U.S. Gas Properties Woodford I, LLC?

A. No, I do not.

Q. If I refer to the NextEra subsidiaries that perform similar, although not identical functions to U.S. Gas Properties Woodford I, LLC as cousins in kind of the genealogy, would you understand what I'm talking about?

A. I'll try.

Q. So you would agree that NextEra is transferring some of the wells that are the subject of the Woodford Arkoma play in the area of mutual interest to FPL, but not all?

A. That's my understanding.

Q. So assumedly, the wells that are not transferred to FPL would be housed -- those assets would be housed in one of the cousins?

A. They may be in that same legal entity.

Q. But not all of what FPL is doing in oil and gas exploration holdings or gas reserves around the country would be done out of Woodford, right?

If I look on 14-666, there's a Bakken, a Barnett, an Eagle Ford, Haynesville. There are all kinds of entities out there?

A. Correct.

Q. So these entities, I assume, would be doing similar functions to what is going on at Woodford, right?

A. The gas infrastructure business involves midstream activities, gathering activities, which I guess is midstream, some pipeline work.

So generally speaking, yes.

Q. I just want to get it at a high level. I'm not asking you about what each of these subsidiaries does.

A. That's good. I can't answer that question.

Q. Page 6 -- let me step away from the cousins issue. I may come back to it. That was a predicate to some questions I'll ask you later.

Page 6 --

A. I'm sorry?

Q. I apologize, of the testimony, Line 20 -- let me check my notes here. Let me strike that question.

You have reference in your testimony that FPL would have a role as a non-operator in the joint venture with PetroQuest, have you not?

A. That would be our position.

Q. Would FPL have an ownership interest in the assets of the project?

MR. BUTLER: Charles, let me ask, just to be sure of your question, up until a couple of minutes ago you were pretty careful distinguishing GRCO or the sub from FPL. Are you referring to FPL sort of collectively, including the sub this point?

MR. REHWINKEL: That's a good clarification. I'm talking about FPL through the GRCO.

MR. BUTLER: So including that. It's the same for these questions?

MR. REHWINKEL: Right.

MR. MOYLE: Do or do not?

MR. BUTLER: Do not have to distinguish.

BY MR. REHWINKEL:

Q. My intention, and I'll try to be real careful about this, is when I ask you about FPL's investment, I'm talking about the GRCO affiliate, assuming that the transfer occurs.

A. Okay.

Q. So if the transfer occurs, will FPL have an ownership interest in the assets of the gas reserves project?

A. Right. The way this conveyance works is that we are assigned from the operator an undivided interest, in accordance with the percentages of this transaction, of each of the assets that they own.

Q. So if there was a bankruptcy or some other kind of a sale, if there was some distribution of the assets of the leasehold interest, whatever, FPL would have an ownership interest in those?

A. I don't know how to answer your bankruptcy question.

Q. Forget about the bankruptcy. What about if there was a distribution of these assets for whatever reason?

A. These assets give us -- well, some of these assets are real property, but most of these assets that we're paying for give us rights to produce in these properties.

Q. On Page 7, Lines 16 and 17, you state: "That plan calls for the drilling of additional wells before the end of 2014."

Do you see that?

A. I do.

Q. Can you tell me what the status of these additional wells is? Have they been drilled yet?

A. There's been -- we've received an AFE on the first -- well, it's my understanding there's only one rig and they have begun, but we have no completed well and no production yet.

I don't know what that means in terms of the end of the year. We were anticipating an estimate that we would have four producing wells by year-end and I don't know what the -- whether they'll be able to make up time or not. So --

Q. So you're saying that drilling is occurring right now with one rig?

A. It's not drilling, not production, but they are in the development process on this first well.

Q. Are you expecting that four wells will be drilled by the end of this year?

A. That's what I don't know the answer to, whether they will get all four producing.

Q. On Page 8, Line 19, can you just tell me what you mean by the term "the new Woodford project"?

A. U.S. Gas with PetroQuest had a predecessor transaction and as a part of that, of this new transaction, they have assigned certain of the unearned acreage rights to us. So that's what I'm referring to when I say "the new Woodford project."

It's the transaction that was effective in June of this year versus the original, which was in 2010.

Q. Can you tell me what you know about how USG and PetroQuest went about assigning the portions of the Woodford project acreage to what would become GRCO?

A. I don't know anything about their original transaction other than the working interest and rights that U.S. Gas had, because those -- they paid to carry in those original transactions when they were drilling in those 19 sections --

Q. "They" being who?

A. U.S. Gas. And because the new transaction carves out the undeveloped acreage and the probable acreage and assigns that to us, ultimately if the

Commission okays this transaction we had to reimburse U.S. Gas for that portion, the carry that was attributable to earning that acreage.

Q. Do you understand or do you know what the basis was for what got assigned to what would become GRCO and what was retained?

A. Yes. They are retaining the producing wells. So in each section there's a producing well, an approved undeveloped and not producing well, and a probable, and they've assigned all but the developed producing wells to us.

Q. Going back to the chart --

MR. REHWINKEL: Why don't we just give this an exhibit, John?

MR. BUTLER: Sure.

MR. REHWINKEL: The corporate org chart will be Exhibit 1.

(A document was marked as Exhibit 1.)

Q. So in Exhibit 1, going to 14-666, do you know whether FPL has a long range plan to utilize any of these, what I'll call "cousins", to find oil and gas reserves, to use similar transactions as the one that's the subject of the petition in this docket?

A. I do not.

Q. Do you know whether FPL has identified, assuming that the Woodford project is approved, what the next project would be that they would go after?

A. I do not.

Q. Would you know if there was such a plan?

A. I'm usually the last to know.

Q. Do you know whether USG Woodford or whatever entity of USG that retained the producing wells -- in other words, that would not be transferred to GRCO -- is an entity that has a DDA or a drilling and development agreement with PetroQuest?

A. I understood that they did prior to our agreement, yes.

Q. When you say "did", do they still?

A. I just don't know.

Q. So would you know whether the terms and conditions of that DDA are different from the DDA that is attached to Mr. Forrest's testimony?

A. I don't know. I don't know.

Q. So you couldn't testify as to whether the carry was the same or different?

A. I can't testify to it.

The carry is relevant in coming up with the net book value of the earned acreage, the carry on the original transaction. In the analysis that we performed at the final day of the testimony, the

$10 million earned acreage value, the dollars of carry are relevant in coming up with that $10 million value, but I don't know the percent of carry paid, if that's what you're asking me, and I certainly never read their agreement, don't have access to the agreement.

Q. So when you filed your testimony did you make any effort to understand what the carry would be on any other DDA that an FPL or NextEra cousin had with any developer --

A. No.

Q. -- including PetroQuest?

A. No.

Q. Can you tell me whether NextEra has a plan to make all of the gas reserve investment entities such as Woodford Property One and GRCO, if it's approved, to make them all structured and managed in the same way?

A. They can't be. The strategy is completely different.

Q. What do you mean by that?

A. We are trying to invest in properties where we believe we can lock in a low price for customers. We want to develop and produce to the end of the production life of those properties, transmit the natural gas here to our facilities.

That's not what U.S. Gas or any of these entities is in the business to do.

Q. Do you know whether it's FPL's plan to create a separate subsidiary for each gas reserve investment that you would make, assuming this petition is approved?

A. We have discussed that. From a legal perspective and from a tax planning perspective, that would be the optimal approach. That's why you see -- one of the reasons you see so many entities in NextEra.

Q. So for instance, if FPL were to do, hypothetically, the next play in Haynesville -- which I think is in the State of Louisiana, maybe a little bit in Texas -- would it be likely that that would be done by a separate subsidiary?

A. I don't know. We'd have to weigh the pros and cons.

MR. MOYLE: John, would you mind, the last answer before that one, she trailed off. I didn't hear it.

(The portion requested was read back by the reporter as above recorded.)

MR. MOYLE: Sorry.

MR. REHWINKEL: That's okay.

BY MR. REHWINKEL:

Q. So I'm looking on Page 11 of Lines 10 through 12 of your direct and the reason I asked for that is I'm looking on line 12, you used the plural "subsidiaries."

So is that kind of a presumptive, the way that you would do this?

A. Again, I mean, I understand there's a benefit to doing that. I think the more likely outcome for us might be an entity per state, but we would obviously -- we'd be weighing that based on the facts we have in front of us. So today it's just a hypothetical.

Q. Page 12, Lines 1 through 9, this is where you kind of describe where you get to the $52.8 million. That's part of the $68.2 million that you would reimburse USG for; is that right?

A. Yes.

Q. Has that number changed or would that number change at all?

A. It will likely be less, given the delay that we've experienced in the drilling program.

Q. Do you know, if you only drill one well out of four, what the difference would be?

A. Well, a well is approximately $5 million.

Q. So that would be a rule of thumb that one could rely on to kind of understand how that number might change, that 58.2?

A. Well, the 58.2 includes -- you know, I don't know. We haven't looked at that.

Q. Lines 11 and 12 -- actually, let me say Page 14. I apologize, let me strike that question.

Let's go back to Page 12. We'll go down to Lines 11 through 21. This is where you discuss that there was an allocation of interests to the FPL subsidiary, GRCO, and what USG would retain in the joint venture with PetroQuest.

Is that generally true?

A. Right, we're reimbursing them for the earned acreage.

Q. And there would be an allocation -- the producing wells they would keep, the other two categories go to GRCO; is that right?

A. Right. The idea being that the carry that they were paying while they were drilling was buying acreage over all properties. So we're just simply carving up the portion of the carry associated with the properties that we're going to purchase from U.S. Gas.

Q. And just so I understand, if I can ask the question this way, the retained wells or the wells that would stay in the NextEra/USG side of the fence, you're saying that the way those were allocated would not implicate the affiliate transaction rule.

Is that your testimony?

A. Right. These were costs they paid to a third party for participating. These are all third party costs that U.S. Gas paid.

Q. So what I want to know is, is there a possibility that the NextEra side of USG got a better allocation because the FPL side got a worse allocation?

This is a hypothetical. I'm just asking, is there a way that could have occurred?

A. You know, it's still not book value, so what we're trying to come up with here in a very logical way is the net book value of the properties that are going to be transferred to us. That's all we're doing. We're not applying a different method for transferring the value.

In terms of what they kept versus what -- you know, it made a lot of sense, the fact that they had producing wells that they were already, you know, earning revenue on and that had been depleted, to exclude those and to transfer the remaining acreage for us to develop.

I wasn't involved in the negotiations, but I think it was a logical way to carve this up.

Q. So you couldn't testify as to what exactly -- what the exact basis was for allocating the interest?

A. Well, I guess the other obvious reason is we want the production. So if we allocate producing wells to FPL, as you guys have seen on the depletion schedules, they produce very rapidly the first two years. It made a lot of sense.

These were 2010 investments. It made sense for us to have the undeveloped properties.

Q. Do you know when all of those wells, the producing wells, were drilled?

A. No, but I know the agreement originated in 2010.

Q. But they probably weren't drilling all the wells in 2010?

A. I do not know.

Q. We talked earlier about the independent accounting firm as the same one. You're down to two candidates or is this different?

A. No, no, no. We got Deloitte, that's our external auditor, performing these agreed procedures.

This is a one-time exercise. We just want to make sure there was not any concern on the part of any of the parties that we hadn't performed a proper calculation of net book value. So they're just affirming that through these procedures.

Q. Now, on Page 14, Lines 11 through 18, you discuss the Affiliate Transfer Rule or Rule 25-6.1351.

Do you see that?

A. Yes.

Q. Now, where did you get your understanding of the exemption for purchase of fuel and related transportation services?

A. From the rule.

Q. So does your interpretation assume that the Commission would agree with you that this transaction is eligible for recovery under the -- and the fuel costs, under this interpretation of the rule?

A. I haven't thought about it. I think it's so logical to transfer it to net book value. But yes, I think the Commission will ultimately agree that it should be recovered in the costs.

Q. If for whatever reason the Commission agreed that this transaction was appropriate to be included in base rates, would you say that the Affiliate

Transaction Rule still would exempt it?

MR. BUTLER: Charles, I'm going to note that that is a hypothetical circumstance that we have not offered to enter into, and our proposal is to have them approve the Fuel Clause recovery and if they don't, we're not going to go forward.

So just understand that you're posing a hypothetical.

MR. REHWINKEL: I'm just trying to understand the interpretation of the rule.

BY MR. REHWINKEL:

Q. So let me ask you this way. If for whatever reason the Commission were to allow this not under the Fuel Clause, but in base rates --

MR. BUTLER: And if we proceeded on that basis, right?

MR. REHWINKEL: That's correct.

Q. -- and if you proceeded, would you agree that there would not be an exemption from the affiliate transaction rule?

A. I would interpret it differently -- you're right, that provision that I pointed to would not apply. I would agree with you. I cannot imagine the Commission trying to apply the higher-lower rule to this transaction.

Q. As part of the work you did to prepare your testimony, did you make any inquiries about whether the basis for the transaction at issue here today would create any transfers of benefits or gain to FPL's or NextEra's nonregulated operations?

A. Well, certainly we explored very carefully the proper way to make the transfer.

Q. And that's because you did what you call net book value?

A. Yes.

Q. Page 15, Lines 1 through 2, what do you mean by "market price" in that sentence there?

A. Well, the whole notion of the structure is that we independently negotiated with PetroQuest. Both U.S. Gas looked at this transaction from the standpoint that they certainly were going to be entering into it and wanted to make sure it was a proper transaction for them to enter into. They knew they were going to provide us the option to take that transaction later, so we evaluated the reasonableness of this transaction from our customers' perspective.

Transferring at net book value puts us in exactly the same place as if we had been the original purchaser. So it's the cost of the assets less the depletion that occurred.

Q. What do you mean by "market"?

A. Well, that negotiation with PetroQuest determined a market price for this conveyance.

Q. So is the market there gas reserves?

A. It's the market for these rights and for the working interest that we have entered into, yes.

Q. The next line or lines down, four through seven, you use the term "quite generous", by saying there will not be any -- "USG will not be compensated for any gain in my result."

Is there a possibility that the converse will be true, that there could be a loss? For example, the market for gas reserves or the right to drill or right to -- would go down?

A. Right. So if you look at this from the standpoint of U.S. Gas as a counter party, they have entered into a transaction without any control over whether they're going to keep it or have to turn it over.

There's clearly a cost for them to provide that option to us and we certainly could have argued and structured an option cost that we would have loaded onto this transaction to reimburse them for, which in my view still would have been the cost of the transaction, and we didn't do that. That was provided without cost to FPL's customers.

So they're taking the risk. Now, how they've laid off that risk or if they have, I don't know.

Q. But if the transaction occurs and you step in their shoes and pay the net book value that you show and the market has declined from the time you agree to do that, the market value of these assets, in essence USG would not bear the risk of loss there, because FPL is right there and you pay on that net book value agreed at that time?

A. They didn't hedge it and they got lucky. You know, again, I don't know how they laid off that risk.

Q. Page 19, Lines 1 through 6 -- actually, Line 5, there is a reference to third party reserve engineers. Who is that? Is that --

A. That is a third party reserve.

Q. Is that what the reference is here?

A. I don't know that they would be the firm we would use in the future. They are a third party reserve engineer.

Q. So is this an entity that you are trying to take on or hire, like you're trying to do with the accounting and recordkeeping?

A. This is a one-time annual exercise, where they reevaluate the reserves for purposes of financial reporting in this case.

Q. So when you say one time, it occurs once a year?

A. Yeah.

Q. So it's recurring, the need for this service, right?

A. Right. When I said one time, I mean it's a one-time exercise, yeah.

Q. Now, would these entities also provide the same service for what I've referred to earlier as the cousins or these other --

A. They may, but that's what Dr. Taylor does.

Q. But Dr. Taylor works for NextEra, so he wouldn't --

A. Right, but you asked me about whether these folks would do it for the cousins. Dr. Taylor does it for the cousins. They may also do it for third parties, I don't know, but that's his skill set.

Q. Here's where I'm going with this. My question is, would there be a third party reserve engineering entity that would be providing services for the FPL subsidiary that would be the same as the function for the cousins?

A. That could be.

Q. Page 20, Lines 5 through 7, this is where you discuss for the first time, I think, the Sarbanes-Oxley process which you also refer to as SOX, all caps.

So these SOX processes, are there ones that you would do specific to FPL or would this be a NextEra process?

A. No, every entity has its own set of Sarbanes-Oxley processes and these would be specific for FPL.

Q. Why wouldn't these processes already be in place for the cousins, for example?

A. They have Sarbanes-Oxley processes.

Q. So would you just do the same ones for them or would they be different?

A. No, because there are differences. But we certainly have borrowed -- you know, certainly we're learning everything we can from them.

Q. Okay. On Page 20 and 21 at the bottom, starting on Line 19 and continuing on to Line 13 of Page 21, we're talking about you intend to contract with a firm, experienced firm specializing in oil and gas back office outsourcing.

What's the status of that?

A. I think we just discussed that.

Q. That's the one that you're down to two?

A. We're down to two firms and we are trying to finalize our decision.

Q. So they wouldn't provide any legal services through that entity. No legal services, right, through that entity?

A. No, no.

Q. Will there be dedicated FPL employees working on the gas reserves venture?

Initially I'm talking about the GRCO, but down the road also.

A. There will be a lot of folks working on this, obviously. The first time you do anything you apply a lot of resources to it.

We are not assigning in the accounting operation anyone full time to this. That's part of the beauty of being able to outsource some of the heavy duty lifting on the transactional side.

I do not believe that there is any plan today to assign or hire a GRCO employee. Whether that changes in the future, I don't know.

Q. Are there employees who are working in the NextEra organization who will allocate costs to GRCO? Is that part of the $300,000 that we talked about in

KO-5?

A. Right. They'll charge, hopefully, a direct charge of time spent to the extent necessary in support on the commercial side, yes.

Q. Do you know how many employees right now are charging time to this GRCO gas reserve petition venture?

A. No, we're absorbing the cost of this activity and U.S. Gas is not. Everybody is working on their own side of the transaction.

Q. At some point in time if you went down this, and if the Commission approves this, that time would all have to be removed from base rates and allocated to fuel costs?

A. Well, that time isn't in base rates. Take my time, for instance. I'm a base rate employee to the extent I work on GRCO, and I certainly will be if this goes forward. I'm not going to be charging GRCO, because it wouldn't be incremental, for one.

Q. It would or would not be?

A. It would not be incremental. My time is in the base rates. I was here at the last rates set.

So we just really don't have that issue. To the extent the EMT group through Sam Forrest relies on U.S. Gas, those folks aren't in our base rates, obviously. Those are folks that have nothing to do with FPL today and they would be charging them, because those would be incremental costs.

Q. On Page 23, Line 1 through 8, you talk about things we just touched upon here. You state that one of the tests for Order 14546 is whether these costs are again recognized in base rates, just generally; is that right?

A. Yes.

Q. And your testimony on Lines 6 through 8 is that there was "neither recognition nor anticipation of gas reserve project costs in the 2013 test year that formed the basis for FPL's current base rates"?

A. Correct.

Q. What do you mean by "neither recognition nor anticipation"?

A. To my knowledge, there was not even a strategy being thought about at the time. So there wasn't a plan.

Q. You testified earlier that NextEra and PetroQuest started working in Woodford together as a joint venture as early as 2010, right?

A. They may have been working together prior to that, but yes, I know of the one transaction that they entered into in 2010.

Q. Now, what is your basis for saying or what do you mean by "the 2013 test year that formed the basis for FPL's current basis rates"?
What do you mean by that?
A. Well, that was our last base rate final test year, 2013, so we were anticipating a forecast in the costs for that test year. That would be part of our base rates.
Q. Is it your testimony that the base rates were set based on the 2013 test year by the Commission in the order?
A. It formed the basis for the ultimate rate, yes.
Q. Even though it was a settlement?
A. Well, it's the basis upon which we settled.
Q. And it's your testimony that as of the time you prepared your testimony here that -- well, let me strike that and ask it this way.
Do you have knowledge that prior to the preparation of the MFRs -- which I think were filed on March 17th of 2012. Does that sound right?
A. Yes.
Q. No one in FPL or NextEra had any strategy or discussion or anticipation about engaging in this type of gas reserves venture that's the subject of your

petition?

A. Well, I clearly could not testify to that. I wouldn't know what might have been in somebody's head. But I'm intimately familiar with the MFRs and the forecast and there was never any discussion that I was a part of or any numbers in the MFRs that contemplated a gas reserve estimate.

Q. Do you know whether there were any other gas reserve projects that FPL contemplated prior to the filing of the petition in this docket?

A. Yes, we looked at another transaction.

Q. Just one prior?

A. There's only one that I'm aware of.

MR. REHWINKEL: Let's go off the record for a second.

(Discussion off the record.)

BY MR. REHWINKEL:

Q. All right. Let me ask you this question.

Do you know the proximity to the filing of this petition, which was done in late June, June 25th, to when you were looking at a different gas reserve?

A. March and April.

Q. Of 2014?

A. Uh-huh, yeah.

Q. All right. Page 23, Lines 12 through 13, you state, "This investment is solely intended to secure natural gas for the operation of FPL's generating plants."

Do you see that?

A. Yes, I do.

Q. Does that mean you're affirmatively testifying that none of the gas that FPL would receive from this venture would be sold or conveyed to anyone other than FPL for its use in generating gas?

A. I'm saying that's not the intent of the strategy. I think the commercial folks in Sam Forrest's team might have an opportunity to trade the position and if they did, that would fall under their, you know, asset-opting function.

You'd have to ask him about his intentions there, but that's clearly not why we developed the strategy.

Q. Did you say "asset-opting"?

A. That's what we call it in shorthand, but the strategy that came out of the settlement for --

Q. Asset optimization?

A. Yes.

Q. Okay. Page 25, Lines 13 through 21 -- I think I've asked you about this. You have developed a projection of costs to be incurred for the Woodford project using your best estimate of costs, etc. Will these numbers change based on kind of what you know now that will occur between now and the end of the year?

A. I think what I'm trying to say here is we'll file an update as per the cycle for fuel and we'll have a much better view of the actual costs at that time than we have today, or certainly than we had in June.

Q. Page 26, Lines 3 through 6 -- I'm really focused on Lines 5 and 6 -- you're saying, "The Commission auditors will have full access to FPL's and GRCO's books and records containing all the transactions recorded from the JIBs."

Do you see that?

A. Yes, I do.

Q. Is in joint interest billing?

A. Yes, we call them JIBs.

Q. All right. So is it your testimony that the Commission would not have access to any of the transactions behind the JIB? They wouldn't know what went into that, just what was on that and how you reported it on your books?

A. That JIB shows the transaction. It is an item-by-item, hundreds of pages of transactional information, and that's the actual cost incurred. There are overhead lines too coming from the operator, but that's the actual cost incurred for each line.

Q. They wouldn't know whether the overhead was allocated correctly?

A. There's an agreement as part of the DDA that specifies the operational allocations and as I understand it, it's typically -- there's a typical industry approach based on allocations.

Q. They would have the DDA to look at and they would have the numbers, but they wouldn't know whether the DDA was followed. They wouldn't be able to verify that, the staff auditors?

A. Well, they do -- they would do what we do, right. You've got a contract. You have activities that are being performed under that contract and you're being charged. You're on the phone daily with the operating folks. You know what's happening as they perform those operations, so you ask questions, you validate. You know, you use your layers of controls and you ascertain whether those costs are reasonable.

Now, in addition, just as we do on our undivided interests agreements, we have audit rights. So FPL will be able to go in and audit the operator.

That's commonly performed in this industry too. Every couple of years you go in and audit the JIBS.

Q. So would the staff auditors have access to your audit?

A. Yes, yes, they'd have access to the results of our audit performed.

Q. They would not be able to replicate the audit, do it themselves?

A. They would not be able to audit PetroQuest's books, just as they're not able to go audit Georgia Power's or JEA.

Q. Now, the Georgia Public Service Commission ostensibly has the ability to audit JEA, I mean share its books?

A. Sure. They're auditing those, I would imagine, from the standpoint of their customers, yes.

Q. KO-4, this is an example, a very simple example --

A. A textbook example of a JIB, yes.

Q. And what I see here in this example, this bill goes to Country Service Company and then you see there a percentage and then you see the total plot and their ability to see whether the math works out that you got a bill that's reflective of your percent, your enumerator percentage of the overall denominator, right?

A. That's what's shown on the summary page, right.

Q. Now, the document, the JIB that you got, in this simplified example this lists a handful of partners or investors, right?

A. Yeah.

Q. Would FPL's JIB show everybody that has an interest? Would you be able to see who they were?

A. It's my understanding.

Q. And staff would be able to see who they were?

A. Staff is going to have access to review the JIB, certainly. It's our invoice from our operator.

Q. Right. Page 26, Line 20, tell me what you mean by the phrase "removed from rate base."

A. The phrase "will be removed from FPL's rate base in the ESR?

Q. Yes.

A. So when we do base rate setting or prepare our earnings surveillance reports, we start with consolidated FPL results and then we make adjustments, and those adjustments are identical to what's been ordered by the Commission in the last rate filing.

So we'll adjust out quip that's earning A, B, C, we'll adjust out the special funds for the trust assets associated with the large decommissioning trust, and we'll adjust out any investment or expense or other revenue activity that is related to cost.

So that's what we're talking about here, because this would be costs recoverable. The financial results associated with GRCO would be pulled out for base rate-making.

Now, that's limited, of course, to the non -- the items that are not part of capital structure.

Q. I think you're going to record this investment partially in 123.1, that investment in subsidiaries?

A. Are you asking me on FPL's books?

Q. Yes.

A. It will be rolled up and recorded when you look at just FPL unconsolidated as equity investment subs and earnings in subs, along with the intercompany notes payable. But that's not where rate-making starts or where the ESR starts.

It starts with consolidated FPL, which will show every line item of FPL parent and GRCO in a consolidated basis.

Q. Okay. So account 123.1, is that generally allowed to be included in rate base for purposes of setting base rates or earning surveillance calculations?

A. No, because we don't have that account on a consolidated basis.

Q. Is it generally considered allowable for base rates?

You're saying it's not because you just don't have it or is investment subsidiaries considered as an account that the Commission usually utilizes to set rates upon?

A. I think the confusion on this is between what FERC does and what our Commission does in Florida.

FERC mandates that you have to file your FERC form on a consolidated basis and their premise for that is that the subsidiary activity will not be a part of the electric or gas utility operation. That's not always the case, but that's their premise.

So they start their rate-making from that unconsolidated view. You may have to add in dollars from a consolidated basis, but that's not what it's based on. Our Commission starts from a consolidated financial statement.

Our subsidiaries are all a part of FPL regulated operations, including GRCO. There's no reason to begin to separate on an unconsolidated basis. So the reporting of activity in those accounts that we just talked about is just not relevant to our rate-making or our ESR process.

Q. So are you presuming that GRCO would be regulated above line operations for purposes of including it where you do; you're just transferring it from base rates to clause?

A. That's correct.

Q. Did you do any research or look at any Commission order that said that account 123.1 was an appropriate account for purposes of setting base rates?

A. No.

Q. Let's just look at the memorandum of understanding, KO-1, real quick.

Did you have any responsibility for the preparation of this document?

A. I reviewed it.

Q. Before it was signed?

A. Yes.

Q. At the time you reviewed it and prepared it did you understand what all of the various mineral interests are in Paragraph A?

MR. BUTLER: Sorry, I'm going to object to the form of question. You said the time she reviewed it and prepaid it. I think the testimony was she just reviewed it.

BY MR. REHWINKEL:

Q. Let me rephrase that.

At the time that you reviewed this prior to its reparation, did you understand what the mineral interests are in kind of the second half of Paragraph A?

A. I think generally, yes.

Q. Do you know what a mineral servitude is?

A. I don't see that -- oh, I can't define it for you, no.

Q. What about farm-out right?

A. I have read about that. I can't -- I can't recall the exact definition, but I have read about farm-outs.

Q. And then Paragraph C on the third line there, it talks about the earliest negotiations of the project documents. Do you know what that time frame is?

A. No, I don't know how early that might have been.

Q. Paragraph E, Subsection D on the next page, you see that paragraph?

A. Are you on D, "D" as in David?

Q. E, D.

A. Okay.

Q. There's a reference to "USG Woodford shall bear all of the costs and is entitled to all of the benefits resulting from any hedges put in place by USG Woodford for gas extracted from the wells."

Can you explain what is meant there or discussed there about with regard to hedges?

A. Well, that's what we were talking about earlier. I didn't know it, and they may or may not have laid on hedges to try to protect them from the risk of the value increasing versus dropping, etc.

So they may have hedged the risk, not knowing the timing or whether or not they'd be conveying the assets to us.

Q. So you don't know whether they did or not?

A. I don't. It's not relevant to FPL's purchase.

Q. Let's go to your rebuttal testimony, please. On Page 4, Lines 21 and 22, is your testimony here that -- actually, lines 19 through 22 -- that with respect to accounting for this, is that FPL's primary goal is to ensure that one hundred percent of the costs that are invested are recovered from the customers?

A. Well, in this section I'm talking about my concern and the assurance that I'm providing that we will be able to effectively control the costs, report the costs, and ensure that our actual costs are what makes up the ultimate rate.

Q. Page 5, Line 19, what is your definition of "robust industry standard controls"?

A. Well, the construct of the billing process for these undivided interests is such that there are -- there's just massive amounts of transactional data, and so the industry has evolved and I don't know for how long, probably forever, into this process of being able to transmit information electronically from operators to non-operators. They have a very standardized set of processes.

The firms and you know, the active effective efficient operation that operators have of very robust, meaning good dynamic controls in place that allow them to properly manage and report on the significant amount of transactional data.

It's also a very dynamic business, the

drilling process. It's a lot less dynamic when you're in production, but while you're drilling it's pretty dynamic. So the controls have to work to ensure that we have financial reporting that is reasonable, and that's what I'm referring to.

Q. Can you turn to Page 6. I want to ask you about Lines 11 through 16, and on Line 13 you have a phrase "utility rate base."

What is your definition of "utility rate base"?

A. Utility rate bases are investments, assets used on behalf of customers, typically covered through rates on that basis.

Q. What is the utility that you're referring to there?

A. Well, I'm using it there, you know, in a generic sense, but it's us, it's FPL.

Q. All right. You say that you are rebutting Witness Ramas here, right?

A. That's correct.

Q. And you say on Lines 1 through 4 on Page 10 that, "She says because the Exhibit KO-6 identifies the project as investments instead of plant and service, they do not qualify for utility rate base."

Do you see that?

A. Yes, I do.

Q. Can you show me where she says that?

A. Page 10, Lines 1 through 4. It's the end of a sentence that begins on Page 9.

"Similarly, the sample fuel and purchase power recovery cost schedule provided by FPL in Exhibit KO-6 identifies the projects as investments -- identifies the projects as investments, not as plant and service items.

"The investments in the projects proposed by FPL or its subsidiary are not for plant in-service items that would qualify for rate base. Rather, they would be for investments in a highly competitive industry."

Q. Now, is she referring to electric utility rate base or gas utility rate base? What is your understanding there?

A. My understanding is the titling that I used on my schedule somehow disqualified this for recovery as utility rate base. She doesn't specify whether she's talking about electric or gas.

Q. What do you mean by "utility rate base" when you use it?

A. Well, there's utility rate base for gas and electric utilities.

Q. Is FPL an electric utility or a gas utility?
A. It's an electric utility.
Q. Is FPL authorized to sell gas to the public for higher --
A. I'm sorry?
Q. Is FPL authorized to sell natural gas to the public for higher compensation?
A. No.
Q. Do FPL franchise agreements authorize them to sell natural gas?
A. No.
Q. On Page 6, Line 18, through Page 7, Line 10, this is -- you reference the Care project and the emission control equipment, right?
A. Yes.
Q. Now, are the Care assets that you reference there, are those actual pieces of equipment, tangible pieces of equipment that FPL owns?
A. I believe so.
Q. Does the investment that you propose in GRCO constitute an investment in tangible equipment?
A. Some is.
Q. Such as?
A. Well, there's compressors and pipes and pumps and cars and roads that are built; you know, all

sorts of true tangible equipment.

Q. And FPL would own those?

A. An undivided interest, that's correct.

Q. Are all of the investments represented tangible pieces of equipment?

A. No. Some of the investments represent our rights to access and to ownership of our working interest of those.

Q. Do you know what the percentage of tangible pieces of equipment are to overall investment?

A. No.

Q. Are there any -- anything in the Care assets that are not represented by ownership interest in tangible assets?

A. I don't know. We certainly have rate base. The utility has rate base that's not a tangible asset. It's on our books and records.

Q. With respect to the Care assets?

A. I don't know.

Q. Page 7, Line 19, you use the phrase, "In accordance with GAAP and the Securities and Exchange Commission, SEC requirements".

What do you mean by that, the word "requirements"?

A. Well, we're a public filer, so our financial statements as filed have to be consistent with Generally Accepted Accounting Principles, which is what the SEC requires. So that's what I mean by that.

Q. Is it your testimony that the Successful Efforts method of accounting is required by the SEC for your operation of the GRCO?

A. I think in our circumstance it would be the proper method to utilize.

Q. I guess that wasn't my question. Is it required?

A. If the Commission would order us to use full cost, we would have to seek -- well, we'd have a number of issues. We'd have to seek preferability. So we'd have to have Deloitte support us in seeking a preferability letter to be filed, and then we'd have the problem and I don't know how we'd resolve that, of having to consolidate across the entities.

It's important to note that for us, these differences are completely immaterial based on the transaction we have today, completely immaterial.

MR. BUTLER: I'm sorry, for the record, you're saying "immaterial," right?

THE WITNESS: Immaterial.

MR. REHWINKEL: That's how I heard it. It might not have been --

BY MR. REHWINKEL:

Q. Is it FPL's position or is it your testimony, I guess I should first ask, that the Commission rules allow use you to use the FERC USOA for natural gas companies?

A. You were looking at my testimony, so --

Q. Is it your testimony that the -- let me strike that.

Is it FPL's position that the Commission's rules allow FPL to use the FERC USOA for natural gas companies in recording your costs on your books for rate-making purposes?

A. I think it can, yes.

Q. How so?

A. Well, that's what we've proposed.

Q. So it's your position that the rules allow you to use the natural gas USOA?

A. The rules don't contemplate -- clearly the rules don't contemplate an electric utility investing in a gas development production. That's clear. So we're trying to take all the rules that are important for us to manage, be it SEC, generally accepted accounting rules, and we're trying to find the right fit, and I think we've done a good job of doing so.

Q. Page 9, Line 11, what is your definition of "reasonable" there?

A. Accountants don't use the word "accurate." We use the word "reasonable," and that's because when you account for hundreds of thousands, if not millions of transactions, invariably there's little stuff that goes wrong, and so "reasonable" means applying the right level of resources to get a result that's reasonably accurate, and that's what we aim to do and we are able to do.

Q. Is included in that definition that there are no improper transfers of benefits to nonregulated affiliates? Is that subsumed in the term "reasonable"?

A. Well, absolutely. The rates are going to be based on their rules and requirements, and those include affiliate transaction rules and requirements, that's correct.

MR. MOYLE: That was Page 9?

MR. REHWINKEL: That was Page 9, Line 11, of the rebuttal.

BY MR. REHWINKEL:

Q. Page 9, Line 22, what is your definition of "actual costs"?

A. The costs we've recorded. The costs we've recorded in the financials should be the basis for the costs in the bills, that's correct.

Q. Page 10, Line 1, is it your testimony that the staff auditors would -- should use sampling to audit this transaction, the Woodford transaction, the very first time?

A. That's the approach that auditors typically have to use, because the numbers of transactions are quite voluminous.

Q. Would it be voluminous in this case?

A. Yes. The 38 wells will have thousands of transactions associated with them, yes.

Q. So are you expecting all 38 wells to be in place by the end of 2015?

A. I believe we intend to complete the drilling part by the end of 2015. Whether that's the case or not, I'm not certain.

Q. I think we've covered this, but on Line 20 and 21 of Page 11, you reference "vendors and joint venture partners that the staff would" -- I mean, your external auditors would be able to sample and agree on invoices from those entities.

Who are you referring to there? First of all, PetroQuest I guess is one. That's the joint venture partner, right?

A. I think this is a generic statement, right.

Q. But in this example PetroQuest would be the joint venture partner?

A. That's correct.

Q. The JIB would come from them, right?

A. That's correct.

Q. And then the vendors would be --

A. The third party consultant that you've asked us about, the reserve engineer.

Again, I was making the statement generically, not specifically.

Q. I understand.

On Page 12, Lines 3 through 6, this is another one. The question there, it says:

"Do you agree with OPC Witness Ramas' conclusion on Page 20, Lines 12 through 15 of her testimony, that because the Commission would have no ability to audit PetroQuest, it does not have jurisdiction over FPL gas reserve activity?"

Do you see that?

A. Yes.

Q. Can you show me where you get that from her testimony?

A. Beginning with the fact that the Commission -- this question goes to, "Would the Commission be able to audit PetroQuest or similar joint venture operators."

She states "no", and then on Line 12 she says, "The fact that the Commission would have no authority to audit the entity incurring the joint venture cost that would travel through the fuel costs recovery clause is relevant to OPC's position that these ventures fall outside of the Commission's regulatory purview."

Q. Now, is she saying because they wouldn't have to audit, they don't have jurisdiction?

A. That's the way I read it.

Q. She used the word "relevant," doesn't she?

A. Yes.

Q. Do you consider yourself an expert on Accounting Standard Classification or ASC 932?

A. No.

Q. Would you consider yourself an expert on the Successful Efforts method of accounting provided for in ASC 932?

A. No.

Q. Can you tell me what's your understanding of the differences between the Successful Efforts method of accounting that you intend to use and the full cost method of accounting provided for in ASC 932?

A. Yes. Generally speaking, the Successful

Efforts method is -- I would describe it as more conservative, that the costs of exploration are charged directly to the income statement; whereas in full cost virtually all the activities are capitalized and then there's a ceiling test with specific requirements that's applied to test for impairment.

So you put the vast majority of your costs on the balance sheet as a full cost company and then you only remove them from the balance sheet if you have impairment of the assets or unsuccessful wells drilled.

This is a more conservative method, which should be beneficial to customers.

Q. When you say "this", I think you mean Successful Efforts?

A. Yes.

Q. Now, you're proposing that your investment in the gas reserves be afforded cost of service treatment through inclusion in the Fuel Clause, right?

A. That's correct.

Q. Under the Successful Efforts method of accounting, if an exploratory well is drilled and approved resources are not found, how would the costs associated with that exploratory work be accounted for?

A. They would be expensed.

Q. And I think you just answered this, but if under -- well, strike that.

How would that expense under that scenario that I just asked you about, if you incurred it, how would that be recorded in the Fuel Clause?

A. How would it be recorded?

Q. How would it be submitted for recovery? Would you submit it in that period?

A. Yes, I mean, our rates as we set them today, certainly fuel costs are based on our actual costs incurred, unless the Commission orders differently. So it would be included in the period in which it was written off.

Again, recall that they're talking about $5 million. A well, it's not like an electric power plant.

Q. If such costs associated with unsuccessful wells are included in the expense and the Fuel Clause, would that cause the amount of expense associated with the Woodford project to be higher in those periods than you would otherwise expect?

A. Yes. If you wrote off the entire cost of the well in one period before there was any production, then you would be expensing that quicker than you would through depreciation.

Q. Would there be an offset in another period if you expensed those well costs on an unsuccessful well? Would there be an offset?

A. Well, you're not going to have future depletion. You've essentially written off the cost of the well.

Q. So the depletion that you would project at the time you presented a gas reserve investment to the Commission, it wouldn't occur --

A. That's correct.

Q. -- so there would be somewhat of a tradeoff?

A. Timing, yes.

Q. We talked earlier about your plan to use the FERC USOA natural gas chart of accounts in your consolidated financial statements; is that right?

A. On a condensed basis, yes.

Q. On the GRCO subsidiary, however, they will be recorded not on that basis, on the natural gas USOA chart of accounts, but in the natural gas industry standard basis; is that right?

A. Well, the extracted industry oil and gas petroleum industry standard basis, yes. In the detailed ledger, yes.

Q. And then as you state on Page 5 of your rebuttal, you will map the industry standard cost recording on your subsidiary's books to the USOA, the FERC USOA natural gas condensed chart of accounts on your consolidated financial statements, correct?

A. That's right.

Q. If you do that, is it your position that the mapped amounts will be fully compliant with the detailed accounting instructions provided for in FERC's natural gas uniform system of accounts?

A. No. We've explained that we are going to use a condensed chart of accounts and that there are some instructions in the natural gas chart of accounts that are simply not applicable, and I think we gave some examples of that in discovery.

So what we're attempting to do is, you know, meet all requirements, obviously. We're talking about recording the detailed transactions in the subsidiary ledger, mapping those to a condensed version, the high level accounts, on the natural gas chart of accounts for purposes of consolidating those with FPL all else.

Q. Can you tell me what factors cause there to be that lack of compliance?

A. Well, the FERC natural gas chart of accounts certainly recognized that some of these natural gas distribution pipeline companies would invest in reserving. You see the accounts there for reserve investments. They acknowledge some version of full cost, but it's just simply not -- I'll describe it as not kept up with the Generally Accepted Accounting Principles there today.

It may not be odd to someone in the natural gas LDC business, but there are some provisions in there that call for you to account for things in a certain way, depending on the timing of the investments that you've made that just aren't applicable to us.

I think we're able to provide the essence of the compliance. You know, align these appropriately with the accounts that the Commission and other parties would be used to seeing. It will look more familiar than something in the industry standard, but still be able to talk to our operator, as it were, in terms of transacting the data.

THE COURT REPORTER: Do you think we could take a break?

MR. REHWINKEL: I think we're doing goo on time. Let's do ten.

(Whereupon a recess was taken.)

BY MR. REHWINKEL:

Q. Interrogatory 95, do you have that in front of you?

A. Yes.

Q. You give one example of a difference between the Successful Efforts Method of Accounting and the natural gas USOA, right?

A. No, I don't think I'm talking about Successful Efforts, am I? I think this whole question goes to --

Q. I'm sorry, the industry standard -- I apologize, the industry standard versus the USOA for natural gas?

A. Yes.

Q. Can you tell me beyond this account 105.1, what the others are that you're aware of, the other differences?

A. Well, I mentioned in the previous answer that there's a whole section on -- give me a minute.

Q. Sure.

A. The gas plan instructions in -- well, the gas plan instructions in Item 1C talk about when you have a purchaser conveyance, that you've got to record that at original cost.

We're very familiar with that on the

electric side, right, because the notion is that the regulator wants to ensure that if properties have already been dedicated to public use, that you're not stepping up the basis.

Well, that notion is carried over to the natural gas chart of accounts. Clearly, when we do a purchase or a conveyance, a transaction with another counter party, we're not going to apply these rules. We're not going to search out whether or not, you know, we can ascertain -- I'm sure we can never be able to anyway -- what the original cost of that mineral right is or that leasehold or whatever it is.

So those -- the application of those instructions simply doesn't apply. We're not going to record AFPC on these. There's a whole section, obviously, on AFPC.

You know, if you go through, you just see the detailed accounts call for you to break out, you know, the land rights separate from some of the tangible property, whereas for GAAP purposes or transactional purposes, really, those well costs are all treated similarly. Other than for tax reasons you have tangible and intangible.

So, you know, my notion on this is that we should use the structure. It's a structure that makes sense at the highest level. We should rely and conform to the GAAP standards, because that's the basis on which our books and records really fundamentally have to be recorded.

The Commission, I think, enjoys having rates anchored to what's proper from a GAAP perspective, and then we can try to bridge the gap. There are certainly going to be some instructions here that just aren't going to be applicable.

Q. Are those all the differences that you've listed?

A. Those are a few that I could find right away as I went through here. I have not diagrammed everything.

In fact, in accounting for a business you turn back to your chart of accounts all the time and you find that you may need a new account or there may be a distinction or assessment you have to make.

It's not something that I would even be able to tell you today I know every single difference that might arise.

Q. So the mapping that we've discussed that's in your testimony, is it your testimony that will only be done for the purposes of presenting FPL's consolidated financial statements?

A. The mapping is what we will do to bridge the gap from the subsidiary detailed ledger to our SAP ledger, and from that ledger we can report on a consolidated or on an unconsolidated basis.

Q. Well, do you have Interrogatory 95 with you? Am I incorrect in reading there that you won't be using the mapping for the standalone accounts for FPL?

A. It's not that we won't use the mapping. It's that we were pointing out that all of the detail gets collapsed for unconsolidated purposes into those three accounts. So it's not that the mapping won't apply.

I know this is probably difficult, because it's conceptual to you and it's very practical to me, but we use mapping in financial statements all the time. The audit staff is quite familiar with it, because our financials are reported in SAP natural accounts that have nothing to do with the electric USOA. Then there's configuration that maps or links it to the USOA for FERC. We're just trying to replicate that here in a subledger.

I mean, folks that have to do this for a living are pretty familiar with the configuration, what we call "mapping" and the linkage between accounts. It allows you to record a transaction one time, but report it in many different ways. That's the beauty of financial accounting systems.

Q. Okay. What is the source for what you call the FERC natural gas condensed chart of accounts?

A. The USOA.

Q. Who came up with the condensation or the condensing of that? Is that something that FPL devised?

A. Well, I mean, the simple way to think of it is FERC devised it, because they have their top level hierarchy and then below that they have these planned accounts and detailed operating accounts, and we said we're going to have all the transactions at the detailed level.

No one would -- it would be inefficient and costly to replicate all those in the detail in the SAP FERC ledger, so we'll use the higher level portion of the chart of accounts.

Q. Does FERC authorize any utility to use the condensed version that you use?

A. I am sure that every natural gas company that's regulated under the Federal Power Act has to use those accounts, has to use all those accounts.

Q. Not just at the condensed level?

A. I would imagine they would be required to use all of those.

Q. Okay. Has the Florida Public Service Commission, to your knowledge, ever authorized a natural gas utility that it regulates to use just the condensed chart of accounts?

A. Not to my knowledge.

Q. As proposed, will FPL be the one that makes the decision about what level of condensation, if you will, of the chart of accounts are used?

A. We make those decisions every day.

Q. So the answer is yes?

A. Yes.

Q. Okay. Back on Interrogatory 95, you indicate that with the mapping, account 105.1, "plant held for future use will be reviewed for wells that have not yet been proved"; is that right?

A. That's right.

Q. Would the amount mapped by the company to gas plant held for future use for wells that have not been proved be included in the capital cost to which FPL would apply a return in the fuel cost recovery clause calculations?

A. Yes, it would.

Q. Is there a limit, to your knowledge, on how long a well could be recorded in the unproved -- be identified as unproved and remain in gas plant held for future use?

A. State the question for me one more time, please.

Q. Is there a limit on how long a well could be identified as unproved and also remain in gas plant held for future use?

A. I think there is in the FERC USOA, yes. It applies a restriction similar to what I think it applies in the electric chart of accounts.

Q. And what is that, do you know?

A. We can look it up.

Q. And as a corollary to that I want to ask you, is that what you intend to apply for purposes of accounting for cost recovery and the cost for such wells, if there are any?

A. Here again it says, "This includes production properties related to leases acquired on or before October 7, 1969."

It goes on --

MR. MOYLE: Do you mind identifying the document you're referencing?

THE WITNESS: It's just the balance sheet account number 105, gas plant held for future use. I have a copy of that portion of the

Uniform System of Accounts Part 201.

MR. MOYLE: Thank you.

THE WITNESS: I do not -- wait, it goes on.

No, it does not appear to have an absolute bright line. It just says "The original cost of gas plant owned" -- again, excluding land and land rights -- "owned and held for future use under a definite plan," and then it goes on and on about what you do for planned changes.

BY MR. REHWINKEL:

Q. Is FPL presenting any time constraint or a definite plan?

A. No, but typically what controls your timing to have to develop these properties are the leases that you have with the leaseholders and you know, they don't hold those leases open for you indefinitely. As I understand it, you know, each lease could have a different time before that lease might expire.

So we are contractually obligated to move under certain periods of time to develop the properties.

Q. So would it be the primary term of the lease or the secondary term of the lease that governed this?

A. I don't know what you mean by the "primary term" or the "secondary term."

Q. Okay. Let's look at KO-3. As I understand it, this is an estimate of a purchase accounting entry that would be made by FPL's subsidiary at the time it obtains the Woodford property ownership interest in the GRCO subsidiary, right?

A. That's correct.

Q. And it shows that as of the date of the acquisition, the amount you would record in account 221, unproved property in acquisition, would be $23 million, right?

A. 211 is unproved.

Q. 211, I apologize, yes.

But that's the amount you would record?

A. That was our estimate, yes.

Q. Can you tell me what FERC natural gas USOA account 221 would be mapped to by FPL in preparing its consolidated financial statement?

A. Are you asking about 221 or 211?

Q. 211, I apologize.

A. It's 105. Yes, just as we've shown on KO-7, we show it as 105.1.

Q. Right.

A. Who knows what --

Q. And just, I think, to confirm an answer you gave earlier, the mapping of those dollars to 105.1

would mean they would be included in their return calculation, the fuel cost recovery?

A. That's correct.

Q. Can you tell me by what date FPL will know if all of the amounts included in the $23 million for unproved property acquisition costs will be determined to be proved?

A. Well, our drilling plan, which you asked me about earlier, calls for all drilling to be complete next year.

Q. So is it your testimony at this time that you expect to know whether that $23 million number stays that way or changes by the end of 2015?

A. It was my testimony -- if I misunderstood the question, I apologize -- that the drilling program is contemplated to be completed within approximately a year, a little over a year. We'll know at that point whether or not -- we will have drilled and re-classed that property to 101.

Q. Is it possible that some portion of that $23 million or the investments associated with that $23 million could remain in unproved property acquisition costs for more than a year?

A. Yes.

Q. Do you know how long?

A. No.

Q. Would that be again a function of the lease?

A. Well, what's driving the timing of the drilling is the ability of the operator to get the rigs out there and to perform the drilling. So obviously, it's a complicated business.

We're intent on trying to get these wells drilled. If we're unable to, then the lease would come into play in terms of how long we have access to those properties.

Q. So just so -- I think this is a truism, but while a well or the investment associated with a well remains in this unproved property acquisition cost category, obviously you would be receiving no natural gas from that well, right?

A. That's true.

Q. But FPL would receive a return on these dollars, regardless of whether they were producing natural gas?

A. Just as we do on the electric side of the business with property held for future use.

Q. Under the Successful Efforts method of accounting, if a well had previously not been proved -- under the Successful Efforts Method of Accounting, if a well that had previously not yet been proved is determined to not have recoverable gas reserves, how is this determination accounted for?

A. It's written off, charged to expense.

Q. Are any capital costs incurred associated with that well expense?

A. Yes.

Q. And the Fuel Cost Recovery Clause -- I think you've already answered this, but just to be sure -- under this example or this situation, those expenses would be accounted for in the fuel cost recovery account?

A. It would be charged to expense.

Q. For that period?

A. The period that it had been recognized that it was not going to be able to be developed.

Q. How many wells that would have been transferred to the FPL subsidiary from USG have been drilled as of today?

A. I understand they're in the process of drilling the first well. Sam would be able to tell you, I'm sure, a lot more current information about that.

Q. Do you know whether any of the wells that are -- for which exploratory drilling have been completed in the AMI, have turned out to be unsuccessful or not proved?

A. In this I think they have all been successfully drilled. This is the 19 producing wells that U.S. Gas has retained.

Q. If there was to be a well that was drilled and turned out to be dry or non-proved, would that have to be disclosed at some level?

A. Are you talking about to our investors?

Q. Yes.

A. No, it's $5 million.

Q. On Page 8 of your direct, let's go back to that for a second, you reference a $122.4 million number?

A. I'm sorry, I'm not there yet.

Q. All right.

A. Page 8 where?

MR. BUTLER: Line 6.

THE WITNESS: Thank you, John.

BY MR. REHWINKEL:

Q. Is that number still a good number? Has that been revised in any way?

A. I don't have a revised number.

Q. Do you expect that it will be revised?

A. It could end up being exactly that, because that's the amount of the drilling costs that will take place -- oh, no, I'm sorry. I'm thinking about the total potentially being exactly the same. The carve-out of the two may change.

I can't answer the question, I'm sorry.

Q. But sitting here today, you have no information one way or the other whether it will go up, go down, or stay the same?

A. No, I don't.

Q. Do you know whether FPL's estimated cost savings to customers over the duration of the Woodford project assumes that one hundred percent of the wells drilled under the agreement are successful and end up having proved reserves?

A. Please repeat the question.

Q. Is it true that under your estimated cost savings calculation for customers over the duration of the Woodford project, that you assume that one hundred percent of the wells drilled under the agreement are successful and end up having proved reserves?

MR. BUTLER: You're referring to cost savings. Are you talking about a document that she produced?

MR. REHWINKEL: No.

A. I shouldn't even attempt to answer that question.

Q. You don't know?

A. I don't know.

Q. If your proposal is approved, is it your testimony that the Commission will regulate GRCO or whatever the subsidiary's name is, for which the investment is being made?

A. I think you said is it my --

Q. Is it FPL's position that the Florida Public Service Commission would regulate the subsidiary, which is GRCO right now?

A. It's my position that the Commission would regulate the recovery of costs through GRCO's activities as a non-operator in the drilling of those reserves.

Q. What do you mean by "regulate the costs"?

A. Well, GRCO is a regulated entity for purposes of cost recovery and rates. So I think of it from a financial reporting perspective as fully regulated by the Florida Public Service Commission.

The activities of GRCO, though, through the operator are regulated by all sorts of layers of regulation that take place in the petroleum industry. I don't think the Florida Public Service Commission is going to go regulate the operations of that joint venture.

Q. Is it because they wouldn't have the authority to?

A. I don't know.

Q. So you're saying that other than for providing cost recovery assumedly through the fuel costs, the Florida Public Service Commission would have no regulatory oversight over GRCO and whatever clone of that were developed down the road?

A. It's too broad of a question.

You know, the activities associated with FPL undertaking this gas reserve strategy on behalf of its customers and the rates -- the costs and rates that would result from that would be fully regulated by this Commission.

We are asking them for permission to approve a strategy, but the activities of the operator are not regulated by the Florida Public Service Commission.

Q. Do you know what it means for a well to be shut in?

A. No, I don't.

Q. Is it your understanding that FPL could -- well, that the joint venture could successfully drill a well and then close it for a period of time? In other words, stop production, cap it?

A. I imagine it can be ordered to stop production. I imagine, yes. I mean, there could be circumstances.

I would agree with you, there could be circumstances where drilling would begin and then stopped. I understand that to be unusual in this case.

Q. If such a circumstance were to happen -- and this is merely a hypothetical. I think you're not planning on it to happen -- but if it did happen under Successful Efforts method of accounting, what would happen?

A. I think it depends on the exact circumstances of the cessation of production.

Q. What is one possible outcome for accounting?

A. Well, if it stops completely, you'd be writing off the cost. If production is held in abeyance for some period because something technical occurred, then there would just be reduced depletion.

So in our case, reduced depletion expense, because you'd have output that would stop. Presumably your capital spending during drilling would stop too. But I mean it's a hypothetical. I'm struggling to understand.

Q. Well, let's just say there was a well and you had spent $5 million on the well and it was producing and then it was stopped. So you'd have $5 million assumedly that would be mapped somehow to --

A. 101, account 101, because it would be in production. That would be a hypothetical.

Q. But it would earn a return, would it not?

A. Uh-huh, yes.

Q. So as long as it wasn't determined that it was written off or production was permanently ceased, but the assumption was that it would be temporarily over some period shut down, capped, whatever the word is, it wouldn't be producing, but the return would be earned on that $5 million?

A. That's correct, similar -- very analogous to what happens in the electric industry when you have an outage of a plant.

Q. And depletion would not accrue against it, if you will. In other words, so the net book value, in rough terms, would not decline during that period?

A. That's correct. Because you don't have production, you wouldn't have a return.

Q. Do you know what shut-in royalties are?

A. No.

MR. REHWINKEL: That's all I have. Thank

you very much for your time.

THE WITNESS: You're welcome.

MR. REHWINKEL: Whoever is next.

CROSS EXAMINATION

BY MS. BARRERA:

Q. Hi, I'm Martha Barrera, and I only have a few questions for you.

Could you please refer to Page 9, Lines 11 through 14 of your direct testimony?

A. Yes, I'm there.

Q. And this has to do with the tax obligations.

In your opinion, would FPL's proposed legal structure to establish a subsidiary allow maximum flexibility to minimize state tax obligations?

A. That's correct.

Q. And can you explain how that would be accomplished?

A. Yes. The ability to produce benefits using the strategy would depend on the state, and as we've analyzed Oklahoma, we would likely be in the same situation in terms of our state taxation obligation with or without the sub.

But we didn't want to forego proposing it here, because if we enter into transactions in other states, it would be beneficial, and the way it would work is that if we have a separate subsidiary, separate legal entity as an LLC, our tax planning folks can determine based on apportionment factors, which means --

MR. MOYLE: Charles, we would note for the record we can't hear because of the helicopter.

A. -- the company could analyze whether or not it was more beneficial to remit the state taxes on a consolidated FPL basis looking through that subsidiary or designating that subsidiary as a taxpayer and considering whether on a standalone basis the tax obligation was lower.

It would depend, you know, the state taxable income of the subsidiary versus the consolidated. But in each period they can look at that and determine whether or not they wanted the state legal entity, the operating legal entity, to be a disregarded entity or not.

So it gives them flexibility, you know. We're obviously obligated to pay our tax obligations, but we want to minimize it as much as possible, and it gives them added flexibility.

Q. Okay. And that would be corporate tax, right?

A. This is the state income tax obligation.

Q. Can you refer to Exhibit KO-7?

A. Yes.

Q. That's the condensed chart of accounts and the question is, has FPL had communications and/or discussion with the Federal Energy Regulatory Commission, FERC, regarding the company's condensed chart of accounts reflected in your exhibit?

A. No. The accounting for the gas reserves activity is not subject to regulation under the Federal Power Act as a natural gas entity, utility. So we wouldn't look to FERC to direct our requirements in that regard.

Q. And why did FPL not reach out to FERC to determine whether they had any concerns?

A. It's not a regulated activity under FERC, so when we compile our FERC reporting, which is the issue we were talking about earlier today, FERC mandates that we produce our electric utility reporting on an unconsolidated basis, and as we discussed, Mr. Rehwinkel and I, the activities of that subsidiary won't show up in this FERC natural gas chart of accounts. They will be showing up on the unconsolidated FPL FERC Form 1 as simply investment in a subsidiary, equity in our subsidiary and the intercompany notes payable.

So FERC is not going to have any reason to have anything to say about that.

Q. And can I refer you to your direct testimony, Page 16, Line 14 to 16.

A. Page 16?

Q. Yes, direct testimony, Line -- it's really Line 16.

A. Yes, I'm there.

Q. Would you -- excuse me. Hold on.

On Page 16, Lines 13 to 16, you state that, "FPL will use Successful Efforts accounting, which is the method preferred by the SEC."

Is FPL proposing to utilize their Successful Efforts accounting to record activities related to Woodford project investments?

A. Yes.

Q. And if you could refer to your testimony on Page 18, Lines 9 to 19, is it the case that FPL is proposing to utilize depletion for recovery costs associated with FPL's capital investments for the Woodford project?

A. That's correct.

Q. Now, Rule 25-6.0436(2)(A) states that: "No utility shall change any existing depreciation rate or initiate any new depreciation rate without prior

Commission approval."

If you know, how does this section of the rule comport with FPL's planned utilization of depletion accounting? You know, you focus on the term "initiate" and you use depreciation rates without prior Commission approval.

A. Okay. My understanding is that rule is written in the context of regulation of electric utility, where depreciation rates are analyzed and developed for purposes of electric generating plant and electric related property.

The depreciation rate setting process there is quite complex, in that you are determining not just the life of that asset, but you are estimating and including in the rate development other parameters of costs associated with that asset's life and on retirements, cost of removal, etc.

It is an extremely complex process to settle those rates. That's why it's only typically done every four years, when the study is required.

This is a far simpler circumstance, quite unlike the use of an electric generating plant. An electric generating plant can produce the same number of megawatts in the 25th year of its life as it might in the first two.

In this case it would make no sense to have a well that's producing MCF of gas and to deplete the cost of that well in any sort of method other than a units of production method. So we don't need to file a 15-volume study with the Commission, and of course, the rules didn't contemplate this sort of an investment.

This is sort of a mathematical exercise based on one significant estimate, certainly the estimate of the ultimate reserves, but then you're just applying the math around the production that you have in that period and the actual costs you've incurred. So it's a far simpler exercise.

Each year the Commission will get to review our math and the assumptions that we've made and affirm whether or not that rate is proper. If the Commission believes it's not, you know, we would be ordered to calculate that differently.

Q. Based on your insert, if you know, would FPL seek a waiver of this rule in order to implement those Successful Efforts on depletion accounting?

A. I don't think this circumstance necessarily falls into that rule. I don't think this rule contemplated the investment that we're making.

MS. BARRERA: One second, please. Off the record.

BY MS. BARRERA:

Q. Regarding the seeking of a waiver, would that -- this rule applies to the electric utility, to the electric depreciation. Would that also apply to gas, if you know?

A. I don't have the rule in front of me. I thought it did specify. I know I've looked at it before.

It does not specify. Again, my understanding is that this Commission -- and again, it's my understanding that this Commission has not regulated a natural gas utility that has invested in productive gas reserves. So it doesn't -- I don't see that it specifies that it's electric only.

MS. BARRERA: Okay, thank you. I have no more questions.

MR. MOYLE: So now it's my turn and I have a number of questions.

CROSS EXAMINATION

BY MR. MOYLE:

Q. Let me just pick up on the last line of questions to make sure we're clear on this.

You, in your testimony, have some comments about the Commission rules and you just answered questions from staff about the depreciation rule and FIPUG is taking the position that those are legal questions and for the record, you're not a lawyer, correct?

A. No, I'm not.

Q. And you're not testifying as to what those legal requirements are, correct?

You're testifying, as I understand it, as to what your understanding is of PSC rules; is that correct?

A. Yes. I have to apply the rules, yes. I'm testifying as to my understanding.

Q. Well, thanks for clarifying that.

So there are a number of sort of clean-up questions that I'm going to kind of bounce around a little bit from an organizational standpoint.

The acronym GRCO is Gas Reserve Company; is that right?

A. Yes.

Q. So it could just -- it will be New Co. for an entity that's not yet created and it's contemplated that you'll create it in the future.

Your current contemplation is each entity will have a bundle of assets; is that right? Help me understand what's contemplated with respect to New Co.

or GRCO?

A. Well, as I was discussing with Mr. Rehwinkel, we really haven't had to cross the next bridge, but there are considerations around, you know, the legal structure that are important for the legal team to weigh in on. There are considerations from a tax planning perspective that we'll weigh and depending on what that next investment looks like.

But right now for the Woodford Shale it will be one legal entity as a direct wholly owned subsidiary of FPL.

Q. Do you understand that to be common in the industry, that set-up, that structure, or do you not have an understanding?

A. Well, I don't know. In the industry meaning like petroleum --

Q. Oil and gas.

A. I haven't studied their financials. I don't know.

Q. So let me tell you something that -- let me pose the question this way.

My understanding of a single purpose limited liability company is -- you have a single purpose limited liability company. This exhibit that's been provided with NextEra shows a lot of companies, but that another advantage of having a single purpose limited liability company is it insulates -- it confines liability.

Do you have any understanding related to that?

A. Yes.

Q. In your testimony you didn't reference that at all as to, you know, what might be an advantage of a separate subsidiary company. You talked about tax advantages and things like that, but I guess we could agree that there's also an advantage with respect to liability, correct?

A. That's correct, that's my understanding.

Q. Do you know if that is part of what is considered?

A. Yes, I think we've said that in response to discovery.

Q. You also, I guess -- you know, we're all learning about oil and gas drilling, but there are accidents that happen. There are fires, the deep water event that happened with BP a few years ago.

I mean, the business has risks associated with it that potentially could be significant, correct?

A. As does the electric utility, yes.

Q. I'll come back to that in a little bit.
Let's just start coming from a macro perspective. I want to understand from your perspective, because you're the witness here and you're an officer of FPL responsible for accounting and rates; isn't that right?
A. Not rates, accounting and financial reporting.
Q. So like when FPL, the regulated company or NextEra, files an SEC filing, do you review those?
A. I'm responsible for the FPL portion. We're joint filers with NextEra, our parent, and I sign those financial statements.
Q. Do you get into all the NextEra side of the business or just the regulated end?
A. I'm responsible for FPL.
Q. So my question is please explain to me how the Woodford deal works for FPL, as you understand it.
A. How it works. I can describe what I did in my testimony, which is -- you're not asking for a description of strategy. When you say "how it works," it's so broad. We can talk about everything. We can talk about strategy all the way through the accounting.
Q. How about this. I will tell you how I

understand it works and you can tell me if I got it right or not.

A. We can try that.

Q. The way I understand it works is that FPL will be obligated to pay for the production cost and related cost -- and Mr. Rehwinkel had asked you about things -- Oklahoma taxes, everything that goes into efforts to provide natural gas, to extract and provide natural gas to FPL for the use in its plants; is that right?

A. Right. You're talking about sort of the legal and reporting aspects and the rights you receive for the amounts paid.

It's very similar to the undivided interest we have in the electric facility. You own your interest in each and every part of those facilities and according to those contractual documents you have a right to those, whatever that output is.

In the case of Woodford it's natural gas.

Q. And just one side note or footnote. Undivided property interest, help me understand that.

A. That means if there's one automobile and we have a 75 percent working interest -- well, we have 75 percent of our 80, I guess, because it's fractions of an interest.

We have that fractional interest in all the costs and the rights associated and certainly the obligations associated with that asset.

Q. So if you and I owned a car and you had 75 percent and I had 25 percent, you would be responsible for 75 percent of the costs and you would get to drive it 75 percent of the time. Is that essentially it?

A. That's essentially it, except we, of course, have the working interest and the carry that creates some differences during the drilling period, between costs and receiving output. But, yes, in general.

Q. So back on sort of the premise question about how the deal works for FPL, let's assume that the Commission approves this and we're in year two and FPL comes in and says, hey, your guidelines -- you approved our guidelines so we can go up to $750 million in oil and gas projects. Here is all the documents that relate to that $750 million.

So what happens there? Then the Commission looks at it and says okay, assuming they don't find any issues, then that 750, you earn a return on the 750 that you invested, subject to depletion/depreciation; is that right?

A. To the extent the Commission approves the guidelines and we execute -- are able to execute, find advantageous acquisitions of mineral interests and rights to drill and other properties that we can transport to our facilities at hopefully lower -- from our analysis at a lower cost than we can otherwise buy in the market, then we would package those costs that we had incurred in those investments, like I have here in this example KO-6, and we would earn a return on the investment.

We wouldn't earn a return on the cost expenses. The recovery model would work like it does in the utility business for gas or electric assets and investments.

Q. And just so I'm clear -- I'm not a financial CPA type background -- but the expenses, the ratepayers would still pay for the expenses that are incurred. It's just that they don't pay for a return on the expenses?

A. That's correct.

Q. They only pay for the return on the capital investments, right?

A. That's correct, just as they pay for a hundred percent of the fuel costs today.

Q. So FPL's shareholders, assuming this deal is approved and moves forward, have a potential to earn a return on whatever the capital portion is of that. Just assume it's maxed out at 750. They get the opportunity to earn a return on the capitalized portion of that 750, right?

A. That's right, that's exactly right. Our customers are paying that return anyway.

Q. Say that again.

A. Our customers are paying our gas providers a return on investment, presumably at much higher rates.

Q. We'll talk about that later.

A. Advantageous strategy, if we can execute properly.

Q. Let's just take it a step at a time.

So out of that 750, can you give me just a ballpark estimated ratio as to what you expect to be capitalized vis-a-vis what would be expensed?

A. No. I think the 750 was not identifying an investment, which is what it would take for us to figure out what's the drilling plan, when will the capital cost be required, what's the production out of those assets.

The 750 was set as a sort of a broad guideline that Witness Forrest needs to testify to.

Q. And I'm just using it for purposes of trying to have a shorthand conversation, to make sure I understand how this potentially could work.

I'm assuming that it gets maxed out. It may not, because that's the maximum guideline, but we're using it for purposes of our conversation. Are we clear on that?

A. Yes. I can't answer your question. I was trying to explain to you why I can't answer your question.

Q. Well, we can do it on a dollar, if you know. Through the Fuel Clause, if you assume that there's a dollar that would flow through based on what your proposed project is, can you give me a sense as to how much of that dollar would be accounted for as a capitalized cost and how much of that dollar would be accounted for as an expense cost?

A. What I would suggest you look to -- and it's not my exhibit -- because I don't know that there's a rule of thumb. I mean, some of these conveyances you can pay up front for the exploration cost. Some of these conveyances you don't pay anything up front. You enter into a contract and you pay as the drilling is performed. There are many different scenarios that could result.

But Witness Forrest has an exhibit in here that shows you based on this transaction and the dollars spent what the return is in that revenue requirement versus what the operating expenses and depletion are. So I would suggest you look at that.

Q. I'll talk about that some more.

Just so we're clear on the record, what does it reflect in the exhibit with respect to the question?

A. Well, it shows a return of $15 million in one year or you could go down to the bottom, it shows return of $195 million in total nominal dollars out of a $709 million revenue requirement, less than a third.

Q. In answering my question you had made a comment about, well, if you assume that the market price is greater than the cost of production, that things would move forward. That's how I interpreted it.

Do you have an understanding with respect to how FPL will execute this arrangement if the market price for natural gas is below production cost?

A. Well, we're proposing investment based on our view, which as I understand it, is an assessment of public information about, you know, future prices of gas and once locked in we're going to drill, we're going to produce in these wells, and customers are going to benefit if gas prices are lower than they otherwise would.

To the extent gas prices get lower, it makes this investment less attractive. To the extent they get higher, it makes it more attractive.

Q. You've heard of the financial term "upside down," right?

A. Yes, I've bought a house in Florida before 2008.

Q. To use that term, it means you have an investment where the investment is not worth the money you've paid for it, essentially, correct?

A. Yes.

Q. And in the event that the Woodford project gets upside down, does that affect FPL's plan of execution?

I mean, do they call up and go, "Hey, you know what, hold off, because this isn't really working. You know, the market has gone down significantly. We can buy gas on the market for 50 percent of our production cost, so we don't want you to continue to drill"?

Could that happen?

MR. BUTLER: You're talking about within the Woodford project or plans as to acquiring future projects?

MR. MOYLE: Probably initially within the Woodford project and then I'll ask if there are any differences with respect to future plans.

A. I think you have to ask Witness Forrest.

Q. You don't have any understanding --

A. I don't know whether we can dial it on or off or whether that would be even appropriate.

Q. I'll ask him.

It's my understanding that there is not that market tie or flexibility, that this is just kind of a straight, hey, whatever the production costs are, you think they're going to be a lot less than the market price, and they may be?

A. Long term investments require that kind of analysis.

Q. The reason I'm asking the question is to explore the level of thinking as to what happens if that turns out not to be the case. Is there a contingency plan? How is that going to impact ratepayers?

You're saying you don't really have that information, that I should ask Mr. Forrest?

A. Yes.

Q. So I asked you how does the deal work for FPL. We talked about that.

My next question is, how does the deal work for ratepayers? And you know, my understanding of that is as long as the production costs are less than the market costs, ratepayers would potentially benefit by the margin between the production costs and market price, right?

A. Right. The same exhibit I referred you to shows a nominal value to customers of $394 million on this investment versus $106 million in PD.

Q. From an accounting standpoint or a rate-making standpoint, if hypothetically you assume that production costs exceeded the market costs by a hundred million dollars, would there be any adjustment with respect to the hundred million dollars by which the production costs exceeded the market costs?

A. No, no more than there is today on, you know, out of money PPAs that we have entered into on behalf of customers years ago that are far more costly than our voided costs. These are long term investment decisions.

Q. Explain to me if you would, carry, you're understanding of carry, the term C-A-R-R-Y.

A. In this -- I can explain it in this instance. I don't know if I know -- I'm sure I don't know the universe of application.

But in this instance we are, in effect, through carry reimbursing PetroQuest for costs that they've already incurred. You know, they didn't just fall into the PetroQuest AMI yesterday. They developed -- you know, they explored this, developed it, secured the leases, did all the work that's involved in making that available to us, and from the time we signed the contract in June had we not had to go through the regulatory approval, you know, they're drilling today.

So we're in effect through carry paying them an outside amount relative to the output we're going to receive, because they've incurred all these costs months, if not years in advance of being able to drill these wells.

Q. Does that include interest or return on their investment, the carry, or is it just simply cost?

A. The carry is a negotiated amount. It's a negotiated percentage. Presumably from their perspective it's a reasonable way for them to recover all of the costs they have incurred in exploring and developing those properties prior to drilling and production.

Q. Okay. So in this case in Woodford, do you know if the carry includes an interest component or profit component for PetroQuest?

A. I have no idea.

Q. But part of what is being asked for by the PSC is the carry, right?

I mean, that's part of what you're asking, asking that it be approved as a rate that should be recovered or a cost that should be recovered in the Fuel Clause?

A. The carry for us is no different than the drilling cost or part of the drilling costs themselves. It's our portion of the costs that have to be paid to get our 75 percent of our joint interest.

Q. I'm just trying to delve a little bit into the subparts of the carry.

A. I can't help you. I don't know if Witness Forrest can. Those are negotiated terms.

Q. And you weren't involved in any way in the negotiation between USG and FPL related to the transfer of the Woodford wells, correct?

A. Well, remember, the commercial negotiations were between USG and PetroQuest and FPL and PetroQuest, right? That's the commercial transaction. The MOU just codified the way in which we would then transfer that at-cost investment from one entity to the other and no, I was not involved in the negotiation.

MR. MOYLE: Could you read that answer back, please?

(The portion requested was read back by the reporter as above recorded.)

BY MR. MOYLE:

Q. My understanding is that FPL, a regulated utility, has not engaged in direct negotiations with PetroQuest. Do I have that wrong?

A. You'll have to ask Witness Forrest.

Q. Okay. Well, I will. But you talked about that in some of your testimony, as to what -- you have an MOU attached to your testimony, right?

A. Yes. That's the transaction between U.S. Gas and FPL. That's codifying that transaction, yes.

Q. And you were asked earlier some questions about what kind of deal is that and I thought you said it's an asset purchase as compared to a stock transaction; is that right?

A. That's right. I was asked a series of questions about the legal entity chart and I was trying to make clear that we weren't buying that legal entity.

It wasn't a stock transaction that we were purchasing the equity in that legal entity. We were buying these sets of assets from U.S. Gas.

Q. I'm confused as to how liabilities are treated, and let me refer you to your testimony. On Page 7, Line 4, you testify, "USG will assign all of its right and obligations under the PetroQuest agreement to FPL."

Then again on Page 11 at Line 16 you say -- you reference the assignment of USG's rights and obligations of ownership of the working interest.

Do you see that?

A. I see the one on seven. I'm sorry, where is the Line 11 reference or I'm sorry, Page 11 reference?

Q. You have it on 11, Line 16.

A. Yes, I do see it.

Q. So is it your understanding that that's what's being assigned?

A. Yes.

Q. Well, if you go to the MOU, the MOU under paragraph E(a) says something different, doesn't it?

A. It says exactly the same thing, "rights, liabilities and obligations."

Q. I don't see the word "liabilities" in the testimony.

A. Well, obligations. I think I referred to working capital -- no, that's in the MOU.

But look, we're going to be assigned all the agreements that U.S. Gas has entered into with PetroQuest, which gives us the right to participate in the development of production of those properties.

Along with that comes obligations. At the time of the transfer there will presumably be both assets and liabilities on the financials, some of which will be assumed and some will not, depending on the production of those assets.

Q. And I just want to understand what the deal is. So that's why I'm asking about liabilities, because in my understanding of liabilities, that can be a significant component as to whether liabilities are being transferred or not being transferred.

Would you agree with that?

A. Yes. And all rights and obligations of the properties are being transferred upon Commission approval.

Q. So does that include liabilities or you're not sure or -- how is it envisioned in your mind that liabilities will be treated?

A. If there's an obligation, which is considered a liability, either an obligation to act, a commitment to act, or an obligation to pay, and that obligation is appropriate for FPL, to be transferred to FPL because it represents an obligation for natural gas that has not yet been received, right, so we're not going to take an obligation or a liability for revenue they've already received, then that liability, in your vernacular, would be assigned.

Q. Hypothetically, there's a farmer out there who has a pig farm that has a big operation, things are going great. There's a drilling operation nearby and all of a sudden there's a sinkhole that develops and it completely consumes the pig farm and all his money and profits, and this occurred while USG was contracted with PetroQuest.

With respect to how the deal is structured, I think we'd call that a contingent liability. Do you understand that that contingent liability that I hypothetically presented is coming over to FPL or is it remaining with USG?

A. I think the answer to that hypothetical has to be it depends, right? I mean, if there's a normal operating obligation that is incurred and it is owed by FPL because it's connected with the gas that we're going to take out of the production facilities after transfer, we will pay that obligation.

If there's some contingent obligation that arises, I'm sure the lawyers will have to figure out who owes who what.

Q. As part of due diligence, was there any effort made to look at liabilities that were being transferred, do you know?

A. Well, a contingent liability, yes, as a part of any due diligence -- and I did not participate in the due diligence on contingent obligations -- but as part of any due diligence you consider liabilities that could arise, right? So there's environmental and I'm sure other forms of review that took place.

Q. So do you know whether it took place or not in this case, with respect to Woodford?

A. Whether "it" took place?

Q. "It" being the due diligence review of liabilities.

A. Yes. We participated -- that's why I spoke earlier about U.S. Gas having a commercial -- entering into a commercial arrangement with PetroQuest and FPL, because we had to perform our own due diligence also. So those steps took place as they would with any transaction.

Q. At the end of the day did you have a document that was a due diligence report that said we've done the due diligence and here's what we've discovered and found?

A. I'm sure there are documents. I don't have any.

Q. And why do you say you're sure?

A. Well, typically, due diligence is a process that involves a fair number of people and a lot of work and so there are project management documents at a minimum.

Q. If I'm asking you stuff that's beyond your scope of knowledge, just tell me that, if this is another Mr. Forrest question. But I don't want to ask Mr. Forrest this question and he says you should ask Ms. Ousdahl this question.

A. I would suggest you ask Sam Forrest about the negotiation of the PetroQuest agreement.

Q. But with respect to the due diligence associated with the liabilities, I think you're saying you think that was done, but you can't testify that that was done. You just are making an assumption because it's usually done?

MR. BUTLER: John, the due diligence was part of the negotiation process that Mr. Forrest in a better position to address.

MR. MOYLE: All right. Thank you for

clarifying that. I'll take that representation and leave it alone with the due diligence.

THE WITNESS: Thank you.

BY MR. MOYLE:

Q. So you were asked questions about the corporate structure, and in your testimony you say that you're having single purpose entities for tax flexibility.

It was unclear to me whether you're talking about out-of-state tax or Florida tax. Just to be clear, you're talking, I think, about out-of-state tax, right?

A. I think we said state income tax, yes, and I was referring to the states in which we would be participating in production.

Q. Right, because Florida has a state corporate income tax, right?

A. Yes, it does.

Q. Have you looked at that -- well, okay. So with respect to the state taxes, you haven't tried to differentiate between in-state or out-of-state, have you?

A. In doing what?

Q. When you say the term "state income taxes," what are you referencing, what states?

A. Particularly here we looked at the legal entity opportunity to provide flexibility in minimizing the obligation for the state taxes that would result from the drilling process. But to analyze those you look at both. You look at whether or not you're going to file a consolidated Florida and this other state or whether you're going to file independently.

The concern is on having our business taking place in a new state other than just Florida and Georgia today.

Q. So it's anticipated, if I understand it correctly, that taxes paid in Oklahoma, income taxes, severance taxes, if there's severance taxes, any taxes paid in Oklahoma will ultimately be something that will be sought for recovery from ratepayers?

A. Yes.

Q. Did you ever practice public accounting?

A. No.

Q. Never?

A. No.

Q. Do you presently hold any other corporate positions other than those you identified in your testimony?

A. I'm the vice president, comptroller, and chief accounting officer.

Q. For FPL, the regulated company?

A. FPL.

Q. So Exhibit 1 to your deposition is your company's response to Public Counsel's third request for production of documents.

A. What is Exhibit 1?

MR. BUTLER: The org chart that they identified earlier.

THE WITNESS: Oh, I'm sorry.

BY MR. MOYLE:

Q. Do you have familiarity with the NextEra entity organization chart?

A. I have familiarity with it from the standpoint of ensuring that I've properly taken account of affiliate transactions. But because we only bill at the highest level with the affiliates, I only worry about NextEra and the other first level subsidiaries, operating subsidiaries, so I do not have familiarity with all of the legal entity detail in NextEra resources.

Q. But to go back to my question with respect to being an officer or director, you're not an officer or director of any of these companies that are set forth on this exhibit except Florida Power & Light

Company, the regulated company that serves electricity to retail customers in Florida, correct?

A. That's correct.

Q. I wasn't a hundred percent clear on your discussion with Mr. Rehwinkel about which entities are subject to the jurisdiction, in your understanding, of the Florida Public Service Commission.

Out of all the entities listed in this exhibit, is the only entity that's subject to the jurisdiction, as you understand it, of the Florida Public Service Commission Florida Power & Light Company, the regulated Florida utility which serves retail ratepayers?

A. And all of our subsidiaries that show up on Chart A.

Q. So let's go to Chart A.

Do you believe the Commission, if they had a question about something that took place at Private Fuel Storage, LLC, that they could open a docket related to Private Fuel Storage, LLC and look into the issues related to that entity?

A. Yes, I think at the time it had a zero cost basis, but at the time it held an investment, yes.

Q. And same answer with respect to all of the entities that are set forth herein?

A. Yes.

Q. And the New Co., is it contemplated that the New Co. would be appropriately showing up on Chart A if it's approved?

MR. BUTLER: Are you substituting that term for GRCO?

MR. MOYLE: Yes, because it's easier for me to remember. Sometimes I have trouble with your acronyms.

BY MR. MOYLE:

Q. So it would be subject to the full authority, in your opinion, and regulation of the Commission?

A. Well, we had this conversation about the fact that the FPSC reporting and rate making, in particular associated with that entity, would be subject to the FPSC jurisdiction. They could not regulate the drilling activities that occur in Oklahoma.

Q. Is it contemplated, for example, I think on one of these charts that showed some sales of commodities coming out of these Woodford projects to Shell, a Shell company? You're familiar with a big petroleum company Shell?

A. Yeah, some are Shell, but I don't know what exhibit you're referring to.

Q. It doesn't really matter. Let me get to the question this way.

Right now in the Fuel Clause, if Shell Natural Gas is selling natural gas to Florida Power & Light, the regulated company, and they say here, it costs a hundred million dollars, and provide that information to FPL to pay the bill, do you contemplate that New Co. would in effect be in a similar position to the Shell entity that I just described; that what they would be showing to the Commission is similarly here's the cost, the production cost?

A. No, the Commission would seek far more, because we're actually engaged in the production of drilling.

So for Shell, they get an invoice, I'm assuming, that says X number of BCF, I don't know if they're invoicing Shell, you know, X dollars and delivered at X point.

In our case, we're going to produce the MCI, so there's going to be -- you know, recall that we talked about thousands of pages of transactions with information about how those costs arose.

Q. You confused me about that. Have you ever seen a JIB?

A. Yes.

Q. Because the example you have attached to your testimony is three pages.

A. Well, I also have -- I was being expedient, right? This is why it's an electronic supported activity. The undivided interest really means an undivided interest in every cost that the operator incurs in exploration, development, production.

Q. Who did you see the JIB from?

A. I've seen a Devon JIB -- I don't know, a couple of other companies.

Q. You would agree that in a nonoperating role, that New Co. is wholly dependent on PetroQuest to execute, right?

A. PetroQuest acts as operator. They -- I'm trying to analogize it to what I see and know about, our circumstances with our other undivided interests. Clearly they act, but they're acting on behalf of all owners. So there is much communication with owners, but they are the experts and we're able to ask questions and understand and deliberate with them.

But yes, they drive that activity. They're the ones with experience. That's the benefit of having experience.

Q. So the answer to the question is yes, that you are wholly dependent on PetroQuest to execute --

A. I'm sorry to interrupt.

It's not completely passive, but yes, the operator is an important consideration.

Q. And that same question would be true whether we're talking about New Co. or FPL, the regulating utility, correct?

A. Absolutely.

Q. I'm going to give you an exhibit and ask you to look at it, if you would, and I'll go ahead and mark this.

(A document was marked as Exhibit 2.)

Q. Did you or anybody at FPL review the SEC filings of PetroQuest before entering into this arrangement?

A. I did not. I have referred to it once or twice to look at something in particular, but I didn't do it. I wasn't in a position of evaluating whether or not this was the proper operator.

Q. All right. So if I read your testimony right with respect to the price that was paid for the USG assets, you believe that that represented fair market value, correct?

A. The agreed price -- yes, yes.

Q. And the reason you believe that is because that was the deal that USG struck whenever they struck the deal in 2010?

A. Yes -- no, no, no. The deal that U.S. Gas struck in June of 2014?

Q. Right, the deal that U.S. Gas struck with FPL in June of 2014.

A. No, we're not stepping into U.S. Gas' transaction that they struck with PetroQuest in 2010, but we had to reimburse -- we're stepping into a new transaction that U.S. Gas entered into with PetroQuest in June of 2014, but we had to reimburse them a portion of the carry they paid, because they were reassigning some of those properties and interest as a parts of that 2010 transaction.

Q. So to go to your testimony on Page 14, Line 20, you say: "Transfer at cost puts FPL in the same position it would have been if it could have transacted for this investment on its own with PetroQuest, an independent third party seller. In essence, FPL will be paying the market price for this transaction as measured at the time of USG's initial purchase."

A. Yes, June 2014. Those are the assets that we're purchasing and the interest we are purchasing.

Q. So when did USG make its initial purchase?

A. This purchase that is being transferred to us is the purchase USG made with PetroQuest in June.

Q. So what is the 2010 deal? That was a USG deal as well, was it not?

A. They had an original transaction with U.S. Gas in 2010. They carved up a portion of those properties in order to make it available to us. That formed the basis of the new transaction in June.

Q. And the costs that were accounted for and the carry, all that related back to the 2010 deal?

A. No. The costs that you see on my Exhibit KO-2, $58 million all relate to the only agreement that's really relevant to FPL, which is the June transaction.

The $10 million is not a payment to PetroQuest. It's reimbursing U.S. Gas for letting go of some of that acreage where they'd already paid a carry. They were never going to get to develop it.

So the basis of this commercial transaction in June of '14, we're not trying to replicate anything that happened in 2010.

Q. Was there anything -- do you know, was there any effort to check, you know, the market price with respect to the transaction cost in June when this happened, when you said okay, here, we're going to settle on this as the negotiated number between FPL and USG?

Was there any effort, do you know, to look and see how does this look compared to market?

A. Okay, let me make sure I understand.

When you say "the price paid between U.S. Gas and FPL," that's to be determined, unless you're referring to -- are you referring to the $10.2 million, the earned acreage amount?

That's based on dollars they've already spent and carry, which we then assigned to the probables and the PUDs that are going to be transferred to FPL.

So there's not a determined transfer price for the point in time when the properties are actually going to be transferred after Commission approval. That would depend upon whatever the net book value is. It would have been the market price at the date of the June transaction, less any depletion that occurred.

Q. Have you ever seen a situation in which fair market value was less than net book value of an asset?

A. Sure.

Q. And with respect to ratepayers, if that situation is present with these assets, don't you believe that should be something that would be looked at to say, okay, you know, is the market value of these assets less than the book value that we're paying for them?

A. We did the best job we could of trying to find the means by which we could even enter into this transaction and go through a prolonged regulatory process.

In that process U.S. Gas already took on risks that they were not compensated for. It made perfect sense to us to try to balance the interests of all parties by saying let's transfer this at net book value. Any other way you go somebody is getting cheated and somebody is gaining the system.

The idea here was to put us back in the position as if we had been able to transact it on day one.

Q. And just so we're clear, when is day one?

A. June 2014, whenever that transaction is.

Q. So this exhibit that I just gave you and that I'm going to have marked, I want to take you to Page 11 of it.

And for the record, this is PetroQuest Energy's Form 10-Q that was filed this month on the 4th of November.

So if you look at Note 8, there's a note there about fair value measurements and it references ASC Topic 820. Do you have any familiarity with or understanding of ASC Topic 820?

A. Yes, I do.

Q. As I read this, it goes through a process that suggests how you determine fair value for an asset.

A. The value swops here, though. These are swops. These are hedges, it looks like. You know, they're in the form of swaps. So this isn't a physical valuation.

Q. How do you know that?

A. Well, I'm just reading it.

Q. I'm referencing you to Note 8. It says "Fair Value Measurements."

A. So about halfway down it says, "The company classifies its commodity derivatives based on the data used to determine fair value."

So these are derivative instruments. It says, "In the form of swaps, based on NYMEX pricing." This isn't a value of their reserve.

Q. Okay. Is it anticipated that New Co. will continue to be involved in hedging or will it be involved in any hedging to protect the investment in the Woodford project?

A. I believe the plan -- this is a physical hedge, so I don't believe we're talking about layering financial hedges on top of the physicals.

Q. Because PetroQuest does that, right?

A. They have a market play. They're producing at market prices.

Q. And this is not a market play?

A. No, clearly not.

Q. Have you had any discussions with Commission staff about the Woodford project or anybody from FPL have any discussions with Commissioners or Commission staff about the Woodford project, that you're aware of?

A. I have not. I don't know what conversations others may or may not have had.

Q. There was an exhibit I'd like to put in front of you that was already used in the deposition of Mr. Taylor. It's the PetroQuest Energy 2013 annual financial report.

A. Thank you.

Q. Do you have it?

A. Yes, I do, sorry.

Q. So let me refer you to Page 20. At the top in bold there's a statement that says: "Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, which may in turn limit our ability to remain in compliance with debt covenants and make payments on our debt."

Did you or FPL consider the financial structure or capitalization of PetroQuest before entering into this arrangement?

A. I did not. Others might have.

Q. And with respect to that statement, has FPL included a similar statement in its SEC filings?

A. We have a number of statements about the ability to finance our required investment in our business, yes. Capital markets acquisition is an issue for any capitally intensive business, which this is.

Q. I read this statement as saying we may think we have a concern about cash flow potentially that could affect business operations, and just put simply, does FPL, the regulated entity -- or actually, it should be NextEra -- does NextEra similarly say we have a concern about cash flow that might affect operations of NextEra subsidiaries, both regulated and nonregulated?

A. I think -- my understanding is PetroQuest has been in operation for quite sometime. They have adequate liquidity.

What typically these sorts of risk factors go to is that, you know, the cost of capital may be quite high. If your assets income is limited, if your free cash flow is limited, the cost may increase. I think they're advising investors. They go on in some detail about that.

Q. So the NextEra similar 10Q would have that statement in it or not, based on your --

A. It's not worded this way, but as I said, we have statements in our risk factors that talk about access to capital markets.

Q. And then also on Page -- this is F17, toward the back of this document. It's under Note 9, "Long Term Debt".

A. Yes, I'm there.

Q. Would you just read the first sentence of the last paragraph in the record, please?

A. The last paragraph on F17. "The credit agreement," that one?

Q. Yes, ma'am.

A. "The credit agreement is secured by a first priority lien on substantially all the assets of the company and its subsidiaries, including a lien on all equipment, and at least 80 percent of the aggregate total value of the borrower's oil and gas properties."

Q. What does that signify to you?

A. That they've mortgaged their assets, as does FPL. All of our activities, all of our lending is based on the mortgage of our assets.

Q. So did you know that before reading this, that PetroQuest did this?

A. No. Again, I haven't studied PetroQuest.

Q. In response to a question earlier from Staff, I thought the testimony was you're investing, you're taking an interest in the assets of PetroQuest in relating to their drills and other equipment and I guess --

A. Oh, I see.

Q. I guess I read this to say, well, your interest would be subordinate to the mortgage interest, correct?

A. Well, I'm not a bankruptcy lawyer, but we're not taking an interest in PetroQuest's equity as an entity.

Q. And in their physical assets -- you don't have an interest in their physical assets?

A. Well, we all have -- the way these transactions work is you have a grouping. They call it unitization of interests, and they may be leases, they may be actually surface rights, their mineral rights, whatever they are. There's a grouping of interests and assets, and part of it is to take fractional interests in those.

That's all we're doing. We're taking a fractional interest in this unitization of properties that many, many other -- I don't know how many other working interest holders there are in this AMI -- have an interest in. We're not taking an interest in the equity of PetroQuest.

Q. So we're back to the car, and essentially the bank has the title to the car, right?

A. I'd have to study this more. I do not know that the bank, in their case -- that subordinating their assets for this credit facility have an interest, have mortgaged the working interest properties they hold. I don't know the answer to that. I'd have to study the heck out of this.

I don't know, I don't know.

Q. Back on the subsidiary that we talked about, you make a reference, I think to, "The subsidiary provides more transparency than would otherwise be the case."

Can you describe that?

A. What we were thinking -- and sometimes the accounting is a bit academic, but when you have all the activities of an operation in this case accounted for separately in a subsidiary financial statement, it's very easy to -- they're isolated by virtue of the way they're structured -- very easy to report out all that activity.

We felt it would be helpful both to us internally and to parties like yourself and the staff to be able to look at that activity separate and apart from the utility. So it just seemed like a benefit to us.

You know, there's more work involved, there's no question, but it seemed beneficial.

Q. Several times today during the course of the testimony you have talked about strategic decisions and the strategy of this initiative.

Were you involved in strategy discussions related to the Woodford project in particular or the larger effort to seek PSC approval to have these type of investments considered on an annual basis?

MR. BUTLER: I'm going to object to the form of the question. I don't recall her discussing the strategic considerations with respect to this proposal. If she did, okay, but I would appreciate if you don't predicate your question like that.

MR. MOYLE: I probably shouldn't have predicated it anyway, because I can just ask the question.

BY MR. MOYLE:

Q. Have you been involved in any strategic discussions related to this Woodford project or the larger effort as contemplated by FPL in its petition?

A. No. My involvement has been limited to executing on this in this fashion and the regulatory piece.

Q. As an accountant, in your training were you ever trained related to fiduciary duties?

A. Yes, we have -- I mean, from a comptrollership perspective we have responsibilities.

Q. Do you have an understanding of the term "fiduciary duty"?

A. I have my layman's understanding, right, from the standpoint of my discipline.

Q. Go ahead and give it to me, if you would.

A. Well, I'll put it in terms that I would relate to. As comptroller of the organization I have responsible -- I have, I think, a fiduciary duty to make sure that I'm protecting the assets and the interests of the business for its shareholders.

I think about it that way.

Q. What duties do you think you owe to ratepayers?

A. Well, I think one serves the other, right? If I'm controlling and ensuring the proper security, safety and operation of the assets to the extent I have that responsibility, then those are predominantly utility rate payer assets and we're performing the proper service to our customers.

So they don't run in contradiction of one another.

Q. So you've been with Florida Power & Light how many years?

A. 10 years.

Q. You've never seen an occasion where the interest of FPL shareholders conflicted with the interest of FPL ratepayers?

A. I don't find in the conduct of my job that those run in conflict to one another. If I do a good job as comptroller for this company, I'm doing a good job in assuring the use of those assets for customers.

Q. Hypothetically, if a situation were to occur where there was a conflict, how would you contemplate dealing with it?

A. It's too -- in any decision you make you have to weigh the framework of the rule, right? Everything I do has a rule around it, the compliance requirements with the ethical consideration.

I mean, every conflict that you encounter, the specifics matter. I don't think a hypothetical is a fair question, if I can say that, on something so broadly worded.

Q. So back to my discussion point earlier about if the market for natural gas goes way south and you can get natural gas for one-tenth of the price that you can get it today -- if that's what the market does -- and the PSC approves this project as proposed by FPL, if FPL continues to move forward with the project and pay the production costs and the production costs are 10 times more than the market costs, you don't see that as potentially presenting a conflict of interest as to whether you continue on with this project or whether you say this isn't working for our ratepayers, we'll go pay market price?

MR. BUTLER: John, in your hypothetical are you assuming that FPL has the option, the discretion to continue paying the production costs or not?

MR. MOYLE: No, I just assume whatever she understands the arrangement to be with the current deal that's on the table.

MR. BUTLER: So in other words, if the arrangements were that there's a contractual obligation to pay, but FPL simply met its contractual obligation, would that be your question?

MR. MOYLE: Yes.

A. Markets are going to move after you make long term investment decisions. This is no different -- I mean, it's a different investment and activity.

But in terms of the decision-making and the regulatory nature of this investment, it's no different than building a power plant. We're going to build a power plant based on some view of market prices, right, and the benefits of that power plant against alternatives, and we're going to be right or wrong or maybe very right or very wrong.

This is no different. But you can't rethink the decision 10 years into the investment, so I'm struggling with your hypothetical. We all have to evaluate the facts we have in front of us and make the best decision for customers.

Q. So would it be your testimony that in looking at this and thinking through this and considering it, that there's no scenario where you believe there could be a conflict between FPL and its shareholders and FPL and its ratepayers?

A. Do I think this decision presents a conflict?

Q. Or the execution of your proposal on a go-forward basis?

A. No, there's nothing about this that I'm aware of that presents a conflict, either in the decision-making or the execution of.

Q. And if you are presented with a conflict between shareholders and ratepayers, you don't know what you'd do, correct?

A. It's too hypothetical.

Q. Well, that last question is not a hypothetical. If a conflict arises between shareholders and ratepayers, what would you do?

MR. BUTLER: John, it's hypothetical in the sense that you haven't presented an actual conflict of interest and you haven't provided any details on what the conflict is. So I think that's where the problem lies.

BY MR. MOYLE:

Q. Do you think FPL has a fiduciary duty to it's ratepayers?

A. I think FPL has proven every single day the way we conduct our business, that we're trying to do the best job for the ratepayers as we can. So yes, I think we internalize that and take it extremely seriously.

Q. So you said yes, so the answer would be yes --

A. My view of what a fiduciary responsibility is. Remember we talked about my layman's view.

Q. And you believe that that fiduciary duty is owed to ratepayers?

A. I think we make -- the things that we do at FPL are on behalf of our customers, yes.

Q. Okay. I'm trying to get the "yes" or the "no". I think you've given me the "yes", correct?

A. I think I might have forgotten the question.

Q. Do you think FPL has a fiduciary duty to it's ratepayers?

MR. BUTLER: John, if you're asking that in a sense other than her lay view, I'm objecting to it as calling for a legal conclusion.

MR. MOYLE: I understand.

BY MR. MOYLE:

Q. Could you just answer yes or no, please?

A. Yes.

Q. Thank you. We'll just give that the same way we do with respect to your testimony on the Fuel Clause and how the Fuel Clause works; is that fair?

Like the Fuel Clause, that's testimony based on your layman's view, correct, of how the Fuel Clause works?

A. You're going to need to be more specific. I have a very specific set of experiences around the accounting of the Fuel Clause, so I don't think it's the same as asking me what the fiduciary duty is.

MR. BUTLER: I observed that you are more closely informed on that than your generic question about fiduciary duties about a week ago.

BY MR. MOYLE:

Q. Page 22, Line 1 you're asked "Why is Fuel Clause recovery appropriate?"

A. Are you in the direct?

Q. Yes, ma'am. As I read that answer, you started by citing a PSC order.

A. Wait, on Page 21?

Q. 22, I'm sorry.

A. Yes, I'm there.

Q. That represents your understanding, correct?

A. Yes, my read and my understanding, yes, based on the written word and the later decisions, yes.

Q. Do you know where the authority for the Fuel Clause recovery comes from? Is there a statute that says the PSC can recover things through a Fuel Clause, things like this project?

MR. BUTLER: You're asking for a legal conclusion.

A. I don't know for sure. I know it originated in like the early 80s and it's been around a long, long time. I don't know.

Q. Is there anything, any cost that would not be included -- you know, I can reference you to Page 24, to the question on Line 5 describing the types of costs that FPL proposes to recover for the fuel cost for the Woodford project and any future reserve projects. I was going to kind of ask that in the negative.

Are there any costs that are not contemplated being recovered through the Fuel Clause related to the Woodford project?

A. Well, consistent with what we do today for clause recovery we would include capital costs as a part of the determination of the cost of capital we associate with return capital issues. So long term debt, equity and deferred taxes would all be subsumed within consolidated FPL base rate setting and then applied to costs. All other costs we would flow through the clause.

MR. MOYLE: Want to take a little break?

THE COURT REPORTER: Yes.

(Whereupon a recess was taken.)

BY MR. MOYLE:

Q. You were using the term "mapping" in the accounting sense. I didn't understand what that was.

Could you please explain mapping?

A. Yes. Mapping is like linking two different items together. So you have relationships between those items. You might have a one-for-one relationship or you might have a many-to-one, sometimes you have a one-to-many. That's a mapping and that's what we do in accounting, in our financial systems, because you have many different ways in which you have to report information under different charts of accounts and you do the mapping, which is configuration of the system to do that.

Q. So that's kind of a term of art used in the accounting world?

A. Okay.

Q. Agreed?

A. Yeah, must be. It's like everyday

vernacular for me.

Q. You testified previously you reviewed the MOU that's attached to your testimony. Why did you review it or why were you asked to review it?

A. Because it formalizes or memorializes the transaction that would occur at the time of transfer and because I have to record it and because I was testifying it, it was logical that I would.

Q. I assume you were reviewing it on behalf of FPL; is that right?

A. Absolutely.

Q. Did someone ask you to review it or how did you come about doing that?

A. I don't remember. I knew it was being worked and knowing me, I asked somebody to let me look at it.

Q. Have you or anybody else that you know of in FPL given consideration to what happens if PetroQuest gets into financial difficulty and doesn't have adequate capital to execute on these projects?

A. I have not, and I cannot answer for others.

Q. With respect to motivations by USG to enter into this arrangement, to do this deal, in your testimony you suggest that USG may not have gotten everything that they could have, if I understand it, because there was no value for an option; is that right?

A. That's correct.

Q. And you also, I think, make the point that USG didn't make any profit on the deal. It was just their book cost?

A. On the transfer.

Q. On the transfer, is that right?

A. That's right.

Q. Does that suggest to you that it was not an arm's length negotiation and transaction? They're affiliated companies, right?

A. Yes.

Q. So it was not negotiations in the context of, you know, the car that you and I owned jointly and selling it to Charles. That would not be -- this transaction between corporate affiliates is not an arm's length transaction; would you agree with that?

A. No, it's not. We talked earlier about the commercial transactions between us -- U.S. Gas and PetroQuest and ourselves, looking at that transaction with PetroQuest.

Q. You talked with Mr. Rehwinkel about the allocation of existing wells and the yet to be developed assets. Do you have an understanding as to why USG got all of the existing wells and why the yet to be developed assets were part of what's transferred?

A. Yes, I think I answered that on the record, that it wouldn't be as advantageous for us to take producing wells because the production curve declined so quickly. We knew they entered into the agreement in 2010, so it's far more beneficial for us and our customers to take wells that aren't producing yet.

Q. And to the extent that you invest in these projects and the Commission approves it and something happens and the extraction is delayed, you would continue to earn a return on that just as you would a piece of land that you may have for a plant in service, correct, in the electric context?

A. That's correct.

Q. You talk about an authorization for expenditure and there's a process related to that.

Have you ever contemplated who was going to be executing those, assuming the project gets approved, who would be executing these authorizations for expenditures?

Would that be something that would be done by FPL? Would it be contracted out to a third party? How would that be done?

A. No, the AFE process is originated by the operator. So they initiate an AFE prior to drilling a well, and the AFE includes all sorts of geologic information about the well, where it's going to be drilled and how it's going to be drilled, and it includes financial information, which is their estimate on a line-by-line basis of the type of costs they expect to incur, tangible and intangible.

That's the request to the company. The controlled areas, they're asking the company do you consent to the drilling of the -- well, the non-operator. The non-operator has that information to review, consults with the operator to make a decision on whether or not to commence drilling.

Q. Has FPL given consideration as to how that process would work if the PSC approves your petition?

A. Yes. It would work the way it works in industry, where the operator, PetroQuest, initiates the -- so the next well that's going to get drilled after the transfer takes place, if it does, they would initiate an ARP. They would send it to FPL as the working interest owner. We would consider whether or not we wanted to drill, which of course we intend to consent to every well unless there's a problem, and then we would authorize. And that's part of the control too, to authorize the commencement of drilling on our behalf for our work.

Q. Who gets the meeting invite when they say we're going to have a meeting in this conference room to talk about whether we can execute this order or does that meeting not even take place?

A. I don't know how Sam Forrest would be -- it's the commercial team.

From an accounting perspective we're taking that AFE, and once authorized commercially then we're going to record those costs in our system. It's not as actual cost, but as estimates to which we will report variance, commercial activity.

Q. Do you know whether you're going to be looped in on that decision?

A. I try to be in on everything in the early days because I want to learn. But no, it is not an accounting exercise. It's a control step, certainly, but it's not an accounting exercise.

Q. Are you aware of any other regulated utilities that are involved in investing in oil and gas plays, such as what is contemplated in FPL's petition?

A. Yes, I am.

Q. Who?

A. Northwestern Energy, I've spoken quite a few times with their assistant comptroller, who is a colleague of mine.

Q. Anybody else?

A. That's the only company I've spoken with. I think there are a couple of others.

Q. And they do electricity and gas?

A. Yes, they do.

Q. If this turns out to be a roaring success or if this turns out to be a dismal failure, either way, who within FPL or within the NextEra organization, who gets credit for the idea?

A. I don't know whose idea it was. I wish it would have been mine.

MR. BUTLER: Unless it's a dismal failure.

Q. Do you see any risk associated with this proposed business arrangement that could befall FPL's shareholders? Have you looked at it from that perspective?

A. Well, the risks that could impact shareholders of the company are really no different than the risks that could impact our shareholders today, and that would be that we would be somehow negligent or imprudent in executing on these activities and there would be a financial price to

pay, and that price would be paid by shareholders.
Q. And when you say "we", really that's PetroQuest, correct?
A. No. I mean, again, we're not a completely passive party. They act as operator, but there is a level of commercial activity that takes place.
Q. So if they're not doing a good job, they're already delayed on this one well that turns into months and months and months, what do you understand to be your recourse?
A. You know, I'm not -- I've certainly read the contract 13 times to make sure I understood it and I can't recite to you all the contractual remedies, but the company has, as it would in any commercial arrangement, some actions that it can take to try to right the shift.
Q. And you don't understand that one of those is to go and say, "Hey, we're taking over, we're going to Oklahoma to operate this business"?
A. I do not know. I know that is a very limited -- it is an option in our other joint venture arrangements, if the operator is acting in a negligent manner.
Q. You don't have any history of accounting related to this area, oil and gas, correct?

A. No, I do not.

Q. Were you involved in the development of FPL's proposed guidelines?

A. No, I was not.

Q. You referenced some separate legal entities for regulated operations. Both of them, as I read it, were entities that hold money; is that right?

A. I'm sorry, are you referring to page --

Q. Line 3, you're asked the question: "Has FPL previously had separate legal entities for regulated operations?"

A. Yes, KPB was originally set up to -- we were evidently factoring the receivables years ago and it was a way in which to minimize tax obligations. KPB now holds the trust associated with the -- predominantly the storm funds and some of the decommissioning trust funds.

Q. Was it a coincidence that none of these relate to trust-like arrangements or is that not contemplated with respect to the New Co. as well?

A. I'm sorry, I don't understand.

Q. I just was -- I noticed that both of the examples you used are trust-type arrangements. There was no rhyme or reason to that, right?

A. Well, recovery funding does not have a trust. It's mortgage-backed securities. It's the securitization for storm losses that we suffered back in the mid 2000s that are being recovered through this legal entity that holds that securitized asset.

Q. Page 13, "Is the calculation of earned acreage to be paid to USG reasonable?" From whose perspective are you answering that question?

A. I'm sorry, I see the 10.2, but where are you referring to?

Q. Page 13.

A. Oh, the question.

Q. "Is the calculation of earned acreage to be paid USG reasonable?" "Yes," and you go on from there.

Whose perspective are you answering that question from, FPL's, that you believe that it was a reasonable cost?

A. Yes.

Q. And you didn't do any independent analysis to reach that conclusion?

A. No. Again, I wasn't assessing a market value. We were assessing the cost of that earned acreage based on carry paid.

MR. MOYLE: Do you have any questions?

MR. BUTLER: I do not.

MR. MOYLE: Thank you for your patience, and for the record, I think I gave you five minutes to get to your appointment.

MR. BUTLER: I have one redirect question.

CROSS EXAMINATION

BY MR. BUTLER:

Q. Ms. Ousdahl, you were asked earlier by Mr. Moyle about recovery of cost associated with the Woodford project, and you answered that all of the costs would be included in the Fuel Clause calculation for recovery.

How would that work with respect to costs of FPL personnel?

A. Right. I was intent on explaining that we were not including deferred taxes in recovery, but we would not include any non-incremental costs. So only the incremental costs associated with this activity would be included in cost recovery.

MR. BUTLER: Okay, thank you. That's all the questions I have.

(Whereupon, the taking of the deposition was concluded at 5:25 p.m.)

\- - -

CERTIFICATE OF OATH

I, Alice J. Teslicko, RMR, a Notary Public for the State of Florida at large, do hereby certify that the witness, KIMBERLY OUSDAHL, appeared personally before me and was duly sworn.

Signed and sealed this 18th day of November, 2014.

____

Alice J. Teslicko, RMR

Commission No. EE031095
My Commission Expires:
December 14, 2014

CERTIFICATE

STATE OF FLORIDA)
) ss.
COUNTY OF PALM BEACH)

I, ALICE TESLICKO, RMR, a Registered Merit Reporter and Notary Public for the State of Florida at Large, do hereby certify that I reported the deposition of Kimberly Ousdahl, a witness called by the Office of Public Counsel in the above-styled cause; and that the foregoing pages constitute a true and correct transcription of my shorthand report of the deposition of said witness.

I further certify that I am not an attorney or counsel of any of the parties, nor a relative or employee of counsel connected with the action, nor financially interested in the action.

WITNESS my hand and official seal in the City of Hobe Sound, County of Martin, State of Florida, this 18th day of November, 2014.

____
Alice J. Teslicko, RMR

My commission expires:
December 14, 2014
Commission No. EE310095

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

KIMBERLY OUSDAHL

SUBSCRIBED AND SWORN before and to me

this ____ day of _________, ____.

____

NOTARY PUBLIC

My Commission expires:

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON

I, ____________________, do hereby certify that I have read the foregoing transcript of my deposition, given on ________________, and that together with any additions or corrections made herein, it is true and correct.

____
Deponent

The foregoing instrument was acknowledged before me this _____ day of ___________, 2014, by ______________________, who is personally known to me or has produced ____________________ as identification and who did not take an oath.

____
Notary Signature

NOTARY PUBLIC, State of Florida
____
Commission Number

Q.

Please provide a current corporate organization chart for NextEra Energy, Inc., in the form of the "Entity Organization Report" that FPL attaches to Diversification Reports that it submits to the Florida Public Service Commission. The chart should display all subsidiaries and affiliates at all levels of its corporate structure, including, but not limited to, limited liability companies, partnerships, and joint ventures. This request for a corporate organization chart includes, but is not limited to, all subsidiaries and/or affiliates of USG.

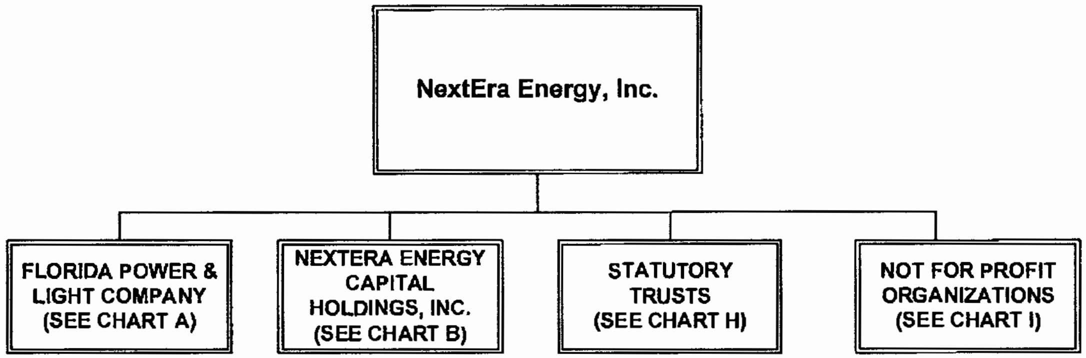
A.

Documents responsive to this request are provided as Bates Nos. FCR-14-00649 through FCR-14-00699.

EXHIBIT
1
Gistafe 11/12/14

Reflects corporate structure as of July 31, 2014

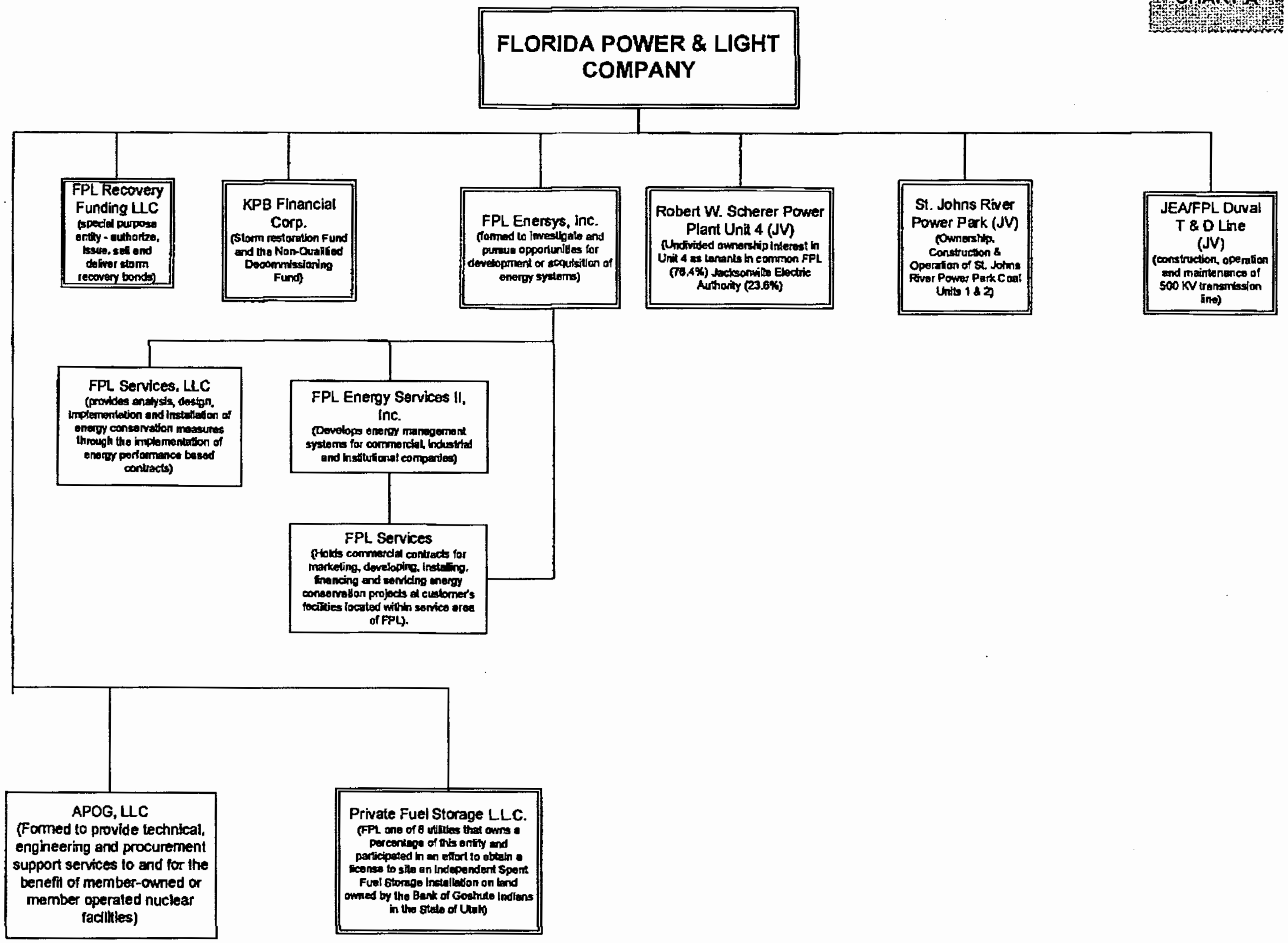
NextEra Energy, Inc.
Entity Organization Chart



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

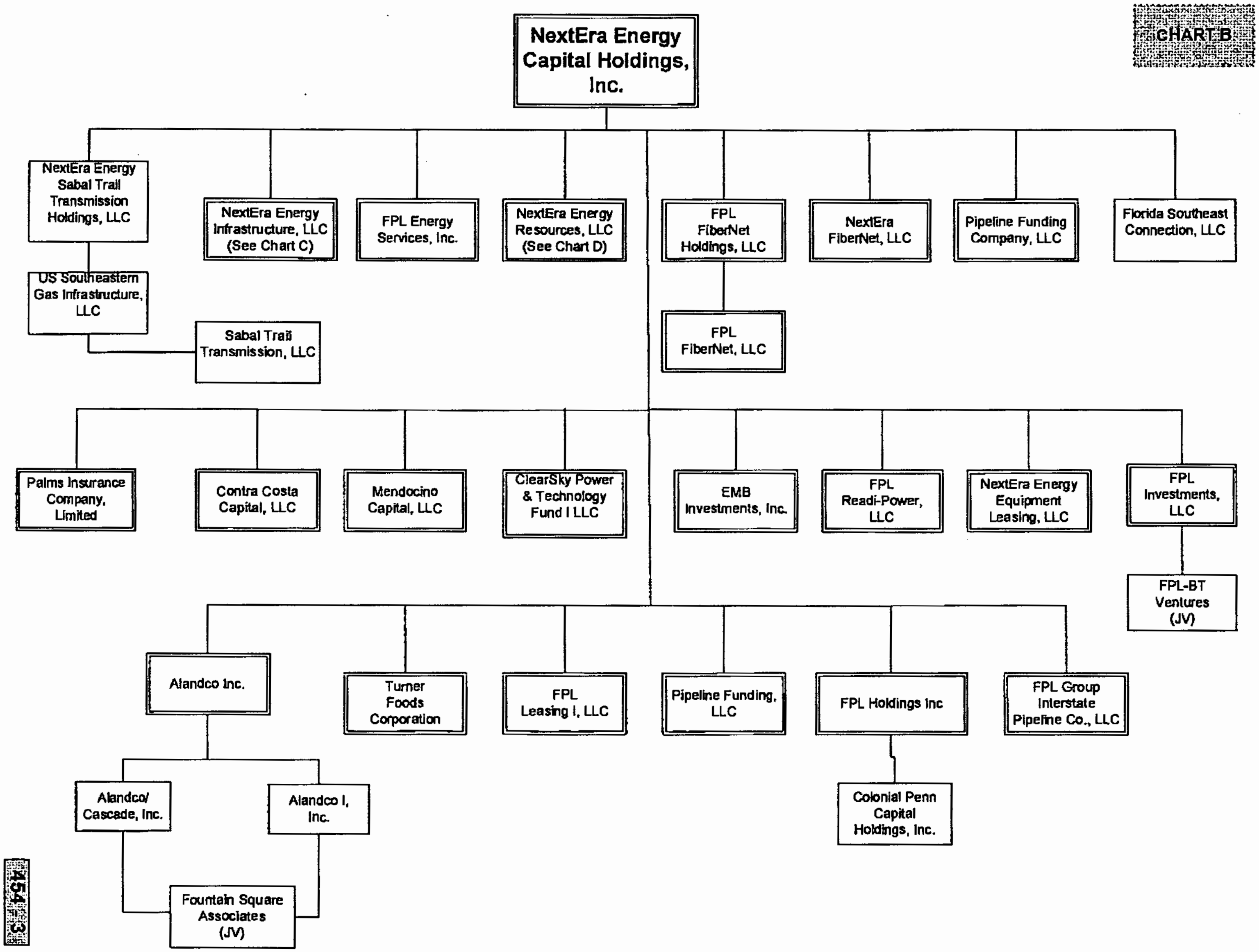
CHART A



454-2

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

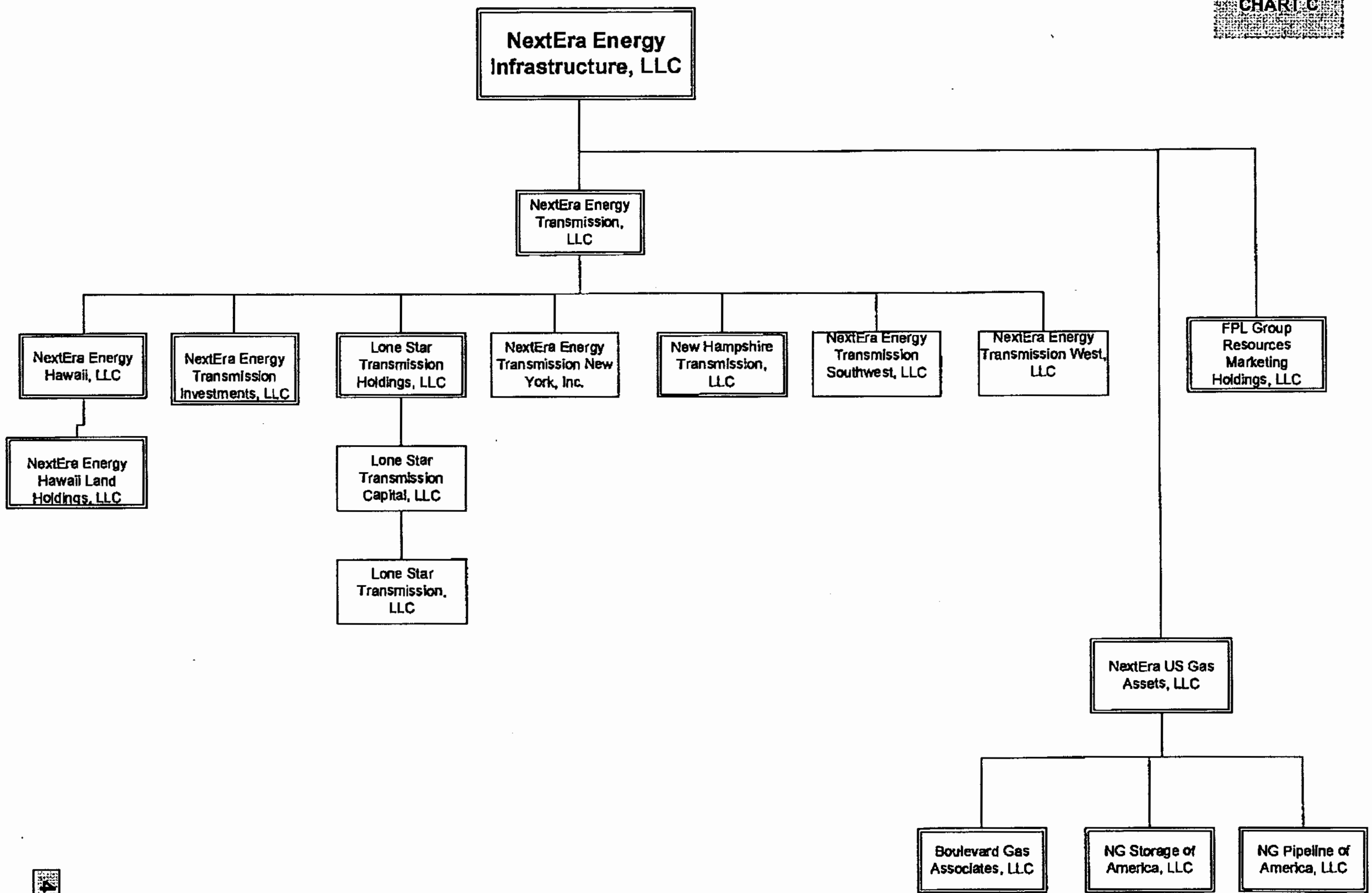
Reflects corporate structure as of July 31, 2014



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART C

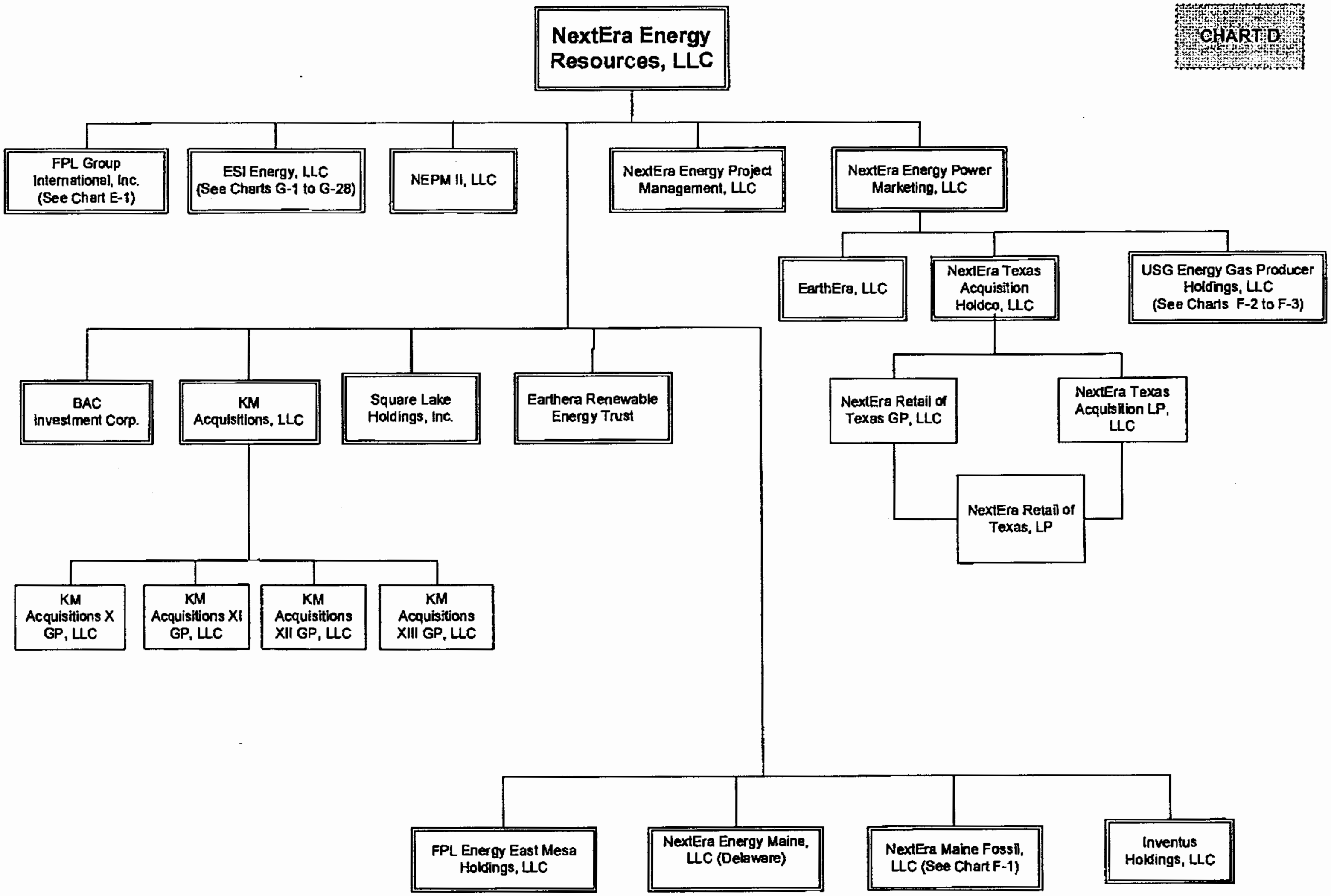
Reflects corporate structure as of July 31, 2014



454-4

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

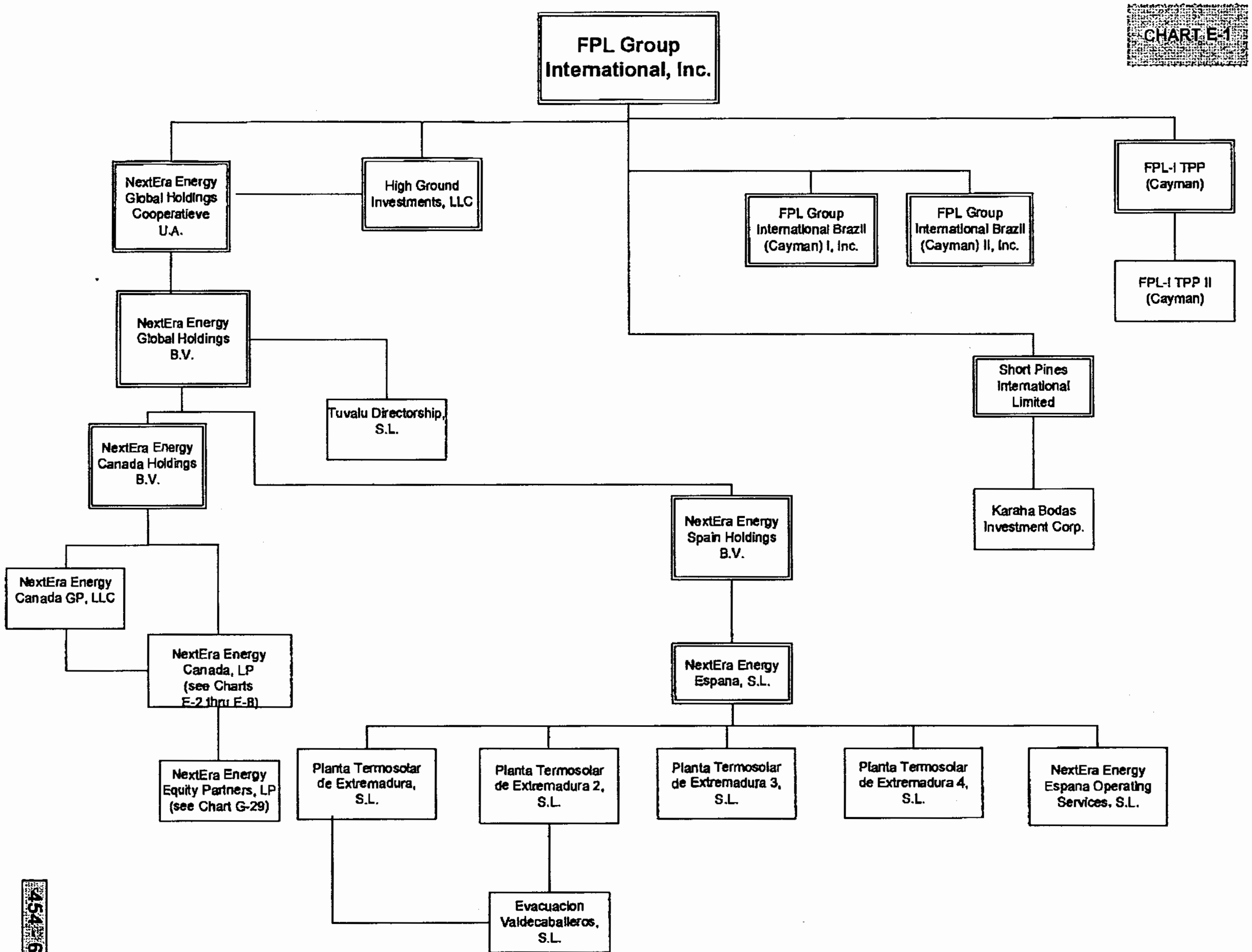


454-5

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-1



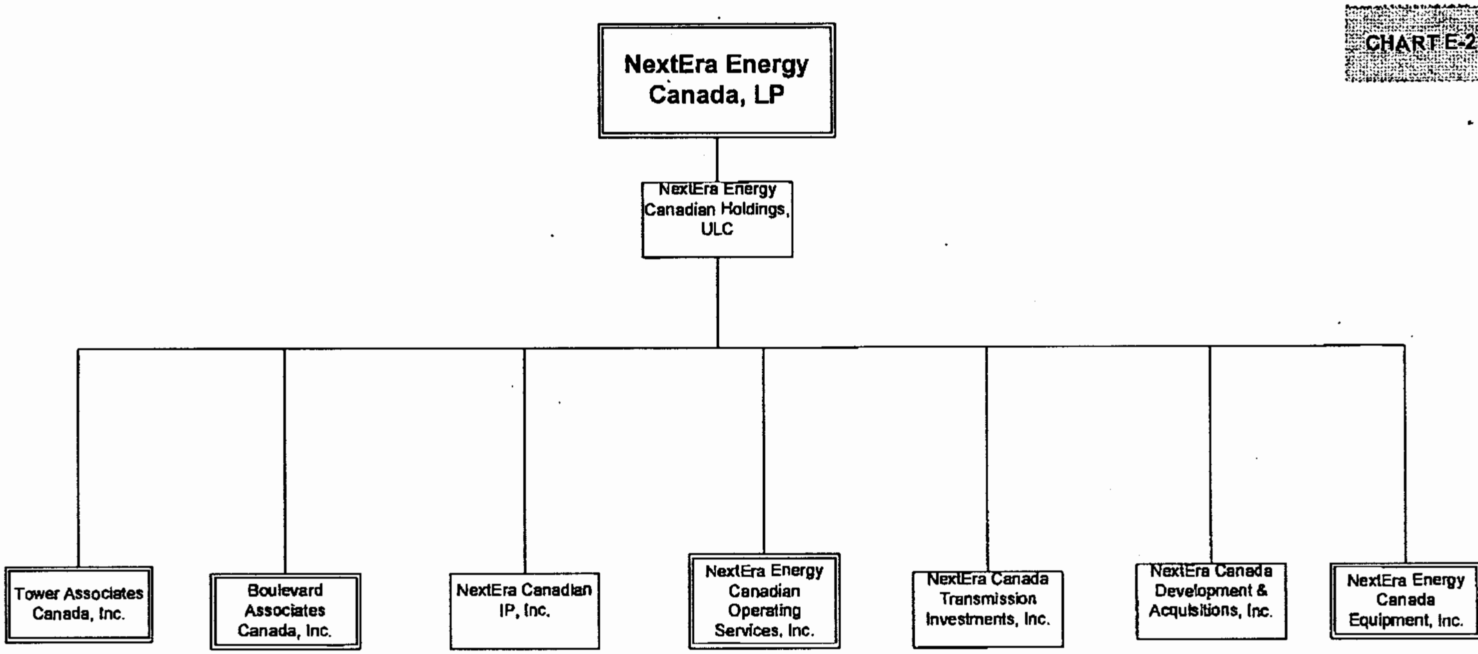
4546

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

FCR-14-00654

Reflects corporate structure as of July 31, 2014

CHART E-2

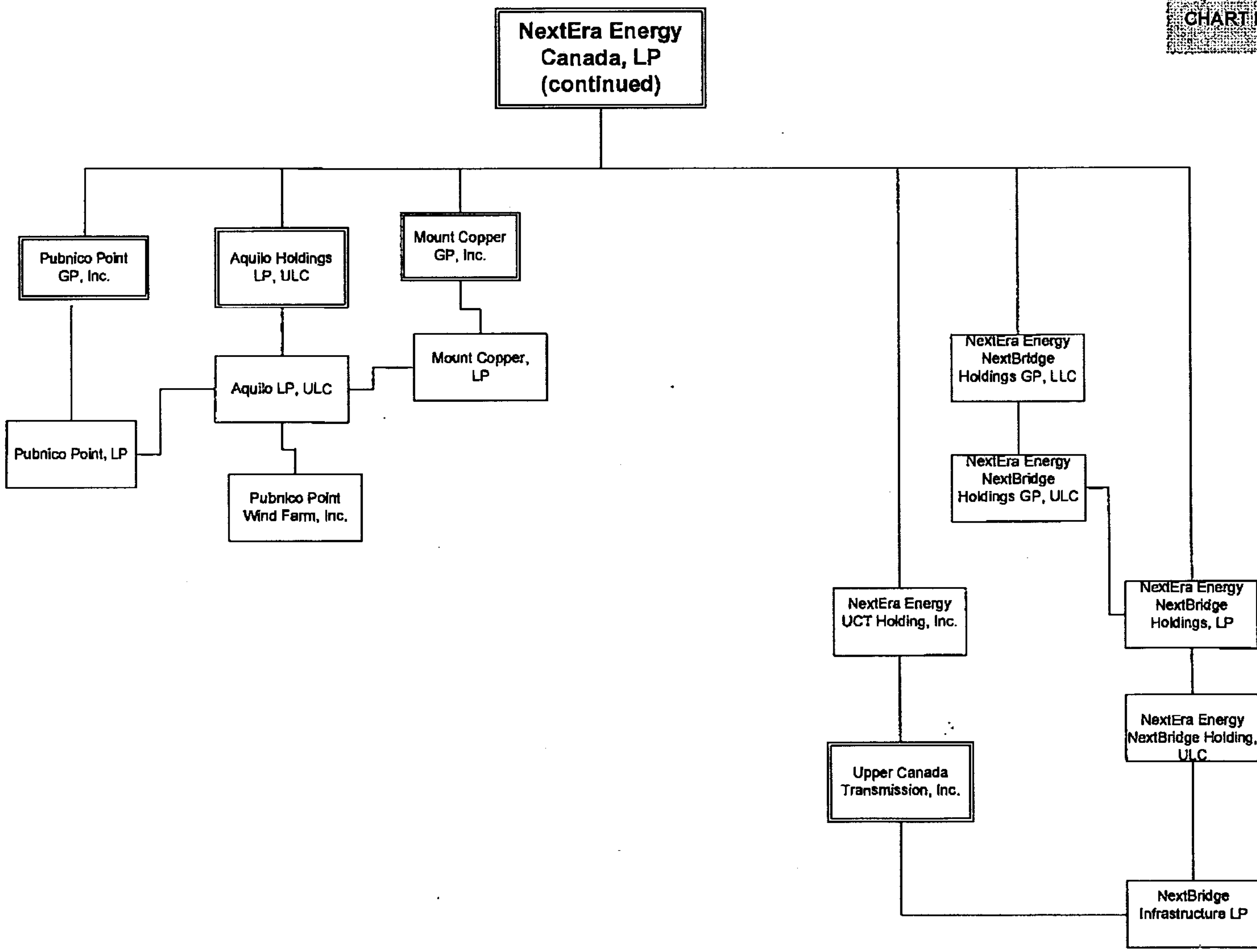


454-6A

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-3

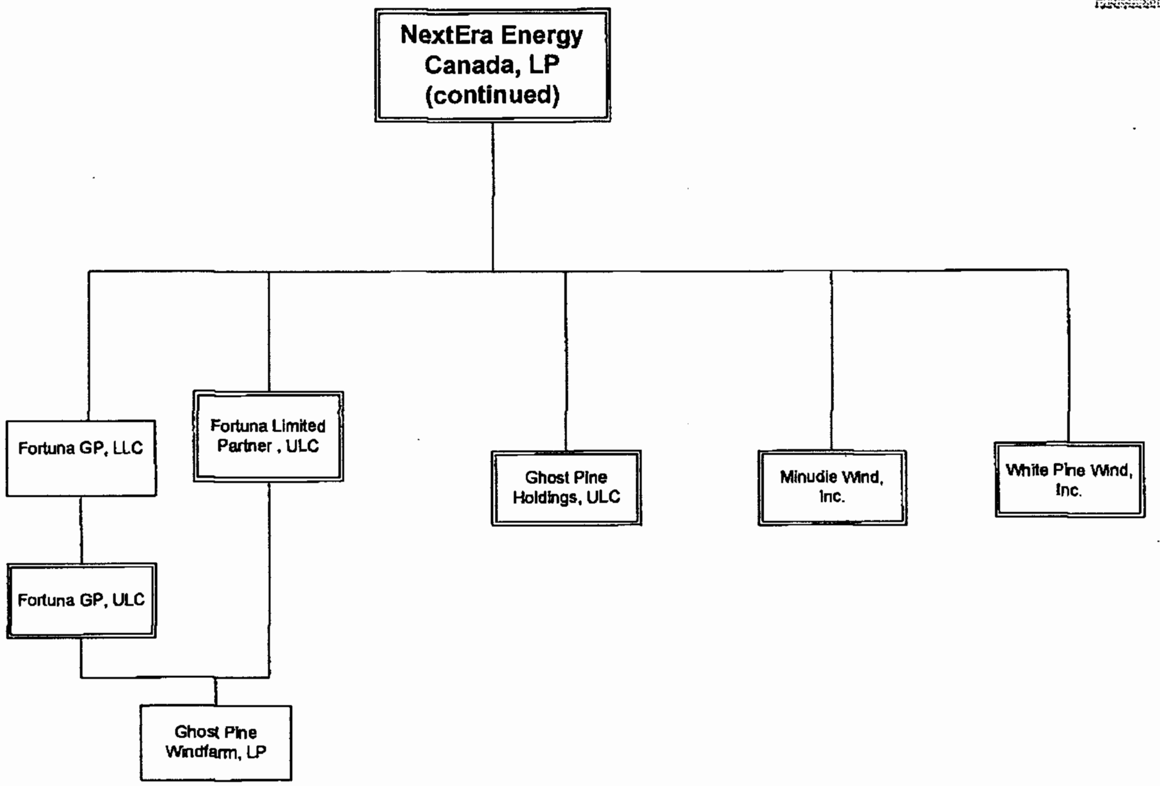


454-6B

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-4

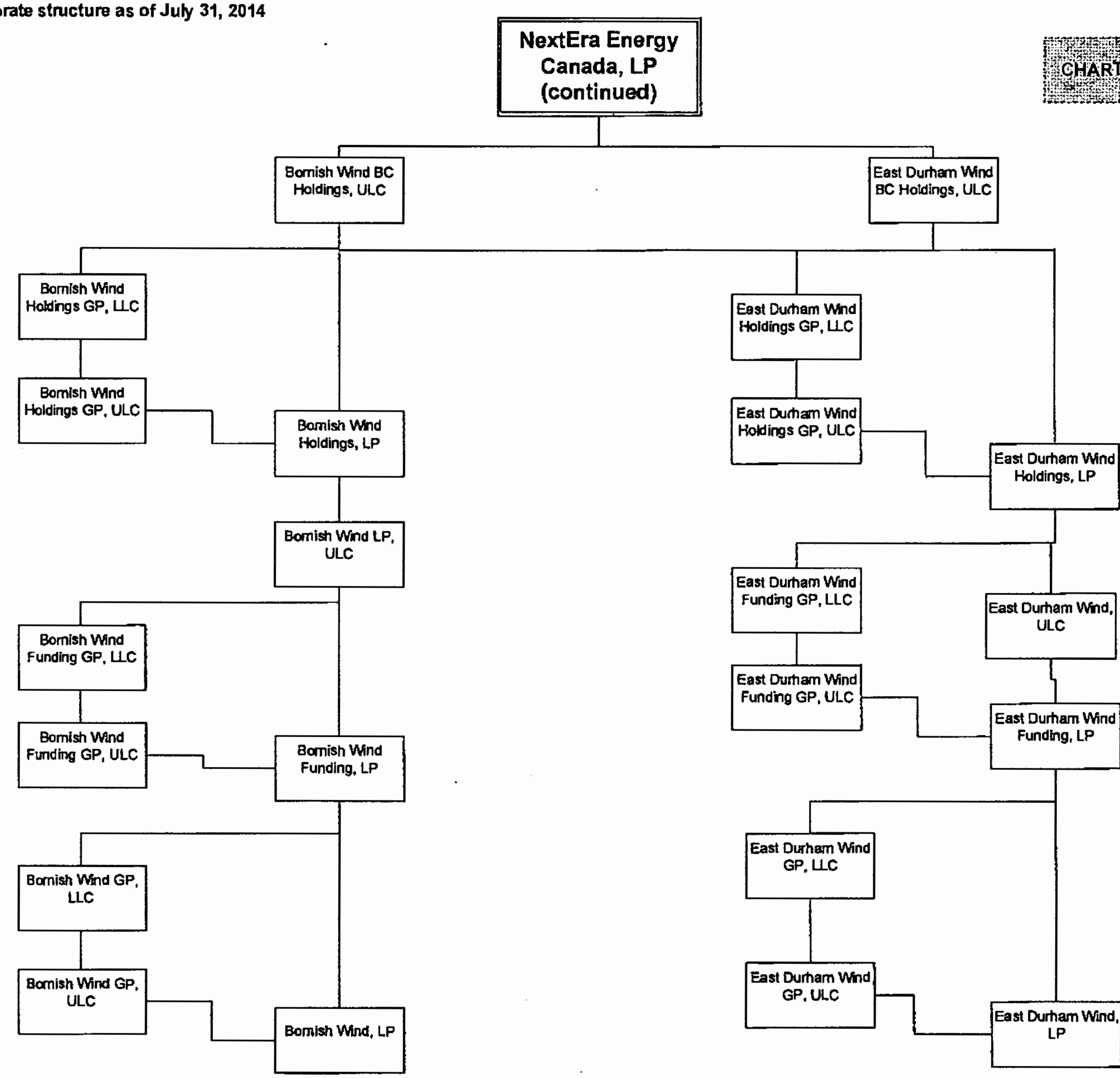


45456

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-5

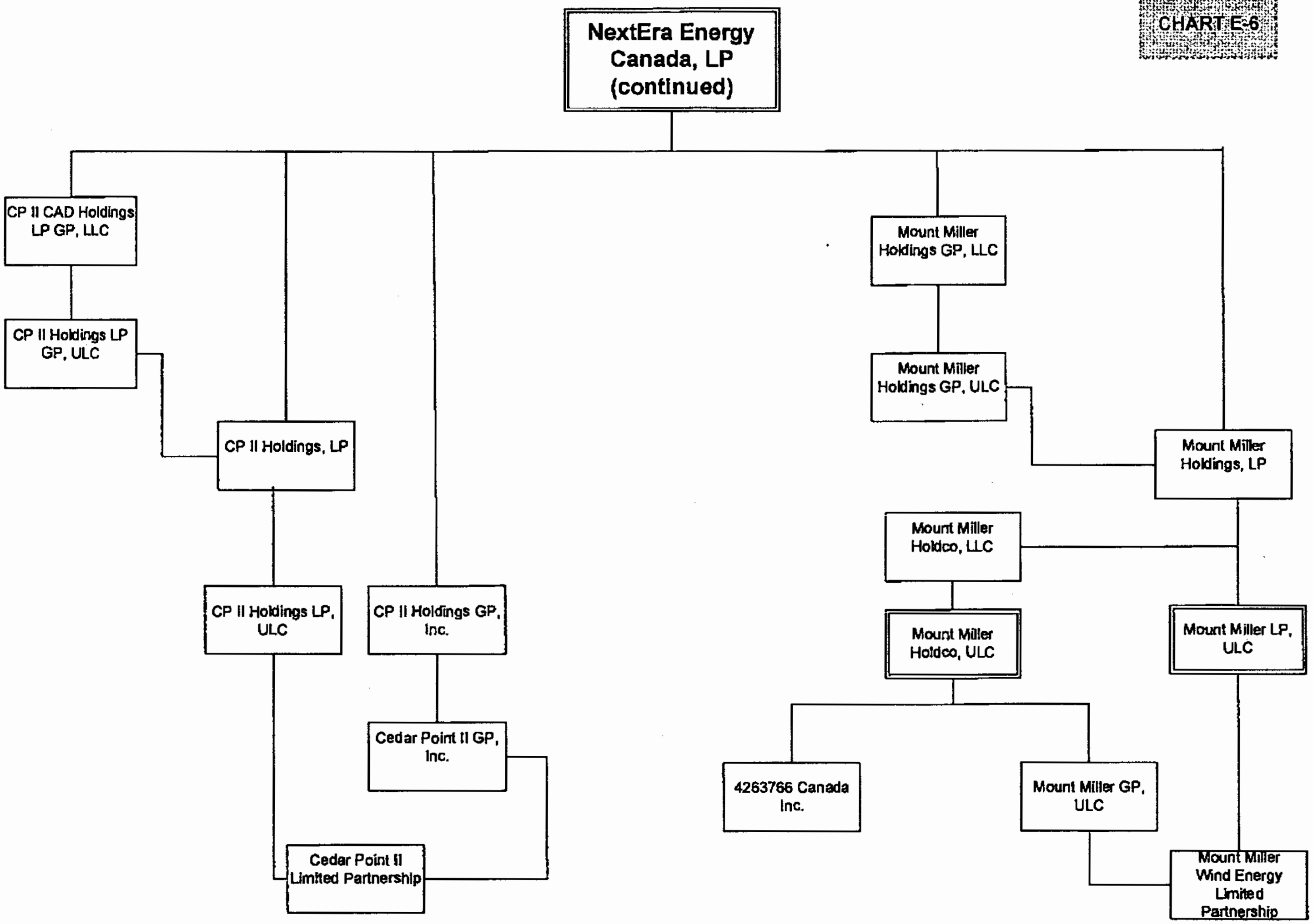


454-6D

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-6

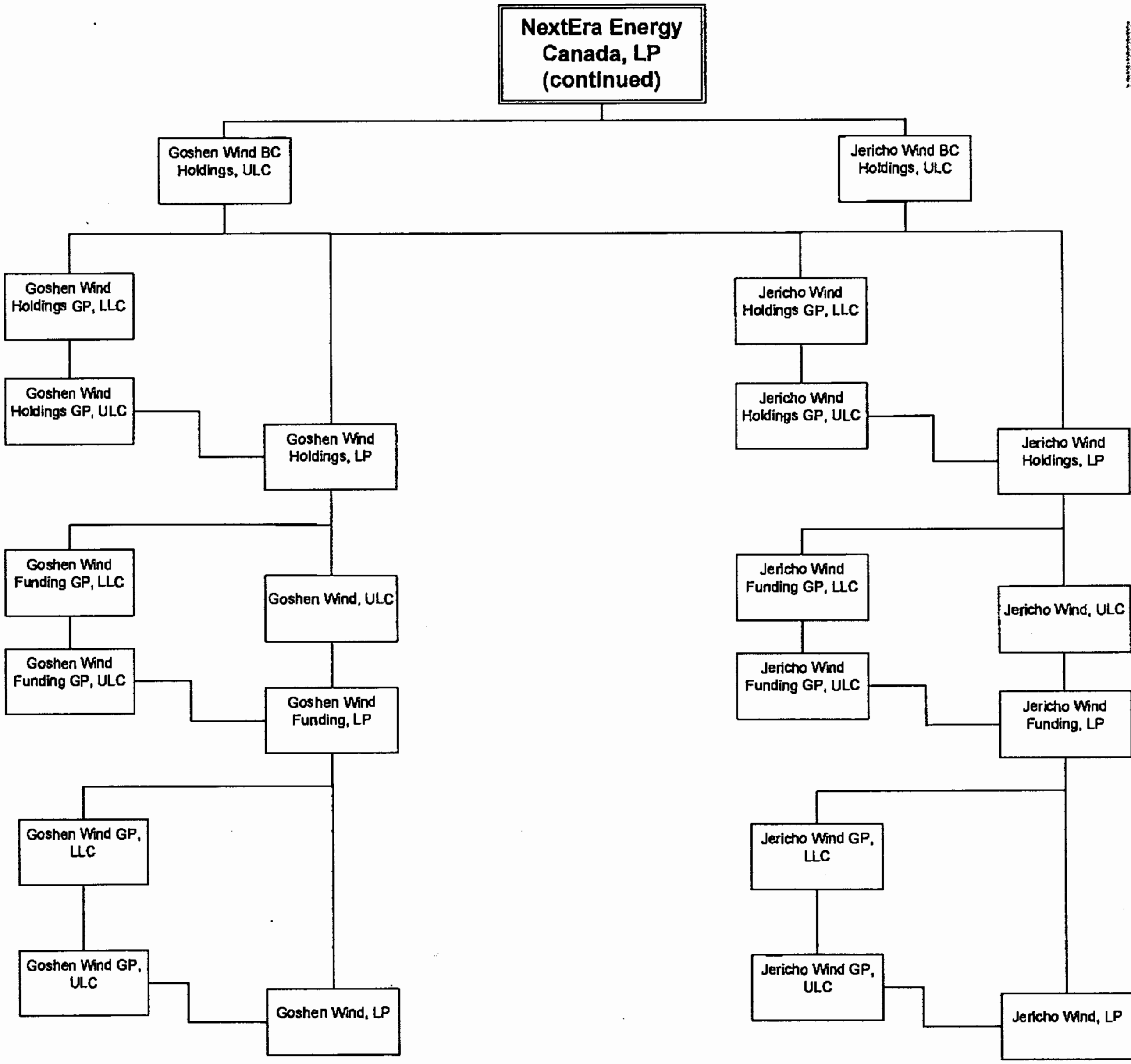


454-6E

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-7



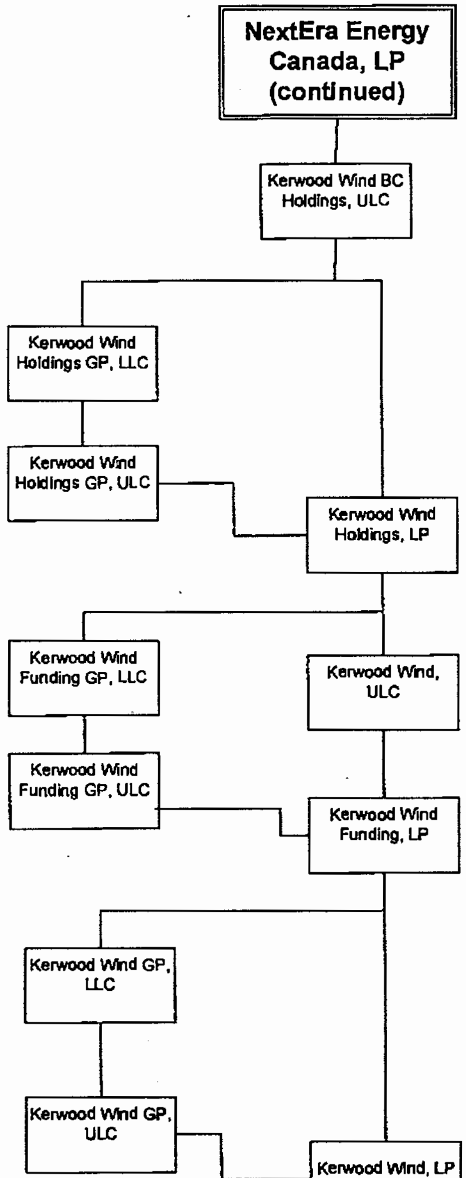
454-6F

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

FCR-14-00660

Reflects corporate structure as of July 31, 2014

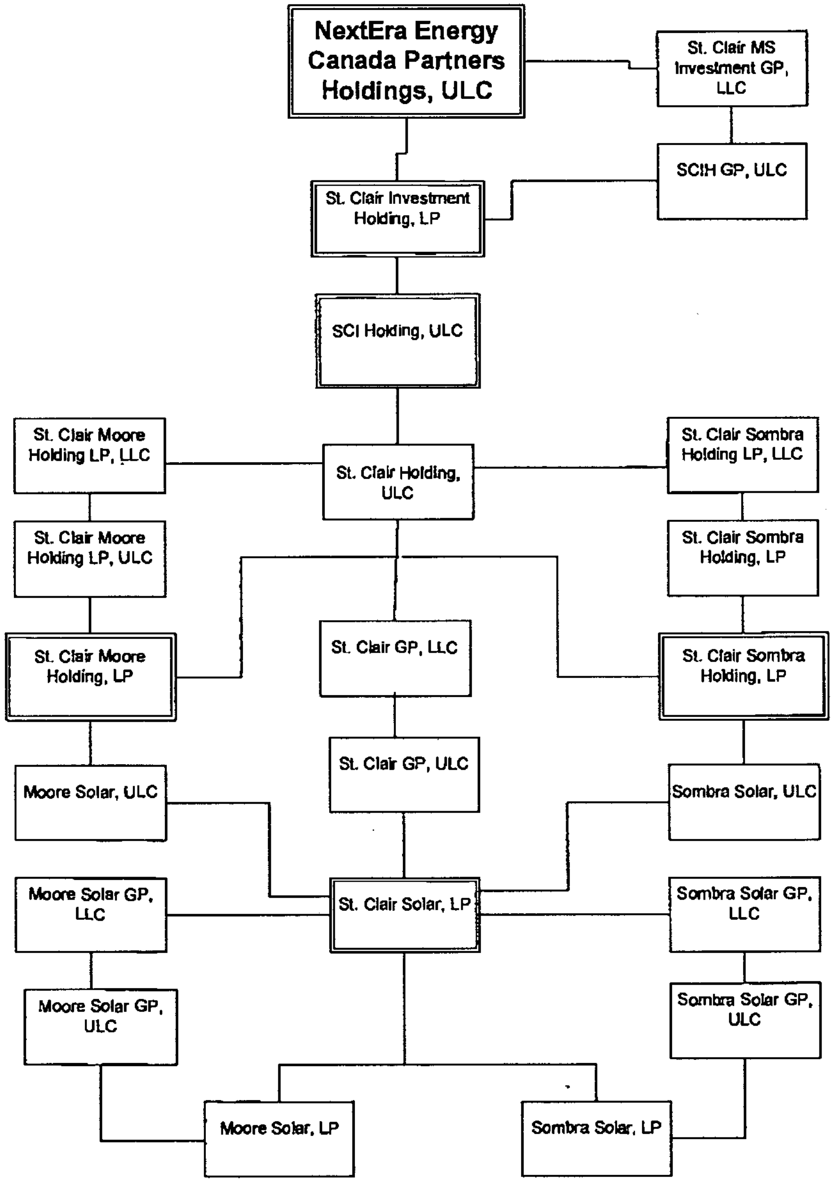
CHART E-8



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART E-9

Reflects corporate structure as of July 31, 2014

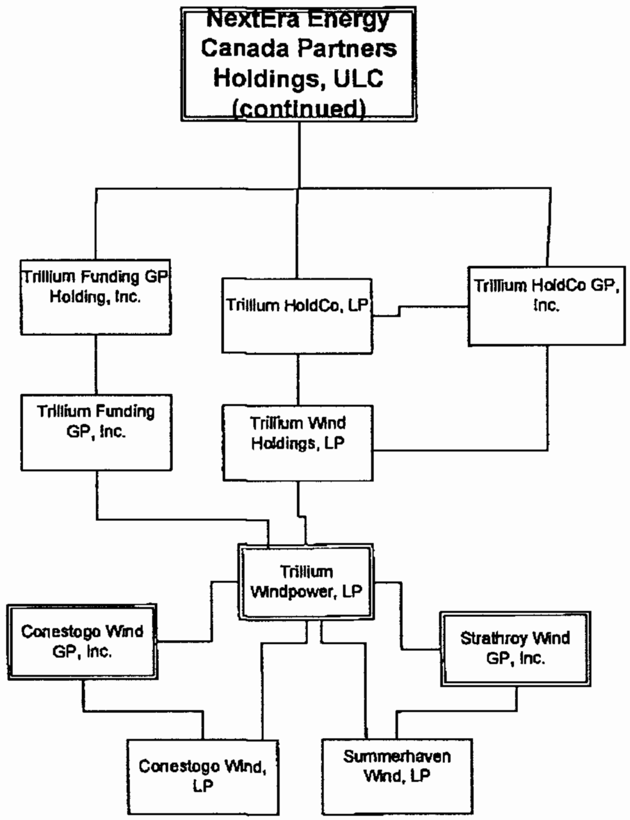


454-6H

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-10

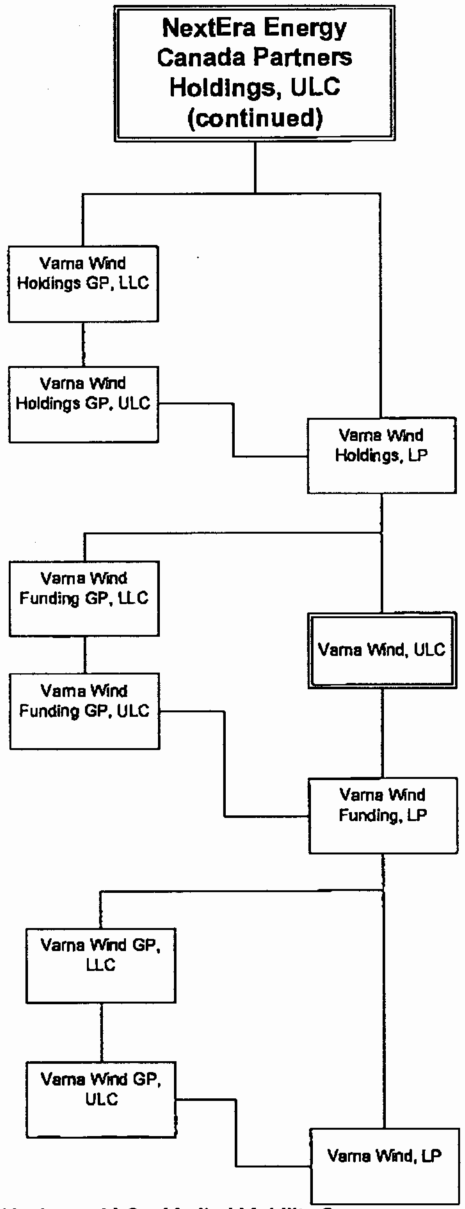


454-61

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART E-11

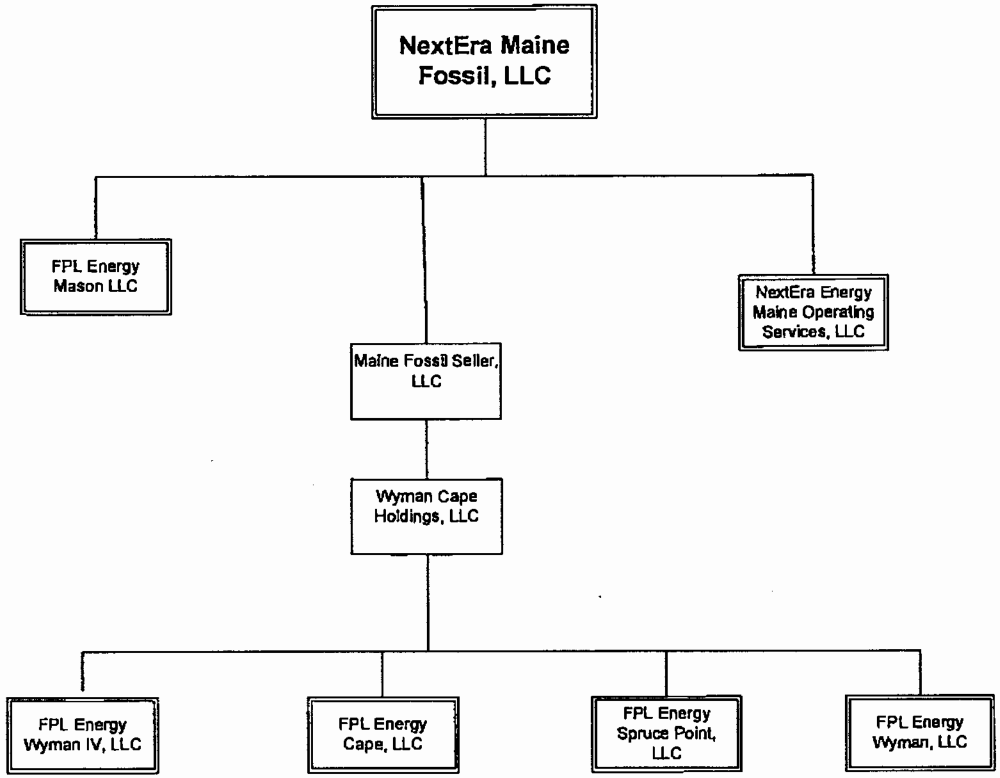


454-63

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

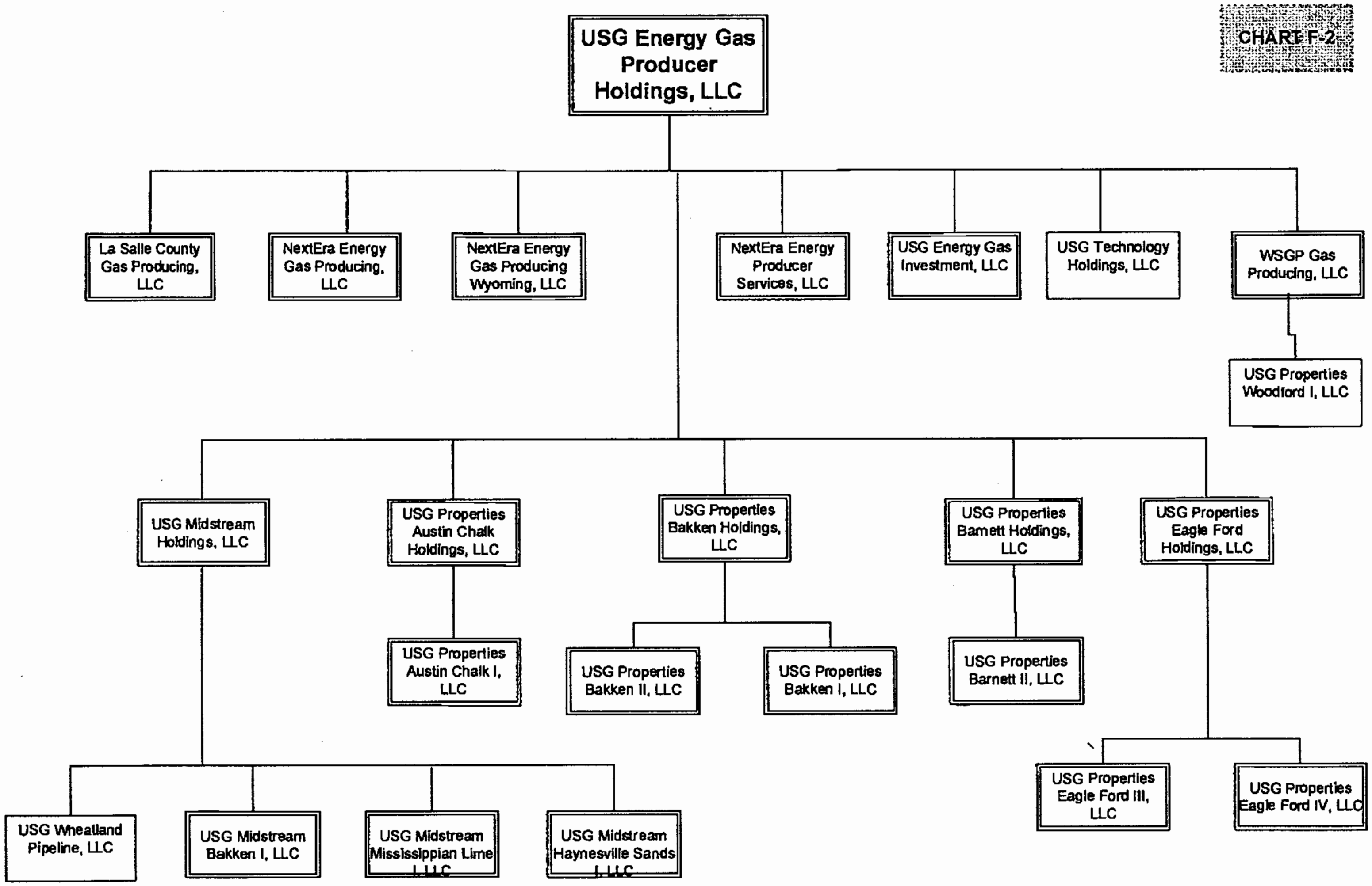
CHART F-1



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART F-2

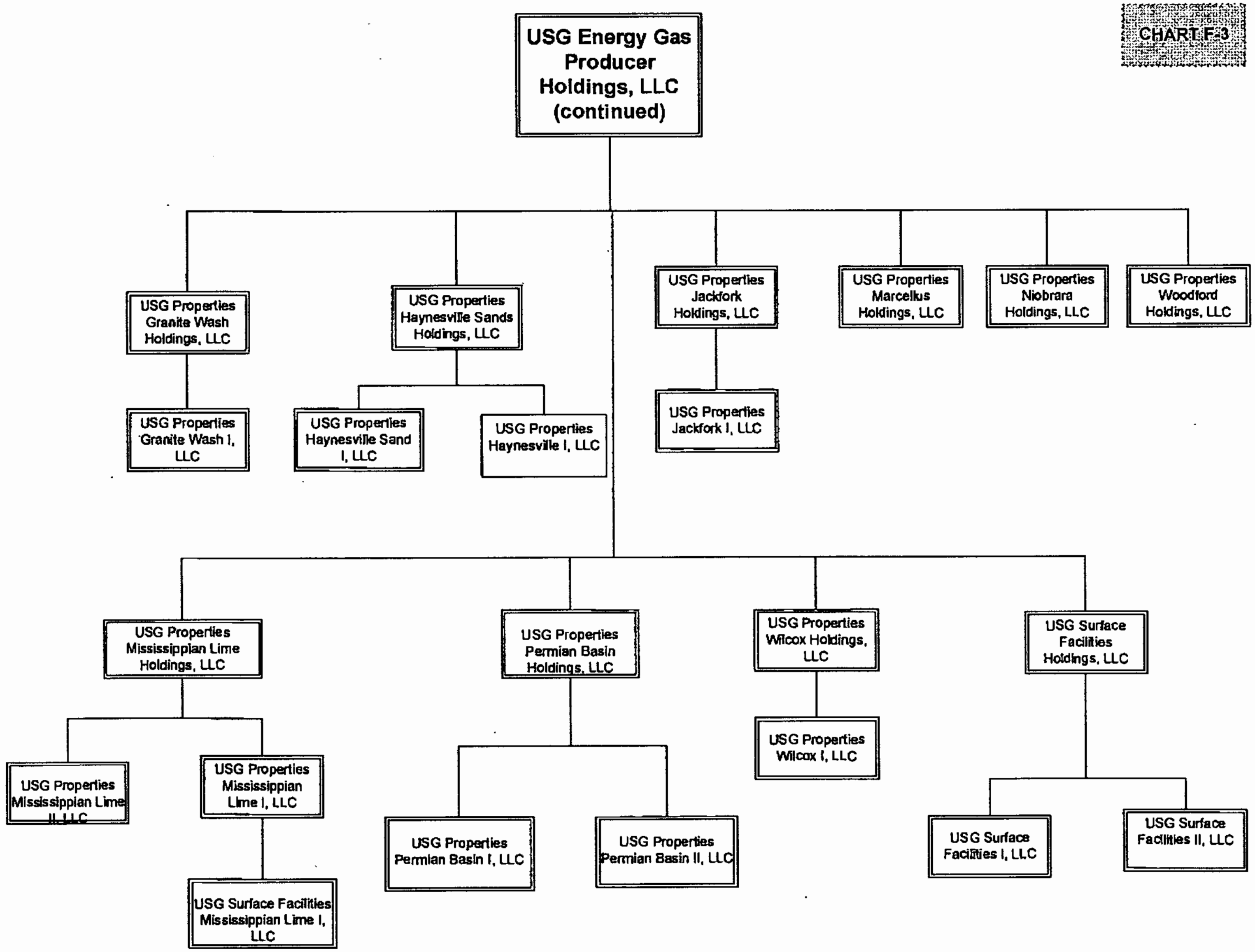


454-8

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

CHART F-3

Reflects corporate structure as of July 31, 2014

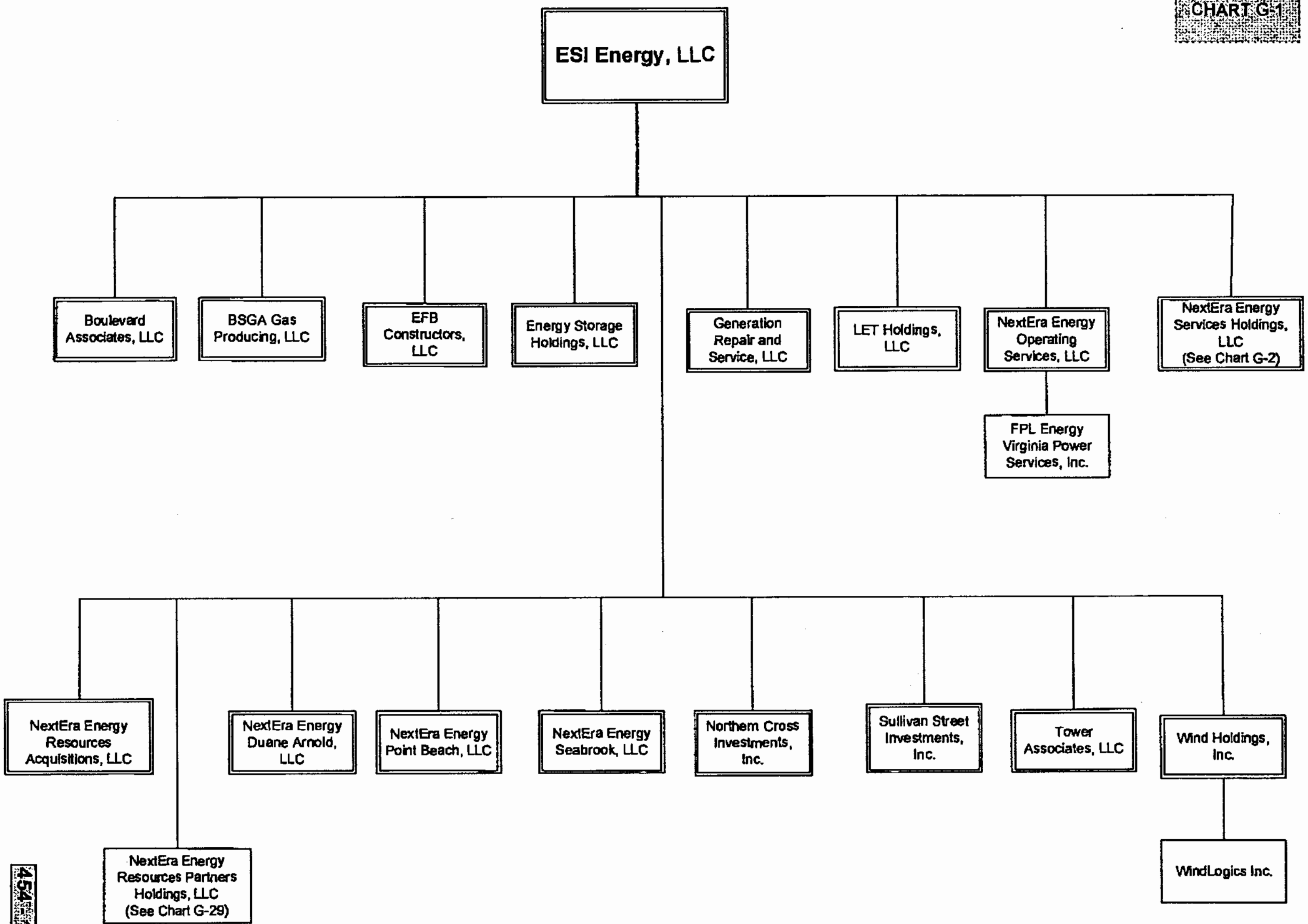


454-9

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-1



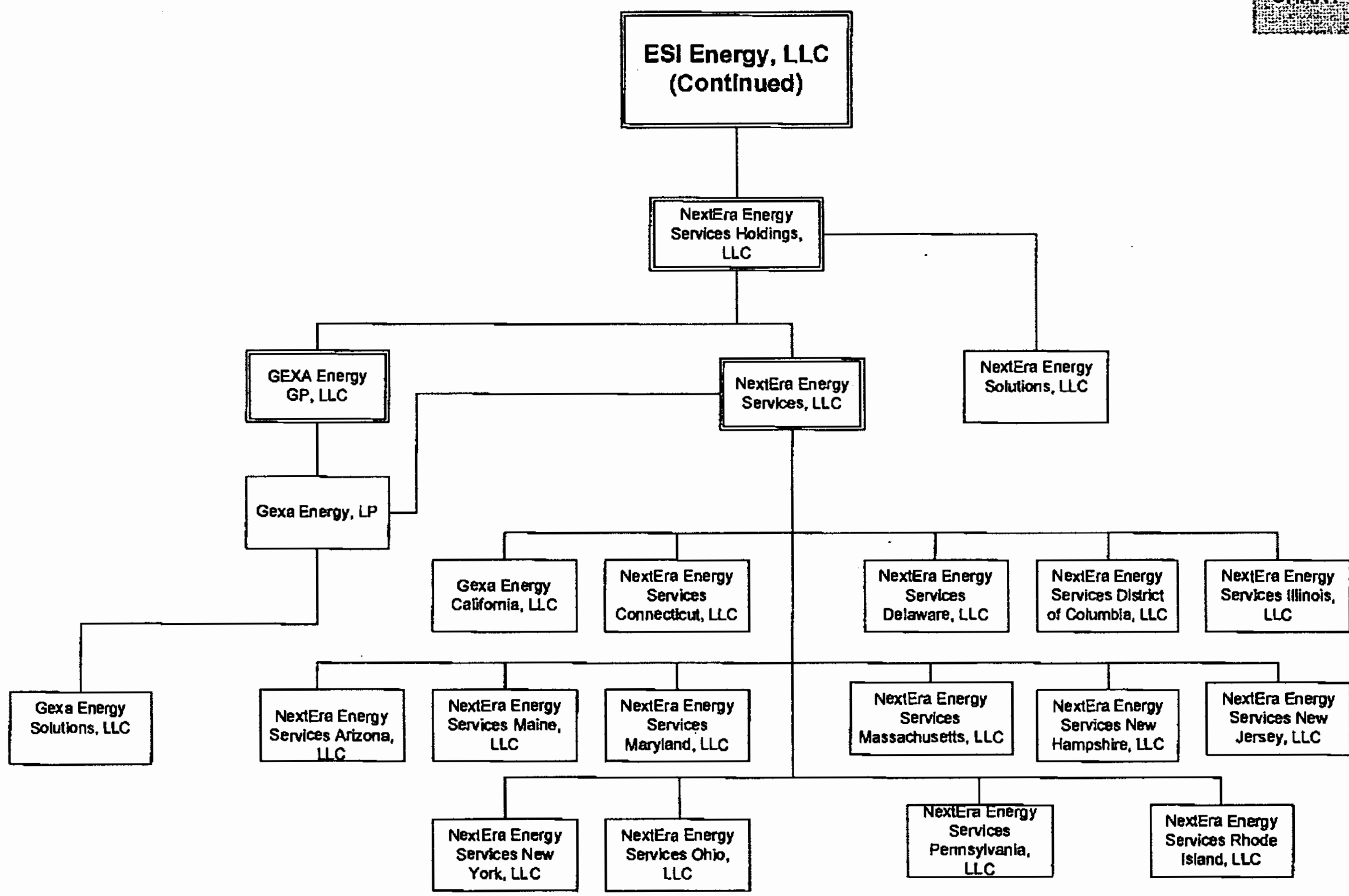
454-10

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

FCR-14-00668

Reflects corporate structure as of July 31, 2014

CHART G-2

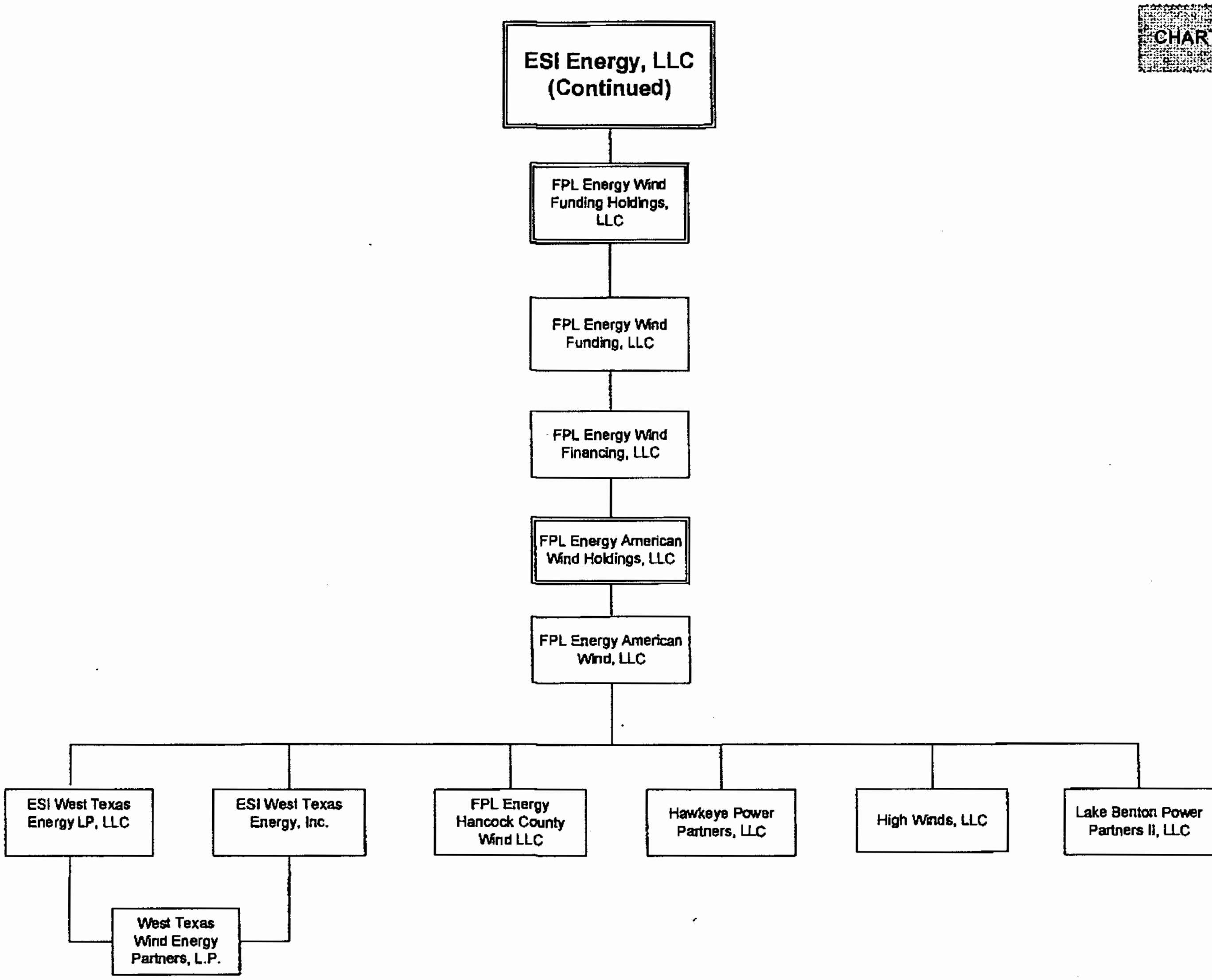


454-11

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-3

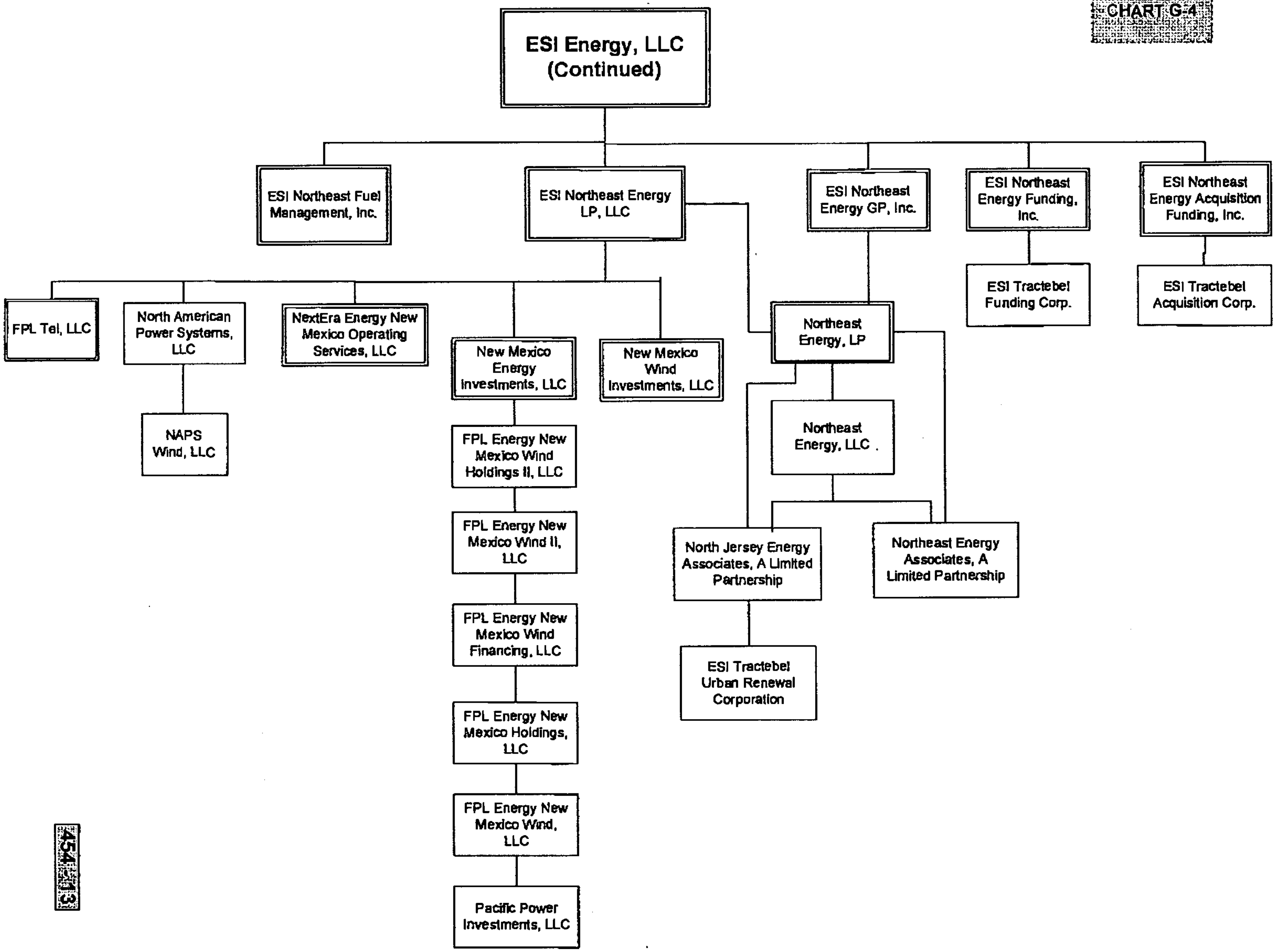


454-12

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-4

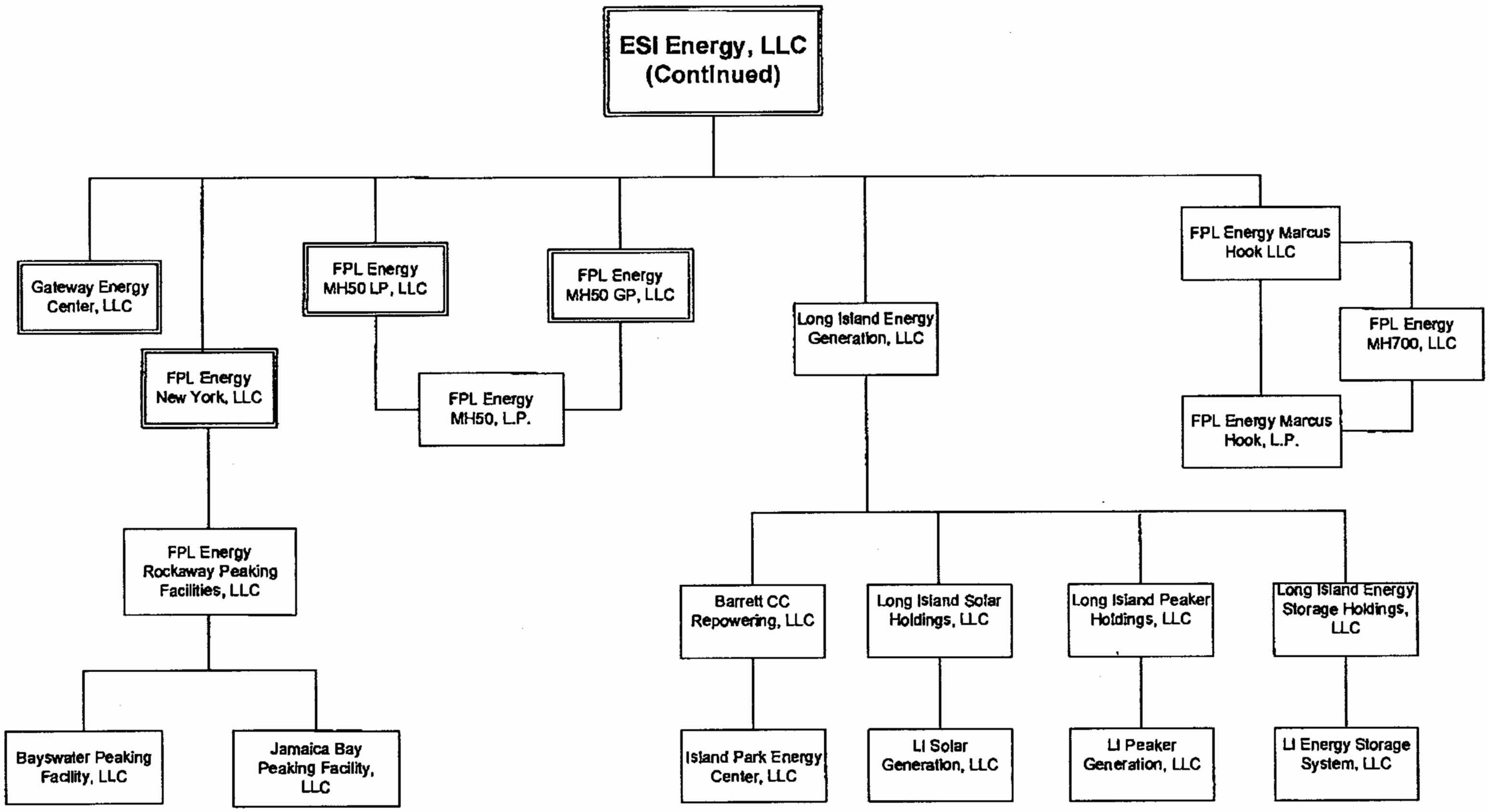


454513

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

Chart G-5

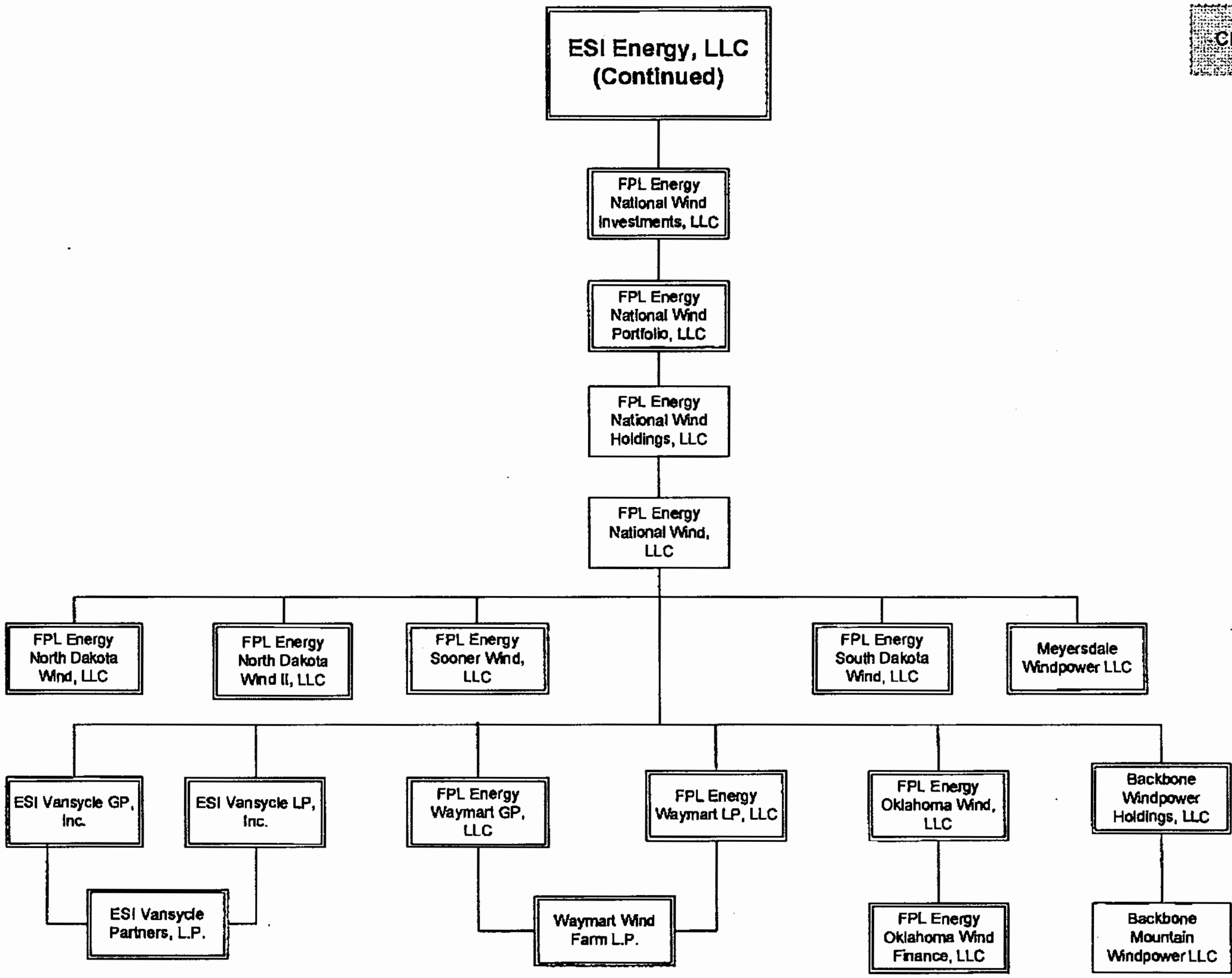


454-14

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

Chart G-6

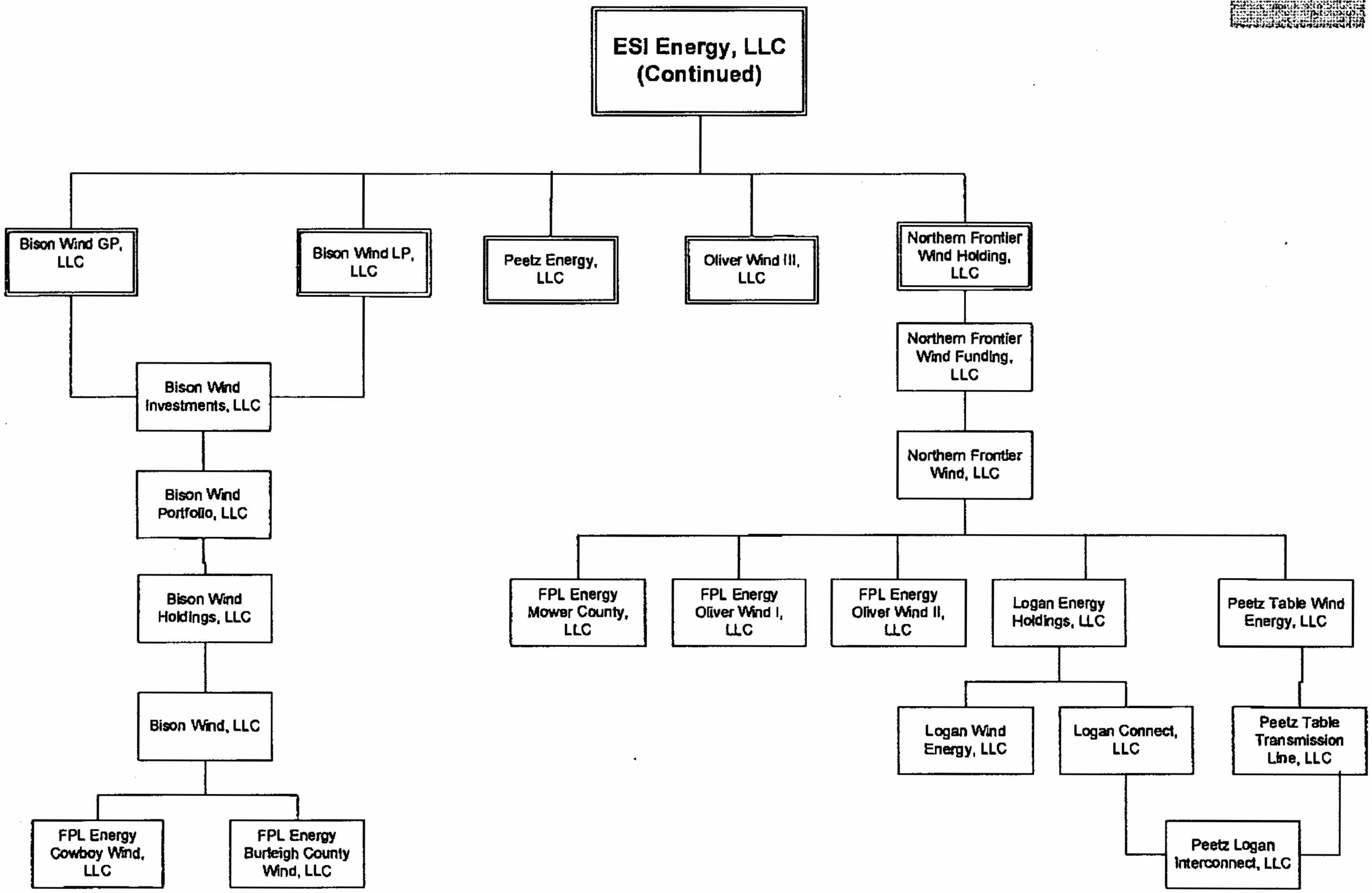


454-15

LP = Limited Partnership   GP = General Partnership   JV = Joint Venture   LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-7

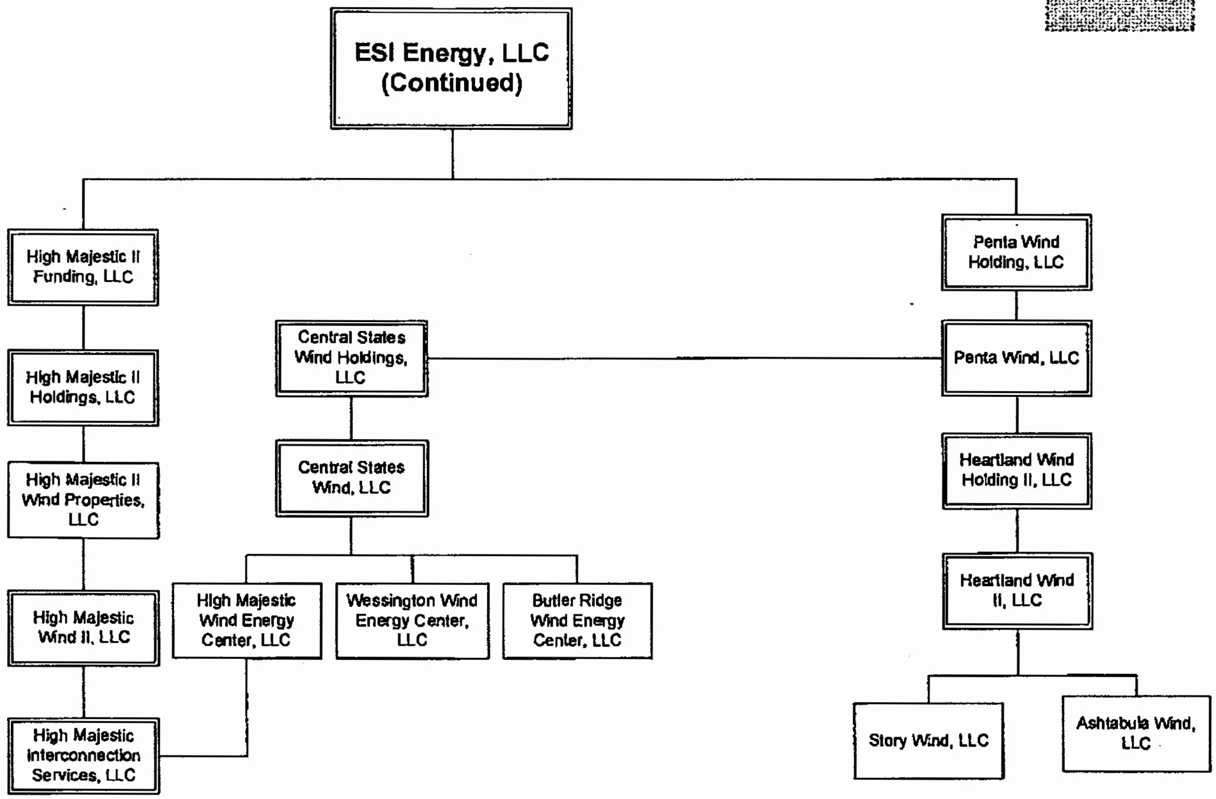


454-16

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-8

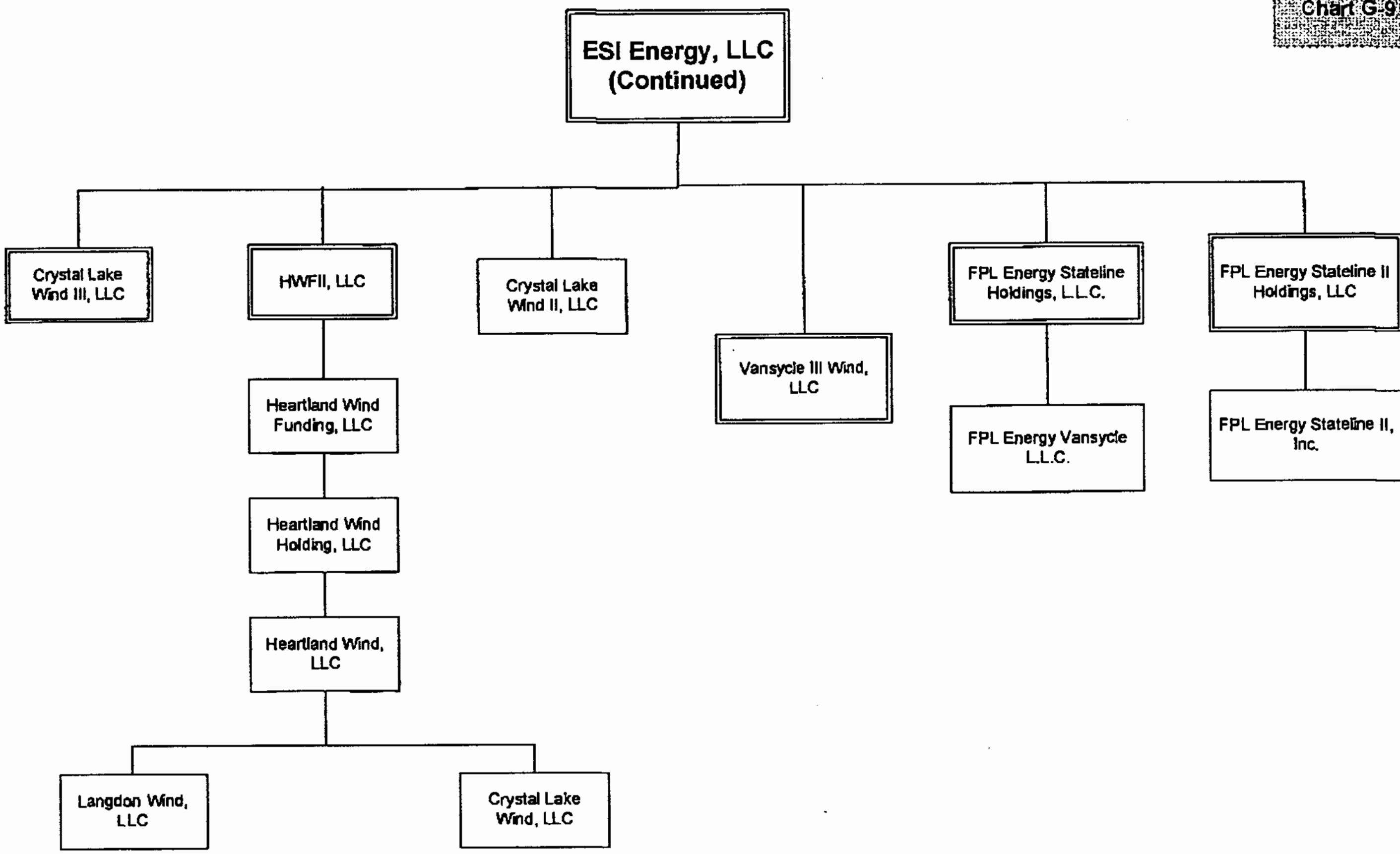


454-17

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

Chart G-9

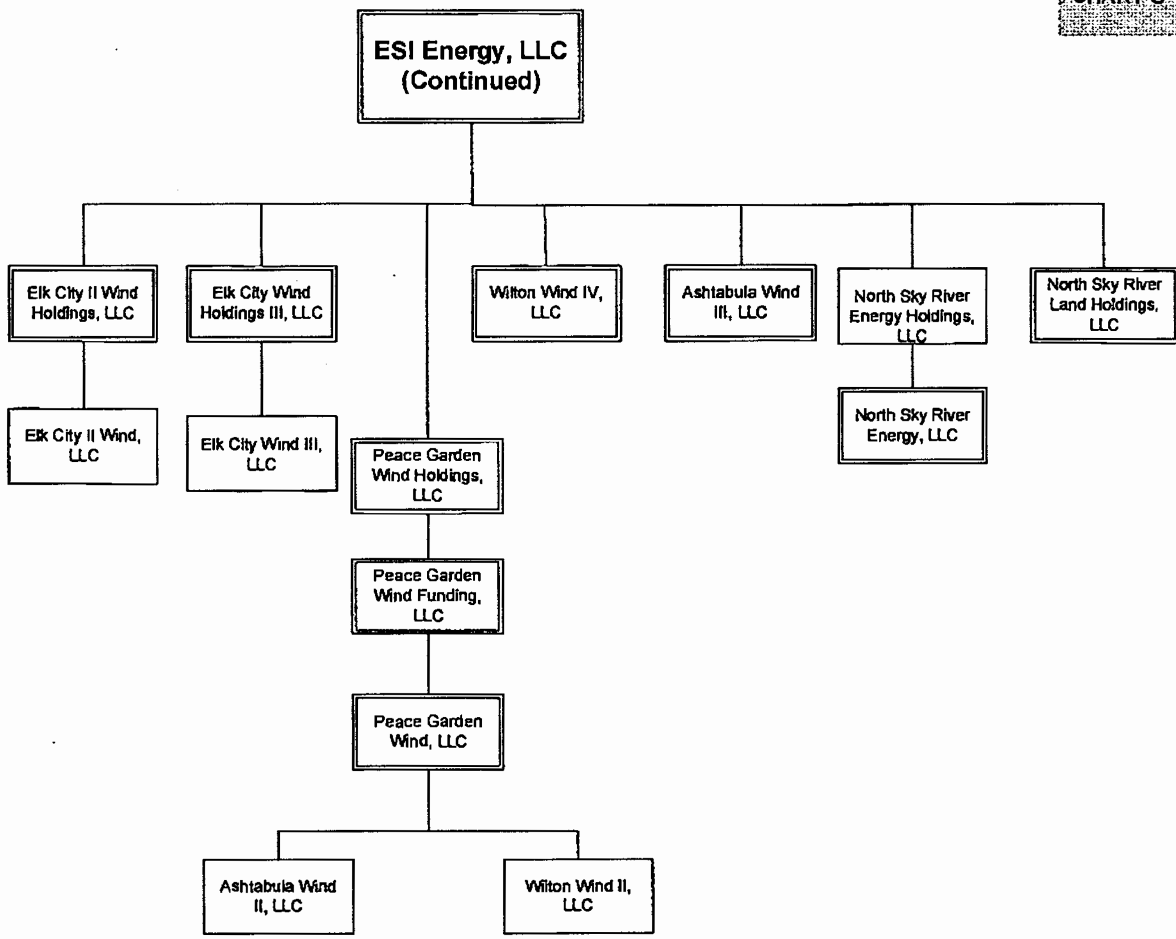


454 18

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-10

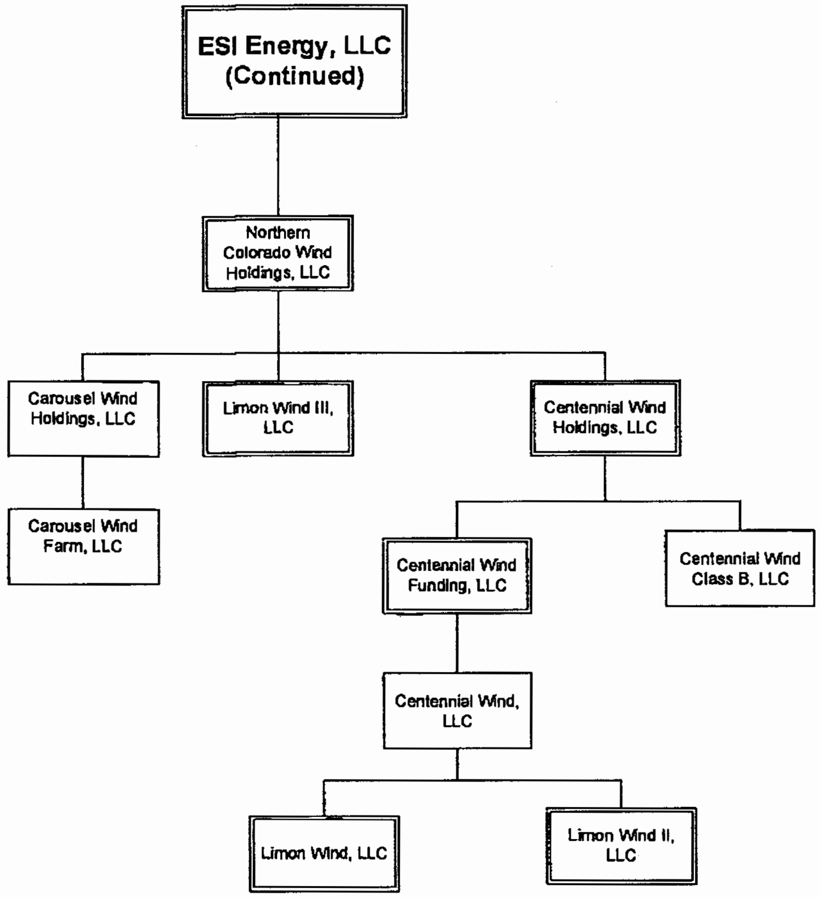


454-19

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-11

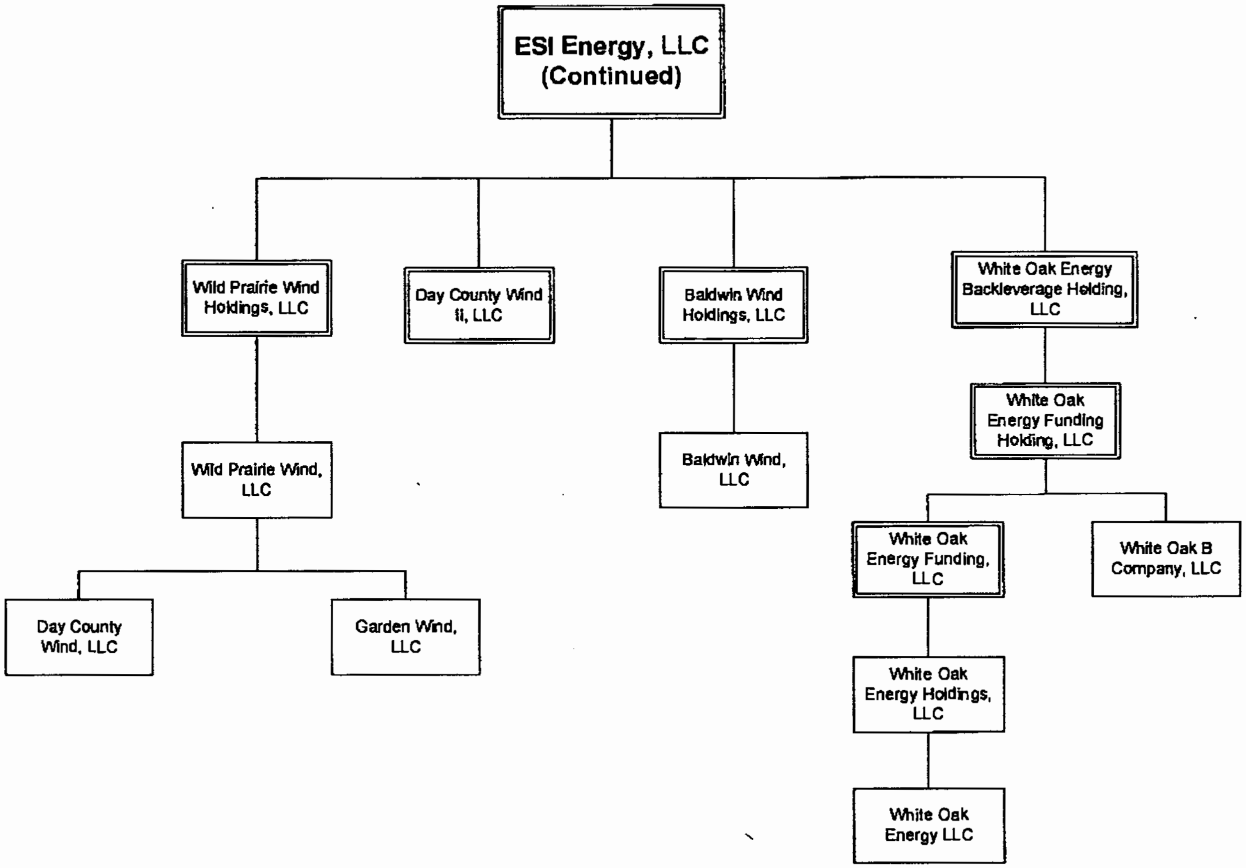


454-20

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-12

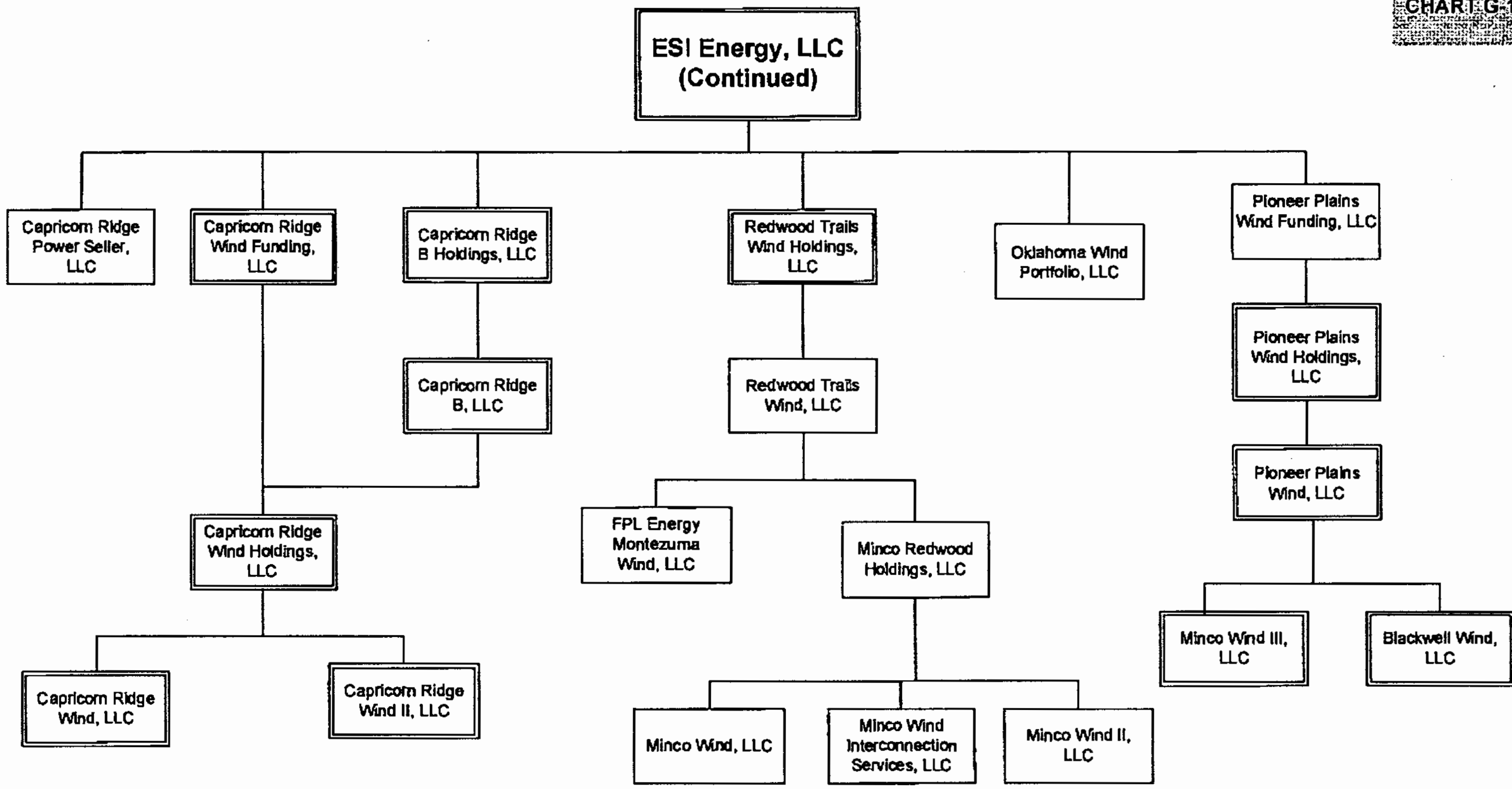


454-21

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-13

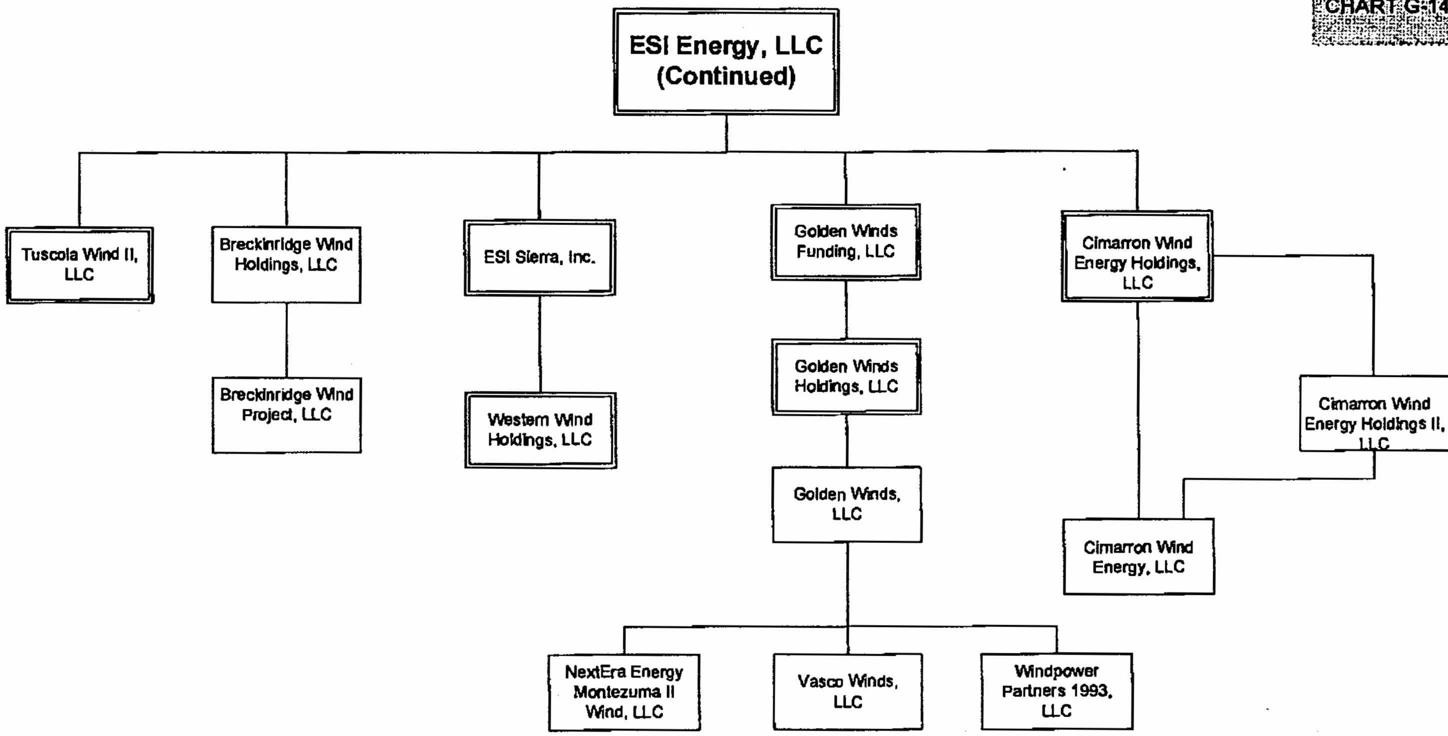


454-22

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

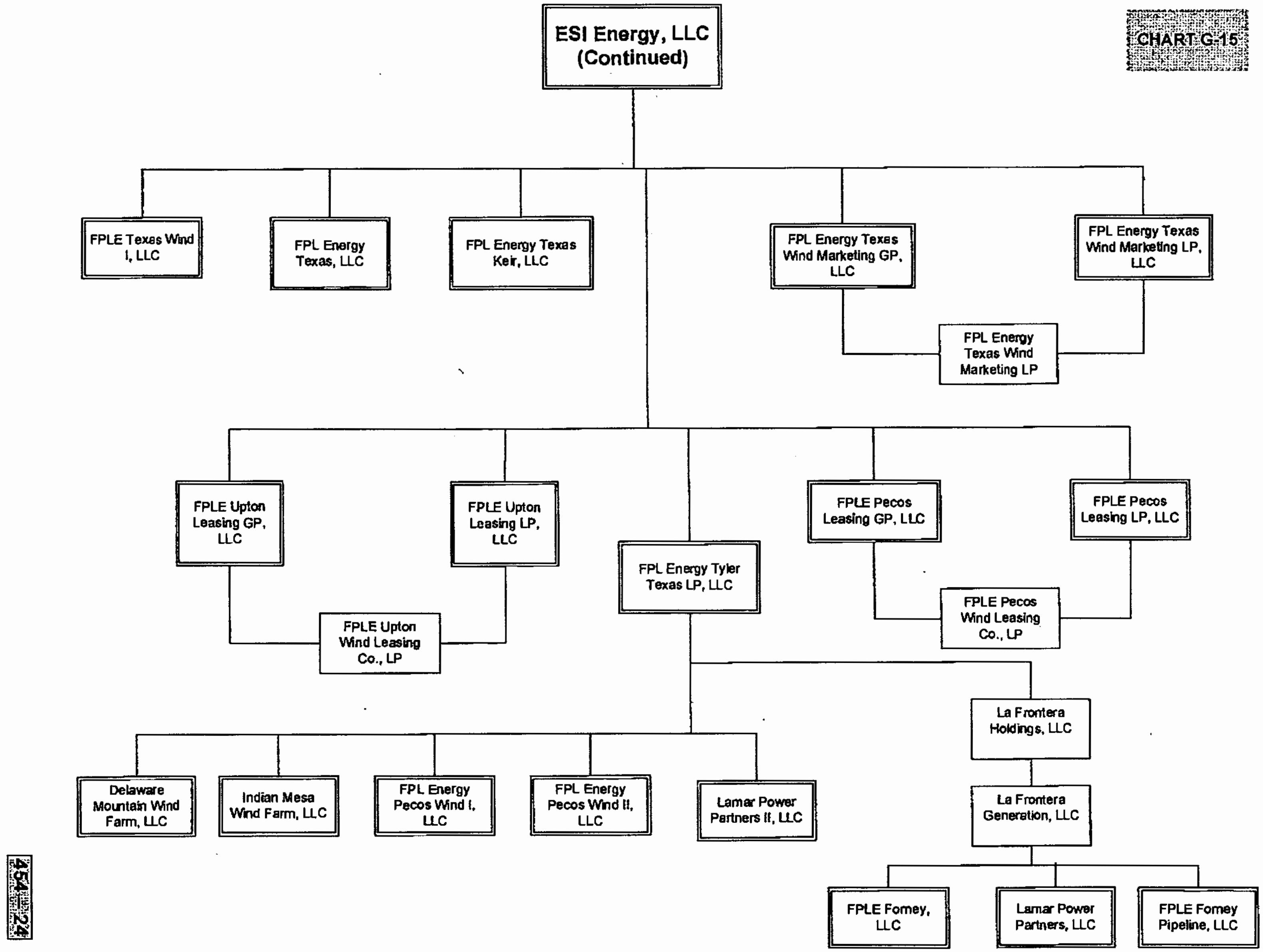
CHART G-14



454-23

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

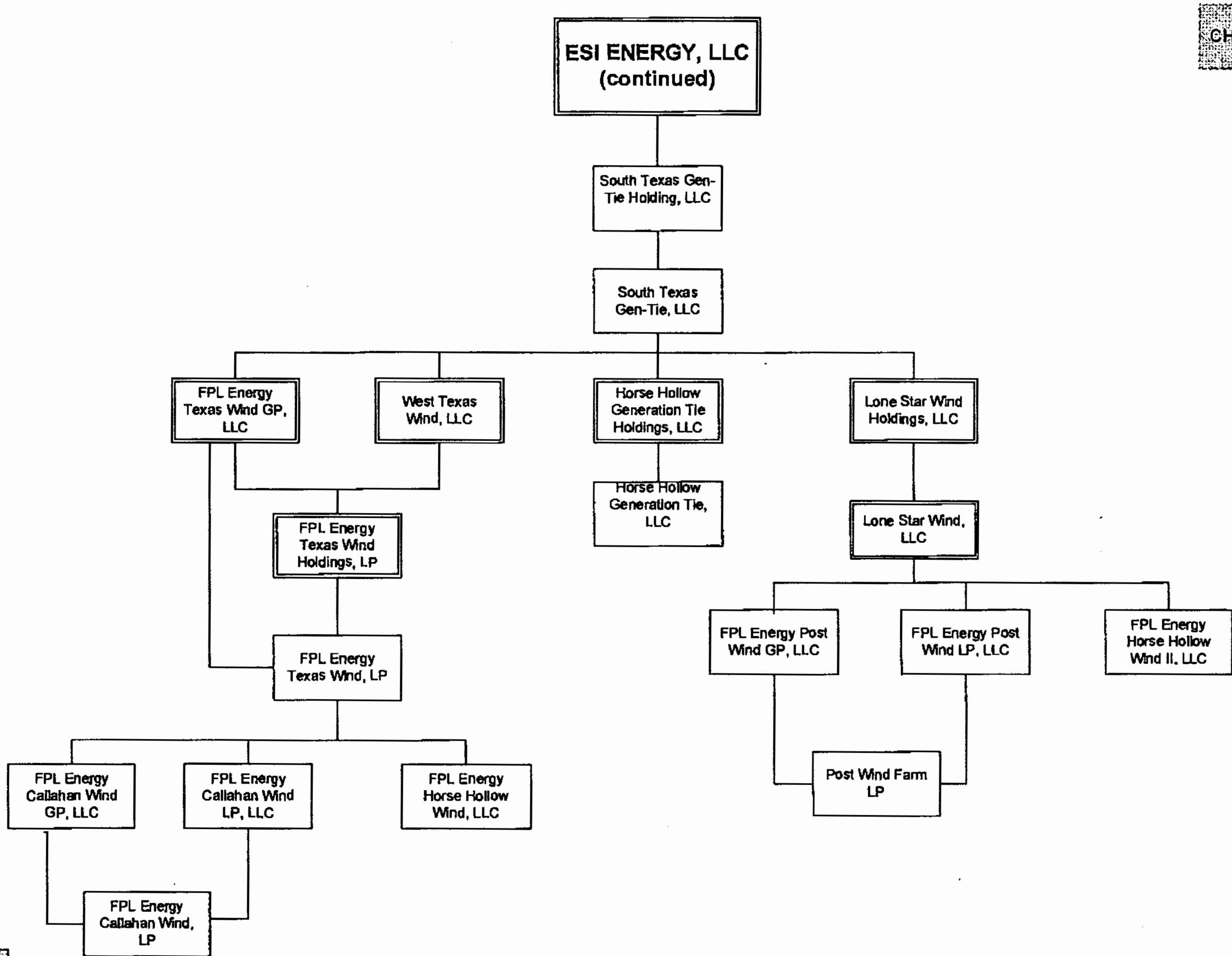
Reflects corporate structure as of July 31, 2014



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-16



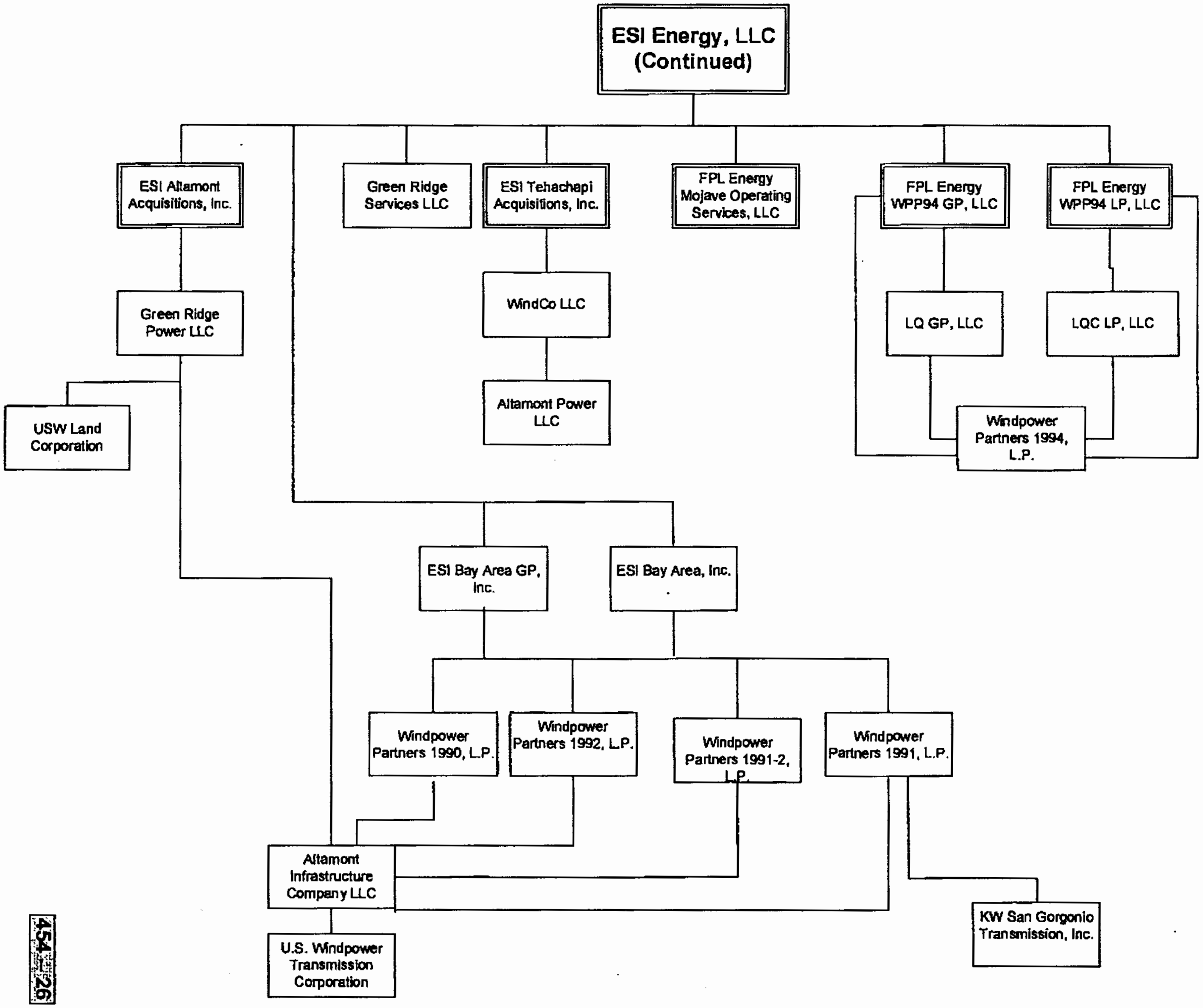
454-25

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

FCR-14-00683

Reflects corporate structure as of July 31, 2014

CHART G-17



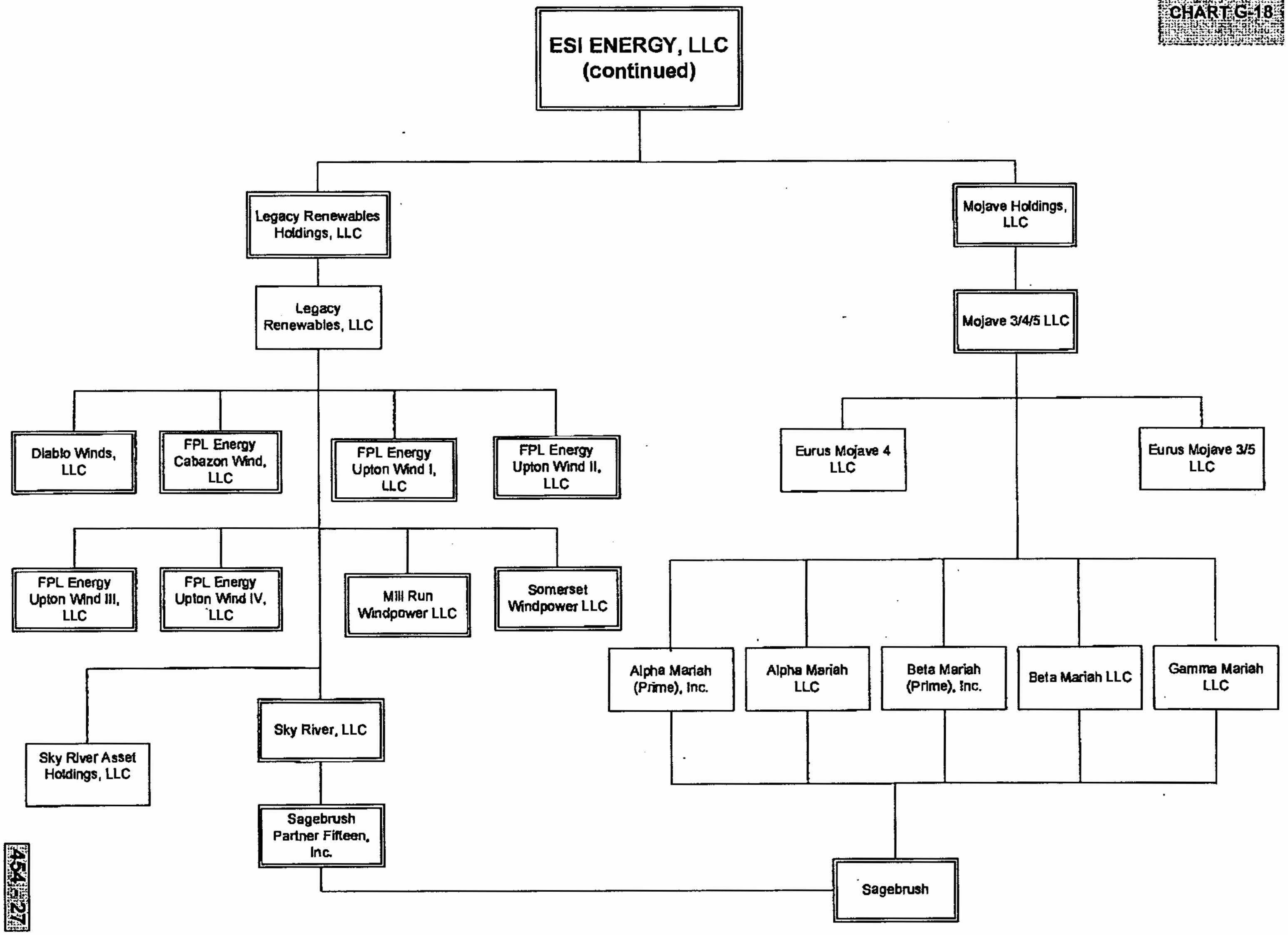
454-26

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

FCR-14-00684

Reflects corporate structure as of July 31, 2014

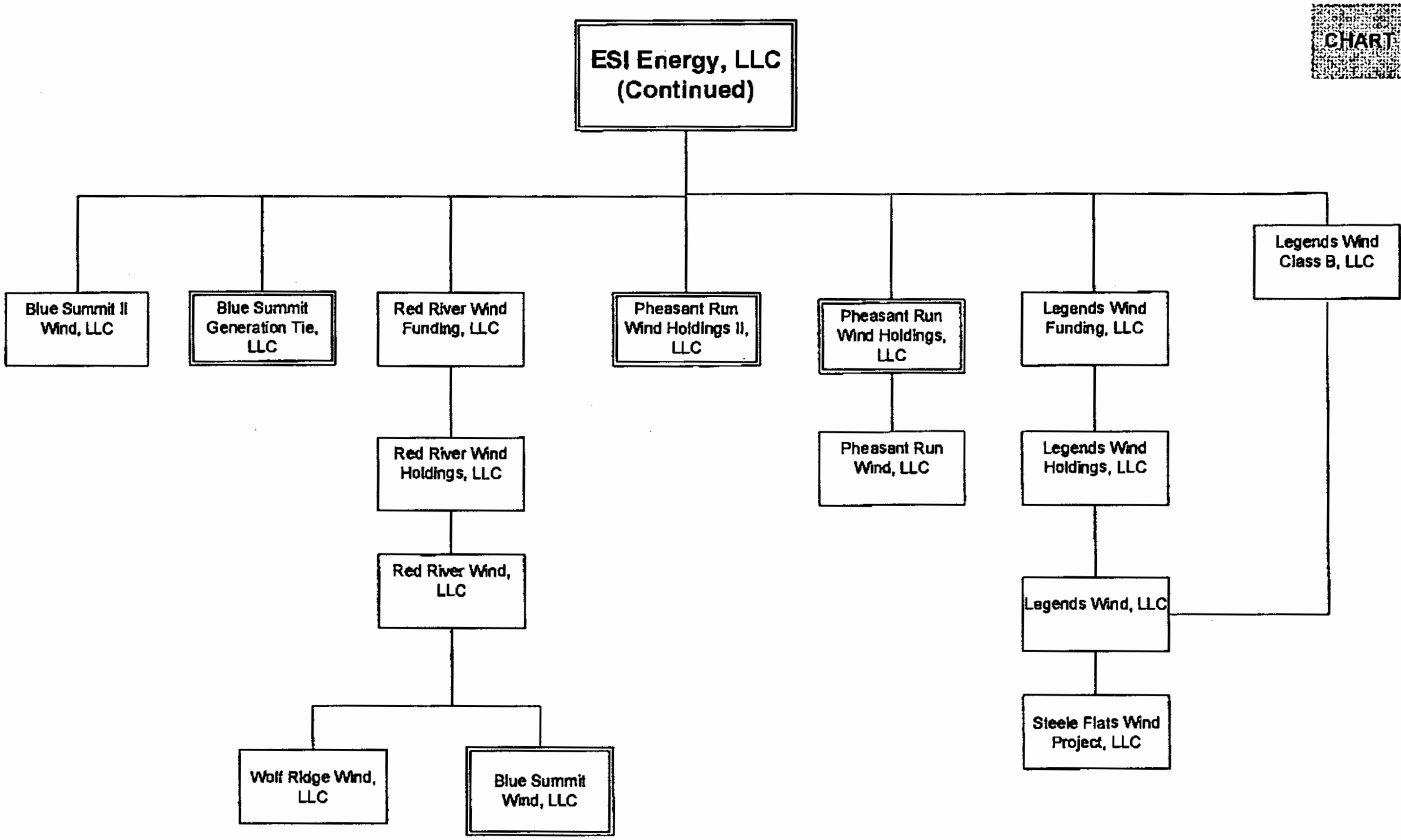
CHART G-18



LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

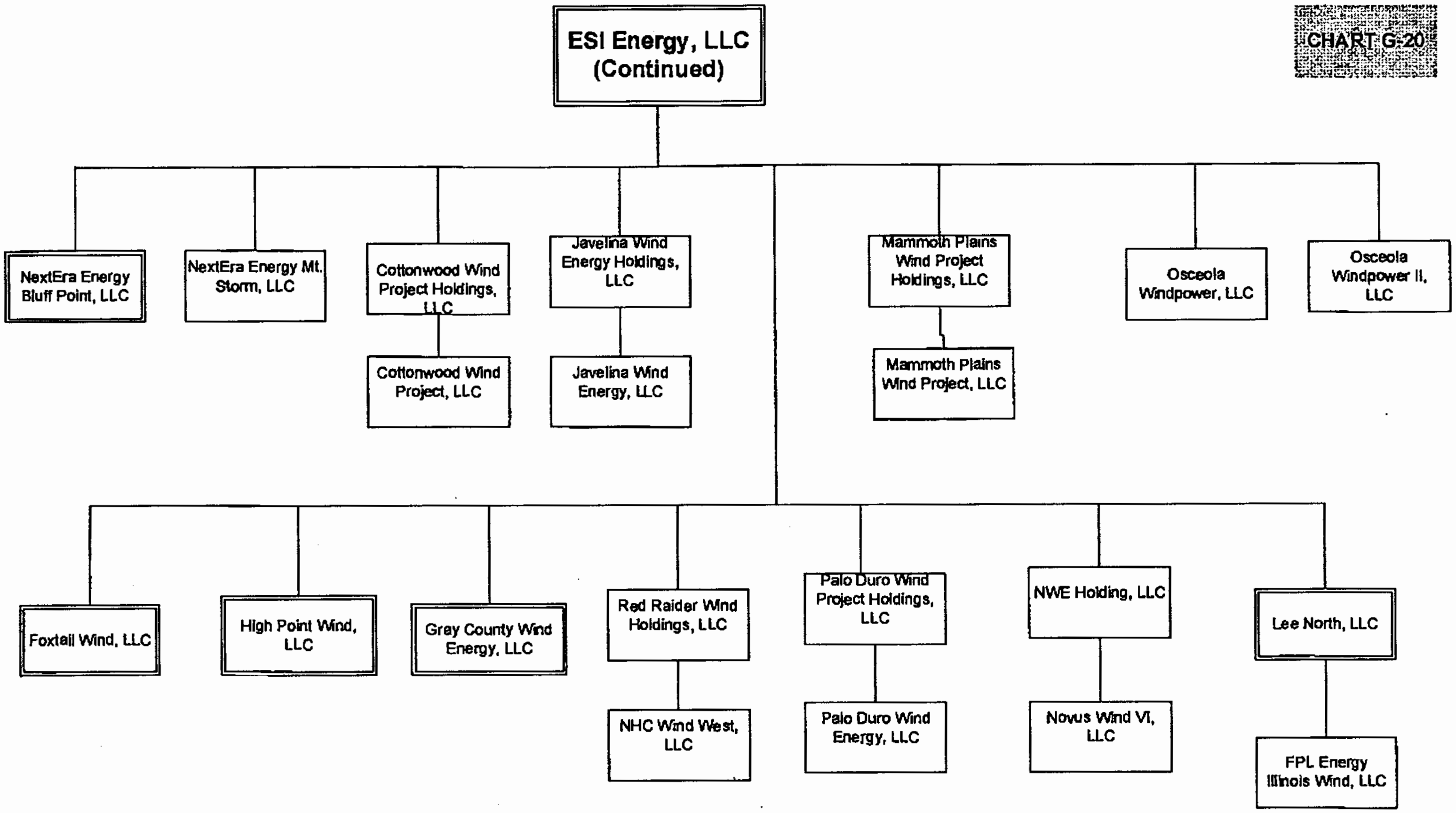
CHART G-19



454-29

LP = Limited Partnership   GP = General Partnership   JV = Joint Venture   LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

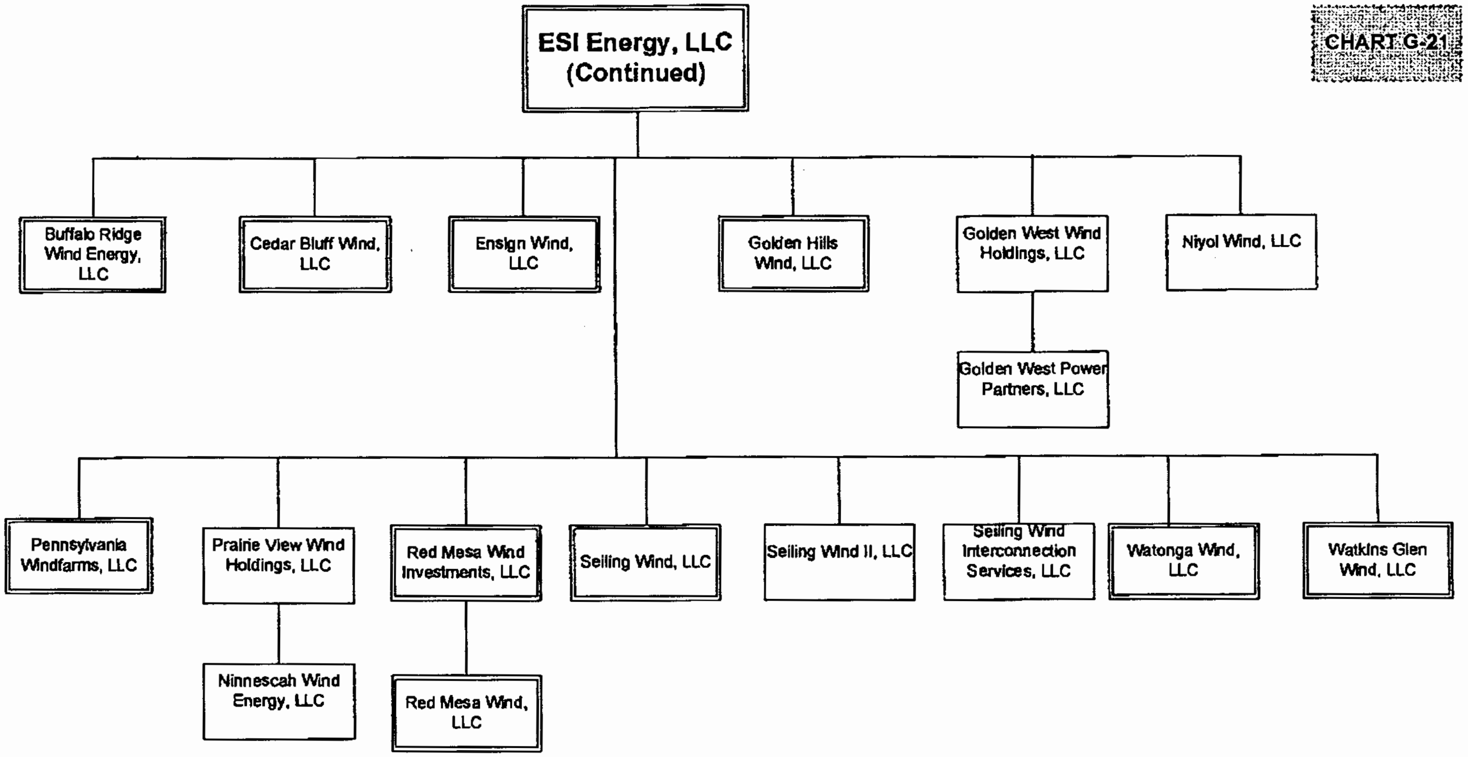


454-30

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-21

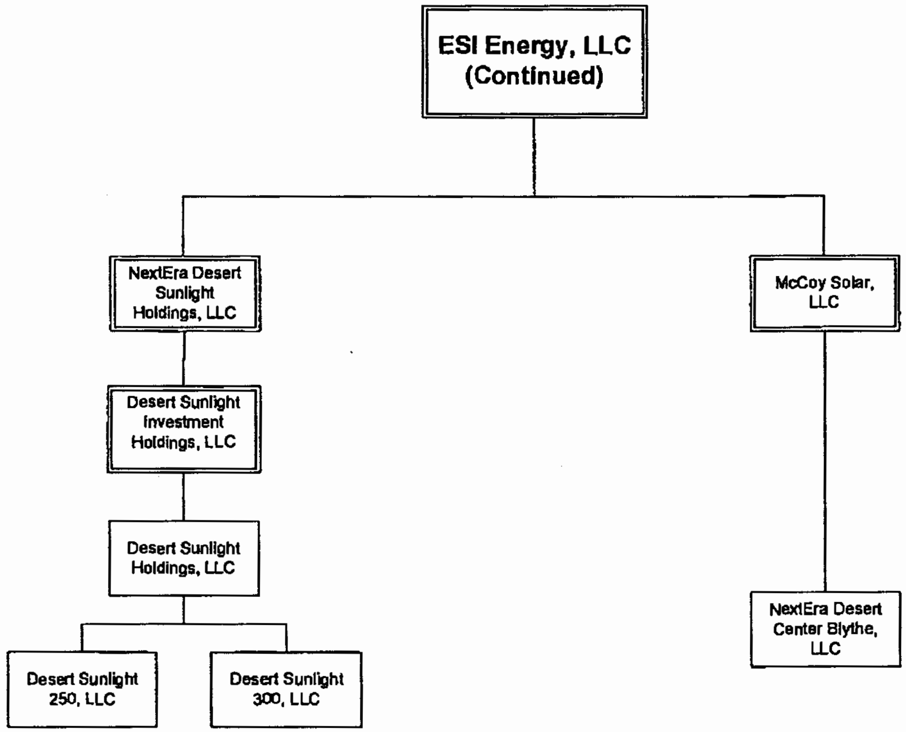


454-31

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-22

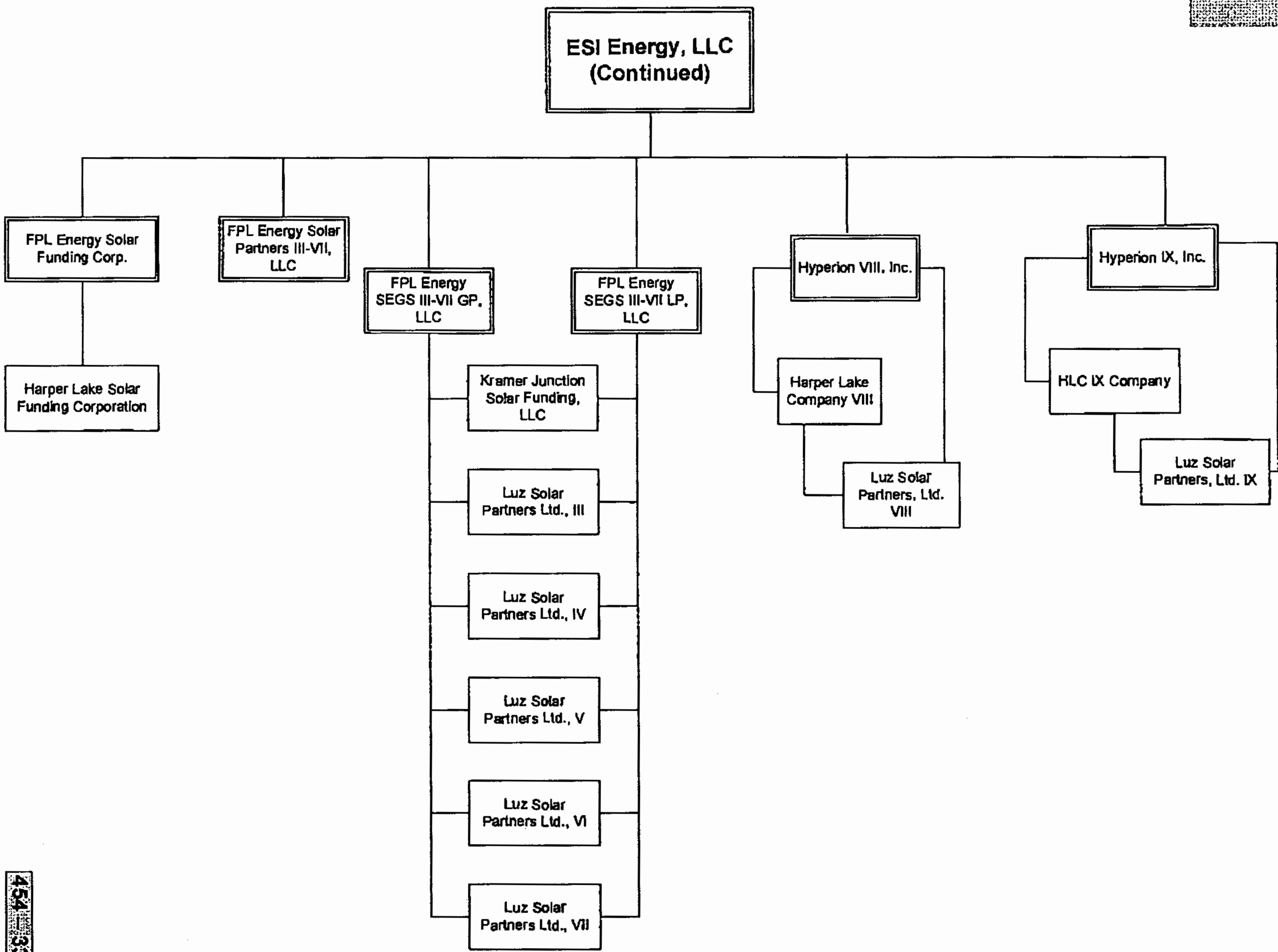


454-32

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

Chart G-23

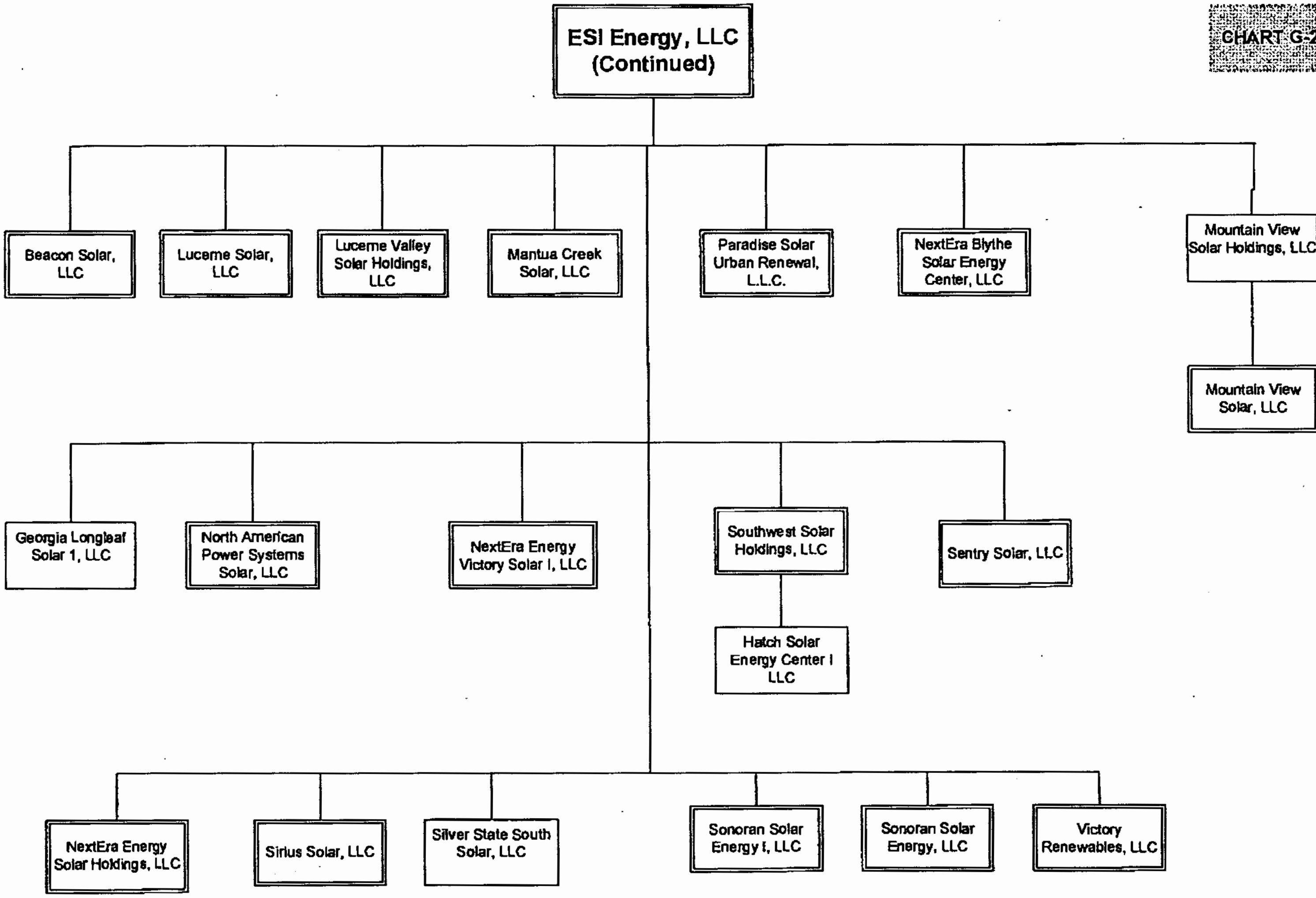


454-33

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-24

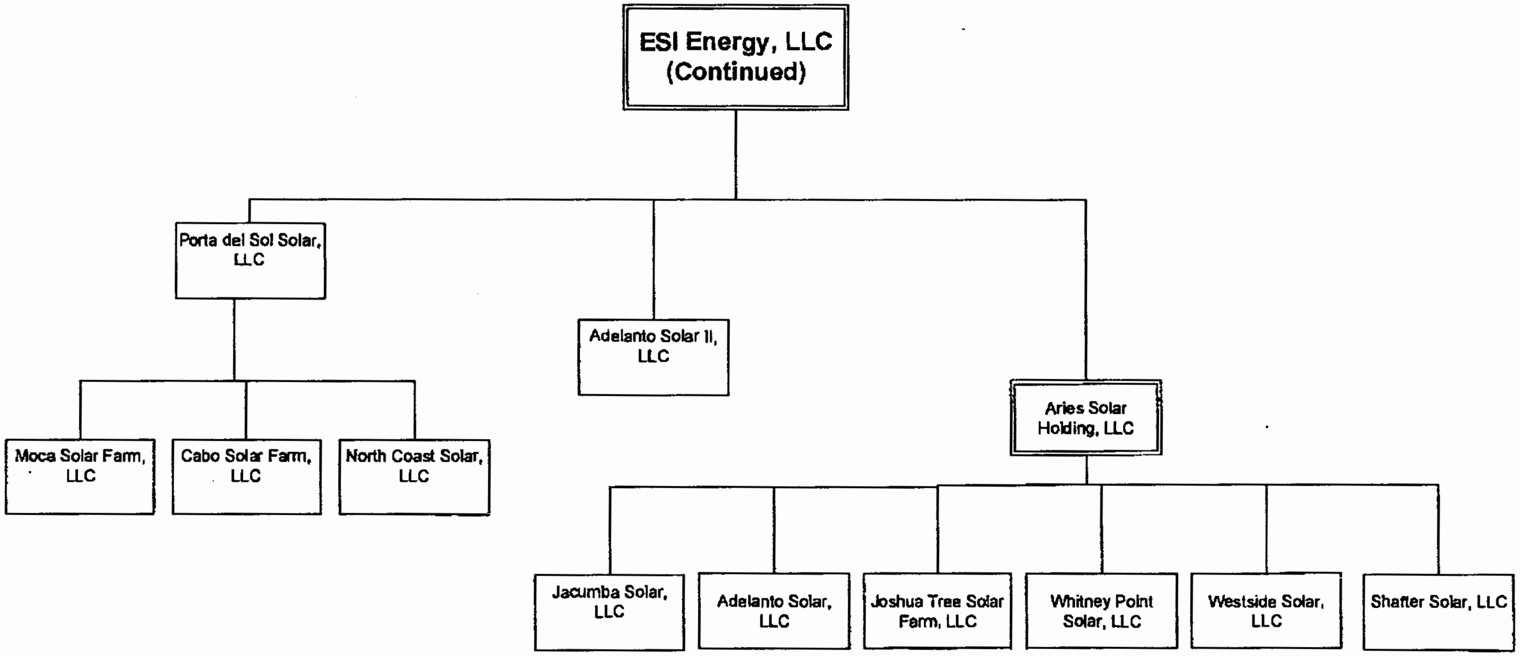


454 34

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-25

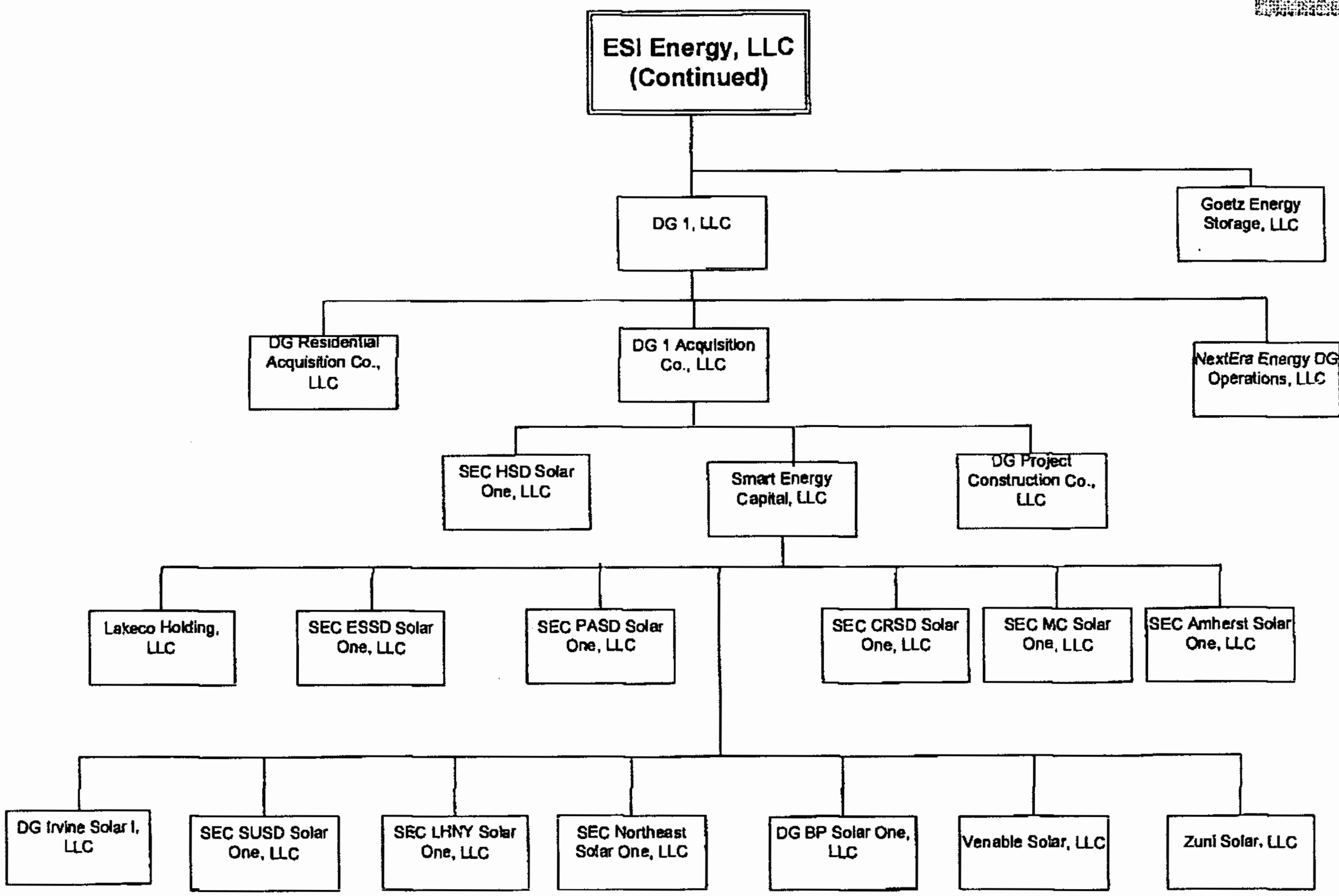


454-35

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-26

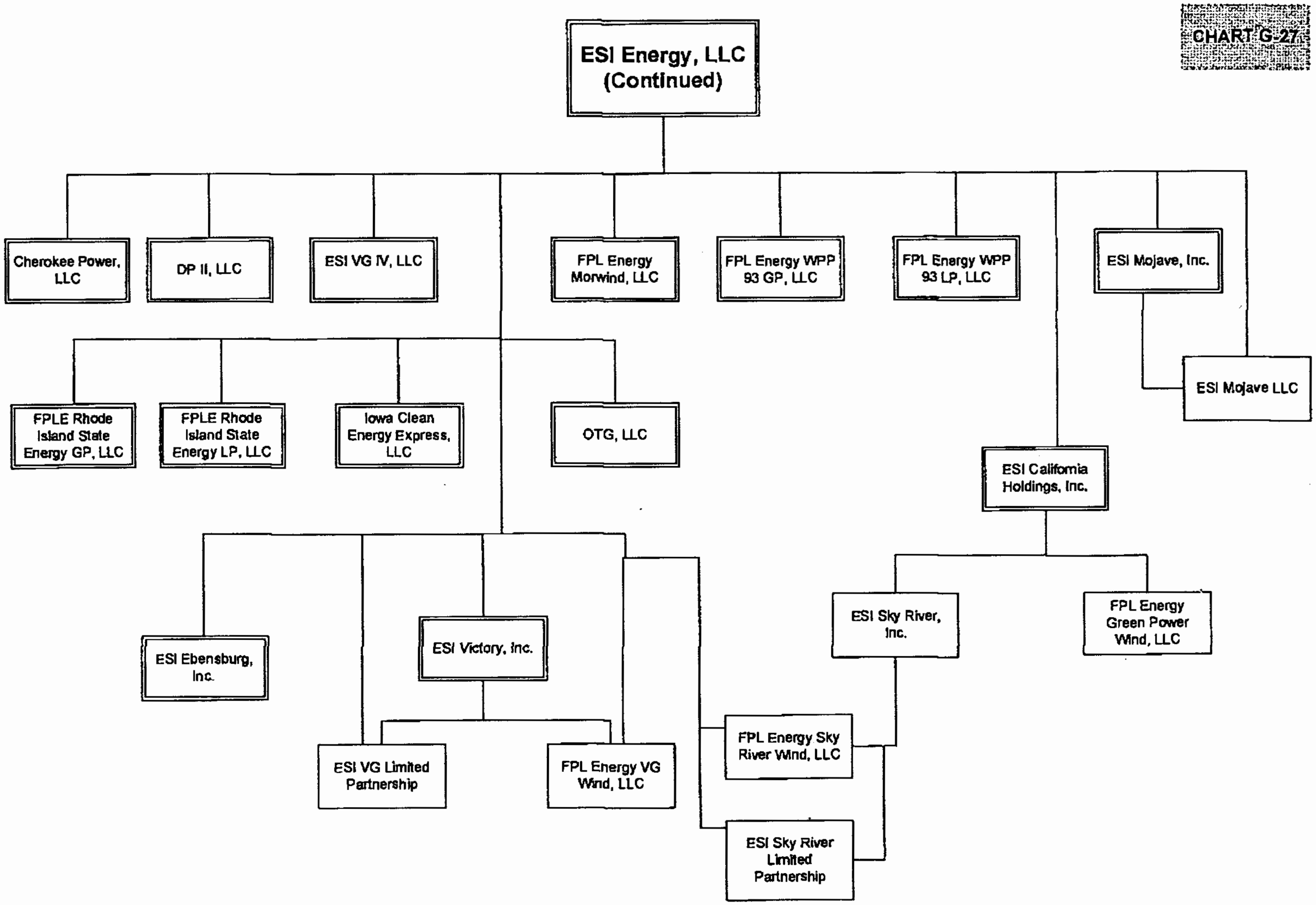


454-36

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-27

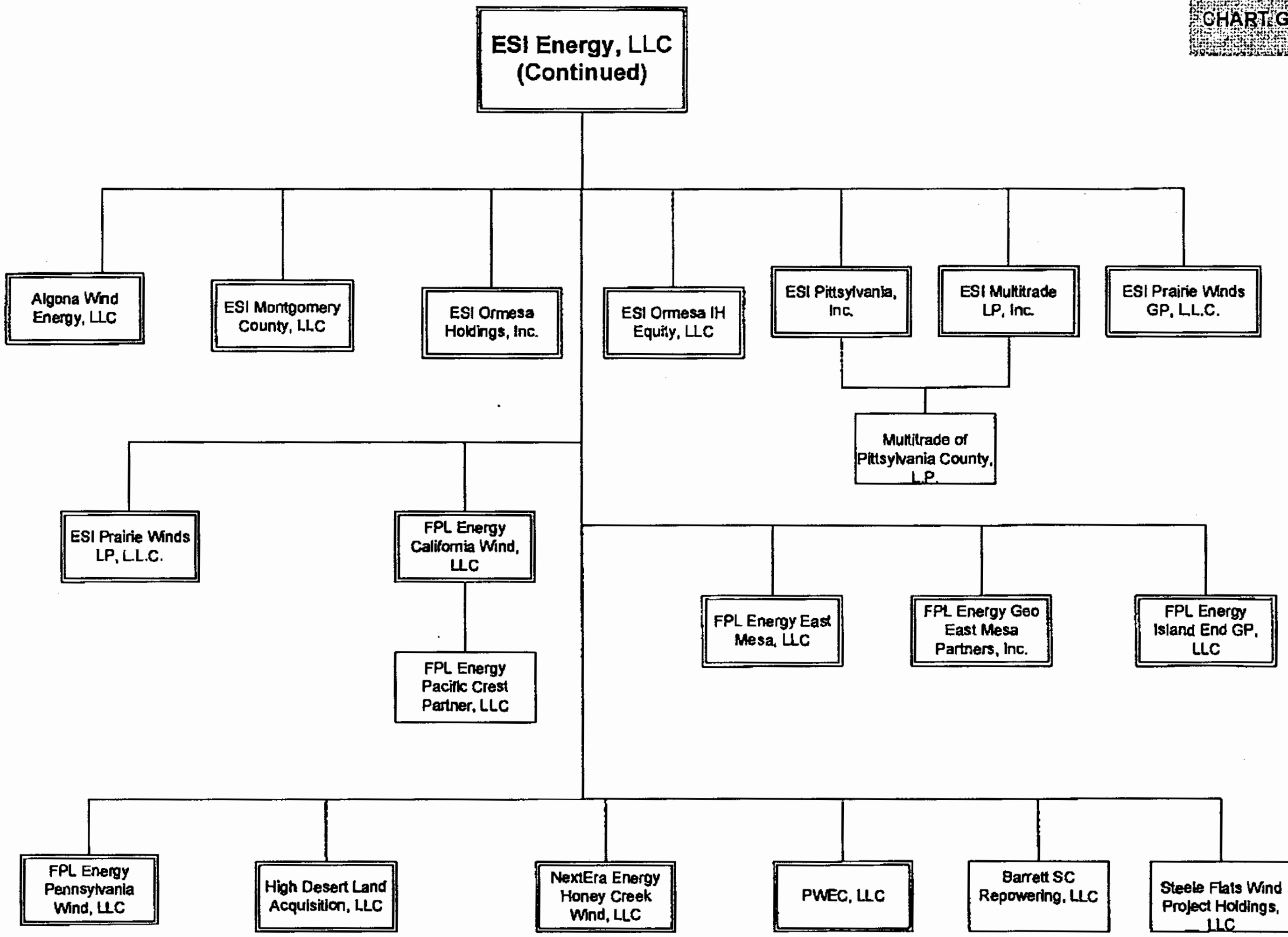


454-37

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-28

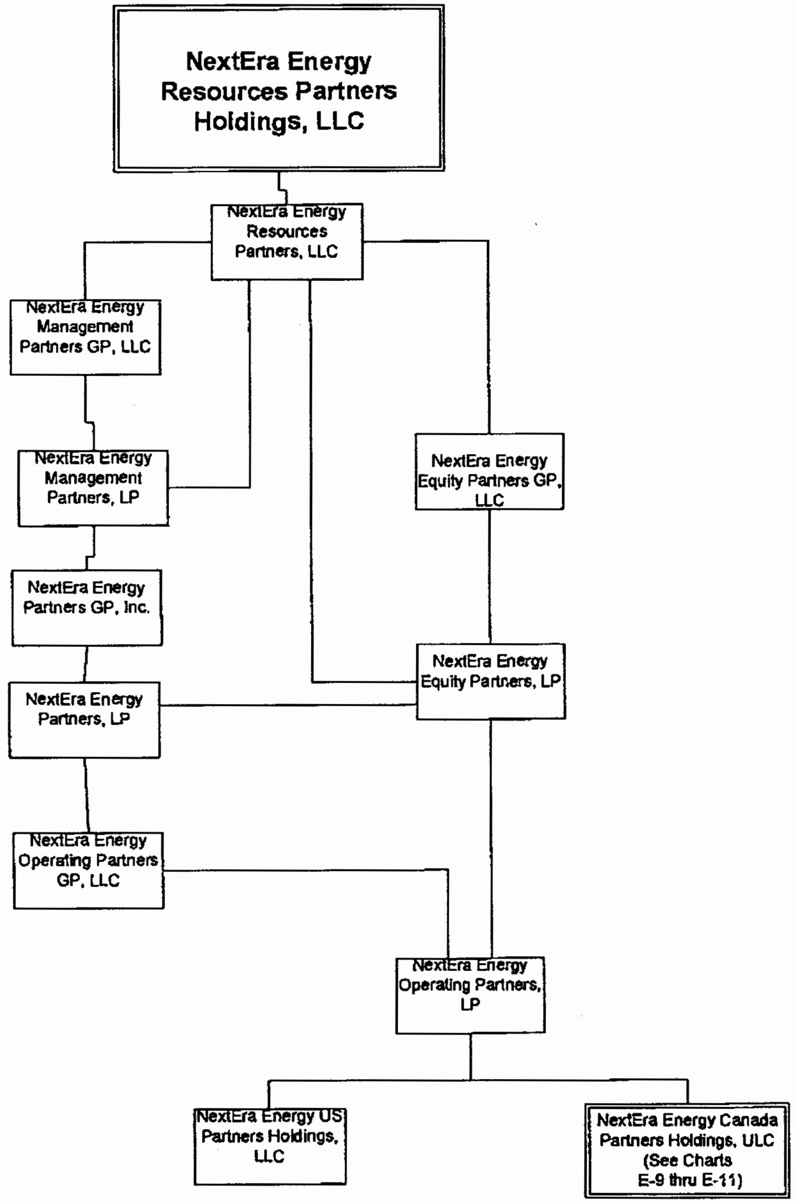


454-38

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-29

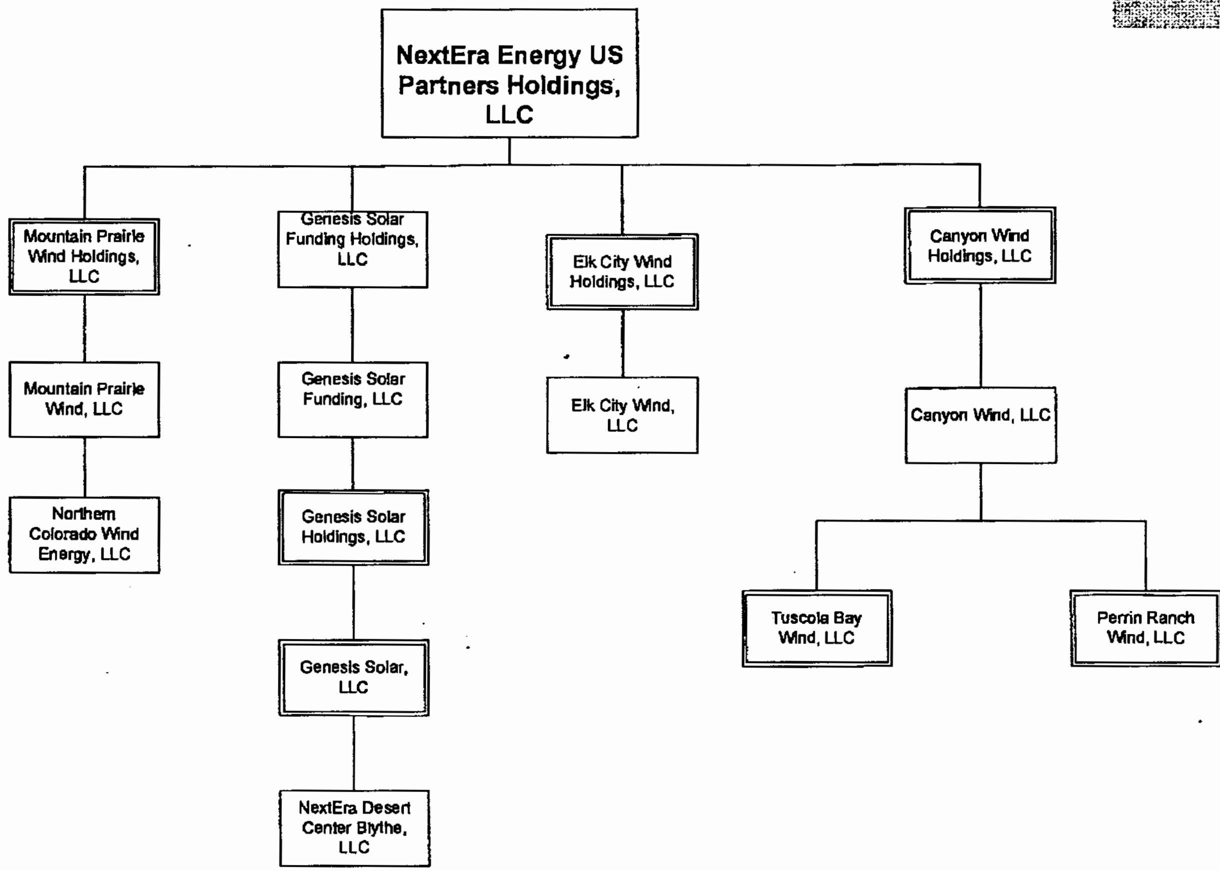


454-39

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART G-30

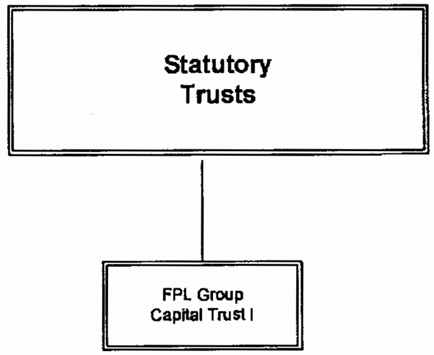


454-40

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART H



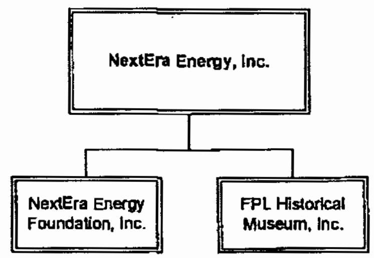
454-40

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

Reflects corporate structure as of July 31, 2014

CHART I

NON-PROFIT ORGANIZATIONS



454-41

LP = Limited Partnership GP = General Partnership JV = Joint Venture LLC = Limited Liability Company

PETROQUEST ENERGY INC

FORM 10-Q
(Quarterly Report)

Filed 11/04/14 for the Period Ending 09/30/14

Address	400 E KALISTE SALOOM RD SUITE 6000
	LAFAYETTE, LA 70508
Telephone	3372327028
CIK	0000872248
Symbol	PQ
SIC Code	1311 - Crude Petroleum and Natural Gas
Industry	Oil & Gas Operations
Sector	Energy
Fiscal Year	12/31

EXHIBIT
2
Ausdahl 11/12/14

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended: September 30, 2014

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from: to:

Commission file number: 001-32681

PETROQUEST ENERGY, INC.
(Exact name of registrant as specified in its charter)

DELAWARE (State of Incorporation)	72-1440714 (I.R.S. Employer Identification No.)
400 E. Kaliste Saloom Rd., Suite 6000 Lafayette, Louisiana (Address of principal executive offices)	70508 (Zip code)

Registrant's telephone number, including area code: (337) 232-7028

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 31, 2014 there were 66,021,408 shares of the registrant's common stock, par value $.001 per share, outstanding.

PETROQUEST ENERGY, INC.

Table of Contents

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	September 30, 2014	December 31, 2013
	(unaudited)	(Note 1)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,403	$ 9,153
Revenue receivable	24,215	26,568
Joint interest billing receivable	25,163	26,556
Derivative asset	1,387	521
Prepaid drilling costs	522	477
Other current assets	6,823	8,132
Total current assets	63,513	71,407
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	2,151,119	2,035,899
Unevaluated oil and gas properties	128,217	98,387
Accumulated depreciation, depletion and amortization	(1,624,980)	(1,553,044)
Oil and gas properties, net	654,356	581,242
Other property and equipment	14,887	13,993
Accumulated depreciation of other property and equipment	(9,952)	(8,901)
Total property and equipment	659,291	586,334
Derivative asset	132	—
Other assets, net of accumulated amortization of $7,295 and $5,689, respectively	6,501	9,449
Total assets	$ 729,437	$ 667,190
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 47,979	$ 47,341
Advances from co-owners	16,850	969
Oil and gas revenue payable	27,224	22,664
Accrued interest and preferred stock dividend	4,090	12,909
Asset retirement obligation	1,426	3,113
Derivative liability	106	1,617
Accrued acquisition cost	9,920	—
Other accrued liabilities	11,744	8,924
Total current liabilities	119,339	97,537
Bank debt	72,500	75,000
10% Senior Notes	350,000	350,000
Asset retirement obligation	47,398	45,423
Derivative liability	14	—
Accrued acquisition cost	10,000	—
Other long-term liability	127	135
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value; authorized 5,000 shares; issued and outstanding 1,495 shares	1	1
Common stock, $.001 par value; authorized 150,000 shares; issued and outstanding 64,412 and 63,664 shares, respectively	64	64
Paid-in capital	285,394	280,711
Accumulated other comprehensive income (loss)	879	(1,096)
Accumulated deficit	(156,279)	(180,585)
Total stockholders' equity	130,059	99,095
Total liabilities and stockholders' equity	$ 729,437	$ 667,190

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Operations
(unaudited)
(Amounts in Thousands, Except Per Share Data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues:				
Oil and gas sales	$ 56,486	$ 55,578	$ 177,033	$ 129,630
Expenses:				
Lease operating expenses	13,019	12,652	37,445	31,208
Production taxes	1,709	1,248	4,678	3,757
Depreciation, depletion and amortization	22,294	22,475	64,424	49,882
General and administrative	6,319	9,132	19,028	20,199
Accretion of asset retirement obligation	724	543	2,223	1,203
Interest expense	7,050	8,071	22,066	14,051
	51,115	54,121	149,864	120,300
Other income:				
Other income	198	185	602	500
Derivative income	—	45	—	202
	198	230	602	702
Income from operations	5,569	1,687	27,771	10,032
Income tax expense (benefit)	(389)	17	(389)	(474)
Net income	5,958	1,670	28,160	10,506
Preferred stock dividend	1,287	1,287	3,854	3,854
Net income available to common stockholders	$ 4,671	$ 383	$ 24,306	$ 6,652
Earnings per common share:				
Basic				
Net income per share	$ 0.07	$ 0.01	$ 0.37	$ 0.10
Diluted				
Net income per share	$ 0.07	$ 0.01	$ 0.37	$ 0.10
Weighted average number of common shares:				
Basic	64,265	63,096	64,073	62,936
Diluted	64,352	63,242	64,128	63,105

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Comprehensive Income
(unaudited)
(Amounts in Thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$ 5,958	$ 1,670	$ 28,160	$ 10,506
Change in fair value of derivative instruments, accounted for as hedges, net of income tax expense (benefit) of $520, ($46), $520, and $485, respectively	4,533	(78)	1,975	819
Comprehensive income	$ 10,491	$ 1,592	$ 30,135	$ 11,325

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Cash Flows
(unaudited)
(Amounts in Thousands)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Cash flows from operating activities:		
Net income	$ 28,160	$ 10,506
Adjustments to reconcile net income to net cash provided by operating activities:		
Deferred tax benefit	(389)	(474)
Depreciation, depletion and amortization	64,424	49,882
Accretion of asset retirement obligation	2,223	1,203
Non-cash share-based compensation expense	4,025	3,105
Amortization costs and other	1,636	1,138
Non-cash derivative income	—	(202)
Payments to settle asset retirement obligations	(2,902)	(2,415)
Changes in working capital accounts:		
Revenue receivable	2,353	(13,819)
Prepaid drilling costs	(45)	735
Joint interest billing receivable	1,279	13,612
Accounts payable and accrued liabilities	6,561	(11,781)
Advances from co-owners	15,881	(13,315)
Other	2,655	(5,266)
Net cash provided by operating activities	125,861	32,909
Cash flows from investing activities:		
Investment in oil and gas properties	(133,048)	(261,707)
Investment in other property and equipment	(860)	(970)
Sale of oil and gas properties	8,564	18,915
Sale of unevaluated oil and gas properties	1,640	—
Net cash used in investing activities	(123,704)	(243,762)
Cash flows from financing activities:		
Net proceeds (payments) for share based compensation	651	(379)
Deferred financing costs	(204)	(487)
Payment of preferred stock dividend	(3,854)	(3,854)
Proceeds from issuance of 10% Senior Notes	—	200,000
Deferred financing costs of 10% Senior Notes	—	(4,922)
Proceeds from bank borrowings	10,000	62,000
Repayment of bank borrowings	(12,500)	(37,000)
Net cash provided by (used in) financing activities	(5,907)	215,358
Net increase (decrease) in cash and cash equivalents	(3,750)	4,505
Cash and cash equivalents, beginning of period	9,153	14,904
Cash and cash equivalents, end of period	$ 5,403	$ 19,409
Supplemental disclosure of cash flow information:		
Cash paid during the period for:		
Interest	$ 36,606	$ 19,479
Income taxes	$ 132	$ 11

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1—Basis of Presentation

The consolidated financial information for the three and nine month periods ended September 30, 2014 and 2013 , has been prepared by the Company and was not audited by its independent registered public accountants. In the opinion of management, all normal and recurring adjustments have been made to present fairly the financial position, results of operations, and cash flows of the Company at September 30, 2014 and for all reported periods. Results of operations for the interim periods presented are not necessarily indicative of the operating results for the full year or any future periods.

The balance sheet at December 31, 2013 has been derived from the audited financial statements at that date. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles have been condensed or omitted. These consolidated financial statements should be read in conjunction with the audited financial statements and related notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2013 . Certain prior year amounts have been reclassified to conform to current year presentations.

Unless the context otherwise indicates, any references in this Quarterly Report on Form 10-Q to "PetroQuest," the "Company," "we," or "us" refer to PetroQuest Energy, Inc. (Delaware) and its wholly-owned consolidated subsidiaries, PetroQuest Energy, L.L.C. (a single member Louisiana limited liability company), PetroQuest Oil & Gas, L.L.C. (a single member Louisiana limited liability company), TDC Energy LLC (a single member Louisiana limited liability company) and Pittrans, Inc. (an Oklahoma corporation).

Note 2—Acquisitions

Gulf of Mexico Acquisition:

On July 3, 2013, the Company acquired certain shallow water Gulf of Mexico shelf oil and gas properties (the "Acquired Assets"), for an aggregate cash purchase price of $188.8 million , reflecting an effective date of January 1, 2013 (collectively, the "Gulf of Mexico Acquisition"). The Acquired Assets included 16 wells located on seven platforms.

The aggregate cash purchase price of the Gulf of Mexico Acquisition was financed with the net proceeds from the sale of $200 million in principal amount of the Company's 10% Senior Notes due 2017 (the "New Notes"). In connection with the transaction, the Company recorded $5.0 million of deferred financing costs related to the New Notes and incurred $4.0 million of acquisition-related costs, including $2.6 million related to a bridge commitment fee, which were recognized as general and administrative expenses.

The Gulf of Mexico Acquisition was accounted for under the purchase method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The fair value of proved and unevaluated oil and gas properties was estimated using the income approach based on estimated reserve quantities, costs to produce and develop reserves, and forward prices for oil and gas, which represent Level 2 and Level 3 inputs. Asset retirement obligations were determined in accordance with applicable accounting standards.

The following table summarizes the acquisition date fair values of the net assets acquired (in thousands):

Oil and gas properties	$	192,067
Unevaluated oil and gas properties		12,033
Asset retirement obligations		(15,319)
Net assets acquired	$	188,781

The following unaudited summary pro forma financial information for the nine month period ended September 30, 2013 has been prepared to give effect to the Gulf of Mexico Acquisition as if it had occurred on January 1, 2012. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2012 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities and other factors. Amounts in thousands, except per share amounts.

		Nine Months Ended September 30, 2013
Revenues	$	162,494
Income from operations		15,487
Income available to common stockholders		12,107
Basic earnings per share		0.19
Diluted earnings per share		0.19

Fleetwood Joint Venture:

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million . The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash ($3 million paid in July 2014 and $7 million due in January 2015) and $14 million in cash funding for future drilling, completion and lease acquisition costs. If the $14 million in drilling, completion and lease acquisition costs is not fully funded by December 31, 2015 , any remaining balance becomes payable at the election of our joint venture partner.

Amounts payable with regard to the joint venture are reflected as accrued acquisition costs in the Consolidated Balance Sheet. The amounts payable related to the $14 million discussed above are classified as current and long term based on the current exploration and development plans under the joint venture. All of the costs associated with the joint venture are considered unevaluated at September 30, 2014 .

Note 3—Convertible Preferred Stock

The Company has 1,495,000 shares of 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") outstanding.

The following is a summary of certain terms of the Series B Preferred Stock:

Dividends . The Series B Preferred Stock accumulates dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends are cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by the Company's debt agreements, assets are legally available to pay dividends and the Company's board of directors or an authorized committee of the board declares a dividend payable, the Company pays dividends in cash, every quarter.

Mandatory conversion . The Company may, at its option, cause shares of the Series B Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of the Company's common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date the Company gives the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

Conversion rights . Each share of Series B Preferred Stock may be converted at any time, at the option of the holder, into 3.4433 shares of the Company's common stock (which is based on an initial conversion price of approximately $14.52 per share of common stock, subject to adjustment) plus cash in lieu of fractional shares, subject to the Company's right to settle all or a portion of any such conversion in cash or shares of the Company's common stock. If the Company elects to settle all or any portion of its conversion obligation in cash, the conversion value and the number of shares of the Company's common stock it will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Series B Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to $50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of the Company's common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

Note 4—Earnings Per Share

A reconciliation between the basic and diluted earnings per share computations (in thousands, except per share amounts) is as follows:

For the Three Months Ended September 30, 2014	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	4,671	64,265		
Attributable to participating securities		(123)			
BASIC EPS	$	4,548	64,265	$	0.07
Net income available to common stockholders	$	4,671	64,265		
Effect of dilutive securities:					
Stock options		—	87		
Attributable to participating securities		(123)	—		
DILUTED EPS	$	4,548	64,352	$	0.07

For the Nine Months Ended September 30, 2014	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	24,306	64,073		
Attributable to participating securities		(649)			
BASIC EPS	$	23,657	64,073	$	0.37
Net income available to common stockholders	$	24,306	64,073		
Effect of dilutive securities:					
Stock options		—	55		
Attributable to participating securities		(649)	—		
DILUTED EPS	$	23,657	64,128	$	0.37

For the Three Months Ended September 30, 2013	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	383	63,096		
Attributable to participating securities		(8)			
BASIC EPS	$	375	63,096	$	0.01
Net income available to common stockholders	$	383	63,096		
Effect of dilutive securities:					
Stock options		—	146		
Attributable to participating securities		(8)	—		
DILUTED EPS	$	375	63,242	$	0.01

For the Nine Months Ended September 30, 2013	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	6,652	62,936		
Attributable to participating securities		(151)			
BASIC EPS	$	6,501	62,936	$	0.10
Net income available to common stockholders	$	6,652	62,936		
Effect of dilutive securities:					
Stock options		—	169		
Attributable to participating securities		(151)	—		
DILUTED EPS	$	6,501	63,105	$	0.10

Common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 5,148,000 shares were not included in the computation of diluted earnings per share for any of the 2013 and 2014 periods presented because the inclusion would have been anti-dilutive. Options to purchase 868,300 and 985,700 shares of common stock were outstanding during the three and nine month periods ended September 30, 2014 , respectively, and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

Options to purchase 1,199,000 and 1,245,000 shares of common stock were outstanding during the three and nine months ended September 30, 2013 , respectively, and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

Note 5—Long-Term Debt

On August 19, 2010, the Company issued $150 million in principal amount of its 10% Senior Notes due 2017 (the "Existing Notes"). On July 3, 2013, the Company issued an additional $200 million in principal amount of its 10% Senior Notes due 2017 (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of face value plus accrued interest from March 1, 2013. The New Notes have terms that, subject to certain exceptions, are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013. The Notes are guaranteed by certain of PetroQuest's subsidiaries. The subsidiary guarantors are 100% owned by PetroQuest and all guarantees are full and unconditional and joint and several. PetroQuest has no independent assets or operations and the subsidiaries not providing guarantees are minor, as defined by the rules of the Securities and Exchange Commission (the "SEC").

The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At September 30, 2014 , $2.9 million had been accrued in connection with the March 1, 2015 interest payment and the Company was in compliance with all of the covenants contained in the Notes.

The Company and PetroQuest Energy, L.L.C. (the "Borrower") have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia. The Credit Agreement provides the Company with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Company to use up to $25 million of the borrowing base for letters of credit. The Credit Agreement matures on October 3, 2016. As of September 30, 2014 the Company had $72.5 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to the Company's oil and gas properties as of January 1 and July 1 of each year. In connection with the most recent redetermination, the borrowing base was increased to $220 million (subject to the aggregate commitments of the lenders then in effect) effective September 30, 2014. The aggregate commitments of the lenders is currently $170 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions.

The next borrowing base redetermination is scheduled to occur by March 31, 2015 . The Company or the lenders may request two additional borrowing base re-determinations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 80% of the aggregate total value of the Borrower's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1% . For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Company) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Company pays commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0 and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0 , all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits the Company to repurchase up to $10 million of the Company's common stock during the term of the Credit Agreement, so long as after giving effect to such repurchase the Borrower's Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of September 30, 2014 , the Company was in compliance with all of the covenants contained in the Credit Agreement.

Note 6—Asset Retirement Obligation

The following table describes the changes to the Company's asset retirement obligation liability (in thousands):

	Nine Months Ended September 30,	
	2014	2013
Asset retirement obligation, beginning of period	$ 48,536	$ 27,260
Liabilities incurred	224	498
Liabilities assumed	—	15,319
Liabilities settled	(2,902)	(2,415)
Accretion expense	2,223	1,203
Revisions in estimated cash flows	743	987
Asset retirement obligation, end of period	48,824	42,852
Less: current portion of asset retirement obligation	(1,426)	(1,502)
Long-term asset retirement obligation	$ 47,398	$ 41,350

Note 7—Derivative Instruments

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. When the conditions for hedge accounting are met, the Company may designate its commodity derivatives as cash flow hedges. The changes in fair value of derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a derivative does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense). At September 30, 2014 , all of the Company's derivative instruments were designated as effective cash flow hedges.

Oil and gas sales include increases (reductions) to revenue related to the settlement of gas hedges of $337,000 and $767,000 , Ngl hedges of $28,000 and $5,000 and oil hedges of ($125,000) and ($538,000) for the three months ended September 30, 2014 and 2013 , respectively. For the nine months ended September 30, 2014 and 2013 , oil and gas sales include increases (reductions) to revenue related to the settlement of gas hedges of ($4,802,000) and $422,000 , Ngl hedges of $28,000 and $5,000 , and oil hedges of ($1,231,000) and ($684,000) , respectively.

As of September 30, 2014 , the Company had entered into the following commodity derivative instruments:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
October - December 2014	Swap	45,000 Mmbtu	$4.14
2015	Swap	10,000 Mmbtu	$4.16
Crude Oil:			
October - December 2014	Swap (LLS)	650 Bbls	$101.05
October - December 2014	Swap (WTI)	350 Bbls	$93.26
Pentane:			
October - December 2014	Swap	100 Bbls	$91.58

LLS - Louisiana Light Sweet

WTI - West Texas Intermediate

At September 30, 2014 , the Company had recognized accumulated other comprehensive income of approximately $0.9 million related to the estimated fair value of its effective cash flow hedges. Based on estimated future commodity prices as of September 30, 2014 , the Company would reclassify approximately $0.8 million , net of taxes, of accumulated other comprehensive income into earnings during the next 12 months . These gains are expected to be reclassified to oil and gas sales based on the schedule of oil and gas volumes stipulated in the derivative contracts.

Derivatives designated as hedging instruments:

All of the Company's swap contracts are designated as effective cash flow hedges. The following tables reflect the fair value of the Company's effective cash flow hedges in the consolidated financial statements (in thousands):

Effect of Cash Flow Hedges on the Consolidated Balance Sheet at September 30, 2014 and December 31, 2013 :

	Commodity Derivatives		
Period	Balance Sheet Location		Fair Value
September 30, 2014	Derivative asset	$	1,519
September 30, 2014	Derivative liability	$	(120)
December 31, 2013	Derivative asset	$	521
December 31, 2013	Derivative liability	$	(1,617)

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for the three months ended September 30, 2014 and 2013 :

Instrument		Amount of Gain Recognized in Other Comprehensive Income	Location of Gain Reclassified into Income		Amount of Gain Reclassified into Income
Commodity Derivatives at September 30, 2014	$	5,293	Oil and gas sales	$	240
Commodity Derivatives at September 30, 2013	$	110	Oil and gas sales	$	234

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for the nine months ended September 30, 2014 and 2013 :

Instrument		Amount of Gain (Loss) Recognized in Other Comprehensive Income	Location of Loss Reclassified into Income		Amount of Loss Reclassified into Income
Commodity Derivatives at September 30, 2014	$	(3,510)	Oil and gas sales	$	(6,005)
Commodity Derivatives at September 30, 2013	$	1,047	Oil and gas sales	$	(257)

Derivatives not designated as hedging instruments:

During 2013, the Company utilized a three-way collar contract that was not designated as an effective cash flow hedge and therefore the changes in fair value on this derivative were recorded as derivative income in the statement of operations. This contract expired on December 31, 2013. The following tables reflect the fair value of this contract in the consolidated financial statements (in thousands):

Effect of Non-designated Derivative Instruments on the Consolidated Statement of Operations for the three months ended September 30, 2014 and 2013 :

Instrument		Amount of Gain Recognized in Derivative Income
Commodity Derivatives at September 30, 2014	$	—
Commodity Derivatives at September 30, 2013	$	45

Effect of Non-designated Derivative Instruments on the Consolidated Statement of Operations for the nine months ended September 30, 2014 and 2013 :

Instrument	Amount of Gain Recognized in Derivative Income	
Commodity Derivatives at September 30, 2014	$	—
Commodity Derivatives at September 30, 2013	$	202

Note 8 – Fair Value Measurements

As defined in ASC Topic 820, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC Topic 820 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

- Level 1: valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;
- Level 2: valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;
- Level 3: valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

The Company classifies its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at September 30, 2014 were in the form of swaps based on NYMEX pricing for oil and natural gas and OPIS Mt. Bellevue pricing for natural gas liquids. The fair value of these derivatives is derived using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. As a result, the Company designates its commodity derivatives as Level 2 in the fair value hierarchy.

The following table summarizes the net valuation of the Company's derivatives subject to fair value measurement on a recurring basis as of September 30, 2014 and December 31, 2013 (in thousands):

	Fair Value Measurements Using					
Instrument	Quoted Prices in Active Markets (Level 1)		Significant Other Observable Inputs (Level 2)		Significant Unobservable Inputs (Level 3)	
Commodity Derivatives:						
At September 30, 2014	$	—	$	1,399	$	—
At December 31, 2013	$	—	$	(1,096)	$	—

The fair value of the Company's cash and cash equivalents and variable-rate bank debt approximated book value at September 30, 2014 and December 31, 2013 . The fair value of the Notes was approximately $ 365 million and $364 million as of September 30, 2014 and December 31, 2013 , respectively, as compared to the book value of $ 350 million as of each date. The fair value of the Notes was determined based upon a market quote provided by an independent broker, which represents a Level 2 input.

Note 9—Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of ceiling test write-downs recognized in prior periods, the Company has incurred a cumulative three year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the realizability of its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance for a portion of the deferred tax asset. The valuation allowance was $34.7 million as of September 30, 2014 .

Note 10 - Other Comprehensive Income

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the three month period ended September 30, 2014 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of June 30, 2014	($2,294)	($1,360)	($3,654)
Other comprehensive loss before reclassifications:			
Change in fair value of derivatives	5,293		5,293
Income tax effect	(1,969)	1,360	(609)
Net of tax	3,324	1,360	4,684
Amounts reclassified from accumulated other comprehensive loss:			
Oil and gas sales	(240)		(240)
Income tax effect	89	—	89
Net of tax	(151)	—	(151)
Net other comprehensive income	3,173	1,360	4,533
Balance as of September 30, 2014	$879	$0	$879

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the nine month period ended September 30, 2014 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2013	($688)	($408)	($1,096)
Other comprehensive loss before reclassifications:			
Change in fair value of derivatives	(3,510)		(3,510)
Income tax effect	1,395	(2,004)	(609)
Net of tax	(2,115)	(2,004)	(4,119)
Amounts reclassified from accumulated other comprehensive loss:			
Oil and gas sales	6,005		6,005
Income tax effect	(2,323)	2,412	89
Net of tax	3,682	2,412	6,094
Net other comprehensive income	1,567	408	1,975
Balance as of September 30, 2014	$879	$0	$879

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the three month period ended September 30, 2013 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of June 30, 2013	$1,418	$0	$1,418
Other comprehensive income before reclassifications:			
Change in fair value of derivatives	110	—	110
Income tax effect	(41)	—	(41)
Net of tax	69	—	69
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	(234)	—	(234)
Income tax effect	87	—	87
Net of tax	(147)	—	(147)
Net other comprehensive loss	(78)	—	(78)
Balance as of September 30, 2013	$1,340	$0	$1,340

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the nine month period ended September 30, 2013 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2012	$521	$0	$521
Other comprehensive income before reclassifications:			
Change in fair value of derivatives	1,047	—	1,047
Income tax effect	(389)	—	(389)
Net of tax	658	—	658
Amounts reclassified from accumulated other comprehensive income:			
Oil and gas sales	257	—	257
Income tax effect	(96)	—	(96)
Net of tax	161	—	161
Net other comprehensive income	819	—	819
Balance as of September 30, 2013	$1,340	$0	$1,340

Note 11 - Recently Issued Accounting Standards

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers" to clarify the principles for recognizing revenue and to develop a common revenue standard and disclosure requirements. The core principle of ASU 2014-09 is that an entity will recognize revenue when it transfers control of goods or services to customers at an amount that reflects the consideration to which it expects to be entitled in exchange for those goods and or services. The standard is effective for fiscal years beginning after December 15, 2016, and for interim periods within those fiscal years. Early application is not permitted. Entities can choose to apply the standard using either a full retrospective approach or a modified retrospective approach, with the cumulative effect of initially applying ASU 2014-09 recognized at the date of initial application. We are currently evaluating the effect that this new standard will have on our consolidated financial statements and related disclosures, however, we do not expect the adoption of the standard will have a material impact on our results of operations, financial position, or related disclosures.

Item 2.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the Company's MD&A contained in the Form 10-K for the fiscal year ended December 31, 2013 (the "2013 10-K") and in conjunction with the consolidated financial statements included in this Form 10-Q and in the 2013 10-K.

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with primary operations in Oklahoma, Texas, and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

We have successfully diversified into onshore, longer life basins in Oklahoma and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in East Texas through 2013, we have invested the majority of our capital into growing our longer life assets. During the ten year period ended December 31, 2013 , we have realized a 95% drilling success rate on 918 gross wells drilled. Comparing 2013 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 294% and estimated proved reserves by 262% . At September 30, 2014 , 88% of our estimated proved reserves and 71% of our third quarter of 2014 production were derived from our longer life assets.

We are focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the Woodford joint development agreement ("JDA"), which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures in the Woodford Shale and Mississippian Lime. Under the terms of the JDA, as amended, we will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The drilling carry is subject to extensions in one year intervals and as of September 30, 2014 , approximately $37.6 million remained available.

During 2013, we closed the Gulf of Mexico Acquisition (discussed below) which significantly enhanced our 2013 production. As a result of our drilling programs in each of our operating areas, as well as the Gulf of Mexico Acquisition, we set Company records in 2013 for estimated proved reserves at year end and total production, including a 36% increase in oil and natural gas liquids production from 2012.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million , reflecting an effective date of January 1, 2013 . The Gulf of Mexico Acquisition was financed with the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017 . The acquired assets included 16 gross wells located on seven platforms.

During 2013, the Gulf of Mexico Acquisition contributed 4.5 Bcfe of production, including 235,000 barrels ("bbls") of oil, and added 30.5 Bcfe of estimated proved reserves as of December 31, 2013. During the first nine months of 2014, the Gulf of Mexico Acquisition assets produced 6.7 Bcfe, including 375,000 barrels of oil. As a result of the Gulf of Mexico Acquisition, our acreage position in the Gulf Coast Basin increased 23% to 46,801 net acres. See "Note 2 - Acquisition" in Item 1. Financial Statements for additional details related to this transaction.

We believe the Gulf of Mexico Acquisition represents both a strategic and transformative transaction for us. This transaction builds upon our existing strategy of utilizing free cash flow from our shorter life, Gulf Coast Basin assets to develop our longer-life resource assets. As evidenced by the larger percentage of our production and estimated proved reserves now located in our longer lived basins, we have successfully leveraged our Gulf Coast free cash flow to help fund our substantial diversification efforts over the past several years.

Fleetwood Joint Venture

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The assets acquired under the joint venture include an average 37% working interest in an approximately 30,000 acre leasehold position in Louisiana and exclusive rights, along with our joint venture partner, to a 200 square mile proprietary 3D survey which has generated several conventional and shallow non-conventional oil focused prospects.

The purchase price was comprised of $10 million in cash ($3 million paid in July 2014 and $7 million due in January 2015) and $14 million in cash funding for future drilling, completion and lease acquisition costs. If the $14 million in drilling, completion and lease acquisition costs is not fully funded by December 31, 2015, any remaining balance becomes payable at the election of our joint venture partner.

Critical Accounting Policies

Reserve Estimates

Our estimates of proved oil and gas reserves constitute those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties.

Disclosure requirements under Staff Accounting Bulletin 113 ("SAB 113") include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average will also be used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or when the properties are determined to be impaired.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated properties and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effect of cash flow hedges in place, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil or gas prices decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of oil and gas properties could occur in the future.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in fair value of those derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil and natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense).

Our hedges are specifically referenced to NYMEX prices for oil and natural gas and OPIS Mt. Bellevue pricing for natural gas liquids. We evaluate the effectiveness of our hedges at the time we enter the contracts, and periodically over the life of the contracts, by analyzing the correlation between NYMEX and OPIS prices and the posted prices we receive from our designated production. Through this analysis, we are able to determine if a high correlation exists between the prices received for the designated production and the NYMEX or OPIS prices at which the hedges will be settled. At September 30, 2014 , our derivative instruments were designated as effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX or OPIS prices, discount rates and price movements. As a result, we calculate the fair value of our commodity derivatives using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. Our fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of our default risk for derivative liabilities.

Results of Operations

The following table sets forth certain information with respect to our oil and gas operations for the periods noted. These historical results are not necessarily indicative of results to be expected in future periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Production:				
Oil (Bbls)	170,014	219,402	642,511	460,822
Gas (Mcf)	8,153,145	8,351,200	23,033,254	21,519,550
Ngl (Mcfe)	2,397,236	1,238,719	5,186,794	3,560,179
Total Production (Mcfe)	11,570,465	10,906,331	32,075,114	27,844,661
Sales:				
Total oil sales	$ 16,670,934	$ 23,663,415	$ 64,279,648	$ 48,831,937
Total gas sales	29,109,608	25,009,383	87,469,799	61,980,015
Total ngl sales	10,705,208	6,905,048	25,283,882	18,818,166
Total oil and gas sales	$ 56,485,750	$ 55,577,846	$ 177,033,329	$ 129,630,118
Average sales prices:				
Oil (per Bbl)	$ 98.06	$ 107.85	$ 100.04	$ 105.97
Gas (per Mcf)	3.57	2.99	3.80	2.88
Ngl (per Mcfe)	4.47	5.57	4.87	5.29
Per Mcfe	4.88	5.10	5.52	4.66

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $337,000 and $767,000 , Ngl hedges of $28,000 and $5,000 and oil hedges of ($125,000) and ($538,000) for the three months ended September 30, 2014 and 2013 , respectively. The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of ($4,802,000) and $422,000 , Ngl hedges of $28,000 and $5,000 , and oil hedges of ($1,231,000) and ($684,000) for the nine months ended September 30, 2014 and 2013 , respectively.

Net income available to common stockholders totaled $4,671,000 and $383,000 for the quarters ended September 30, 2014 and 2013 , respectively, while net income available to common stockholders totaled $24,306,000 and $6,652,000 for the nine months ended September 30, 2014 and 2013 , respectively. The primary fluctuations were as follows:

Production Total production increased 6% and 15% during the three and nine month periods ended September 30, 2014 , respectively, as compared to the 2013 periods. Gas production during the three month period ended September 30, 2014 decreased 2% from the comparable period in 2013 due primarily to normal production declines at our dry gas Oklahoma fields and legacy Gulf Coast fields as well as downtime at certain of our Gulf of Mexico properties that has since been fully restored. These production declines were mostly offset by the successful drilling program in our Carthage field. Gas production during the nine month period ended September 30, 2014 increased 7% from the comparable period in 2013 due primarily to added production from the wells acquired in the Gulf of Mexico Acquisition, which closed on July 3, 2013, and to a lesser extent as a result of the successful drilling program in our Cathage field. Partially offsetting this increase were decreases in gas production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf Coast fields. As a result of an anticipated full year of production from the wells acquired in the Gulf of Mexico Acquisition and increased drilling activity during 2014, we expect our average daily gas production in 2014 to increase as compared to 2013 .

Oil production during the three month period ended September 30, 2014 decreased 23% from the 2013 periods due primarily to normal production declines at certain of our legacy Gulf Coast fields as well as downtime at certain of our Gulf of Mexico properties that has since been fully restored. Oil production during the nine month period ended September 30, 2014 increased 39% from the 2013 period primarily due to added production from the wells acquired in the Gulf of Mexico Acquisition. As a result of an anticipated full year of production from the wells acquired in the Gulf of Mexico Acquisition, we expect our average daily oil production to be significantly higher during 2014 as compared to 2013 .

Natural gas liquids ("Ngl") production during the three and nine month periods ended September 30, 2014 increased 94% and 46% from the respective 2013 periods due to the successful drilling program in the liquids rich portion of our Oklahoma acreage position and in our Carthage field. Additionally, Ngl production increased as a result of added production from the wells acquired in the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases as a result of normal production declines at our legacy Gulf Coast fields. As a result of increased drilling activity during 2014 as well as an anticipated full year of production from the wells acquired in the Gulf of Mexico Acquisition, we expect our average daily Ngl production for 2014 to increase significantly as compared to 2013 .

Prices Including the effects of our hedges, average gas prices per Mcf for the three and nine month periods ended September 30, 2014 were $3.57 and $3.80 as compared to $2.99 and $2.88 for the respective 2013 periods. Average oil prices per Bbl for the three and nine months ended September 30, 2014 were $98.06 and $100.04 as compared to $107.85 and $105.97 for the respective 2013 periods and average Ngl prices per Mcfe were $4.47 and $4.87 for the three and nine months ended September 30, 2014 , as compared to $5.57 and $5.29 for the respective 2013 periods. Stated on an Mcfe basis, unit prices received during the three months ended September 30, 2014 were 4% lower than the prices received during the comparable 2013 period, while unit prices received during the nine months ended September 30, 2014 were 18% higher than the prices received during the comparable 2013 period.

Revenue Including the effects of hedges, oil and gas sales during the three months ended September 30, 2014 increased 2% to $56,486,000 , as compared to oil and gas sales of $55,578,000 during the 2013 period. This increase was the result of an overall increase in production as discussed above, partially offset by lower average realized prices. Including the effects of hedges, oil and gas sales during the nine months ended September 30, 2014 increased 37% to $177,033,000 , as compared to oil and gas sales of $129,630,000 during the 2013 period. This increase was the result of higher average realized prices for our production during 2014 as well as increased production as discussed above.

Expenses Lease operating expenses for the three and nine months ended September 30, 2014 totaled $13,019,000 and $37,445,000 , respectively, as compared to $12,652,000 and $31,208,000 during the respective 2013 periods. Per unit lease operating expenses totaled $1.13 and $1.17 per Mcfe, respectively, during the three and nine month periods ended September 30, 2014 as compared to $1.16 and $1.12 per Mcfe during the respective 2013 periods. The increase in per unit lease operating expenses for the nine month period ended September 30, 2014 is primarily due to an increase in expensed workovers during the 2014 period as compared to the 2013 period. As a result of the Gulf of Mexico Acquisition, we expect an increase in the overall amount of lease operating expenses during the remainder of 2014, but we expect per unit lease operating expenses to generally approximate per unit amounts in 2013.

Production taxes for the three and nine months ended September 30, 2014 totaled $1,709,000 and $4,678,000 , respectively, as compared to $1,248,000 and $3,757,000 , respectively, during the 2013 periods. Per unit production taxes totaled $0.15 per Mcfe during each of the three and nine month periods ended September 30, 2014 as compared to $0.11 and $0.13 per Mcfe during the respective 2013 periods. The increase in total production taxes was primarily due to increased production from onshore wells subject to severance taxes as well as an increase in Louisiana severance tax rates effective July 2013 and July 2014.

General and administrative expenses during the three and nine months ended September 30, 2014 totaled $6,319,000 and $19,028,000 , respectively, as compared to $9,132,000 and $20,199,000 during the 2013 periods. General and administrative expenses decreased 31% and 6% , respectively, during the 2014 periods primarily due to acquisition-related costs associated with the Gulf of Mexico acquisition of $2,872,000 and $3,878,000, respectively, included in general and administrative expenses for the three and nine months ended September 30, 2013 . Included in general and administrative expenses for the three and nine month periods ended September 30, 2014 are share-based compensation costs of $1,442,000 and $5,177,000 , respectively, compared to $1,600,000 and $3,665,000 , respectively, during the 2013 periods. We capitalized $3,362,000 and $11,331,000 , respectively, of general and administrative expenses during the three and nine month periods ended September 30, 2014 compared to $3,526,000 and $9,682,000 , respectively, during the 2013 periods.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the three and nine months ended September 30, 2014 totaled $21,913,000 , or $1.89 per Mcfe, and $63,373,000 , or $1.98 per Mcfe, respectively, as compared to $22,107,000 , or $2.03 per Mcfe, and $48,978,000 , or $1.76 per Mcfe, respectively, during the comparable 2013 periods. The decrease in the per unit DD&A rate for the three months ended September 30, 2014 is primarily the result of the successful drilling program in our Carthage field. The increase in the per unit DD&A rate for the nine months ended September 30, 2014 is primarily the result of the Gulf of Mexico Acquisition, which had a higher cost per unit as compared to our overall amortization base. We expect our full year DD&A rate to remain consistent with the 2014 third quarter rate.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $7,050,000 and $22,066,000 during the three and nine months ended September 30, 2014 , respectively, as compared to $8,071,000 and $14,051,000 , respectively, during the 2013 periods. During the three and nine month periods ended September 30, 2014 , our capitalized interest totaled $2,704,000 and $7,327,000 , respectively, as compared to $1,757,000 and $4,525,000 , respectively, during the 2013 periods. The decrease in interest expense for the three months ended September 30, 2014 is the result of an increase in capitalized interest due to our acquisition of the Fleetwood unevaluated properties. The increase in interest expense for the nine months ended September 30, 2014 was a result of the issuance of $200 million of 10% senior notes due 2017, which were used to finance the Gulf of Mexico Acquisition, in July 2013. As a result, we expect interest expense during 2014 to be higher than 2013.

Income tax expense (benefit) during each of the three and nine months ended September 30, 2014 was ($389,000) as compared to $17,000 and ($474,000), respectively, during the 2013 periods. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of ceiling test write-downs recognized in prior periods, we have incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was $34,659,000 as of September 30, 2014.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities principally through cash flow from operations, bank borrowings, other credit facilities, issuances of equity and debt securities, joint ventures and sales of assets. At September 30, 2014 we had a working capital deficit of approximately $ 55.8 million as compared to a working capital deficit of approximately $26.1 million as of December 31, 2013. Approximately $10 million of the deficit increase is attributable to our Fleetwood joint venture. Since we operate the majority of our drilling activities, we have the ability to reduce our capital expenditures to manage our working capital deficit and liquidity position. To the extent our capital expenditures during the remainder of 2014 exceed our cash flow and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of assets to fund a portion of our drilling budget.

Prices for oil and natural gas are subject to many factors beyond our control such as weather, the overall condition of the global financial markets and economies, relatively minor changes in the outlook of supply and demand, and the actions of the Organization of Petroleum Exporting Countries ("OPEC"). Oil and natural gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the bank credit facility, thus reducing the amount of financial resources available to meet our capital requirements. Lower prices and reduced cash flow may also make it difficult to incur debt, including under our bank credit facility, because of the restrictive covenants in the indenture governing the Notes. See "Source of Capital: Debt" below. Our ability to comply with the covenants in our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as oil and natural gas prices.

<u>Source of Capital: Operations</u>

Net cash flow from operations increased from $ 32.9 million during the nine months ended September 30, 2013 to $ 125.9 million during the 2014 period. The increase in operating cash flow during 2014 as compared to 2013 is primarily attributable to increases in oil and gas revenues as well as the timing of payment of payables and receipt of advances from co-owners based on increased operational activity.

<u>Source of Capital: Debt</u>

On August 19, 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Existing Notes"). On July 3, 2013, we issued an additional $200 million in principal amount of 10% Senior Notes due 2017 (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of face value plus accrued interest from March 1, 2013. The New Notes have terms that, subject to certain exceptions, are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013. The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At September 30, 2014, $2.9 million had been accrued in connection with the March 1, 2015 interest payment and we were in compliance with all of the covenants contained in the Notes.

We have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IberiaBank, Bank of America, N.A. and The Bank of Nova Scotia. The Credit Agreement provides us with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows us to use up to $25 million of the borrowing base for letters of credit. Our Credit Agreement matures on October 3, 2016. As of September 30, 2014 we had $72.5 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to our oil and gas properties as of January 1 and July 1 of each year. In connection with the most recent redetermination, the borrowing base was increased to $220 million (subject to the aggregate commitments of the lenders then in effect) effective September 30, 2014 . The aggregate commitments of the lenders is currently $170 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions.

The next borrowing base redetermination is scheduled to occur by March 31, 2015 . We or the lenders may request two additional borrowing base re-determinations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of our assets, including a lien on all equipment and at least 80% of the aggregate total value of our oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1% . For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by us) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, we pay commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

We are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0 and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0 , all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits us to repurchase up to $10 million of our common stock during the term of the Credit Agreement, so long as after giving effect to such repurchase our Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of September 30, 2014 , we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

Our shelf registration statement allows us to publicly offer and sell up to $350 million of any combination of debt securities, shares of common and preferred stock, depositary shares and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

Source of Capital: Joint Ventures

In May 2010, we entered into a joint development agreement with WSGP Gas Producing, LLC ("WSGP"), a subsidiary of NextEra Energy Resources, LLC, whereby WSGP acquired approximately 29 Bcfe of our Woodford proved undeveloped reserves as well as the right to earn 50% of our undeveloped Woodford acreage position through a two phase drilling program. We received approximately $57.4 million in cash at closing, net of $2.6 million in transaction fees, and an additional $14 million in each of 2011 and 2012. In addition, since May 2010, WSGP has funded a share of our drilling costs under a drilling program, which we refer to as the drilling carry. As of September 30, 2014 , approximately $37.6 million of drilling carry remained available.

Source of Capital: Divestitures

We do not budget property divestitures; however, we are continuously evaluating our property base to determine if there are assets in our portfolio that no longer meet our strategic objectives. From time to time we may divest certain non-strategic assets in order to provide liquidity to strengthen our balance sheet or capital to be reinvested in higher rate of return projects.

In January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. In December 2013, we sold our non-operated Wyoming assets for a cash purchase price of $1.0 million. In September 2014, we completed the sale of our Eagle Ford assets for net proceeds of approximately $9.7 million.

Use of Capital: Exploration and Development

Our 2014 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $170 million and $180 million , of which $ 145.1 million was incurred during the first nine months of 2014. Because we operate the majority of our drilling activities, we expect to be able to control the timing of a substantial portion of our capital investments. During the nine months ended September 30, 2014 , we funded our capital expenditures with cash flow from operations, asset sales and cash on hand. To the extent our capital expenditures during the remainder of 2014 exceed our cash flow and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of assets to fund a portion of our drilling budget.

Use of Capital: Acquisitions

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million . The acquired assets include 16 gross wells located on 7 platforms.

In June 2014, we entered into a joint venture in Louisiana for an aggregate purchase price of $24 million. The purchase price is comprised of $10 million in cash ($3 million paid in July 2014 and $7 million due in January 2015) and $14 million in cash funding for future drilling, completion and lease acquisition costs.

We expect to finance our future acquisition activities, if consummated, through cash on hand or available borrowings under our bank credit facility. We may also utilize sales of equity or debt securities, sales of properties or assets or joint venture arrangements with industry partners, if necessary. We cannot assure you that such additional financings will be available on acceptable terms, if at all.

Disclosure Regarding Forward Looking Statements

This Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. When used in this Form 10-Q, the words "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are our ability to integrate our acquisitions with our operations and realize the anticipated benefits from the acquisitions, any unexpected costs or delays in connection with the acquisitions, our ability to find oil and natural gas reserves that are economically recoverable, our ability to realize the anticipated benefits from the Fleetwood joint venture, the volatility of oil and natural gas prices, the uncertain economic conditions in the United States and globally, the declines in the values of our properties that have resulted and may in the future result in additional ceiling test write-downs, our ability to replace reserves and sustain production, our estimate of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for future operations, the uncertainties involved in prospect development and property acquisitions or dispositions and in projecting future rates of production or future reserves, the timing of development expenditures and drilling of wells, hurricanes and other natural disasters, changes in laws and regulations as they relate to our operations, including our fracing operations in shale plays or our operations in the Gulf of Mexico, and the operating hazards attendant to the oil and gas business as well as the risks, trends and uncertainties discuss under the "Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Form 10-Q. The Company undertakes no duty to update or revise these forward-looking statements.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We experience market risks primarily in two areas: commodity prices and interest rates. Because our properties are located within the United States, we do not believe that our business operations are exposed to significant foreign currency exchange risks.

Commodity Price Risk

Our revenues are derived from the sale of our crude oil, natural gas and natural gas liquids production. Based on projected sales volumes for the remainder of 2014 , a 10% change in the prices we receive for our crude oil, natural gas and natural gas liquids production would have an approximate $1.9 million impact on our revenues.

We seek to reduce our exposure to commodity price volatility by hedging a portion of production through commodity derivative instruments. In the settlement of a typical hedge transaction, we will have the right to receive from the counterparties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparties this difference multiplied by the quantity hedged. During the three and nine months ended September 30, 2014 , we received (paid) $0.2 million and ($6.0) million , respectively, to the counterparties to our derivative instruments in connection with hedge settlements.

We are required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

Our Credit Agreement requires that the counterparties to our hedge contracts be lenders under the Credit Agreement or, if not a lender under the Credit Agreement, rated A/A2 or higher by S&P or Moody's. Currently, the counterparties to our existing hedge contracts are lenders under the Credit Agreement.

As of September 30, 2014 , we had entered into the following commodity derivative instruments:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
October - December 2014	Swap	45,000 Mmbtu	$4.14
2015	Swap	10,000 Mmbtu	$4.16
Crude Oil:			
October - December 2014	Swap (LLS)	650 Bbls	$101.05
October - December 2014	Swap (WTI)	350 Bbls	$93.26
Pentane:			
October - December 2014	Swap	100 Bbls	$91.58

LLS - Louisiana Light Sweet

WTI - West Texas Intermediate

The Company has approximately 4.1 Bcf of gas volumes at an average price of $4.14 per Mcf, 92,000 barrels of oil volumes at an average price of $98.33 per Bbl, and 9,200 barrels of pentane volumes at an average price of $91.58 per Bbl hedged for the remainder of 2014. Additionally, the Company has approximately 3.7 Bcf of gas volumes at $4.16 per Mcf hedged for 2015. For further discussion of our commodity derivative instruments, please see Item 1, Note 7 "Derivative Instruments" in this Form 10-Q.

Interest Rate Risk

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 17% of our total debt as of September 30, 2014 . Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of September 30, 2014 , and assuming a 10% increase in interest rates and no change in the amount of debt outstanding, the potential effect on interest expense for the remainder of 2014 is less than $0.1 million .

Item 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, completed an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Securities and Exchange Act of 1934, as amended (the "Exchange Act"). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded:

i. that the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and

ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the period covered by this report that have materially affected, or that are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II

Item 1. LEGAL PROCEEDINGS

NONE.

Item 1A. RISK FACTORS

For information regarding risks, uncertainties and assumptions, please see Part 1, Item 1A of our 2013 10-K. Except as disclosed below, there are no material changes from risk factors previously disclosed in our 2013 10-K and our quarterly report on Form 10-Q for the quarter ended June 30, 2014.

Oil and natural gas prices are volatile, and an extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Historically, the markets for oil and natural gas have been volatile. For example, for the four years ended December 31, 2013, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $68.01 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.01 per MMBtu to a low of $1.91 per MMBtu. These markets will likely continue to be volatile in the future. The prices we will receive for our production, and the levels of our production, will depend on numerous factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;

- the actions of OPEC;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the Federal Energy Regulatory Commission;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;
- the price and level of foreign imports of oil and natural gas; and
- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline further. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record ceiling test write-downs and may cause our estimated proved reserves at December 31, 2014 to decline compared to our estimated proved reserves at December 31, 2013. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of September 30, 2014 , the aggregate amount of our outstanding indebtedness, net of cash on hand, was $417.1 million . We have $97.5 million of additional availability under our bank credit facility, subject, however, to limitations on incurrence of indebtedness under the indenture governing our 10% senior notes due 2017, which we refer to as our 10% notes. In addition, we may also incur additional indebtedness in the future. Our high level of debt could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our outstanding indebtedness, including our 10% notes, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;
- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;
- we will need to use a substantial portion of our cash flows to pay interest on our debt, approximately $35 million per year for interest on our 10% notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our Series B Preferred Stock of approximately $5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 10% notes, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 10% notes, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended September 30, 2014 .

	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program	Maximum Number (or Approximate Dollar Value) of Shares that May be Purchased Under the Plans or Programs
July 1 - July 31, 2014	8,409	$ 6.58	—	—
August 1 - August 31, 2014	—	—	—	—
September 1 - September 30, 2014	78,453	$ 5.97	—	—
Total	86,862	$ 6.03	—	—

(1) All shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards.

Item 3. DEFAULTS UPON SENIOR SECURITIES

NONE.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

NONE.

Item 6. EXHIBITS

10.1 Eighth Amendment to Credit Agreement dated as of September 29, 2014, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPM Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank, Bank of America, N.A. and The Bank of Nova Scotia (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on September 30, 2014).

Exhibit 31.1, Certification of Chief Executive Officer pursuant to Rule 13-a-14(a)/Rule 15d-14(a), promulgated under the Securities Exchange A 1934, as amended.

Exhibit 31.2, Certification of Chief Financial Officer pursuant to Rule 13-a-14(a)/Rule 15d-14(a), promulgated under the Securities Exchange A 1934, as amended.

Exhibit 32.1, Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-O Act of 2002.

Exhibit 32.2, Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Ox Act of 2002.

Exhibit 101.INS, XBRL Instance Document

Exhibit 101.SCH, XBRL Taxonomy Extension Schema Document.

Exhibit 101.CAL, XBRL Taxonomy Extension Calculation Linkbase Document.

Exhibit 101.DEF, XBRL Taxonomy Definitions Linkbase Document

Exhibit 101.LAB, XBRL Taxonomy Extension Label Linkbase Document.

Exhibit 101.PRE, XBRL Taxonomy Extension Presentation Linkbase Document

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PETROQUEST ENERGY, INC.

Date: November 4, 2014

/s/ J. Bond Clement

J. Bond Clement
Executive Vice President, Chief Financial Officer
(Authorized Officer and Principal
Financial and Accounting Officer)

EXHIBIT 31.1

I, Charles T. Goodson, certify that:

1. I have reviewed this Form 10-Q of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
November 4, 2014

EXHIBIT 31.2

I, J. Bond Clement, certify that:

1. I have reviewed this Form 10-Q of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
November 4, 2014

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of PetroQuest Energy, Inc. (the "Company") on Form 10-Q for the quarter ending September 30, 2014 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Charles T. Goodson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
November 4, 2014

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of PetroQuest Energy, Inc. (the "Company") on Form 10-Q for the quarter ending September 30, 2014 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, J. Bond Clement, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
November 4, 2014

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Scott A. Goorland
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5633
(561) 691-7135 (Facsimile)
scott.goorland@fpl.com

November 26, 2014

--VIA UPS OVERNIGHT DELIVERY--

VERITEXT – Production Department
One Biscayne Tower, Suite 2250
Two South Biscayne Boulevard
Miami, Florida 33131

Re: Docket No. 140001-EI – In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor
Job # 1967081

To: Veritext – Production Department

Pursuant to instructions from Zipporah Gibbs, I am enclosing the late-filed exhibit for Sam Forrest Volume 2 Deposition.

Additionally, I am enclosing the original errata sheets and signed affidavits from witness depositions of Sam Forrest, Kim Ousdahl, and Dr. Tim Taylor. The Errata Sheet for witness, Terry Deason is a PDF copy. It will be replaced with the original under separate cover.

All documents have been scanned and electronically sent to litsup-fla@veritext.com. Please contact me if you have any questions. Thank you for your assistance.

Sincerely

for

Scott A. Goorland
Principal Attorney

Attachments

cc: Zipporah Gibbs, zgibbs@veritext.com

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 57
PARTY: STAFF
DESCRIPTION: Deposition of Tim Taylor, 11/12/14, including late-filed exhibits 2 and 3

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON
31 /2-5	should read as below	transcribed improperly

"In some instances in resource plays they will allow an undrilled well that is end-to-end with a producing well to be classified as proved undeveloped."

60/5	"MCF" instead of "NCF"	transcribed improperly
75/21	"reserve" insted of "reserved"	" "

I, Timothy D. Taylor, do hereby certify that I have read the foregoing transcript of my deposition, given on ________________, and that together with any additions or corrections made herein, it is true and correct.

Timothy D. Taylor
Deponent

The foregoing instrument was acknowledged before me this 20 day of November, 2014, by Timothy D. Taylor, who is personally known to me or has produced ______________________ as identification and who did not take an oath.

LeAnn R. B
Notary Signature

NOTARY PUBLIC, State of Florida

____
Commission Number

LEEANN R. BREHM
Commission # FF 092442
Expires February 12, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

TIMOTHY TAYLOR

SUBSCRIBED AND SWORN before and to me this 20 day of November, 2014

____

NOTARY PUBLIC

My Commission expires:

NOTARY PUBLIC STATE OF FLORIDA
LEEANN R. BREHM
Commission # FF 092442
Expires February 12, 2018
Bonded Thru Troy Fain Insurance 800-385-7019

57

Deposition of Tim Taylor 11/12/14, including late-filed Exhibits #2 and 3

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FILED: October 25, 2014

IN RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR
_____________________________________/

Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida
November 12, 2014
9:15 a.m. - 12:15 p.m.

DEPOSITION OF TIMOTHY TAYLOR

Taken on behalf of the Alice Teslicko before Alice J. Teslicko, RMR, Notary Public in and for the State of Florida at Large, pursuant to a Notice of Taking Deposition in the above cause.

APPEARANCES:

FOR THE OFFICE OF PUBLIC COUNSEL:

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JOHN TRUITT, ESQ.
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FOR FLORIDA INDUSTRIAL POWER USERS GROUP:

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(850) 681-3828
jmoyle@moylelaw.com

APPEARANCES - CONTINUED

Also Present:

Andrew Maurey - Florida Public Service Commission
Kurt Howard - FPL
Richard Ross - FPL

Appearing Telephonically:

Erik Sayler - Office of Public Counsel
Tarik Noriega - Office of Public Counsel
Patty Christensen - Office of Public Counsel
Donna Ramas - Office of Public Counsel
Florida Public Service Commission Staff
Inna Weintraub - FPL
Sol Stamm - FPL
Terry Deason - FPL

- - -

I N D E X

EXHIBITS

MR. TRUITT: John Truitt with the Office of Public Counsel.

MR. REHWINKEL: Charles Rehwinkel with the Office of Public Counsel.

MR. MOYLE: John Moyle with Moyle Law Firm representing the Florida Industrial Power Users Group.

MR. ROSS: Rich Ross, FPL.

MR. HOWARD: Kurt Howard, FPL.

MR. BUTLER: John Butler, counsel for FPL.

MR. GOORLAND: Scott Goorland, counsel for FPL.

THE WITNESS: Tim Taylor, I'm the chief technical officer of NextEra Project Management Gas Infrastructure.

MR. MAUREY: Andrew Maurey, the Florida Public Service Commission.

MS. BARRERA: Martha Barrera, counsel for Florida Public Service Commission.

THE COURT REPORTER: Would the folks on the phone please identify yourself for the record?

A VOICE: Commission Staff is on the line.

MR. SAYLER: Erik Sayler for the Office of Public Counsel. Expected to dial in a little later is Tarik Noriega --

MR. NORIEGA: I'm here.

MR. SAYLER: Okay, and Patty Christensen.

MR. NORIEGA: Tarik Noriega, Office of Public Counsel. Good morning.

MS. RAMAS: Donna Ramas, listening on behalf of the Office of Public Counsel.

Thereupon:

TIMOTHY TAYLOR

was called as a witness by the Office of Public Counsel, and having been duly sworn, was examined and testified as follows:

THE WITNESS: I do.

BY MR. TRUITT:

Q. Good morning, Dr. Taylor. John Truitt with the Office of Public Counsel.

A. Good morning.

MR. GOORLAND: Can we get everybody on the phone to mute, please?

MS. WEINTRAUB: Excuse me, I just wanted to say Inna Weintraub, Terry Deason, and Sol Stamm from FPL are listening.

MR. GOORLAND: Now can we get everyone on the phone to go on mute, please.

BY MR. TRUITT:

Q. Dr. Taylor, have you ever been deposed before?

A. Yes, I have.

Q. So I'm just going to state a couple of basic ground rules so we're on the same page.

A. Okay.

Q. First off, I want to start with that any questions you don't understand, please ask me to clarify. I want to make sure we have everything clear on the record.

MR. TRUITT: We're under the agreement that the objections except to the form of the question are reserved until the hearing; is that correct?

MR. GOORLAND: Uh-huh.

BY MR. TRUITT:

Q. Did you get the notice for this deposition?

A. Yes.

Q. Did you bring all the materials as requested by notice?

A. Yes.

Q. Do you have any other formality issues before we start with the rest of the questions?

A. I do not.

Q. So you are the same Dr. Taylor that caused to be filed direct testimony with exhibits in this docket?

A. Yes.

Q. And you're the same Dr. Taylor that filed rebuttal testimony with exhibits to this docket; is that correct?

A. I am.

Q. I'd like to ask you to keep in mind that any questions by reference to direct rebuttal testimony, I'm asking for the answer at the time you prepared that testimony, okay. And of course, in your answer, if you need to change it as a different answer now, please state that for the record.

Do you have any changes or corrections to any of your direct testimony at this time?

A. No.

Q. Do you have any changes to any of the exhibits that were attached to your direct at this time?

A. No.

Q. Any changes to your rebuttal testimony?

A. No.

Q. And any changes to the exhibits attached to your rebuttal?

A. No.

Q. So I'd like to start out where you started in your direct testimony. You discuss the difference

between wet and dry gas. Do you remember that?
MR. BUTLER: Do you have a page reference?
MR. TRUITT: Yes, it's going to be on Page 8, starting at line 8. It's specifically where I'm going. .
BY MR. TRUITT:
Q. You stated that natural gas contains significant fractions of other hydrocarbons that is referred to as wet gas.
What's the threshold percentage of other hydrocarbons, meaning not methane, that determines whether gas is wet or dry, is that dividing line?
A. It's generally a function of the BTU value of the gas and whether or not liquids can be extracted from that gas. So there's no clear cut off, but generally speaking, it is whether or not enough NGLs can be extracted to be of economic value.
Q. And then on Page 9, lines 5 and 6, you describe pipeline quality natural gas is 85 percent methane. You use a percentage there.
Is that an industry accepted standard or is that a working number for what you use in your work?
A. It's a generally industry accepted standard.
Q. So then back to the wet/dry gas. Is there kind of a rule of thumb percentage that anyone uses in

the wet and dry distinction?

A. Again, it's whether or not enough NGLs can be extracted to be of economic value.

Q. Next on your direct I'd like to flip to Page 11. We are looking at the paragraph starting on Line 10, about the decline curve analysis.

You state in your testimony -- the actual word you used is "sufficient historical production data," Line 15. What constitutes sufficient historical production?

A. Generally, that refers to having enough production to have established the trend of decline in the well. Not only the initial decline, but the shape of the decline curve.

Q. And how long in the industry -- when you look at that in determining the shape and the decline of the curve, what is the general rule of thumb in terms of the time or is it purely identified by output of the well?

A. It's identified by the output of the well and it's on a case-by-case basis, but generally at the minimum, several months, preferably more than a year.

Q. In relation to that sufficient historical production data, do you use a sliding scale, whereby longer periods of time create more certainty?

If you have more historical data, you have more certainty in terms of your analysis?

A. Yes.

Q. What is that scale? Is it a linear scale relation, X amount more time? It's X times more confident or how does that work?

A. Again, it's on an individual case basis and the data will show me if the decline scenario that I'm forecasting has been established by that data.

Q. Is there a -- in terms of outside of your job, as an industry standard, is there a -- when the industry looks at these things, is there a point at which you would say everyone in the industry would agree that that production data is accurate?

A. No.

Q. Do different geographical regions have a different scale for the sufficient historical data or is it simply based on the well itself on an individual basis?

A. Define "scale".

Q. Well, like you were saying, you like to have a minimum of several months, preferably more than a year, however you take a case-by-case basis. So that's the scale I'm meaning.

If you look at a geographical region, say in the Northeast, does that have a longer or shorter time frame that you'd like to see? Less than a year, more than a year, than it does in Oklahoma, for example?

A. Well, every play has its own characteristics and so yes, there would be variances from play to play.

Q. Are there variances in a play?

A. There can be, yes.

Q. What could cause variances in a play?

A. The amount of liquid, hydrocarbons in the production stream, the amount of water that's being produced, and whether or not that is constant with time or declining.

Q. Now, in terms of -- again, we're still on this historical data discussion.

Do different drilling or completion techniques require different amounts of historical data to make this analysis? Like for example, a vertical well versus a horizontal well, does that affect the analysis or is it simply in the output of what comes out?

A. Yes.

Q. Yes to which? Does the vertical well or horizontal --

A. Yes, the difference between a vertical and a horizontal well, there would be differences between the vertical and the horizontal well.

Q. Do vertical wells require more historical data or less historical data than a horizontal well?

A. Not necessarily, no. Again, it's a function of the individual well performance data.

Q. I want to shift gears for a second. If we look at the rebuttal -- so everyone is on the same page, beginning on Page 9. Let's see, it's going to be Line 10.

You had stated, I'm quoting, referring to PetroQuest, you called them "an industry leader in the region." What is your definition of an industry leader in oil and gas explorations, when you use that term in your rebuttal testimony?

A. Well, I identified them as an industry leader in this region and it's based on my experience of many years; and specifically, I'm familiar with how much it costs to drill a well, how much it costs to operate a well.

I've seen AFEs from PetroQuest. We have other projects with them. They've consistently met their AFEs. They've been reasonable cost and -- reasonable capital costs and reasonable operating costs, and that in my mind makes them an industry leader.

Q. And just to be clear for the transcript, AFE means what?

A. AFE means Authority for Expenditure.

Q. Is the length of time someone is in business part of the factor for being an industry leader in the region?

A. Yes.

Q. How long has PetroQuest been in the gas exploration business?

A. I think since 1985.

Q. How long has PetroQuest being drilling in the Woodford Shale?

A. Since 2003.

Q. Have there been any other companies that you would term industry leaders that have been drilling in the Woodford longer than PetroQuest?

A. You know, I honestly have not done an analysis to see what the other companies' performance have been.

Q. Do you know how long anyone has been drilling in the Woodford?

A. First production from the Woodford Shale was in 1939.

Q. So if they've been drilling in the Woodford since 2003, would you call that a long history of drilling in the Woodford?
A. Yes, I would.
Q. Again, in your rebuttal, flip back to Page 5, where you're discussing your Exhibits TT11 and 12, the type curve analysis.
You mentioned that you use 19 wells in the area of mutual interest to create this type curve, and then you had said that you made them all zero because they had started at different times, so the chart would be clear.
When was the actual year the first well in that chart, either of those type curves, was drilled?
A. 2010.
Q. Now, which type curve was the 2010 well drilled in?
A. The western type curve.
Q. And then on the eastern, what year was that drilled?
A. I don't remember.
Q. Now, the type curves, if we're looking at Exhibits TT11 and TT12, show -- again, like I said, a 25-year analysis and we had a discussion earlier where you had stated that you needed at least a couple of

months, preferably more than a year to put this together.

When was the actual date you created these type curves?

A. Several months ago. I don't remember the exact -- the exact date.

Q. Summer of this year, is that about right?

A. Yes, summer of this year.

Q. Before or after, okay.

Now, if you have the -- you have these lines that are labeled "Production of Individual Existing PetroQuest wells in the AMI" and zero to 25 years out, and then you put the type curve in between the average, and I understand that.

So if we only have a well in the western, for example, that's four years old, so everything after year four is extrapolated based on the data that you have; is that correct?

A. Correct, and I stated that in my testimony.

Q. Was PetroQuest the initial driller for all 19 wells that you used for the type curves?

A. Yes.

Q. And are all of the 19 wells used in those type curves in Pittsburg County?

A. Yes.

Q. For the moment, the last one on this type curve, are all the wells in this type curve horizontals?

A. Yes.

Q. Now, again, I'm still inside your rebuttal and we're kind of talking -- we're going to flip to a production schedule here on Page 4, the answer starting at Line 9. You stated, "With regards to output and reserve levels, you don't expect any such variances to be significant."

What is your definition of "significant", specifically in this context?

A. Well, generally speaking, you know, I examined all the production data from every well in the AMI, all these 19 wells, and my type curve which we just discussed, I presented a graph that shows that there was very little variance between the production for the individual wells, and so I would say certainly within 10 to 20 percent early in the life of a well would be insignificant.

Q. Now, is that industry standard, all wells within production early 10 to 20 percent is insignificant, or what's the factor that affects that 10 to 20 percent choice here?

A. It's not an industry standard. That's my opinion.

Q. Now, also looking at some historical data in the rebuttal on Page 7, we're looking at the answer starting at Line 3. You mention that you examined the actual operating cost for each of the wells for the 12 prior months.

Why did you pick 12 months?

A. That's generally the period that is available to us in an LOS statement. I like to look at the trailing 12 months as being representative of what the current operating costs are.

There are other costs available prior to that, but I examined only the previous 12 months as being the most representative.

Q. Okay. You said you only examined the prior 12 months. Is that just in this instance or whenever you look at these types of --

A. In every instance.

Q. Again, is that an industry standard, to only look at 12 months?

A. It is an industry standard to look at the trailing 12 months of operating cost, yes.

Q. Okay. Off gears from the rebuttal on direct just a little bit, are you familiar with Natural Gas Intelligence, that data source?

A. No.
Q. Are you familiar with Baker Hughes Services?
A. Yes.
Q. How are you so familiar with them? What do you understand them to do?
A. Baker Hughes, and the company now called Baker, is a large service company in the oil and gas industry.
Q. Are you aware that Baker Hughes publishes information on active wells and drilling rigs and things of that nature?
A. Yes.
Q. Do you find their material to be generally accurate in the field?
A. Generally, but not always.
Q. Let me go back to the rebuttal again on Page 8. In the answer starting on Line 20, you disagreed with Mr. Lawton that the activity is "far from coming to a basic drilling standstill," in quotes?
A. Yes.
Q. What would you qualify as a basic drilling standstill?
A. No rigs running.
Q. At all?

A. At all.
Q. So 50 percent reduction in rigs is not a drilling standstill?
A. No, a basic standstill. A standstill is zero.
Q. Now, then following that rebuttal it goes on the top of Page 9. You stated that there are 37 rigs in 2014. What's the source for that information?
A. There was various sources; IHS, Drilling Info, and I think also some from Baker Hughes.
Q. Now, to clarify on the 37 rigs in 2014, is that 37 rigs operating at one time or how is that number --
A. No, that's 37 rigs operating during the year.
Q. So if Rig A starts and stops sometime during the year, it's been counted for the year?
A. Yes.
Q. That was not re-added again?
A. I did not double count any rigs.
Q. Okay. How long does the rig remain active on the well site in Oklahoma?
A. It would depend on the contract with the operating company. It may drill one well and leave or it may drill multiple wells.

Q. In terms of your reviewing this project, what were you seeing in terms of how long the rig was actually taking to drill a well, specifically just a well?

A. I can only speak for our experience with PetroQuest, but a rig there typically takes 20 to 30 days to drill a well.

Q. Does the area of mutual interest overlap any other counties besides Pittsburg County?

A. I can't remember exactly. There may be a small overlap into Hughes County, but I don't remember.

Q. In terms of this 37 rig number that you had in your rebuttal testimony, were any of those in Pittsburg County?

A. Yes.

Q. Were any of those in the AMI specifically?

A. Yes.

Q. Were any of those PetroQuest rigs?

A. Yes.

Q. How many of those were PetroQuest rigs?

A. In the AMI, one.

Q. Okay. Outside the AMI?

A. Two -- three total, sorry.

Q. Three total. So one in the AMI and two outside?

A. Yes.

Q. Also in your rebuttal on Page 9 again you point out -- you mention permit numbers. What was your source of information for the permits?

A. State of Oklahoma Conservation Commission.

Q. Now, are you aware of a requirement that once you receive a permit you have to drill within a specified time frame?

A. You have to drill within a specified time frame or the permit expires, yes.

Q. What was that time frame?

A. Six months.

Q. Can that be extended?

A. I don't know. I'm assuming like in most states it could be, yes.

Q. Are you familiar at all with the extension procedures?

A. No.

Q. In terms of those permits, the 37 -- I'm sorry, 97, how many of those are in Pittsburg County?

A. I don't know.

Q. Okay. And then how many of those are from PetroQuest?

A. If I remember correctly, 23.

Q. In terms of AMI, when was the most recent well drilled by PetroQuest in the AMI?

A. I don't remember, but probably 2013, 2012 or 2013.

Q. Has PetroQuest drilled any in the Woodford outside of the AMI this year?

A. Yes.

MR. MOYLE: Can I just object to that answer? And I want to make sure I understand how we're handling objections. That last answer, he said he didn't know and he ventured a guess. It's speculative. I would object on the grounds it's speculative.

If this depo is coming in, you know, I want to preserve those objections.

Maybe we can go off the record on this.

(Discussion off the record.)

BY MR. GOORLAND:

Q. Back to PetroQuest drilling. Are they currently on schedule with the well that's proposed to start drilling in its drilling plan, do you know that or not?

A. No.

Q. Are they not on schedule or you don't know?

A. They are not on schedule.

Q. How far behind schedule are they?
A. Several weeks.
Q. Do you know PetroQuest's historical percentage for starting drilling on time?
A. No.
Q. Do you know PetroQuest's historical percentage for completion of wells on time?
A. No.
Q. Do you know PetroQuest's historical percentage of completing jobs within or under budget?
A. No.
Q. Do you know why they're several weeks behind schedule?
A. It was a matter of preparing the surface location and acquiring a rig. The rig was late in arriving.
Q. Was that for a well in the AMI?
A. Yes.
Q. Switching gears to go to Forrest A. Garb & Associates. You engaged them to perform a third party analysis?
A. No.
Q. Who engaged Forrest A. Garb & Associates to perform a third party analysis?
A. FPL.

Q. Do you know when FPL engaged Forrest A. Garb & Associates to perform an analysis?

A. During the summer.

Q. The summer of what year?

A. The summer of 2014.

Q. Was that for the analysis of the Woodford project?

A. Yes.

Q. Do you know of Forrest A. Garb & Associates being engaged by FPL to analyze any other drilling venture projects?

A. No.

Q. You stated both in direct and rebuttal -- and direct is on Page 23 and rebuttal in Page 6 -- regarding Forrest A. Garb, to engage in four third party analyses.

Is that standard industry practice when you go to invest in gas reserves and drilling operations?

A. Not necessarily, no.

Q. What would be a reason you would not engage a third party to analyze data before investing?

A. To get a level of comfort that the other analysis that has been done is reasonable.

MR. BUTLER: Excuse me, I think you may have not heard the word "not."

BY MR. TRUITT:

Q. What would be a reason you would not hire a third party to perform an analysis?

A. I apologize for misunderstanding. You would not have a third party analysis if you trusted your internal analysis and you didn't have a requirement to go outside for a third party analysis.

Q. In your experience in the industry, does that happen very often, that people don't hire third party analysts?

A. Yes.

MR. TRUITT: If we can go off the record for just a second.

(Discussion off the record.)

BY MR. GOORLAND:

Q. Dr. Taylor, I'm looking at Exhibit TT10, which is confidential in its entirety, and just to be clear for the record, I'll make sure we don't disclose any confidential information, okay.

First there's two pages I'm going to have you look at. First page, it's labeled 3 of 30 in the top right corner under the Exhibit TT10, where that stamp is in the corner. Page 3 of 30, the second paragraph. I'll give you a minute to read that.

Tell me when you've read the second

paragraph and then I'll point out the other section.

Okay, and then also Page 26 of 30 of TT10. There's a 26 of 30. There's a numbered list on that page and I'm going to ask you again to read the one numbered five. If you could let me know when you're done with that.

A. Yes.

Q. Those two statements that I've just asked you to look at, are those accurate statements?

A. The first one relates to the reserve categories and that statement is correct.

On Page 26 it relates to the information that they used in their economic analysis, Forrest Garb's economic analysis, and it's true with the exception of a couple of things.

One, they verified production data themselves from the public record. So even though we may have provided them some production data, they would also verify that.

And then on the direct operating costs, we provided them the LOS statements that we used in our analysis.

Q. Now, when you say "we", who do you mean exactly?

A. My department. I did.

Q. Where did you and your department obtain the data from?

A. PetroQuest.

Q. Now, with respect to the -- you said some of the production data was gained from public information and that was the data you handed them.

Generally speaking, when is that type of transfer of data handled? Is that normally done by Forrest A. Garb when they verify these things?

Again, I'm trying not to touch on confidential information, but generally speaking, is the type of data transfer for analysis, as you described it, the industry standard or are there variations to where Forrest A. Garb or companies like it would get data?

A. As to the production data, it's industry standard sources.

Q. Okay. As to all of the other data, does it always come from the company or are there other methods that these third party companies can get the data to analyze it?

A. It generally comes from the companies.

Q. Generally, again, I'm asking is it always or is there any other way to do it?

A. I can't speak for the rest of the industry, but in my experience it always comes from the companies.

Q. In terms of when your unit was looking at the Woodford project, did you engage any other entities to gather data or perform tests or anything like that?

A. No.

Q. Was all the data you obtained for the Woodford project from PetroQuest or public source data? I should say that.

A. Yes.

Q. You mentioned several times in direct that in terms of the proved, unproved, etc, the proximity of the wells. Do you remember that discussion in your testimony?

A. Yes.

Q. Is there any other analysis that ever goes into that classification?

I'll give you a hypothetical. If you have this well and it's proven and you have the well next to it, it automatically falls into the category that you just discussed, the next category down, and then it kind of shifts over over time.

Do you just rely on this well producing or does the industry ever do anything else to classify wells in another fashion? Is there any other method for classifying wells?

A. Excuse me, I'm not sure I'm following your question. Could you restate it, please?

Q. Okay. So in your discussion of the well and the classifications, you have one producing and the one next to it, you know, falls in the classification as it shifts down the line. So I'm understanding in the example you gave in your testimony that if the well next to it is producing, then this one falls in the next classification.

Is there another method to assign that classification for those other wells, other than the wells next to it producing?

Is there an analysis you can go out in the field and perform and say, okay, it would fall in this classification?

A. The SEC and the SPE and the SPW and the API have very clearly defined reserve classifications.

Now, there have been some instances in resource plays, which shales are, where the SEC has been more lenient in the classification of reserves. In other words, in some cases they will allow -- in new plays they will allow only the adjacent wells to a producing well to be called a proved undeveloped well.

In some instances on resource plays they will allow end-to-end producing wells and non-undrilled wells to be classified as PDP and proved undeveloped.

So there is some flexibility in the classification, but it's generally -- generally as described here.

Q. In terms of the three source plays that you mentioned that there were some flexibility, what factors allow for that flexibility in those plays?

A. A sufficient amount of production and enough wells to be drilled to demonstrate that this formation is producing under similar circumstances in all areas where that classification is being requested.

Q. In your experience in the industry, in deciding whether to invest in drilling or not -- again, like I said, in your experience-- do they rely solely on information from the drillers themselves to determine whether they should invest or do they seek out third parties to perform things such as, you know, geological analyses or things of that nature?

A. If they have the internal capability of doing so, they'll do an internal analysis first. If they do not have that internal capability, they will often use an outside source to examine the data you described.

Q. So it's my understanding of that answer that they don't go perform any extra testing, get more data themselves?

A. Generally, if you're investing in a project you're not allowed to go into someone else's field and perform tests.

Q. In your analysis of the Woodford project, did you review any of the rules or regulations created by the Oklahoma Commerce Commission?

I think earlier you said "confirmation commission," but it's commerce commission.

A. No.

Q. In terms of when you analyze the project itself and recommend to invest, you stated you didn't look at the rules and regulations for that commission.

Do you analyze at all the regulatory scheme or the framework that's existing in the area when you're looking at the project?

A. As a nonoperating working interest owner, we do not do that. We rely on the operator to provide that level of comfort.

Q. Are you familiar with any press releases by the Oklahoma Commerce Commission regarding potential connections between waste water injection and seismic activities?

A. No.

Q. I'll skip the series and just ask the blanket question. Are you familiar with anything regarding the Oklahoma Commerce Commission's reaction to seismic activities?

A. No.

Q. Do you know where PetroQuest will be injecting the waste water disposal from extracting in AMI?

A. Yes.

Q. Where are they going to be injecting that?

A. It is nearby, but not in the AMI.

Q. So it's in Oklahoma?

A. It's in Oklahoma. They have a salt water disposal facility outside of the AMI, where the water will be disposed.

Q. Do you know the formation it's going to be injected into?

A. It's called the Hartshorne Sandstone.

Q. Now, as a hypothetical, if environmental compliance costs increase, then wouldn't you agree that logically, production costs would increase?

A. If the environmental costs are part of the production cost, yes.

Q. Is there an instance where you wouldn't consider that part of the production costs?

A. I don't know. You're getting outside of my area of expertise.

Q. Okay. Then based on your experience I'll just ask one more question on that topic. Are environmental compliance costs normally in production or is that not --

A. Yes, normally they are.

Q. So in the Woodford project are environmental compliance costs going to be part of the production costs?

A. It's my understanding that PetroQuest is in compliance with all environmental regulations.

Q. But in terms of the question, are the environmental compliance costs going to be considered part of the production costs in this Woodford project?

A. It is my assumption that yes, they would be.

Q. When examining the Woodford project, what risks are on your checklist of risks in your analysis when you look at a project?

I would assume that you have certain things you would look for. What is your internal list when you look at a project like this?

A. I look at the production risk, geologic risk, drilling risk, and operating cost risk.

Q. Okay. For each of those drilling, production, geologic and operating cost risks -- for example, in geologic risks, what constitutes geologic risks in this arena?

A. First of all, the confirmation that the formation we're drilling in is present in all areas that we want to drill and that they are not influenced unduly by faulting activity.

Q. In your risk analysis of the Woodford project, are there any risks of faulting activity or any geologic risks that --

A. No.

Q. Now, in terms of drilling risks, what do you consider?

A. I look at the history of drilling in the area by the company I'm interested in dealing with and whether or not they've been able to maintain their capital costs within a reasonable range of expectation.

Q. Now, in terms of capital cost and production cost risk, when you're analyzing that I would assume that, you know, production costs can vary over time, depending on a number of factors; is that correct?

A. Yes.

Q. In terms of the variance of production cost, what percentage of variance, from what you're anticipating, do you consider to be okay, now we're outside the range of what I'm comfortable with?

A. If I saw operating costs that were 20 to 30 percent higher than I had anticipated or that my analysis showed, I would consider that to be outside my range of comfort.

Q. Okay. Now, in preparation for the original petition filing, so everything coming into the Public Service Commission, how long did it take you to review the Woodford project?

A. I don't remember specifically, but several weeks.

MR. TRUITT: If we can go off the record, please.

(Discussion off the record.)

BY MR. TRUITT:

Q. You said it took several weeks to review this project. When did you first begin working on reviewing the Woodford?

A. Again, I don't remember specifically, but it would have been in the spring of 2014.

Q. Did you personally give Forrest A. Garb &

Associates any data for any other drilling projects besides the Woodford project to review and analyze?

A. No.

Q. Either before the Woodford project or after?

A. Are you asking have I ever used them as a client?

Q. No. I'm asking for any other investing in drilling, this type of an arrangement for anywhere else other than PetroQuest?

A. No, I have not used them.

Q. Have you handed them any other data to analyze on behalf of FPL for any other investment besides the Woodford project?

A. I handed them all the data that we had from PetroQuest and that's all.

Q. Only for the Woodford project. You haven't handed them on behalf of FPL any data for any other projects?

A. I have not.

MR. TRUITT: We don't have any further questions for the witness. If the other parties do --

MS. BARRERA: I don't have any questions.

MR. MOYLE: Are you doing okay? You want a break or do you want to charge ahead?

THE WITNESS: I'm okay. Let's go.

MR. MOYLE: Let's get going and then we'll take a break.

MR. GOORLAND: How long do you think you've got?

MR. MOYLE: It will depend on how he answers the questions. I don't know.

CROSS EXAMINATION

BY MR. MOYLE:

Q. We met briefly. I'm John Moyle. I represent the Florida Industrial Power Users Group.

Let me just start by understanding the capacity in which you're testifying in this case. Tell me your understanding as to the capacity in which you're testifying, if you can.

A. I was asked by FPL to analyze the productive potential and provide them a volume of forecast of wells to be drilled in AMI.

Q. And who asked you to do that?

A. Sam Forrest.

Q. Did he ask you verbally or did he ask in writing to do that?

A. I think it was verbally. I'm sorry, I don't remember an in-writing request, so I'm assuming it was verbally.

Q. Did he tell you why he was making that request?

A. Yes, because they felt like this might be a potential project for them. It would be attractive to them and they wanted me to apply my expertise as to evaluating it.

Q. When you had initial communication, was there a discussion about you doing this and potentially being a witness in a Public Service Commission proceeding?

A. No, not at that time, no.

Q. When did that topic come up?

A. During the summer of 2014.

Q. And then with respect to the testimony that you are providing, do you consider yourself an expert?

A. I do.

Q. And in what areas do you consider that you have expertise?

A. In the area of reservoir engineering, petrophysics, economic evaluation, decline curve analysis, and reserve estimations, and other areas of petroleum engineering.

Q. Let's get them all. Would you read back the answer, please?

(The portion requested was read back by the reporter as above recorded.)

MR. BUTLER: You might want to check, but I think the word "reserve" was before "estimation."

BY MR. MOYLE:

Q. You said "other areas." I want to understand all the areas in which you're claiming expertise. So if you would further delineate the description of other areas for me, please.

A. I've had a considerable amount of experience in project management of oil and gas projects. I've been a chief operating officer of two companies that required knowledge of field operations.

Q. So the answer about chief operating officer, if we were looking at broad topics that you have expertise, I assume that would fall under project management, execution of oil and gas projects; is that fair?

A. Yes.

Q. Anything else?

A. I have a considerable amount of experience in log analysis, some experience in drilling, although I do not consider myself to be a drilling expert.

Q. So we'll scratch that off the list?

A. Scratch it off, and that's enough.

Q. Nothing else?
A. No.
Q. The first one, reservoir engineering, what is that?
A. There are three basic areas of petroleum engineering; reservoir engineering, drilling and production. Reservoir engineering focuses on the estimation and economic evaluation of reserves in the ground.
Q. So this is the portion of this business where you're trying to look at seismic data and other information to figure out, you know, what's underneath and does it make sense to drill and try to capture what may be underneath; is that fair?
A. Yes.
Q. And then drilling is when you actually take the well and sink it and try to extract the materials, right?
A. Yes.
Q. And you don't have expertise in drilling, as we've just talked about, right?
A. I have a great deal of knowledge about drilling, but I would not consider myself to be an expert.
Q. How about production, do you have expertise

in production?

A. I do.

Q. What is production?

A. Production is the surface -- once the hydrocarbons get to the surface, the production engineer handles the accumulation of those reserves and getting them to the sales point.

Q. The accumulation and what?

A. Accumulation of the oil, gas, whatever the product is and getting it to the market, to the sales point.

Q. So is that more just about moving the commodity from point A to point B and how to do that?

A. And the equipment necessary to do that in between, yes.

Q. As part of production does it include marketing or no?

A. No.

Q. And you have an engineering degree, right?

A. Yes.

Q. Did you do any reservoir engineering with respect to the Woodford project?

A. Yes.

Q. What did you do?

A. I examined the well logs for all the

19 wells that had been drilled. I examined the production data from all of the 19 wells that had been producing. I looked at the geology and the seismic data that had been performed by PetroQuest. I constructed type curves that I felt were representative of the production of future wells to be drilled. I applied those then to an economic -- oil and gas economic evaluation program, and I provided the monthly output from that to FPL for their use.

Q. Am I correct in that the area that encompasses the Woodford project at this point is in Pittsburg County, Oklahoma? Is that right?

A. Yes.

Q. To be clear, how many wells information did you look at that were in Pittsburg County, Oklahoma?

A. 19.

Q. And were all 19 owned by PetroQuest?

A. Yes, all 19 were operating by PetroQuest.

Q. What's petrophysics?

A. Log analysis.

Q. I'm sorry?

A. Well log analysis.

Q. And what's involved in well log analysis?

A. When a company drills a well, they typically will run a number of different well logs using electrical devices that are nuclear devices that bring information into a receptor in the well bore. That information is transmitted to the surface and a graphic representation of that is printed out on the surface or in digital form, and we look at that to determine porosity, permeability, and then fluid saturation.

Q. And you did that as it relates to Woodford?

A. To the extent that those logs were available, yes, I did.

Q. Were they available?

A. Not in all wells, no.

Q. How many wells were they available for?

A. I don't remember for sure, but I think two to four. However, I did have -- I did have another type of log information on all the wells, which is called a mud log.

Q. M-U-D, mud?

A. Mud log.

Q. What's a mud log?

A. A mud log is an examination of the cuttings that come to the surface by a mud logger, who determines what the composition of the -- composition of the rock that's being drilled and whether or not there are any hydrocarbons present.

Q. Does it follow that a well log analysis provides better information, in that it's actually giving you information as to what's being extracted in terms of hydrocarbons, as compared to a mud log?

A. The best source of information is the actual production data itself.

Q. But relative to what you described with respect to the well log analysis, is that better data than the mud log?

A. Not necessarily, no.

Q. Why not?

A. Because you're looking at different things. So in a horizontal well you don't typically have the first type of log that I described. You have only the mud log.

Q. Why did you only look at two to four well log analyses for the Woodford project?

A. Because those are the only ones that had pilot holes drilled so that those logs could be run through the Woodford formation.

Q. Pilot holes, is that right?

A. Yes.

Q. What are pilot holes?

A. Pilot holes are holes that are drilled through the formation that you're going to go horizontal in so that you can get a well log to see where the top and the bottom is, so you'll know where to kick off your horizontal section.

Q. Is there an industry standard with respect to the information to be reviewed with respect to analyzing a property?

I know that's not a very clear question. But ultimately rate payers are being asked in this case to make -- to be involved in operations in Oklahoma. From what you've told me, there's 19 wells in Pittsburg County where this is and you looked at between two and four well log analyses.

I would expect that if there were more data, that would be a preferable approach, to look at additional well log analysis to reach a conclusion; is that correct?

A. With the seismic data that was available and those two to four logs, that was sufficient to determine where the horizontal well should be placed.

Q. And is it your testimony that that would be sufficient in the industry, throughout the industry, for companies looking at doing this investment or no?

A. Every case is different.

Q. Describe the economic evaluation you did. I assume you did one, correct?

A. Yes.

Q. Describe what you did, please.

A. After building the type curves I fed that information by location into each of the undrilled wells. I then used the information as to operating cost, capital cost, differentials, yields, shrinks, and all the other factors that go into the evaluation, entered that into a PHDWin, and PHDWin generated a cash flow summary and a log-in forecast summary.

Q. So a lot of times investors will look -- you would agree with this -- you're an expert, you believe in economics or economic evaluation; is that right?

A. Yes.

Q. Do you believe you have expertise beyond just the oil and gas industry?

A. I have expertise in the oil and gas economic evaluation of projects, yes.

Q. But it's not -- you would agree it's not beyond that? You don't have expertise in economic evaluation of the aerospace industry?

A. No, I do not.

Q. When people are making decisions with respect to whether to invest, is there a bottom line number that they ask for?

Do they say, look, I appreciate all the

analysis, but tell me what's my rate of return? Is that a conversation that you're familiar with?

A. Some companies use rate of return as a measure of deciding whether or not they're going to participate in a project, yes.

Q. And what's the rate of return -- did you come up with a rate of return in this case?

A. I did, for our internal evaluation for gas infrastructure.

Q. And what was that number?

MR. GOORLAND: Is that confidential?

MR. BUTLER: Yes, it is.

MR. GOORLAND: It's one of those confidential items we're going to need to deal with.

MR. MOYLE: Why doesn't he write it on a piece of paper and you can give it to me, I can look at it, and we can put the piece of paper in an envelope.

I mean, everybody signed a confidentiality agreement. So I don't have a problem if he testifies to it and you black it out or you can put it on a piece of paper and put it in the envelope.

MR. GOORLAND: All right.

MR. BUTLER: Why don't we do it as a late filed exhibit.

MR. MOYLE: I want to see it now. Why don't we just take a little break and you guys can work through that.

(Whereupon a recess was taken.)

MR. MOYLE: For the record, the witness has written on a piece of paper the projected rate of return, as I understand it, that resulted from his economic evaluation, and that has been placed in an envelope and is going to be treated as confidential for the purposes of this deposition.

(A document was marked as Exhibit 1 Confidential.)

BY MR. MOYLE:

Q. I would just like the witness to confirm that he indeed has done what I just described?

A. I did, yes.

Q. And with respect to that return, who did you do that for?

A. I did it first for USG, the company that I work for, then I provided the volume forecast from that to FPL.

Q. So the volume forecast is separate and apart from the number; is that right?

A. It's part of the analysis that we did for internal purposes, and then I provided the volume forecast to FPL for them to do their analysis.
Q. Did you give FPL everything you gave USG?
A. I think I gave them only the output from the PHDWin program I was describing earlier. PHDWin oil and gas economic software.
Q. Why did you not give them more?
A. They didn't need all the individual pieces of data that went into that analysis.
Q. Did they tell you that or did you make that assumption?
A. They asked for the volume forecast, so that's what I gave them.
Q. Did you have conversations with them about the rate of return number that is Exhibit A to your deposition?
A. No.
Q. Who did you have conversations with about that number?
A. The management of my company.
Q. And to be clear, what is your company?
A. It is NextEra Project Management Gas Infrastructure and Development.
Q. That's not a Florida company, is it?

A. No.
Q. Where is it?
A. Houston.
Q. Who owns your company?
A. NextEra Energy.
Q. Do you know if it's NextEra Energy or NextEra Energy Resources or are they the same?
A. In my mind they're the same.
Q. And do you know who owns NextEra Energy?
A. No -- shareholders.
Q. Shareholders of?
A. NextEra Energy Resources.
Q. Of the companies we discussed, do you know, does the Public Service Commission have jurisdiction over any of those companies?
MR. BUTLER: Sorry, "these companies" being what, John?
MR. MOYLE: The ones he just described, the one he works for.
MR. BUTLER: But one of them was FPL.
MR. MOYLE: Well, I didn't hear him say FPL in his response.
MR. BUTLER: You made some pretty broad statements.
MR. MOYLE: Let's just start over.

BY MR. MOYLE:
Q. What's the name of the company you work for?
A. NextEra Energy Management Resources. I'm sorry, NextEra Energy Project Management --
Q. Resources?
A. -- Gas Infrastructure and Development.
Q. A Houston company, right? Does the PSC have jurisdiction over your company, to your understanding?
A. No, not to my knowledge, no.
Q. And then who owns your company?
A. We're getting beyond what I understand about the ownership of the company, so I'm going to -- I don't know. It's either NextEra Energy Resources or NextEra Energy, one of those entities here in Florida.
Q. Okay. The owner -- and I don't mean to press you. I'm just trying to understand, you know.
The Commission, do they have jurisdiction over these people or not? The next level up, do you have an understanding as to whether the Commission has jurisdiction over that next ownership layer?
A. Yes.
Q. What is your understanding?
A. That they have the jurisdiction over the Florida based companies here in Juno Beach --
Q. Other than --

A. -- particularly FPL.
Q. So it's your belief that the Commission has jurisdiction over NextEra Energy Resources?
A. I don't know. I'll back up from that. I don't know.
Q. Who's the president of your company?
A. T.J. Tuscai -- I'm sorry, T-U-S-C-A-I.
Q. Do you know if any officers or directors of your company -- and when I say your company, I'm talking about NextEra Energy Project Management, LLC -- any officers or directors of your company, are they also officers or directors of Florida Power & Light, the regulated utility?
A. Not to my knowledge, no, but I don't know.
Q. So who do you report to in your company?
A. T.J. Tuscai.
Q. And what is your job for NextEra Energy Project Management, in summary fashion?
A. I'm the chief technical officer and my job is to do economic and reserve evaluation on the projects that we own and the projects that we are anticipating acquiring, and to maintain our internal reserve database.
Q. What's an internal reserve database?
A. We do quarterly reporting, internal

quarterly reporting on all of the properties that we own in the United States.

Q. And why do you do this?

MR. BUTLER: John, I'm going to object. This is getting way beyond the scope of anything that has to do with FPL or FPL's PSC regulated matters. You want to know about who he works for and his job description, that is possibly relevant, but how in the world reports are prepared by his employer and it isn't regulated by the PSC relates to the request we're making in this docket.

MR. MOYLE: I think you'll see how I'm going to try to tie it together.

MR. BUTLER: I don't think so. This is just way beyond the scope of what he is here to testify for FPL.

MR. MOYLE: So if I ask him whether he's going to do this for Florida Power & Light should this deal go forward, you know, this being what he does now, you would contend that's an irrelevant question?

MR. BUTLER: If you want to ask him that question, that's fine.

MR. MOYLE: I was trying to get to that

question by asking him why he does this.

MR. BUTLER: Not by taking a detour through the unregulated business. Stick with the FPL related work he's done and I have no objection to the question.

BY MR. MOYLE:

Q. If the Commission approves FPL's petition, is that going to change your job in any way, shape or form, as you understand it?

A. No.

Q. Why not?

A. There's no reason for it to change.

Q. So if I understand, what you do is you do a lot of analysis for NextEra Energy Project Management, LLC related to gas reserves and holdings and things like that.

That expertise that you have, that you've testified to, is not something that you anticipate sharing with FP&L in any way, shape or form if this petition is approved; is that correct?

A. If they ask me for my help, I will give it to them.

Q. How does that work, when they ask for your help? If they ask for your help and say give us these drill analyses, do they charge you for that or do you

just kind of do it?
Is there a corporate brethren? How does that work?
A. It's because we're their corporate brethren.
Q. And then NextEra Energy Project Management, what business is that in?
A. The acquisition and ownership of oil and gas assets in the United States.
Q. Nonoperating?
A. Nonoperating.
Q. And just so the record is clear, when we talk about nonoperating versus operating, could you explain that?
A. Our working interest does not involve the field operation. There's an operator of record in every one of the wells that we have an interest in and it is not us.
Q. Would it be proper to say you, in effect, are akin to an investor?
A. Say again, please.
Q. Would it be proper to say you -- "you" being your company -- are akin to an investor?
A. In some sense, yes, we are an investor, but we also are an active participant in the decision-making going forward as to the development

plan.

Q. And how so?

A. The operating company typically has technical meetings, as described by our contract with them, and we are participants in those technical meetings.

Q. And ultimately, if I understand the contract, your role is to -- basically you have an option you give a thumbs-up or a thumbs-down on a particular drilling project; is that correct?

A. Yes.

Q. And is that the same with respect to things that are done through NextEra Energy Project Management, LLC?

A. Yes.

Q. When you analyze a project for NextEra Energy Project Management, LLC, do you do anything differently than what you've done in this case?

A. No.

Q. So it's exactly the same?

A. Exactly the same.

Q. I think you talked about earlier that other businesses may have other practices; is that right?

A. They could, yes.

Q. Well, you've worked for other companies previously, right?

A. Yes.

Q. Did SOCO International do anything differently when they were doing economic evaluations?

A. The role I played for them is exactly the role I play now and we did things exactly the same.

Q. No variation at all?

A. Not that I remember, no.

Q. What's an EOR study?

A. Enhanced oil recovery.

Q. That's what you do after you pull oil out initially, you come back and try to get some more?

A. Yes.

Q. In Florida we haven't had a lot of opportunity to have conversations like this, so I appreciate your patience in answering some questions that you probably viewed as very elementary and fundamental, but discovery is the time for us to understand things you've testified to.

I'm a little confused between non-gas liquids and oil and I was hoping that you could explain the difference to me.

A. Okay. In the reservoir you can have coexisting oil and gas. The gas may have a high BTU factor. In other words, it has some liquids embedded in it. Because of the pressure in the reservoir, the liquids in the reservoir may be in a gaseous phase. When you bring it to the surface, run it through a processing plant, you can extract those liquids.

There also might be oil coexisting in the reservoir in conjunction with or separate from the gas. So you can have in the most complex situation oil with gas in solution in the oil, plus a gas cap, and natural gas liquids in the gas.

Q. Okay. So in one of these projects, just to make sure I'm clear, you have dry natural gas, right, and what is dry natural gas?

MR. GOORLAND: One of which projects?

MR. MOYLE: The Woodford project.

A. The Woodford project is dry natural gas.

Q. Is dry natural gas the 85 percent methane?

A. At least, yes.

Q. So if I said what's the definition of dry natural gas, you'd say 85 percent -- it's natural gas that has at least 85 percent methane content?

A. That or more, yes. It's different in different areas.

Q. Okay. But dry natural gas wouldn't be something that had less than 85 percent?

A. Dry natural gas would be gas that does not have a sufficient amount of liquids that it could be extracted and sold commercially.

Q. Okay. What's wet gas?

A. Wet gas is gas with a higher BTU value, higher than 1 million BTUs per NCF, and that BTU value can equate to NGLs, which can extract the -- through a plant process extract the liquids from the gas to get the remaining gas back to a dry gas status.

Q. The Woodford project, what is that focused on, dry gas?

A. Dry gas.

Q. And then NGLs, those are non-gas liquids?

A. Natural gas liquids.

Q. I'm sorry, natural gas liquids?

A. Natural gas liquids.

Q. And what are those?

A. Those are things like ethane, propane, butane, that can be extracted from natural gas that have a high BTU value.

Q. And they're liquids?

A. They will be in a liquid form when they're extracted from the gas through the plant process.

Q. And so are there separate markets for all these products; oil, dry gas, wet gas, NGLs?

A. Yes.

Q. Are there other products, other than the four that we've talked about, that result from the operations that are contemplated in the Woodford project?

A. No.

Q. Just so we're clear, dry natural gas, wet gas, NGLs, and oil, right?

A. Yes.

Q. What did you do in preparing your testimony? I mean, just tell me the steps that you took. Did you meet with PetroQuest?

Just give me a kind of rundown of the things you did in order to prepare and file testimony.

A. First of all, NextEra Project Management already owns a working interest in 17 of the 19 wells in the AMI. So we had access already to some of the production data and drilling data for those wells. So they were not unfamiliar to us.

When we began evaluating the undrilled location we did the things that I described before, in building a type curve and running the economics, and yes, I talked to and visited with PetroQuest on a number of occasions to get additional information from them or to clarify information at our end.

Q. You said "a number of occasions". Two, three, ten?

A. Three, three to five.

Q. Who did you meet with?

A. I met with their reservoir engineer, I met with their chief operating officer, and I met with their geologist.

Q. What were the purpose of the meetings?

A. Again, to get as much information as I could in order to do the best analysis that I could. Part of that was related to the geology and the seismic that they had shot in the area.

Q. When we talk about these meetings, were you doing that as your role as an officer of the NextEra Energy Project Management, LLC?

A. Yes.

Q. You weren't doing it on FPL's behalf?

A. At that time we had been asked by FPL to do that work and so yes, it was partly on FPL's behalf.

Q. So I assume that this activity has gone on for some time. If you have five meetings, it probably didn't make a lot of sense to have five meetings in a month.

When was the first time you had occasion to visit PetroQuest related to the idea of FPL becoming involved?

A. I really don't remember, but it would have been in the early summer of 2014, and I did not visit PetroQuest. I talked to them over the phone and then they came to my office once.

Q. What is your recollection about this concept of FPL becoming involved in the Woodford project? How did it arise?

A. Well, you know, as I said, we already own an interest in some of the wells and it appeared to us internally that this might be attractive to FPL because it's a dry gas project, which would fit their -- fit their MO perfectly.

Q. You said dry what, I'm sorry?

MR. GOORLAND: Dry gas.

A. So we approached FPL about whether or not they would be interested in doing a project like this. I wasn't the one doing that. It had to be on a level above me, but later I got involved in it.

Q. Does your company have projected -- your company being NextEra Energy Project Management -- have returns that it would like to realize based on its investments?

A. Yes.

MR. BUTLER: Object to the question. Whatever NextEra Project Management has, unless it happened by way of financial targets, isn't relevant to his testimony in this proceeding about FPL's project.

MR. MOYLE: Well, I think it is relevant.

MR. BUTLER: I disagree.

MR. MOYLE: I will tell you and make a proffer as to how I think it's relevant; in that if the returns of the company that he works for, NextEra Energy Project Management, Inc., they have benchmarked financial returns that are hypothetically of a certain percent and this project is a drag on achieving those returns, I think it's relevant to show with respect to motivation how this arrangement, whereby these assets would be transferred to FPL, may have come about. So I think that's the basis for the question.

It's discovery. I think it's relevant and we can overcome that objection.

MR. BUTLER: I would not object to his answering the question as to whether this met their expectations, but I am not going to permit him to testify as to any specifics and the quantification of what those are.

MR. MOYLE: Well, I'm willing to treat it as confidential, as we have.

MR. BUTLER: It's not about being confidential. This is a matter of getting into the business of an unregulated affiliate for reasons that I think are beyond a plausible connection in this proceeding.

MR. MOYLE: Well, let's just pull the record on this point and then we'll move on.

BY MR. MOYLE:

Q. So sir, I'm asking you whether the company has internal rate of returns, the company being NextEra Energy Project Management, LLC. I think you've acknowledged that they do. I have asked you what those are and you know what those are, correct?

A. Yes.

Q. I would like for you to write them on a piece of paper and give those to me and we'll treat them as confidential, as we did with Exhibit A.

Are you willing to do that?

MR. BUTLER: I'm going object to that, John.

As I said, I'm willing to have you ask him whether, you know, the evaluation that he performed would have met the expectations in that regard. But as to the specifics of what their targets are, I do not believe that's relevant to this proceeding and I would direct him not to answer that question in either a confidential or nonconfidential format.

MR. MOYLE: Okay.

BY MR. MOYLE:

Q. Is NextEra Energy Project Management in the business to maximize profits?

A. Yes.

Q. Why was it motivated to divest the Woodford assets?

A. We didn't see it as a divestment. We have projects all over the country and our budget was full with those projects. So this seemed to us a good opportunity for FPL to work with one of our existing partners to develop dry gas assets. We didn't have it in our budget to do that.

Q. And if I asked you what your budget was and how much this project was and what percentage that related to of your budget, would you be able to answer those questions?

A. I would not answer those questions.

MR. BUTLER: And I would object to that, John.

Q. So you would be able to, but you would not answer them based on the instruction of your attorney;

is that right?

A. Yes.

MR. BUTLER: Yes.

Q. And he answered "yes" too, right?

A. Yes.

MR. BUTLER: If he has a different answer than mine, we're going to have to go out in the hall.

BY MR. MOYLE:

Q. I guess I'm a little unclear, because Mr. Butler represents Florida Power & Light, the regulated utility. You're here testifying on behalf of NextEra Energy Project Management, LLC.

So I guess he's representing you in this deposition; is that right?

A. Yes.

Q. So the idea of this arrangement, did it originate with NextEra Energy Project Management, LLC, USG, FPL? Who gets credit for that deal?

A. I honestly don't know. That came about with senior management of both companies in discussion about this project and I wasn't involved in those discussions.

Q. Okay. And there's no witness from PetroQuest in this docket, right? You know, the

witnesses who are testifying in this case?
A. There are no PetroQuest witnesses.
Q. Are you aware that FPL has proposed guidelines to the PSC that they want to be able to invest up to $750 million a year in oil and gas ventures?
A. I'm aware that they proposed guidelines, but I'm not familiar with them.
Q. With respect to the deal flow that your company sees, I assume it's well in excess of $750 million; is that fair?
MR. BUTLER: I'm going to object to the question again. You're going into a scope of an unregulated business that is well beyond this proceeding.
MR. MOYLE: And I would contend that it is relevant in this proceeding, because you're asking for guidelines to allow for up to $750 million to be invested and being recovered from rate payers, and I want to explore is that likely to happen.
If this company, which is a corporate affiliate with FPL, a regulated company, has deal flow-through of three, four, $5 billion a year, that makes it more likely than not that the

$750 million target I think would be hit, and that's what I want to explore.

MR. BUTLER: I don't think it has anything to do with that, John. I think however they run their business is one, not a subject of this proceeding, and there can be any number of factors that would affect the volume of the deals that that company would pursue, completely independent of what FPL's approach might be.

You know, if you want to ask him whether he thinks it's feasible to do that based on his experience at, you know, NextEra Project Management and prior employers, sure, I won't object to that.

BY MR. MOYLE:

Q. Is it contemplated that your company will be -- if the PSC approves FPL's petition, that your company will be involved in providing opportunities, deals, if you will, to be reviewed by the venture that would be put together with PetroQuest and FPL?

A. Not necessarily, no.

Q. So it's not contemplated or it could be or you just haven't gotten to that?

A. We haven't discussed it beyond this project.

Q. And with respect to a $750 million cap, I

can represent to you that that's what's been proposed by FPL in their guidelines.
In your opinion, do you think that's feasible, to reach that cap?
A. I can't comment on that. I don't know.
Q. Based on your experience in the oil and gas business?
A. There are billions of projects, billions of dollars in projects that occur in the marketplace in this industry every year.
Q. So are there high net worth individuals that invest in these projects?
MR. BUTLER: I'm sorry, whose projects?
Being the FPL project, the Woodford project?
MR. MOYLE: No, to oil and gas ventures.
A. Certainly there are some.
Q. Because you were an independent consultant at various times in your career, correct?
A. Yes.
Q. So could a high net worth individual come in and say, "I got a billion dollars. I'd like to get your help to invest a billion dollars in oil and gas projects in Oklahoma, Texas"?
MR. BUTLER: Excuse me, that would be coming to FPL?

MR. MOYLE: To him as an independent consultant.

A. In my role with Project Management, no.

Q. Why not?

A. That's outside the course of my work.

Q. I'm sorry, we're not communicating. That's my fault.

When you were an independent consultant --

MR. BUTLER: If he were still an independent consultant.

BY MR. MOYLE:

Q. If you were an independent consultant and someone came to you with a billion dollars, Boone Pickens' cousin, and said, "I got a billion dollars, but I don't really have the time to figure out which are good projects, can you do that for me, I'll give you a percent of the investment," what would you have said?

A. I would say yes, I can probably do that or I'll try.

Q. So that's kind of an indirect way of asking the question, do you think it's feasible that FPL could find $750 million worth of projects?

A. I don't know.

Q. You're a financial expert. What is your understanding of filings that are made with the Securities and Exchange Commission?

MR. BUTLER: Where did you get that he's a financial expert?

MR. MOYLE: I thought he said he's an expert in economics.

MR. GOORLAND: I think he said oil and gas.

MR. BUTLER: Oil and gas economics evaluations.

MR. MOYLE: I'm sorry, I skipped a step.

BY MR. MOYLE:

Q. Do you have any familiarity with SEC filings? You referenced, I think, some SEC filings in your testimony.

A. Yes.

Q. What is your familiarity with it?

A. I worked for a company in the past who were publicly traded companies and they had to file with the SEC, and I was involved in doing some of the SEC type evaluations for the company.

Q. So it would be fair not to say you're an expert, but you have familiarity with how the Securities and Exchange Commission works?

A. Yes.

Q. Do you have an understanding as to

statements made to the Securities and Exchange Commission, that if you're a publicly held company they need to be true and accurate?

A. Yes.

Q. And do you also understand that if you make incorrect, false, misleading statements to the SEC, that there's potential liability associated with being materially, false, misleading?

MR. BUTLER: I'm going to object to that as calling for a legal conclusion and going beyond his testimony.

BY MR. MOYLE:

Q. You can go ahead and answer it, but just based on your understanding.

A. It's my understanding that if you make false statements to the SEC, there could be repercussions, yes.

Q. Hypothetically, if PetroQuest made filings with the SEC where they said something that was different from your testimony, would that be of concern to you?

A. No.

Q. Why not?

A. I don't get involved in their filings. I don't even know what their filings are. It's irrelevant to what I do.

Q. I have an exhibit I'd like to use. Pass that down to the witness.

(A document was marked as Exhibit 2.)

So I refer you to Page 8 of the exhibit I just provided to you. There's a section there that says "Oklahoma Woodford", that starts during 2013.

A. Yes.

Q. Can you just take a minute and read that?

A. Yes.

Q. You agree the last sentence says:

"We have allocated approximately 50 percent of our 2014 capital budget to operations in the Woodford Shale, as we expect to participate in the drilling of approximately 58 gross wells, all of which will target liquids rich gas, as well as to obtain 3D seismic data over acreage recently acquired to target liquids rich gas," correct?

A. That's what they said, yes.

Q. Do you have any reason to think that the term "liquids rich gas" was different than what we talked about previously?

A. No.

Q. You would agree liquids rich gas is not the same as dry gas?

A. Correct.

Q. You would agree that in this statement filed with the SEC PetroQuest is telling the investment community that they are targeting liquids rich gas, correct?

A. That's what it says, yes.

MR. BUTLER: John, could you identify for the record what you have there? What is that?

MR. MOYLE: I'm sorry, I probably didn't. It's a PetroQuest Energy 2013 Annual Report.

BY MR. MOYLE:

Q. Isn't that right, the document you have in front of you, sir?

A. Yes.

Q. Which you testified you haven't reviewed and you don't review these filings?

A. I have not. I have not reviewed it.

Q. Has there been any reserve engineering done relative to the Woodford project before this Commission?

A. The work I did I termed "reserved engineering."

Q. So what you performed you would classify as reserve engineering?

A. Yes.

Q. So it doesn't necessarily have to cumulate in a report that says "here's our reserve engineering report"?
A. I am not following you, I'm sorry.
Q. In terms of reserve engineering, that's a discipline that involves, I assume, a lot of different components. You can look at stuff and give a verbal opinion, you can issue reports based on your review; is that fair?
A. Yes.
Q. Did you prepare any reports, you know, like a reserve engineering report in this case?
A. No.
Q. But you rendered verbal opinions as to the reserves and also provided testimony?
A. I provided data to FPL.
Q. There's a statement on Page 26 of this document, and I'll read it and I'll just ask you to confirm that it's in here.
It says, "Reserve engineering is the complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner."
Is PetroQuest wrong when they say that?
A. They are correct in saying it cannot be

measured in an exact manner.

Q. How about it involves a subjective process, are they making a false statement in that respect, you believe?

A. No, it's not false. I think they're just covering their butts. It's depending on how good you are doing this to whether or not you think it's subjective.

Q. So you don't have a reason to think that statement is untrue?

A. No.

Q. And above that in bold they say: "Our actual production, revenues, and expenditures related to our reserves are likely to differ from our estimates of proved targets" -- I'm sorry, "of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material."

You don't have any reason to disagree with that statement, do you?

A. No. In fact --

Q. I'm sorry, you said "no"?

A. No, because every publicly traded company is required to identify the risk to their investors and this is the way PetroQuest is doing it. If you look at these same reports from other companies, you'll see the same kind of verbiage.

Q. They're doing that, you would agree, because that's what they believe the risks are, correct?

A. They're doing that to identify the potential risks to the shareholders, yes.

Q. But you don't sit here today -- you wouldn't question any risk that has been identified by PetroQuest as a risk in their SEC filing, would you?

A. I can only comment on the risk that I've looked at in the Woodford project.

Q. Assume they're different. Assume that this report has a whole bunch of additional risks. You wouldn't take the position that PetroQuest is wrong. You would take the position that PetroQuest has identified more risks than I've identified, correct?

A. I wouldn't take any position on what PetroQuest has done. It's immaterial to what I do. I have not relied on that at all.

Q. Okay. So notwithstanding your lack of reliance, this is what the investment community would rely on with respect to PetroQuest, correct?

A. Whether they rely on it or not I'm not certain, but it certainly is what PetroQuest puts in their document.

Q. Let's talk about the risks for a second.

There's a section in this document on Page 19, item 1A, "Risk Factors." It goes from Page 19 to Page 31. I don't want you to take the time to read it.

There's some headlines, but if you can answer generally, you don't take issue with any of the risks that PetroQuest identified here on Pages 19 to 31 of Exhibit 2, correct?

A. Again, these are boilerplate risks, potential risks that every publicly traded company puts in their reports. So I'm not going to say whether or not these are appropriate risks or not.

Certainly they are potential risks, that's true. I agree with that.

Q. All right. Would you agree that seismic risk may be another risk that could result from oil and gas exploration and drilling and production operations?

A. I haven't seen any evidence of that, no.

Q. Are you aware of a class action lawsuit in Oklahoma alleging that activity related to the oil and gas industry has resulted in sinkholes?

A. No, I have not. I'm not aware of that.

Q. Do you have an opinion with respect to whether things related to the oil and gas business affect seismic conditions?

A. I do not.

Q. Can you just spend a minute -- you mentioned it and there was some questions about production costs and environmental costs of disposing of water.

Do you know what's in that water? I've seen reference to salt water. I understand chemicals are used in this process. What is the byproduct of the production effort?

A. Most of the water is just the water that was in place in the reservoir and is produced in conjunction with the gas and/or oil. It's a brine water. Generally it has a saline content.

There is also initially some water that was injected into the reservoir in the fracking process that is recovered. But for the most part, it's brine water, salt water.

Q. And the brine is naturally occurring?

A. Yes.

Q. And the fracturing process, describe that for me, if you would?

A. Companies inject water and other chemicals into the reservoir to fracture the rock, exactly what the title is being. The reason for that in the shale reservoirs is that they have a relatively high porosity, so they have a high storage of gas, but they have a very low permeability. So the pores aren't well connected.

The only way to connect them is to frack the reservoir and that's done by high pressure injection of water and other chemicals. Sometimes it's a gel solution and sand. They will also inject sand.

So that once we create the fracture, the sand will hold the fracture apart and keep it from collapsing.

Q. So what role does the water play?

A. It provides the material to convey the sand and it's the material that we can pressure up, because it's an incompressible fluid, to create the pressure we need to frack from.

Q. And does the sand play a role of breaking the rock up?

A. No.

Q. What does the sand do?

A. No, the sand is injected after the fracture is created.

Q. Does the chemical work to fracture the rock?

What does the chemical do?

A. Again, I'm not an expert in that area, but in general, it provides stability agents for the gel fluid that's going to transfer the sand into the reservoir to keep it from dissolving, and that's about all I know.

Q. Do you know what the chemicals are?

A. No.

Q. And you don't have any judgment as to whether there may be potential liability associated with those efforts?

MR. BUTLER: I'm going to object to that as calling for a legal conclusion.

BY MR. MOYLE:

Q. You can go ahead and answer.

A. State your question again.

Q. If I were to put together a list of, you know, potential liabilities, like in this report, based on what you do know, do you think that there's potential risks, potential liability related to contamination or other potential things related to the extraction process?

MR. BUTLER: Same objection.

A. I haven't seen any evidence of contamination. I know that PetroQuest is in compliance with all the Federal Safe Drinking Water Acts and all other local and state requirements there, so I don't see any evidence that that has occurred.

Q. But you also don't know what chemicals are injected?

A. I've seen a list of those, but I'm not a chemical engineer. So I don't know, I couldn't identify them for you.

Q. And then horizontal drilling, I assume that that means that the drill runs horizontally as compared to vertically, correct?

A. Yes.

Q. As a matter of practice when you're doing horizontal drilling, are you able to exceed a property boundary with the horizontal drill?

Do you understand my question?

A. Are you asking could you drill off of your property and onto someone else's.

Q. Yes.

A. Yes, you could. There are laws against that, but you could.

Q. There's probably been lawsuits that resulted from that as well. Are you aware of any?

A. Probably.

Q. And what we're talking about is horizontal

drilling, right?
A. Yes.
Q. And what we're talking about also involves fracturing or fracking; is that right?
A. Yes.
Q. Let me take you to a couple of places in your testimony, if I could.
You would agree that in this business there's no certainty with respect to volumes and properties of hydrocarbons that will be extracted. There's estimates, and the results may vary from the estimates, correct?
A. There is no absolute certainty, that's correct.
Q. So on Page 5, Line 10 you say -- in summarizing your testimony, you say you summarized the volumes of natural gas that can be recovered under the 19 sections.
I'm new to this area, but I thought that the use of the word "may" there, rather than "can", would be more accurate. Would you agree with that?
A. I stick with what I said here.
Q. So you think that it's a certainty that the volumes that you set forth will be recovered?
A. I think they can be, yes.

Q. Can be. But they cannot be as well, right?

A. There is no absolute certainty.

Q. And when you say on Page 5, Line 18, "economically recovered," what did you mean?

A. I mean that in the context here of estimating the total amount of gas that can be produced, that refers to the economic limit of the wells.

In other words, when the operating costs exceed the revenue, then it's no longer economically feasible to recover more gas.

Q. Do you have an understanding with respect to FPL's petition, what would happen if the production costs exceeded the market price?

A. No.

Q. In the natural gas and oil world you're familiar with, if production costs exceed market costs, you typically don't continue to lose money; is that right?

A. That's right. In my world, when the revenue is exceeded by the costs we stop producing that well or we look at some other way to enhance the production from that well.

Q. So with respect to "economically recovered," you had given me, you know, a return that the company you work for likes -- actually, I'm sorry, the number you gave me was what you calculated based on looking at this project, right? Exhibit A, the confidential exhibit?

A. What you asked for was what is my company's range of rate of return that is acceptable to us.

Q. And we didn't answer that question, right?

A. I did answer that question, yes. I wrote it on a piece of paper.

Q. My recollection -- the record will be clear. My recollection is what I asked you was with respect to this specific project -- you know, you did an economic analysis and the results of that economic analysis indicated that the return would be the number on the paper; is that right?

A. That's not what I answered. I thought you were asking me about what the minimum rate of return would be acceptable for our company.

Q. Okay. So to go back to -- I'm sorry, we miscommunicated on that. Did you do an analysis specifically with respect to the Woodford project, to indicate what the return for the Woodford project would be?

A. Yes.

Q. And how does that relate -- well, what were the results of that?

A. It met our -- and when I say "our", I'm talking about NextEra Project Management -- it met our requirements for investment.

Q. Did you come up with a number after doing that analysis?

A. An internal number, yes.

Q. Okay. Was it a range or was it just a specific number?

A. It was a number, but there were some sensitivities.

Q. And could you write that number on a piece of paper for me, please, and we'll have it marked as a confidential exhibit?

We probably need to label it "Result of analysis related to Woodford project."

MR. BUTLER: John, I'm going to propose something here. I would like to have him provide that and to substitute it for what was provided as Exhibit 1 Confidential, because I think Dr. Taylor misunderstood what you asked, what I understood you to be asking and what I was okay with him providing on a confidential basis, which was the result -- you know, what did his analysis indicate was the return that would be generated by this project, not what his company expects as sort of a target range of return.

The other question, you know, you were asking about subsequently and that's what I had objected to.

MR. MOYLE: I'll think about that and I appreciate it. Let me consider it. We're kind of the middle of a deposition.

I understand, but let's just kind of move forward with this and figure that out.

BY MR. MOYLE:

Q. So could I get you, like you did previously, to take a piece of paper and write for me the number that you just testified to that resulted from your economic analysis related to the Woodford specific project?

A. I can tell you it exceeded our investment requirements. I do not remember the number exactly. I can get that number, but I don't have it with me.

Q. I thought you just said it was within that range?

A. No, I said that range was the minimum requirements that were acceptable to us.

I do not remember the exact number that I came up with for this project. There were dozens and dozens of projects since then.

Q. But you remember it exceeded the range?

A. Yes, yes.

Q. Do you have any recollection by order of magnitude?

A. No.

MR. MOYLE: John, could I get a late filed exhibit for that number?

MR. BUTLER: Yeah, if we go off the record --

MR. MOYLE: Actually, you know, what, strike that. I don't need it.

BY MR. MOYLE:

Q. I'm still trying to understand, you know, your business and your company. Is it fair to say your company is involved in oil production?

A. Yes, we own interests in oil and gas wells.

Q. And same with oil marketing, natural gas exploration, natural gas production?

A. We don't do any marketing ourselves. That's done by the operating company. We don't operate any wells. We're a nonoperating working interest only.

Q. Is it your understanding that the petition before the Commission is asking for approval in a way that rate payers would become involved in those businesses?

A. Yes.

Q. With respect to the nonoperational aspects, is it a fair statement to say that companies like yours are principally involved in the financing of these projects, of these oil and goods projects?

A. No, it's not principally involved in financing, because like I said earlier, we get involved in the decision-making process as well in some cases.

Q. When you make that decision, who makes it? There's a piece of paper you have to sign and say, yeah, we want to go forward with this project or not, right?

A. As far as drilling a well?

Q. Yes, sir.

A. That's handled on an individual well basis. We do our analysis on an individual well basis. It's checked by land, it's checked by me and my department. We go to a committee meeting once a week and we review the economics of each one of those wells and eventually it gets signed off by the -- if we consent, the president of the company.

Q. Do you have an understanding as to how this process would work if this petition is approved?

A. I'm assuming that FPL would need that same level of scrutiny on proposals and whether or not that would be done by us, my company or not, I don't know.

Q. So that hasn't been something that you really have any information on, correct?

A. FPL has said that they would like me to continue with help in that regard, but nothing has been arranged for that to happen.

Q. The oil and gas business, it has as a byproduct greenhouse gases that are emitted in the atmosphere; is that right?

A. Yes.

Q. And is the oil and gas industry now involved in rules and regulations that the EPA is proposing related to greenhouse gases?

A. I don't know.

Q. If they were, that could be a potential cost, if the EPA imposes new regulations relating to greenhouse gases. You'd agree with that, right?

A. If those new regulations resulted in additional cost, then yes.

Q. And the primary greenhouse gas is methane?

A. Yes.

Q. Are you aware of a similar business model construct being proposed by FPL in this petition?

A. Similar to what?
Q. Do you understand sort of the business construct that FPL is proposing in this case?
A. Yes, I think so.
Q. What do you understand it to be?
A. You asked me if I'm familiar with another proposal?
Q. Another --
A. No, I'm not.
Q. So the business construct that FPL is proposing would be the first of its kind as you know it in the oil and gas industry?
A. I don't know.
Q. You don't know. But as far as you do know, there's no one else doing it the way FPL is proposing to do it in this case?
A. There may have been other utility companies that have done that. I'm not sure. I don't know.
Q. You've had conversations with PetroQuest. You've had a business relationship with them since when, 2010?
A. Uh-huh.
Q. Is that right?
A. Yes.
Q. Do you have any views with respect to their

capitalization? Have you looked at their finances, their SEC filings?

A. No, I have not.

Q. So you don't have any information one way or the other as to their financial wherewithal?

A. No.

Q. You would agree, would you not, that a business model whereby the production costs of an operating company, where those production costs are covered and paid for irrespective to market conditions, arguably presents less risk to that operating company, correct?

A. Yes.

Q. You also would agree, would you not, that the proposal by FPL that with respect to PetroQuest, the amount and composition of what's extracted really is not relevant to things, because they're going to be paid for their costs irrespective of whether they get a lot or a little; is that your understanding?

A. I'm not following you.

Q. My understanding of this deal is that PetroQuest is going to be paid for their production costs, okay. Right, isn't that how it currently works?

A. They will pay for their part of their ownership of the production costs.

Q. And that's similar to what this deal is envisioning, right?

A. This deal -- every working interest owner will pay their proportional share of the operating costs.

Q. And right now in your business construct you have to go to the market and be able to get a number off the market that covers those costs, right?

MR. BUTLER: Get a number off the market? What do you mean?

BY MR. MOYLE:

Q. A price for your wares, for your commodities that you're selling. They have to cover your production costs?

A. Yes.

Q. And this new construct that the Commission is being asked to consider, that's out of the equation, correct? The market price is out of the equation?

I think you just agreed to that.

A. Yeah, I don't know where this is going, but this is out of the realm of what I did.

I did a reserve analysis of this AMI and the wells to be drilled in it and I provided that volume forecast to FPL. I'm not that familiar with what all the other business constructs are beyond that point.

Q. So that's fair. If you say, look, I don't really know how this is going to work in the regulatory scheme, I'll take that as an answer.

A. That's my answer.

Q. So related to the last question I asked you, you don't have a lot of familiarity with the operations of the regulated utility?

A. No, I do not.

Q. Okay. In your economic analysis I understand that you made an assumption about operating costs on a go-forward basis would remain flat, would remain the same. They wouldn't escalate; is that right?

A. Yes.

Q. And you made the same assumption with respect to capital costs; is that correct?

A. That's correct.

Q. And you would stick by that assumption even if I pointed in this annual report to suggestions that operating costs may go up and that capital costs may go up in the future; is that right?

A. I would, and they might go down.

Q. And what was the basis for your assumption that they would remain the same?

A. Like I said in my testimony, you know, I looked at the previous 12 month's LOS statement for each one of these wells and for the projects in total. I looked at the technological advances and the manufacturing mode that's going to be entered into when the wells begin drilling. That's going to lower the capital costs and it's going to lower the operating costs.

Producing multiple wells from a common surface facility will also lower the operating costs. I assumed those operating costs would stay the same, rather than reduce them.

Q. Did PetroQuest tell you about the technological advancements that would result in lower operating costs?

A. No, but I did discuss with them how the wells are to be drilled on a manufacturing basis and using the common surface locations to drill multiple wells.

Q. Did you have conversations with them about this technological advancement and the costs that might be saved?

A. Not that I remember, no.

Q. In the oil and gas industry have you seen people contract with reference to CPI, the consumer price index?
A. I don't know.
Q. And why do you not know?
A. I don't know anything about that.
Q. So with respect to projected costs, your belief is that people don't reference CPI?
A. I didn't say that. I said I don't know anything about that. I don't use that CPI.
Q. How many of these economic evaluations have you done?
A. Hundreds.
Q. I'm sorry?
A. Hundreds.
Q. And what is the time frame? You looked at this for how many years going forward, the economic analysis you did?
A. 30-plus years. I don't remember the number on it.
Q. So it's your testimony that with respect to the assumptions of the cost, you don't expect those to go up in 30 years?
A. No, I do not.
Q. You expect them to go down?

A. I'm projecting them to stay flat.
Q. You just answered my technological question, to say that it's driving costs down. You would think there would be maybe some additional technological improvements over 30 years that might drive the price down further?
A. Right, but I took the conservative assumption that they would not go down.
Q. Did you do any sensitivity analysis that would look at the price going up?
A. No.
Q. On Page 22, I think Line 22 of direct, you used the term "economically viable." Would you define that term, please?
A. That it makes more money than you spend to get it out, and the rates of return from our standpoint were acceptable and met our internal requirements.
Q. Do you know if FPL, the regulated utility, has a similar metrics?
A. No, I do not.
Q. You don't have any information one way or the other?
A. I do not.
Q. So when you say it's economically viable,

you're making that comment from the perspective of the nonregulated entity that you work for, correct?

A. Yes.

Q. Why were the DJ Basin assets sold when you worked for Texas American?

A. To make a profit.

Q. Do companies ever sell assets because they're not producing and they kind of want to get out of them and move on to something else?

A. Companies sell assets for all kinds of reasons, and that could be one of the reasons, yes.

Q. Did you make the decision to transfer these assets to FPL?

A. I did not.

Q. Who did?

A. Senior management of both companies. I wasn't involved in that.

Q. You got any names for me?

A. I can give you the names of the presidents of both companies or officers in the companies; T.J. Tuscai, Sam Forrest, and Jim Robo.

Q. And Mr. Robo is affiliated with which company?

A. He's the president of NextEra Energy Resources, the parent company.

Q. So underneath him you would have both the regulated FPL and the unregulated company you work for, correct?

A. Yes.

Q. So counsel for OPC asked you some questions about the Forrest Garb & Associates report. Did you ask that that report be prepared?

A. No.

Q. Who did?

A. FPL.

Q. Did you rely on it in providing your testimony?

A. No. I had already done my analysis before they did theirs. I looked at their results.

Q. So why did you attach it to your testimony?

A. Because FPL had requested that a third party analysis be done, and it confirmed the work that I did.

Q. There's not a witness from Forrest Garb & Associates who's testifying in this case, is there?

A. No.

Q. And if I asked you a bunch of questions about their report, you wouldn't have any firsthand information about it, would you?

A. No.

Q. Give me just a few minutes to go over my notes.

There's terminology in the industry called "conventional plays and unconventional plays." Are you familiar with --

(Discussion off the record.)

Couple other points. Conventional play versus unconventional play, are you familiar with the terms?

A. Yes.

Q. What we're talking about is all unconventional plays; is that right?

A. Yes.

Q. And the chief distinction is because conventional plays are vertical drilling, whereas unconventional plays are horizontal, associated with fracturing and things like that; is that right?

A. Horizontal and shale plays, generally, yes.

Q. You would agree that unconventional plays typically require the application of more advanced technology and higher drilling completion cost to produce relative to conventional plays?

A. Yes.

Q. What's the difference in the eastern and western areas of the AMI?

A. The 19 wells are spread out over 19 sections and some are in the east and some are in the west.

When I looked at the individual performance of each well, there was a noticeable difference between the EUR, the Estimated Ultimate Recovery, in the wells in the west than there were from the wells in the east. So I felt it was proper then to develop type curves reflective of that difference.

So the EURs for the wells in the west are lower than the EURs for the wells on the east.

Q. So which -- I think you said it, but just for my sake, which is likely to produce more? Which is a better -- better wells, east or west?

A. From the wells that have been drilled so far, the wells on the east are better.

Q. And do you know how these wells are going to be allocated if this deal goes through?

MR. BUTLER: Allocated to whom?

MR. MOYLE: Allocated to the subsidiary corporation to be created/FPL, as to what is retained by the unregulated FPL subsidiary. I think it's called USG.

A. The only thing that will be retained by USG is the wells that we already own an interest in. There's 17 of the 19 wells. Everything else will go through FPL, if it's approved by the Commission.

Q. There's a memorandum of understanding that's been entered into between USG and Florida Power & Light. You would agree that that represents the deal between those two?

A. I assume so, but I've not seen that and I have no knowledge about it. I was not involved in that.

Q. So USG Woodford, are you involved with them?

A. Yes.

Q. How so?

A. If that's a subsidiary -- excuse me for asking you a question, but that's a subsidiary that we formed to own the Woodford interest?

Q. I don't know the answer, but I think it may be. I don't know. You know, I'm trying to understand the corporate structure.

MR. BUTLER: Are you asking questions out of a memorandum of understanding? He just said he doesn't understand it. Wouldn't it be more appropriate to ask Mr. Forrest those questions?

MR. MOYLE: I don't know, John. I'm looking at a whole bunch of notes.

MR. BUTLER: You're looking at a whole bunch of stuff other than the witness you're deposing.

MR. GOORLAND: He's already told you the relationship between the two of them and the business deal is something that --

MR. MOYLE: Well, we haven't had any conversation about USG Woodford. I asked him if he knows who it is. He said, "yeah, I think so." So it's appropriate followup to say who is it and how do you work with them.

A. I think it's a subsidiary that was formed to hold the Woodford interest until they were transferred to FPL.

Q. Were you involved in --

A. No.

Q. -- the decision to do that or discussions?

A. No.

Q. What's wildcatting?

A. That's exploration, pure exploration, where there have been no other wells drilled in the area.

(A document was marked as Exhibit 3.)

Q. I've handed you what's been marked as Exhibit 3. I'll represent to you that it came from the PetroQuest Energy website.

There's a section at the left that says "About PetroQuest Energy." It says: "PetroQuest Energy is an independent energy company engaged in the exploration, development, acquisition, and production of oil and natural gas reservoirs in East Texas, Arkoma Basin, South Louisiana, and the shallow waters of the Gulf of Mexico."

Is this your understanding as to the business that PetroQuest Energy is in?

A. Yes.

Q. And the Arkoma Basin, that's where the Woodford project is, correct?

A. Yes.

Q. So when people are talking about this Woodford project, if it's termed "Exploration, development, acquisition, and production of oil and natural gas projects," you wouldn't disagree with that, correct?

A. That this Woodford project is not an exploration project.

Q. Why not?

A. 19 wells have been drilled in the 19th section in the AMI. That clearly makes it a development project and not an exploration project.

Q. Is there a term of art where you kind of pass that line, X number of wells and X number of square miles means it's not -- you know, it goes from exploration to development?

A. No, not in my opinion. It varies from project to project.

Q. So there's nothing I can look to that would clearly define the distinction between the exploration and development; is that correct?

A. Not to my knowledge, no.

Q. You would agree that with respect to risk involved, that the operator, PetroQuest, would be in a better position to understand and evaluate risk confronting it than you?

A. What risk?

Q. All risks related to their operations.

A. To the extent they had more data to analyze, then that would be true.

Q. Do you think that they have more data than you do?

A. Give me an example of the risk you're trying to discuss and I'll tell you. As far as operating costs -- well, you tell me.

Q. Operating costs.

A. I've examined 12-month historical operating costs for every well in the 19 wells. I have looked at that and come up with an average for what I think would be appropriate for ongoing. So I don't think there's any risk in the operating costs.

Q. But when you were a consultant you were aware that companies would put together projected budgets for the next forward-going year, right? That's a common business practice?

A. Yes.

Q. I would assume PetroQuest has done that?

A. I would assume, yes.

Q. Have you seen their projected operating budget for 2015?

A. No, I have not.

Q. So that would be an example, if they have that, of additional information that might be informative with respect to future production costs, correct?

A. I have not been privy to their budget, so yes.

Q. So the underlying question, which was who do you think is in a better position to evaluate risks, costs, business operations, you or PetroQuest, I assume PetroQuest would be the answer, correct?

A. We are partners with PetroQuest. We discuss things jointly. So if there is a risk that needs to be addressed, we would do that jointly.

Q. But they don't give you all their data. They don't share every piece of information they have with you as a nonoperating partner, do they?

A. Not every piece of information, no.

Q. If you call them up and say "I want X or Y or Z," do they just regularly and routinely hand it over to you?

A. Yes, they do. If we request it, they hand it over.

Q. Okay. So you believe that you are as well qualified to understand the risks confronting PetroQuest on a going forward basis as they are?

A. For the risks that affected the work I did, yes.

Q. And this project is projected to be a 30-year project, correct?

A. Yes.

Q. You anticipate staying involved in this effort if the Commission approves it?

A. Not for 30 years, no.

Q. Other than water, are there other disposal issues that are attendant to these operations?

A. Water is the only one I'm aware of.

Q. You don't have a solid waste disposal component?

A. No. It's a dry gas project, so there are no waste products other than the associated water production.

Q. And wet gas, do you have another byproduct that you need to dispose of?

A. No.

Q. So with respect to the four commodities that we talked about, it's your testimony that there's no solid waste component associated with any of them that have to be disposed of?

A. Well, that's not what you asked me before. But certainly if you're producing oil and it has a high asphaltene content, some of that may need to be extracted and disposed of or used as road topping material.

Q. It's anticipated that there may be oil associated with this?

A. It is anticipated there will not be oil associated with this project.

Q. The deposition notices, I know we cross noticed your deposition, they asked you to bring documents you relied on. What documents did you bring today to your deposition?

A. I brought the documents that have been presented in my exhibits, my direct testimony, the discovery, and rebuttal.

Q. And that was it?

A. That's it.

Q. On your rebuttal you used -- on Page 5, Line 7, you used the phrase "very low" in similar questions asked by OPC. Can you put a percentage?

A. State your question again. I didn't hear it.

Q. Sure. Page 5, Line 7 of your rebuttal you say, "The production risk of the Woodford project to PetroQuest is very low." I want to understand what you mean by "very low."

A. Less than 10 percent.

Q. Those are your words, they're not industry --

A. That's my opinion.

Q. And then the same question with respect to Page 5, Line 18, "high level of confidence". Can you give a percentage on that?

A. 90 percent confidence.

Q. Do you know when people are making significant investment decisions in the oil and gas business, have you heard of them getting more than one reserve analysis opinion done?

A. Yes.

Q. And that was not done in this case, right?

A. It was done. I did a reserve analysis and

Forrest Garb & Associates did a reserve analysis.

Q. And theirs was that 30-page report, correct?

A. Yes.

Q. And yours is what, your analysis?

A. My analysis are the results that I presented here in my exhibits.

Q. But you did not do a similar report?

A. I did not do a similar report, no.

MR. MOYLE: All right. Well, thank you for your time. I don't have any further questions.

MR. BUTLER: Staff, let me ask a question -- off the record.

(Discussion off the record.)

CROSS EXAMINATION

BY MR. BUTLER:

Q. Dr. Taylor, you were asked by Mr. Moyle about rate payers becoming involved in the activities that are associated with the Woodford project.

Do you remember that question?

A. Yes.

Q. And you had said that rate payers would become involved in those activities. I'd like you to explain in what sense you understand that rate payers, the actual customers of FPL, would be involved in the activities of the project?

A. Only to the extent that FPL would be involved. I didn't mean to imply that they would directly be involved.

MR. BUTLER: Thanks. That's all I have. Thank you.

(Whereupon, the taking of the deposition was concluded at 12:15 p.m.)

- - -

CERTIFICATE OF OATH

I, Alice J. Teslicko, RMR, a Notary Public for the State of Florida at large, do hereby certify that the witness, Timothy Taylor, appeared personally before me and was duly sworn.

Signed and sealed this 18th day of November, 2014.

____

Alice J. Teslicko, RMR

Commission No. EE031095
My Commission Expires:
December 14, 2014

CERTIFICATE

STATE OF FLORIDA)
) ss.
COUNTY OF PALM BEACH)

I, ALICE TESLICKO, RMR, a Registered Merit Reporter and Notary Public for the State of Florida at Large, do hereby certify that I reported the deposition of Timothy Taylor, a witness called by the Office of Public Counsel in the above-styled cause; and that the foregoing pages constitute a true and correct transcription of my shorthand report of the deposition of said witness.

I further certify that I am not an attorney or counsel of any of the parties, nor a relative or employee of counsel connected with the action, nor financially interested in the action.

WITNESS my hand and official seal in the City of Hobe Sound, County of Martin, State of Florida, this 18th day of November, 2014.

____
Alice J. Teslicko, RMR

My commission expires:
December 14, 2014
Commission No. EE310095

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

TIMOTHY TAYLOR

SUBSCRIBED AND SWORN before and to me this ____ day of __________, ____.

____

NOTARY PUBLIC

My Commission expires:

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON

I, ____________________, do hereby certify that I have read the foregoing transcript of my deposition, given on ________________, and that together with any additions or corrections made herein, it is true and correct.

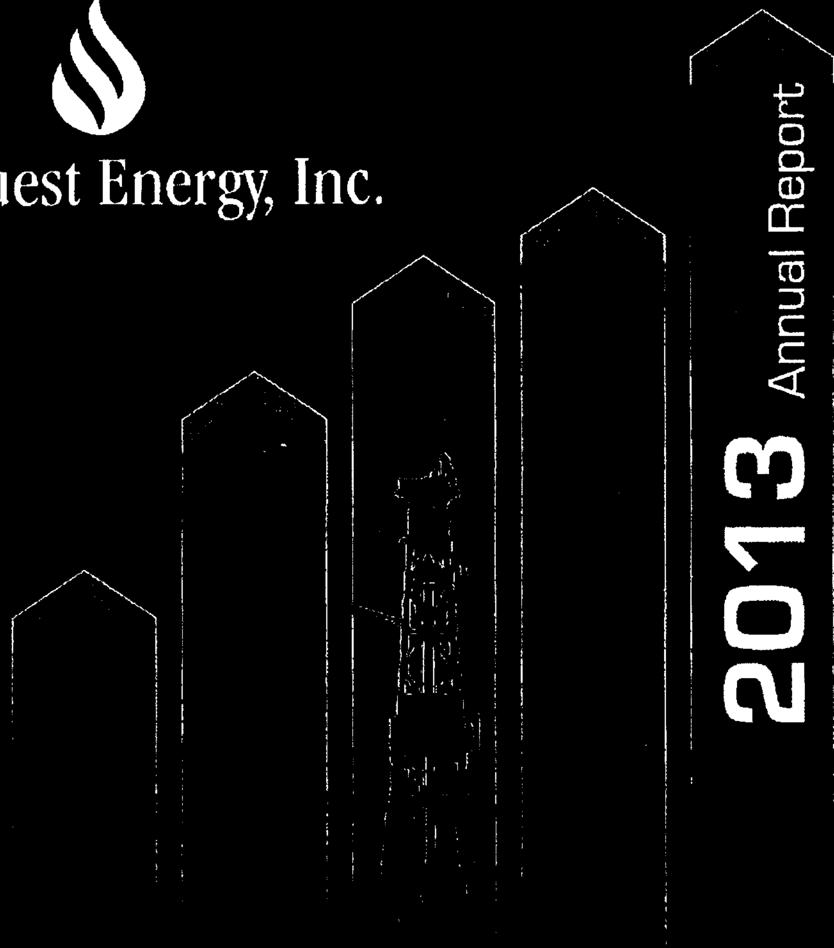
____
Deponent

The foregoing instrument was acknowledged before me this _____ day of ___________, 2014, by ______________________, who is personally known to me or has produced ____________________ as identification and who did not take an oath.

____
Notary Signature

NOTARY PUBLIC, State of Florida
____
Commission Number

PetroQuest Energy, Inc.



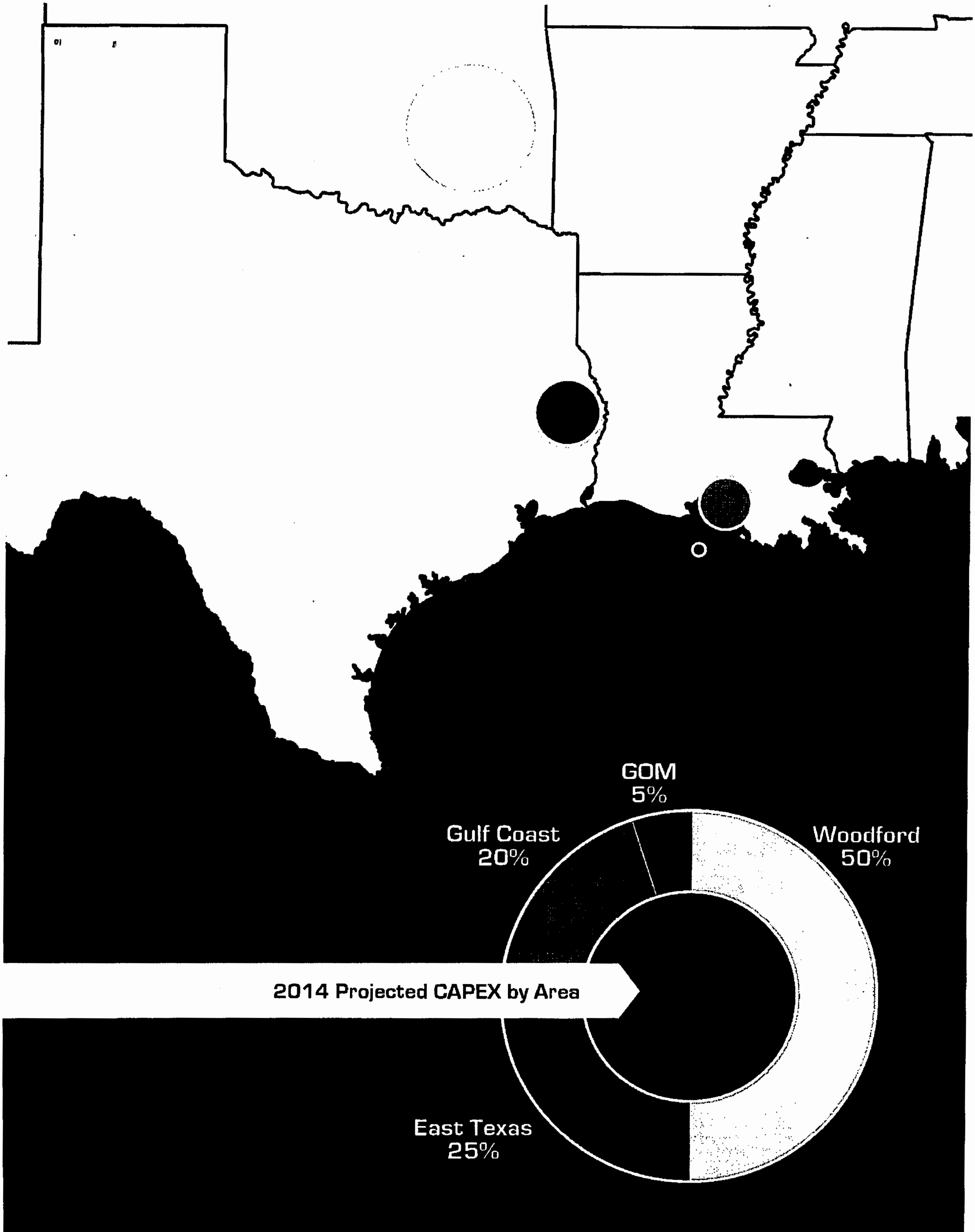
2013 Annual Report

RESOURCES. RETURNS. GROWTH.

EXHIBIT
2
Taylor 11/12/14

Corporate Profile

PetroQuest Energy, Inc. is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas reserves in Texas, the Arkoma Basin, South Louisiana and the shallow waters of the Gulf [illegible]


GOM
5%
Gulf Coast
20%
Woodford
50%
2014 Projected CAPEX by Area
East Texas
25%

	2009 Annual	2010 Annual	2011 Annual	2012 Annual	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2013 Annual
Production									
Natural Gas, MMcf	28,065	24,502	24,463	27,466	6,437	6,732	8,351	7,706	29,226
NGL, MMcfe	2,533	2,470	2,288	3,367	1,065	1,257	1,239	1,194	4,754
Crude Oil, MBbl	600	663	572	521	126	116	219	220	681
Total, MMcfe	34,199	30,951	30,183	33,957	8,256	8,683	10,906	10,221	38,066
Financial ($ Thousands, except per share amounts)									
Total Revenues	$ 218,684	$ 179,263	$ 160,700	$ 141,591	$ 36,009	$ 38,102	$ 55,587	$ 53,172	$ 182,870
Net Income (Loss)	(90,190)	47,126	10,548	(132,079)	3,887	4,949	1,670	3,576	14,082
Preferred Stock Dividends	5,140	5,139	5,139	5,139	1,280	1,287	1,287	1,285	5,139
Net Income (Loss) Available to Common Stockholders	$ (95,330)	$ 41,987	$ 5,409	$ (137,218)	$ 2,607	$ 3,662	$ 383	$ 2,291	$ 8,943
Per Common Share:									
Basic	$ (1.72)	$ 0.67	$ 0.08	$ (2.20)	$ 0.04	$ 0.06	$ 0.01	$ 0.04	$ 0.14
Diluted	$ (1.72)	$ 0.66	$ 0.08	$ (2.20)	$ 0.04	$ 0.06	$ 0.01	$ 0.04	$ 0.14

Financial & Operational Highlights

Five Year Review	2009	2010	2011	2012	2013
Reserves ($ Thousands, except per unit amounts)					
Natural Gas, MMcf	156,853	174,566	241,926	192,968	254,168
NGL, MMcfe	10,508	8,373	15,111	25,360	29,140
Crude Oil, MBbl	1,931	1,623	1,395	1,655	3,084
Total, MMcfe	178,947	192,677	265,407	228,258	301,811
Percent Developed	62%	65%	61%	74%	67%
Percent Dry Gas	88%	91%	91%	85%	84%
Percent Gulf Coast	23%	13%	9%	13%	19%
Future Undiscounted Net Cash Flows, $000s	$ 272,271	$ 442,505	$ 635,327	$ 406,818	$ 769,968
SEC PV-10, Before Taxes, $000s	$ 176,995	$ 255,651	$ 341,373	$ 239,269	$ 474,818
Commodity Prices					
PetroQuest Realized, Natural Gas, $/Mcf	$ 5.84	$ 4.37	$ 3.22	$ 2.31	$ 2.99
Henry Hub Cash Market Average, Natural Gas, $/Mcf	3.94	4.37	4.00	$ 2.75	$ 3.73
PetroQuest Realized, NGL, $/Mcfe	5.38	7.78	9.51	$ 6.32	$ 5.23
PetroQuest Realized, Crude Oil, $/Bbl	68.57	79.47	104.99	$ 108.97	$ 103.49
WTI (Cushing) Spot Average, Crude Oil, $/Bbl	61.99	79.51	95.04	$ 94.10	$ 98.05
PetroQuest Realized, Natural Gas Equivalent, $/Mcfe	6.39	5.78	5.32	$ 4.17	$ 4.80
Per Unit Analysis, $/Mcfe					
Total Revenues	$ 6.40	$ 5.79	$ 5.32	$ 4.17	$ 4.80
Lease Operating Expense and Production Taxes	1.26	1.42	1.38	$ 1.17	$ 1.25
Gas Gathering Costs	0.01	0.00	0.00	$ 0.00	$ 0.00
Gross Operating Margin	5.13	4.37	3.94	$ 3.00	$ 3.55
Interest Expense	0.37	0.32	0.32	$ 0.29	$ 0.57
General and Administrative	0.55	0.69	0.68	$ 0.68	$ 0.70
Preferred Stock Dividends	0.15	0.17	0.17	$ 0.15	$ 0.14
Gross Cash Margin	$ 4.06	$ 3.19	$ 2.77	$ 1.88	$ 2.14

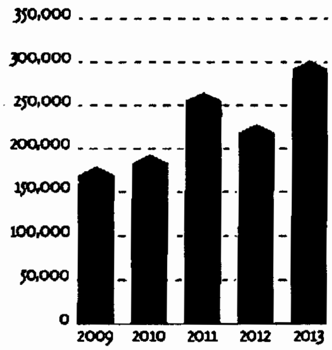
PetroQuest Energy – Focused On Resources, Returns, And Growth

As investors and regular readers of PetroQuest's annual report know, I am always an optimist. I believe in the resilience of our national economy and the recovery in commodity prices that should accompany improving macro-economic conditions. I think 2013 was a pivotal year for overall economic conditions as well as commodity prices in the United States; although it may be a modest macro-economic recovery, I do think an economic recovery is underway.

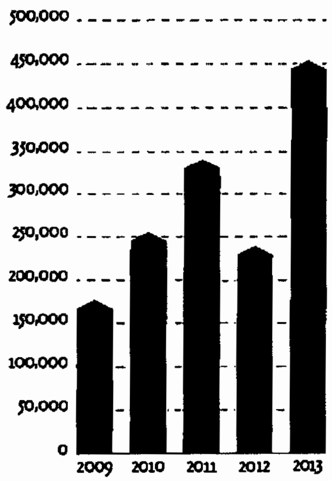
To Our Stockholders

The shale revolution has demonstrated how abundant our natural gas resources are in this country. I am a proponent of utilizing natural gas as both a bridge fuel in our nation, as well as an exported commodity. I am not convinced we will export gas on sufficient a scale to fully expose domestic gas prices to international market pricing, but I certainly believe exportation can be used to moderate the volatility of domestic natural gas prices. Regarding the use of natural gas as a bridge fuel, over the past few years our industry has touted the resource volumes discovered in various U.S. shale gas plays, and although the wheels of change are often fairly slow to rotate in the United States, I think the trend of commercial fleet conversions to natural gas as a transportation fuel will continue. As this happens, I expect that there will eventually be infrastructure constructed to support the long-haul over-the-road transportation fleets on our interstate highway network. This development will be the strategic signal that large-scale use of natural gas in the transportation sector is underway.

Proved Reserves, MMcfe



PPV-10, Before Taxes, $000



There has been a lot of attention in our industry, within both the political establishment and media, regarding the potential to export natural gas. Several facilities along the U.S. Gulf Coast and elsewhere are nearing completion, which should allow some level of export gas throughput. Obviously this is a positive step for producer companies like PetroQuest, and any daily export volumes should positively impact gas prices from the demand side. Given that gas prices in Europe and the far East range between two and eight times higher than domestic prices, it only makes good business sense that we should be able to export a small portion of our resources to capture some of this arbitrage opportunity. Job creation to manufacture and maintain full-scale liquefaction facilities throughout the United States would be a benefit on a national level, and depending on how much gas ultimately is exported, the national benefit might extend into the geopolitical arena. Recent events in the Ukraine, along with historical Eastern European reliance on Russia for gas imports, may ultimately result in a global gas market served by a variety of LNG exporters. Exporting LNG from the U.S. could potentially benefit not only the U.S. economy, but enable the U.S. to compete globally in a variety of markets as nations like Poland and the Ukraine seek diversified energy supplies.

Together, there are a number of macro-economic and industry-specific developments that should positively impact natural gas prices over the next few years. 2013 was a better year than 2012 in terms of average natural gas prices, and as a result of the extreme winter we have just witnessed, 2014 should be better than last year. I have not discussed oil price fundamentals because I think over the next few years the oil markets should remain fairly stable. Yes, there will be short-term seasonal price fluctuations and the occasional geopolitical event may impact oil prices, but in general the increasing productivity of oil prone basins in the U.S. continues to add to overall U.S. oil production. At PetroQuest we remain focused on finding and developing oil or natural gas liquids-rich projects to generate cash flow, but I still think there is higher upside potential for natural gas price moves than oil. This is why I think it is so important to consider macro-economic factors when considering an investment in PetroQuest given our estimated 2014 production split is approximately 70% natural gas and 30% oil and natural gas liquids.

Deep Resources

2013 was an important year for PetroQuest as we made the largest acquisition in the history of our company. We achieved company records for annual production as well as proved reserves. Combined with our active leasing campaign, we have laid the foundation for 2014 to be a year of production and reserve growth in excess of 20% as we fully expect to break the record achieved in 2013. We plan to drill 80% more gross wells in 2014, which is a continuation of our overall operational theme of the past few years. With deep resources in our asset portfolio, our focus for 2014 turns to efficient execution of our operations and higher-return projects.

Investors and regular readers of this letter are familiar with the overall PetroQuest strategy of the past ten years, namely to build, expand and develop long-life onshore resources plays with cash flow generated from our expertise in finding, developing and operating Gulf Coast assets. These two asset classes are complimentary in that the free cash flow derived from large, high-return Gulf Coast projects can be redeployed into our Woodford, Cotton Valley and emerging Mississippian Lime positions.

The overall objective of this growth strategy is to increase production and reserve growth each year with minimal reinvestment capital expenditures in order to generate the cash flow required to drill and develop our onshore resource projects. It's true that our acquisition in 2013 was achieved through a bond issuance, but the important thing for shareholders to bear in mind when evaluating PetroQuest is that we are committed to growing production and reserves on debt adjusted per share basis.

We have laid the foundation for 2014 to be a year of production and reserve growth in excess of 20%.

Gulf Coast Experience, Gulf Coast Expertise, Gulf Coast Cash Flow

One of my observations in my 30+ years of energy sector experience is the disparity between company operating strategies and the ever-shifting asset favorites among energy investors. This is a natural phenomenon, particularly over the past eight years with the discoveries of various onshore shale basins, but we have deliberately maintained our focus and expertise in Gulf Coast assets as a means to generate cash flow for other projects, rather than chasing the latest "hot" trends and paying exorbitant leasehold rates. This strategy works. In 2012 Gulf Coast assets generated approximately \$50 million in cash flow while requiring less than \$20 million in capital expenditures, and in 2013 they generated nearly \$80 million in cash flow while spending approximately \$40 million. In 2014, we project our free cash flow growth trend will continue while spending only approximately \$30 million; in fact, we are allocating only 5% of our capital budget to the offshore Gulf of Mexico in 2014, while 20% will be allocated to onshore Gulf Coast projects. That is a perfect demonstration of the value we create by operating in the Gulf Coast because when Gulf Coast wells are successful they can generate large production and reserve volumes, which in turn create very large cash flow numbers even in lower commodity price environments. Very simply, this is why we continue to prioritize Gulf Coast assets as critical elements of the PetroQuest asset mix.

To support this strategy, last year PetroQuest spent approximately \$190 million to acquire shallow offshore proved reserves of 5.3 million barrels of oil equivalent (BOE), which represents a price of \$45,000 per flowing BOE and finding and development costs of \$36.41 per BOE. Even more notable is the fact the transaction included an additional 3.2 million BOE of possible reserves (P3). These assets generated \$28.3 million in free cash flow in the second half of 2013 and are projected to generate additional substantial free cash flow during 2014. PetroQuest will operate 80% of these reserves, and will re-deploy the cash flow into our long-lived assets to grow production and reserves onshore.

Further, we remain both committed to and excited by our La Cantera/Thunder Bayou projects, which are located in Vermilion Parish, Louisiana. We believe the La Cantera discovery alone could ultimately produce over 180 billion cubic feet equivalent (Bcfe) of natural gas, within a deep geologic expression containing several shallow fields that have produced from 529 Bcfe to over 1.4 trillion cubic feet equivalent (Tcfe).

140001 Gas Hearing - 01029

During 2013, the three wells producing at La Cantera contributed more than $28.1 million in net field level cash flow. The La Cantera/Thunder Bayou complex is a series of very large fields that contain multi pay zones that we are only now beginning to fully understand. La Cantera contains booked volumes of 103 billion cubic feet (Bcf) of proved reserves and we estimate Thunder Bayou contains un-risked reserves potential of 162 Bcfe. We expect to spud Thunder Bayou during the second quarter of 2014 and if successful, this project should contribute significant levels of free cash flow over the next several years

Onshore Resource Plays - Accelerate Development, Focus On Returns

Now that I have outlined our strategy in terms of generating cash flow from our Gulf Coast assets, how are we going to deploy that capital to grow the company? The answer lies in our continuing efforts to acquire, drill and develop onshore resource plays. For many years PetroQuest has been focused in the Arkoma Woodford shale basin in southeastern Oklahoma. We initially leased acreage and began drilling in this area in 2004 as part of our diversification effort, which continues, to create a company with a production and reserves split between high-impact shallow gulf projects and long-lived onshore resource plays that generate steady production and reserve growth over time. Our Woodford shale program has proven to be the crown jewel in our onshore portfolio.

Our Woodford shale program has proven to be the crown jewel in our onshore portfolio.

One of the critical aspects to leading an energy company is creating an environment in which the team can generate prospects, pursue ideas, and execute our programs by following the strategic vision of asset diversity set by the company's Board and executives. Our initial leasing and drilling campaign in the Woodford focused on dry gas projects in our Lake McAlester and Hoss Areas, but when gas prices began to fall a few years ago, our team was tasked with sourcing natural gas liquids projects. Our team did a magnificent job in creating new liquids-rich drilling opportunities for PetroQuest in our West Relay and North Relay areas, located in Hughes County, Oklahoma. We began leasing acreage there four years ago and have continued to add to our position since, which now comprises over 30,000 acres. These are the areas in which we will focus our 2014 Woodford drilling program, as we plan to drill between 30-50 liquids-rich wells using multi-pad drilling sites, funding this program through the combination of Gulf Coast-generated cash flow and approximately $50 million of remaining funds in our Woodford joint venture

In 2013 we allocated 29% of our capital spending to our Woodford program, and in 2014 we are going to increase that to 50%, which is in recognition of the superior rates of return we are generating in addition to our intention to dramatically increase our pace of operations in this area. Last year I wrote about our continuing evaluation of our Woodford position in order to high-grade our drilling prospects, prioritizing liquids-rich prospects. This work has been completed and PetroQuest is in a position to drill over three times as many Woodford wells in 2014 as we did during 2013. This should result in very significant production growth and reserve additions in our Woodford acreage. In the last nine years we have drilled 127 Woodford wells; in 2014-15 alone we expect replicate nearly 80% of this activity as we plan to drill a total of 100 wells.

Along with our Woodford program, we continued to move our East Texas Cotton Valley play forward in 2013. Rates of return on our liquids-rich Cotton Valley acreage range between 40% at a $3.50 per MMcfe gas price, to 66% at $4.50 per MMCfe. Our operational efficiency has improved, with average initial production rates 44% higher in 2013 than 2011; in 2013, PetroQuest Cotton Valley well averaged 6.3 MMcf of gas and 458 BOE of natural gas liquids, per well. This is an area that we continue to evaluate because of its competitive economics at current gas prices as well as PetroQuest's running room in terms of our drilling inventory. As I write this letter, PetroQuest has some 210 gross Cotton Valley horizontal locations, 183 Bossier horizontal locations and 197 Travis Peak vertical locations with over 500 additional prospective Upper and Middle Cotton Valley horizontal wells. This is an area in which our operations team will be drilling wells for years to come. We plan to allocate 25% of our capital spending to East Texas in 2014 to drill 6 horizontal wells.

Finally, we continued to collect seismic and scientific data on our Mississippian Lime acreage in Northern Oklahoma in 2013. We are in the process of developing and assessing our reservoir models to identify our best drilling prospects, and I expect this effort to continue for the balance of 2014 as our technical teams further refine our understanding of this play. We do know that the Mississippian Lime is highly variable, but we are encouraged that our initial results are in line with other industry well performance in terms of initial production rates. This area will remain a focus area for PetroQuest in 2014, but we do not plan to allocate a great deal of capital or drill many wells in 2014 given the high-impact projects we have ahead of us in the Gulf Coast/Gulf of Mexico, Woodford Shale and Cotton Valley.

Farewell To A Good Friend

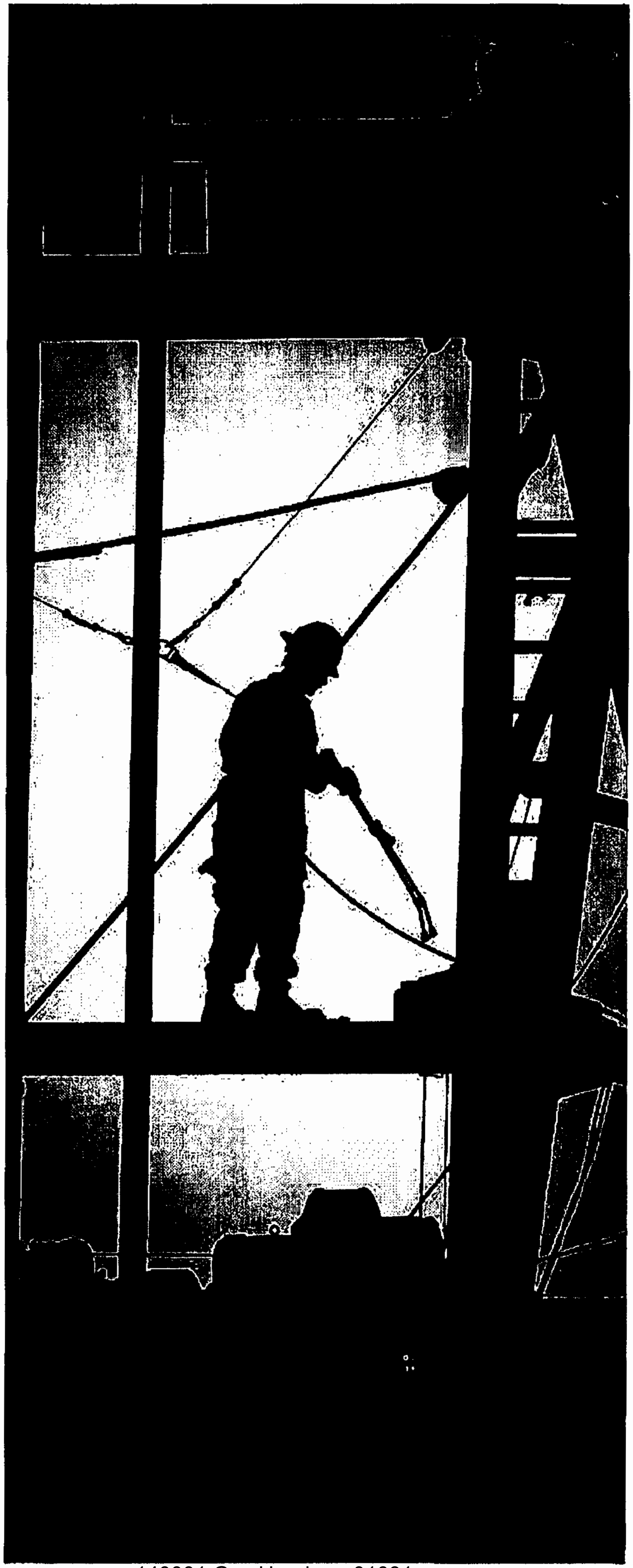
Let me end this year's President's letter by recognizing one of the long-term visionaries who contributed mightily to the success of PetroQuest Energy, Dan Fournerat. Dan played a pivotal role in the success of PetroQuest Energy throughout his 28 year association with the Company. While he formally joined the company in 2001, he served as a trusted legal advisor since the Company's formation. We were blessed when Dan agreed to join the company as our General Counsel and Chief Administrative Officer, a position he held until his untimely passing in September 2013. Dan was a devoted family man and a respected leader in our community, and he will be sorely missed.

PetroQuest Employees – Our Number One Resource

As we draw a line under 2013 with this annual report and look forward to a successful 2014, I want to compliment PetroQuest's employees and contractors from the executive level, to our technical staff, our field operations team, finance/accounting employees, and the administrative staff, as each and every one of our 127 employees plays a critical role to our organization and its success. In the end, investors will evaluate PetroQuest on its returns and financial performance, but in leading the company, I know there is much more to our story than just financial and operational metrics. But I also know there is so much more to our story in terms of our employees who tirelessly work on behalf of our investors to produce results. Each and every member of our team should be proud of their performance in 2013, and I have great confidence and enthusiasm about a positive future for PetroQuest Energy in 2014 and beyond.

Charles T. Goodson

Charles T. Goodson
President, Chairman, and Chief Executive Officer
February 28, 2014



UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2013
or

Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission File Number: 001-32681

PETROQUEST ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	72-1440714
State of Incorporation:	I.R.S. Employer Identification No.

400 E. Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (337) 232-7028

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	New York Stock Exchange

Securities registered pursuant to Section 12 (g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☐ Yes ☒ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
☐ Yes ☒ No

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer		Accelerated filer	☒
Non-accelerated filer	(Do not check if a smaller reporting company)	Smaller reporting company	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
☐ Yes ☒ No

The aggregate market value of the voting common equity held by non-affiliates of the registrant as of June 28, 2013, based on the $3.96 per share closing price for the registrant's Common Stock, par value $.001 per share, as quoted on the New York Stock Exchange, was approximately $162,000,000 (for purposes of this disclosure, the registrant assumed its directors, executive officers and beneficial owners of 5% or more of the registrant's Common Stock were affiliates).

As of February 27, 2014, the registrant had outstanding 65,794,156 shares of Common Stock, par value $.001 per share.

Document incorporated by reference: portions of the definitive Proxy Statement of PetroQuest Energy, Inc. to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with respect to the Annual Meeting of Stockholders to be held on May 21, 2014, which are incorporated by reference into Part III of this Form 10-K.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-K are forward looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected.

Among those risks, trends and uncertainties are:

- the volatility of oil and natural gas prices;
- our indebtedness and the significant amount of cash required to service our indebtedness;
- the recent financial crisis and continuing uncertain economic conditions in the United States and globally;
- our ability to obtain adequate financing when the need arises to execute our long-term strategy and to fund our planned capital expenditures;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions imposed by restrictive debt covenants;
- our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable;
- approximately 40% of our production being exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise;
- losses and liabilities from uninsured or underinsured drilling and operating activities;
- our ability to market our oil and natural gas production;
- changes in laws and governmental regulations, increases in insurance costs or decreases in insurance availability, and delays in our offshore exploration and drilling activities that may result from the April 22, 2010 sinking of the Deepwater Horizon and subsequent oil spill in the Gulf of Mexico;
- our need to obtain bonds or other surety to maintain compliance with regulations as well as regulatory initiatives relating to oil and natural gas development, hydraulic fracturing, and derivatives;
- proposed changes to U.S. tax laws;
- competition from larger oil and natural gas companies;
- Securities and Exchange Commission (sometimes referred to herein as the "SEC") rules that could limit our ability to book proved undeveloped reserves in the future;
- the likelihood that our actual production, revenues and expenditures related to our reserves will differ from our estimates of proved reserves;
- our ability to identify, execute or efficiently integrate future acquisitions;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and natural gas prices;
- losses or limits on potential gains resulting from hedging production;
- the unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel;
- the loss of key management or technical personnel;

- the operating hazards attendant to the oil and gas business;

- governmental regulation relating to hydraulic fracturing and environmental compliance costs and environmental liabilities;

- the operation and profitability of non-operated properties;

- potential conflicts of interest resulting from ownership of working interests and overriding royalty interests in certain of our properties by our officers and directors;

- the loss of our information and computer systems; and

- the impact of terrorist activities on global economies.

Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that such expectations reflected in these forward looking statements will prove to have been correct.

When used in this Form 10-K, the words "expect," "anticipate," "intend," "plan," "believe," "seek," "estimate" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K.

You should read these statements carefully because they discuss our expectations about our future performance, contain projections of our future operating results or our future financial condition, or state other "forward-looking" information. You should be aware that the occurrence of any of the events described under "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Risk Factors" and elsewhere in this Form 10-K could substantially harm our business, results of operations and financial condition and that upon the occurrence of any of these events, the trading price of our common stock could decline, and you could lose all or part of your investment.

We cannot guarantee any future results, levels of activity, performance or achievements. Except as required by law, we undertake no obligation to update any of the forward-looking statements in this Form 10-K after the date of this Form 10-K.

As used in this Form 10-K, the words "we," "our," "us," "PetroQuest" and the "Company" refer to PetroQuest Energy, Inc., its predecessors and subsidiaries, except as otherwise specified. We have provided definitions for some of the oil and natural gas industry terms used in this Form 10-K in "Glossary of Certain Oil and Natural Gas Terms" beginning on page 52.

Part I

Item 1 and 2. Business and Properties Items

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Texas, and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

We have successfully diversified into onshore, longer life basins in Oklahoma and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2013, we have invested approximately $1.1 billion into growing our longer life assets. During the ten year period ended December 31, 2013, we have realized a 95% drilling success rate on 918 gross wells drilled. Comparing 2013 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 294% and estimated proved reserves by 262%.

At December 31, 2013, 81% of our estimated proved reserves and 63% of our 2013 production were derived from our longer life assets.

As a result of the impact of low natural gas prices on our revenues and cash flow, we have focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the Woodford joint development agreement ("JDA"), which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures in the Woodford Shale and the Mississippian Lime. During February 2012, we amended the JDA to accelerate the entry into Phase 2 of the drilling program effective March 1, 2012 and satisfy the drilling carry ratio. Under the amended JDA, the Phase 2 drilling carry was expanded to provide for development in both the Mississippian Lime and Woodford Shale plays whereby we will pay 25% of the cost to drill and complete wells and receive a 50% ownership interest. The Phase 2 drilling carry is subject to extensions in one year intervals and as of December 31, 2013, approximately $51.6 million remained available. See "Liquidity and Capital Resources - Source of Capital: Joint Ventures."

During 2013, we acquired certain producing properties in the shallow waters of the Gulf of Mexico pursuant to the Purchase and Sale Agreements, each dated as of June 19, 2013, between our subsidiary PetroQuest Energy, L.L.C. and each of Hall-Houston Exploration II, L.P., Hall-Houston Exploration III, L.P., Hall-Houston Exploration IV, L.P., and GOM-H Exploration, LLC, respectively ("Gulf of Mexico Acquisition"). The aggregate purchase price of the Gulf of Mexico Acquisition was $188.8 million and it contributed 30.5 Bcfe to our estimated proved reserves at December 31, 2013 as well as 4.5 Bcfe of production during 2013. Since entering into the JDA and as a result of the Gulf of Mexico Acquisition as well as the success of our drilling programs in each of our operating areas, we have grown our estimated proved reserves by 69% and production by 11% since year end 2009, including a 36% increase in our oil and natural gas liquids production during 2013.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013. The Gulf of Mexico Acquisition was financed with the net proceeds from the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017, (sometimes referred to herein as our "10% senior notes"). The transaction included 16 gross wells located on seven platforms (the "Acquired Assets").

During 2013, the Acquired Assets contributed 4.5 Bcfe of total production, including 235,000 barrels of oil, and added 30.5 Bcfe of estimated proved reserves as of December 31, 2013. As a result of the Gulf of Mexico Acquisition, our acreage position in the Gulf Coast Basin increased 23% to 46,801 net acres. See "Note 2 - Acquisition" in Item 8. Financial Statements and Supplementary Data for additional details related to this transaction.

We believe the Gulf of Mexico Acquisition represents both a strategic and transformative transaction for us. This transaction builds upon our existing strategy of utilizing free cash flow from our shorter life, Gulf Coast Basin assets to develop our longer-life resource assets. As evidenced by the larger percentage of our production and estimated proved reserves now located in our longer lived basins, we have successfully leveraged our Gulf Coast free cash flow to help fund our substantial diversification efforts over the past several years. We plan to utilize a portion of the free cash flow generated from these acquired properties to accelerate the development of our Woodford Shale and Cotton Valley resource plays. In addition, based upon our experience and successful track record in exploiting reservoirs in the Gulf Coast Basin and Gulf of Mexico, we believe that we will be able to create value above the current estimated proved reserves associated with the Acquired Assets.

Business Strategy

Maintain Our Financial Flexibility. Because we operate approximately 89% of our total estimated proved reserves and manage the drilling and completion activities on an additional 4% of such reserves, we expect to be able to control the timing of a substantial portion of our capital investments. Our 2014 capital expenditures, which include capitalized interest and overhead but exclude acquisitions, are expected to range between $140 million and $150 million. We expect to be able to actively manage our 2014 capital budget in the event commodity prices, or the health of the global financial markets, do not match our expectations. During 2014, we also plan to maintain our commodity hedging program and, as in during prior years, we may continue to opportunistically dispose of certain non-core or mature assets to provide capital for higher potential exploration and development properties that fit our long-term growth strategy. During December 2012, we sold our non-operated Arkansas assets for $8.5 million. During January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. During December 2013, we sold our non-operated Wyoming assets for $1.0 million.

Pursue Balanced Growth and Portfolio Mix. We plan to pursue a risk-balanced approach to the growth and stability of our reserves, production, cash flows and earnings. Our goal is to strike a balance between lower risk development activities and higher risk and higher impact exploration activities. We plan to allocate our 2014 capital investments in a manner that continues to geographically and operationally diversify our asset base, while focusing on oil and natural gas liquids projects as the pricing for these products is presently expected to be more attractive than that of natural gas. Through our portfolio diversification efforts, at December 31, 2013, approximately 81% of our estimated proved reserves were located in longer life and lower risk basins in Oklahoma and Texas and 19% were located in the shorter life, but higher flow rate reservoirs in the Gulf Coast Basin. In terms of production diversification, during 2013, 63% of our production was derived from longer life basins versus 75% and 66% in 2012 and 2011, respectively. Our 2013 production was comprised of 77% natural gas, 11% oil and 12% natural gas liquids.

Target Underexploited Properties with Substantial Opportunity for Upside. We plan to maintain a rigorous prospect selection process that enables us to leverage our operating and technical experience in our core operating areas. During 2014, we intend to primarily target properties that provide us with exposure to oil or natural gas liquids reserves and production. In evaluating these targets, we seek properties that provide sufficient acreage for future exploration and development, as well as properties that may benefit from the latest exploration, drilling, completion and operating techniques to more economically find, produce and develop oil and gas reserves. We believe that our deep experience and expertise in operating in the Gulf of Mexico can enhance the value of the assets we acquired in the Gulf of Mexico Acquisition.

Concentrate in Core Operating Areas and Build Scale. We plan to continue focusing on our operations in Oklahoma, Texas and the Gulf Coast Basin. Operating in concentrated areas helps us better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. We have substantial geological and reservoir data, operating experience and partner relationships in these regions. We believe that these factors, combined with the existing infrastructure and favorable geologic conditions with multiple known oil and gas producing reservoirs in these regions, will provide us with attractive investment opportunities, as evidenced by the Gulf of Mexico Acquisition.

Manage Our Risk Exposure. We plan to continue several strategies designed to mitigate our operating risks. We have adjusted the working interest we are willing to hold based on the risk level and cost exposure of each project. For example, we typically reduce our working interests in higher risk exploration projects while retaining greater working interests in lower risk development projects. Our partners often agree to pay a disproportionate share of drilling costs relative to their interests, allowing us to allocate our capital spending to maximize our return and reduce the inherent risk in exploration and development activities. We also strive to retain operating control of the majority of our properties to control costs and timing of expenditures and we expect to continue to actively hedge a portion of our future planned production to mitigate the impact of commodity price fluctuations and achieve more predictable cash flows.

2013 Financial and Operational Summary

During 2013, we invested $328.1 million in exploratory, development and acquisition activities. We drilled 36 gross exploratory wells and 4 gross development wells realizing an overall success rate of 88%. These activities were financed through our cash flow from operations, cash on hand, issuance of 10% senior notes and borrowings under our bank credit facility. During 2013, our production increased 12% to 38.1Bcfe as a result of the Gulf of Mexico Acquisition as well as the success of our La Cantera prospect and our Oklahoma and Texas drilling programs. Partially offsetting these increases were decreases as a result of the sale of our non-operated Arkansas assets on December 31, 2012 as well as declining dry gas production in our Woodford Shale area. Our estimated proved reserves at December 31, 2013 increased 32% from 2012 as discussed in greater detail below.

Oil and Gas Reserves

Our estimated proved reserves at December 31, 2013 increased 32% from 2012 totaling 3.1 MMBbls of oil, 29.1 Bcfe of natural gas liquids (Ngls) and 254.2 Bcf of natural gas, with a pre-tax present value, discounted at 10%, of the estimated future net revenues based on average prices during 2013 ("PV-10") of $475 million. The increase in our estimated proved reserves during 2013 was primarily the result of the Gulf of Mexico Acquisition and the effect of the increase in the historical 12-month average price per Mcf of natural gas used to calculate our estimated proved reserves, along with the success in our drilling programs. At December 31, 2013, our standardized measure of discounted cash flows, which includes the estimated impact of future income taxes, totaled $454 million. See the reconciliation of PV-10 to the standardized measure of discounted cash flows below. Our PV-10 and standardized measure of discounted cash flows utilized prices (adjusted for field differentials) for the years ended December 31, 2013 and 2012 as follows:

	12/31/2013	12/31/2012
Oil per Bbl	$106.19	$102.81
Natural gas per Mcf	$3.11	$2.20
Ngl per Mcfe	$5.10	$6.07

Ryder Scott Company, L.P., a nationally recognized independent petroleum engineering firm, prepared the estimates of our proved reserves and future net cash flows (and present value thereof) attributable to such proved reserves at December 31,

2013. Our internal reservoir engineering staff is managed by an individual with 32 years of industry experience as a reservoir and production engineer, including eleven years as a reservoir engineering manager with PetroQuest. This individual is responsible for overseeing the estimates prepared by Ryder Scott.

The following table sets forth certain information about our estimated proved reserves as of December 31, 2013:

	Oil (MBbls)	NGL (Mmcfe)	Natural Gas (Mmcf)	Total Mmcfe*
Proved Developed	2,709	23,173	163,728	203,152
Proved Undeveloped	375	5,967	90,440	98,659
Total Proved	3,084	29,140	254,168	301,811

* Oil conversion to Mcfe at one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

As of December 31, 2013, our proved undeveloped reserves ("PUD reserves") totaled 98.7 Bcfe, a 64% increase from our PUD reserves at December 31, 2012. This increase was due primarily to the effects of a 41% increase in the historical 12-month average natural gas price per Mcf used in estimating our reserves, which was $3.11 per Mcf as of December 31, 2013 as compared to $2.20 per Mcf as of December 31, 2012. During 2013, we spent $3.8 million converting 4 Bcfe of PUD reserves at December 31, 2012 to proved developed reserves at December 31, 2013. PUD reserves added from extensions and discoveries were primarily the result of successful drilling in our Woodford Shale acreage in Oklahoma. Following is an analysis of the change in our PUD reserves as of December 31, 2013:

	MMcfe
PUD Reserve balance at December 31, 2012	59,993
PUD reserves converted to proved developed	(4,109)
PUD reserves added from revisions or extensions and discoveries	13,452
PUD reserves removed for 5 year rule	(4,279)
PUD reserves added due to improved gas prices	33,308
PUD reserves acquired	308
PUD reserves sold	(146)
PUD reserves revised	132
PUD Reserve balance at December 31, 2013	98,659

Approximately 76% of our PUD reserves at December 31, 2013 were associated with the future development of our Oklahoma properties. We expect all of our PUD reserves at December 31, 2013 to be developed over the next five years. At December 31, 2013, we had no PUD reserves that had been booked for longer than five years. Estimated future costs related to the development of PUD reserves are expected to total $15.8 million in 2014, $50.0 million in 2015, $36.5 million in 2016, $24.5 million in 2017 and $9.6 million thereafter. However, because 92% of our PUD reserves at December 31, 2013 are comprised of natural gas, the specific timing of the development of PUD reserves over the next five years is highly dependent upon the prevailing price of natural gas.

The estimated cash flows from our proved reserves at December 31, 2013 were as follows:

	Proved Developed (M$)	Proved Undeveloped (M$)	Total Proved (M$)
Estimated pre-tax future net cash flows (1)	$ 635,348	$ 134,620	$ 769,968
Discounted pre-tax future net cash flows (PV-10) (1)	$ 443,789	$ 31,029	$ 474,818
Total standardized measure of discounted future net cash flows			$ 453,882

(1) Estimated pre-tax future net cash flows and discounted pre-tax future net cash flows (PV-10) are non-GAAP measures because they exclude income tax effects. Management believes these non-GAAP measures are useful to investors as they are based on prices, costs and discount factors which are consistent from company to company, while the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. As a result, the Company believes that investors can use these non-GAAP measures as a basis for comparison of the relative size and value of the Company's reserves to other companies. The Company also understands that securities analysts and

rating agencies use these non-GAAP measures in similar ways. The following table reconciles undiscounted and discounted future net cash flows to standardized measure of discounted cash flows as of December 31, 2013:

	Total Proved (M$)
Estimated pre-tax future net cash flows	$ 769,968
10% annual discount	(295,150)
Discounted pre-tax future net cash flows	474,818
Future income taxes discounted at 10%	(20,936)
Standardized Measure of discounted future net cash flows	$ 453,882

We have not filed any reports with other federal agencies that contain an estimate of total proved net oil and gas reserves.

Core Areas

The following table sets forth estimated proved reserves and annual production from each of our core areas (in Bcfe) for the years ended December 31, 2013 and 2012.

	2013		2012	
	Reserves	Production	Reserves	Production
Oklahoma Woodford	193.8	17.0	146.4	16.3
E. Texas	48.1	6.0	46.7	6.4
Gulf Coast Basin (1)	57.2	14.3	30.0	8.7
Other (2)	2.7	0.8	5.2	2.6
	301.8	38.1	228.3	34.0

(1) On July 3, 2013 we closed the Gulf of Mexico Acquisition which added 30.5 Bcfe of estimated proved reserves and 4.5 Bcfe of production for year end 2013.

(2) On December 31, 2012 we sold our non-operated Arkansas assets which produced 2 Bcfe in 2012.

Oklahoma - Woodford

During 2013, we continued our evaluation of the Woodford Shale as we drilled and participated in 25 gross wells, achieving a 100% success rate. In total, we invested $36.2 million during 2013 acquiring approximately 13,500 net acres prospective for liquids rich Woodford Shale gas and drilling and completing wells. In addition, during 2013 we utilized $21.1 million of total drilling carry under the amended JDA and plan to continue utilizing the drilling carry during 2014. Average daily production from our Oklahoma properties during 2013 totaled 47 MMcfe per day, a 5% increase from 2012 average daily production. We added approximately 23 Bcfe of estimated proved reserves from our drilling program during the year. We also experienced positive revisions to our proved reserves as a result of higher average prices, which along with our drilling success resulted in a 32% increase in our estimated proved reserves. We have allocated approximately 50% of our 2014 capital budget to operations in the Woodford Shale as we expect to participate in the drilling of approximately 58 gross wells, all of which will target liquids rich gas, as well as obtain 3-D seismic data over acreage recently acquired to target liquids rich gas.

East Texas

During 2013, we invested $11.3 million in our East Texas properties where we drilled one gross well, achieving a 100% success rate, plugged and abandoned several mature wells and acquired approximately 2,000 net acres. Net production from our East Texas assets averaged 16.3 MMcfe per day during 2013, a 6% decrease from 2012 average daily production and our estimated proved reserves increased 3% from 2012, primarily as a result of successful drilling in our Carthage field. We have allocated approximately 25% of our 2014 capital budget to drilling six gross wells as well as various plugging and abandonment operations at our Carthage field.

Gulf Coast Basin

During 2013, we drilled five gross wells in the Gulf Coast Basin, achieving a 40% success rate. In total, we invested $232.9 million in this area including $188.8 million for the Gulf of Mexico Acquisition. Production from this area increased 65% from 2012 totaling 39.1 MMcfe per day in 2013 due to the Gulf of Mexico Acquisition as well as the inception of production from our third well at our La Cantera prospect. Our estimated proved reserves in this area increased 91% from 2012 primarily as a result of the 30.5 Bcfe (net of current year production) added through the Gulf of Mexico Acquisition. We have allocated approximately 25% of our 2014 capital budget to various drilling, re-completion and plugging and abandonment projects in the Gulf Coast Basin.

Markets and Customers

We sell our oil and natural gas production under fixed or floating market contracts. Customers purchase all of our oil and natural gas production at current market prices. The terms of the arrangements generally require customers to pay us within 30 days after the production month ends. As a result, if the customers were to default on their payment obligations to us, near-term earnings and cash flows would be adversely affected. However, due to the availability of other markets and pipeline connections, we do not believe that the loss of these customers or any other single customer would adversely affect our ability to market production. Our ability to market oil and natural gas from our wells depends upon numerous factors beyond our control, including:

- the extent of domestic production and imports of oil and natural gas;
- the proximity of the natural gas production to pipelines;
- the availability of capacity in such pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and natural gas production; and
- federal regulation of gas sold or transported in interstate commerce.

We cannot assure you that we will be able to market all of the oil or natural gas we produce or that favorable prices can be obtained for the oil and natural gas we produce.

In view of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we are unable to predict future oil and natural gas prices and demand or the overall effect such prices and demand will have on the Company. During 2013, one customer accounted for 35% and two accounted for 14% each of our oil and natural gas revenue. During 2012, one customer accounted for 30%, one accounted for 17% and one accounted for 12% of our oil and natural gas revenue. During 2011, one customer accounted for 20%, one accounted for 18%, one accounted for 15% and one accounted for 11% of our oil and natural gas revenue. These percentages do not consider the effects of commodity hedges. We do not believe that the loss of any of our oil or natural gas purchasers would have a material adverse effect on our operations due to the availability of other purchasers.

Production, Pricing and Production Cost Data

The following table sets forth our production, pricing and production cost data during the periods indicated. Three of our core areas, the Gulf Coast Basin, East Texas and Oklahoma, which includes primarily Woodford Shale reserves, represented greater than 15% of our total estimated proved reserves.

	Year Ended December 31,		
	2013	2012	2011
Production:			
Oil (Bbls):			
Gulf Coast Basin	512,041	346,513	425,145
East Texas	82,500	87,368	96,923
Oklahoma - Woodford	971	171	145
Other	85,468	86,538	49,883
Total Oil (Bbls)	680,980	520,590	572,096
Gas (Mcf):			
Gulf Coast Basin	9,876,771	5,691,109	6,342,638
East Texas	4,123,416	4,360,290	2,871,284
Oklahoma - Woodford	15,055,601	15,349,219	12,736,622
Other	170,055	2,065,610	2,512,389
Total Gas (Mcf)	29,225,843	27,466,228	24,462,933
NGL (Mcfe):			
Gulf Coast Basin	1,312,995	885,881	1,356,384
East Texas	1,333,725	1,479,441	924,668
Oklahoma - Woodford	1,971,376	947,935	553
Other	136,127	53,517	6,241
Total NGL (Mcfe)	4,754,223	3,366,774	2,287,846
Total Production (Mcfe):			
Gulf Coast Basin	14,262,012	8,656,068	10,249,892
East Texas	5,952,141	6,363,939	4,377,490
Oklahoma - Woodford	17,032,803	16,298,180	12,738,045
Other	818,990	2,638,355	2,817,928
Total Production (Mcfe)	38,065,946	33,956,542	30,183,355
Average sales prices (1):			
Oil (per Bbl):			
Gulf Coast Basin	$ 105.74	$ 108.75	$ 108.50
East Texas	98.61	104.42	101.59
Oklahoma - Woodford	90.52	92.53	89.61
Other	97.59	95.75	85.61
Total Oil (per Bbl)	103.83	105.85	105.33
Gas (per Mcf)			
Gulf Coast Basin	3.70	2.92	4.12
East Texas	3.73	2.82	3.92
Oklahoma - Woodford	2.25	1.51	2.42
Other	3.54	2.20	3.12
Total Gas (per Mcf)	2.95	2.06	3.11
NGL (per Mcfe)			
Gulf Coast Basin	7.12	8.45	10.41
East Texas	4.70	5.72	8.19
Oklahoma - Woodford	4.31	4.49	5.15
Other	5.21	6.30	9.49
Total NGL (per Mcfe)	5.22	6.10	9.51
Total Per Mcfe:			
Gulf Coast Basin	7.02	7.14	8.43
East Texas	5.00	4.69	6.55
Oklahoma - Woodford	2.49	1.69	2.42
Other	11.79	4.99	4.32
Total Per Mcfe	4.78	3.90	5.24

	Year Ended December 31,		
	2013	2012	2011
Average Production Cost per Mcfe (2):			
Gulf Coast Basin	$ 1.60	$ 1.78	$ 1.61
East Texas	1.47	1.56	2.12
Oklahoma - Woodford	0.47	0.49	0.76
Other	5.03	2.12	1.08
Total Average Production Cost per Mcfe	1.15	1.15	1.28

(1) Does not include the effect of hedges.
(2) Production costs do not include production taxes.

Oil and Gas Producing Wells

The following table details the productive wells in which we owned an interest as of December 31, 2013:

	Gross	Net
Productive Wells:		
Oil:		
Gulf Coast Basin	23	12.09
East Texas	4	3.32
Oklahoma - Woodford	1	0.03
Other	27	9.34
	55	24.78
Gas:		
Gulf Coast Basin	24	11.80
East Texas	98	65.12
Oklahoma - Woodford	584	166.45
Other	—	—
	706	243.37
Total	761	268.15

Of the 761 gross productive wells at December 31, 2013, two had dual completions.

Oil and Gas Drilling Activity

The following table sets forth the wells drilled and completed by us during the periods indicated. All wells were drilled in the continental United States.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploration:						
Productive:						
Gulf Coast Basin	1	0.94	2	0.74	5	2.28
East Texas	1	0.99	6	3.25	4	1.34
Oklahoma - Woodford	22	5.66	30	7.15	35	9.95
Other	7	2.11	46	4.73	50	4.58
	31	9.70	84	15.87	94	18.15
Non-productive:						
Gulf Coast Basin	3	0.62	—	—	—	—
East Texas	—	—	—	—	1	0.50
Oklahoma - Woodford	—	—	1	0.34	—	—
Other	2	0.62	1	0.50	—	—
	5	1.24	2	0.84	1	0.50
Total	36	10.94	86	16.71	95	18.65
Development:						
Productive:						
Gulf Coast Basin	1	0.24	—	—	—	—
East Texas	—	—	—	—	2	0.60
Oklahoma - Woodford	3	1.36	15	4.78	1	0.05
Other	—	—	6	0.10	20	0.68
	4	1.60	21	4.88	23	1.33
Non-productive:						
Gulf Coast Basin	—	—	—	—	—	—
East Texas	—	—	—	—	—	—
Oklahoma - Woodford	—	—	—	—	—	—
Other	—	—	—	—	—	—
	—	—	—	—	—	—
Total	4	1.60	21	4.88	23	1.33

At December 31, 2013, we had 19 gross (14.26 net) wells in progress in Oklahoma, Texas and the Gulf Coast Basin.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2013:

	Leasehold Acreage			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Kansas	—	—	4,091	2,046
Louisiana	4,954	1,614	11,653	6,593
Mississippi	721	721	—	—
Oklahoma	102,344	48,463	89,039	58,705
Texas	47,224	24,865	9,607	4,658
Federal Waters	50,657	31,470	7,124	7,124
Total	205,900	107,133	121,514	79,126

Leases covering 17% of our net undeveloped acreage are scheduled to expire in 2014, 19% in 2015, 27% in 2016 and 37% thereafter. Of the acreage subject to leases scheduled to expire during 2014, 65% relates to undeveloped acreage in the Mississippian Lime trend where we are evaluating future development plans after a full review of seismic data. We expect to hold the majority of the acreage scheduled to expire in 2014 through drilling or lease extensions.

Title to Properties

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements; pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind that we own.

Federal Regulations

Sales and Transportation of Natural Gas. Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 and the Federal Energy Regulatory Commission ("FERC") regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all "first sales" of natural gas. Thus, all of our sales of gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

The Outer Continental Shelf Lands Act (the "OCSLA"), which was administered by the Bureau of Ocean Energy Management, Regulation and Enforcement (the "BOEMRE") and, after October 1, 2011, its successors, the Bureau of Ocean Energy Management (the "BOEM") the Bureau of Safety and Environmental Enforcement (the "BSEE"), and the FERC, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC, BOEM or BSEE action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

Our natural gas sales are generally made at the prevailing market price at the time of sale. Therefore, even though we sell significant volumes to major purchasers, we believe that other purchasers would be willing to buy our natural gas at comparable market prices.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue. The impact of the ongoing economic downturn on natural gas supply and demand fundamentals has resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005 (the "2005 EPA") was signed into law. This comprehensive act contains many provisions that will encourage oil and gas exploration and development in the U.S. The 2005 EPA directs the FERC, BOEM and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. To date, we do not believe we have been, nor do we anticipate we will be affected any differently than other producers of natural gas.

In 2007, the FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our administrative costs. To date, we do not believe we have been, nor do we anticipate that we will be affected any differently than other producers of natural gas.

Sales and Transportation of Crude Oil. Our sales of crude oil, condensate and natural gas liquids are not currently regulated, and are subject to applicable contract provisions made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal Leases. We maintain operations located on federal oil and natural gas leases, which are administered by the BOEM or the BSEE, pursuant to the OCSLA. The BOEM and the BSEE regulate offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Gulf of Mexico shelf, and removal of facilities.

The BOEM handles offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, NEPA analysis and environmental studies, and the BSEE is responsible for the safety and enforcement functions of offshore oil and gas operations, including the development and enforcement of safety and environmental regulations, permitting of offshore exploration, development and production activities, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs. Our federal oil and natural gas leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed regulations and orders that are subject to interpretation and change by the BOEM or BSEE. We are currently subject to regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines, and the BOEM or the BSEE may in the future amend these regulations. Please read "Risk Factors" beginning on page 19 for more information on new regulations.

To cover the various obligations of lessees on the Outer Continental Shelf (the "OCS"), the BOEM and the BSEE generally require that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. While we have been exempt from such supplemental bonding requirements in the past, the BOEM has recently notified us that beginning in 2014 we will need to post supplemental bonding or some form of collateral for certain of our offshore properties. We are currently evaluating the cost of compliance with these supplemental bonding requirements and the potential collateral that would be required to be provided. We believe that we will be able to satisfy the collateral requirements using a combination of our existing cash on hand and letters of credit available under our bank credit facility. Our borrowings available under our bank credit facility will be reduced to the extent we issue letters of credit to support the issuance of these bonds or other surety. The cost of compliance with these supplemental bonding requirements is not expected to be material. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

Hurricanes in the Gulf of Mexico can have a significant impact on oil and gas operations on the OCS. The effects from past hurricanes have included structural damage to pipelines, wells, fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and the BSEE will continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEMRE historically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEM or the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs to future storms.

The Office of Natural Resources Revenue (the "ONRR") in the U.S. Department of the Interior administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the ONRR.

Federal, State or American Indian Leases. In the event we conduct operations on federal, state or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management ("BLM") or the BOEM or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the United States. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates that we could charge for gas, the transportation of gas, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

Legislative Proposals

In the past, Congress has been very active in the area of natural gas regulation. New legislative proposals in Congress and the various state legislatures, if enacted, could significantly affect the petroleum industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

Environmental Regulations

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, regulations and rules regulating the release of materials into the environment or otherwise relating to the protection of human health, safety and the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Our activities with respect to exploration and production of oil and natural gas, including the drilling of wells and the operation and construction of pipelines, plants and other facilities for extracting, transporting, processing, treating or storing natural gas and other petroleum products, are subject to stringent environmental regulation by state and federal authorities, including the United States Environmental Protection Agency (the "USEPA"). Such regulation can increase the cost of planning, designing, installing and operating of such facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in oil and gas production operations, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production, would result in substantial costs and liabilities to us.

Solid and Hazardous Waste. We own or lease numerous properties that have been used for production of oil and gas for many years. Although we have utilized operating and disposal practices standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under these properties. In addition, many of these properties have been operated by third parties that controlled the treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future contamination.

We generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. The USEPA has limited the disposal options for certain hazardous wastes. Furthermore, it is possible that certain wastes generated by our oil and gas operations which are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes, and therefore be subject to more rigorous and costly disposal requirements.

Naturally Occurring Radioactive Materials ("NORM") are radioactive materials which precipitate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed or arranged for the disposal of hazardous substances at a site. CERCLA also authorizes the USEPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. State statutes impose similar liability.

Under CERCLA, the term "hazardous substance" does not include "petroleum, including crude oil or any fraction thereof," unless specifically listed or designated and the term does not include natural gas, natural gas liquids, liquefied natural gas, or synthetic gas usable for fuel. While this "petroleum exclusion" lessens the significance of CERCLA to our operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance" in the course of our ordinary operations. We also currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, "hazardous substances" may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site, and we have not been notified of any claim, liability or damages under CERCLA.

Endangered Species Act. Federal and state legislation including, in particular, the federal Endangered Species Act of 1973 ("ESA"), imposes requirements to protect imperiled species from extinction by conserving and protecting threatened and endangered species and the habitat upon which they depend. With specified exceptions, the ESA prohibits the "taking," including killing, harassing or harming, of any listed threatened or endangered species, as well as any degradation or destruction of its habitat. In addition, the ESA mandates that federal agencies carry out programs for conservation of listed species. Many state laws similarly protect threatened and endangered species and their habitat. We operate in areas in which listed species may be present. For example, the American Burying Beetle, listed in 1989 as endangered, is present in regions overlying the Woodford shale in Oklahoma. As a result, we may be required to adopt protective measures, obtain incidental take permits, and otherwise adjust our drilling plans to comply with ESA requirements.

Oil Pollution Act. The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of $350 million and for offshore facilities of all removal costs plus $75 million, and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, oil throughput, proximity to sensitive areas, type of oil handled, history of discharges and other factors. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in our industry. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

As a result of the explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in 2010, Congress considered but did not enact legislation that would eliminate the current cap on liability for damages and increase minimum levels of financial responsibility under OPA. If enacted, such legislation could increase our obligations and potential liability, but adoption of such legislation is uncertain. We are not aware of the occurrence of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Discharges. The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the United States, including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control and Countermeasure Plans and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us. The CWA also prohibits spills of oil and hazardous substances to waters of the United States in excess of levels set by regulations and imposes liability in the event of a spill. State laws further provide civil and criminal penalties and liabilities for spills to both surface and groundwaters and require permits that set limits on discharges to such waters.

Hydraulic Fracturing. Our exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health and the environment, and in response to a Congressional directive, the USEPA has commissioned a study to identify potential risks associated with hydraulic fracturing. The USEPA published a progress report on this study in December 2012 and a final draft report will be delivered in 2014. Additionally, in May 2012 the BLM proposed to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposal, issued a revised proposal in May 2013. The revised proposal, which also addresses disclosure of fluids used in the hydraulic fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process, has also generated substantial public comment and no final rule has yet been promulgated. Some states now regulate utilization of hydraulic fracturing and others are in the process of developing, or are considering development of, such rules. Depending on the results of the USEPA study and other developments related to the impact of hydraulic fracturing, our drilling activities could be subjected to new or enhanced federal, state and/or local regulatory requirements governing hydraulic fracturing.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and criminal liability for non-compliance. An agency could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

According to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases ("GHG") may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act ("CAA") definition of an "air pollutant", and in response the USEPA promulgated an endangerment finding paving the way for regulation of GHG emissions under the CAA. The USEPA has also promulgated rules requiring large sources to report their GHG emissions. Sources subject to these reporting requirements include on- and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year in aggregate emissions from all site sources. We are not subject to GHG reporting requirements. In addition, the USEPA promulgated rules that significantly increase the GHG emission threshold that would identify major stationary sources of GHG subject to CAA permitting programs. As currently written and based on current Company operations, we are not subject to federal GHG permitting requirements. Regulation of GHG emissions is new and highly controversial, and further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Company. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, the Company cannot predict the financial impact of related developments on the Company.

The USEPA has promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. The new regulations will require use of equipment to capture gases that come from the well during the drilling process (so-called green completions) after January 1, 2015. Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. While these new requirements are expected to increase the cost of natural gas production, we do not anticipate that we will be affected any differently than other producers of natural gas.

Coastal Coordination. There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act ("CZMA") was passed to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

The Louisiana Coastal Zone Management Program ("LCZMP") was established to protect, develop and, where feasible, restore and enhance coastal resources of the state. Under the LCZMP, coastal use permits are required for certain activities, even if the activity only partially infringes on the coastal zone. Among other things, projects involving use of state lands and water bottoms, dredge or fill activities that intersect with more than one body of water, mineral activities, including the exploration and production of oil and gas, and pipelines for the gathering, transportation or transmission of oil, gas and other minerals require such permits. General permits, which entail a reduced administrative burden, are available for a number of routine oil and gas activities. The LCZMP and its requirement to obtain coastal use permits may result in additional permitting requirements and associated project schedule constraints.

The Texas Coastal Coordination Act ("CCA") provides for coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development and establishes the Texas Coastal Management Program that applies in the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may affect agency permitting and may add a further regulatory layer to some of our projects.

OSHA. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act, and similar state statutes require us to organize and/or disclose information about hazardous materials used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens.

Management believes that we are in substantial compliance with current applicable environmental laws and regulations described above and that continued compliance with existing requirements will not have a material adverse impact on us.

Corporate Offices

Our headquarters are located in Lafayette, Louisiana, in approximately 49,200 square feet of leased space, with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma, in approximately 13,100 square feet and 11,800 square feet, respectively, of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

Employees

We had 126 full-time employees as of February 5, 2014. In addition to our full time employees, we utilize the services of independent contractors to perform certain functions. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement.

Available Information

We make available free of charge, or through the "Investors—SEC Documents" section of our website at www.petroquest.com, access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed or furnished to the Securities and Exchange Commission. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and the charters of our Audit, Compensation and Nominating and Corporate Governance Committees are also available through the "Investors—Corporate Governance" section of our website or in print to any stockholder who requests them.

Item 1A. Risk Factors

Risks Related to Our Business, Industry and Strategy

Oil and natural gas prices are volatile, and an extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Historically, the markets for oil and natural gas have been volatile. For example, for the four years ended December 31, 2013, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $68.01 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.01 per MMBtu to a low of $1.91 per MMBtu. These markets will likely continue to be volatile in the future. The prices we will receive for our production, and the levels of our production, will depend on numerous factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the FERC;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;

- the price and level of foreign imports of oil and natural gas; and

- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record additional ceiling test write-downs and may cause our estimated proved reserves at December 31, 2014 to decline compared to our estimated proved reserves at December 31, 2013. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, which in turn may limit our ability to remain in compliance with debt covenants and make payments on our debt.

The aggregate principal amount of our outstanding indebtedness net of cash on hand as of December 31, 2013 was $416 million. We have $75 million of additional availability under our bank credit facility, subject, however, to limitations on incurrence of indebtedness under the indenture governing our 10% senior notes. In addition, we may also incur additional indebtedness in the future. Specifically, our high level of debt could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our outstanding indebtedness, including our 10% senior notes, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;

- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;

- we will need to use a substantial portion of our cash flows to pay interest on our debt, approximately $35 million per year for interest on our 10% senior notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") of approximately $5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;

- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;

- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;

- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 10% senior notes, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 10% senior notes, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our 10% senior notes, and to fund planned capital expenditures will depend on our ability to generate sufficient cash flow from operations in the future. To a certain extent, this is subject to general economic, financial, competitive, legislative and regulatory conditions and other factors that are beyond our control, including the prices that we receive for our oil and natural gas production.

We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under our bank credit facility in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 10% senior notes, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on our 10% senior notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and could impair our liquidity.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, future hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile prices of oil and natural gas, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

We may not be able to obtain adequate financing when the need arises to execute our long-term operating strategy.

Our ability to execute our long-term operating strategy is highly dependent on having access to capital when the need arises. We historically have addressed our long-term liquidity needs through bank credit facilities, second lien term credit facilities, issuances of equity and debt securities, sales of assets, joint ventures and cash provided by operating activities. We will examine the following alternative sources of long-term capital as dictated by current economic conditions:

- borrowings from banks or other lenders;
- the sale of non-core assets;
- the issuance of debt securities;
- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices, our credit ratings, interest rates, market perceptions of us or the oil and gas industry, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these sources when the need arises.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our bank credit facility and the indenture governing our 10% senior notes contain a number of significant covenants that, among other things, restrict or limit our ability to:

- pay dividends or distributions on our capital stock or issue preferred stock;
- repurchase, redeem or retire our capital stock or subordinated debt;
- make certain loans and investments;
- place restrictions on the ability of subsidiaries to make distributions;
- sell assets, including the capital stock of subsidiaries;
- enter into certain transactions with affiliates;
- create or assume certain liens on our assets;
- enter into sale and leaseback transactions;
- merge or to enter into other business combination transactions;
- enter into transactions that would result in a change of control of us; or
- engage in other corporate activities.

Also, our bank credit facility and the indenture governing our 10% senior notes require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our bank credit facility and the indenture governing our 10% senior notes impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our bank credit facility and our 10% senior notes. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility and our 10% senior notes to become immediately due and payable. If that should occur, we may not be able to pay all such debt or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. If we were unable to repay those amounts, the lenders could accelerate the maturity of the debt or proceed against any collateral granted to them to secure such defaulted debt.

Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.

As is generally the case in the Gulf Coast Basin where approximately 40% of our current production is located, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. In order to maintain or increase our reserves, we must constantly locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities, either of which would have a material adverse effect on our financial condition.

Approximately 40% of our production is exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise.

At December 31, 2013, approximately 40% of our production and approximately 20% of our estimated proved reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise. Some of these adverse conditions can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In addition, according to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases may be contributing to global warming of the earth's atmosphere and to global climate change, which may exacerbate the severity of these adverse conditions. As a result, such conditions may pose increased climate-related risks to our assets and operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks; however, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We maintain several types of insurance to cover our operations, including worker's compensation, maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator's extra expense coverage, which covers the control of drilling or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We review the net capitalized costs of our properties quarterly, using a single price based on the beginning of the month average of oil and natural gas prices for the prior 12 months. We also assess investments in unproved properties periodically to determine whether impairment has occurred. The risk that we will be required to further write down the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. As a result of the decline in commodity prices, we recognized ceiling test write-downs totaling $137.1 million and $18.9 million during the years ended December 31, 2012 and December 31, 2011, respectively. While no such write-downs occurred during 2013, we may experience further ceiling test write-downs or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

Factors beyond our control affect our ability to market oil and natural gas.

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;
- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;

- the demand for oil and natural gas by utilities and other end users;
- the availability of altemate fuel sources;
- the effect of inclement weather, such as hurricanes;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on our business or operations.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the BOEMRE issued a series of active "Notices to Lessees and Operators", or NTLs, and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters are also required to demonstrate the availability of adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business.

We may need to obtain bonds or other surety in order to maintain compliance with applicable regulations, which, if required, could be costly and reduce borrowings available under our bank credit facility or any other credit facilities we may enter into in the future.

Regulations with respect to offshore operations govem, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS of the Gulf of Mexico and removal of facilities. Lessees subject to these regulations are generally required to have substantial net worth or post bonds or other acceptable assurances so that the various obligations of lessees on the Gulf of Mexico shelf will be met. While we have been exempt from such supplemental bonding requirements in the past, the BOEM has recently notified us that beginning in 2014 we will need to post supplemental bonding or some form of collateral for certain of our offshore properties. We are currently evaluating the cost of compliance with these supplemental bonding requirements and the potential collateral that would need to be provided. We believe that we will be able to satisfy the collateral requirements using a combination of our existing cash on hand and letters of credit available under our bank credit facility. Our borrowings available under our bank credit facility will be reduced to the extent we issue letters of credit to support the issuance of these bonds or other surety. The cost of compliance with these supplemental bonding requirements is not expected to be material.

Federal and state legislation and regulatory initiatives relating to oil and natural gas development and hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to enhance oil and natural gas production. Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the USEPA is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The USEPA published a progress report on this study in December 2012, and the final draft report is scheduled for completion during 2014. The USEPA has also promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. The new regulations will require use of equipment to capture gases that come from the well during the drilling process (so-called green completions) after January 1, 2015. Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. Additionally, in May 2012, the BLM proposed rules to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, issued a revised proposal in May 2013. The revised proposal which also addresses disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process, has also generated substantial public comment and no final rule has yet been promulgated.

A number of states, including Louisiana and Texas, have required operators or service companies to disclose chemical components in fluids used for hydraulic fracturing. Some states have also imposed, or are considering, more stringent regulation of oil and natural gas exploration and production activities involving hydraulic fracturing by, among other things, promulgating well completion requirements, imposing controls on storage, recycling and disposal of flowback fluids, and increasing reporting obligations. In addition, concerns related to the impacts from hydraulic fracturing have led several states to ban new natural gas development or to impose moratoria on use of hydraulic fracturing in various sensitive areas, including some areas overlying the Marcellus Shale. Similar action could be taken to preclude or limit natural gas development in other locations.

Recent seismic events have been observed in some areas (including Oklahoma, Ohio and Texas) where hydraulic fracturing has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection associated with use of hydraulic fracturing. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

Concerns regarding climate change have led the Congress, various states and environmental agencies to consider a number of initiatives to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane. Among other things, in the absence of new federal legislation, the USEPA promulgated regulations imposing reporting and other requirements on sources of significant emissions of greenhouse gases. Stricter regulations of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, or could adversely affect demand for the oil and natural gas we produce. In addition, climate change that results in physical effects such as increased frequency and severity of storms, floods and other climatic events, could disrupt our exploration and production operations and cause us to incur significant costs in preparing for and responding to those effects.

Although it is not possible at this time to predict the final outcome of the USEPA's study or the requirements of any additional federal or state legislation or regulation regarding hydraulic fracturing, management of drilling fluids, well integrity requirements or climate change, any new federal or state restrictions imposed on oil and gas exploration and production activities in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves. In addition to increased regulation of our business, we may also experience an increase in litigation seeking damages as a result of heightened public concerns related to air quality, water quality, and other environmental impacts.

The adoption of derivatives legislation by Congress, and implementation of that legislation by federal agencies, could have an adverse impact on our ability to mitigate risks associated with our business.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Reform Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation required the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation, which they have done since late 2010. The CFTC has introduced dozens of proposed rules coming out of the Dodd-Frank Reform Act, and has promulgated numerous final rules based on those proposals. The effect of the proposed rules and any additional regulations on our business is not yet entirely clear, but it is increasingly clear that the costs of derivatives-based hedging for commodities will likely increase for all market participants. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the Act. While rules proposed by the CFTC and federal banking regulators appear to allow for non-cash collateral and certain exemptions from margin for end users, the rules are not final and uncertainty remains. The full range of new Dodd-Frank requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to mitigate and otherwise manage our financial and commercial risks related to fluctuations in oil and natural gas prices. In addition, final rules were promulgated by the CFTC imposing federally-mandated position limits covering a wide range of derivatives positions, including non-exchange traded bilateral swaps related to commodities including oil and natural gas. These position limit rules were vacated by a Federal court in September 2012, and the CFTC has appealed that decision and could re-promulgate the rules in a manner that addresses the defects identified by the court. If these position limits rules go into effect in the future, they are likely to increase regulatory monitoring and compliance costs for all market participants, even where a given trading entity is not in danger of breaching position limits. These and other regulatory developments stemming from the Dodd-Frank Reform Act, including stringent new reporting requirements for derivatives positions and detailed criteria that must be satisfied to continue to enter into uncleared swap transactions, could have a material impact on our derivatives trading and hedging activities in the form of increased transaction costs and compliance responsibilities. Any of the foregoing consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

From time to time legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, among others, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. Such proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year time frame. We removed approximately 4.3 Bcfe and 5.5 Bcfe of proved undeveloped reserves in 2013 and 2012, respectively, as a result of the five year rule. These write-downs represented approximately 1% and 2% of the respective total year-end proved reserves at December 31, 2013 and 2012.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

Although the estimates of our oil and natural gas reserves and future net cash flows attributable to those reserves were prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers, we are ultimately responsible for the disclosure of those estimates. Reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and work-over and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Historically, the difference between our actual production and the production estimated in a prior year's reserve report has not been material. Our 2013 production, excluding the impact from the Gulf of Mexico Acquisition, was approximately 8% greater than amounts projected in our 2012 reserve report. We cannot assure you that these differences will not be material in the future.

Approximately 33% of our estimated proved reserves at December 31, 2013 are undeveloped and 8% were developed, non-producing. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop and produce our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of undeveloped reserves is generally subject to the approval of development plans and related activities by applicable state and/or federal agencies. Statutes and regulations may affect both the timing and quantity of recovery of estimated reserves. Such statutes and regulations, and their enforcement, have changed in the past and may change in the future, and may result in upward or downward revisions to current estimated proved reserves.

You should not assume that the standardized measure of discounted cash flows is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the standardized measure of discounted cash flows from proved reserves at December 31, 2013 are based on twelve-month average prices and costs as of the date of the estimate. These prices and costs will change and may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by oil and natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor we use when calculating standardized measure of discounted cash flows for reporting requirements in compliance with accounting requirements is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.

Acquisitions of oil and gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that have provided us opportunities to grow our production and reserves. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations.

Even though we perform due diligence reviews (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to perform an in-depth review of every individual property and all records involved in each acquisition. However, even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our bank credit facility contains certain covenants that limit, or which may have the effect of limiting, among other things acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2013 are in the form of swaps placed with the commodity trading branches of JPMorgan Chase Bank and Wells Fargo Bank, N.A., both of which participate in our bank credit facility. We cannot assure you that these or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. Oil and natural gas hedges increased our total oil and gas sales by approximately \$0.9 million, \$9.1 million and \$2.4 million during 2013, 2012 and 2011, respectively. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand for oil and natural gas. In accordance with customary industry practice, we rely on independent third-party service providers to provide most of the services necessary to drill new wells. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, drilling rig crews and other personnel, trucking services, tubulars, fracking and completion services and production equipment, including equipment and personnel related to horizontal drilling activities, could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

The loss of key management or technical personnel could adversely affect our ability to operate.

Our operations are dependent upon a diverse group of key senior management and technical personnel. In addition, we employ numerous other skilled technical personnel, including geologists, geophysicists and engineers that are essential to our operations. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of any of these key management or technical personnel could have an adverse effect on our operations.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to risks inherent in the oil and natural gas industry, such as:

- unexpected drilling conditions including blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The trend toward stricter requirements and standards in environmental legislation and regulation is likely to continue. Our drilling plans may be delayed, modified or precluded as a result of new or modified environmental mandates, including those imposed to protect the American Burying Beetle and other endangered species that may be present in the vicinity of our operations. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages and further may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

We cannot control the activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of drilling and development activities on our partially owned properties operated by others therefore will depend upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors potentially creates conflicts of interest.

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in certain properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business. There is a potential conflict of interest between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Outstanding Common Stock

Our stock price could be volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may continue to be highly volatile. During 2013, the sales price of our stock ranged from a low of $3.55 per share (on February 28, 2013) to a high of $5.39 per share (on January 23, 2013). Factors such as announcements concerning changes in prices of oil and natural gas, the success of our acquisition, exploration and development activities, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.

We have issued 1,495,000 shares of Series B Preferred Stock, which are presently convertible into 5,147,734 shares of our common stock. In addition, pursuant to our stock incentive plan, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon the conversion of the Series B Preferred Stock, the exercise of any outstanding stock awards or the grant of any restricted stock. In addition, if we raise additional funds by issuing additional common stock, or securities convertible into or exchangeable or exercisable for common stock, further dilution to our existing stockholders will result, and new investors could have rights superior to existing stockholders.

The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.

At December 31, 2013, we had reserved approximately 1.9 million shares of common stock for issuance under outstanding options and approximately 5.1 million shares issuable upon conversion of the Series B Preferred Stock. All of these shares of common stock are registered for sale or resale on currently effective registration statements. We may issue additional restricted securities or register additional shares of common stock under the Securities Act in the future. The issuance of a significant number of shares of common stock upon the exercise of stock options, the granting of restricted stock or the conversion of the Series B Preferred Stock, or the availability for sale, or sale, of a substantial number of the shares of our common stock eligible for future sale under effective registration statements, under Rule 144 or otherwise, could adversely affect the market price of the common stock.

Provisions in our certificate of incorporation and bylaws could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation and bylaws may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of "blank check" preferred stock;

- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting stock;
- a restriction on the ability of stockholders to call a special meeting and take actions by written consent; and
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders.

We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.

We have not paid dividends on our common stock, in cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. We are currently restricted from paying dividends on our common stock by our bank credit facility, the indenture governing the 10% senior notes and, in some circumstances, by the terms of our Series B Preferred Stock. Any future dividends also may be restricted by our then-existing debt agreements.

Item 1B **Unresolved Staff Comments**

None

Item 3. **Legal Proceedings**

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

Item 4. **Mine Safety Disclosures**

Not applicable.

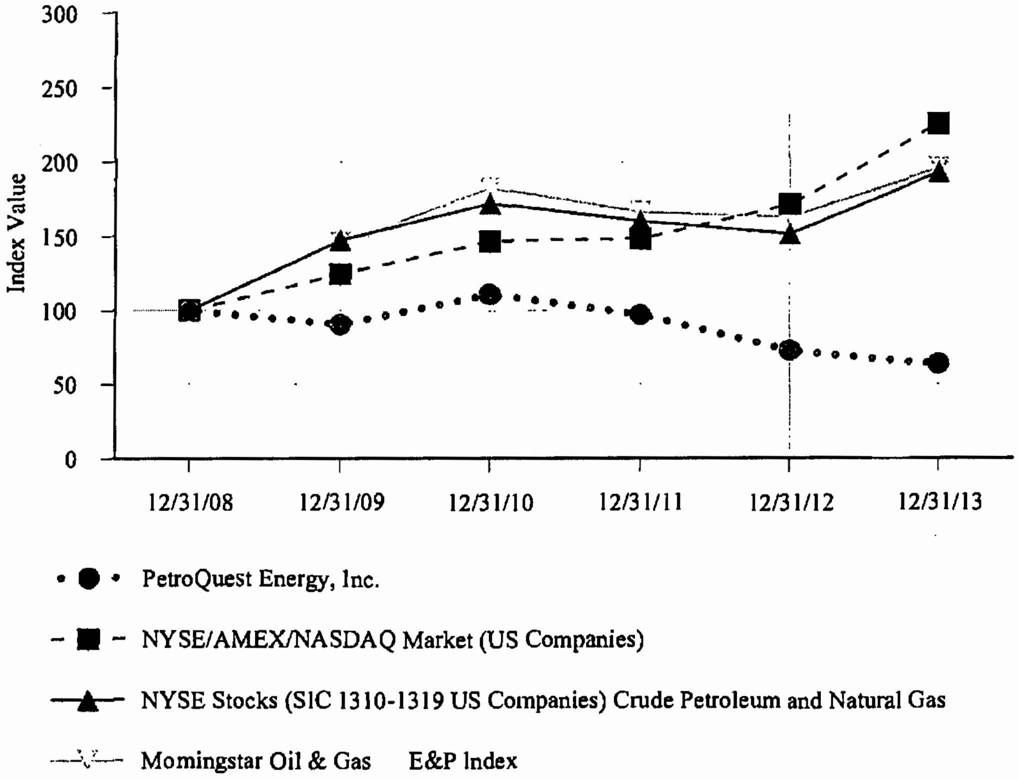
PART II

Item 5.

Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The following graph illustrates the yearly percentage change in the cumulative stockholder retum on our common stock, compared with the cumulative total retum on the NYSE/AMEX Stock Market (U.S. Companies) Index, the NYSE Stocks—Crude Petroleum and Natural Gas Index and the Momingstar Oil and Gas E&P Index (added this year for additional reference), for the five years ended December 31, 2013.

Comparison of 5 Year Cumulative Total Return
Assumes Initial Investment of $100
December 31, 2013



	PetroQuest Energy, Inc.	NYSE/AMEX/ NASDAQ Market (US Companies)	NYSE Stocks (SIC 1310-1319 US Companies) Crude Petroleum and Natural Gas	Momingstar Oil & Gas E&P Index
12/31/2008	$100.00	$100.00	$100.00	$100.00
12/31/2009	90.68	124.87	147.61	145.52
12/31/2010	111.39	146.97	172.27	182.68
12/31/2011	97.63	148.55	160.57	166.65
12/31/2012	73.22	171.78	152.25	163.40
12/31/2013	63.91	225.94	193.44	196.19

Market Price of and Dividends on Common Stock

Our common stock trades on the New York Stock Exchange under the symbol "PQ." The following table lists high and low sales prices per share for the periods indicated:

		High		Low
2012				
1st Quarter	$	7.39	$	5.41
2nd Quarter		6.46		4.26
3rd Quarter		7.05		4.82
4th Quarter		7.00		4.69
2013				
1st Quarter	$	5.39	$	3.55
2nd Quarter		5.10		3.85
3rd Quarter		4.74		3.87
4th Quarter		4.93		3.63

As of February 27, 2014, there were 287 common stockholders of record.

We have never paid a dividend on our common stock, cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. In addition, under our bank credit facility, the indenture governing the 10% senior notes, and, in some circumstances, the terms of our Series B Preferred Stock, we are restricted from paying cash dividends on our common stock. The payment of future dividends, if any, will be determined by our Board of Directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. See Item 1A. "Risk Factors – Risks Relating to our Outstanding Common Stock – We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted."

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2013.

	Total Number of Shares Purchased (1)		Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Program	Maximum Number (or Approximate Dollar Value) of Shares that May be Purchased Under the Plans or Programs
October 1—October 31, 2013	—	$	—	—	—
November 1—November 30, 2013	57,145	$	4.18	—	—
December 1—December 31, 2013	—	$	—	—	—

(1) All shares repurchased were surrendered by employees to pay tax withholding upon the vesting of restricted stock awards.

Item 6. **Selected Financial Data**

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2013 has been derived from the audited Consolidated Financial Statements of the Company for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and notes thereto. The following information is not necessarily indicative of future results of the Company. All amounts are stated in U.S. dollars unless otherwise indicated.

	Year Ended December 31,				
	2013	2012 (1)	2011 (2)	2010	2009 (3)
	(In thousands except per share and per Mcfe data)				
Average sales price per Mcfe	$ 4.80	$ 4.17	$ 5.32	$ 5.78	$ 6.39
Revenues	182,870	141,591	160,700	179,263	218,684
Net income (loss) available to common stockholders	8,943	(137,218)	5,409	41,987	(95,330)
Net income (loss) available to common stockholders per share:					
Basic	0.14	(2.20)	0.08	0.67	(1.72)
Diluted	0.14	(2.20)	0.08	0.66	(1.72)
Oil and gas properties, net	581,242	333,946	405,351	312,940	321,875
Total assets	667,190	433,403	516,166	439,517	410,459
Long-term debt	425,000	200,000	150,000	150,000	178,267
Stockholders' equity	99,095	87,591	222,390	208,162	162,105

(1) The year ended December 31, 2012 includes a pre-tax ceiling test write-down of $137.1 million.

(2) The year ended December 31, 2011 includes a pre-tax ceiling test write-down of $18.9 million.

(3) The year ended December 31, 2009 includes a pre-tax ceiling test write-down of $156.1 million.

Item 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

PetroQuest Energy, Inc. is an independent oil and gas company incorporated in the State of Delaware with operations in Oklahoma, Texas, and the Gulf Coast Basin. We seek to grow our production, proved reserves, cash flow and earnings at low finding and development costs through a balanced mix of exploration, development and acquisition activities. From the commencement of our operations in 1985 through 2002, we were focused exclusively in the Gulf Coast Basin with onshore properties principally in southern Louisiana and offshore properties in the shallow waters of the Gulf of Mexico shelf. During 2003, we began the implementation of our strategic goal of diversifying our reserves and production into longer life and lower risk onshore properties. As part of the strategic shift to diversify our asset portfolio and lower our geographic and geologic risk profile, we refocused our opportunity selection processes to reduce our average working interest in higher risk projects, shift capital to higher probability of success onshore wells and mitigate the risks associated with individual wells by expanding our drilling program across multiple basins.

We have successfully diversified into onshore, longer life basins in Oklahoma and Texas through a combination of selective acquisitions and drilling activity. Beginning in 2003 with our acquisition of the Carthage Field in Texas through 2013, we have invested approximately $1.1 billion into growing our longer life assets. During the ten year period ended December 31, 2013, we have realized a 95% drilling success rate on 918 gross wells drilled. Comparing 2013 metrics with those in 2003, the year we implemented our diversification strategy, we have grown production by 294% and estimated proved reserves by 262%. At December 31, 2013, 81% of our estimated proved reserves and 63% of our 2013 production were derived from our longer life assets.

As a result of the impact of low natural gas prices on our revenues and cash flow, we have focused on growing our reserves and production through a balanced drilling budget with an increased emphasis on growing our oil and natural gas liquids production. In May 2010, we entered into the JDA, which provided us with $85 million in cash during 2010 and 2011, along with a drilling carry that we have utilized since May 2010 to enhance economic returns by reducing our share of capital expenditures in the Woodford Shale and the Mississippian Lime. During 2013, we closed the Gulf of Mexico Acquisition. The aggregate purchase price of the Gulf of Mexico Acquisition was $188.8 million and it contributed 30.5 Bcfe to our estimated proved reserves at December 31, 2013 as well as 4.5 Bcfe of production during 2013. As a result of the JDA, the Gulf of Mexico Acquisition and the success of our drilling programs in each of our operating areas, we have grown our estimated proved reserves by 69% and production by 11% since year end 2009, including a 36% increase in our oil and natural gas liquids production during 2013.

Gulf of Mexico Acquisition

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013. The Gulf of Mexico Acquisition was financed with the issuance of an additional $200 million in aggregate principal amount of our 10% Senior Notes due 2017. The transaction included 16 gross wells located on seven platforms.

During 2013, the Acquired Assets contributed 4.5 Bcfe of total production, including 235,000 barrels of oil, and added 30.5 Bcfe of estimated proved reserves as of December 31, 2013. As a result of the Gulf of Mexico Acquisition, our acreage position in the Gulf Coast Basin increased 23% to 46,801 net acres. See "Note 2 - Acquisition" in Item 8. Financial Statements and Supplementary Data for additional details related to this transaction.

We believe the Gulf of Mexico Acquisition represents both a strategic and transformative transaction for us. This transaction builds upon our existing strategy of utilizing free cash flow from our shorter life, Gulf Coast Basin assets to develop our longer-life resource assets. As evidenced by the larger percentage of our production and estimated proved reserves now located in our longer lived basins, we have successfully leveraged our Gulf Coast free cash flow to help fund our substantial diversification efforts over the past several years. We plan to utilize a portion of the free cash flow generated from these acquired properties to accelerate the development of our Woodford Shale and Cotton Valley resource plays. In addition, based upon our experience and successful track record in exploiting reservoirs in the Gulf Coast Basin and Gulf of Mexico, we believe that we will be able to create value above the current estimated proved reserves associated with the Acquired Assets.

Critical Accounting Policies

Reserve Estimates

Our estimates of proved oil and gas reserves constitute those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. At the end of each year, our proved reserves are estimated by independent petroleum engineers in accordance with guidelines established by the SEC. These estimates, however, represent projections based on geologic and engineering data. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quantity and quality of available data, engineering and geological interpretation and professional judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such oil and gas properties.

Disclosure requirements under Staff Accounting Bulletin 113 ("SAB 113") include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. Pricing is based on a 12-month average price using beginning of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves. In addition, the 12-month average is also used to measure ceiling test impairments and to compute depreciation, depletion and amortization.

Full Cost Method of Accounting

We use the full cost method of accounting for our investments in oil and gas properties. Under this method, all acquisition, exploration and development costs, including certain related employee costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include the costs of drilling exploratory wells, including those in progress and geological and geophysical service costs in exploration activities. Development costs include the costs of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production and general corporate activities are expensed in the period incurred. Sales of oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

The costs associated with unevaluated properties are not initially included in the amortization base and primarily relate to ongoing exploration activities, unevaluated leasehold acreage and delay rentals, seismic data and capitalized interest. These costs are either transferred to the amortization base with the costs of drilling the related well or are assessed quarterly for possible impairment or reduction in value.

We compute the provision for depletion of oil and gas properties using the unit-of-production method based upon production and estimates of proved reserve quantities. Unevaluated costs and related carrying costs are excluded from the amortization base until the properties associated with these costs are evaluated. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs related to non-producing reserves. Our depletion expense is affected by the estimates of future development costs, unevaluated costs and proved reserves, and changes in these estimates could have an impact on our future earnings.

We capitalize certain internal costs that are directly identified with acquisition, exploration and development activities. The capitalized internal costs include salaries, employee benefits, costs of consulting services and other related expenses and do not include costs related to production, general corporate overhead or similar activities. We also capitalize a portion of the interest costs incurred on our debt. Capitalized interest is calculated using the amount of our unevaluated property and our effective borrowing rate.

Capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization ("DD&A") and related deferred taxes, are limited to the estimated future net cash flows from proved oil and gas reserves, including the effect of cash flow hedges in place, discounted at 10 percent, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the full cost ceiling). If capitalized costs exceed the full cost ceiling, the excess is charged to write-down of oil and gas properties in the quarter in which the excess occurs.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from estimated proved oil and gas reserves will change in the near term. If oil or gas prices decline, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that further write-downs of oil and gas properties could occur in the future.

Future Abandonment Costs

Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including changing technology, the timing of estimated costs, the impact of future inflation on current cost estimates and the political and regulatory environment.

Derivative Instruments

We seek to reduce our exposure to commodity price volatility by hedging a portion of our production through commodity derivative instruments. The estimated fair values of our commodity derivative instruments are recorded in the consolidated balance sheet. The changes in fair value of those derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil or natural gas quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense).

Our hedges are specifically referenced to NYMEX prices for oil and natural gas. We evaluate the effectiveness of our hedges at the time we enter the contracts, and periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices we receive from our designated production. Through this analysis, we are able to determine if a high correlation exists between the prices received for the designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2013, our derivative instruments were designated effective cash flow hedges.

Estimating the fair value of derivative instruments requires valuation calculations incorporating estimates of future NYMEX prices, discount rates and price movements. As a result, we calculate the fair value of our commodity derivatives using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. Our fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of our default risk for derivative liabilities.

Results of Operations

The following table sets forth certain information with respect to our oil and gas operations for the periods noted. These historical results are not necessarily indicative of results to be expected in future periods.

	Year Ended December 31,		
	2013	2012	2011
Production:			
Oil (Bbls)	680,980	520,590	572,096
Gas (Mcf)	29,225,843	27,466,228	24,462,933
Ngl (Mcfe)	4,754,223	3,366,774	2,287,846
Total Production (Mcfe)	38,065,946	33,956,542	30,183,355
Sales:			
Total oil sales	$ 70,476,065	$ 56,635,786	$ 60,064,426
Total gas sales	87,449,370	63,535,262	78,664,373
Total ngl sales	24,878,243	21,262,236	21,756,917
Total oil and gas sales	$ 182,803,678	$ 141,433,284	$ 160,485,716
Average sales prices:			
Oil (per Bbl)	$ 103.49	$ 108.79	$ 104.99
Gas (per Mcf)	2.99	2.31	3.22
Ngl (per Mcfe)	5.23	6.32	9.51
Per Mcfe	4.80	4.17	5.32

The above sales and average sales prices include increases (reductions) to revenue related to the settlement of gas hedges of $1,098,000, $6,846,000 and $2,609,000, oil hedges of ($232,000), $1,529,000 and ($192,000), and Ngl hedges of $61,000, $722,000 and zero for the twelve months ended December 31, 2013, 2012 and 2011, respectively.

Comparison of Results of Operations for the Years Ended December 31, 2013 and 2012

Net income (loss) available to common stockholders totaled $8,943,000 and ($137,218,000) for the years ended December 31, 2013 and 2012, respectively. The primary fluctuations were as follows:

Production Total production increased 12% during the year ended December 31, 2013 as compared to the 2012 period. Gas production during the year ended December 31, 2013 increased 6% from the 2012 period. The increase in gas production was primarily the result of added production from the Gulf of Mexico Acquisition which closed on July 3, 2013. Additionally, gas production increased as a result of the successful drilling programs in our La Cantera field and our liquids rich Woodford acreage. Partially offsetting these increases were decreases in gas production due to normal production declines at our dry gas Oklahoma fields as well as certain of our legacy Gulf of Mexico fields in addition to the loss of production resulting from the sale of our Fayetteville assets in December 2012. As a result of a full year of production from the wells acquired in the Gulf of Mexico Acquisition and increased drilling activity planned for 2014, we expect our average daily gas production in 2014 to increase as compared to 2013.

Oil production during the year ended December 31, 2013 increased 31% as compared to the 2012 period due primarily to added production from the Gulf of Mexico Acquisition as well as the continued success of our La Cantera field. Partially offsetting these increases were decreases as a result of continued normal production declines in certain of our legacy Gulf of Mexico and East Texas fields. As a result of a full year of production from the wells acquired in the Gulf of Mexico Acquisition, we expect our average daily oil production to be significantly higher during 2014 as compared to 2013.

Ngl production during the year ended December 31, 2013 increased 41% from the 2012 period due to the success experienced in our La Cantera field and the liquids rich portion of our Oklahoma properties, as well as added production from the Gulf of Mexico Acquisition. Partially offsetting these increases were decreases as a result of normal production declines at certain of our legacy Gulf of Mexico fields. As a result of the increase in drilling activity planned for 2014 as well as a full year of production from the wells acquired in the Gulf of Mexico Acquisition, we expect our daily Ngl production for 2014 to increase significantly compared to that of 2013.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2013 were $2.99 as compared to $2.31 for the 2012 period. Average oil prices per Bbl for the year ended December 31, 2013 were $103.49 as compared to $108.79 for the 2012 period and average Ngl prices per Mcfe were $5.23 for the year ended December 31, 2013, as compared to $6.32 for the 2012 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2013 were 15% higher than the prices received during the 2012 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2013 increased 29% to $182,804,000, as compared to oil and gas sales of $141,433,000 during the 2012 period. The increased revenue during 2013 was primarily the result of higher average realized prices for our production during 2013 as well as increased production as discussed above.

Expenses Lease operating expenses for the year ended December 31, 2013 totaled $43,743,000 as compared to $38,890,000 during the 2012 period. Per unit lease operating expenses totaled $1.15 per Mcfe during both of the twelve month periods ended December 31, 2013 and 2012. We expect the absolute amount of lease operating expenses to increase during 2014 as compared to 2013 as a result of the Gulf of Mexico Acquisition but we expect per unit lease operating costs to approximate per unit amounts in 2013.

Production taxes for the year ended December 31, 2013 totaled $3,950,000 as compared to $885,000 during the 2012 period. The significant reduction during the 2012 period was the result of recording a receivable of $2,717,000 during June 2012 for refunds relative to severance tax previously paid on our Oklahoma horizontal wells that we are receiving incrementally through June, 2015. Because the majority of the assets purchased in the Gulf of Mexico Acquisition are located in Federal waters and are therefore not subject to production taxes, we do not expect a meaningful change to our production taxes during 2014 as compared to 2013.

General and administrative expenses during the year ended December 31, 2013 totaled $26,512,000 as compared to $22,957,000 during the 2012 period. Included in general and administrative expenses was non-cash, share-based compensation expense as follows (in thousands):

	Year Ended December 31,	
	2013	2012
Stock options:		
Incentive Stock Options	$ 310	$ 786
Non-Qualified Stock Options	222	660
Restricted stock	3,684	5,464
Non-cash share-based compensation	$ 4,216	$ 6,910

General and administrative expenses increased 15% during the year ended December 31, 2013 as compared to the 2012 period. Included in general and administrative expenses during the 2013 period is $4,018,000 of transaction-related costs related to the Gulf of Mexico Acquisition. In addition, during 2013, we recognized approximately $895,000 in general and administrative expenses associated with benefits due under the compensation agreements of the Company's Executive Vice-President and General Counsel, who passed away unexpectedly in September 2013. We capitalized $13,514,000 of general and administrative costs during the year ended December 31, 2013 as compared to $11,925,000 during the comparable 2012 period. General and administrative expenses in 2014 are expected to be lower than 2013 due to these non-recurring items.

DD&A expense on oil and gas properties for the year ended December 31, 2013 totaled $69,357,000, or $1.82 per Mcfe, as compared to $59,496,000, or $1.75 per Mcfe, during the comparable 2012 period. The increase in the per unit DD&A rate is primarily the result of the Gulf of Mexico Acquisition, which had a higher cost per unit as compared to our overall amortization base. After taking into effect the Gulf of Mexico Acquisition, we expect our DD&A rate for 2014 to be higher than the full year rate during 2013.

At December 31, 2012, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged $2.21 per Mcf of natural gas, $102.81 per barrel of oil, and $6.07 per Mcfe of Ngl. As a result of lower natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recognized ceiling test write-downs of $137,100,000 during the year ended December 31, 2012. No such ceiling test write-down occurred during 2013.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $21,886,000 during the year ended December 31, 2013, as compared to $9,808,000 during 2012. During the year ended December 31, 2013, our capitalized interest totaled $6,570,000 as compared to $7,036,000 during the 2012 period. The increase in interest expense was a result of the issuance of an additional $200 million of 10% senior notes, which were used to finance the Gulf of Mexico Acquisition in addition to increased borrowings outstanding under our bank credit facility during 2013 as compared to 2012. As a result, we expect interest expense for 2014 to be higher than that of 2013.

Income tax expense during the year ended December 31, 2013 totaled $320,000, as compared to $1,636,000 during the 2012 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of the ceiling test write-downs recognized during 2012, we have incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was $45,531,000 as of December 31, 2013.

Comparison of Results of Operations for the Years Ended December 31, 2012 and 2011

Net income (loss) available to common stockholders totaled ($137,218,000) and $5,409,000 for the years ended December 31, 2012 and 2011, respectively. The primary fluctuations were as follows:

Production Total production increased 13% during the year ended December 31, 2012 as compared to the 2011 period. Gas production during the year ended December 31, 2012 increased 12% from the 2011 period. The increase in gas production was primarily the result of the success of our drilling programs in the Woodford Shale in Oklahoma, the Carthage field in East Texas, and the La Cantera field in South Louisiana. Gas production also increased at our West Cameron Block 402 well due to a successful recompletion during the fourth quarter of 2011. Partially offsetting these increases were normal production declines particularly in our Gulf Coast region.

Oil production during the year ended December 31, 2012 decreased 9% as compared to the 2011 period due primarily to continued normal production declines in our onshore Louisiana and offshore Gulf of Mexico fields. Partially offsetting these decreases were increases from the inception of production from our La Cantera field during March 2012, our Eagle Ford Shale field where five new wells commenced production during the third and fourth quarters of 2012 and at our Mississippian Lime field where initial oil production from our first wells began during the second quarter of 2012 with four additional wells beginning production during the fourth quarter. Additionally, oil production increased at our Ship Shoal field as a result of three successful recompletions performed during the fourth quarter of 2012.

Ngl production during the year ended December 31, 2012 increased 47% from the 2011 period due to the inception of production from our La Cantera field, the liquids rich portion of our Oklahoma properties, and an increase in production at our Carthage field in East Texas. These increases were partially offset by the normal production declines particularly in our Gulf Coast region.

Prices Including the effects of our hedges, average gas prices per Mcf for the year ended December 31, 2012 were $2.31 as compared to $3.22 for the 2011 period. Average oil prices per Bbl for the year ended December 31, 2012 were $108.79 as compared to $104.99 for the 2011 period and average Ngl prices per Mcfe were $6.32 for the year ended December 31, 2012, as compared to $9.51 for the 2011 period. Stated on an Mcfe basis, unit prices received during the year ended December 31, 2012 were 22% lower than the prices received during the 2011 period.

Revenue Including the effects of hedges, oil and gas sales during the twelve months ended December 31, 2012 decreased 12% to $141,433,000, as compared to oil and gas sales of $160,486,000 during the 2011 period. The decreased revenue during 2012 was primarily the result of lower natural gas and Ngl prices as well as reduced oil production during the period.

Expenses Lease operating expenses for the year ended December 31, 2012 totaled $38,890,000 as compared to $38,571,000 during the 2011 period. Per unit lease operating expenses totaled $1.15 per Mcfe during the twelve month period ended December 31, 2012 as compared to $1.28 during the 2011 period. Per unit lease operating expenses decreased primarily due to the increase in overall produced volumes during the period.

Production taxes for the year ended December 31, 2012 totaled $885,000 as compared to $3,100,000 during the 2011 period. The significant decrease during the 2012 period was the result of recording a receivable of $2,717,000 during June 2012 for refunds relative to severance tax previously paid on our Oklahoma horizontal wells that we expect to receive over the next three years. Beginning in July 2012, we are no longer required to submit the full rate of Oklahoma severance tax on those wells qualifying for the horizontal tax credit.

General and administrative expenses during the year ended December 31, 2012 totaled $22,957,000 as compared to $20,436,000 during the 2011 period. Included in general and administrative expenses was non-cash share-based compensation expense as follows (in thousands):

	Year Ended December 31,	
	2012	2011
Stock options:		
Incentive Stock Options	$ 786	$ 493
Non-Qualified Stock Options	660	703
Restricted stock	5,464	3,637
Non-cash share-based compensation	$ 6,910	$ 4,833

General and administrative expenses increased 12% during the year ended December 31, 2012 as compared to the comparable period of 2011 primarily due to increased non-cash share-based compensation expense during 2012. We capitalized $11,925,000 of general and administrative costs during the year ended December 31, 2012 as compared to $11,176,000 during the comparable 2011 period.

DD&A expense on oil and gas properties for the year ended December 31, 2012 totaled $59,496,000, or $1.75 per Mcfe, as compared to $57,143,000, or $1.89 per Mcfe, during the comparable 2011 period. The decrease in the per unit DD&A rate is primarily the result of a decrease in the depletable base due to the ceiling test write-downs recognized during 2012.

At December 31, 2012, the prices used in computing the estimated future net cash flows from our estimated proved reserves, including the effect of hedges in place at that date, averaged $2.21 per Mcf of natural gas, $102.81 per barrel of oil, and $6.07 per Mcfe of Ngl. As a result of lower natural gas prices and their negative impact on certain of our longer-lived estimated proved reserves and estimated future net cash flows, we recognized ceiling test write-downs of $137,100,000 during the year ended December 31, 2012. We also recognized a ceiling test write-down of $18,907,000 during the twelve months ended December 31, 2011.

Interest expense, net of amounts capitalized on unevaluated properties, totaled $9,808,000 during the year ended December 31, 2012, as compared to $9,648,000 during 2011. During the year ended December 31, 2012, our capitalized interest totaled $7,036,000 as compared to $7,034,000 during the 2011 period.

Income tax expense (benefit) during the year ended December 31, 2012 totaled $1,636,000, as compared to ($1,810,000) during the 2011 period. We typically provide for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes.

As a result of the ceiling test write-downs recognized, we have incurred a cumulative three-year loss. Because of the impact the cumulative loss has on the determination of the recoverability of deferred tax assets through future earnings, we assessed the realizability of our deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, we established a valuation allowance for a portion of our deferred tax asset. The valuation allowance was $50,866,000 as of December 31, 2012.

Liquidity and Capital Resources

We have financed our acquisition, exploration and development activities to date principally through cash flow from operations, bank borrowings, other credit facilities, issuances of equity and debt securities, joint ventures and sales of assets. At December 31, 2013, we had a working capital deficit of $26.1 million compared to a deficit of $31.3 million at December 31, 2012. Since we operate the majority of our drilling activities, we have the ability to reduce our capital expenditures to manage our working capital deficit and liquidity position. To the extent our capital expenditures during 2014 exceed our cash flow and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of non-core assets to fund a portion of our drilling budget.

Prices for oil and natural gas are subject to many factors beyond our control such as weather, the overall condition of the global financial markets and economies, relatively minor changes in the outlook of supply and demand, and the actions of OPEC. Oil and natural gas prices have a significant impact on our cash flows available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our bank credit facility is subject to periodic re-determination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce. Lower prices and/or lower production may decrease revenues, cash flows and the borrowing base under the bank credit facility, thus reducing the amount of financial resources available to meet our capital requirements. Lower prices and reduced cash flow may also make it difficult to incur debt, including under our bank credit facility, because of the restrictive covenants in the indenture governing the Notes. See "Source of Capital: Debt" below. Our ability to comply with the covenants in our debt agreements is dependent upon the success of our exploration and development program and upon factors beyond our control, such as oil and natural gas prices.

Source of Capital: Operations

Net cash flow from operations decreased from $88.6 million during the year ended December 31, 2012 to $59.9 million during the 2013 period. The decrease in operating cash flow during 2013 as compared to 2012 was primarily attributable to the decrease in our accounts payable to vendors, advances from co-owners and the increase to our revenue receivable offset by the reduction in accounts receivable from our joint partners.

Source of Capital: Debt

On August 19, 2010, we issued $150 million in principal amount of 10% Senior Notes due 2017 (the "Existing Notes") in a public offering. On July 3, 2013, we issued an additional $200 million in aggregate principal amount of 10% Senior Notes due 2017. (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of their face value plus accrued interest from March 1, 2013. The New Notes have terms that, subject to certain exceptions, are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013.

The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2013, $11.7 million of interest had been accrued in connection with the March 1, 2014 interest payment and we were in compliance with all of the covenants contained in the Notes.

We have a Credit Agreement (as amended, the "Credit Agreement" and sometimes referred to elsewhere in this Form 10-K as our "bank credit facility") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A. and IberiaBank. The Credit Agreement provides us with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows us to use up to $25 million of the borrowing base for letters of credit. Our bank credit facility matures on October 3, 2016. As of December 31, 2013, we had $75.0 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to our oil and gas properties as of January 1 and July 1 of each year. On July 3, 2013, the borrowing base was increased from $150 million to $200 million (subject to the aggregate commitments of the lenders then in effect). As of December 31, 2013, the aggregate commitments of the lenders is $150 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions. The next borrowing base redetermination is scheduled to occur by March 31, 2014. We or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of our assets, including a lien on all equipment and at least 80% of the aggregate total value of our oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternate base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by us) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, we pay commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

We are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0, and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits us to repurchase up to $10 million of our common stock during the term of the Credit Agreement, as long as after giving effect to such repurchase our Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of December 31, 2013, we were in compliance with all of the covenants contained in the Credit Agreement.

Source of Capital: Issuance of Securities

Our shelf registration statement allows us to publicly offer and sell up to $350 million of any combination of debt securities, shares of common and preferred stock, depositary shares and warrants. The registration statement does not provide any assurance that we will or could sell any such securities.

Source of Capital: Joint Ventures

In May 2010, we entered into a joint development agreement with WSGP Gas Producing, LLC ("WSGP"), a subsidiary of NextEra Energy Resources, LLC, whereby WSGP acquired approximately 29 Bcfe of our Woodford proved undeveloped reserves as well as the right to earn 50% of our undeveloped Woodford acreage position through a two phase drilling program. We received approximately $57.4 million in cash at closing, net of $2.6 million in transaction fees, and an additional $14 million in each of 2011 and 2012. In addition, since May 2010, WSGP has funded a share of our drilling costs under a drilling program, which we refer to as the drilling carry. As of December 31, 2013, approximately $51.6 million of drilling carry remained available.

Source of Capital: Divestitures

We do not budget property divestitures; however, we are continuously evaluating our property base to determine if there are assets in our portfolio that no longer meet our strategic objectives. From time to time we may divest certain non-strategic assets in order to provide liquidity to strengthen our balance sheet or capital to be reinvested in higher rate of return projects. We are currently exploring divestment opportunities for our Mississippian Lime and South Texas assets. We cannot assure you that we will be able to sell any of our assets in the future.

On December 31, 2012, we sold our non-operated Arkansas assets for a net cash purchase price of $8.5 million. In January 2013, we sold 50% of our saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10 million. In December 2013, we sold our non-operated Wyoming assets for a cash purchase price of $1.0 million.

Use of Capital: Exploration and Development

Our 2014 capital budget, which includes capitalized interest and general and administrative costs, is expected to range between $140 million and $150 million. Because we operate the majority of our drilling activities, we expect to be able to control the timing of a substantial portion of our capital investments. We plan to fund our capital expenditures with cash flow from operations and cash on hand. To the extent our capital expenditures during 2014 exceed our cash flow and cash on hand, we plan to utilize available borrowings under the bank credit facility or proceeds from the potential sale of non-core assets. To the extent additional capital is required, we may utilize sales of equity or debt securities or we may reduce our capital expenditures to manage our liquidity position.

Use of Capital: Acquisitions

On July 3, 2013, we closed the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million. The Acquired Assets include 16 gross wells located on seven platforms.

We believe the acquisition of the Acquired Assets represents both a strategic and transformative transaction for us. This transaction builds upon our existing strategy of utilizing free cash flow from our shorter life, Gulf Coast Basin assets to develop our longer life resource assets. We plan to utilize a portion of the free cash flow generated from these acquired properties to accelerate the development of our Woodford Shale and Cotton Valley resource plays.

We do not budget acquisitions; however, we are continuously evaluating opportunities to expand our existing asset base or establish positions in new core areas.

We expect to finance our future acquisition activities, if consummated, through cash on hand or available borrowings under our bank credit facility. We may also utilize sales of equity or debt securities, sales of properties or assets or joint venture arrangements with industry partners, if necessary. We cannot assure you that such additional financings will be available on acceptable terms, if at all.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2013 (in thousands):

	Total	2014	2015	2016	2017	2018	After 2018
10% senior notes (1)	$ 490,000	$ 35,000	$ 35,000	$ 35,000	$385,000	$ —	$ —
Credit Agreement debt (1)	80,581	1,673	1,860	77,048	—	—	—
Operating leases (2)	8,005	1,384	1,452	1,414	1,312	411	2,032
Asset retirement obligations (3)	48,536	3,113	3,183	4,469	185	3,945	33,641
Purchase commitments (4)	4,563	4,563	—	—	—	—	—
Total	$ 631,685	$ 45,733	$ 41,495	$ 117,931	$386,497	$ 4,356	$ 35,673

(1) Includes principal and estimated interest.
(2) Consists primarily of leases for office space and office equipment.
(3) Consists of estimated future obligations to abandon our oil and gas properties.
(4) Consists of certain drilling rig and seismic contracts.

Item 7A **Quantitative and Qualitative Disclosures About Market Risk**

We experience market risks primarily in two areas: interest rates and commodity prices. Because all of our properties are located within the United States, we believe that our business operations are not exposed to significant market risks relating to foreign currency exchange risk.

Our revenues are derived from the sale of our crude oil and natural gas production. Based on projected annual sales volumes for 2014, a 10% decline in the estimated average prices we expect to receive for our crude oil and natural gas production would result in an approximate $19.7 million decline in our revenues for 2014.

We periodically seek to reduce our exposure to commodity price volatility by hedging a portion of production through commodity derivative instruments. In the settlement of a typical hedge transaction, we will have the right to receive from the counterparties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparties this difference multiplied by the quantity hedged. During the year ended December 31, 2013, we received approximately $0.9 million from the counterparties to our derivative instruments in connection with net hedge settlements.

We are required to pay the difference between the floating price and the fixed price (when the floating price exceeds the fixed price) regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

Our Credit Agreement requires that the counterparties to our hedge contracts be lenders under the Credit Agreement or, if not a lender under the Credit Agreement, rated A/A2 or higher by S&P or Moody's. Currently, the counterparties to our existing hedge contracts are JPMorgan Chase Bank and Wells Fargo Bank, both of whom are lenders under the Credit Agreement. To the extent we enter into additional hedge contracts, we would expect that certain of the lenders under the Credit Agreement would serve as counterparties.

As of December 31, 2013, we had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2014	Swap	40,000 Mmbtu	$4.12
Crude Oil:			
January - June 2014	Swap (LLS)	450 Bbls	$100.58
2014	Swap (LLS)	400 Bbls	$101.15
2014	Swap (WTI)	350 Bbls	$93.26

LLS - Louisiana Light Sweet

WTI - West Texas Intermediate

At December 31, 2013, we recognized a net liability of approximately $1.1 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2013, we would realize a $0.7 million loss, net of taxes, as an decrease to oil and gas sales during the next 12 months. This loss is expected to be reclassified based on the schedule of gas volumes stipulated in the derivative contracts.

During January 2014, we entered into the following additional hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Crude Oil:			
March - December 2014	Swap	5,000 Mmbtu	$4.285

After executing the above transactions, the Company has approximately 16.1 Bcf of gas volumes, at an average price of $4.14 per Mcf, and approximately 355,000 barrels of oil volumes at an average price of $98.18 per barrel, hedged for 2014.

Debt outstanding under our bank credit facility is subject to a floating interest rate and represents 18% of our total debt as of December 31, 2013. Based upon an analysis, utilizing the actual interest rate in effect and balances outstanding as of December 31, 2013, and assuming a 10% increase in interest rates and no changes in the amount of debt outstanding, the potential effect on interest expense for 2013 is $0.2 million.

Item 8. Financial Statements and Supplementary Data

Information concerning this Item begins on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company's management, including its Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the Company's disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded the following:

i. that the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure; and

ii. that the Company's disclosure controls and procedures are effective.

Notwithstanding the foregoing, there can be no assurance that the Company's disclosure controls and procedures will detect or uncover all failures of persons within the Company and its consolidated subsidiaries to disclose material information otherwise required to be set forth in the Company's periodic reports. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures.

Changes in Internal Control Over Financial Reporting

There have been no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2013 that have materially affected, or that are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, and for performing an assessment of the effectiveness of internal control over financial reporting as of December 31, 2013. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our system of internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management performed an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2013 based upon criteria in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework). Based on our assessment, management believes that our internal control over financial reporting was effective as of December 31, 2013 based on these criteria.

Ernst & Young LLP, our independent registered public accounting firm, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2013.

March 5, 2014

/s/ Charles T. Goodson
Charles T. Goodson
Chairman and
Chief Executive Officer

/s/ J. Bond Clement
J. Bond Clement
Executive Vice President-
Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). PetroQuest Energy, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, PetroQuest Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows, and stockholders' equity for each of the three years in the period ended December 31, 2013 and our report dated March 5, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 5, 2014

Item 9B. **Other Information**

NONE

PART III

Items 10, 11, 12, 13, & 14.

Pursuant to General Instruction G of Form 10-K, the information concerning Item 10. Directors, Executive Officers and Corporate Governance, Item 11. Executive Compensation, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 13. Certain Relationships and Related Transactions, and Director Independence and Item 14. Principal Accounting Fees and Services, is incorporated by reference to the information set forth in the definitive Proxy Statement of PetroQuest Energy, Inc. relating to the Annual Meeting of Stockholders to be held May 21, 2014, to be filed pursuant to Regulation 14A under the Securities Exchange Act of 1934 with the Securities and Exchange Commission.

PART IV

Item 15. **Exhibits, Financial Statement Schedules**

(a) 1. FINANCIAL STATEMENTS

The following financial statements of the Company and the Report of the Company's Independent Registered Public Accounting Firm thereon are included on pages F-1 through F-27 of this Form 10-K:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2013 and 2012
Consolidated Statements of Operations for the three years ended December 31, 2013
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2013
Consolidated Statements of Cash Flows for the three years ended December 31, 2013
Consolidated Statements of Stockholders' Equity for the three years ended December 31, 2013
Notes to Consolidated Financial Statements

2. FINANCIAL STATEMENT SCHEDULES:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. EXHIBITS:

** 2.1 Plan and Agreement of Merger by and among Optima Petroleum Corporation, Optima Energy (U.S.) Corporation, its wholly-owned subsidiary, and Goodson Exploration Company, NAB Financial L.L.C., Dexco Energy, Inc., American Explorer, L.L.C. (incorporated herein by reference to Appendix G of the Proxy Statement on Schedule 14A filed July 22, 1998).

** 2.2 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration II, L.P. (incorporated herein by reference to Exhibit 2.1 to Form 8-K filed on June 20, 2013).

** 2.3 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration III, L.P. (incorporated herein by reference to Exhibit 2.2 to Form 8-K filed on June 20, 2013).

** 2.4 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and Hall-Houston Exploration IV, L.P. (incorporated herein by reference to Exhibit 2.3 to Form 8-K filed on June 20, 2013).

** 2.5 Purchase and Sale Agreement dated as of June 19, 2013, between PetroQuest Energy, L.L.C. and GOM-H Exploration, LLC (incorporated herein by reference to Exhibit 2.4 to Form 8-K filed on June 20, 2013).

3.1 Certificate of Incorporation of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 4.1 to Form 8-K filed September 16, 1998).

3.2 Certificate of Amendment to Certificate of Incorporation dated May 14, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed June 23, 2009).

3.3 Bylaws of PetroQuest Energy, Inc., as amended of December 20, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed December 21, 2007).

3.4 Certificate of Domestication of Optima Petroleum Corporation (incorporated herein by reference to Exhibit 4.4 to Form 8-K filed September 16, 1998).

3.5 Certificate of Designations, Preferences, Limitations and Relative Rights of The Series a Junior Participating Preferred Stock of PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit A of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).

3.6 Certificate of Designations establishing the 6.875% Series B Cumulative Convertible Perpetual Preferred Stock, dated September 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K filed on September 24, 2007).

4.1 Rights Agreement dated as of November 7, 2001 between PetroQuest Energy, Inc. and American Stock Transfer & Trust Company, as Rights Agent, including exhibits thereto (incorporated herein by reference to Exhibit 1 to Form 8-A filed November 9, 2001).

4.2 Form of Rights Certificate (incorporated herein by reference to Exhibit C of the Rights Agreement attached as Exhibit 1 to Form 8-A filed November 9, 2001).

4.3 Indenture, dated August 19, 2010, between PetroQuest Energy, Inc. and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on August 19, 2010).

4.5 First Supplemental Indenture, dated August 19, 2010, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on August 19, 2010).

4.6 Second Supplemental Indenture, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and The Bank of New York Mellon Trust Company, N.A. (incorporated herein by reference to Exhibit 4.2 to Form 8-K filed on July 3, 2013).

4.7 Registration Rights Agreement, dated July 3, 2013, among PetroQuest Energy, Inc., the Subsidiary Guarantors identified therein, and J.P. Morgan Securities LLC, as representative of the several initial purchasers named therein (incorporated herein by reference to Exhibit 4.3 to Form 8-K filed on July 3, 2013).

†10.1 PetroQuest Energy, Inc. 1998 Incentive Plan, as amended and restated effective May 14, 2008 (the "Incentive Plan") (incorporated herein by reference to Appendix A of the Proxy Statement on Schedule 14A filed April 9, 2008).

†10.2 Form of Incentive Stock Option Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 10-K filed February 27, 2009).

†10.3 Form of Nonstatutory Stock Option Agreement under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 10-K filed February 27, 2009).

†10.4 Form of Restricted Stock Agreement for executive officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 10-K filed February 27, 2009).

†10.5 PetroQuest Energy, Inc. Annual Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on May 13, 2010).

†10.6 PetroQuest Energy, Inc. Annual Incentive Plan, as amended and restated (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on June 8, 2010).

†10.7 PetroQuest Energy, Inc. 2012 Employee Stock Purchase Plan (incorporated herein by reference to Appendix A to Schedule 14A filed March 28, 2012).

†10.8 PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed November 15, 2012).

†10.9 PetroQuest Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 9, 2013).

†10.10 Form of Award Notice of Restricted Stock Units - Employees (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed November 15, 2012).

†10.11 Form of Award Notice of Restricted Stock Units - Outside Director/Consultant under the PetroQuest Energy, Inc. Long-Term Cash Incentive Plan (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed November 15, 2012).

†10.12 Form of Restricted Stock Agreement - Executive Officers (including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, J. Bond Clement, Tracy Price and Edward E. Abels, Jr.) under the PetroQuest Energy, Inc. 1998 Incentive Plan (incorporated herein by reference to Exhibit 10.4 to Form 8-K filed November 15, 2012).

10.13 Credit Agreement dated as of October 2, 2008, among PetroQuest Energy, L.L.C., PetroQuest Energy, Inc., JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A., and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 6, 2008).

10.14 First Amendment to Credit Agreement dated as of March 24, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed March 24, 2009).

10.15 Second Amendment to Credit Agreement dated as of September 30, 2009, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Calyon New York Branch, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed October 1, 2009).

10.16 Third Amendment to Credit Agreement dated as of August 5, 2010, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Credit Agricole Corporate and Investment Bank, Bank of America, N.A., Wells Fargo Bank, N.A. and Whitney National Bank (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on August 6, 2010).

10.17 Fourth Amendment to Credit Agreement dated as of October 3, 2011, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., TDC Energy LLC, JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., Iberiabank and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on October 4, 2011).

10.18 Fifth Amendment to Credit Agreement dated as of March 29, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Form 8-K filed on March 29, 2013).

10.19 Sixth Amendment to Credit Agreement dated as of June 19, 2013, among PetroQuest Energy, Inc., PetroQuest Energy, L.L.C., JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A., IBERIABANK and Whitney Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 20, 2013).

†10.20 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Charles T. Goodson and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed January 6, 2009).

†10.21 Amended Executive Employment Agreement dated effective as of December 31, 2008, between W. Todd Zehnder and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed January 6, 2009).

†10.22 Amended Executive Employment Agreement dated effective as of December 31, 2008, between Arthur M. Mixon, III and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to Form 8-K filed January 6, 2009).

†10.23 Amended Executive Employment Agreement dated effective as of December 31, 2008, between J. Bond Clement and PetroQuest Energy, Inc. (incorporated herein by reference to Exhibit 10.20 to Form 10-K filed February 27, 2009).

†10.24 Executive Employment Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed May 10, 2012).

†10.25 Executive Employment Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed February 5, 2014).

†10.26 Form of Amended Termination Agreement between the Company and each of its executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, and J. Bond Clement (incorporated herein by reference to Exhibit 10.6 to Form 8-K filed January 6, 2009).

†10.27 Termination Agreement dated May 8, 2012 between PetroQuest Energy, Inc. and Tracy Price (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed May 10, 2012).

†10.28 Termination Agreement dated February 1, 2014 between PetroQuest Energy, Inc. and Edward E. Abels, Jr. (incorporated herein by reference to Exhibit 10.2 to Form 8-K filed February 5, 2014).

†10.29	Form of Indemnification Agreement between PetroQuest Energy, Inc. and each of its directors and executive officers, including Charles T. Goodson, W. Todd Zehnder, Arthur M. Mixon, III, , J. Bond Clement, Tracy Price, Edward E. Abels, Jr., William W. Rucks, IV, E. Wayne Nordberg, Michael L. Finch, W.J. Gordon, III and Charles F. Mitchell, II (incorporated herein by reference to Exhibit 10.21 to Form 10-K filed March 13, 2002).
10.30	Form of Surrender and Cancellation Agreement for Directors and Executive Officers (incorporated herein by reference to Exhibit 10.1 to Form 8-K filed on September 16, 2010).
10.31	Joint Development Agreement dated May 17, 2010, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.2 to Form 10-Q filed on August 5, 2010).
10.32	Second Amendment to the Joint Development Agreement dated February 24, 2012, among PetroQuest Energy, L.L.C., a Louisiana limited liability company, WSGP Gas Producing, LLC, a Delaware limited liability company, and NextEra Energy Gas Producing, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 10.22 to Form 10-K filed March 5, 2012).
14.1	Code of Business Conduct and Ethics (incorporated herein by reference to Exhibit 14.1 to Form 10-K filed March 8, 2006).
*21.1	Subsidiaries of the Company.
*23.1	Consent of Independent Registered Public Accounting Firm.
*23.2	Consent of Ryder Scott Company, L.P.
*31.1	Certification of Chief Executive Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
*31.2	Certification of Chief Financial Officer pursuant to Rule 13-a-14(a) / Rule 15d-14(a), promulgated under the Securities Exchange Act of 1934, as amended.
*32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Executive Officer.
*32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, of Chief Financial Officer.
*99.1	Reserve report letter as of December 31, 2013, as prepared by Ryder Scott Company, L.P.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definitions Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** The registrant agrees to furnish supplementally a copy of any omitted schedule to the Agreements to the SEC upon request.

† Management contract or compensatory plan or arrangement

(b) Exhibits. See Item 15 (a) (3) above.
(c) Financial Statement Schedules. None

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas used in this Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams issued by a state bordering on the Gulf of Mexico.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

Extension well. A well drilled to extend the limits of a known reservoir.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lead. A specific geographic area which, based on supporting geological, geophysical or other data, is deemed to have potential for the discovery of commercial hydrocarbons.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Ngl. Natural gas liquid.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells, as the case may be.

Possible reserves. Those additional reserves that are less certain to be recovered than probable reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Probable reserves. Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved oil and gas reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved properties. Properties with proved reserves.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology. A grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resources. Quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production.

Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved properties. Properties with no proved reserves

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 5, 2014.

PETROQUEST ENERGY, INC.

By: /s/ Charles T. Goodson
CHARLES T. GOODSON
Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 5, 2014.

By:	/s/ Charles T. Goodson CHARLES T. GOODSON	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)
By:	/s/ J. Bond Clement J. BOND CLEMENT	Executive Vice President, Chief Financial Officer, Treasurer (Principal Financial and Accounting Officer)
By:	/s/ W.J. Gordon, III W.J. GORDON, III	Director
By:	/s/ Michael L. Finch MICHAEL L. FINCH	Director
By:	/s/ Charles F. Mitchell, II, M.D. CHARLES F. MITCHELL, II, M.D.	Director
By:	/s/ E. Wayne Nordberg E. WAYNE NORDBERG	Director
By:	/s/ William W. Rucks, IV WILLIAM W. RUCKS, IV	Director

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
PetroQuest Energy, Inc.

We have audited the accompanying consolidated balance sheets of PetroQuest Energy, Inc. as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, cash flows and stockholders' equity for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of PetroQuest Energy, Inc. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), PetroQuest Energy, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated March 5, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 5, 2014

PETROQUEST ENERGY, INC.
Consolidated Balance Sheets
(Amounts in Thousands)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,153	$ 14,904
Revenue receivable	26,568	17,742
Joint interest billing receivable	26,556	42,238
Other receivable	—	9,208
Derivative asset	521	830
Prepaid drilling costs	477	1,698
Other current assets	8,132	2,964
Total current assets	71,407	89,584
Property and equipment:		
Oil and gas properties:		
Oil and gas properties, full cost method	2,035,899	1,734,477
Unevaluated oil and gas properties	98,387	71,713
Accumulated depreciation, depletion and amortization	(1,553,044)	(1,472,244)
Oil and gas properties, net	581,242	333,946
Other property and equipment	13,993	12,370
Accumulated depreciation of other property and equipment	(8,901)	(7,607)
Total property and equipment	586,334	338,709
Other assets, net of accumulated amortization of $5,689 and $4,240, respectively	9,449	5,110
Total assets	$ 667,190	$ 433,403
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable to vendors	$ 47,341	$ 58,960
Advances from co-owners	969	20,459
Oil and gas revenue payable	22,664	26,175
Accrued interest and preferred stock dividend	12,909	6,190
Asset retirement obligation	3,113	2,351
Derivative liability	1,617	233
Other accrued liabilities	8,924	6,535
Total current liabilities	97,537	120,903
Bank debt	75,000	50,000
10% Senior Notes	350,000	150,000
Asset retirement obligation	45,423	24,909
Other long-term liability	135	—
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.001 par value; authorized 5,000 shares; issued and outstanding 1,495 shares	1	1
Common stock, $.001 par value; authorized 150,000 shares; issued and outstanding 63,664 and 62,768 shares, respectively	64	63
Paid-in capital	280,711	276,534
Accumulated other comprehensive income (loss)	(1,096)	521
Accumulated deficit	(180,585)	(189,528)
Total stockholders' equity	99,095	87,591
Total liabilities and stockholders' equity	$ 667,190	$ 433,403

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Operations
(Amounts in Thousands, Except Per Share Data)

	Year Ended December 31, 2013	2012	2011
Revenues:			
Oil and gas sales	$ 182,804	$ 141,433	$ 160,486
Gas gathering revenue	66	158	214
	182,870	141,591	160,700
Expenses:			
Lease operating expenses	43,743	38,890	38,571
Production taxes	3,950	885	3,100
Depreciation, depletion and amortization	71,445	60,689	58,243
Ceiling test write-down	—	137,100	18,907
General and administrative	26,512	22,957	20,436
Accretion of asset retirement obligation	1,753	2,078	2,049
Interest expense	21,886	9,808	9,648
	169,289	272,407	150,954
Other income (expense):			
Other income (expense)	588	606	(1,008)
Derivative income (expense)	233	(233)	—
	821	373	(1,008)
Income (loss) from operations	14,402	(130,443)	8,738
Income tax expense (benefit)	320	1,636	(1,810)
Net income (loss)	14,082	(132,079)	10,548
Preferred stock dividend	5,139	5,139	5,139
Net income (loss) available to common stockholders	$ 8,943	$ (137,218)	$ 5,409
Earnings per common share:			
Basic			
Net income (loss) per share	$ 0.14	$ (2.20)	$ 0.08
Diluted			
Net income (loss) per share	$ 0.14	$ (2.20)	$ 0.08
Weighted average number of common shares:			
Basic	63,054	62,459	61,937
Diluted	63,208	62,459	62,325

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Comprehensive Income
(Amounts in Thousands)

	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Net income (loss)	$ 14,082	$ (132,079)	$ 10,548
Change in fair value of derivatives, net of income tax (expense) benefit of $309, $2,079 and ($2,388) respectively	(1,617)	(3,510)	5,120
Comprehensive income (loss)	$ 12,465	$ (135,589)	$ 15,668

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
Consolidated Statements of Cash Flows
(Amounts in Thousands)

	Year Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$ 14,082	$ (132,079)	$ 10,548
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred tax expense (benefit)	320	1,636	(1,810)
Depreciation, depletion and amortization	71,445	60,689	58,243
Ceiling test write-down	—	137,100	18,907
Accretion of asset retirement obligation	1,753	2,078	2,049
Share based compensation expense	4,216	6,910	4,833
Amortization costs and other	1,473	881	625
Non-cash derivative expense (benefit)	(233)	233	—
Payments to settle asset retirement obligations	(3,335)	(2,627)	(905)
Changes in working capital accounts:			
Revenue receivable	(8,826)	(1,882)	(2,474)
Prepaid drilling and pipe costs	1,221	4,479	5,530
Joint interest billing and other receivable	15,685	3,981	(35,252)
Accounts payable and accrued liabilities	(12,865)	20,916	34,599
Advances from co-owners	(19,490)	(13,408)	25,904
Other	(5,592)	(316)	(1,621)
Net cash provided by operating activities	59,854	88,591	119,176
Cash flows used in investing activities:			
Investment in oil and gas properties	(298,824)	(147,771)	(194,536)
Investment in other property and equipment	(1,679)	(1,743)	(1,286)
Sale of oil and gas properties	19,913	837	14,000
Sale of unevaluated oil and gas properties	487	8,889	28,461
Net cash used in investing activities	(280,103)	(139,788)	(153,361)
Cash flows used in financing activities:			
Net payments for share based compensation	(38)	(981)	(1,133)
Deferred financing costs	(320)	(42)	(517)
Payment of preferred stock dividend	(5,139)	(5,139)	(5,139)
Proceeds from bank borrowings	73,000	102,500	22,000
Repayment of bank borrowings	(48,000)	(52,500)	(22,000)
Proceeds from issuance of 10% Senior Notes	200,000	—	—
Costs to issue 10% Senior Notes	(5,005)	—	—
Net cash provided by (used in) financing activities	214,498	43,838	(6,789)
Net decrease in cash and cash equivalents	(5,751)	(7,359)	(40,974)
Cash and cash equivalents, beginning of period	14,904	22,263	63,237
Cash and cash equivalents, end of period	$ 9,153	$ 14,904	$ 22,263
Supplemental disclosure of cash flow information:			
Cash paid during the period for:			
Interest	$ 20,101	$ 16,026	$ 16,017
Income taxes	$ 12	$ 105	$ 51

See accompanying Notes to Consolidated Financial Statements.

PetroQuest Energy Inc.
Consolidated Statements of Stockholders' Equity
(Amounts in Thousands)

	Common Stock	Preferred Stock	Paid-In Capital	Other Comprehensive Income (Loss)	Accumulated Deficit	Total Stockholders' Equity
December 31, 2010	$ 62	$ 1	$ 266,907	$ (1,089)	$ (57,719)	$ 208,162
Options exercised	—	—	234	—	—	234
Retirement of shares upon vesting of restricted stock	—	—	(1,368)	—	—	(1,368)
Share-based compensation expense	—	—	4,833	—	—	4,833
Derivative fair value adjustment, net of tax	—	—	—	5,120	—	5,120
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	10,548	10,548
December 31, 2011	$ 62	$ 1	$ 270,606	$ 4,031	$ (52,310)	$ 222,390
Options exercised	—	—	260	—	—	260
Retirement of shares upon vesting of restricted stock	1	—	(1,242)	—	—	(1,241)
Share-based compensation expense	—	—	6,910	—	—	6,910
Derivative fair value adjustment, net of tax	—	—	—	(3,510)	—	(3,510)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net loss	—	—	—	—	(132,079)	(132,079)
December 31, 2012	$ 63	$ 1	$ 276,534	$ 521	$ (189,528)	$ 87,591
Options exercised	—	—	731	—	—	731
Retirement of shares upon vesting of restricted stock	1	—	(1,057)	—	—	(1,056)
Share-based compensation expense	—	—	4,216	—	—	4,216
Issuance of shares under employee stock purchase plan	—	—	287	—	—	287
Derivative fair value adjustment, net of tax	—	—	—	(1,617)	—	(1,617)
Preferred stock dividend	—	—	—	—	(5,139)	(5,139)
Net income	—	—	—	—	14,082	14,082
December 31, 2013	$ 64	$ 1	$ 280,711	$ (1,096)	$ (180,585)	$ 99,095

See accompanying Notes to Consolidated Financial Statements.

PETROQUEST ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Summary of Significant Accounting Policies

PetroQuest Energy, Inc. (a Delaware Corporation) ("PetroQuest") is an independent oil and gas company headquartered in Lafayette, Louisiana with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma. It is engaged in the exploration, development, acquisition and operation of oil and gas properties in Oklahoma and Texas as well as onshore and in the shallow waters offshore the Gulf Coast Basin.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of PetroQuest and its subsidiaries, PetroQuest Energy, L.L.C., PetroQuest Oil & Gas, L.L.C, Pittrans, Inc. and TDC Energy LLC (collectively, the "Company"). All intercompany accounts and transactions have been eliminated. Certain prior period amounts have been reclassified to conform to current year presentation.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

The Company utilizes the full cost method of accounting, which involves capitalizing all acquisition, exploration and development costs incurred for the purpose of finding oil and gas reserves including the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. The Company also capitalizes the portion of general and administrative costs that can be directly identified with acquisition, exploration or development of oil and gas properties. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold, or management determines these costs to have been impaired. Interest is capitalized on unevaluated property costs. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to accumulated depreciation, depletion and amortization with no gain or loss recognized.

Depreciation, depletion and amortization of oil and gas properties is computed using the unit-of-production method based on estimated proved reserves. All costs associated with evaluated oil and gas properties, including an estimate of future development costs associated therewith, are included in the depreciable base. The costs of investments in unevaluated properties are excluded from this calculation until the related properties are evaluated, proved reserves are established or the properties are determined to be impaired. Proved oil and gas reserves are estimated annually by independent petroleum engineers.

The capitalized costs of proved oil and gas properties cannot exceed the present value of the estimated net future cash flows from proved reserves based on historical first of the month average twelve-month oil, gas and natural gas liquid prices, including the effect of hedges in place (the full cost ceiling). If the capitalized costs of proved oil and gas properties exceed the full cost ceiling, the Company is required to write-down the value of its oil and gas properties to the full cost ceiling amount. The Company follows the provisions of Staff Accounting Bulletin ("SAB") No. 106, regarding the application of ASC Topic 410-20 by companies following the full cost accounting method. SAB No. 106 indicates that estimated future dismantlement and abandonment costs that are recorded on the balance sheet are to be included in the costs subject to the full cost ceiling limitation. The estimated future cash outflows associated with settling the recorded asset retirement obligations should be excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test.

Cash and Cash Equivalents

The Company considers all highly liquid investments with a stated maturity of three months or less to be cash and cash equivalents. The majority of the Company's cash and cash equivalents are in overnight securities made through its commercial bank accounts, which result in available funds the next business day.

Accounts Receivable

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. As of December 31, 2013 and 2012, the Company had $0.1 million recorded related to an allowance for doubtful accounts on its joint interest billing receivable. At December 31, 2012, $9.2 million was recorded as an other receivable relative to net proceeds from the sale of the Company's non-operated Arkansas assets, which were collected in January 2013.

Other Current Assets

Other current assets at December 31, 2013 and 2012 included $3.1 million and $0.4 million, respectively, related to an insurance receivable related to operations in our Oklahoma acreage.

Other Property and Equipment

During 2006, the Company acquired a gas gathering system used in the transportation of natural gas. The costs related to this system are depreciated on a straight line basis over the estimated remaining useful life, generally 14 years. The costs related to other furniture and fixtures are depreciated on a straight line basis over estimated useful lives ranging from 3-8 years. During 2012, a field office servicing the Company's Oklahoma assets was built and is being depreciated over 39 years.

Other Assets

Other assets at December 31, 2013 and 2012 included $7.4 million and $3.5 million, respectively, related to deferred financing costs, which are amortized over the life of the related debt. Additionally, other assets includes the long-term portion of a severance tax receivable from the state of Oklahoma, which is payable over the next 1.5 years.

Other Accrued Liabilities

Other accrued liabilities at December 31, 2013 and 2012 included $6.5 million and $5.7 million, respectively, related to accrued incentive compensation costs.

Income Taxes

The Company accounts for income taxes in accordance with ASC Topic 740. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures are capitalized and depreciated, depleted and amortized on the unit-of-production method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, the Company may use certain provisions of the Internal Revenue Code which allow capitalization of intangible drilling costs. Other financial and income tax reporting differences occur primarily as a result of statutory depletion. Deferred tax assets are assessed for realizabilty and a valuation allowance is established for any portion of the asset for which it is more likely than not will not be realized.

Revenue Recognition

The Company records natural gas and oil revenue under the sales method of accounting. Under the sales method, the Company recognizes revenues based on the amount of natural gas or oil sold to purchasers, which may differ from the amounts to which the Company is entitled based on its interest in the properties. Gas balancing obligations as of December 31, 2013 and 2012 were not significant.

Certain Concentrations

The Company's production is sold on month to month contracts at prevailing prices. The Company attempts to diversify its sales among multiple purchasers and obtain credit protection such as letters of credit and parental guarantees when necessary.

The following table identifies customers from whom the Company derived 10% or more of its net oil and gas revenues during the years presented. Based on the availability of other customers, the Company does not believe the loss of any of these customers would have a significant effect on its business or financial condition.

	Year Ended December 31,		
	2013	2012	2011
Shell Trading Co.	35%	30%	18%
Laclede Energy	14%	17%	20%
Unimark, LLC	14%	(a)	(a)
JP Morgan Ventures Energy	(a)	12%	(a)
Texon LP	(a)	(a)	15%
Gary Williams	(a)	(a)	11%

(a) Less than 10 percent

Derivative Instruments

Under ASC Topic 815, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in stockholders' equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is effective. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense). The Company does not offset fair value amounts recognized for derivative instruments. The cash settlements of hedges are recorded as adjustments to oil and gas sales. Oil and gas revenues include additions related to the net settlement of hedges totaling $0.9 million, $9.1 million and $2.4 million during 2013, 2012 and 2011, respectively.

The Company's hedges are specifically referenced to NYMEX prices for oil and natural gas. The effectiveness of hedges is evaluated at the time the contracts are entered into, as well as periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices received from the designated production. Through this analysis, the Company is able to determine if a high correlation exists between the prices received for its designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2013, the Company's derivative instruments were designated as effective cash flow hedges. See Note 7 for further discussion of the Company's derivative instruments.

Note 2—Acquisition

On July 3, 2013, the Company acquired certain shallow water Gulf of Mexico shelf oil and gas properties (the "Acquired Assets"), for an aggregate cash purchase price of $188.8 million, reflecting an effective date of January 1, 2013 (collectively, the "Gulf of Mexico Acquisition"). The Acquired Assets included 16 gross wells located on seven platforms.

The aggregate cash purchase price of the Gulf of Mexico Acquisition was financed with the net proceeds from the sale of $200 million in aggregate principal amount of the Company's 10% Senior Notes due 2017. The Company subsequently registered the 10% Senior Notes due 2017 in an exchange offer completed in September 2013 (the "New Notes"). The New Notes have terms that, subject to certain exceptions, are substantially identical to the Company's existing $150 million aggregate principal amount of 10% Senior Notes due 2017. In connection with the transaction, the Company recorded $5 million of deferred financing costs related to the New Notes and incurred $4.0 million of acquisition-related costs, including $2.6 million related to a bridge commitment fee, which were recognized as general and administrative expenses.

The Gulf of Mexico Acquisition is accounted for under the purchase method of accounting, which involves determining the fair value of the assets acquired and liabilities assumed. The fair value of proved and unevaluated oil and gas properties was estimated using the income approach based on estimated reserve quantities, costs to produce and develop reserves, and forward prices for oil and gas, which represent Level 2 and Level 3 inputs. Asset retirement obligations were determined in accordance with applicable accounting standards.

The following table summarizes the acquisition date fair values of the net assets acquired (in thousands):

Oil and gas properties	$	192,067
Unevaluated oil and gas properties		12,033
Asset retirement obligations		(15,319)
Net assets acquired	$	188,781

The following unaudited summary pro forma financial information for the twelve month periods ended December 31, 2013 and 2012 has been prepared to give effect to the Gulf of Mexico Acquisition as if it had occurred on January 1, 2012. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2012 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following unaudited pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities and other factors. Amounts are presented in thousands, except per share amounts.

		Twelve Months Ended December 31,		
		2013		2012
Revenues	$	215,666	$	187,104
Income (Loss) from Operations		19,858		(135,406)
Net Income (Loss) available to common stockholders		14,399		(142,181)
Basic Earnings (loss) per Share	$	0.22	$	(2.28)
Diluted Earnings (loss) per Share	$	0.22	$	(2.28)

Note 3—Convertible Preferred Stock

The Company has 1,495,000 shares of 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") outstanding.

The following is a summary of certain terms of the Series B Preferred Stock:

Dividends. The Series B Preferred Stock accumulates dividends at an annual rate of 6.875% for each share of Series B Preferred Stock. Dividends are cumulative from the date of first issuance and, to the extent payment of dividends is not prohibited by the Company's debt agreements, assets are legally available to pay dividends and the Company's board of directors or an authorized committee of the board declares a dividend payable, the Company pays dividends in cash, every quarter.

Mandatory conversion. The Company may, at its option, cause shares of the Series B Preferred Stock to be automatically converted at the applicable conversion rate, but only if the closing sale price of the Company's common stock for 20 trading days within a period of 30 consecutive trading days ending on the trading day immediately preceding the date the Company gives the conversion notice equals or exceeds 130% of the conversion price in effect on each such trading day.

Conversion rights. Each share of Series B Preferred Stock may be converted at any time, at the option of the holder, into 3.4433 shares of the Company's common stock (which is based on an initial conversion price of approximately $14.52 per share of common stock, subject to adjustment) plus cash in lieu of fractional shares, subject to the Company's right to settle all or a portion of any such conversion in cash or shares of the Company's common stock. If the Company elects to settle all or any portion of its conversion obligation in cash, the conversion value and the number of shares of the Company's common stock it will deliver upon conversion (if any) will be based upon a 20 trading day averaging period.

Upon any conversion, the holder will not receive any cash payment representing accumulated and unpaid dividends on the Series B Preferred Stock, whether or not in arrears, except in limited circumstances. The conversion rate is equal to $50 divided by the conversion price at the time. The conversion price is subject to adjustment upon the occurrence of certain events. The conversion price on the conversion date and the number of shares of the Company's common stock, as applicable, to be delivered upon conversion may be adjusted if certain events occur.

Note 4—Earnings Per Share

A reconciliation between the basic and diluted earnings per share computations (in thousands, except per share amounts) is as follows:

For the Year Ended December 31, 2013	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	8,943	63,054		
Attributable to participating securities		(257)	—		
BASIC EPS	$	8,686	63,054	$	0.14
Net income available to common stockholders	$	8,943	63,054		
Effect of dilutive securities:					
Stock options		—	154		
Attributable to participating securities		(256)	—		
DILUTED EPS	$	8,687	63,208	$	0.14

For the Year Ended December 31, 2012	Loss (Numerator)		Shares (Denominator)	Per Share Amount	
BASIC EPS					
Net loss available to common stockholders	$	(137,218)	62,459	$	(2.20)
Effect of dilutive securities:					
Stock options		—	—		
Restricted stock		—	—		
DILUTED EPS	$	(137,218)	62,459	$	(2.20)

For the Year Ended December 31, 2011	Income (Numerator)		Shares (Denominator)	Per Share Amount	
Net income available to common stockholders	$	5,409	61,937		
Attributable to participating securities		(154)	—		
BASIC EPS	$	5,255	61,937	$	0.08
Net income available to common stockholders	$	5,409	61,937		
Effect of dilutive securities:					
Stock options		—	388		
Attributable to participating securities		(153)	—		
DILUTED EPS	$	5,256	62,325	$	0.08

Common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 5.1 million shares during 2013 and 2011 were not included in the computation of diluted earnings per share because the inclusion would have been anti-dilutive. Options to purchase 1.2 million and 0.1 million shares of common stock were outstanding during the year ended December 31, 2013 and 2011, respectively, and were not included in the computation of diluted earnings per share because the options' exercise prices were in excess of the average market price of the common shares.

An aggregate of 0.9 million shares of common stock representing options to purchase common stock and unvested shares of restricted common stock and common shares issuable upon the assumed conversion of the Series B Preferred Stock totaling 5.1 million shares were not included in the computation of diluted earnings per share for the year ended December 31, 2012, because the inclusion would have been anti-dilutive as a result of the net loss reported for the period.

Note 5—Share-Based Compensation

Share-based compensation expense is reflected as a component of the Company's general and administrative expense. A detail of share-based compensation expense for the periods ended December 31, 2013, 2012 and 2011 is as follows (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Stock options:			
Incentive Stock Options	$ 310	$ 786	$ 493
Non-Qualified Stock Options	222	660	703
Restricted stock	3,684	5,464	3,637
Restricted stock units	1,611	277	—
Share-based compensation	$ 5,827	$ 7,187	$ 4,833

During the years ended December 31, 2013, 2012 and 2011, the Company recorded income tax benefits of approximately $1.8 million, $2.3 million and $1.6 million, respectively, related to share-based compensation expense recognized during those periods. Any excess tax benefits from the vesting of restricted stock and the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and the Company has net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for any periods presented.

At December 31, 2013, the Company had $6.8 million of unrecognized compensation cost related to unvested restricted stock and stock options. This amount will be recognized as compensation expense over a weighted average period of approximately three years.

Stock Options

Stock options generally vest equally over a three-year period, must be exercised within 10 years of the grant date and may be granted only to employees, directors and consultants. The exercise price of each option may not be less than 100% of the fair market value of a share of common stock on the date of grant. Upon a change in control of the Company, all outstanding options become immediately exercisable.

The Company computes the fair value of its stock options using the Black-Scholes option-pricing model assuming a stock option forfeiture rate and expected term based on historical activity and expected volatility computed using historical stock price fluctuations on a weekly basis for a period of time equal to the expected term of the option. The Company recognizes compensation expense using the accelerated expense attribution method over the vesting period. Periodically, the Company adjusts compensation expense based on the difference between actual and estimated forfeitures.

The following table outlines the assumptions used in computing the fair value of stock options granted during 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
Dividend yield	—%	—%	—%
Expected volatility	79.6% - 79.8%	79.2% - 79.6%	78.5% - 79.7%
Risk-free rate	0.9% - 1.815%	0.8% - 1.1%	1.1% - 2.2%
Expected term	6 years	6 years	6 years
Forfeiture rate	5.0%	5.0%	5.0%
Stock options granted (1)	395,642	125,487	395,280
Wgtd. avg. grant date fair value per share	$ 2.91	$ 3.71	$ 5.09
Fair value of grants (1)	$ 1,150,000	$ 465,000	$ 2,011,000

(1) Prior to applying estimated forfeiture rate

The following table details stock option activity during the year ended December 31, 2013:

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Remaining Life	Aggregate Intrinsic Value (000's)
Outstanding at beginning of year	1,924,941	$ 5.61		
Granted	395,642	4.22		
Expired/cancelled/forfeited	(120,090)	7.22		
Exercised	(308,000)	2.81		
Outstanding at end of year	1,892,493	5.67	5.8 years	$ 360
Options exercisable at end of year	1,317,795	$ 5.99	4.3 years	$ 324
Options expected to vest	545,963	4.95	9.1 years	$ 34

The total fair value of stock options that vested during the years ended December 31, 2013, 2012 and 2011 was $0.8 million, $1.7 million and $1.1 million, respectively. The intrinsic value of stock options exercised was immaterial for all periods presented.

The following table summarizes information regarding stock options outstanding at December 31, 2013:

Range of Exercise Price	Options Outstanding 12/31/2013	Wgtd. Avg. Remaining Contractual Life	Wgtd. Avg. Exercise Price	Options Exercisable 12/31/2013	Wgtd. Avg. Exercise Price
$2.24—$4.48	684,141	5.4 years	$3.75	316,499	$3.26
$4.48—$6.72	389,320	5.1 years	$5.64	275,997	$5.78
$6.72—$8.96	809,032	6.5 years	$7.26	715,299	$7.22
$8.96—$11.20	10,000	2.1 years	$9.99	10,000	$9.99
	1,892,493	5.8 years	$5.67	1,317,795	$5.99

Restricted Stock

The Company computes the fair value of its service based restricted stock using the closing price of the Company's stock at the date of grant, and compensation expense is recognized assuming a 5% estimated forfeiture rate. Restricted stock granted to employees prior to 2011 generally vests over a five-year period with one-fourth vesting on each of the first, second, third and fifth anniversaries of the date of the grant. No portion of the restricted stock vests on the fourth anniversary of the date of the grant. Prior to 2013, restricted stock granted to directors generally vested evenly over a three year period. In 2013, restricted stock granted to directors vests one year from the date of grant, to align with their term on the board. Beginning January 1, 2011, restricted stock granted to employees generally vests evenly over a three year period. Upon a change in control of the Company, all outstanding shares of restricted stock will become immediately vested. Compensation expense related to restricted stock is recognized over the vesting period using the accelerated expense attribution method.

The following table details restricted stock activity during 2013:

	Number of Shares	Wgtd. Avg. Fair Value per Share
Outstanding at beginning of year	1,805,829	$ 6.28
Granted	1,078,000	4.18
Expired/cancelled/forfeited	(186,926)	5.85
Lapse of restrictions	(770,452)	6.95
Outstanding at December 31, 2013	1,926,451	$ 4.88

The weighted average grant date fair value of restricted stock granted during the years ended December 31, 2013, 2012 and 2011 was $4.18, $5.24 and $7.54, respectively, per share. The total fair value of restricted stock that vested during the years ended December 31, 2013, 2012 and 2011 was $5.4 million, $4.7 million and $5.6 million, respectively. At December 31, 2013, the weighted average remaining life of restricted stock outstanding was two years and the intrinsic value of restricted stock outstanding, using the closing stock price on December 31, 2013, was $8.3 million.

Restricted Stock Units

The Company granted restricted stock units ("RSUs") to employees during 2013 and 2012. The RSUs vest in one-third increments on each of the first, second and third anniversaries of the date of grant. Cash payment will be made to employees on each vesting date based upon the Company's closing stock price on that date. Upon change in control of the Company, all of the RSUs will immediately vest. Compensation expense is recognized on a straight line basis over the vesting period assuming a 5% estimated forfeiture rate. The Company computes the fair value of the RSUs using the closing price of the Company's stock for purposes of determining the amount of the liability at the end of each period. During 2013 the Company paid $1.6 million for units that vested during the period. As of December 31, 2013, the Company had a liability for RSUs outstanding and expected to vest in the amount of $0.3 million and an intrinsic value on all RSUs outstanding of $5.5 million.

	Number of Shares
Outstanding at beginning of year	1,096,158
Granted	703,777
Expired/Cancelled/Forfeited	(141,378)
Vested/Paid	(385,140)
Outstanding at December 31, 2013	1,273,417

Note 6—Asset Retirement Obligation

The Company accounts for asset retirement obligations in accordance with ASC Topic 410-20, which requires recording the fair value of an asset retirement obligation associated with tangible long-lived assets in the period incurred. Asset retirement obligations associated with long-lived assets included within the scope of ASC Topic 410-20 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. The Company has legal obligations to plug, abandon and dismantle existing wells and facilities that it has acquired and constructed.

The following table describes all changes to the Company's asset retirement obligation liability (in thousands):

	Year Ended December 31, 2013	Year Ended December 31, 2012
Asset retirement obligation, beginning of period	$ 27,260	$ 30,427
Liabilities assumed	15,319	—
Liabilities incurred	498	892
Liabilities settled	(3,335)	(2,627)
Accretion expense	1,753	2,078
Revisions in estimated cash flows	7,041	(3,510)
Asset retirement obligation, end of period	48,536	27,260
Less: current portion of asset retirement obligation	(3,113)	(2,351)
Long-term asset retirement obligation	$ 45,423	$ 24,909

Note 7—Derivative Instruments

The Company seeks to reduce its exposure to commodity price volatility by hedging a portion of its production through commodity derivative instruments. When the conditions for hedge accounting are met, the Company may designate its commodity derivatives as cash flow hedges. The changes in fair value of derivative instruments that qualify for hedge accounting treatment are recorded in other comprehensive income (loss) until the hedged oil, natural gas or natural gas liquids (Ngl) quantities are produced. If a hedge becomes ineffective because the hedged production does not occur, or the hedge otherwise does not qualify for hedge accounting treatment, the changes in the fair value of the derivative are recorded in the income statement as derivative income (expense). At December 31, 2013, the Company designated all of its derivative instruments as effective cash flow hedges. At December 31, 2012, the Company designated all derivative instruments except its three-way collar as effective cash flow hedges.

Oil and gas sales include additions (reductions) related to the settlement of gas hedges of $1,098,000, $6,846,000 and $2,609,000, Ngl hedges of $61,000, $722,000 and zero, and oil hedges of ($232,000), $1,529,000 and ($192,000), for the years ended December 31, 2013, 2012 and 2011, respectively.

As of December 31, 2013, the Company had entered into the following gas hedge contracts:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
2014	Swap	40,000 Mmbtu	$4.12
Crude Oil:			
January - June 2014	Swap (LLS)	450 Bbls	$100.58
2014	Swap (LLS)	400 Bbls	$101.15
2014	Swap (WTI)	350 Bbls	$93.26

LLS - Louisiana Light Sweet

WTI - West Texas Intermediate

At December 31, 2013, the Company had recognized a net liability of approximately $1.1 million related to the estimated fair value of these derivative instruments. Based on estimated future commodity prices as of December 31, 2013, the Company would realize a $0.7 million loss, net of taxes, during the next 12 months. These losses are expected to be reclassified to oil and gas sales based on the schedule of oil and gas volumes stipulated in the derivative contracts.

During January 2014, the Company entered into the following additional hedge contract accounted for as a cash flow hedge:

Production Period	Instrument Type	Daily Volumes	Weighted Average Price
Natural Gas:			
March - December 2014	Swap	5,000 Mmbtu	$4.285

Derivatives designated as hedging instruments:

The following tables reflect the fair value of the Company's effective cash flow hedges in the consolidated financial statements (in thousands):

Effect of Cash Flow Hedges on the Consolidated Balance Sheet at December 31, 2013 and December 31, 2012:

	Commodity Derivatives		
Period	Balance Sheet Location		Fair Value
December 31, 2013	Derivative asset	$	521
December 31, 2013	Derivative liability	$	(1,617)
December 31, 2012	Derivative asset	$	830

Effect of Cash Flow Hedges on the Consolidated Statement of Operations for the twelve months ended December 31, 2013, 2012 and 2011:

Instrument	Amount of Gain (Loss) Recognized in Other Comprehensive Income		Location of Gain Reclassified into Income	Amount of Gain Reclassified into Income	
Commodity Derivatives at December 31, 2013	$	(1,617)	Oil and gas sales	$	994
Commodity Derivatives at December 31, 2012	$	(3,510)	Oil and gas sales	$	9,097
Commodity Derivatives at December 31, 2011	$	5,120	Oil and gas sales	$	2,417

Derivatives not designated as hedging instruments:

The Company's three-way collar contract for 2013 gas production was not designated as an effective cash flow hedge and therefore both realized and unrealized (mark-to-market) gains or losses on this derivative were recorded as derivative expense (income) in the statement of operations. The following tables reflect the fair value of this contract in the consolidated financial statements (in thousands):

Effect of Non-designated Derivative Instrument on the Consolidated Balance Sheet at December 31, 2012:

	Commodity Derivatives		
Period	Balance Sheet Location	Fair Value	
December 31, 2012	Derivative liability	$	(233)

Effect of Non-designated Derivative Instrument on the Consolidated Statement of Operations for the twelve months ended December 31, 2013, 2012 and 2011:

Instrument	Amount of Gain (Loss) Recognized in Derivative Income (Expense)	
Commodity Derivatives at December 31, 2013	$	233
Commodity Derivatives at December 31, 2012	$	(233)
Commodity Derivatives at December 31, 2011	$	—

Note 8 - Fair Value Measurements

ASC Topic 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

- Level 1: valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;
- Level 2: valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;
- Level 3: valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

The Company classifies its commodity derivatives based upon the data used to determine fair value. The Company's derivative instruments at December 31, 2013 were in the form of swaps based on NYMEX pricing for oil and natural gas. The fair value of these derivatives is derived using an independent third-party's valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. As a result, the Company designates its commodity derivatives as Level 2 in the fair value hierarchy.

The following table summarizes the Company's assets (liabilities) that are subject to fair value measurement on a recurring basis as of December 31, 2013 and December 31, 2012 (in thousands):

Instrument	Fair Value Measurements Using Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity Derivatives:			
At December 31, 2013	$ —	$ (1,096)	$ —
At December 31, 2012	$ —	$ 597	$ —

The fair value of the Company's cash and cash equivalents and variable-rate bank debt approximated book value at December 31, 2013 and 2012. As of December 31, 2013, the fair value of the Company's $350 million 10% Senior Notes due 2017 (the "Notes") was approximately $364.0 million. As of December 31, 2012, the fair value of the Company's $150 million in principal amount of Notes was approximately $155.3 million. The fair value of the Notes was determined based upon a market quote provided by an independent broker, which represents a Level 2 input.

Note 9—Long-Term Debt

On August 19, 2010, PetroQuest issued $150 million in principal amount of Notes (the "Existing Notes") in a public offering. On July 3, 2013, PetroQuest issued an additional $200 million in aggregate principal amount of Notes. PetroQuest subsequently registered the Notes in an exchange offer completed in September 2013 (the "New Notes" and together with the Existing Notes, the "Notes"). The New Notes were issued at a price equal to 100% of their face value plus accrued interest from March 1, 2013. The New Notes have terms that, subject to certain exceptions, are substantially identical to the Existing Notes. The net proceeds from the offering were used to finance the $188.8 million aggregate cash purchase price of the Gulf of Mexico Acquisition, which also closed on July 3, 2013. The Notes are guaranteed by certain of PetroQuest's subsidiaries. The subsidiary guarantors are 100% owned by PetroQuest and all guarantees are full and unconditional and joint and several. PetroQuest has no independent assets or operations and the subsidiaries not providing guarantees are minor, as defined by the rules of the Securities and Exchange Commission.

The Notes have numerous covenants including restrictions on liens, incurrence of indebtedness, asset sales, dividend payments and other restricted payments. Interest is payable semi-annually on March 1 and September 1. At December 31, 2013, $11.7 million had been accrued in connection with the March 1, 2014 interest payment and the Company was in compliance with all of the covenants contained in the Notes.

The Company and PetroQuest Energy, L.L.C. (the "Borrower") have a Credit Agreement (as amended, the "Credit Agreement") with JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A., Capital One, N.A. and IberiaBank. The Credit Agreement provides the Borrower with a $300 million revolving credit facility that permits borrowings based on the commitments of the lenders and the available borrowing base as determined in accordance with the Credit Agreement. The Credit Agreement also allows the Borrower to use up to $25 million of the borrowing base for letters of credit. The credit facility matures on October 3, 2016. As of December 31, 2013, the Borrower had $75.0 million of borrowings outstanding under (and no letters of credit issued pursuant to) the Credit Agreement.

The borrowing base under the Credit Agreement is based upon the valuation of the reserves attributable to the Borrower's oil and gas properties as of January 1 and July 1 of each year. On July 3, 2013 the borrowing base was increased from $150 million to $200 million (subject to the aggregate commitments of the lenders then in effect). As of December 31, 2013, the aggregate commitments of the lenders is $150 million and can be increased to up to $300 million by either adding new lenders or increasing the commitments of existing lenders, subject to certain conditions. The next borrowing base redetermination is scheduled to occur by March 31, 2014. The Borrower or the lenders may request two additional borrowing base redeterminations each year. Each time the borrowing base is to be re-determined, the administrative agent under the Credit Agreement will propose a new borrowing base as it deems appropriate in its sole discretion, which must be approved by all lenders if the borrowing base is to be increased, or by lenders holding two-thirds of the amounts outstanding under the Credit Agreement if the borrowing base remains the same or is reduced.

The Credit Agreement is secured by a first priority lien on substantially all of the assets of the Company and its subsidiaries, including a lien on all equipment and at least 80% of the aggregate total value of the Borrower's oil and gas properties. Outstanding balances under the Credit Agreement bear interest at the alternate base rate ("ABR") plus a margin (based on a sliding scale of 0.5% to 1.5% depending on total commitments) or the adjusted LIBO rate ("Eurodollar") plus a margin (based on a sliding scale of 1.5% to 2.5% depending on total commitments). The alternate base rate is equal to the highest of (i) the JPMorgan Chase prime rate, (ii) the Federal Funds Effective Rate plus 0.5% or (iii) the adjusted LIBO rate plus 1%. For the purposes of the definition of alternative base rate only, the adjusted LIBO rate is equal to the rate at which dollar deposits of $5,000,000 with a one month maturity are offered by the principal London office of JPMorgan Chase Bank, N.A. in immediately available funds in the London interbank market. For all other purposes, the adjusted LIBO rate is equal to the rate at which Eurodollar deposits in the London interbank market for one, two, three or six months (as selected by the Borrower) are quoted, as adjusted for statutory reserve requirements for Eurocurrency liabilities. Outstanding letters of credit are charged a participation fee at a per annum rate equal to the margin applicable to Eurodollar loans, a fronting fee and customary administrative fees. In addition, the Borrower pays commitment fees based on a sliding scale of 0.375% to 0.5% depending on total commitments.

The Company and its subsidiaries are subject to certain restrictive financial covenants under the Credit Agreement, including a maximum ratio of total debt to EBITDAX, determined on a rolling four quarter basis, of 3.5 to 1.0, and a minimum ratio of consolidated current assets to consolidated current liabilities of 1.0 to 1.0, all as defined in the Credit Agreement. The Credit Agreement also includes customary restrictions with respect to debt, liens, dividends, distributions and redemptions, investments, loans and advances, nature of business, international operations and foreign subsidiaries, leases, sale or discount of receivables, mergers or consolidations, sales of properties, transactions with affiliates, negative pledge agreements, gas imbalances and swap agreements. However, the Credit Agreement permits the Borrower to repurchase up to $10 million of the Company's common stock during the term of the Credit Agreement, as long as after giving effect to such repurchase the Borrower's Liquidity (as defined therein) is greater than 20% of the total commitments of the lenders at such time. As of December 31, 2013, the Borrower was in compliance with all of the covenants contained in the Credit Agreement.

Note 10—Related Party Transactions

Two of the Company's senior officers, Charles T. Goodson and Stephen H. Green, or their affiliates, are working interest owners and overriding royalty interest owners and E. Wayne Nordberg and William W. Rucks, IV, two of the Company's directors, are working interest owners in certain properties operated by the Company or in which the Company also holds a working interest. As working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners, they are entitled to receive their proportionate share of revenues in the normal course of business.

During 2013, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson and Green, or their affiliates, in the amounts of $92,000 and $269,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues disbursed in the amount of $200. During 2012, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson, Green and Nordberg, or their affiliates, in the amounts of $104,000, $387,000 and $100, respectively. During 2011, in their capacities as working interest owners or overriding royalty interest owners, revenues, net of costs, were disbursed to Messrs. Goodson and Green, or their affiliates, in the amounts of $293,000, $546,000, respectively, and with respect to Mr. Nordberg, costs billed exceeded revenues in the amount of $9. No such disbursements were made to Mr. Rucks during any reported period. With respect to Mr. Goodson, gross revenues attributable to interests, properties or participation rights held by him prior to joining the Company as an officer and director on September 1, 1998 represent all of the gross revenue received by him during these periods.

In its capacity as operator, the Company incurs drilling and operating costs that are billed to its partners based on their respective working interests. At December 31, 2013, the Company's joint interest billing receivable included approximately $19,000 from the related parties discussed above or their affiliates, attributable to their share of costs. This represents less than 1% of the Company's total joint interest billing receivable at December 31, 2013.

Periodically, the Company charters private aircraft for business purposes. During 2012 and 2011, the Company paid approximately $16,900 and $128,200, respectively, to a third party operator in connection with the Company's use of flight hours owned by Charles T. Goodson through a fractional ownership arrangement with the third party operator. These amounts represent the cost of the hours purchased by Mr. Goodson. No such amounts were incurred during 2013. The Company's use of flight hours purchased by Mr. Goodson was pre-approved by the Company's Audit Committee and there is no agreement or obligation by or on behalf of the Company to utilize this aircraft arrangement.

Note 11—Ceiling Test Write-downs

As a result of lower natural gas prices and their negative impact on certain of the Company's longer-lived estimated proved reserves and estimated future net cash flows, the Company recognized ceiling test write-downs of $137.1 million and $18.9 million during 2012 and 2011, respectively. No such write-down occurred during 2013. At December 31, 2012, the prices used in computing the estimated future net cash flows from the Company's estimated proved reserves, including the effect of hedges in place at that date, averaged $2.21 per Mcf of natural gas, $102.81 per barrel of oil and $6.07 per Mcfe of Ngl. The Company's cash flow hedges in place decreased the ceiling test write-down by approximately $2.2 million and $3.9 million during 2012 and 2011, respectively.

Note 12—Other Comprehensive Income

The following table represents the changes in accumulated other comprehensive income (loss), net of tax, for the year ended December 31, 2013 (in thousands):

	Gains and Losses on Cash Flow Hedges	Change in Valuation Allowance	Total
Balance as of December 31, 2012	$ 521	$ —	$ 521
Other comprehensive loss before reclassifications	(585)	(408)	(993)
Amounts reclassified from accumulated other comprehensive income	(624)	—	(624)
Net other comprehensive loss	(1,209)	(408)	(1,617)
Balance as of December 31, 2013	$ (688)	$ (408)	$ (1,096)

Refer to Note 7 - Derivative Instruments for additional details about the effect of the above reclassifications.

Note 13—Investment in Oil and Gas Properties—Unaudited

The following tables disclose certain financial data relative to the Company's oil and gas producing activities, which are located onshore and offshore in the continental United States:

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities
(*amounts in thousands*)

	For the Year-Ended December 31,		
	2013	2012	2011
Acquisition costs:			
Proved (1)	$ 177,880	$ 352	$ 2,720
Unproved (1)	35,008	15,677	43,207
Divestitures—unproved (2)	(487)	(8,889)	(14,461)
Exploration costs:			
Proved	34,344	72,361	92,466
Unproved	20,112	18,033	5,919
Development costs	41,328	18,740	34,400
Capitalized general and administrative and interest costs	19,911	18,961	18,210
Total costs incurred	$ 328,096	$ 135,235	$ 182,461

	For the Year-Ended December 31,		
	2013	2012	2011
Accumulated depreciation, depletion and amortization (DD&A)			
Balance, beginning of year	$ (1,472,244)	$ (1,265,603)	$ (1,175,553)
Provision for DD&A	(69,357)	(59,496)	(57,143)
Ceiling test writedown	—	(137,100)	(18,907)
Sale of proved properties and other (3)	(11,443)	(10,045)	(14,000)
Balance, end of year	$ (1,553,044)	$ (1,472,244)	$ (1,265,603)
DD&A per Mcfe	$ 1.82	$ 1.75	$ 1.89

(1) During 2013, the Company closed on the Gulf of Mexico Acquisition for an aggregate cash purchase price of $188.8 million (see Note 2 - Acquisition). Additionally, the Company acquired 13,500 net unevaluated acres in Oklahoma targeting the Woodford Shale.

(2) During 2012, the Company sold an additional portion of its Mississippian Lime acreage for $6.1 million. During 2011, the Company sold a portion of its unproved Mississippian Lime acreage for $14.5 million.

(3) During 2013, the Company sold 50% of its saltwater disposal systems and related surface assets in the Woodford for net proceeds of approximately $10.4 million. and its non-operated Wyoming assets for a cash purchase price of $1.0 million. During 2012, the Company sold its non-operated Arkansas assets for a net cash purchase price of $8.5 million. During 2011, the Company received an additional $14 million payment associated with the achievement of certain production metrics stipulated under the joint development agreement.

At December 31, 2013 and 2012, unevaluated oil and gas properties totaled $98.4 million and $71.7 million, respectively, and were not subject to depletion. Unevaluated costs at December 31, 2013 included $11.3 million of costs related to 19 exploratory wells in progress at year-end. These costs are expected to be transferred to evaluated oil and gas properties during 2014 upon the completion of drilling. At December 31, 2012, unevaluated costs included $12.7 million related to 17 exploratory wells in progress. All of these costs were transferred to evaluated oil and gas properties during 2013. The Company capitalized $6.6 million, $7.0 million and $7.0 million of interest during 2013, 2012 and 2011, respectively. Of the total unevaluated oil and gas property costs of $98.4 million at December 31, 2013, $50.3 million, or 51%, was incurred in 2013, $12.1 million, or 12%, was incurred in 2012 and $36.0 million, or 37%, was incurred in prior years. The Company expects that the majority of the unevaluated costs at December 31, 2013 will be evaluated within the next three years, including $34.4 million that the Company expects to be evaluated during 2014.

Note 14—Income Taxes

The Company typically provides for income taxes at a statutory rate of 35% adjusted for permanent differences expected to be realized, primarily statutory depletion, non-deductible stock compensation expenses and state income taxes. As a result of the ceiling test write-downs recognized during 2011 and 2012, the Company incurred a cumulative three-year loss. Because of the impact the cumulative loss had on the determination of the recoverability of deferred tax assets through future earnings, the Company assessed the realizability of its deferred tax assets based on the future reversals of existing deferred tax liabilities. Accordingly, the Company established a valuation allowance of $45.5 million as of December 31, 2013.

An analysis of the Company's deferred taxes follows (amounts in thousands):

	December 31,		
	2013	2012	2011
Net operating loss carryforwards	$ 21,810	$ 16,641	$ 2,409
Percentage depletion carryforward	8,645	7,317	6,103
Alternative minimum tax credits	784	784	784
Contributions carryforward and other	189	156	130
Temporary differences:			
Oil and gas properties	(7,248)	12,575	(21,860)
Asset retirement obligation	18,056	10,141	11,319
Derivatives	408	(222)	(2,388)
Share-based compensation	2,887	3,474	2,952
Valuation allowance	(45,531)	(50,866)	—
Deferred tax liability	$ —	$ —	$ (551)

At December 31, 2013, the Company had approximately $70.7 million of operating loss carryforwards, of which $12.1 million relates to excess tax benefits with respect to share-based compensation that have not been recognized in the financial statements. If not utilized, approximately $8.7 million of such carryforwards would expire in 2025 and the remainder would expire by the year 2033. The Company has available for tax reporting purposes $24.7 million in statutory depletion deductions that may be carried forward indefinitely.

Income tax expense (benefit) for each of the years ended December 31, 2013, 2012 and 2011 was different than the amount computed using the Federal statutory rate (35%) for the following reasons (amounts in thousands):

	For the Year Ended December 31,		
	2013	2012	2011
Amount computed using the statutory rate	$ 5,041	$ (45,655)	$ 3,058
Increase (reduction) in taxes resulting from:			
State & local taxes	317	(2,870)	192
Percentage depletion carryforward	(1,323)	(1,309)	(2,507)
Allowance for alternative minimum tax	—	—	8
Non-deductible stock option expense (1)	115	292	183
Share-based compensation (2)	780	9	346
Other	1,132	303	(300)
Change in valuation allowance	(5,742)	50,866	(2,790)
Income tax expense (benefit)	$ 320	$ 1,636	$ (1,810)

(1) Relates to compensation expense recognized on the vesting of Incentive Stock Options.

(2) Relates to the write-off of deferred tax assets associated with share based compensation that will not be recognized for tax purposes.

Note 15—Commitments and Contingencies

The Company is a party to ongoing litigation in the normal course of business. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material. At December 31, 2010, the Company had accrued $2.3 million in connection with estimated liabilities related to certain legal matters. All of these matters were settled during 2011, which resulted in an additional charge of $1.4 million included in other expense for the year ended December 31, 2011.

Lease Commitments

The Company has operating leases for office space and equipment, which expire on various dates through 2018. Future minimum lease commitments as of December 31, 2013 under these operating leases are as follows (in thousands):

2014	$ 1,384
2015	1,452
2016	1,414
2017	1,312
2018	411
Thereafter	2,032
	$ 8,005

Total rent expense under operating leases was approximately $1.4 million, $1.4 million and $1.3 million in 2013, 2012 and 2011, respectively.

Note 16—Oil and Gas Reserve Information—Unaudited

The Company's net proved oil and gas reserves at December 31, 2013 have been estimated by independent petroleum engineers in accordance with guidelines established by the SEC using a historical 12-month average pricing assumption.

The estimates of proved oil and gas reserves constitute those quantities of oil, gas,and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

During 2013, the Company's estimated proved reserves increased by 32%. This increase was primarily due to the Gulf of Mexico Acquisition, the success of the Company's drilling programs and approximately 33 Bcfe of PUD reserves added as a result of the increase in the historical 12-month average price per Mcf of natural gas used to calculate estimated proved reserves. In total, the Company added approximately 63 Bcfe of proved reserves in Oklahoma, 41 Bcfe in the Gulf Coast and 6 Bcfe in Texas. Overall, the Company had a 88% drilling success rate during 2013 on 40 gross wells drilled.

The following table sets forth an analysis of the Company's estimated quantities of net proved and proved developed oil (including condensate), gas and natural gas liquid reserves, all located onshore and offshore the continental United States:

	Oil in MBbls	NGL in MMcfe	Natural Gas in MMcf	Total Reserves in MMcfe
Proved reserves as of December 31, 2010	1,623	8,373	174,566	192,677
Revisions of previous estimates	(294)	308	8,418	6,962
Extensions, discoveries and other additions	595	8,627	82,113	94,310
Purchase of producing properties	43	91	1,292	1,641
Production	(572)	(2,288)	(24,463)	(30,183)
Proved reserves as of December 31, 2011	1,395	15,111	241,926	265,407
Revisions of previous estimates	215	(958)	(52,076)	(51,744)
Extensions, discoveries and other additions	647	14,572	46,390	64,844
Sale of reserves in place	(81)	—	(15,806)	(16,292)
Production	(521)	(3,365)	(27,466)	(33,957)
Proved reserves as of December 31, 2012	1,655	25,360	192,968	228,258
Revisions of previous estimates	(123)	520	37,738	37,518
Extensions, discoveries and other additions	434	6,099	30,429	39,132
Purchase of producing properties	1,833	1,915	22,274	35,187
Sale of reserves in place	(34)	—	(15)	(218)
Production	(681)	(4,754)	(29,226)	(38,066)
Proved reserves as of December 31, 2013	3,084	29,140	254,168	301,811
Proved developed reserves				
As of December 31, 2011	1,160	11,071	143,441	161,472
As of December 31, 2012	1,225	20,608	140,307	168,265
As of December 31, 2013	2,709	23,173	163,728	203,152
Proved undeveloped reserves				
As of December 31, 2011	235	4,040	98,485	103,935
As of December 31, 2012	430	4,752	52,661	59,993
As of December 31, 2013	375	5,967	90,440	98,659

The following tables (amounts in thousands) present the standardized measure of future net cash flows related to proved oil and gas reserves together with changes therein, as defined by ASC Topic 932. Future production and development costs are based on current costs with no escalations. Estimated future cash flows have been discounted to their present values based on a 10% annual discount rate.

Standardized Measure

	December 31,		
	2013	2012	2011
Future cash flows	$ 1,265,663	$ 748,914	$ 1,080,392
Future production costs	(301,710)	(220,750)	(264,219)
Future development costs	(193,985)	(121,346)	(180,846)
Future income taxes	(40,072)	(10,205)	(86,612)
Future net cash flows	729,896	396,613	548,715
10% annual discount	(276,014)	(164,218)	(244,834)
Standardized measure of discounted future net cash flows	$ 453,882	$ 232,395	$ 303,881

Changes in Standardized Measure

	Year Ended December 31,		
	2013	2012	2011
Standardized measure at beginning of year	$ 232,395	$ 303,881	$ 236,375
Sales and transfers of oil and gas produced, net of production costs	(134,184)	(92,562)	(116,398)
Changes in price, net of future production costs	57,293	(138,842)	(10,219)
Extensions and discoveries, net of future production and development costs	70,181	104,066	178,901
Changes in estimated future development costs, net of development costs incurred during this period	(24,327)	69,499	915
Revisions of quantity estimates	57,468	(56,352)	11,236
Accretion of discount	23,927	34,137	25,565
Net change in income taxes	(14,061)	30,617	(18,215)
Purchase of reserves in place	191,964	—	4,805
Sale of reserves in place	(411)	(8,186)	—
Changes in production rates (timing) and other	(6,363)	(13,863)	(9,084)
Net increase (decrease) in standardized measure	221,487	(71,486)	67,506
Standardized measure at end of year	$ 453,882	$ 232,395	$ 303,881

The historical twelve-month average prices of oil, gas and natural gas liquids used in determining standardized measure were:

	2013	2012	2011
Oil, $/Bbl	$106.19	$102.81	$101.42
Ngls, $/Mcfe	5.10	6.07	8.62
Natural Gas, $/Mcf	3.11	2.20	3.34

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Note 17 - Summarized Quarterly Financial Information - Unaudited

Summarized quarterly financial information is as follows (amounts in thousands except per share data):

	Quarter Ended			
	March 31	June 30	September 30	December 31
2013:				
Revenues	$ 36,009	$ 38,102	$ 55,587	$ 53,172
Income from operations	4,236	4,109	1,687	4,370
Income available to common stockholders	2,607	3,662	383	2,291
Earnings per share:				
Basic	$ 0.04	$ 0.06	$ 0.01	$ 0.04
Diluted	$ 0.04	$ 0.06	$ 0.01	$ 0.04
2012:				
Revenues	$ 36,041	$ 33,413	$ 33,951	$ 38,186
Loss from operations (1)	(18,314)	(52,183)	(35,919)	(24,027)
Loss available to common stockholders (1)	(18,608)	(54,520)	(38,639)	(25,451)
Earnings per share:				
Basic	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)
Diluted	$ (0.30)	$ (0.87)	$ (0.62)	$ (0.41)

(1) Loss from operations and net loss available to common stockholders reported during the three months ended March 31, June 30, September 30 and December 31, 2012 included ceiling test write-downs of $20.1 million, $53.5 million, $35.4 million and $28.1 million, respectively.

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-190645) of PetroQuest Energy, Inc. and the related Prospectus, and

(2) Registration Statement (Form S-3 No. 333-124746) of PetroQuest Energy, Inc. and the related Prospectus, and

(3) Registration Statement (Form S-3 No. 333-42520) of PetroQuest Energy, Inc. and the related Prospectus, and

(4) Registration Statement (Form S-3 No. 333-89961) of PetroQuest Energy, Inc. and the related Prospectus, and

(5) Registration Statement (Form S-8 No. 333-188731) pertaining to the PetroQuest Energy, Inc. 2013 Incentive Plan, and

(6) Registration Statement (Form S-8 No. 333-184926) pertaining to the PetroQuest Energy, Inc. 2012 Employee Stock Purchase Plan, and

(7) Registration Statement (Form S-8 No. 333-174260) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(8) Registration Statement (Form S-8 No. 333-151296) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(9) Registration Statement (Form S-8 No. 333-134161) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(10) Registration Statement (Form S-8 No. 333-102758) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(11) Registration Statement (Form S-8 No. 333-88846) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(12) Registration Statement (Form S-8 No. 333-67578) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(13) Registration Statement (Form S-8 No. 333-52700) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan, and

(14) Registration Statement (Form S-8 No. 333-65401) pertaining to the PetroQuest Energy, Inc. 1998 Amended and Restated Incentive Plan;

of our reports dated March 5, 2014, with respect to the consolidated financial statements of PetroQuest Energy, Inc. and the effectiveness of internal control over financial reporting of PetroQuest Energy, Inc. included in this Annual Report (Form 10-K) of PetroQuest Energy, Inc. for the year ended December 31, 2013.

/s/ Ernst & Young LLP

New Orleans, Louisiana
March 5, 2014

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 FAX (713) 651-0849
TELEPHONE (713) 651-9191

EXHIBIT 23.2

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to (i) the inclusion of our reserve report relating to certain estimated quantities of the proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2013 of PetroQuest Energy, Inc. (the "Company") in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2013, filed as Exhibit 99.1 of the Form 10-K, and (ii) the incorporation by reference in this Annual Report on Form 10-K prepared by the Company for the year ending December 31, 2013, and to the incorporation by reference thereof into the Company's previously filed Registration Statements on Form S-3 (File Nos. 333-190645, 333-124746, 333-42520 and 333-89961) and Form S-8 (File Nos. 333-188731, 333-184926, 333-174260, 333-151296, 333-134161, 333-102758, 333-88846, 333-67578, 333-52700 and 333-65401), of information contained in our report relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2013. We further consent to references to our firm under the headings "Business and Properties - Oil and Gas Reserves" and "Risk Factors," and included in or made a part of the Annual Report on Form 10-K prepared by the Company for the year ended December 31, 2013.

We further wish to advise that we are not employed on a contingent basis and that at the time of the preparation of our report, as well as at present, neither Ryder Scott Company, L.P. nor any of its employees had, or now has, a substantial interest in PetroQuest Energy, Inc. or any of its subsidiaries, as a holder of its securities, promoter, underwriter, voting trustee, director, officer or employee.

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 5, 2014

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

I, Charles T. Goodson, certify that:

1. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 (e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the

audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
March 5, 2014

EXHIBIT 31.2

I, J. Bond Clement, certify that:

1. I have reviewed this Form 10-K of PetroQuest Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 (e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the

audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
March 5, 2014

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2013 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Charles T. Goodson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/Charles T. Goodson
Charles T. Goodson
Chief Executive Officer
March 5, 2014

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of PetroQuest Energy, Inc. (the "Company") on Form 10-K for the year ending December 31, 2013 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, J. Bond Clement, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. Bond Clement
J. Bond Clement
Chief Financial Officer
March 5, 2014

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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Corporate Information

Board of Directors

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

W.J. Gordon III *#^
Vice President of Strategic Planning
Franciscan Missionaries of Our Lady Health System

Michael L. Finch *#^
Private Investments

Charles F. Mitchell II, M.D. *#^
Physician, Private Investments

E. Wayne Nordberg *#^
Hollow Brook Associates, LLC

William W. Rucks, IV *#^
Private Investments

* Member of the Compensation Committee
\# Member of the Audit Committee
^ Member of the Nominating and
Corporate Governance Committee

Senior Management

Charles T. Goodson
Chairman of the Board,
Chief Executive Officer, and President

W. Todd Zehnder
Chief Operating Officer

Edward E. Abels, Jr.
Executive Vice President, General Counsel,
and Corporate Secretary

J. Bond Clement
Executive Vice President
Chief Financial Officer, and Treasurer

Art M. Mixon
Executive Vice President
Operations and Production

Tracy Price
Executive Vice President
Business Development & Land

Stephen H. Green
Senior Vice President
Exploration

Mark K. Castell
Vice President - Oklahoma Assets

Edgar A. Anderson
Vice President - ArkLaTex

Corporate Address

PetroQuest Energy, Inc.
400 East Kaliste Saloom Road, Suite 6000
Lafayette, Louisiana 70508
Telephone: (337) 232-7028
Fax: (337) 232-0044
Web: www.petroquest.com

Exploration Offices

1800 Hughes Landing Blvd., Suite 200
The Woodlands, Texas 77380
Telephone: (281) 465-3900
Fax: (281) 465-3999

1717 S. Boulder, Suite 201
Tulsa, Oklahoma 74119
Telephone: (918) 582-2770
Fax: (918) 582-2778

Transfer Agent and Registrar

American Stock Transfer & Trust Company
59 Maiden Lane
New York, New York 10038
Telephone: (718) 921-8145

Independent Auditors

Ernst & Young LLP
New Orleans, Louisiana 70170

Legal Counsel

Porter & Hedges, LLP
Houston, Texas 77002

Onebane Law Firm
Lafayette, Louisiana 70502

Annual Meeting

The Company's Annual Meeting of Stockholders will be held at 9:00 A.M. CDT on May 14, 2014, at the City Club at River Ranch at 221 Elysian Fields Drive, Lafayette, LA, 70508.

Form 10-K

Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our Corporate Secretary at our Corporate Address or on the Company's website at www.petroquest.com.

Common Stock Listing

Listed on NYSE as PQ

PetroQuest Energy, Inc.

PETROQUEST.COM

PetroQuest Energy, Inc.

- HOME
- ABOUT PQ
- INVESTORS
- PROJECTS
- NEWS
- CONTACT

ABOUT PETROQUEST ENERGY

PetroQuest Energy, Inc. is an independent energy company engaged in the exploration, development, acquisition and production of oil and natural gas reserves in East Texas, Arkoma Basin, South Louisiana and the shallow waters of the Gulf of Mexico.

INVESTOR INFORMATION

As of 11/10/2014 5:15:00 PM ET

NYSE PQ $3.90 -0.11 -2.74%

Open:	4.03	Prev Close:	4.01
Day High:	4.19	Day Low:	3.87
Year High:	7.82	Year Low:	3.64

Volume:	635,362
Market Cap:	$244,258,026
Outstanding:	62,630,263
Outstanding as of:	01/04/2010

Quote delayed 20 minutes

Click for detailed stock chart and quote

RECENT NEWS

Nov 3, 2014
PetroQuest Energy Announces Third Quarter Results And Updates Operations

Oct 21, 2014
PetroQuest Energy, Inc. Invites You To Join Its 2014 Third Quarter Earnings Conference Call

Sep 30, 2014
PetroQuest Energy Announces Sale Of Eagle Ford Assets And Borrowing Base Redetermination

EVENTS

December 10, 2014
WEBCAST -Capital One Securities Conference-New Orleans 9:20AM CT

November 04, 2014
PetroQuest Energy, Inc. Third Quarter Earnings 2014 Conference Call - 9:30AM EST

September 23, 2014
WEBCAST -OGIS Oil & Gas Investment Symposia -San Francisco 2:45PM PT

August 19, 2014
WEBCAST -EnerCom Oil & Gas Conference-Denver 10:30AM MST

August 05, 2014
PetroQuest Energy, Inc. Second Quarter Earnings 2014 Conference Call - 9:30AM EST

June 24 , 2014
WEBCAST -GHS 100 Energy Conference-Chicago 8:00AM CT

June 10 , 2014
WEBCAST - EnerCom Oil & Gas Conference-London 12:15PM EDT

May 6, 2014
CONFERNCE CALL - PetroQuest Energy, Inc. First Quarter 2014 Earnings Conference Call - 9:30AM ET

April 8, 2014
WEBCAST -IPAA OGIS Conference - New York- 9:10AM ET

For Additional News and Insight

"));

EXHIBIT
3
Taylor 11/12/14

ERRATA SHEET

PAGE / LINE	CHANGE / CORRECTION	REASON
19 / 19	an affiliate / a fully	transcription error
20 /9,12,18,23	Gunner / Gunter	transcription error
21 /6,18	Gunner / Gunter	transcription error
24 / 23	delete the word "not"	transcription error
30 / 8	add a comma after the word "cost"	transcription error
33 / 2	reg / rate	transcription error
69 / 18	absolutely / absolute	transcription error
76 / 10	absolutely / absolute	transcription error
77 / 17	fuel / full	transcription error
83 / 25	product / project	transcription error
84 / 1	a / an	transcription error
102 / 7	add the word "of" after the word "aware"	transcription error
111 / 20	chip / tip	transcription error
130 / 2	add the words "of being" after the word "category"	transcription error
146 / 8	typing / timing	transcription error
154 / 14	that / there	transcription error
157 / 2	oppose / propose	transcription error

I, Terry Deason, do hereby certify that I have read the foregoing transcript of my deposition, given on October 25, 2014, and that together with any additions or corrections made herein, it is true and correct.

Terry Deason

Terry Deason, Deponent

The foregoing instrument was acknowledged before me this 24th day of November, 2014, by Terry Deason, who is personally known to me.

Christina DeMeo

Notary Signature

CHRISTINA DEMEO
MY COMMISSION # FF 097253
EXPIRES: April 4, 2018
Bonded Thru Notary Public Underwriters

NOTARY PUBLIC, State of Florida

FF 097253

Commission Number

58

Deposition of Terry Deason
11/14/14

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 140001-EI

FILED: October 25, 2014

IN RE: FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR
_______________________________________/

Florida Power & Light Company
700 Universe Blvd.
Juno Beach, Florida
November 13, 2014
8:35 a.m. - 1:10 p.m.

DEPOSITION OF TERRY DEASON

Taken on behalf of the Alice Teslicko before Alice J. Teslicko, RMR, Notary Public in and for the State of Florida at Large, pursuant to a Notice of Taking Deposition in the above cause.

APPEARANCES:

FOR THE OFFICE OF PUBLIC COUNSEL:

CHARLES J. REHWINKEL, ESQ.
JOHN TRUITT, ESQ.
111 West Madison Street, Room 812
Tallahassee, FL 32399
(850) 488-9330
rehwinkel.charles@leg.state.fl.us
truitt.john@leg.state.fl.us

FOR THE FLORIDA PUBLIC SERVICE COMMISSION:

MARTHA F. BARRERA, ESQ.
2540 Shumard Oak Blvd.
Tallahassee, FL 32399
(850) 413-6212
mbarrera@psc.state.fl.us

FOR FLORIDA POWER & LIGHT:

JOHN BUTLER, ESQ.
SCOTT A. GOORLAND, ESQ.
700 Universe Blvd.
Juno Beach, FL 33408
(561)304-5639
john.butler@fpl.com
scott.goorland@fpl.com

FOR FLORIDA INDUSTRIAL POWER USERS GROUP:

MOYLE LAW FIRM, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
(850) 681-3828
jmoyle@moylelaw.com

APPEARANCES - CONTINUED

Also Present:

Andrew Maurey - Florida Public Service Commission
Kurt Howard - FPL
Richard Ross - FPL

Appearing Telephonically:

Erik Sayler - Office of Public Counsel
Tarik Noriega - Office of Public Counsel
Donna Ramas - Office of Public Counsel
Florida Public Service Commission Staff
Inna Weintraub - FPL
Ken Hoffman - FPL
Charles Guyton - FPL

- - -

I N D E X

EXHIBITS

(None marked)

Thereupon:

TERRY DEASON

was called as a witness and having been first duly sworn, was examined and testified as follows:

THE WITNESS: I do.

MR. REHWINKLE: In the room, Charles Rehwinkel, Office of Public Counsel.

MR. TRUITT: John Truitt, Office of Public Counsel.

MR. MOYLE: Jon Moyle, Florida Industrial Power Users Group, FIPUG.

MR. ROSS: Rich Ross with FPL.

MR. BUTLER: John Butler, counsel for FPL.

THE WITNESS: Terry Deason, Radey Law.

MR. MAUREY: Andrew Maurey, Florida Public Service Commission.

MS. BARRERA: Martha Barrera, Florida Public Service Commission.

THE COURT REPORTER: And on the phone, please.

MS. RAMAS: Donna Ramas, Office of Public Counsel.

MR. SAYLER: Erik Sayler, Office of Public Counsel.

MR. NORIEGA: Tarik Noriega, Office of

Public Counsel, good morning.

MS. WEINTRAUB: Inna Weintraub, Charlie Guyton, and Ken Hoffman, FPL.

A VOICE: Public Service Commission staff.

MR. REHWINKLE: Is there anyone else? Okay.

DIRECT EXAMINATION

BY MR. REHWINKLE:

Q. All right. Good morning, Mr. Deason.

A. Good morning.

MR. REHWINKLE: Before we get started, Mr. Butler, I assume we will use the standard agreement about all objections except as to form of the question will be reserved?

MR. BUTLER: Yes.

BY MR. REHWINKLE:

Q. And you will not waive reading and signing?

A. That's right.

Q. And I think, for the record, I don't think there's any chance we'll get into confidential information today, so I don't think we have to deal with that at least with Mr. Deason's deposition.

Okay. Mr. Deason, do you understand that I'm asking you questions today related to your testimony in this docket and I expect to be able to rely upon the answers you give me here today in my cross examination of you and the hearing in this matter?

A. Yes.

Q. Will you also agree with me that unless the context requires otherwise, that when I ask you about a question and/or an answer in your prefiled testimony, that I'm asking you to answer me based on your knowledge as of the time you prepared and submitted that testimony?

A. Yes.

Q. Today do you have any changes or corrections to make to your testimony or exhibits?

A. No.

Q. Do you have any exhibits?

A. I have one.

Q. The CV?

A. Yeah, no.

Q. Can you tell me how you came to be involved in this case?

A. Yes. I was contacted by FPL concerning the subject matter of this docket and was asked to basically come up to speed on the issues, and then at a later time after intervenors filed their testimony I was further contacted about the possibility of providing rebuttal testimony.

MR. REHWINKLE: Did someone else join the call? I heard a beep. Hello?

BY MR. REHWINKLE:

Q. The first time you were contacted, can you tell me when was?

A. I don't have a precise date. It was probably somewhere in the neighborhood of a few weeks before intervenor testimony was filed.

Q. But it was after the petition was filed?

A. Yes, definitely after the petition was filed.

Q. So would it be true then that prior to filing the petition and testimony FPL did not seek your advice about the filing in any way?

A. That is correct.

Q. Apart from the filing or the preparation of your rebuttal testimony in this docket, did FPL seek your advice on whether the transaction constituted hedging?

A. Let me be clear on the question. Before the petition was filed or after the petition was filed?

Q. After the petition was filed, but separate and apart from the task of getting you to file testimony.

A. Okay, and I want to make sure I have the question correct. Did they ask my advice as to whether the transaction constituted hedging?

Q. Yes.

A. No, they did not ask that question. However, they did want me to review hedging orders in the context of this case and to help me draw my own conclusions.

Q. And without disclosing the content of any communications that FPL considers privileged, if any, can you tell me on what aspects of the project you were asked to give -- to render services?

A. Yes, it was generally as to whether the transaction, the proposal, whether it met sound rate-making policies and whether it was consistent with other policies of the Commission.

That was the general approach and what I was tasked with generally.

Q. Would you agree with me that in presenting Commission orders or interpreting Commission orders for purposes of testifying for the Commission, that it's not appropriate to contort, misconstrue, or misuse those orders?

A. Yes, I agree.

Q. Would you agree that when presenting your testimony about the testimony of another witness, that it would be improper to contort, misconstrue, or misuse the testimony of another witness?

A. Yes.

Q. I want to ask you a question not about this particular case, but can you tell me in the past how many different initiatives, cases, or other projects FPL has asked you to provide consulting or advisory services on?

A. That I do not have a specific number. If I were -- if you want an estimate just based upon sitting here today, I can provide you that, but I don't have a specific number.

Q. What is your estimate?

A. My guess would be more than a half dozen, probably less than a dozen, somewhere in that neighborhood.

Q. Have you consulted with FPL -- and I'm not asking you about what. I'm just asking you, have you consulted with FPL about matters other than those of which you have filed testimony?

MR. MOYLE: Scope of time?

A. Yes, the answer is yes, but I need to clarify that. It was a matter where it was contemplated I would file testimony, but testimony was not ever filed.

Q. Are you able to tell me when that was?
A. I'd have to ask -- can I confer with my attorney?
Q. You can go ahead and do that.
MR. BUTLER: Maybe we need to address and see what it is. It may be something --
MR. REHWINKLE: I don't have any problem with you consulting.
MR. BUTLER: Let's just go outside for a second.
(Discussion off the record.)
What we would propose is that Mr. Deason can answer your question as to the topic that he was asked to address, without reviewing specific circumstances of it.
MR. REHWINKLE: That's fine with me.
MR. BUTLER: Sufficient for your purposes?
MR. REHWINKLE: Yes.
THE WITNESS: Do you want me to answer or do you want to repeat the question?
BY MR. REHWINKLE:
Q. My question is what matter did you consult with FPL about filing testimony, but upon which testimony was never filed, to the extent that you worked it out with Mr. Butler to answer?

A. The general subject matter was acquisition adjustment policy.

Q. Can you tell me what time frame that would have been in?

A. I believe it was somewhere perhaps about a year ago.

Q. Have you ever consulted with FPL about filing testimony and advised them that you could not support the proposal that they wanted you to file testimony?

A. Yes and no. I have always been able to provide testimony in dockets, but the testimony has always been my own, and there have been certain limitations on what was in my testimony.

So, you know, it's not really a yes or a no answer. It's probably a little of both.

Q. But did you ever refuse to provide testimony at all on a matter that they asked you to rebut testimony on, that they ultimately then submitted a case to the Commission on?

A. No.

Q. Let me just -- one more area outside of gas reserves, then I want to come back to gas reserves, of course. I know you provided testimony in the 2012 reg case?

A. Yes.

Q. And I know that you provided testimony in the recent smart meter case, 130223?

A. Yes.

Q. And you provided testimony in this case?

A. Yes.

Q. Are there any others that you can recall that you provided testimony on?

A. Yes, I provided testimony on two different occasions in the nuclear cost recovery clause docket.

Q. What was the subject matter?

A. Here again, it was the correct policy implications of recovery through the nuclear cost recovery clause.

Q. Was it related to up rates?

A. That was one of the subject matters, yes, and it was not direct testimony, it was rebuttal testimony.

Q. Any others that you recall?

A. There may be others, but I can't recall any right at the moment.

Q. Have you ever filed testimony on behalf of NextEra in a state other than Florida?

A. No.

Q. Have you ever consulted with NextEra on a regulatory matter outside the State of Florida?

A. Yes.

Q. Can you tell me what about?

MR. BUTLER: I'm not sure that -- I would need to consult with him again. I'm not aware what it is. I need to find out.

MR. REHWINKLE: Where I'm going with this, all I want to know is did he consult and did he refuse to provide testimony for NextEra, something like that.

A. I maybe can short circuit it. I was asked to look at a situation in another state and it did not involve testimony, and after initial discussions no further action was taken.

So it was preliminary and did not result in any further work on my part.

Q. Okay. After FPL asked you to provide services in the gas reserves docket, as a part of your services that you provided to them in support in anticipation of filing testimony did you ask them to make any changes or suggest any changes to the proposal that they filed?

A. No.

Q. I know you said earlier that FPL asked you to bring yourself up to speed on the docket and that was the first contact.

A. Yes.

Q. What did you do to educate yourself on the issues of the case?

A. I reviewed the petition, I reviewed the prefiled testimony and exhibits, and I reviewed Commission orders that I felt were relevant to the subject matter of the petition.

Q. Anything else?

A. An analysis of Commission rules, as well as Commission orders.

Q. Did FPL provide you any internal documents, such as strategic plans, anything like that, related to their plans for the gas reserve?

A. No.

Q. My question to you was as a part of bringing yourself up to speed. Your answer is no to that?

A. That's correct, the answer is no.

Q. If I asked you in a broader context, have they provided you with any such strategic plans about what they want to do with gas reserves in this docket in the future generally, what would your answer be?

A. The answer would be no.

Q. Other than providing you documents in either type of scenarios, have they shared with you in any way what their strategic plan or goals for gas reserves are?

A. No, nothing beyond what has been filed publicly in this docket.

Q. Okay. Is the testimony you filed intended to give the Commission guidance on FPL's ability, experience, or competence to manage the gas reserves investment strategy that's reflected in the petition or guidelines?

A. No.

Q. Does your testimony contain an opinion about whether the Commission needs to inquire into FPL's qualifications to undertake the gas reserves investment strategy?

A. I do not address that in my testimony.

Q. As a part of your services that you provided to FPL in preparation of your testimony in this docket, did you do any research into how many electric utilities are investing in gas reserves in a way analogous to the FPL proposal?

A. I did not.

Q. Did you do any research about gas reserves issues in any state other than Florida?

A. No.

Q. Let's go to Page 2 of your testimony, the lines 9 through 13, and the way I read this testimony is it's a list of the types of matters or issues that you provided testimony about; is that right?

A. Yeah. It's not an exhaustive list, it's more illustrative, but that's correct.

Q. And this only -- does this list only include matters or issues related to testimony subsequently to you leaving the Public Service Commission as a Commissioner?

A. Yes.

Q. I would assume that even though this list is not exhaustive, if you had testified in any state, including Florida, about matters specifically related to gas reserves you would have listed it here; is that a fair assumption on my part?

A. Well, I think it's probably a fair assumption, but it's a simple answer. I've not consulted on gas reserves for any other company or any other state.

Q. Okay. Of the testimony that you've listed here or the subject matters that you've listed here, which of them is most closely related to or analogous to the issues that are before the Commission on the gas reserve petition?

A. Well, limiting it to this illustrative list, I would say probably the last one indicated there would be most applicable. But here again, let me reiterate, this is an illustrative list and my purpose in this docket is to address regulatory policy from a general perspective and then apply it to the specifics of what's being proposed here.

Q. So just so I'm clear, is that the prudence determinations?

A. Yes. Probably of that limited list, that would be probably the most relevant.

Q. What have you testified about that's not on this list that would be analogous or most closely related to the gas reserve petition issues before the Commission?

A. There's nothing that comes to mind that would be more analogous.

Q. Page 5 of your testimony you take issue with Donna Ramas' testimony filed on behalf of our office, right?

A. Yes.

Q. And the specific issue on Page 5 is her issue about the applicability of PSC Order 14546?

A. Yes.

Q. Now, you have read that order, I assume?

A. Yes.

Q. Completely, and you would agree that despite the fact that the Commission approved a stipulation of a broad range of parties, that they said that they adopted the order as if it was their own, the stipulation as if it was their own?

A. Yes.

Q. Do you see an order that adopts the stipulation as any different than an order that is a full determination on a contested hearing in any different light?

Is there any qualitative difference between the two orders?

MR. BUTLER: Charles, are you referring generally or where it says "we adopt this as our own"?

MR. REHWINKLE: Generally.

A. No, I believe if the Commission says they adopt it, well, then it has the full force and effect of an order that had resulted from an affiliate adjudicated proceeding.

Q. Whether or not they have this language that says that the Commission approves the stipulation of the parties and adopts the provision therein as its own? Does that language mean anything?

A. I think it provides clarification. I don't know that it provides more than that.

Q. Okay. Now, this order was issued in 1985, right?

A. I trust you if you say it was 1985. That would fit --

Q. July 8th, 1985, would you accept that?

A. I accept that.

Q. Now, at that time you were an aide to Commissioner Gunner; is that right?

A. Yes.

Q. Now, your testimony isn't that as an aide to Commissioner Gunner you had any special insight or involvement in the structure or the language or the stipulation itself as part of this order, is there?

A. Well, if you could define what you mean by "special insight". I'm needing clarification on your question.

Q. So as an aide to Commissioner Gunner did you have any role in facilitating the stipulation that the parties themselves reached?

A. No.

Q. Did you have any -- as an aide to Commissioner Gunner did you have any role in the language that ended up in the order adopting the stipulation?

A. I had input into the consideration of the stipulation, but as to whether that resulted in any modification or any specific language in the order, I would doubt that it had that effect.

Q. And you're not here representing that because you were an aide to Commissioner Gunner, that you had some special insight to the language that's in this order, are you?

A. Well, that's kind of a yes and no. I was there, I participated, I consulted with the commissioner. So I had insights into what the considerations were, what the concerns were. But I'm not sitting here saying that I had some special effect on the outcome or any particular language in the order.

Q. Okay. Now, in your testimony dealing with this order you don't recount that you were the aide to Commissioner Gunner, as far as the Commission giving that anyway, in the testimony that you filed, right?

A. That is not part of my testimony.

Q. On Page 5 in the first line you quote item 10 from the order, correct?

A. Yes.

Q. And on that first line the phrase "fossil fuel-related costs normally recovered through base rates" is there. Do you see that?

A. I do.

Q. Now, you would agree with me that that language has not been changed, amended, or modified or overruled by any subsequent Commission order, would you?

A. I agree that it has not been overruled. It has been interpreted in subsequent orders by the Commission, but I don't recall the Commission saying that they are changing any particular words or phraseology in this particular item, item 10.

Q. By corollary to the answer you just gave me, you have not read an order that says that any of the words here should be disregarded, changed, or construed in a different manner than their plain meaning?

A. No, other than that there have been additional orders which have made decisions referencing this particular paragraph, and those decisions speak for themselves.

Q. And obviously you agree that item 10 has a bearing on the Commission's determination of the petition that FPL filed in this matter?

A. Yes, I think it has a bearing. I don't know that it in and of itself should be determinative and result in one outcome or another, but it is guidance for the Commission to use.

Q. You would agree, based on your view of what FPL filed of Mr. Forrest and Ms. Ousdahl, both reference that order in their direct testimony, right?

A. I know Ms. Ousdahl does and I would think that Mr. Forrest probably does as well.

Q. And you didn't -- you don't take issue with the way they present that order having a bearing on the Commission's consideration, do you?

A. I do not take issue with that.

Q. Now, tell me what -- based on the words that we just reviewed that are on the first line of Page 5, what does "fossil fuel related costs normally recovered through base rates mean" by itself?

A. It would be those costs related to the acquisition and transportation and the ultimate utilization of fuel; all of those costs that are ancillary to or in addition to the commodity price of fuel.

Q. What about the phrase "normally recovered through base rates," what is your understanding of what that means?

A. Well, it would be -- at this time in the history of the fuel adjustment, the fuel adjustment was designed to provide a recovery mechanism of fuel costs, primarily the commodity prices of fuel. Over the years that has evolved to some extent to include other type costs which impact the commodity price of fuel, but which are really not the purchase price of the fuel itself as a commodity.

So as time evolved those type of costs were appropriately included within the confines of the fuel clause, and the way I interpret this phrase is that it's those type of costs which historically had not been part of the fuel clause and that if they were -- if those costs were incurred or those investments made, then they would to that point historically would have been recovered through base rates and the recovery would have been delayed until there had been a rate case filed to include those costs.

Q. So is it your testimony that these are costs that are of the type that were normally included in base rates?

A. Yes, they were the type of costs that if they were determined to be prudent and provide benefit to customers, that they wouldn't have not heretofore been eligible for recovery through clause, but would have been eligible through the base rates.

Q. So that's probably the first prong of a test that's in item 10. The second prong is they're not currently recovered in base rates, would you agree?
A. Yes, I agree.
Q. The next phrase there, "but which were not recognized in determining current base rates," that's like the second prong of the test; you agree?
A. Yes, I agree.
Q. And then there's a third prong of the test after the "and" on line three which says, "which if expended, will result in fuel savings to customers."
You agree with that?
A. I do.
Q. So item 10 is like a three-prong test for consideration of the costs in the Fuel Clause. If they're not the kind that are -- they're these ancillary costs that are either expensed or gathered, right?
A. I'm sorry, could you repeat your question?
Q. Well, strike the question. I think I understand where we are.
Now, you mentioned that there are subsequent orders to Order 14546 that interpret that order; is that right?
A. Yes, that is correct.

Q. And have you -- in your testimony have you cited all the orders that you think are relevant to being used to give interpretation or context to Order 14546?

A. I cannot say that it, again, is an exhaustive list of every order that could be relevant or could be helpful to the Commission, but I believe that I have cited most of those either directly or indirectly, in the sense that there is one order by the Commission that has an appendix or attachment that provides a fairly comprehensive list of orders that have interpreted this particular provision.

Q. Other than -- but I guess my question to you is along these lines; are there any other orders that you're aware of that you haven't cited in your testimony that have a bearing on the interpretation of Order 14546?

A. Sitting here today, no.

Q. Okay. And are there any articles or treatises or the like, materials that have interpreted that order that you're aware of, that order meaning 14546?

A. No.

Q. Now, when the Commission adopted the stipulation that's part of Order 14546, are you aware of them taking any actions to amend the stipulation or asking the parties to change the language in any way?

A. I'm not aware of that.

Q. And I'm not suggesting it happened. I'm just asking you if in your role as a Commissioner employee at the time, were you aware that the Commission asked that any language be changed or modified before they would approve it?

A. Not that I recall.

Q. And in the order itself, you would agree that there's no language in the order that changes or modifies the language that's in the stipulation?

A. I agree, there is not.

Q. And there's nothing in Order 14546 that suggests that any particular word in the stipulation should be given more or less weight?

A. No, I'm not aware of any such language in the order.

Q. Likewise, there's no language that suggests that any words in the order and the stipulation approved therein should be ignored?

A. No, there's no such language in the order that I recall.

Q. On Page 6 of your testimony, lines 1 and 2, you use the phrase "regardless of the nature of the

investment." Do you see that?
A. I do.
Q. Is that a phrase that's contained in Order 14546?
A. Those particular words are not in that order, I agree.
Q. Is there anything in the order that gives rise to the use of that phrase, "regardless of the nature of the investment," that you can point me to in Order 14546?
A. Yes. Once again, it's paragraph 10, and the change in focus at the Commission to include within the confines of the clause investments that typically would have been not eligible for the clause and if they were going to be recovered, would have been recovered through base rates.
Q. So that's your basis for saying "regardless of the nature of the investment"?
A. Yes.
Q. What does the -- in the context of that phrase, what does the last sentence in item 10 mean, "Recovery of such costs should be made on a case-by-case basis after Commission approval"?
A. Sorry, you're referring to ten again?
Q. Yes, in 14546.

MR. BUTLER: You're talking about -- he has it on Page 5, lines 4 and 5. Is that what you're referring to?

MR. REHWINKLE: Yes.

A. Okay, I see that sentence. And the question is --

Q. So does that sentence suggest that the Commission will make a determination about whether the investment proposed should be recovered pursuant to the other provisions of 14546?

A. No, I think this is within the context of costs that are expended that historically had not been recovered through the clause, and that if there is going to be such costs expended which meet the requirements of this paragraph, that the Commission would consider those on a case-by-case basis.

Q. But it's not automatic. The Commission has to make a determination and they would exercise discretion, judgment, application of policy, orders, law, etc. --

A. Yes.

Q. -- in making that, okay.

So if that's true, the phrase "regardless of the nature of the investment" would be qualified, wouldn't it, by the Commission as to making a determination about the investment?

A. Yes and no.

If the investment is made and reduces fuel costs and it's fossil fuel related, it is eligible for consideration by the Commission. Then on a case-by-case basis the Commission will judge whether that investment is prudently incurred and whether the cost benefits, risks associated with that, the Commission will make a determination of whether that investment is in the public interest and whether it should be allowed to be recovered.

Q. So is it your testimony that item 10 is a checklist that if you meet those, then the project is automatically eligible for recovery in the Fuel Clause?

MR. BUTLER: I'm sorry, automatically eligible or automatically going to be recovered?

MR. REHWINKLE: Eligible.

A. Yes, by this language I think if it meets the other criteria, it's eligible for consideration.

Obviously the Commission is not bound to include it. There are other judgmental factors within the Commission's discretion and within its jurisdiction that it considers before it allows costs to be recovered.

Q. Would the corollary of what you just stated, that it doesn't meet the three criteria that are established in item 10, doesn't meet any of them, it's not eligible for recovery under the Fuel Clause?

A. No, I would not go that far. If it doesn't meet the requirements of -- the other requirements of this particular paragraph 10, well, then obviously it wouldn't be eligible through this paragraph.

But the Commission has broad regulatory authority and has the requirement to regulate in the public interest, and if an investment is made which provides benefits for customers, the Commission has the discretion to consider it and to include it in recovery either through base rates or through a clause mechanism.

Q. So has the Commission found that an item didn't meet all three of the checklist items in ten and nevertheless allowed recovery through the Fuel Clause?

MR. BUTLER: You're asking have they done that?

MR. REHWINKLE: Yes.

A. Not to my recollection.

Q. Do you consider the terms "investment" and "cost" to be the same thing?

A. No, I don't consider them to be precisely the same thing.

Q. Cost is -- an investment is cost, but cost is not always investment; would you agree with that?

A. When I use the term "investment", I'm usually thinking about items that are capitalized and there can be costs that are incurred as expense.

Q. So is the word "investment" included in paragraph 10?

MR. BUTLER: You mean does the word appear?

MR. REHWINKLE: I'm sorry, the word.

A. No, it does not. The word "costs" appears, but I don't see the word "investment".

Q. Okay. So would you agree that an expense item and an investment or capital item are both types of costs?

A. Yes, I would agree with that.

Q. So the paragraph on Page 6, lines 2 through 4 --

MR. BUTLER: I'm sorry, which page?

MR. REHWINKLE: I'm still on Page 6, lines 2 through 4.

BY MR. REHWINKLE:

Q. You say, "It was the intent of the Commission to emphasize that any prudent investment (regardless of whether or not it otherwise might have been a reg based type item), should be pursued to save customers money."

Do you see that?

A. I do.

Q. Now, when you say it was the intent, is it your testimony here on Page 6 that you're saying that that's what the Commission intended on July 8th, 1985, when they issued this Order 14546?

A. Yes.

Q. What is your basis for saying that?

A. My experience and the subsequent decisions of the Commission and my participation at the time that this decision was made by the Commission.

Q. Okay. Is there any documentation contemporaneous, that was created contemporaneous with the issuance of Order 14546 that says that sentence?

A. No, I think this particular provision speaks for itself and I think that's what this provision means.

Q. When you say "this provision" --

A. I'm talking about item 10.

Q. But you can't point to me that the language that's in your sentence that goes from line 2 to line 4, starting with "it was" and ends with "money", is reflected in a document that was contemporaneously created with Order 14546?

A. There's no such language and there's no such language that says it's not. There's just no language to that effect other than the language in item 10.

Q. And you would agree that the sentence that's in paragraph -- that's in lines 2 through 4 that I just read into the record I think accurately, that sentence is not included in Order 14546?

A. Yes, this sentence is my sentence and it does not appear in the order.

Q. Okay. When you use the term "emphasize" on line 2, you say "it was the intent of the Commission to emphasize that any prudent investment," where do you find that the Commission expressed that they wanted to emphasize that concept?

A. I do not think that the word "emphasize" is there. I think it has to be read in the context of what was happening at this particular time in the fuel adjustment clause.

This was a significant deviation from policy that existed before and the Commission was making clear, and in my opinion, was emphasizing to the regulated utilities that it was paramount for them to consider ways to save fuel costs as opposed to just going out and buying fuel and automatically be recovered through the clause on a dollar-for-dollar basis.

The Commission had a concern that there was a responsibility on the utility's part to look for ways to save money, and if that meant to allow recovery through the clause of items that typically had been reserved for base rates, that they wanted to let the utilities know that those type items would be eligible for consideration to reach the paramount goal of saving money for customers.

So I think in essence that was the emphasis. That was the message being sent.

Q. That language is not in the order in any way?

A. I agree, that language is not in the order.

Q. And on lines 4 through 7 you state that the order was a declaration to the utilities to "think outside the box"?

A. Yes.

Q. And that concept, you would agree, is not written into the order in any way?

A. That terminology is mine and that terminology is not in the order.

Q. On Page 6, starting on line 10, you start to talk about what you call the second phrase, which I think is really kind of the third prong of the test in item 10, right?

A. Yeah, I think it's the second phrase that Witness Ramas relies upon, so that's why I classified it as the second.

Q. Now, she quotes the language from the order that says "will result in fuel savings to customers" accurately. You'd agree with that, wouldn't you?

A. Yes.

Q. Now, you say that language should be interpreted -- to be read as it is expected to or should or hopefully will; is that right?

A. Yes, I think that makes the most sense, and it's not just me saying that. It's the Commission saying that in application of this language in subsequent orders of the Commission.

Q. Now, the Commission didn't say "it is expected to" in the order, did they?

A. No, the term "will" is used, but the Commission has interpreted that in subsequent orders to be expected.

Q. On Page 7, line 7 through 12, you use the phrase "to encourage innovative ways to save fuel costs." You see that?

A. Yes.

Q. And you say that item 10 is an incentive "for a utility to pursue innovative approaches to fuel savings"?

A. Yes.

Q. Is there a Commission document starting with issue Order 14546 that contains that language, that you're aware of?

A. Not that I'm aware. I think that's the result of Commission decisions subsequent, but I don't think that particular language is contained in any orders, that I recall.

Q. I think you referenced a subsequent order, and the one that I think you were mostly referring to is Order 11-0080?

A. I believe that's correct, if you'll give me just a moment.

Q. Sure.

A. Could you repeat the order number again?

Q. PSC 11-0080.

A. I have a lot of orders here. Could you give me the date of the order?

Q. Yeah, it's January 31, 2011. It's the order that's got the attachment to it.

A. All right, that helps.

Okay, I have that order.

Q. Now, this order was issued in 2011 and I think you had left the Commission by this time; is that right?

A. Yes.

Q. So it's not your testimony that you have any specific or special insight into this order by virtue of your employment with the Commission?

A. That's correct.

Q. Can you tell me what the subject matter of this order was, what the specific issue was that the Commission was deciding?

A. Well, it was concerning the recovery of Scherer Unit Four turbine upgrade costs.

Q. And what did the Commission decide?

A. I think the Commission decided that those upgrade costs were not eligible for recovery through the Environmental Cost Recovery Clause, as I recall.

Q. What about fuel costs?

A. Was not eligible for recovery through the Fuel Clause.

Q. Now, you have cited in your testimony language from this order and the Attachment A to the order, right?

A. Yes.

Q. Do you know when Attachment A -- how that attachment was developed? Was it an attachment to a staff recommendation and the Commission attached it to their order?

A. You know, I don't know that for a fact, but I just know from experience that this is the type of thorough analysis that the staff does in these matters. So I would not be surprised if this had been part of staff's analysis and had probably been part of a recommendation to the Commission.

Q. Now, when it comes to interpreting the order -- well, first of all, tell me what your understanding of Attachment A is. What does it represent?

A. It provides a listing with explanations of dockets and orders in which the language from item 10 of the previous order we discussed, where that particular language was used by the Commission and in some cases interpreted by the Commission to make decisions.

Q. And they describe that on Page 9 of the order. They say Attachment A -- "In attachment A to this order we have included a complete review of the capital costs that have been recovered through the Fuel Clause pursuant to Order 14546," right?

A. Yes.

Q. I think in your testimony you cite from Attachment A in certain areas; is that right?

A. I probably do. I mean, if you could direct me, but I'm not surprised if I did.

Q. Well, let's go to Page eight. Look at lines 10 through 17.

A. Okay. If you'll give me just a moment.

Q. Sure.

A. Okay, I see that.

Q. So your testimony there purports to cite to Attachment A; is that right?

A. Well, either Attachment A or to the bulk, the main body of the order itself. It's one or the other.

Q. Is it your understanding that the language in the orders that are listed in Attachment A controls over the verbiage that is in the reasons for approval column of attachment A?

Which would you look to to find out what the Commission intended; would you look to the language of the specific orders or Attachment A?

A. I think Attachment A serves a very good purpose, in that it provides the listing, but if one wanted to delve deeper and to get perhaps a fuller understanding, they may wish to go to the order itself, which Attachment A I think is just a summary of the essence of the decision.

Q. So in some cases in Attachment A there are quotes and in some cases there are summaries of the language in the specific orders that are cited; would you agree with that?

A. I would agree with that.

Q. Now, are there any of the orders -- do you cite the language from the underlying orders that are included in Attachment A in your testimony or are you citing to the Commission's characterization of them either in the main order or in Attachment A?

A. I don't recall. I perhaps could have quoted from Attachment A, the language there, but I don't recall doing that. But if you could direct me to a specific case, I might be able to confirm it one way or the other.

Q. I don't see that you quoted directly from an order, so I was asking you, are you -- when you quote from Order 11-0080, you appear to be quoting from Attachment A.

I'm just wondering if you went and looked at the underlying orders and incorporated that in your testimony or you are relying on Attachment A?

A. Well, let me clarify this. I can be corrected, I may be in error here, but it's my recollection that when I referred to Order 11-0080, that if I had a quote, it was from the main body of the order and not from the attachment.

Q. When you say "the order", you mean 11-0080?

A. Order Number 11-0080 itself. I believe I probably quoted some language from the order, but not the attachment.

But I'm not saying that I did not quote anything from the attachment. Just sitting here right now at the moment, I don't recall quoting from the attachment.

Q. Okay. On Page 8, lines 1 through 5, you quote Order 11-0080 and on line 3 specifically the phrase "should produce fuel savings."

Do you see that?

A. I do.

Q. Is that -- and there's also the phrase on line 4, it says "otherwise will result in burning lower priced fuel".

Do you see that? That's on line 4-5.

A. Yes. That's a direct quote from the order.

Q. Correct. Is it your testimony that those phrases modify or give context to the word "will" in

item 10 of Order 14546?
A. Yes, and specifically I mean the words "should produce fuel savings" is utilized in this order. So it did not -- this order did not use the word "will produce fuel savings".
Q. On line 6 you use the word -- well, you use the word "estimated". You see that?
A. Yes.
Q. Is estimated the same as forecasted?
A. I think those terms are very similar. I'm not sure they're exactly the same. I think a forecast probably is an estimate. I'm not sure all estimates are forecasts.
Q. In this context you quote the Commission. Is the Commission talking about a forecast when they use the word "estimate"?
A. Well, I need to find the word "estimated", I know it's in here somewhere. I'm looking at the order.
Q. In my copy it's on Page 9, in the paragraph that starts with "we find the appropriate interpretation." I don't know if you have that.
A. Yes, I have that.
Q. It's about four, five lines from the bottom.
A. In that paragraph?

Q. Yes.
A. I'm sorry, I'm not seeing the word "estimated". I'm sure it's there. If you'll give me just a moment.
Q. I have it highlighted.
A. Always coming to my rescue.
Okay, I do see the term "estimated".
Q. Now, is that the reference -- you put that one word in quotes in this line. Is that what you're referring to?
A. It is.
Q. Now, in this context that is contained in Order 11-0080, is the word "estimated" the same as forecasted, as the Commission used it?
A. I'm not sure there's a meaningful distinction here, the way I read this use of the term "estimated", and whether it's a forecast or not.
Q. Well, why did you include that in your testimony, that word "estimated" in quotes? Why did you take it out of the order and put it in your testimony?
A. Because I felt it was significant to rebut Witness Ramas' assertion that the language in item 10 of the previous order we discussed required that there would be guaranteed fuel savings, and that this

language here "estimated" meant that it didn't have to be guaranteed, but that it needed to be estimated, and the Commission would make a judgment as to whether that estimate was credible and whether they felt like these costs would be eligible for recovery.

Q. Now, is the phrase "would be estimated" contained in Order 11-0080?

A. Well, where I quote "estimated" it does not say "would be estimated", but I really don't know whether the term "would be estimated" appears in the order or not.

Q. You don't take that out because you don't quote it, right? You don't take that phrase out of the order because you don't quote it; is that right?

MR. BUTLER: That phrase being the three words "would be estimated"?

MR. REHWINKLE: Yeah.

A. So we're talking about a phrase, the three words "would be estimated?"

Q. Yes?

A. And the question is does it appear in the order?

Q. Right.

A. I do not know if it appears in the order.

Q. But you weren't quoting it as if it was coming from the order, were you? Because you only put quotes around the word "estimated", right?

A. That's correct, I only put quotes on "estimated".

MR. MOYLE: Can I trouble someone to read that sentence into the record that we've been talking about the last few minutes?

BY MR. REHWINKLE:

Q. Can you read the sentence that starts -- that was my next question, John, but thank you -- that starts "that capital"?

A. Yes. "That capital investment provided FPL customers an estimated $24 million in fuel savings in the form of reduced fuel costs to FPL customers by lowering the delivered price or input price of coal."

MR. MOYLE: Okay, thank you.

Q. Now, the word "provided", what context does that give you to the word "estimated"? That's the verb, isn't it, in that sentence?

A. Yes, that is the verb provided.

I interpret that to mean that that was a benefit that was being provided to FPL customers and that that benefit was being substantiated by an estimated $24 million in fuel savings.

Q. Okay. So the Commission here -- would you agree with me that the Commission, at the time they issued Order 11-0080, was looking back on what happened with respect to the rail cars at Plant Scherer?

A. Yes, the Commission was looking back to a previous decision to clarify matters relevant to their consideration of the matter in Docket 100404.

Q. Okay. So the Commission here was recounting what happened with respect to the value that the customers got out of the transaction, right?

A. Yes.

Q. So they were recounting that the value was estimated to be $24 million, aren't they?

A. That's the way I read it, yes.

Q. But they're not saying that at the time that it was considered, that there was a forecast that there would be $24 million in savings, are they?

A. No, I read it that way, that they were saying that -- that when the Commission considered the investment in the rail cars, that part of their consideration was an estimated $24 million in fuel savings.

Q. Did you go back and look at the Scherer order and determine that?

A. I don't recall doing that. It may be

summarized in Attachment A, but --

Q. Well, could you look and see if it is?

A. There is terminology in Attachment A that says, "FPL projects that the $24,024,000 cost will save ratepayers more than $24 million above the cost of the cars over a 15-year period."

Q. Where is that?

A. That's in Attachment A to Order 11-0080, and if you'll look under the column "Project", it's the fourth listing under that column and it says "FPL's recovery of rail cars."

Q. So you're saying that that language there is what the Commission determined prior to approving the rail cars, the Plant Scherer rail cars?

A. That's the way I read it. But sitting here today, I don't recall going back to the order itself and confirming that.

Q. Okay.

A. Let me also say this to help clarify.

I also do not recall that when the Commission approved the investment in rail cars, that there was any requirement that there had to be savings demonstrated in actuality, and there was no limitation on the recovery of those costs dependent upon those savings.

Q. You're talking about when the original order was issued?

A. Based upon my recollection, there were no such requirements or restrictions placed on the recovery of the costs associated with the rail cars.

Q. And why is that?

A. Why is that?

Q. Why were there no such restrictions?

A. Because I think the Commission's policy was then and continues to be that an investment is determined on the prudency based upon what is known at the time, and that there is not a requirement that an investment continually produce net savings over the useful life of an investment.

Q. In your testimony you say that Witness Ramas -- well, let's go to Page 9, line 7 through 9.

You use the phrase on line 8, "Requiring gas production costs to have previously been in rate base". Do you see that?

A. I do.

Q. Can you show me in her testimony where she says that?

A. No, that's just the context of her testimony. The way I interpret her testimony is that their requirement that an investment has to be of the type that had previously been included in rate base or eligible for inclusion in rate base.

Q. Okay. So she didn't testify that these costs had to already have been in rate base and you were just transferring them to rate base?

A. I agree, that's not her testimony.

Q. On page 11 you reference the TECO Big Bend One through Four Fuel Conversion Order 12-0498; is that right?

A. I do recall referring to the TECO order.

MR. BUTLER: The order is actually on the prior page, right?

MR. REHWINKLE: Yes, it's cited on Page 10, line 9.

THE WITNESS: Yes, I see that.

BY MR. REHWINKLE:

Q. On Page 10, lines 19 through 21, you use the phrase "specific to the unique factors of TECO's particular project".

Do you see that, 19 through 20?

A. I do.

Q. Now, does that language appear in the order?

A. That specific language is my own and does not appear in the order.

Q. Does that come from your -- from what you recount that Commissioners said at the agenda?

A. Well, I think that's a combination of what the Commissioners said as well as the language of the order itself.

Q. What language is there in the order that is closest to saying "specific to the unique facts of TECO's particular project"?

A. Well, I think it's what's not in the order. There is no language in the order that's saying that the Commission is adopting a new policy that before items can be recovered in the Fuel Clause, that it has to be subject to a limitation on the actual fuel savings.

So it's what's not in the order, which speaks just as loudly as what is in the order.

Q. Well, if we look at the context of the sentence on line 17, you state that, "Two of the Commissioners comment on this future of TECO's petition at the agenda conference where the Big Bend fuel conversion project was approved, characterizing it as specific to the unique factors of TECO's particular projects, without an expectation that other utilities will follow suit".

A. I recall that being the case as well.

Q. Now, the Commissioners' comments didn't find their way into the order; is that a fair statement?

A. That specific language I don't recall being in the order.

Q. On Page 12, line 11, you use the phrase "misuse another Commission order." What do you mean by that?

A. I mean that I believe that that order as it was being presented for the issues in this case was not applicable.

Q. By saying "misuse", are you applying some sort of context that there was an intent to deceive the Commission?

A. No.

Q. Is it your testimony that a wholly owned subsidiary is not an affiliate?

A. That is not my testimony.

Q. Would you agree that a wholly owned subsidiary is an affiliate?

A. Yes.

Q. The context of my question is if you have a regulated entity and it has a subsidiary, you would agree that that's an affiliate. An affiliate is a subsidiary of the regulated entity?

A. Yes.

Q. On Page 14 of your testimony, looking at lines 4 through 6, you state "the gas output that would come from the Woodford" -- and I guess subsequent plays if it's approved -- "will not be sold as a profit-making enterprise."

Do you see that?

A. I do.

Q. What is the basis of that statement?

A. Relying upon testimony of other FPL witnesses.

Q. Specifically?

A. Mr. Forrest.

Q. Can you give me a reference to where he says that?

A. No, I cannot.

Q. Is your testimony here that FPL will never sell the output from a gas reserves venture, such as would be the subject of this petition, for profit?

A. That's not my testimony. That's something that would probably be better to explore with Mr. Forrest.

Q. You're doing good. I'm eliminating questions.

A. I see you making checkmarks. That's encouraging.

MR. MOYLE: But I'm writing.

A. One step forward and two feet back.

Q. Is it your testimony that all proposed FPL investments are -- I don't want to say proposed, proposed for recovery before the Commission -- are qualitatively the same?

A. Repeat your question. I didn't follow.

Q. Is it your petition that all proposed investments that FPL has or will submit to the Public Service Commission are qualitatively the same?

MR. BUTLER: You started your question "is it your petition."

MR. REHWINKLE: I'm sorry, "your position". I should have opened the Red Bull sooner.

A. I'm having difficulty understanding the focus of the question. I'm perhaps missing some distinction that's relevant in the question. Could you rephrase it?

Q. Sure. We talked earlier about the rail cars in Scherer. That's a type of investment, right?

A. Yes.

Q. And FPL sought and got recovery for that investment?

A. Yes.

Q. For the rail cars. They sought and were denied recovery for the turbine upgrade at the Scherer through the Fuel Clause?

A. Yes.

Q. And they're now seeking cost recovery for investing in gas reserves through the Fuel Clause?

A. Yes.

Q. So those are three types of investments.

My question to you is, are those all qualitatively the same? Do they have the same characteristics and should there be the same level of consideration by the Commission of it?

A. They're the same in one respect and different in another respect.

They are the same in that they are designed and are anticipated to produce benefits for customers, not the least of which is actual dollar savings for customers.

The Commission's decisions for the turbine upgrades, as I understand the Commission's decision, said that that was not sufficient. Even though it may be a prudent investment and provide benefit for customers, it is not the type of investment that is eligible for recovery through the clause and so it denied -- the Commission did not deny recovery because it was a bad investment or a bad managerial decision. They denied recovery of the turbine upgrade costs because it did not fit within the Commission's definition of what is eligible for recovery through the clause.

Q. Does FPL deserve any level of deference by the Commission in consideration of what they propose as investments?

A. Here again, this is a question probably both yes and no. FPL has a very good track record of making investments that benefit customers and seeking recovery of those.

So I'm not sure deference is the right word, but I think the Commission should pay attention to investments that are being proposed and apply the necessary scrutiny to those, but not discount or reject those without a very thorough scrutiny of that and evaluation of the potential benefits for customers that are inherent within those proposals from FPL.

Q. Does FPL's burden of proof differ depending on the type of petition they bring before the Commission on fuel cost recovery?

A. No, I don't think so.

Q. I may have already asked you this with respect to hedges, but let me ask you specifically this way.

Are you providing any expert testimony on whether the gas reserve proposal by FPL is a hedge?

A. No, I do not consider myself an expert on hedges. I am aware of the Commission's policy, sat on the Commission when the Commission first issued an order concerning hedges. I think I have a good working knowledge of what the Commission's policy is and how that is beneficial to customers, but I do not hold myself out as an expert in the field of hedging.

Q. Okay. Do you know -- have you done any research about whether any other Commission around the country has deemed this type of investment in natural gas reserves as a physical hedge?

A. I have done no such research.

Q. Page 18, if you could turn there, please --

MR. BUTLER: Hey Charles, my apology, but my second cup of tea is making it hard for me to focus on your questions.

MR. REHWINKLE: We're almost done, but I certainly --

MR. BUTLER: Do you mind, just a very short break, five minute break?

MR. REHWINKLE: Sure.

(Whereupon a recess was taken.)

BY MR. REHWINKLE:

Q. I want you to go to Page 18 of your testimony.

When FPL buys natural gas as a commodity on the market, do customers bear the risk of non-production or non-delivery under the gas contracts that FPL has?

A. As a general matter I would say yes. I think there are provisions within those contracts that provide guarantees or recourse in case of nonperformance, but there's certainly risks associated with that that ultimately are borne by customers.

Q. Have the customers at FPL experienced increased costs because of non-production or non-delivery of gas, natural gas, under commodity purchases by FPL, to your knowledge?

A. Here again, this is a question that's not really a yes or no.

I would say no, in the sense that I'm not aware of any particular non-performance and there was some type of a penalty or repercussions that were borne by customers.

But there are risks associated with producing natural gas and so one would anticipate that the market itself anticipates that there are risks in that and that the market provides a price which has that amount of risk associated with it as part of the market price.

Q. And consequently, FPL takes that risk into consideration in how they purchase and structure the purchase of their natural gas commodities?

A. Well, I can't say for a fact. I would hope and I would fully anticipate that they do that.

Q. But you're not testifying about the risk that's FPL currently has with respect to purchasing natural gas?

A. No, I don't really get into with great specificity the fact of what risks there are currently that FPL has to be aware of and mitigate, but it is my testimony that there are risks already associated with the market price of gas and that those are risks that are being borne by customers.

Q. What does the phrase "price risk" mean that you use on Page 17, line 18? What is your definition of "price risk" at the time you prepared this testimony?

A. It's primarily relating to the volatility of the price and the potential for prices to escalate due to factors beyond the control of FPL or its customers.

Q. In developing your opinions for purposes of your testimony, did you perform an analysis of all the gas venture reserve places on FPL and its customers?

A. No, I did no such study.

Q. If the petition is approved by the Commission, does FPL have a risk that it will not recover the investment at its overall cost of capital calculated at the midpoint of its authorized ROE?

A. Yes, there is a risk of that.

Q. If the Commission approves the petition and allows recovery?

A. Yes, even if it's approved there is a risk, because FPL has a continuing obligation to monitor, manage, oversee the project and the gas that is obtained, and if there were some material error or oversight or malfeasance, well, then that could be determined by the Commission to be an imprudent action and it could result in the objection of recovery of certain costs.

But having said that, I anticipate absent such a finding, that FPL would recover their investment over the life of the project and in that situation there would be a hundred percent recovery of costs.

Q. Are FPL's ratepayers responsible for providing cost recovery in the form of a return on equity for the risks associated with negligence, imprudence, or malfeasance by FPL's management?

A. Well, in the context of the Commission determining what constitutes prudent costs, I think that that's an ongoing obligation of the Commission and is an ongoing obligation of FPL, to prudently manage its affairs and regulation if it's determined that something has been -- if costs have been incurred or actions have been taken that are imprudent and it adversely affects customers, regulation will take steps to protect customers.

Q. Well, all the things that you listed in your prior answer about malfeasance, imprudence, I think you listed some things that could cause FPL not to earn its rate of return on the investment, right?

A. It's possible.

Q. Those are things that would be, I think underlying your subsequent answer, would be taken carry of by the Commission in the form of a disallowance, right, if imprudence was determined?

A. Yes, that is a regulatory tool to disallow costs.

Q. But the customers aren't responsible for a risk associated with FPL shareholders having to absorb a cost because the management that they hired was imprudent in the form of providing a rate of return or a risk premium, if you will, in cost recovery, are they?

A. I'm going to have to ask you to repeat the question or restate it.

Q. If there's a cost associated with -- I think I'll just strike the question.

Order 12-0425, are you familiar with that order?

A. Well, not just by the order number, but if you could put it in context for me --

Q. Page 23. Do you know the context -- you reference this order in the paragraph, in the Q and A that starts on line 9 and goes through 16. You see that?

A. Give me just a moment to look at it.

Q. Sure.

MR. BUTLER: Charles, just to correct the record, I think you said 14-0425. Are you talking about PSC 12-0425?

MR. REHWINKLE: Yes, that's what I meant.

A. Okay, I see that question and answer and I see the reference to Order 12-0425.

Q. What was the context of the issuance of that order, do you know?

A. It's my recollection that that was an order addressing the weighted average cost of capital that would be used for investments eligible for recovery through the Fuel Clause.

Q. Now, this order didn't establish the principle that utilities that had investments that were being recovered through the Fuel Clause or other clauses would for the first time be allowed to earn an AFEDC rate based on the cost of capital, did it?

MR. BUTLER: An AFEDC rate? I don't recall there being anything about AFEDC rates in that order.

MR. REHWINKLE: Overall rate of return.

A. It's my understanding that this order did not establish that, that it offered clarification as to how that number would be determined or calculated.

Q. Wasn't it prior to this order that the rate of return that was applied to investments that were included in the clause was whatever it was in the last rate case order?

A. I don't specifically recall that, but I would not be surprised if that were the fact.

Q. And what this order does, it said instead of using what could be an out-of-date rate of return based on debt rates that may have changed up or down, that the Commission would authorize utilities to use a more current rate of return rate based on a certain designated surveillance report.

Do you agree with that?

A. Yes, that is my understanding.

Q. So when the Public Counsel stipulated to this, they weren't stipulating to the fact that rate of return would be authorized on investment. They were stipulating to the manner or the method of how it would be determined, right?

A. Yes, I agree with that, but I think it's also in the context that I'm rebutting Witness Lawton here, as I recall, and I'm just establishing the fact that it is generally accepted in Florida regulation to allow a rate of return on investments that are eligible for clause recovery and are determined to be prudent.

Q. But the Public Counsel didn't stipulate to that concept. They stipulated to the methodology; would you agree with that?

A. I can agree with that.

Q. So on Page 27 and 28 you quote Section 366.01, Florida Statutes, right?

A. Yes.

Q. You put a phrase in italics "and all the provisions hereof shall be liberally construed for the that purpose"?

A. I did.

Q. Tell me why you used the italics.

A. I thought that particular phrase was particularly relevant.

Q. Are you testifying that that particular phrase should be given greater weight than the rest of that statutory provision?

A. No.

Q. On Page 28, line 19 through 20, you state that 366.01 -- I'm starting on line 19 -- you state:

"Section 366.01, Florida Statutes, makes it clear that the public interest is the ultimate test and not whether an investment incurred to provide electric service to customers at a lower and more stable fuel cost has been traditionally done or whether it fits neatly in a uniformed system of accounts designation", right?

A. Yes.

Q. What is your basis for saying that that statute makes it clear that the public interest is the ultimate test?

A. Because this particular provision speaks to the public interest and requires the Commission to regulate in the public interest.

Q. So where did you find the phrase "ultimate test"? Is that a legal determination that you made?

A. No, it is not a legal determination.

Q. Is that a legal determination that someone at FPL gave you and you included in your testimony?

A. No.

Q. What do you think is the intent of the phrase "shall be liberally construed"? Is that for FPL's benefit or for the benefit of who?

A. It's for the public's benefit.

Q. So it's not your testimony that you read 366.01 as a directive to the Commission to liberally construe statutes in a way that makes it easier for FPL to have the gas reserves petition approved?

A. That's correct, I do not interpret it that way. I do think the Commission has a responsibility to liberally construe the provisions of its controlling statutes to ensure the public is adequately served and that utilities are regulated in the public interest.

Q. You would also agree that they should liberally construe the provisions of the statute to make sure that the public is adequately protected?

A. Yes.

Q. Finally, on Page 30 -- actually, let's just strike that question and let me end my questions. That's all I have.

Thank you.

THE WITNESS: Thank you.

MR. REHWINKLE: Who's next?

MS. BARRERA: I'm next.

CROSS EXAMINATION

BY MS. BARRERA:

Q. Morning, Mr. Deason.

A. Good morning.

Q. Can you please turn to Page 8 of your rebuttal testimony. Here you discuss the recovery of capital projects eligible for cost recovery through the Fuel Clause; is that correct?

A. Yes.

Q. Given your work experience both with the Office of Public Counsel and as a Commissioner, would you agree that you're familiar with Commission practice as it relates to the recovery of capital projects through the Fuel Clause?

A. Yes.

Q. In line 22 of Page 8 through line 2 of Page 9 of your testimony you discuss the Commission practice of reviewing the eligibility of capital projects for recovery through the Fuel Clause on a case-by-case basis; is that correct?

A. Yes.

Q. Do you disagree with this Commission practice?

A. No.

Q. Would you agree that the guidelines proposed by FPL for recovery through the Fuel Clause seeks to avoid the practice of case-by-case review?

A. That's not my understanding of the guidelines, but that may be a question better asked to Mr. Forrest.

Q. Now, please turn to Page 17 of your testimony. Are you there?

A. I am.

Q. On these lines you discuss the expectation that rates will be set to allow for a reasonable rate of return.

Would you agree that the authorized ROE set by the Commission is based on the premise that the company has an opportunity to earn this return?

A. Yes.

Q. Now, following your statement on line 17 to 19, you state that "without the reasonable opportunity to earn its authorized rate of return, the allowed return would have to be substantially higher and result in higher rates for the customers"; is that correct?

A. Yes.

Q. Would you agree that the authorized ROE is set based on a company's opportunity to earn it, not a guarantee that the company will earn it?

A. Yes.

Q. And you state that without a reasonable opportunity to earn its authorized rate of return, the return would be substantially higher.

In your opinion, does the converse also hold true; that if a company was guaranteed to earn its authorized rate of return rather than just an opportunity to earn this return, the rate of return would be lower?

A. All other things being equal, if there was an absolutely guarantee that there would never be any disallowances in the costs requested by a utility, I would think the market would take that into consideration and would bid up the price of those stocks and would indicate a lower cost of equity for a company, but I don't think that's reality.

But from a theoretical level I could see that would be the result.

Q. And based on your experience with the Commission, would you agree that the cost of capital recovered through the Fuel Clause on a prudent -- on prudent capital investments, is trued up each year such that the utility earns its midpoint ROE on this investment?

A. Yes, assuming no disallowances, that would be the result and it would be done on an annual basis and would be trued up.

Q. And would you agree then that prudent capital investments recovered through the Fuel Clause are guaranteed to earn the midpoint ROE?

A. No, I don't necessarily agree with the term "guarantee". That's a very strong term. I think the likelihood is high, but there is also the annual review, and there is an annual review of the prudence of all of those decisions.

So that adds some element of risk associated with fuel recovery that you don't have in base rates, but there are other elements in the fuel recovery which enhances recovery, more timely recovery. So you basically eliminate regulatory lag as a risk.

So there are measures, pros and cons, and think it's important to remember that investors are aware of a regulatory structure or regulatory policies in Florida and those are reflected in the market, and then those professionals that are experts in determining ROE take all that information into consideration and the Commission weighs that in determining what that reasonable return is.

Q. Would placing FPL's investment in the Woodford project above the line provide FPL's -- we're talking the GRCO, it's the unnamed subsidiary --

A. Okay.

Q. -- with an unfair competitive advantage due to its ability to earn a guaranteed return on its investment regardless of its performance?

A. I have to ask to clarify, competitive advantage over whom?

Q. Hold on one second.

The competitive advantage we believe would be favorable or disadvantageous conditions applied to some competitors and not others.

MR. BUTLER: A competitor for what? I'm just trying to understand the context here. You're talking about somebody else who would be selling gas to FPL would be disadvantaged compared to this subsidiary or what?

MS. BARRERA: Participants participating in

Woodford.

MR. BUTLER: If you understand the question.

A. I'm going to answer your question and if it's not responsive, please let me know.

I don't see a competitive disadvantage, because the investment that is being proposed to be made is an investment specifically for the purpose of providing stable, cost effective gas to customers of FPL, and FPL is not making the investment to go into the gas market and to sell a commodity, competing with other producers on the general market.

So in that sense I don't see that there's a competitive concern with the proposal.

Q. If the Commission rules not to grant FPL's petition, is it true that USG will retain all rights, benefits, and responsibilities of the Petroquest joint venture?

A. That is my understanding, but Mr. Forrest could confirm that.

Q. Is it correct to say that if the Commission rules not to grant FPL's proposal, USG will bear all the costs and risks of the Petroquest joint venture?

A. Yes, they would bear all the costs and risks, along with all the benefits.

Q. Here's a hypothetical. If FPL and its customers were to share 50-50 of the Woodford project's gains and losses between the production costs and the market price of gas and share 50-50 the cost of the return on the investment above the line, would that provide FPL with an incentive to maximize the benefits to be shared with customers?

A. I would say it would offer an incentive, but I'm not sure it would maximize, because the way this proposal is structured, a hundred percent of the benefits are going to flow through to customers and if there were a sharing, that might not result in the maximum benefit for customers.

Let me also add, I think it would detract from the benefits of the hedging attributes of the proposal as well.

Q. And in the 50-50 split hypothetical, would that retain for FPL and its customers access to producing wells and therefore the benefits of other stable gas prices relative to market prices, while providing appropriate incentives for FPL to minimize costs and maximize gains?

A. Here again I see where such a proposal -- which is hypothetical, because it's not part of the proposal.

Q. Yes, yes.

A. I could see where there could be some advantages and detriments associated with that. I think that it would necessitate a very thorough review of the various benefits and risks associated with that and what incentives there would be and how that particular mechanism would function.

I am not dismissing it out of hand and saying it has no merits. I think it's really something that's not in front of the Commission at this time.

If the Commission were inclined to consider such a proposal, I think it would necessitate -- it would necessitate a very thorough review, and that has the downside of this particular proposal not coming to fruition, and I think that based upon the cost savings projections as provided by Mr. Forrest, that it's a tremendous opportunity that would go by the wayside.

So I believe the Commission should also consider the potential benefits that are at hand right now and weigh that as to whether a decision that basically modifies this proposal would put the benefits of this proposal in jeopardy.

Q. So really your opinion would be that if the Commission were to consider this, we'd have to have further proceedings on determining whether or not the 50-50 was a --

A. To give it its full due consideration, that's what my recommendation would be, and my fear is that if you would do this you'd have a very -- a proposal which offers very substantial benefits to customers that would not come to fruition.

My recommendation is to consider this proposal and then at some future time if the Commission were inclined to modify the guidelines or the particular structure involved, that it be done in a different proceeding, a new proceeding.

Q. Excuse me one second.

Are you familiar with Mr. Forrest's testimony where he stated that should the petition not be granted, USG would simply retain its interest and value in the Petroquest agreement?

A. That's my understanding. I do recall seeing that in his testimony.

Q. And your testimony or your understanding is that USG is willing to bear all the costs and risks, a hundred percent of the costs and risks associated with the Petroquest joint venture?

A. Yes.

Q. He changed the order of my questions, so that confused the heck out of me.

A. That's okay.

Q. In Witness Forrest's rebuttal testimony he said that FPL would pursue projects only where the fuel savings are expected to exceed the project's revenue requirements.

Do you agree with this assessment?

A. Yes, I think that obviously there needs to be benefits for customers and one of the very most significant benefits is absolutely cost reductions, cost incentives for customers.

So I agree with that.

Q. You may have testified to this before, but in your opinion, are the proposed gas reserve project investments guaranteed to produce fuel savings for FPL customers?

A. No, I don't think there's a guarantee. I think according to the testimony of Mr. Forrest, there is a high probability that there will be absolute fuel savings, somewhere in the 85 percent probability range, but I'm sure you'll discuss that with Mr. Forrest.

Q. Now, please turn to line 16 on Page 11 of your testimony.

A. Okay.

Q. What do you mean by the phrase "asymmetric risk of recovery"?

A. Give me a moment to put this in context.

Q. Sure.

A. This is in the context of the TECO decision and TECO's willingness to put their investment subject to a test of fuel savings, and I was comparing and contrasting what's in front of the Commission with this proposal and making the point that a large portion of the cost of this investment is going to be subject to depletion, and if at any given time the market price of gas were below and this restriction were put in place, that you could have a large portion of the cost of the investment through depletion such that it would not be an opportunity on the back end of the investment to make the investment whole or to have a fuel complete recovery.

So that's what I mean by "asymmetric", comparing to what was done for TECO.

Q. Just to clarify, the fuel savings for FPL customers are dependent on the actual outcome of the drilling and production activities, but FPL will earn its midpoint ROE on its gas reserve investments independent of the outcome of the drilling and production activities.

Would this also be an example of asymmetric risk of recovery?

A. No, I think that is very symmetric. It is symmetric in the policies and the principles that I address in my testimony.

When an investment is made for the benefit of customers and that investment is dedicated specifically for those customers, there is a possibility that economic changes or other changes could have that investment be very beneficial at times and not so beneficial at times, particularly over the very long life of an asset.

So the ultimate test is, is the investment made -- is it prudently incurred, is it expected to provide savings for customers, not that it absolutely, 100 percent will be a guarantee for savings for customers; and the utility in making that investment is entitled to the opportunity to earn a fair return on that investment, but is limited in that return.

So that's where the symmetry comes in. It is an investment made, devoted specifically for customers and in making that investment, that investment is limited to that regulatory rate of return and there's not the upside potential of a really large return, neither is there the risk of earning a return that is substantially below what investors consider to be reasonable.

Q. Now, for purposes of this question will you assume that FPL's petition for approval of the guidelines is approved as filed. Is it your testimony that prudence attaches to the gas reserve investment at the time the investment is made, pursuant to the guidelines?

A. I want to clarify the question. You're saying if the guidelines are approved and FPL uses those guidelines to make an additional investment in a gas reserves project, does the Commission's determination of prudence attach at the time that investment decision is made?

Q. Yes.

A. Yes, I think the Commission would have the ability to look at that investment -- first to make sure that it was consistent with the guidelines. If it were consistent with the guidelines, I think there should be a presumption that it was correct, but not absolutely guaranteed that it was correct.

There's still a burden on FPL to continually manage that investment and to demonstrate that FPL acted prudently in that, but I think there has to be some balance there. If the Commission approves the guidelines, there should be some meaning and substance to that and there should not be a second-guessing of those guidelines after they are put in place.

So as the Commission always does and does a very good job of doing, it balances all of these things in weighing them and making ultimate decisions.

Q. Can you please turn to Page 26 -- I'm sorry, scratch that.

Is it your testimony that as long as the investment is consistent with the guidelines, I guess, prudence attaches at the time of the investment?

A. Yes. I think there's an obligation, first of all, for FPL to abide by the guidelines, to demonstrate to the Commission that a project is consistent with the guidelines, that it offers benefits for customers, and that it will be managed for the benefit of customers.

You know, the purpose of a guideline is to give enough assurance to cost recovery that FPL would be willing to make these investments in a very timely manner when there are opportunities present and not subject an opportunity to the very thorough review that we're going through here, because those opportunities may evaporate before an ultimate determination could be made.

So here again, it's that balance to find opportunities, present them, and make a decision, but obviously FPL has the obligation to continually manage that project so it has the highest probability of providing benefits for customers.

Q. Can you please turn to Page 26, lines 8 to 13 of your rebuttal testimony.

A. Okay, I'm there.

Q. And you quote the order PSC-02-1484 that explained the Commission's policy on fuel hedging.

The order states that, "The Commission retains discretion to evaluate the prudence of hedging programs at the appropriate time."

Would you agree that according to this order, prudence did not automatically attach at the time of the investment, pursuant to the 2002 hedging order?

A. Well, here again, I guess it means -- the significance of the phrase "prudence attaching at the time", I may be missing your meaning of that phrase.

As I understand the proposal that's currently in front of the Commission, that it does provide hedging benefits and those are significant and should not, you know, be understated, but at the same time the primary benefit for customers is absolute dollar fuel savings that are anticipated.

So I think all of these things have to be part of the Commission's balancing of a particular project. The fact that there are certain parameters and guidelines for hedging are good and to the extent they are consistent with a project of this nature, that should be part of the consideration. But at the same time absolute fuel savings for customers is part of the equation, part of the formula, and that has to be part of the balancing as well.

Q. In your opinion, is the proposal in FPL's petition for guidelines for physical hedging and gas reserves different from the framework approved in the 2002 hedging order?

A. I do not read in that order that there is a distinction made between physical hedges and financial hedges, that they are pretty well classified together and acknowledges there should be flexibility in evaluating both physical and financial hedges.

So I don't know -- the fact that this is a physical hedge, I don't know that that makes it somehow fundamentally different when it comes to the evaluation of this project in terms of its hedging benefits. But as I said earlier, this project provides much more than hedging benefits and that is an anticipated reduction in the absolute cost of fuel to customers, and that has to be balanced and weighed as well.

Q. Hold on one second.

The question, which in your opinion is the proposal in FPL's petition for guidelines for physical hedging different from the framework approved in the 2002 hedging order, we're relating it to the prudence determination.

Is the prudence determination in the 2002 hedging order different from what FPL is proposing now for the guidelines?

A. I think there is a potential for a difference in the fact that this project is not simply a 100 percent hedge play, if you want to use that terminology. It is an opportunity that will likely, but not guaranteed, but will likely produce fuel savings, and it is not the goal of a true hedging opportunity or initiative to produce fuel savings.

It could, but it may not, and that is not one of the judgmental factors as to whether that product is a successful hedge or not, as to whether it produces a absolute savings. This project is designed to produce those benefits, but is also a hedge.

So simply to apply the hedging criteria and the guidelines to this project without weighing the benefits of the fuel savings, I'm not so sure that those two are always a hundred percent compatible.

To the extent they can be compatible and consistent, I'm comfortable with that, but sitting here right now I can't say that the hedging guidelines should be applied to this project 100 percent without considering the benefit of the savings in the commodity price of the fuel.

Q. Earlier you stated that a proposed 50-50 sharing of the benefits reduces the benefits to customers. Would also a 50-50 sharing reduce the risk to customers?

A. Yes, I think it would minimize the potential downside. Even though this project has, as I think Mr. Forrest has testified to, an 85 percent probability or somewhere in that neighborhood of producing benefits, there is a 15 percent probability that it would not, and if there is a 50-50 sharing it would mitigate or eliminate some of that risk on the downside.

My concern is that if this were proposed and implemented or attempted to be implemented here, we may forego a hundred percent of the benefits of this project that's currently in front of the Commission. That's my main concern.

MS. BARRERA: All right. We're done with our questions. Thank you very much. Appreciate it.

MR. MOYLE: It's my turn now and I would defer to you, Mr. Deason, as to whether you're ready to charge ahead or take a break.

MS. BARRERA: I'd like to take a break.

THE WITNESS: I want a break too.

MR. MOYLE: Why don't we take five minutes.

(Whereupon a recess was taken.)

CROSS EXAMINATION

BY MR. MOYLE:

Q. We're back on the record.

For the record, John Moyle on behalf of the Florida Industrial Power Users Group, and I want to ask you a host of questions about a number of topics that you discussed in your testimony and some you discussed in prior questioning by the attorneys.

Before we do, some preliminary matters. Just so we're clear, what is the purpose of your testimony as you understand it?

A. The purpose of my testimony is to rebut testimony provided by the intervenors in this docket.

Q. And I read it to be having a lot of context about orders and Commission policy. Is it fair to say that you're holding yourself out as an expert in Commission policy?

A. Yes.

Q. You know you have a level of expertise that precedes that of your able counsel next to you, Mr. Butler?

A. I'm a very humble guy, so my answer is no.

MR. BUTLER: I'm humble too, so I'll say it's yes.

Q. And I'm not going to ask you about me and we'll just move on. I think we've covered that point.

Have you ever testified for consumers since you joined the Radey law firm?

A. Yes.

Q. When and where?

A. It was in the -- first of all, it was in North Dakota and it was in the 2007, 2008 time frame.

Q. And was it for advocacy counsel? Did they have a setup in North Carolina?

A. In North Dakota, I'm sorry.

Q. I'm sorry, in North Dakota.

A. Yes, there was a segment of the staff at the North Dakota Commission which is the advocacy staff, and I was retained by the advocacy staff in North Dakota.

Q. So the advocacy staff in North Dakota is charged with protecting the consumer interest; is that right?

A. Yes.

Q. You would agree that the consumer interest is a significant component of the public interest, correct?

A. Yes, I agree.

Q. With respect to how you determine Commission policy, would you just describe for me how you ascertain Commission policy, in a general context?

A. First of all, your first question was determine, the second question was ascertain. I don't determine Commission policy.

Q. Determine what it is.

A. Oh, determine what it is?

Q. Right.

A. My understanding of that, how do I do that?

Q. Right.

A. Based upon my experience and review of

Commission decisions.

Q. You would agree that Commission decisions, orders are the official documents of the Commission setting forth the policy, correct?

A. Yes.

Q. You would also agree that while your experience may provide insight just based on recollections -- I think you had a conversation with Mr. Rehwinkel where you were trying to recollect something, and I think you can agree with me that having written documents is a better source of information than relying on recollections, correct?

A. As a general matter, I would agree with that.

Q. You would also agree that as a matter of policy, that Mr. Butler or Mr. Rehwinkel or a member of the Florida Bar, if someone calls them and asks them a question about the PSC policy, that they should be able to perform legal research, read opinions, look at the statutes, read Commission rules, and they should be able to answer the question related to policy without having to resort to anything else, correct?

A. Yes, and as most situations in any endeavor, where there's two or more attorneys there's going to be two or more opinions as to what that policy is; reading the same orders and having the same recollections.

The purpose of my testimony to bring that into perspective and provide additional guidance into that for the benefit of the Commissioners.

Q. And you would agree that -- I mean, you view some of these orders differently than Expert Witness Ramas and Mr. Pollock, correct?

A. Yes.

Q. And that's not to say that one is right and one is wrong. They're just different, correct, as a matter of judgment?

A. There is judgment involved and so since there is judgment involved, I think it's helpful to the Commission and very appropriate for experts in the field to provide opinion on that, to provide perspective on that, and hopefully the Commission finds that useful and it helps them in their deliberations and their ultimate decision.

Q. You would agree -- I think you have -- that the best evidence of the Commission policy is the Commission orders, the Commission rules, and the statutes, correct?

MR. BUTLER: I object to that as asked and answered. You can answer it.

A. I can answer? Yes, I agree.

Q. You also agree that ultimately the Commission's decisions related to policy are that of the Commission?

A. Yes.

Q. You would also agree that as a matter of policy, one commission should not act to bind a future commission?

A. I agree that -- in fact, should or even could, I'm not sure that the Commission could bind another future commission, but I don't think that they should either.

However, the Commission should take effort in delineating its policies, to the extent it can, to be consistent in abiding by those policies and when circumstances necessitate a deviation from the policy or a further clarification of a policy, that it be adequately explained so they all can benefit from the guidance from the Commission as to what the future policy is going to be.

Q. You served on the Commission for how many years?

A. 16.

Q. And you follow it closely to this day; is that correct?

A. Yes.

Q. Tell me your understanding with respect to how the Commission articulate its policies.

A. The Commission articulates its policy through its decisions, which are contained in orders and in the rules which it adopts, which are contained -- they are also discussed in orders, as well as the issuance of the rule itself.

I think that would probably be the two main ways that the Commission declares what its policy is.

Q. Do you have an understanding of the phrase or term "incipient policy"?

A. I have a layman's understanding of what that term is.

Q. Please tell me what that understanding is.

A. Incipient, meaning that it is being developed as decisions are being made and that it can evolve to some extent and perhaps greater clarifications given to a policy, and that at some point incipient policy may get clarified and relied upon to the extent that it in essence becomes the rule and perhaps the Commission then should actually adopt a rule, to set out that policy in the form of a rule.

Q. I don't want to put words in your mouth, but let me just try to see if I understand what you said.

A. Okay.

Q. It's your understanding that there can be a process by which incipient policy is developed, but to the extent that goes along at some point, it's probably appropriate to set forth that policy and rule?

A. I think that has been the practice of the Commission and I know the Commission has done that at times. I'm not sure exactly where you draw the line to say that now's the time to adopt a rule, but maybe it's kind of in the eyes of the beholder at that particular time.

Q. Do you know who would make that decision if somebody were to contest whether a rule should be adopted or not?

A. I think the Commission has the ability to propose a rule on its own motion and parties, intervenors, regulated entities, can approach the Commission and propose that a rule be adopted.

Sometimes the Commission gets guidance from the legislature and statute that it deems that the Commission should go to rule-making to provide guidelines for the implementation of a statute.

Q. Mr. Rehwinkel said -- well, let me put a couple of facts in. The fuel costs that we spent some time talking about, is there a rule that addresses the Fuel Clause?

A. No, I don't believe there is a rule addressing the Fuel Clause.

Q. And how long has the Fuel Clause been used?

A. Oh, in Florida it's probably -- well, I started in regulation in 1977 in Florida. The Fuel Clause existed then. It was my understanding it had been around for a long time even before then.

So conceivably the 1960s perhaps, maybe even late 1950s. It's been around a long time. But exactly when it started, I'm not sure. But I know it existed in 1977.

Q. Do you know if there's any statutory authority for the Fuel Clause?

A. Well, yes, the Commission has the obligation under statutes to regulate in the public interest.

Q. 366.01, right?

A. Yes. So to the extent that the Commission in its discretion determines that the best way to regulate utilities in the public interest is to have fuel costs which are perhaps volatile in nature to be recovered through a Fuel Clause, that the Commission has the discretion to do that.

Now, whether there's specific language in the statute that directs the Commission to recover fuel costs in the Fuel Clause, I don't recall that language being in the statute. In fact, I do not think that language exists in the statute.

Q. So given that answer, I guess it would be fair -- you would agree with the statement that there's no express authority for the Commission to allow for recovery of rates through the Fuel Clause, other than general authority to regulate in the public interest, as set forth in 366.01?

A. Well, I would not limit it only to 366.01. There are certain statutory provisions that talks about how rates are duly established and how costs are to be apportioned and concerns about the opportunity to earn a fair rate of return.

All of these things are in the statutes and I think they provide a basis for the Commission to utilize the Fuel Clause to recover fuel costs.

But I don't think that you're going to find a specific statutory provision utilizing the terms or an expression of the legislature directly to the Commission that it shall use or must use or can use a Fuel Clause mechanism.

Q. There's not one, correct?

A. Not to my knowledge.

Q. To compare or contrast the environmental cost recovery clause, do you have an awareness of whether the legislature has acted specifically with respect to the ability of the Commission to allow for certain qualifying environmental expenditures to be recovered?

A. There is a specific statutory language, a statutory provision regarding environmental costs.

MR. BUTLER: Which part of the rebuttal testimony are you addressing right now? This seems far afield.

MR. MOYLE: He's an expert in regulatory matters.

MR. BUTLER: Sure, he's an expert, but he's here to be deposed with respect to his rebuttal testimony and this seems way far afield from it.

MR. MOYLE: He testifies extensively about the Fuel Clause. I want to test his understanding of the words in the Fuel Clause.

MR. BUTLER: I'm not aware of where he testifies extensively about the Fuel Clause. He testifies about this project as being eligible for recovery through it, but --

MR. MOYLE: I think that the record will

speak for itself.

BY MR. MOYLE:

Q. Do you cite orders referencing the Fuel Clause in your testimony?

A. Yes, I do.

MR. BUTLER: But you're not asking him about those orders. You're asking him about the origins of the Fuel Clause and the statutory authority for the Fuel Clause, etc. It seems pretty far afield.

MR. MOYLE: Maybe others than us will be making decisions related to that.

BY MR. MOYLE:

Q. If Mr. Rehwinkel comes in and says, "Mr. Deason, this Fuel Clause has been around forever and there's no rule -- you know, it's way beyond incipient policy," do you have an understanding as to who would make that judgment?

Would that judgment be made -- just leave it at that. Who would make that judgment?

A. Let me make sure I understand the question. Who would make the judgment as to whether the Commission should adopt a rule concerning the Fuel Clause?

Q. Right, do you know?

A. I think that would -- absent direction from the legislature for the Commission to adopt such a rule, I think the decision to propose such a rule and to ultimately adopt a rule would rest with the Commission, and the Commission has not seen it necessary to do so after all these many years.

Q. Who contacted you on behalf of FPL to talk about this case initially?

A. I believe it was Mr. Butler.

Q. Was that a phone call or email, do you remember?

A. Phone call.

Q. Did he share anything about the case when he contacted you, do you recall, as to what FPL was attempting to do?

A. At a very high level he just told me that a petition had been filed and basically what was being requested, and then he quickly just suggested that I review the filing and the testimony --

(Discussion off the record.)

A. -- sorry for the interruption. What was the question?

Q. In terms of what you did after being contacted by Mr. Butler, I think you testified that you read the petition and looked at the testimony.

You were going through what you did.

A. Yes, at Mr. Butler's suggestion that I should do that, which certainly makes sense to me, I should read the petition and read the testimony.

Then I took the further step of looking at orders that were referenced in the petition and in the testimony and then did some further research on my own into orders that I felt may be relevant to the issues at hand, and so I did that to form a foundation to understand the nature of the case and the potential issues that could arise.

Q. Did you do that research yourself?

A. I think some of it I did myself, but I think that a substantial portion of orders or citations to orders, references to orders, were given to me by Mr. Butler. But I did not limit it to just what Mr. Butler provided.

Q. So did you independently go and look for other orders that Mr. Butler may not have provided?

A. Yes, I did that, as well as I may have relied on some research done at FPL. But I directed that -- "Hey, listen, I'd like to see an order dealing with this subject matter. I seem to recall a decision from the Commission in such and such time frame."

So I may not have done the Lexis search or whatever other search tools are out there, but I directed the research, in the sense that I told Mr. Butler what I would like to take a look at.

Q. So Mr. Butler helped coordinate the research; is that right?

A. I think that's probably true, yes.

Q. Did you listen to any transcripts of any agenda conferences as it relates to the issue?

A. No, I don't think I listened to the agenda conferences themselves. I may have read transcripts, but I don't recall actually listening to a recording or a video of an agenda conference.

Q. Do you have a recollection of reviewing transcripts specifically to this matter?

A. I may have. I don't recall specifically.

Q. So when you bill FPL for your work, do you do it on a time basis?

A. Yes, it's on a time basis.

Q. Tell me how you do that.

A. I keep track of my time when I work on a project and I submit it to the correct person at our firm and they come out with a bill. I review the bill and then it is sent to the client and hopefully the client pays it.

Q. In my law practice clients like to see when

I bill by the hour, a narrative as to what I did and why I'm charging them. I assume that's the same with you?

A. Yes, it is.

Q. So your time records should accurately reflect the time spent and what you spent it on in this case, correct?

A. Yes.

Q. And it also would reflect the research that was done and things that you did to come up to speed, correct?

A. Well, yes, but there probably would not be specificity that I spent X number of minutes looking at order X, Y, or Z. If I reviewed orders, it would indicate that I was in that process, but I probably would not list it by each individual order and the amount of time reviewing each specific order.

Q. If you reviewed transcripts, it would likewise reflect that you reviewed transcripts?

A. Probably. I'm not saying it absolutely would a hundred percent of the time, but it probably would.

Q. I have a lot of questions and I'm going to try to ask sort of a big picture question and see if we can engage in a conversation to test my understanding of how you view regulatory policy, given your testimony and your prior answers to questions, and I'm going to preface that by saying in responding to Mr. Rehwinkel I thought you indicated that the authority, as you saw it, of the Commission to regulate in the public interest was broad enough in such a way that the Commission could make a decision related to this project or other projects that may come before it so as long as it made a determination that the petition was in the public interest.

Is that your view?

A. From a broad perspective I would agree with that.

Q. So all of the time spent on this item 10 in this order -- you understand what I'm referencing when I say item 10?

A. I do.

Q. It's a bullet point that was in a previous order that there was a lot of testimony about.

If I understood your comment about the broad authority of the Commission, I interpreted that to mean that you don't think that there's a compulsion, you know, to follow or recognize item 10, as set forth in testimony; is that right?

A. No, that is wrong.

Q. Tell me why.

A. I think item 10 is very instructive for the Commission; not only the specific language of item 10, but how the Commission has utilized that item in subsequent decisions and have offered further clarification of what is contained that item 10, and that it is good for the Commission to be aware that language, to be aware of its decisions, and to make a decision in this case consistent with that language and consistent with prior decisions as it would be consistent with the Commission's policy.

Q. And do you have a view as to whether this project comports with and is consistent with item 10?

A. Yes.

Q. And that view is that you believe it is?

A. Yes.

Q. Notwithstanding the fact that item 10 uses the phrase "will result in fuel savings to customers"?

A. The entirety of the language of item 10 should be recognized by the Commission.

It is my position that the proposal currently in front of the Commission is consistent with all of the language in item 10 and consistent with subsequent decisions of the Commission implementing that item and in further interpreting that item.

Q. I just want to focus on item 10 right now. Do you believe "will" and "shall" are synonymous terms?

A. I think they're pretty much synonymous. Of course, that's a nonlegal interpretation.

Q. In item 10 there's no qualifying words associated with "will result"?

A. Within the confines of item 10?

Q. Right. It doesn't say "will likely result" or "could result" or "may result". I mean, item 10, applying those words as plainly written, you would agree there's nothing to qualify or provide room with respect to item 10?

A. I agree that there's no qualifying words, as you suggested, but I think there's room within the words that are within item 10 to give discretion to the Commission to make those judgments.

Q. So let's spend some time talking about that.

Do you think there's any room in the phrase "fossil fuel related cost"?

MR. BUTLER: Room for what?

MR. MOYLE: Room for interpretation that would allow the Commission to act in the public interest and approve a project that may not give effect to the words "fossil fuel related cost".

A. Sure, it's up to the Commission to interpret that, and the Commission has interpreted that. In some instances it's decided that the purchase of rail cars is a fossil fuel related cost if they're utilized to transport coal, which is a fossil fuel.

The Commission has also determined that a turbine upgrade at a plant which would have resulted in fuel savings was not necessarily a fossil fuel related cost.

So yes, the Commission has the ability to determine what is a fossil fuel related cost.

Q. Is uranium a fossil fuel?

A. You know, I would not classify it as a fossil fuel.

Q. You think the Commission -- let's say this proposal came forward from FPL and everything was the same, except we weren't talking about natural gas, we were talking about a uranium mining operation.

Do you think the Commission could look at that, given item 10 and other things, and say, well, it's not a fossil fuel, we agree with Mr. Deason, but because we think this may be a good thing, we'll go ahead and approve it?

A. You know, we're speaking hypothetically here.

Q. Right.

A. So in the hypothetical, I think it's possible that a case could be shown that a greater reliance on uranium would somehow displace fossil fuels and the net result would be a more efficient system and reduced reliance and reduced costs associated with fossil fuels, perhaps environmental costs associated with fossil fuels.

In the hypothetical all that is possible and that would be up to the Commission to use their discretion. It also would be up to the Commission to use their discretion to say that notwithstanding the language in item 10, we think for broader public policy purposes that such a proposal that has something to do with uranium fuel would -- it would be in the public interest to allow Fuel Clause recovery of that; in the hypothetical.

Q. So the last part of your answer takes me back to my question about -- my understanding is you believe that the public interest authority in 366.01 provides broad discretion to the Commission in a way that they're not constrained by item 10?

A. I agree that the Commission has broad authority and is not necessarily constrained by item 10 in all situations, but that it is best from a regulatory perspective to abide by policy, to be cognizant of and to follow that policy to the extent that it can, and if in the broader -- and in the Commission's broader judgment, if it needs to deviate from that or make an exception, the Commission can.

But that's not relevant here. What's being proposed by FPL fits squarely within the confines of item 10.

Q. And you're aware that's subject to some disagreement and debate, right?

A. Yes, I'm aware of that.

Q. I don't want to belabor the point I tried to make with uranium, but if I asked you the same question and rather than uranium I said a facility that makes solar panels and the testimony was, hey, this is a great deal on this facility, it's going to be able to produce solar panels that are a lot less and you know, we think the market is going to look like this in the future, let's go ahead and step up and buy the solar facility and the same construct that's being used here could be used in that context, I assume your answer would be the same; that you believe that is something that could be considered by the Commission notwithstanding the language in item 10?

A. Here again, speaking in a hypothetical, it's conceivable that the Commission could do that. Whether the Commission would or even should is a different matter.

MR. MOYLE: For the record, if this is proposed at some point, the idea came from me.

MR. BUTLER: We'll give you full credit, John.

BY MR. MOYLE:

Q. Do you know who came up with the idea of the Woodford project?

A. I do not.

Q. We're down to Mr. Forrest. We'll see if he raises his hand.

You'd agree with respect to item 10, that others could view that language differently, right, and that doesn't make it wrong necessarily?

A. I agree that others, very intelligent, knowledgable, experienced people can interpret it differently, and I respect their opinion. I just happen to disagree with them.

Q. Are you familiar with any judicial cases or anything that talk about words being given their plain meaning when interpreting things?

A. I seem to recall that has been cited in cases before, but I can't point you to one.

Q. You authored opinions, I assume, when you were on the Commission, right?

A. I made decisions --

MR. BUTLER: Do you mean authored orders that the Commission issued?

MR. MOYLE: Yeah.

A. -- I made decisions that ended up being in orders, but I never actually wrote an order. Perhaps an occasional dissent that I authored, but the orders themselves I did not author.

Q. I never served as staff, so I'm just going to spend a minute to ask you a couple of questions.

My assumption was that the Commissioners will review draft orders to make sure that the draft orders articulate, you know, policy in a way that is consistent with the Commissioner's view and/or the collective Commission's view.

Is that a correct assumption?

A. Yes and no. The Commissioners have the ability to read the orders before they are issued. Whether they do so is up to them, and it was my experience that it rarely happened; that the Commission had relied upon the staff to write those orders consistent with their decisions and that the staff of the Commission always did a fair job, perhaps not a perfect job, but a fair job in doing that, and that the Commissioners themselves -- I as one, I speak for myself, I did not find it necessary to review every order that left the Commission to make sure it was 100 percent in compliance with what I thought the decision was.

Q. But, you know, talking historically, you wouldn't necessarily feel like you would walk away or distance yourself from an order that may have been entered when you were sitting on the Commission, right?

A. I have never distanced myself from an order that I participated in. Now, at some point it may come up, but it has not heretofore and I don't think it would.

Q. And the reason I'm asking the questions is because I noted that in your testimony, when you wanted to emphasize something you put it in italics, right?

A. Maybe once or twice, as I recall.

Q. And there are ways to emphasize things, you would agree; underlining, bold, putting it in caps. All those are ways in which a writer of a written product can place emphasis on something in a written document, correct?

A. Those are tools available to an author.

Q. For emphasis?

A. For emphasis, I would agree.

Q. When you say on Page 6 about the Commission's intent to emphasize, there was nothing in the order along the lines we just talked about with respect to italics or bold or underlining. I mean, you didn't come to the conclusion on emphasis based on anything in a written document, correct?

A. Not in the style or the way the letters were styled or bolded or capitalized, only in the words themselves.

Q. You don't claim here today to have any kind of special unique knowledge that is -- well, strike that.

Do you have an understanding as to whether oil and natural gas liquids will be sold at market prices as a result of FPL's proposal?

MR. BUTLER: I'm going to object to the form of the question. It's assuming facts not in evidence.

If you're talking about the Woodford project Mr. Forrest makes it pretty clear it's dry gas.

It's not supposed to have oil and gels in it. So I'm not sure if that's what you're referring on.

MR. MOYLE: Well, he answered a question of Mr. Rehwinkel where he said, as I understood it, that dry gas was not subject to any kind of market sales, and I want to just test his knowledge and see if he has an understanding one way or the other with respect to whether oil or non-gas liquids are subject to market sales.

MR. BUTLER: That would be fine. That's a generic question.

A. It's my understanding -- and I'm sure you'll explore it with Mr. Forrest in greater detail, it's my understanding that this project, that the investment and all of the gas associated with that is for the benefit of customers.

Now, whether the actual gas molecules themselves that are pumped out of the Woodford project, whether they actually make it to the burner chip in the generating plants at FPL, I'm not sure that's going to be the case 100 percent of the time. It may be more efficient in FPL's system to divert that gas somewhere else and replace it with some other gas that is of equal value in terms of its BTU content and other aspects, to actually burn those molecules at its generating plant, but that's a question of efficiency.

But the important point is that a hundred percent of the gas from the project will benefit customers. So that's the distinction I'm making.

I'm sure Mr. Forrest can explain it better than I.

Q. Do you have any understanding of what will be done with NGLs, non-gas liquids?

A. No, I do not. I know that's not an issue for this project. It could be an issue for future projects, and that would be something Mr. Forrest would need to explain, perhaps.

Q. The Commission's definition of what is eligible for recovery through the Fuel Clause, where would I find that?

A. It's most likely the order -- a good starting point would be Order number 14546.

Q. Anywhere else I would look?

A. I would look at all subsequent orders that reference Order 14546.

Q. Is 14546 the one that has the tenth element in it?

A. Yes.

Q. You made a comment in response to a question from OPC that you were not an expert on hedges, but I think after staff asked you some questions you went on and shared what you know about hedges.

I guess to be clear, you are not an expert in hedges, but you have some familiarity with it based on past experience; is that right?

A. Yes, but I do not hold myself out as an expert in hedges.

Q. Just a quick conversation about your understanding of hedges.

You would agree that under the Commission hedging policy as you understood it, that the utilities that hedge are not making judgments about which way prices may go, correct?

A. I'm not -- I can't speak for the individuals who make those hedging decisions, as to whether that enters into their weighing of different hedging options. I don't know that.

I do know that as a matter of policy, that the Commission has determined that there can be a hedge and the purpose of the hedge is not necessarily to reduce fuel costs. The purpose of the hedge is to manage or to minimize volatility, and whatever the price of the fuel it ends up being is going to be less volatile in the long run or at least during the time that the hedge is in effect.

Q. Are you aware that there are significant financial interests, I'll call them, quote unquote "Wall Street interests," Morgan Stanley, Goldman Sachs, those type entities -- I'm not representing they are actually doing it -- but those type entities that take positions in commodities such as natural gas, with the goal of being to make money on the positions they take, because they are exercising judgment that they think the commodity price will move one way or the other and they want to capitalize on which way they think the commodity price will go?

A. I don't know that for a fact, but what you have described to me is my understanding, that there are commodity markets and there are players in those markets and they certainly intend to make money in those endeavors.

Q. And do you have an understanding that the Commission hedging policy that says we don't really want -- these are my words, not the policy -- we don't really want our investor on utilities acting like these investment houses and betting on which way the markets are going to go?

A. Yeah, I would generally agree with that, and I think there's language in the Commission orders that talks about hedging should be nonspeculative, and I think the Commission also defines what speculative is. So there's some guidance there from the Commission.

Obviously the Commission does not expect nor want the regulated utilities to enter into these markets trying to play the market and trying to second guess things and trying to make money in the market. The hedging activities are to hopefully result in a more stable fuel price regardless of the direction of the commodity price itself.

Q. What's your understanding of a financial hedge?

A. A financial hedge would be one in which the actual -- it's not necessary to actually take possession of the gas molecules themselves. It's merely a financial instrument to help manage the volatility of the price of those gas molecules that are eventually obtained and consumed at the burner tip, at the power plant.

Q. And what's your understanding of a physical hedge, as it's used in hedging vernacular today?

A. Here again, not holding myself as an expert in hedging, that physical means the taking of an asset, the actual physical commodity itself at somewhere along that hedging transaction, whether obtaining it, storing it, then selling it at some point and replacing that with another physical molecules of gas at some point in the transaction; as opposed to being strictly done through the basis of a financial instrument.

Q. You would also agree that what's being proposed in the Woodford project is not the same as the nomenclature with respect to a physical hedge as it's currently referenced and utilized in the hedging program, correct?

A. I do not know that that is correct.

Q. You just don't know one way or the other?

A. I don't know one way or the other. I know that it has been represented by experts in the hedging field that this constitutes a physical hedge, so I'm relying upon that testimony.

Q. Again, we're just having a conversation, but given your experience, couldn't you make the deduction that to the extent that what is being proposed is what happens today under the current hedging program, that we wouldn't be talking today?

A. No, I couldn't agree with that either. This was a proposal that's not just a hedging proposal. This is a proposal to reduce the cost of gas to customers of FPL.

Q. Do you think it is going to reduce the cost?
A. I do.
Q. Can you say that with certainty?
A. This is based upon my understanding of the testimony that's been presented by other witnesses.

I do have experience evaluating the credibility of testimony of expert witnesses. I have scrutinized the testimony of other witnesses in this case, I find it to be very credible. In fact, I find the testimony to be compelling.

There's not going to be a guarantee, but if the Commission approves this project, I sitting here today would anticipate that there would be savings for customers.
Q. I'm fond of the phrase "I wouldn't swear to it" in general conversation, but today actually you are swearing to it and I'm going to ask you a real direct question and see if I can understand your answer.

Is it your testimony that the Woodford project as proposed by FPL will save ratepayers money?
A. No, that is not my testimony, and that was not the question you asked me previously.
Q. I understand.
A. Okay.

Q. And the reason you're not testifying that it will not necessarily save them money is because it requires you to look beyond the horizon as to what markets may or may not do in the future~~,~~ correct?

A. Yes, there are factors out there that are variables that could change and it could impact the net present value of benefits for customers, and it is a possibility that those net present value of benefits could actually go negative.

Q. You would agree, I would think, that what FPL is proposing here has characteristics that are similar to what the financial interests -- the Morgan Stanleys, the Goldmans -- would be doing with respect to financial positions in natural gas futures.

You're betting which way the market is going to go with respect to natural gas, correct?

A. I would disagree with that. I would say it doesn't meet that, because FPL is not engaging in this proposed transaction to beat the market and make money off of the commodity price of the gas.

FPL is proposing to make an investment which it believes will benefit customers by having lower fuel costs as a result of making that investment. FPL is proposing to do that at a regulated rate of return, not with the idea they're going to play the market and reap additional returns for their investors. The returns they're going to achieve is the regulated rate of return.

Q. And that's a fair point. I may not have asked the question well. But the key tenet I'm focusing on is that it's dependent on what the market does in the future with respect as to whether ratepayers save money or not, correct?

A. I agree, and that is no different than what FPL and any other regulated utility does consistently to provide cost effective service to customers.

Q. And that's no different than what the Goldman Sachs and the Morgan Stanleys do with respect to when they take positions on commodities, correct?

A. They're not taking positions to benefit the customers of a regulated utility. They're taking positions to benefit themselves or their stockholders.

Q. But they're betting on which way markets are going to go?

A. And regulated utilities do that all the time, in the sense of how to provide cost effective service to their customers. It happens when a utility enters into a long term contract. They make a decision as to what they think is in their customer's best interest to enter into that contract. Only with hindsight do we know whether that was a good contract or not.

But the Commission reviews that and makes a prudence determination based on the information that is available at the time. This is a prudent thing to do and utility, we want you to do it. We think it's going to benefit our customers.

The Commissioner, as smart as they are, they don't know what the market is going to do either. It could be a good deal, it could be a bad deal.

Same with power purchase agreements that come before the Commission. The Commission is fully informed. It scrutinizes it, makes a decision whether it's in the public interest or not.

Sometimes those contracts turn out to be very good, sometimes maybe not, but that's the nature of the business.

Q. You sat on the Commission when utilities were paying a lot of money to cogenerators for contracts that had long terms on them, right, and some of those payments were very high compared to market conditions, correct?

A. Yes, that did result.

Q. Did you, when you were a Commissioner, explore or look for ways to mitigate against those high payments, those high cogeneration payments?

A. Yes. In fact, the Commission approved some buyouts. Here again, it was a determination based on what we know now, that the best decision is to buy this contract out, that we think that's going to save customers money.

But here again, that's made with the best information available at the time and it may prove to be good, it may not prove not to be good.

Q. And it's not inconceivable that a similar situation could occur with the FPL proposal if it's approved, correct?

I mean, it could go south. You could have a similar situation, depending on what happens in the markets, that these could not be good deals?

A. That is true, and I think Mr. Forrest is very specific in his testimony that it could happen.

Now, he calculates that to be a 15 percent probability or something in that neighborhood. So yes, he's very up front with that, it could happen.

Q. Do you understand how he came up with 15 percent?

A. No, you'd have to ask him that.

Q. You reviewed his testimony, right?

A. I did, and I know he did a sensitivity analysis, okay, and I assume that his probabilities are based upon that sensitivity analysis, based upon a high and a low case for a commodity price of gas and perhaps the reserves that are proven to exist, that are anticipated to exist, I think there's a high and low case for that.

So I believe he did that calculation and based upon those sensitivities, came out with a determination as to those probabilities. But here again, it would be better to ask him that.

Q. I understand. You say you don't know where that 15 percent -- you don't know how he did that, but I guess you're saying -- I mean, do you have a level of comfort in that 15 percent, not knowing how it was arrived at?

A. Well, I know -- I did not go back and try to reduplicate his spreadsheets or the assumptions that he made or any things of that nature. I just know that the analysis he did is the type of analysis that the Commission has historically relied upon, sensitivity analyses, and the Commission is taking comfort in those.

Of course the Commission does not blindly accept those. The Commission exercises its own judgment as to those sensitivities, as to whether it's a prudent investment or not, and you know, this Commission may determine that they're not willing to accept even a 15 percent likelihood or maybe this Commission determines that they think the likelihood is greater than 15 percent that it would go south, as you put it.

But that's all within the discretion of the Commission, and the essence of my testimony is that it needs to get to that point to the Commission, to allow the Commission to use the expertise of its staff and itself to make those judgments, and that it should not be dismissed out of hand because of interpretations of paragraph 10 in a prior order.

Q. How do you think the Commission should view the testimony and comments of the parties in this proceeding who are representing consumers?

A. How the Commission should take that?

Q. Yes.

A. As it always does; take it, evaluate it, determine whether the Commission agrees or disagrees, weigh it. It's part of the evidence in the record, and the Commission weighs all of the evidence.

Q. So the Office of Public Counsel, which represents all of the consumers, opposes FPL's petition, correct?

A. Yes.

Q. And the Industrial Power Users Group, which represents large users, opposes the petition, correct?

A. Yes.

Q. The Florida Retail Federation, which represents a lot of businesses in the state, they oppose the petition, correct?

A. Yes.

Q. Is that significant, in your judgment? I mean, if this is for the benefit of the shareholders, the fact that the people I just described are opposed to it, is that significant?

A. I think it is significant, but it is not determinative. The Commission does not abdicate its responsibilities to the public by seeking a poll of the consumer advocates to see what side of an issue they're on.

Q. And I mean, it's not a poll. I think you would agree that the consumers have submitted reasons and concerns and we're having a rigorous debate about those, correct?

A. As we should.

Q. What is your understanding with respect to FPL's responsibility -- I mean, FPL is not representing the consumers, right? FPL is representing FPL, the regulated utility, and the shareholders of NextEra energy in this case.

A. FPL is representing itself. But I think it's important that the Commission not lose sight of the fact that your clients are FPL's customers and FPL has a long history of making decisions which they think benefits customers. The Commission has agreed it benefits customers and the proof is out there.

FPL provides reliable service at a cost to customers which has consistently been if not the lowest, certainly within that lowest quartile. That's significant as well and the Commission needs to consider that.

Q. A lot of testimony has said we're doing this because we want to benefit ratepayers. You would agree with that, right?

A. I do agree with that, yes.

Q. But just to be clear, I mean, FPL is looking out for -- I mean, it's representing its shareholders, the shareholders of NextEra Energy. It's not representing the ratepayers, correct?

A. It has a responsibility to its shareholders and it also has a responsibility to its customers and this is an important thing that I think perhaps we're missing here, is that a proposal doesn't have to be pro stockholder and anti consumer.

Sometimes there are proposals that benefit both and it is FPL's position that this is a case to where they're willing to make an investment at a regulated rate of return that is going probably to yield benefits for customers, and the Commission has got to weigh that. It's not always us versus them and this may be one of those situations where it is in reality a win-win.

Q. But there's also situations that present as a win-lose, correct?

A. There's no guarantees in regulation and there could -- if this project goes forward, it could result in higher prices, but it wouldn't be for the reason for FPL to earn a higher rate of return than is authorized. It would be for the reason that it is expected to produce customer benefits.

Q. I understand. I'm just exploring with you whether you will freely recognize, and I think you did, that there can be situations -- I phrased them as win-lose, but in which the ratepayer interests are not aligned with the shareholder interest, correct?

A. There can be such cases. I don't think this is one of them.

Q. Well, you don't, but you're not, in making that judgment, giving much credence to the views of the consumer parties, correct?

A. Well, yes, I am, because I have reviewed the testimony that's been provided by the intervenor witnesses and they have made some changes in the commodity price of gas, the forecasts associated with that, and have questioned whether the magnitude of the claimed savings will actually be generated.

But even in some of the scenarios that are provided by the intervenor witnesses, there is still net savings in their analyses as well. So yes, that's important.

Q. Do you agree with the points made by intervenor witnesses? Did you say, "Hey, I've looked at this and this is a fair point, that's a fair point," other than the ones you've described?

A. No, I have not. In terms of the economic analysis of those witnesses, I have made no judgments whether their fuel forecasts are correct. I haven't made judgments like that for the FPL witnesses either.

Q. Do you believe that FPL owes a fiduciary duty to its ratepayers?

A. You'll have to define the term "fiduciary".

Q. Well, do you have an understanding of it?

You're trained in accounting, right?

A. I am.

Q. I'm trying to remember if you were a CPA.

A. I am not a CPA.

Q. But as part of your training for accounting did you have occasion to be --

A. I have a layman's understanding of the term, but I also know that it can have very specific legal meanings. So I would not want to use that term in a sense that would suggest that I'm trying to use some type of a legal definition.

Perhaps I can answer your question this way. I think that FPL as a regulated utility has an obligation to its customers to make decisions and to manage its business such that customers are protected and benefited, such that they get reliable service in a cost effective manner.

They also have to weigh that against making decisions which do not violate their fiduciary responsibility to their stockholders, to make sure that those investments that are made are made in a way that -- that those funds are managed and invested in a way that gives those stockholders a reasonable opportunity to earn a fair return.

So yes, the regulated utility has a

responsibility to manage its affairs for the benefit of its customers.

Q. Okay. So just so the sequence works, please provide your understanding of the phrase "fiduciary duty", and I think Mr. Butler and I can agree that you're not providing a legal conclusion.

A. Fiduciary, in my layman's understanding, is a situation where there is one party that has a very special relationship, often defined by law, as to their conduct into the affairs of another party, such that they have a responsibility to act in the interest of another party.

Q. In the answer you just gave you said that you believe there's a fiduciary duty with respect to shareholders, correct?

A. I think that's clearly understood. I'm comfortable using that term for the shareholders, but -- I think that's something that's been defined in case law, that that is a fiduciary responsibility. But it's not always just accompanying the stockholders. There's fiduciary relationships in other ways that are defined by law.

What I'm saying is I'm not comfortable using that term, because it may not be legally correct. I believe, though, that there is a very strong relationship between a regulated utility and its customers. Whether it falls into the category fiduciary, I'm not willing to say. I'm not really sure.

But I know from a regulatory perspective and from what the regulators in Florida expect of their regulated utilities, there is definitely a responsibility for a regulated utility to manage its affairs, to conduct its business, and provide service in a cost effective manner.

Q. Back to the comment you made where you recognized the fiduciary responsibility to shareholders, you would agree that includes maximizing profits?

A. No, I do not agree with that.

Q. So you don't believe that there's a duty to try to maximize profits for the owner?

A. When you use the term "maximize", there are ways to maximize profits which would not be beneficial for the stockholders and would not be beneficial for the customers. There can be decisions made by management to make decisions not to adequately maintain power plants, not do the required maintenance on facilities, not make the investments that are necessary to make sure service is reliable.

That may result in a momentary or temporary increase in earnings because expenses go down, but it's going to cause expenses to increase later. That's not -- so it depends on what you mean by "maximizing profits".

Q. You make a fair point. But I guess to put a little finer point on it, it would be -- in using business judgment, it would be that at the end of the day the goal is to maximize profits for the business operation, correct?

A. Here again I have difficulty even in that context using the term "maximize". I think there's a responsibility to manage operations. So in the context of a regulated utility, that earnings are reasonable. But I'm not so sure that there's an obligation to maximize those profits, because a regulated utility has other responsibilities.

Q. Okay. I thought in your answer previously you had said yes, after an explanation. But you're familiar with the Commission's practice of trying to answer the questions yes, no, and then explain, right?

A. Yes.

Q. So if I ask you the questions really directly and I ask you to answer it yes or no, and if you feel an explanation is warranted, give it to me.

If you say "see above where I previously talked about it," that's fine too.

A. I thought I was doing well, but I am admonished and I will try to do better.

Q. So the question is do you believe as you understand the term "fiduciary duty", that FPL has a fiduciary duty to its ratepayers?

MR. BUTLER: If you can answer it yes or no.

John, we're not at hearing. There's no obligation that applies to this deposition for him to answer it in yes or no terms, any more that there's an obligation for you, who obviously aren't obviously following it, to stick to the scope of his testimony in your questions.

So he can answer however he sees most appropriate.

BY MR. MOYLE:

Q. My follow-up is going to be are you unable to answer yes or no. So however you want to address it.

A. I think there is a special relationship between a regulated utility and its customers. I'm not sure it falls within a legal definition of fiduciary, but yes, there is a responsibility to manage its business for the benefit of its customers.

Q. Okay. And we've agreed we're not looking to you for the legal definition. We're just looking to you for your understanding of it.

Can you answer that yes or no?

A. No, I can't answer that yes or no, and I think my previous answer explains why I can't really answer your specific question yes or no.

Q. So where do you think that duty comes from?

A. Being a regulated utility.

Q. The duty that you said, the special duty that FPL owes its ratepayers, where does that originate?

A. By being a regulated utility, being under the jurisdiction of the Public Service Commission.

Q. You would agree that customers of FPL are dependent upon FPL to provide them electricity, for the most part, correct?

A. Yes.

Q. And you would agree that FPL's a monopoly. So customers, if they're in the service area of FPL, can't say, "Boy, I'm mad at you. I want to go somewhere else and get service from another electric utility," correct?

A. That is true, but it is also true that customers have other options.

Q. Self-generate?

A. They can self-generate. You mentioned solar as an example and that is becoming more prevalent.

So it is incumbent upon the regulated utility, FPL or any regulated utility, to manage its affairs prudently and efficiently, provide service as such. Because if their prices get way out of line they're either going to -- customers are going to look to alternatives.

So while they're a regulated monopoly they are not immune to competition and solar is an example of that competition.

Q. You need backup power if you're going to go with solar, right? Solar doesn't work real well at night?

A. Unless you want to take cold showers and things of that nature.

Q. So with respect to solar, there's going to be a reduced dependence, but not necessarily an exclusive dependence?

A. Customers do have some choices and it's not only solar. If they're dissatisfied with the prices they're having to pay, they can install more conservation measures.

Q. Let me ask one final question and we'll take a break and I'll review my notes. I do have some more with you.

You were asked a question by Mr. Rehwinkel that was a risk related question and I just want to make sure I understand. You would agree that the risk of production that ratepayers currently face is not as great as the risk of production associated with the Woodford project, correct?

A. I cannot make that conclusion.

Q. So did you look at the Woodford project, you know, in terms of -- you know, it's limited to one County. Wouldn't you think that if you're buying natural gas on the market, that you have the ability potentially to have a supply from a whole lot of additional places other than one county and that that would result in less risk?

A. We have to keep in mind here that what's being proposed, while significant, is still a very very small percentage of the amount of natural gas that FPL consumes, such that it is not the proverbial putting all of the eggs in one basket.

So no, I don't know that that's really that significant of a risk. But here again, that may be something that would be addressed to Mr. Forrest.

Q. Do you know what percent the Woodford project represents of the gas FPL uses on a daily burn rate?

A. I know it's small and I think it's probably somewhere may be around one percent, depending upon maybe the demand on a system at any given point in time. But again, that's something for Mr. Forrest.

MR. MOYLE: Why don't we take a break. I'm going to look over my notes. Thanks for your time.

I'm not done, but I want to take a break.

MR. BUTLER: Let's go off the record.

(Whereupon a recess was taken.)

BY MR. MOYLE:

Q. Okay, back on the record. What is your understanding of prudent costs?

A. Well, it's costs that are incurred prudently and costs that are incurred consistent with a reasonable expectation that they would produce benefits and would not be overly risky.

So I guess prudency can be looked at in many ways, but one would be benefits and the risks associated with obtaining those benefits.

Q. You would agree the Commission should be free to consider all relevant information when making a prudency determination, correct?

A. Well, the key is relevant. As long as it's relevant, certainly, and the Commission has great discretion in what it considers to be relevant, but the Commission scrutinizes things very carefully and usually looks at numerous different aspects of what may or may not make a certain transaction prudent.

Q. So given your time serving on the Commission, there's never been an effort, has there, that you're aware of -- is there a rule that says here's how you determine prudency or is it more like the reasonable man or reasonable person standard; where, you know, you evaluate facts and make judgments based on particular facts and exercise the judgment relative to the qualities you just discussed?

A. I would think it's more like the latter.

Q. The latter?

A. The latter, yes.

Q. It flows and follows to me then that any effort to restrict the Commission with respect to what it can consider related to whether a particular action is prudent or not would be disfavored, correct?

A. As a general matter I would agree, I think the Commission should have the discretion to look at what the Commission considers to be relevant. But again, they have to act within the jurisdiction as well.

Q. So given our discussion, I would take it that you don't read FPL's proposed guideline 2-A to be a limitation on evidence that can be reviewed with respect to prudence?

And I'm happy to show you that document.

A. That would be helpful.

MR. MOYLE: Do you have a copy, John?

MR. BUTLER: You're talking about the guidelines of Mr. Forrest's testimony? I don't have it with me.

MR. MOYLE: I'll give it to him.

Q. Here you go. Just for the record, I will read the guideline into the record.

Guideline 2-A: "Evaluation of the prudence of FPL's having entered into a new gas reserve project will be based on a showing that the project is estimated to generate savings for customers on a net present value, relying solely on information relative to these guidelines available to FPL at the time the transaction was entered, including the use of an independent third party reserve engineering report and FPL's standard price forecasting methodology."

Did I read it correctly?

A. Yes.

Q. So my question is, you don't read this as limiting what the Commission can look at in determining prudence, or do you?

A. Well, the answer is yes and no, okay. It's no in the sense that the Commission has an overarching responsibility to regulate in the public interest, and a guideline does not restrict the Commission from exercising its jurisdiction the way the Commission deems appropriate.

However, on the other hand, I think there is a responsibility on the Commission before it approves the guideline, that it's comfortable with those guidelines, and what is to be part of the prudency determination according to this guideline, the Commission should be comfortable with that and should abide by its guideline and make decisions consistent with the guideline, and if it determines that the guideline is no longer appropriate, change the guideline and put parties on notice that the guideline would no longer be appropriate, such that any future decisions made by FPL would be based upon knowing what the rules of the game are.

So it's a little of yes and no.

Q. Okay. So hypothetically, if FPL comes in and says, "Hey, look, here's a reserve engineering report that we have and we made this investment," you wouldn't take the position that FIPUG or OPC would be precluded from coming in or making arguments or presenting evidence or doing things relative to prudentes, correct? That the Commission could consider testimony from others in making its prudence determination?

A. I think the Commission would be allowed to do that.

Q. And it should be allowed to do that?

A. And should be allowed to do that, that's correct.

But at the same time I think the Commission should be cognizant of the fact -- and the Commission his historically done this -- that if there are guidelines out there that are meant to provide guidance -- guidelines, guidance -- to FPL or other parties as to what is to be expected such that there is some comfort given that if the guidelines are followed, that an investment consistent with those guidelines would not only be eligible, but likely the cost would be recovered and that the rules would not be changed in midstream.

Q. Well, these aren't rules, right?

A. Well, I'm using the term "rule" in a more generic sense. The rules of the game would not be changed midstream.

Q. And when we were talking about how the Commission develops policy previously and I said to you how does the Commission develop policy, you didn't mention guidelines in your answer, did you?

A. I don't believe that I did.

Q. The 50 percent questions that you were asked by counsel for staff, my notes indicate that you thought that was a concept that might be worth exploring, but you'd probably have to do that, I think you said, in a different forum.

I assumed you were contemplating a workshop, possibly?

A. Some type of a different forum. A workshop probably would be a suitable forum to do that.

But I also qualified that answer saying that while it would need a lot more exploration, that a potential downside of that would be that if this opportunity were put on hold while that was explored, this possibility, this opportunity probably would go away and that may result in a loss of a benefit for customers.

Q. But you don't know that. You're speculating as to whether it would not go away, correct?

A. I don't know that for a fact. I think it is a possibility. I don't think it is fair to expect USG to be put in limbo on this deal indefinitely. I don't think it would be reasonable to expect them to do that.

Q. There's nothing within the memorandum of understanding executed between USG and FPL that says the deal goes away, correct?

A. I don't know one way or the other.

Q. You agree that's the best document that represents the agreement between the two parties, as far as you know at this point?

A. It's the best document I know of. It's the only document I know of.

Q. You were asked about a 50 percent proposal. I'm going to put another proposal, I'll say similar to that, may be not unlike that.

If I read your testimony, you say look, when these decisions are made you got to look at them at the point in time they're made. You can't Monday morning quarterback them later. Is that fair?

A. That's generally fair, yes.

Q. So hypothetically, if FPL makes a decision tomorrow and says we're going to go invest in this project and they make it on the market conditions tomorrow and then this all gets approved and it's in the clause, and we get testimony next summer that says hey, they made this decision tomorrow and we hire an expert to go and look at market conditions, the best that they can come up with in November of 2014, would that be Monday morning quarterbacking when the expert says, "Well, they shouldn't have done this because I think the market conditions are such that this was a bad deal"; in your judgment?

A. Yes, I think it would be. This is your opportunity as an intervenor to put before the Commission what you believe is relevant information, and if you have an analysis or analyses which show that it is a bad deal for customers, this is your opportunity to present that.

I don't think it's your opportunity to second guess that in a subsequent proceeding based upon information that's ascertained later that could have been or should have been presented now.

Q. Okay, let's just go with that. So the decision is made tomorrow. I don't know that that decision is made tomorrow under FPL's proposal, do I?

Am I given notice that they're going to do Woodford Two tomorrow, based on how it's being proposed?

A. I think we're talking past each other. I thought you were talking about this project.

Q. No, I'm talking about the guidelines.

A. Something that may happen in the future?

Q. Yeah.

A. Well, you may need to restate your question then.

Q. So the guidelines -- they're asking to have these guidelines approved and they can invest up to $750 million a year in similar projects, correct?

A. That's correct.

Q. Hypothetically, let's just say the Commission approves this and it's done January 1 -- I'll change the hypothetical a little bit. On January 2 FPL pulls the trigger on a project, okay, and they look at the economics and they go this is good, in our judgment.

We don't know about that until a filing is made in the summer. We go retain an expert in the summer and the expert goes back and looks at the decision at that point in time when it was made, January 2015, and provides all this testimony about it's a bad decision, not supported by the economics.

Do you come -- I say you, you being FPL -- is that subject to criticism, in your judgment, as being Monday morning quarterbacking?

A. I am not FPL, so I cannot speak for FPL. I can give you my opinion as to that situation.

Q. Okay.

A. My opinion is that that would be fair game if the testimony that were presented was based upon facts that were known or knowable at the time that trigger was pulled, not by an assessment six months later that shows that the price of gas or some other economic event happened which no one knew or could have known of that happened in the intervening six months period.

But as long as the analysis was done in the sense that well, FPL knew this or they should have known this or this is information that was available at the time the decision was made and is inconsistent with the guidelines, I think you would be free to express why that was a bad decision, and that's something the Commission -- it would be in the Commission's discretion to consider.

But I think that would be the key, would it be information that was known or knowable at the time FPL made its decision.

Q. Would it make sense, in your opinion, to possibly consider a process in which notification was given that this type of investigation was being made so that people would have more realtime information to do an analysis; people being people like OPC and FIPUG?

A. That's possible, but my concern is that they would not be disclosing information that would jeopardize the opportunity being foregone. A lot of it is timing, central typing of things, and I'm not sure that a disclosure of that -- it could conceivably jeopardize an opportunity.

Q. Assuming it was done confidentially?

A. If it was done confidentially, that would work. I would have to really give that some more thought to see.

But that's really something that perhaps could be worked into the guidelines, to give some notice, as long as it doesn't jeopardize the timing and the viability of a project by disclosing information that a market would take and somehow undermine an opportunity for FPL and its customers.

Q. I want to spend a minute and just have you -- let's just talk about the benefits to shareholders for a minute.

There are benefits from this project to FPL's shareholders, correct?

A. Yes.

Q. Have you spent any time looking at the order of magnitude of those possible benefits if FPL's request to put up to $750 million in projects through the Fuel Clause each year is approved?

A. Well, I generally know what the carrying cost is on an investment of a certain magnitude in rough terms.

Q. So what would be the carrying costs of a $750 million investment?

A. Before any depletion, for a revenue requirement associated with $750 million?

Q. Right.

A. Just in really, really -- generally, just rough terms, you can probably in terms of revenue requirements apply a factor of say 20 percent to that. That may be overly generous, but that would also consider a certain anticipation that there's going to be a revenue recovery of that, some magnitude of recovery of the investment.

But walking around, I'd be comfortable saying 20 percent in terms of annual revenue requirements.

Q. So 10 percent of 750 is $75 million. 20 percent is $150 million?

A. Yeah, that would be the calculation.

Q. And as I understand the proposal, in year two there's another 750 that's eligible; is that your understanding?

A. I'm not sure. I don't have that level of detail, as to what those parameters are of the limitations in terms of absolute dollars of investment.

Q. Let me show you the guideline. That's probably a more fair way to approach this.

In guideline 1-D it says: "FPL will not obligate itself to invest more than $750 million in the aggregate on gas reserve projects over the course of any one calendar year."

I read that as saying you can't invest more than 750 in one year, but you're able in the next year to invest a fresh 750. Is that how you read it?

A. I don't read it that way, but obviously this would be better for Mr. Forrest. I read it that it cannot be more than $750 million in the aggregate at any one time, but I may be misreading it, and obviously Mr. Forrest would be the correct person to interpret that.

Q. Okay. I'm thinking aggregate is Project A, Project B, Project C, Project D. In the aggregate you can't go over 750?

A. Well, I'm just seeing the gas reserves projects as plural. It says "aggregate on gas reserves projects", plural.

But I see where your interpretation is plausible. I'm not saying your interpretation is wrong, but I'm saying I interpret it differently. But I could be wrong.

Q. Well, you don't get to file rebuttal testimony on me, so --

MR. BUTLER: It would be too lengthy.

BY MR. MOYLE:

Q. If my interpretation was right, that 150 would be out of it, correct, on an annual basis?

A. If your interpretation is right, it would be additive, but the very good thing about that means that customers are going to benefit extremely, to an extremely large extent, because the guidelines require that it is expected -- and I understand, it's expected customer benefits.

But if there are that many opportunities out there that present savings, just think of the savings that are going to be generated for customers in fuel costs. That would be a tremendous thing. So I'm not sure this is something to fear.

Q. So you are of the belief that every project has to be looked at and evaluated independently and a determination be made that fuel savings are projected to result with each project in order for it to move forward?

MR. BUTLER: You're talking about his interpretation of the guidelines, right?

MR. MOYLE: How this is going to work, guidelines or otherwise.

A. That's my interpretation, my understanding, each individual project has to show that there are anticipated customer savings.

Q. So there would be a file that would have a reserve report, some kind of independent economic analysis. It's not going to be somebody going, "I looked at it and I thought it was good"?

A. I thought the guideline you just showed me detailed some of the information that would be part of the guidelines, and so I would think it would be prudent -- it would just be a prudent business practice to have that type of a review done before an investment of that magnitude is made.

Q. So the shareholders will earn a return on the equity of the investment, the capital investment related to this project, right?

A. Yes.
Q. There was a question related to other investors of the Woodford project. You understand there are other investors besides USG and Woodford that have fractional ownership; is that right?
A. That's my understanding.
Q. The other investors, they either make money or don't based on the market price of the commodities when they're sold, correct, as compared to the production costs?
A. I would anticipate that to be the case, yes.
Q. And that's not how it would work with respect to the New Co. or the generation reserve company, right?
A. That's right.
Q. They wouldn't be tied to the market price?
A. That's right, and those participants would bear those risks and they have the potential to earn very large returns. They also have the potential to lose money, but that's the nature of the market.
Q. Do you have an understanding, when you say they have the potential to lose money, how that would happen? Who's "they"?
A. The entities that you describe as being co-participants in this project other than FPL.

Q. Does the New Co. have an opportunity to lose money on this?

A. I would hope not, because that would mean that the New Co. was not earning -- well, first of all, it's FPL, all of the benefits associated with the transaction are actually being transferred net book value to FPL.

So it's FPL, and being a regulated utility and being willing to make the investment subject to the opportunity to earn a regulated rate of return, one would hope that that rate of return would be in the band that the Commission says. It would not be astronomically high and hopefully it would not be to the point where it was even negative and there would be losses associated with that investment.

Q. The way that I understand this will work is they will take all the accounting information and say, hey, Petroquest made a $10 million investment in it as well. That information goes to the New Co. The New Co. puts that up and it's looked at in the Fuel Clause and assuming everything was done prudently, then the Commission says okay, this $10 million is recoverable and you get a return on that.

Is that your understanding?

A. That's my general understanding, but here again, the details would be better discussed by Mr. Forrest.

Q. I don't see a lot of risk associated with that if you're the New Co., because there's no operational risk. That's all contracted for, right?

A. There's an operator that operates these assets and produces the gas, and I understand FPL has a right to the output from those wells in which it has partial ownership.

Q. Not to belabor it, but you would agree that return on equity is based on a number of calculations, including level of risk, right?

A. I would agree with that, and subjecting this investment to a regulated rate of return that is appropriate for a regulated monopoly would assume that it's lesser risk than perhaps other investments in other industries, like gas drilling and exploration.

Q. Would you disagree with the premise that FPL is in effect, if it creates this subsidiary company -- which Ms. Ousdahl testified that's the current thinking, that a New Co. will be created -- that FPL is in effect providing its ability to operate as a regulated utility to the subsidiary, in the way this is set up?

A. The subsidiary is created for the sole purpose of fulfilling this transaction for the benefit of customers and it would, in essence, become part of regulated operations.

Q. A couple references to your testimony. I have it on Page 4, line 14. You use the phrase "could reduce incentives for utilities to keep those costs low."

A. Yes, I used that phrase.

Q. What were you trying to convey there with respect to incentives?

A. I was conveying the concern that perhaps the necessary function of the Fuel Clause and the benefits it provides, that by having that prompt recovery of costs generally on a dollar-for-dollar basis, if that was a showing of imprudence, that could to some extent act as a disincentive for companies to go out and look for ways to save fuel costs.

Q. How, how would that be a disincentive? If it was found imprudent; is that right?

A. No, the fact that the fuel costs are flowed through on a current basis and generally flow through on a dollar-for-dollar basis, that by that mechanism that could result in a disincentive -- or lack of an incentive perhaps is better -- a lack of incentive for a company to go out and look at ways to cut fuel costs.

Q. Because the rationale would be if you cut fuel costs, maybe there's some capital associated with that, that wouldn't be in the Fuel Clause and we wouldn't earn a return on that; is that right?

A. Yes, that is a good example.

Q. Okay. And with respect to incentives, tell me what incentives there are, if any, for the New Co./FPL that is contemplated in this proposal to keep costs low?

A. The same incentives that a utility, a regulated utility has to manage its affairs. But because it is under the regulation of the Commission, subject to the scrutiny of the Commission, and if it does anything in an imprudent manner, it is subject to having costs disallowed.

Q. But it's not -- Petroquest is the operator. You know, the Commission doesn't have jurisdiction over Petroquest. They go and do oil drilling and then they send a bill that has a bunch of papers attached to it and says "here, this costs $10 million."

So the way I see it, you tell me if I'm wrong, is if I had an invoice for $10 million -- I'm not suggesting that anyone would do this, but I'm just saying, the way the economics work, an invoice for

$10 million of a capital cost is better compared to an invoice for $9 million, because I would earn a return on the larger invoice; is that right?

A. Well, it depends on what the invoice is for, as to whether it's a capital item or not.

Q. A capital cost.

A. Assuming it's a capital cost, yes, that's true. But it happens the same anytime a regulated utility depends on third party vendors. It's no different. They have the responsibility to manage their affairs and to monitor those costs and challenge costs if they think they are inappropriate.

Utilities hire tree-trimming services to go out and trim their lines. They're usually third party vendors. They have a responsibility not to just blindly pay those invoices, but to manage that process and to demonstrate to the Commission that those costs were prudently incurred.

Q. You spent some time in your testimony on the TECO testimony and related to those orders that said we're going to limit the recovery to the fuel savings.

There's nothing that prevents the Commission from considering that in this case, correct?

A. Well, yes and no. I think the Commission has the discretion to do that, but I think the

Commission also needs to consider that if they were going to oppose that requirement in this situation, that it may result in this opportunity going away and not providing benefits for customers.

So once again the Commission has a responsibility to weigh all of that and make a decision, but simply putting that requirement on this and thinking everything else is going to be equal and the project is going to go forward, I'm not so sure that that is a safe assumption to make.

Q. A couple other points and I think we'll be close to being done.

With regard to a prudence determination, I mean, FPL had the option, did they not, they could have just said, "Hey, we're going to get into this business and go forward" and at the next rate case or appropriate time come in and say, "Hey, we made all these investments and we think these are prudent and we'd like to get recovery for those."

They could have done that, right?

A. Yes, I think they probably could have done that. I'm not sure it would have been wise for them to do that, but they could have done that.

Q. And if they did do that, then there would be an order that would address these facts?

A. Yes, there would.

Q. So with respect to what's before the Commission now, assuming it goes to hearing and the motion to dismiss is not granted, there will be an order that will come out and let's say it says to FPL "here's our current thinking and you can go forward with this Woodford project."

That would then be a document that FPL could rely on to govern its future conduct, correct?

A. It would be helpful, but I'm sure it would not be as helpful as the guidelines.

Q. So the guidelines aren't necessary. I mean, it's not your testimony that FPL has to have the guidelines in order to receive direction from the Commission as to how the Commission views this, correct?

A. No, but the guidelines would facilitate the timely consummation of transactions that may go away if FPL did not have the ability to act in a timely manner.

Q. Do you know if FPL is thinking the guidelines will bind the Commission and say, "Hey, you know, it's in the guidelines. You're locked in. You can't back out from the guidelines"?

MR. BUTLER: I'll object, that's asked and answered. You asked that quite a while ago.

THE WITNESS: Do I still answer?

MR. BUTLER: You may, yes.

A. The rules of deposition are different.

I cannot speak for FPL, as to whether they think the Commission would be bound or not, because I'm not a representative of FPL. I can give you my opinion, that I do not think the guidelines would bind the Commission. The Commission has a responsibility to regulate in the public interest consistent with its jurisdiction.

However, if the Commission fully scrutinizes the guidelines and adopts those, I think there is an incumbent responsibility on the Commission to abide by those guidelines, give the assurances they are intending to give to have transactions of the nature that are determined to be beneficial for customers, to have those transactions actually consummated.

So it's a little bit of a balancing on the Commission's part to effectuate that.

Q. So they're not bound by them, but they should give them consideration; is that a fair statement?

A. That's a fair statement, a strong

consideration if they're going to deviate from the guidelines. There needs to be a very compelling reason to do so and if they feel like they need to deviate from the guidelines, they ought to make that pronouncement so they know what the guidelines are going forward and not change the guidelines midstream.

Q. If another utility were to come in with the same petition and the same guidelines, do you think the Commission would have the ability to tell that utility, "no, we're not going to" -- assuming that they granted FPL's petition with the guidelines, do you think the Commission, all the facts being the same, would have the ability to tell the second utility, "No, we're not going to approve this"?

A. Well, rarely are all the facts the same. If we were going to make that unrealistic assumption, I think the Commission would be hard pressed, if all the facts were the same, to treat one regulated entity different from another regulated entity.

Q. If they were similar they'd be hard pressed as well?

A. Well, it depends on how similar or dissimilar they are.

Q. You don't have expertise -- I mean, you didn't look at the Woodford particulars for drilling.

You're not testifying -- you don't have expertise in natural gas trading, natural gas regulation. There's nothing really that you're testifying to or as I understand, have opinions to related to specific natural gas issues?

A. Well, I do have expertise in natural gas regulation at the retail level by a regulated monopoly, but I agree, I don't have expertise in exploration and drilling of natural gas.

Q. And those are what, LDCs; is that right?

A. Yes.

Q. What does that stand for?

A. Local distribution company.

Q. So you don't have any training or education or experience in the natural gas industry other than what you just described?

A. I would agree with that.

Q. And you never held a position with an oil or natural gas company?

A. Correct, I have not.

Q. You've never evaluated the economics of oil and gas reserves?

A. I have not.

Q. You never performed an evaluation acquiring oil and gas reserves and/or production facilities?

A. I have not.

Q. You've never been in a position where you had a responsibility for short term or long term fuel management in operations of an electric utility?

A. I have not.

Q. You never had a responsibility for natural gas hedging, natural gas storage, natural gas transportation, short term energy or fuel trading, or power origination?

MR. BUTLER: I object to that. It's a compound question. But you can answer it if you can.

A. I have not.

Q. You've never negotiated or attempted to negotiate a natural gas purchase agreement, natural gas hedging agreement, natural gas transportation agreement, natural gas transaction, or a natural gas storage agreement, correct?

MR. BUTLER: Same objection.

A. I have not. I have reviewed such transactions from a regulatory perspective, but not engaged in actual negotiation of those transactions.

MR. MOYLE: All right. I appreciate your time. I ran a little bit over my half hour, which probably was expected, but thank you.

I don't have any further questions.

MR. BUTLER: I don't have any redirect, so we will close for Mr. Deason.

(Whereupon, the taking of the deposition was concluded at 1:10 p.m.)

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CERTIFICATE OF OATH

I, Alice J. Teslicko, RMR, a Notary Public for the State of Florida at large, do hereby certify that the witness, Terry Deason, appeared personally before me and was duly sworn.

Signed and sealed this 19th day of November, 2014.

Alice J. Teslicko, RMR

Commission No. EE031095
My Commission Expires:
December 14, 2014

CERTIFICATE

STATE OF FLORIDA)
) ss.
COUNTY OF PALM BEACH)

I, ALICE TESLICKO, RMR, a Registered Merit Reporter and Notary Public for the State of Florida at Large, do hereby certify that I reported the deposition of Terry Deason, a witness called by the Office of Public Counsel in the above-styled cause; and that the foregoing pages constitute a true and correct transcription of my shorthand report of the deposition of said witness.

I further certify that I am not an attorney or counsel of any of the parties, nor a relative or employee of counsel connected with the action, nor financially interested in the action.

WITNESS my hand and official seal in the City of Hobe Sound, County of Martin, State of Florida, this 19th day of November, 2014.

Alice J. Teslicko, RMR

My commission expires:
December 14, 2014
Commission No. EE310095

ACKNOWLEDGMENT OF DEPONENT

I have read the foregoing transcript of my deposition and except for any corrections or changes noted on the errata sheet, I hereby subscribe to the transcript as an accurate record of the statements made by me.

____

TERRY DEASON

SUBSCRIBED AND SWORN before and to me this ____ day of _________, ____.

____

NOTARY PUBLIC

My Commission expires:

ERRATA SHEET

PAGE/LINE	CHANGE/CORRECTION	REASON

I, ______________________, do hereby certify that I have read the foregoing transcript of my deposition, given on __________________, and that together with any additions or corrections made herein, it is true and correct.

____
Deponent

The foregoing instrument was acknowledged before me this _____ day of ____________, 2014, by ________________________, who is personally known to me or has produced _______________________ as identification and who did not take an oath.

____
Notary Signature

NOTARY PUBLIC, State of Florida
____
Commission Number

Objections

34 – Forrest Good reference – show how an independent expert report when nobody from company or who wrote it here to talk about it

36 Hearsay – no default
37 Hearsay – no litigation
38 Hearsay – no reg. proceedings

Somebody from Company to testify

39 Will sure mute dest – ? Dunno – speculative –

36 Hearsay / best evidence
92 Terry Keith – Capital cost via fuel clause
126 Forrest Gard report – ~~what a firm company – experience, reputation for ethics~~
Report N/A; clients rely on them for unbiased, independent reporting – many clients are regulated by SEC – Reference website touts their independence

128/129 – risk profile – Joesph Balzano – not here

140 Melissa Curtow answered – not here
140 Terry Keith – same

167,169 – Jazy Iglesias
167–173 – Melissa Curtow
170–173 Mr. Yupp

EXHIBIT
59
PENGAD 800-631-6989

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 59
PARTY: FIPUG
DESCRIPTION: Forrest/Interrogatory Objections

Abcug Degustor

* Dotson
* Taylor

EXHIBIT NO. 60

DOCKET NO: 140001-EI Gas Reserve

WITNESS: Forrest

PARTY: FPL

DESCRIPTION: Final Order for Northwestern Energy by Montana PSC

DOCUMENTS: Final Order No. 7210b in Docket No. D2012.3.25 by the Public Service Commission of the State of Montana regarding placement of Battle Creek Natural Gas Production Resources in rate base by NorthWestern Energy. Order is cited in FPL's response to staff's 2d set of interrogatories, number 87.

PROFFERED BY: OPC

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 60
PARTY: OPC
DESCRIPTION: Forrest/Final Order for Northwestern Energy by Montana PSC

2012 Mont. PUC LEXIS 76

Montana Public Service Commission

November 15, 2012, Done; November 15, 2012, Done

DOCKET NO. D2012.3.25; ***ORDER 7210b***

Reporter
2012 Mont. PUC LEXIS 76

IN THE MATTER OF NorthWestern Energy's Application to Place the Battle Creek Natural Gas Production Resources in Rate Base and to Recover Associated Expenses

Core Terms

battle, natural gas, acquisition, tracker, customer, forecast, royalty, energy, market price, long-term, capital structure, estimate, gas supply, crossover, bid, unit cost, purchase price, rate base, reliability, calculate, annual, gather, minus, ownership, volume, natural gas production, rate-basing, prudent, transmission, volatility

Counsel

[*1] APPEARANCES: FOR THE APPLICANT: NorthWestern Energy, Al Brogan and Sarah Norcott, 208 North ***Montana***, Suite 205, Helena, MT 59601; FOR THE INTERVENORS: ***Montana*** Consumer Counsel, Bob Nelson, 111 North Last Chance Gulch, Suite 1B, Helena, MT 59601

Panel: TRAVIS KAVULLA, Chairman; GAIL GUTSCHE, Vice Chair; W. A. GALLAGHER, Commissioner; BRAD MOLNAR, Commissioner (dissenting); JOHN VINCENT, Commissioner

Opinion

FINAL *ORDER*

COMMISSION STAFF:

Leroy Beeby, Utility Rate Analyst
Eric N. Eck, Chief, Revenue Requirements Bureau
Dennis Lopach, Chief Legal Counsel
Dagan Lynch, Utility Rate Analyst

Procedural History

1. On March 30, 2012, NorthWestern Energy (NWE) filed an application with the ***Commission*** seeking authorization to include the Battle Creek natural gas production and gathering properties (Battle Creek) in the natural gas utility rate base and to recover associated expenses. Included in the filing was a stipulation and agreement between NWE and the ***Montana*** Consumer Counsel (MCC) regarding Battle Creek return on equity (ROE) and capital structure (ROE/Capital Structure Stipulation).

2. A Notice of Application and Intervention Deadline was issued on April 20, 2012. The MCC intervened in the [*2] docket. Helis Oil and Gas Company, L.L.C. (Helis) and Energy Consultants, L.L.C. (Energy Consultants) intervened in the docket for the sole purpose of seeking a protective ***order***.

3. On May 17, 2012, the ***Commission*** issued Procedural ***Order*** No. 7210.

4. On June 5, 2012, the ***Commission*** issued Protective ***Order*** No. 7210a that granted the Motion for Protective ***Order*** of Helis and Energy Consultants.

5. On September 4, 2012, the ***Commission*** issued a Notice of ***Public*** Hearing.

6. On September 19, 2012, NWE filed a Motion to Admit Testimony and Waive Cross-Examination and Questions of Witnesses. Filed concurrently with the Motion was a second stipulation and agreement between NWE and the MCC (Unit Cost/Market-Price Crossover Point Stipulation).

7. On September 25, 2012, the ***Commission*** issued a Notice of ***Commission*** Action that granted NWE's Motion to admit testimony without the necessity of appearance of witnesses and to waive cross-examination of witnesses by the parties at the hearing.

8. On September 26, 2012, a ***public*** hearing was held in Helena.

9. NWE submitted its post-hearing brief on October 26, 2012. MCC submitted its post-hearing brief on October 30, 2012.

Summary of Application and [*3] **Prefiled Testimony**

Application

10. Battle Creek consists of NWE's interest in the Battle Creek Gas Gathering System (BCGGS) and NWE's interest in wells and reserves in the Battle Creek natural gas field. Specifically, NWE requested that the ***Commission*** issue an ***order***:

. Finding that NWE's acquisition of Battle Creek was prudent and in the ***public*** interest;

. Authorizing the inclusion of Battle Creek in rate base;

. Approving the stipulation between MCC and NWE;

. Authorizing NWE to recover the total revenue requirement of $ 2,494,036 using a rate of $ .01252/therm;

. Authorizing NWE to true-up the Battle Creek costs collected in the natural gas tracker to the actual revenue requirement approved by the ***Commission***; and

. Authorizing NWE to recover variable royalty gas costs and production tax expenses in the natural gas tracker.

11. According to the application, NWE indicated in its 2006 and 2008 Natural Gas Procurement Plans (*2006 Plan* and *2008 Plan*) filed with the ***Commission*** that it might explore the purchase of developed natural gas fields. Since 2009, NWE has been allowed by ***Montana*** law to acquire natural gas production and gathering facilities and [*4] seek inclusion of them in its rate base. *§ 69-3-1413, et seq., MCA*. In its *2010 Plan* in Docket No. N2010.12.111, NWE ***stated*** its preferred form of long-term hedging is ownership of natural gas reserves and production at appropriate prices and described its acquisition of Battle Creek, the inclusion of Battle Creek in the natural gas supply tracker, and its intent to continue to analyze opportunities to purchase natural gas reserves and production assets.

12. According to NWE, the ***Commission***'s comments in response to the utility's *2008 Plan* encouraged NWE to explore potential acquisitions of developed natural gas fields. The ***Commission***'s comments on the *2010 Plan* included the statements that failure by NWE to examine opportunities for purchasing gas reserves would be imprudent and that the ***Commission*** would evaluate the prudence of NWE's gas procurement activities based only on information available to NWE at the time of the acquisition.

13. NWE claimed its Battle Creek acquisition meets prudence and ***public*** interest standards and that it is consistent with the requirements of *§ 69-3-201, MCA* [*5] , that requires NWE to furnish adequate ***service*** at just and reasonable rates.

14. NWE described the BCGGS as including 49 miles of gathering lines and meter houses to 123 wells, two compressors and a dehydration system. The BCGGS, which has been in production since 1978, collects natural gas at the wellhead, then

compresses, dehydrates and delivers it to NWE's natural gas transmission line north of Chinook. NWE owns 65 percent of the BCGGS after purchasing a 58.5 percent interest from Helis for $ 11.4 million in September 2010 and a 6.5 percent interest from Energy Consultants for $ 1 million in November 2010. NWE's total interest in Battle Creek represents 8.4 billion cubic feet (BCF) of natural gas reserves, and includes ownership interests in 170 wells, which will supply about 2.5 percent of NWE's annual 20 BCF market. [1]

15. NWE described the ROE/Capital Structure Stipulation [*6] between it and the MCC. The stipulation proposes: an ROE of 10 percent; a debt cost of 5.48 percent; a capital structure consisting of 52 percent debt and 48 percent equity; and NWE's agreement to include Battle Creek in its next full general rate case.

NWE Pre-filed Direct Testimony

John D. Hines

16. Hines, NWE's vice president of supply, testified that ownership of natural gas assets provides a tool for managing both short- and long-term natural gas price volatility, reliability and long-term costs of NWE's natural gas supply portfolio. Hines said specific benefits include: more stable long-term prices compared to market purchases; the ability to increase or maintain supply output from a field if economic conditions allow; reduced portfolio costs if owned production is located on NWE's gas transmission system because there are no additional transportation costs; improvement to NWE's financial health if natural gas supply assets are rate-based; providing a long-term hedge to market trends by locking in a long-term price for a portion of NWE's gas supply; dampening of price volatility because ownership provides fixed prices over the long term rather than the short-term [*7] contract prices available in the market; and the possibility of lower costs per dekatherm (Dkt) than market costs.

17. Hines repeated the ***Commission***'s comments on NWE's *2010 Plan* in which the ***Commission*** ***stated*** it would be imprudent for NWE to fail to examine the possibility of acquiring natural gas reserves, given recent growth in the nation's reserves and the resulting decrease in natural gas prices. Hines proposed that the forecast market price is the appropriate comparison for evaluating the value of owning natural gas supply assets compared to continuing to purchase natural gas supply from the market. According to Hines, it was reasonable and prudent for NWE to acquire a small percentage of its natural gas supply needs at a fixed price at a time the market price was relatively low compared to recent history.

18. Hines said the total volume of the proved and producing reserves of the Battle Creek acquisition is estimated to be 8.4 BCF, the total cost of acquiring the Helis and Energy Consultants interests in the Battle Creek field was $ 12.4 million, and the first year cost of the natural gas is $ 4.848 per Dkt, including royalty expenses.

19. Hines said NWE's monthly gas supply [*8] tracker rate has included an estimate of the Battle Creek annual revenue requirement on an interim basis pending this filing, an approach approved by the ***Commission*** in its comments on the *2010 Plan.*

20. Hines testified that, prior to acquiring Battle Creek, NWE made at least four formal purchase offers to owners of natural gas properties that were rejected. Hines asserted that NWE's approach to bidding was to maintain value by not submitting a bid price that exceeded its then-current market price forecast and to reduce risk to its customers by only bidding on proved producing reserves. According to Hines, proved undeveloped reserves are inherently more difficult to accurately quantify. Hines explained that NWE did not use the preapproval process for the Battle Creek acquisition because it is not commercially reasonable for a seller to keep the market risk open for the time period required for the preapproval process.

21. Hines said approval of this application would comply with *§ 69-3-201, MCA*, because approval will contribute to rate stability and supply reliability and will move NWE further along the road to becoming a fully integrated [*9] utility for both natural gas and electricity supply.

22. In addition, Hines said NWE complied with the ***Commission***'s specific directions regarding evaluation of natural gas acquisitions that were included in the ***Commission***'s comments on NWE's *2010 Plan.*

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[1] At hearing, NWE witness Patrick Callahan corrected the total number of wells included in NWE's Battle Creek acquisition to 165. Tr., p. 64.

23. First, the ***Commission*** directed NWE to evaluate a potential acquisition's volumes, price, and term. According to Hines, the Battle Creek acquisition is relatively small and reflects NWE's approach of not trying to outperform the market for any single purchase. Regarding the price factor, Hines said the Battle Creek purchase price of $ 12.4 million was less than NWE's calculated break-even purchase amount of $ 13.725 million. Regarding the term for the Battle Creek reserves, Hines said its remaining production period is estimated to be 47 years.

24. Second, the ***Commission*** commented on the *2010 Plan* that NWE should strive for stably priced, reliable ***service***. Hines said the Battle Creek acquisition provides a long-term hedge that protects against upward price trends which improves rate stability for customers. He pointed to benefits of the acquisition, such as providing long-term gas supply at a price below what was forecast **[*10]** at the time of purchase, the location, experienced operating personnel, and facilities in good condition.

25. Third, the ***Commission*** commented on the *2010 Plan* that NWE's filing to include the acquisition of Battle Creek reserves in rate base would provide parties with the opportunity to address the prudence of the acquisition, including a consideration of the performance risk of gas production. The ***Commission*** added that the prudence evaluation will be based solely on information available to NWE at the time transactions were done. Hines said NWE exercised due diligence regarding the expected volume of gas production and conducted financial analyses to determine appropriate purchase bid amounts. Hines asserted that the due diligence NWE performed, including the use of current market forecasts for determining bid values, is evidence of the prudence of acquiring Battle Creek. Hines testified that NWE carefully evaluated the performance risk of the wells and reduced the risk of underproduction by bidding only on the value of proven developed reserves.

26. Finally, Hines said the ROE/Capital Structure Stipulation satisfies the ***Commission***'s ***stated*** expectation that filing regarding a **[*11]** gas supply purchase transaction should include a stipulated agreement with MCC.

Patrick E. Callahan

27. Patrick Callahan, NWE's director of gas growth and storage, listed the following reasons for NWE's acquisition of Battle Creek: (1) the cost of purchasing natural gas assets has declined since natural gas commodity prices have declined ; (2) ownership of a portion of the natural gas supply will provide a reliable supply and reduce exposure to market price volatility, which mitigates customer rate changes; (3) Battle Creek has a well-defined production history; (4) it is connected directly into NWE's natural gas transmission system; (5) its value is in natural gas; (6) the majority of its reserves are proved, developed reserves; and (7) the field is located in an area where NWE has operating experience.

28. Callahan ***stated*** that NWE contacted Albrecht & Associates, Helis' broker for its Battle Creek sale, in May 2010 to request to be included on the list of potential buyers for Helis' 58.5 percent interest in the BCGGS and 165 natural gas wells. Offers to purchase were due to Albrecht by July 14. The effective date of the sale was scheduled for August 1, 2010.

29. Callahan said **[*12]** that the short time frame was typical of producing property offerings in the natural gas industry. According to Callahan, the data available to potential bidders included an asset description, an outline of the sale process, a third-party economic evaluation, an evaluation of the proved developed producing gas reserves and of the proved undeveloped reserves, expense information, and operational information. Callahan said NWE analyzed the evaluation of the proved developed producing reserves and concluded it was a reasonable estimate. He said the estimated future production curve from 2010 through 2020 contained no sudden slope changes or flattening that would be uncharacteristic of a mature reserve like Battle Creek and noted that NWE also reviewed the future production estimates for each of the individual wells.

30. Callahan ***stated*** that NWE hired Jay Waterman, a consultant with Waterman Energy, Inc. of Butte, to prepare a current (June 2010) natural gas price forecast specifically tied to the sales point of the Battle Creek reserves. Waterman provided a price forecast for Alberta Energy Company minus $ 0.10 (AECO minus 10), based on a NYMEX price strip. Callahan testified the AECO **[*13]** minus 10 gas price made sense because NWE was purchasing Battle Creek gas under contract for AECO minus 10. NWE calculated an estimated successful purchase price and a revenue requirement for a NWE-owned 58.5 percent interest in Battle Creek at various assumed purchase prices. The resulting estimated revenue requirements were

then compared to the estimated cost of buying the same amount of natural gas at the current AECO minus 10 price forecast provided by Waterman. This comparison showed that the net present value (NPV) cost to NWE's customers would be the same whether NWE purchased the Helis interest at $ 12 million or continued to buy natural gas at a price of AECO minus 10. NWE submitted an initial bid of $ 11 million to Albrecht in June 2010, which NWE subsequently increased in the second round of bidding in July to $ 11.4 million after Waterman's updated gas price forecast showed the neutral point for customers had moved to $ 11.9 million from $ 12 million.

31. On July 21, 2010, Albrecht notified NWE that Helis would accept the $ 11.4 million bid, contingent on the successful negotiation of a purchase agreement and satisfactory results of the due diligence process. Callahan [*14] testified no problems surfaced during the due diligence process. The sale was effective in August 2010, and NWE took over operations at Battle Creek on October 1, 2010.

32. According to Callahan, the opportunity to purchase Energy Consultants' 6.5 percent interest in BCGGS came in late September 2010, when NWE was notified by Energy Consultants, the contract operator for Helis at BCGGS, that it would be interested in selling its piece of BCGGS. After securing an updated natural gas price forecast from Waterman and adjusting all the data used in the Helis analysis, NWE determined that the neutral point purchase price for customers was $ 1.01 million, and at a price of $ 1 million, NWE's customers would benefit over time. NWE and Energy Consultants entered negotiations and agreed upon the $ 1 million price, again effective August 1, 2010.

33. Callahan provided as exhibits to his testimony the Joint Operating Agreement (JOA) for the BCGGS Joint Venture (Gathering System Joint Venture) dated April 20, 1970, and the JOA for the wells dated December 14, 1976. NWE has replaced Helis as the manager of the Gathering System Joint Venture and is responsible for the day-to-day operation of the [*15] gathering and compression system which is performed by two NWE employees and one contract pumper. The Gathering System Joint Venture charges the owners of the natural gas for gathering and compressing their gas to cover the costs of operating the system.

34. Callahan said NWE operates 156 of the 165 wells in which it owns an interest; Omimex and NFR operate the remaining nine. The operating agreement for the wells is very similar to the Gathering System Joint Venture in that NWE pays all the expenses and then bills the partners.

35. Callahan ***stated*** that all of the natural gas from wells in which NWE owns an interest flows to customers, except for gas from the wells that Omimex and NFR operate that is separately gathered and compressed and goes to Canada. Callahan testified NWE is paid for this volume of natural gas on an AECO price basis with adjustments for transportation by Omimex and NFR and then treats the payment as a revenue credit for the benefit of the NWE customers.

36. Callahan explained that royalty gas is the gas that belongs to the royalty or mineral interest owners. The mineral interest owners include private parties, the ***State*** of ***Montana***, and the federal government, [*16] who, collectively, own royalties in the amount of 12.5 percent of the natural gas produced at BCGGS. Through the years, other individuals or companies have acquired what are called overriding royalty interests over and above the mineral interest royalties. The total of the mineral interest royalty and the overriding royalty for BCGGS is about 17.75 percent of the natural gas produced. According to Callahan, NWE did not pay Helis or Energy Consultants for the royalty volume, but does make monthly royalty payments to the royalty owners. He said no value was assigned to the overriding royalty gas in NWE's economic evaluation of the Helis or Energy Consultants interests. Callahan asserted that there is a customer benefit to having the royalty gas in the Battle Creek supply because NWE buys it at the wellhead price, which is lower than the price NWE pays for gas delivered to its transmission line. Callahan said the 2011 royalty gas price was $ 2.80/Dkt.

37. Callahan provided a comparison of the actual 2011 Battle Creek revenue requirement with the estimate NWE developed when it bid to acquire its ownership interests. It showed the actual 2011 cost was $ 5.271/Dkt compared to NWE's estimate [*17] of $ 5.252/Dkt.

John J. Waterman

38. Waterman, owner and principal engineer of Waterman Energy Inc., provided testimony on his natural gas price forecasts that were used by NWE in the economic evaluation of the Battle Creek reserves.

39. According to Waterman, he developed Battle Creek price forecasts for NWE by determining the basis differential between then-current NYMEX monthly gas futures prices and AECO and then determining the discount from the AECO pricing point to the Battle Creek sales point, which, based on his personal knowledge, was AECO minus 10. Due to the time-sensitive nature of price forecasts, Waterman provided NWE with three separate price forecasts -- in June, July and September 2010 -- during the different phases of the NWE Battle Creek evaluation process. Waterman said he further informed NWE that alternative economic evaluation methods used by unregulated companies include the discounted cash flow method and the NPV of cash flow discounted at 10 percent method (PV-10).

40. Waterman provided a chart of AECO-C pricing by month from 1997 to the time of NWE's Battle Creek evaluations. He ***stated*** his analysis shows that there has been significant price volatility [*18] since January 2000 and that at least four separate price spikes have occurred in the last ten years. He said the current prices are relatively low in comparison, which has resulted in gas assets being available at lower valuations than in the recent past.

41. Waterman said he participated in the operations inspection of BCGGS and found the operating personnel to be experienced and capable, and the facilities to be in good condition.

Brian B. Bird

42. Bird, NWE's chief financial officer and treasurer, provided the chart below to depict the proposals in the ROE/Capital Structure Stipulation:

Capital Structure	Rate	Percent Capitalization	Rate of Return
Equity	10.00%	48.00%	4.80%
Debt	5.48%	52.00%	2.85%
Total		100.00%	7.65%

43. Bird ***stated*** that NWE proposes the same capital structure for Battle Creek as the capital structure authorized by the ***Commission*** in the most recent NWE gas and electric general rate case and for the Spion Kop wind project. The proposed 5.48 percent cost of debt is the same as NWE's overall cost of debt. The proposed ROE of 10 percent is the same as the ROE approved by the ***Commission*** for Spion Kop. Bird pointed out that his testimony [*19] reflects the agreement between NWE and MCC on the issues of ROE, cost of debt, and capital structure. Bird recommended the ***Commission*** approve the ROE/Capital Structure Stipulation.

44. Bird described the valuation methodology employed by NWE to estimate the value of the Helis and Energy Consultants natural gas assets. NWE determined that the NPV of 47-year annual regulated revenue requirement was the upper limit of its bids, and then determined at which prices customers would be indifferent to purchasing the Battle Creek reserves and rate-basing them as compared to purchasing the same amount of natural gas over the next 47 years at the current price forecasts. For Helis, Bird said NWE originally used a 50/50 capital structure and a 10.75 percent ROE when modeling the revenue requirement; for Energy Consultants, a 52/48 capital structure with a 10.25 percent ROE was used.

45. Those calculations were used to estimate the valuations from the sellers' perspectives and the NWE customer indifference prices. For the 58.8 percent Helis interest in BCGGS, Bird testified those valuations were $ 12.4 million and $ 12.689 million (adjusted for current capital structure and ROE), respectively. [*20] Bird said NWE paid $ 11.4 million for Helis' interest, $ 1.289 million less than the customer indifference price. For the 6.5 percent Energy Consultants interest in BCGGS, Bird testified the valuations were $ 1.1 million from the seller's perspective and a customer indifference price of $ 1.036 million (adjusted for current capital structure and ROE). The actual purchase price was $ 1 million.

46. According to Bird, the 47-year net present value (NPV) of the revenue requirement for the Helis purchase at a price of $ 11.4 million is $ 19.632 million compared to $ 20.222 million if the same amount of natural gas was purchased using the July 15, 2010, price forecast. He said the 47-year NPV for the Energy Consultants purchase at the $ 1 million purchase price is $ 1.814 million compared to $ 1.83 million using the September 28, 2010, price forecast.

47. Bird said NWE also modeled the customer impact analysis on a shorter, 20-year duration and commented that those levelized rate calculations yielded a net benefit as well.

48. Bird explained that, because NWE had been purchasing natural gas from the Battle Creek wells at AECO minus 10, it determined that this was the appropriate basis [*21] for the price forecasts. He noted that NWE used its lower regulated rate of return as the discount rate in its revenue requirement comparisons rather than the 10 percent rate that NWE used to discount the sellers' estimated net revenues. He asserted that using the higher 10 percent discount rate to value the sellers' net revenues results in a lower suggested price because the higher the discount rate, the lower the NPV of cash flows.

John M. Smith

49. John Smith, NWE's energy supply manager, ***stated*** that NWE and its predecessor, ***Montana*** Power Company, have purchased the Battle Creek production since the field was first developed in the late 1970s. He said NWE's last contract covering 100 percent purchase production terminated on October 31, 2010, and the contract price was $ 3.1412/Dkt.

50. Smith testified that NWE's Battle Creek costs have been included in the utility's monthly tracker filings since November 2010. Under the bridging concept employed by NWE, the costs have been recovered in the tracker filings on an interim basis until a Battle Creek revenue requirement filing could be made and processed. Smith ***stated*** that the estimated Battle Creek production for the first purchase [*22] of Battle Creek (the Helis interest) for the November and December 2010 monthly tracker filings was valued at $ 5.3959/Dkt and the Year One total annual revenue requirement was calculated at $ 2,544,700. The annual amount divided by 12 resulted in the monthly revenue requirement of $ 212,058, which was included in the November and December 2010 tracker filings.

51. Smith ***stated*** that, following the December 2010 purchase of the Energy Consultants' Battle Creek interest, the monthly revenue requirement of that transaction was added for a total monthly revenue requirement of $ 231,223 from January through June of 2011. He said the estimated January through June 2010 production was valued at $ 5.2957/Dkt.

52. Smith ***stated*** the actual costs and revenues related to the portion of Battle Creek purchased by NWE have been excluded from the natural gas tracker filings since November 2010 because the tracker filings have included the revenue requirement-based computations described above.

53. According to Smith, the Year Two (July 2011 through June 2012) estimated annual revenue requirement for Battle Creek is $ 2,651,370, the monthly tracker value is $ 220,948, and the unit cost is $ 5.4587/Dkt. [*23]

54. Smith ***stated*** that because the Battle Creek revenue requirement has been included in NWE's tracker filings on an interim basis, the NWE-owned portion of Battle Creek actual costs and revenues is excluded from the natural gas tracker deferred account balance and will be trued-up separately. The Battle Creek revenue requirement is included in the forecast gas tracker model in ***order*** to reflect 100 percent of natural gas costs and revenues, including the Battle Creek acquisitions. Smith ***stated*** that royalty payments were inadvertently excluded from the natural gas tracker filings.

55. Smith pointed to NWE witness Patrick DiFronzo's testimony for a comparison of the revenues collected on an interim basis through the monthly natural gas tracker filings and the updated revenue requirement and actual volumes. Smith said the exhibit shows that NWE has under-collected for Battle Creek from November 2010 through December 2011 in the amount of $ 424,322, of which $ 350,922 is attributable to the royalty payments that were excluded in the natural gas tracker filings. NWE recommended that, after the completion of this docket, the under- or over-collection should be determined and flowed through [*24] an amortization account for the next 12-month period.

Patrick J. DiFronzo

56. DiFronzo, NWE's regulatory affairs manager, presented the Battle Creek revenue requirement based on 12 months of actual data. DiFronzo recommended that, upon ***Commission*** approval of the Battle Creek application, gas supply rates should be adjusted in conjunction with the most practical monthly supply tracker filing and the approved revenue requirement amount should be used to true-up the estimated revenue requirement that has been included in tracker filings on an interim basis from November 2010 to the date the approved revenue requirement is included in rates.

57. Going forward, DiFronzo proposed to include the Battle Creek revenue requirement in natural gas supply rates as a separate component filed in conjunction with its annual natural gas supply tracker in ***order*** to develop an all-in natural gas

supply rate. The variable costs would be included in the natural gas tracker filings and would be adjusted as appropriate based on actual annual activity from tracker to tracker. The total revenue requirement would be fixed and subject to adjustment only as the result of a future general revenue requirement [*25] filing.

58. DiFronzo testified that the fixed cost unit rate for Battle Creek is $ 0.1252 per Dkt, a rate that is derived by dividing the total revenue requirement by the test period load. This rate would be in effect until such time as NWE files for an updated Battle Creek revenue requirement that is approved by the ***Commission***.

59. According to DiFronzo, the fixed-cost unit rate for the first Battle Creek acquisition, which is necessary to calculate in ***order*** to true-up the amount billed to customers for the months of November and December 2010, is $ 0.1151 per Dkt.

60. DiFronzo testified that the Battle Creek monthly impact for a residential customer using 100 therms is an increase of $ 0.54.

61. DiFronzo ***stated*** that NWE has computed the current net difference between the revenues included in the monthly natural gas tracker filings on an interim basis and the updated revenue requirement to be an under-collection amount of $ 424,322.

62. According to DiFronzo, future Battle Creek costs, such as expenses and capital costs related to maintenance, future plant additions, inflationary cost adjustments, and increased property taxes, will be included in future general revenue requirement [*26] filings. He said annual property tax expense adjustments will be addressed in NWE's annual natural gas property tax tracker filings. As described in John Smith's testimony, royalties and production-related taxes will be included in the annual gas tracker filings.

MCC Intervenor Testimony

George L. Donkin

63. George Donkin, a consulting economist, ***stated*** that MCC does not object to NWE's request to rate-base Battle Creek and to recover its costs. Donkin testified that the purchase price of $ 12.4 million was reasonable if one accepts NWE's estimates of proved producing gas reserves and future gas production levels. He said NWE's economic analyses using the then-current supply forecasts support the conclusion that the purchase price was reasonable.

64. Regarding Hines's testimony that NWE-owned gas reserves will provide a hedge against gas supply price volatility, Donkin ***stated*** that rate-basing Battle Creek could result in a partial hedge against changes in future gas supply market prices. He said that, although a significant portion of Battle Creek's total cost of ***service*** is not expected to move up or down with future changes in market prices, the gas production taxes and [*27] royalties to be paid by NWE will. Donkin said it is appropriate for production taxes and royalty obligations to be recovered by NWE in its gas cost tracker rates.

65. Donkin disagreed with Hines's testimony that utility-owned gas reserves can help NWE manage gas supply reliability because he believes that natural gas supply reliability is not a significant problem facing NWE. Donkin also rejected Hines's assertion that NWE's ownership of gas reserves will help NWE to manage the long-term costs of its gas supply portfolio. He said if NWE had not acquired Battle Creek and instead continued to purchase the same gas at the AECO minus 10 price, in 2011 ratepayers would have been charged less because the 2011 calendar year AECO minus 10 price was $ 3.61/Dkt, compared to Battle Creek's 2011 average unit cost of $ 5.34/Dkt.

66. Donkin contended that, although the NPV and levelized rate comparisons provided by NWE suggest that, in 2010, when NWE acquired the Helis interest, there would be a net benefit to ratepayers in comparison with purchasing the same amounts of gas in the future at market prices, that outcome is no longer likely given current gas supply market forecasts.

67. Donkin provided [*28] alternative NPV analyses based on June 2012 future AECO minus 10 price forecasts that suggest that Battle Creek will probably result in significant above-market costs for NWE's ratepayers in the future. According to Donkin, his alternative calculations demonstrate that there is significant performance risk associated with gas reserves acquisitions that are coupled with rate base and full cost of ***service*** ratemaking treatment. Donkin ***stated*** that other forms

of performance risks include the possibility that recoverable reserves and/or future production levels are greater or less than originally expected, and the possibility that future actual production and gathering expenses will be greater or less than originally expected.

68. Donkin acknowledged that actual future market prices may differ significantly from the June 2012 forecast he used as the basis of his alternative calculations. For that reason, he prepared a high price scenario that assumed future actual market prices that are much greater than in NWE's June 2012 price forecast. Donkin said the results of this scenario's calculations show that Battle Creek ownership will likely result in little or no cost savings for ratepayers [*29] even with very large increases in future gas market prices.

69. Donkin said that at current and projected future gas supply prices, it appears that Battle Creek will result in mark-to-market (M2M) losses. Donkin defined M2M risk as "the potential for existing hedges to diverge unfavorably from prevailing natural gas market prices." Ex. MCC-1, p. 17. He said reserves acquisitions may be riskier than financial derivatives such as price swaps because acquisitions have longer lives than swaps; however, he acknowledged that both acquisitions and swaps could also produce M2M gains instead of losses.

70. According to Donkin, when the Helis interest was purchased, it was expected to produce a revenue requirement unit cost that would exceed gas supply market prices during 2011-2015 under both Scenario 1 and Scenario 2 in Bird's testimony and exhibits. Donkin said that because Battle Creek was not expected to produce M2M gains until 2015 or 2016 when it was acquired in 2010, the price NWE paid for Battle Creek produced significant M2M risk. Donkin contended that if the unit cost/market-price crossover point was in the second or third year following acquisition, the M2M risk of the Battle Creek [*30] acquisition would have been much less. Donkin recommended that any future purchases by NWE for gas producing properties should have expected unit cost/market-price crossover points of three years or less to reduce the risk of significant M2M losses.

NWE Rebuttal Testimony

John D. Hines

71. Hines disagreed with Donkin's proposal that all future natural gas production acquisitions have a three-year-or-less unit cost/market-price crossover point. Hines ***stated*** that Donkin clearly based his proposal on the fact that market prices had decreased since the time of the purchases. Hines ***stated*** that if Donkin's recommendation is adopted by the ***Commission***, NWE's ability to compete for and purchase natural gas production would be severely limited, to the detriment of its customers. Hines argued that NWE's bids for production assets must be based on the market value of natural gas in ***order*** to be competitive. Hines ***stated*** that market value is determined by calculating the NPV of the stream of annual market values of gas and a seller will evaluate its natural gas production assets based on the market value and consider whether or not bids received are reasonably aligned with that value. [*31] Hines said NWE already considers the unit cost/market-price crossover point as part of its acquisition analysis.

72. Hines said Donkin incorrectly testified that NWE could have continued to purchase the Battle Creek natural gas. According to Hines, Helis was selling its interest in BCGGS close to the time NWE's contract for Battle Creek gas was set to expire, which was October 31, 2010. Hines claimed that Omimex Canada Ltd., which owns the Chinook line that could flow Battle Creek gas north to Canada and which also owns about 25 percent of Battle Creek, Ltd., could have successfully bid for the Helis interest and decided to send the Battle Creek gas north.

73. Hines contended Donkin was also incorrect when he testified that the royalty gas associated with Battle Creek is a risk to customers because the royalty gas price will follow the market price. According to Hines, royalty gas reduces the Battle Creek unit cost because the royalty gas, for which NWE pays the lower wellhead price, displaces the amount of gas that NWE would otherwise purchase for NWE's supply customers at a higher market price.

74. Hines ***stated*** that NWE is evaluating other opportunities to acquire natural gas reserves [*32] and that, since these are market-based transactions, NWE is using the then-current natural gas forecasts in its analyses. Hines asserted that adoption of Donkin's recommendation to limit the amount NWE could bid on gas properties by imposing a three-year-or-less unit

82. As noted by both MCC and NWE, the ***Commission*** itself, in its comments on NWE's 2006 and 2010 gas procurement plans, supported NWE's ***stated*** intent to explore opportunities for acquisitions of developed natural gas properties that could produce benefits for ratepayers and advised NWE that it would be acting imprudently if it did not, given increasing gas reserves and declining prices. Ex. NWE-1, pp. 2, 5; Ex. MCC-1, p. 4. Donkin observed at hearing that acquisitions of natural gas reserves "have been supported [*36] by the ***Commission***, and by the company and by the ***state*** legislature." Tr., p. 100. The acquisition of gas reserves is nonetheless a relatively rare practice for regulated local distribution companies. Tr., pp. 87-88. NWE should remain vigilant that it is not exposing itself to undue risks because of market or geological factors, and should monitor the business and operational practices of its few peers in the utility sector that are engaged in gas production.

83. The ***Commission*** ***stated*** in its comments on the *2010 Plan* that it would evaluate the prudence of any acquisition by NWE of natural gas reserves "based solely on information available to NWE at the time transactions were done." Ex. NWE-1, p. 5 (citing to *2011 Comments*). The ***Commission*** advised NWE to evaluate a potential acquisition's volumes, price, and term and to demonstrate that it provides compelling customer benefit over buying gas supply at market prices. *Id.*, p. JDH-17.

84. In its comments on NWE's *2010 Plan*, the ***Commission*** said that any NWE transaction to purchase significant natural gas reserves "will be best presented to the ***Commission*** in the form of a stipulated agreement concerning the acquisition between [*37] NWE and MCC." *2011 Comments*, P 49. NWE heeded that ***Commission*** suggestion and entered into two stipulations with MCC that enabled both parties to support the Battle Creek application.

85. The ***Commission*** finds that, based on what NWE knew at the time of the transaction, NWE acted prudently in its acquisition of the Battle Creek properties. In its economic analyses of each of the two transactions, NWE calculated the maximum bid price that would produce customer indifference between rate-basing the Battle Creek asset compared to buying the same natural gas volumes over the next 47 years at the then-forecast market prices. *Id.*, p. BBB-8. NWE determined the total break-even purchase price for the Battle Creek assets was $ 13.725 million, and NWE gained significant customer benefit by paying an actual total price of $ 12.4 million for the Helis and Energy Consultants' interests. *Id.*, pp. JDH-18-19.

86. The MCC did not contest the reasonableness of the Battle Creek purchase price. According to Donkin, "The economic analyses performed by NWE using the gas supply market price forecasts available at the time support the conclusion that the purchase price of $ 12.4 million that NWE [*38] paid for Battle Creek was reasonable." Ex. MCC-1, pp. 5-6. Donkin's prefiled testimony raised the issue of the appropriate unit cost/market-price crossover point for potential future acquisitions, which Donkin recommended should be three years or less. *Id.*, p. 23. Donkin pointed out that rates for several years as a result of the Battle Creek purchase are expected to be higher than rates would have been for market price purchases of the same volumes. Tr., p. 90. Donkin's point is ultimately irrelevant in the ***Commission***'s review of the Battle Creek acquisitions because he had the benefit of current market price forecasts at the time of his analysis. As the ***Commission*** clearly ***stated*** in its *2011 Comments*: "...Using subsequent market price information constitutes the use of hindsight which has no place in the proper regulatory evaluation of the prudence of procuring natural gas. " Ex. NWE-2, p. JDH-2.

87. The Unit Cost/Market-Price Crossover Point Stipulation recognizes MCC's concern and will mitigate the risk presented if market prices turn out to be different than the forecast prices upon which an acquisition has been evaluated. As MCC ***stated***, "It simply establishes a crossover [*39] point criterion that proposed acquisitions should meet at various cost points." MCC Br., p. 2. As NWE witness Hines testified, the Stipulation does not affect the Battle Creek acquisition, but addresses the one contested issue in the docket on a prospective basis by providing an agreed-upon framework for future acquisitions. Tr., p. 13. It does not ensure that any future natural gas property acquisitions will be uncontested if they meet the Stipulation's criteria. When asked at hearing if the Stipulation's terms meant that MCC would not contest the prudence of future gas acquisitions if they fell within the parameters of the crossover point matrix, Donkin responded that other factors would still be considered by MCC, such as the net present value analysis and levelized rate calculations. Tr., p. 98.

88. NWE witness Hines testified that the values in the Stipulation will remain in effect as long as market fundamentals stay the same. Tr., p. 50. If there is a fundamental change in the market where gas is trading at significantly higher prices than

cost/market price crossover point would result in a much more volatile gas supply portfolio that is almost entirely dependent on market purchases.

John M. Smith

75. Smith ***stated*** that Donkin's testimony does not accurately assess the benefits resulting from NWE's acquisition of the Battle Creek producing properties. Smith conceded that Donkin was correct to say that NWE could replace lost natural gas production with purchases of Canadian natural gas. However, he pointed out that there are increased costs associated with acquiring additional Canadian supply as a replacement for ***Montana*** production because incremental Canadian production would have to be purchased using full AECO pricing and then be transported to ***Montana*** on TransCanada's Nova Gas Transmission Ltd. (NGTL) pipeline. Smith added that if NWE purchased additional Canadian natural gas on a full-year basis to replace ***Montana*** production, NWE would need to [*33] contract with NGTL for firm capacity in addition to that for which it already contracts. Smith estimated the cost of that capacity to be $ 0.12/Dkt and said it would be paid even if no gas is flowing to ***Montana***.

76. Smith also disputed Donkin's apparent belief that NWE could continue to purchase BCGGS gas under an AECO minus 10 contract. According to Smith, upon expiration of NWE's contract at the end of October 2010, the BCGGS owners could have marketed their gas to third parties served by NWE's gas transmission system or they could have transported their gas to Canada via the Chinook line and sold the gas in Canada.

77. Smith ***stated*** that NWE has tried to purchase natural gas on a long-term basis, but was able to negotiate only one three-year contract in October 2010. Since then, Smith said, NWE has only been able to negotiate yearly renewals.

78. Smith ***states*** that natural gas prices have decreased substantially since the spring of 2008 and that the emphasis in natural gas exploration appears to have shifted to horizontal drilling in large shale formations. Smith ***states*** that as drilling has declined, so has the gas production on NWE's system.

Unit Cost/Market-Price Crossover Point [*34] Stipulation

79. Just prior to hearing, NWE and MCC submitted the Unit Cost/Market-Price Crossover Stipulation as a resolution of Donkin's crossover point issue as it relates to future natural gas acquisitions. Ex. NWE-4. NWE and MCC agreed to the following sliding scale of crossover points for future acquisitions:

20-Year Levelized Unit Revenue Requirement ($ per Mcf)	**Crossover In Years**
Less than $ 4.00	5 or Less
$ 4.00 to $ 5.00	4 or Less
$ 5.00 to $ 6.00	3 or Less

Discussion and Findings of Fact

80. NWE requests that the ***Commission*** find that NWE's acquisition of the Battle Creek natural gas properties was a prudent investment and in the ***public*** interest. NWE Br., p. 4. MCC did not express an opinion as to the appropriate standard of review for this proceeding, but did testify as to the prudence of the Battle Creek purchase price. Ex. MCC-1, pp. 4-5. There is support for NWE's understanding that the prudence standard would be applied to this application. In P48 of the ***Public Service Commission***'s Comments on Northwestern Energy's December 2010 Natural Gas Biennial Procurement Plan, Docket No. 2010.12.111, July 27, 2011 (hereinafter *"2011 Comments"*), the [*35] ***Commission*** said, "NWE will make a filing in the future to include the Battle Creek reserves in rate base. At that time, parties will have the ability to address the prudence of that acquisition ...."

81. The ***Commission*** agrees with NWE's expectation that, in ***order*** to grant NWE's application in this case and approve inclusion of the Battle Creek properties in rate base and recovery of related expenses, the ***Commission*** must find that NWE's acquisition of the Battle Creek properties was prudent. If that finding is made, it will follow that the acquisition was in the ***public*** interest and that the rates and charges that result from rate-basing the acquisition are just and reasonable.

today's prices, NWE would want to revisit the terms of the Stipulation with MCC. *Id.* NWE should continue to use a standardized natural [*40] gas forecast, adjusted for guidance by the ***Commission***, across the processes in which the forward price of natural gas is relevant, including acquisitions of this nature, avoided-cost ratemaking, and electrical generation acquisitions.

89. The ***Commission*** finds the Unit Cost/Market-Price Crossover Point Stipulation is in the ***public*** interest and approves it.

90. NWE purchased the Battle Creek properties after conducting due diligence evaluations of the condition of the properties and the performance risk of the wells. Ex. NWE-1, pp. PEC-10-11, PEC-17-18. The due diligence efforts led NWE to conclude that, "Battle Creek is a mature natural gas field with a well-defined production history." *Id.*, p. PEC-5. Battle Creek production is expected to continue for 47 years. Tr., p. 29. NWE reduced the risk of underproduction by bidding only on the value of proven developed reserves. Ex. NWE-1, p. JDH-13.

91. Regarding NWE's ***stated*** concern about the long-term reliability of natural gas supply (Tr., p. 24), the ***Commission*** agrees with Donkin's assessment that "[N]atural gas supply reliability is not a significant problem facing NWE's management." Ex. MCC-1, p. 8. However, as NWE witness Smith [*41] pointed out, if NWE had to replace its ***Montana*** production with Canadian supplies, it would come at a higher cost. Ex. NWE-2, pp. JMS-2-3.

92. The benefits of the Battle Creek acquisition were enumerated by Hines and Callahan and include: improved ability for NWE to manage short- and long-term natural gas price volatility, reliability and long-term costs; reduced portfolio costs because the assets are located on NWE's gas transmission system; and the well-defined production history of Battle Creek. Ex. NWE-1, pp. JDH 6-8 and pp. PEC 4-5. Donkin noted generally that there are performance risks related to NWE-owned production resources, which can cause unit production costs to fluctuate and affect value to ratepayers, but those risks did not cause Donkin to object to the Battle Creek acquisition. Ex. MCC-1, pp. 6-16. Based on the evidence in the record, the ***Commission*** finds the benefits of the acquisition outweigh the risks.

93. The ***Commission*** finds that the capital structure consisting of cost of debt and ROE that were proposed and supported by NWE and MCC in the ROE/Capital Structure Stipulation are just and reasonable. The capital structure presented in the stipulation is the same [*42] as the capital structure approved by the ***Commission*** in NWE's most recent general rate case and again approved for the acquisition of Spion Kop wind project. Ex. NWE-1, p. BBB-4. The cost of debt is equal to the overall cost of debt for ***Montana*** electric and natural gas delivery ***services*** as of December 31, 2011. *Id.*, p. BBB-5. The ROE of 10 percent is the same as the ROE authorized for Spion Kop. The ***Commission*** approves the ROE/Capital Structure Stipulation, subject to adjustment in the pending natural gas rate case.

94. As with any owned production or generating asset, NWE will be responsible for prudently operating Battle Creek on an ongoing basis. Imprudent operations may subject portions of Battle Creek's costs to disallowance in natural gas trackers.

95. Utility ownership and rate-basing of natural gas assets is one way to provide customers with the benefits of reliable ***service*** at stable prices. Entering into long-term, fixed-price contracts with suppliers is another way. In testimony and at hearing, NWE asserted that long-term, fixed price contracts for natural gas supply are not available. Ex. NWE-1, pp. JMS-4-5; Tr., p. 22. Hines testified at hearing that NWE has found that [*43] suppliers are not willing to enter into long-term contracts and may even be moving to shorter-term contracts. Tr., p. 40. At hearing Donkin endorsed the view that long-term, fixed price contracts are not available as follows:

> ... generally long-term contracts of four or five years or more for natural gas supply are usually not available at fixed prices. They are available at prices tied to market index, but it's very difficult to lock in a long-term fixed price contract. And that's because of the uncertainty associated with the ups and downs of natural gas market conditions and natural gas prices.

Tr., p. 88.

96. The ***Commission*** reiterates that customers benefit from stably priced reliable natural gas supply and finds that rate-basing the Battle Creek properties will contribute to that objective. It is evident from the record that long-term, fixed

price gas supply contracts are generally unavailable at this time. Although the Battle Creek production assets provide just 2.5 percent of the 20 Bcf NWE requires to serve its natural gas customers, these assets will provide a long-term, reliable source of natural gas for NWE and its customers.

97. The ***Commission*** finds that NWE's [*44] purchase of the Battle Creek properties was prudent and in the ***public*** interest and that the properties continue to be used and useful. In addition, the ***Commission*** finds that the rates that result from inclusion of Battle Creek in rate base are just and reasonable.

Conclusions of Law

1. All findings of fact that are properly conclusions of law and that should be considered as such to protect the integrity of this ***Order*** are incorporated herein and adopted as such.

2. The ***Commission*** has provided interested persons and the ***public*** adequate ***public*** notice of all proceedings and an opportunity in this docket. *§ 69-3-104, MCA*.

3. The ***Commission*** supervises, regulates, and controls ***public*** utilities pursuant to *Title 69, Chapter 3, MCA*. *§ 69-3-102, MCA*.

4. NWE is a ***public*** utility subject to the jurisdiction of the ***Commission***. *§ 69-3-101, MCA*.

5. NWE's Battle Creek properties are used and useful in the provision of natural gas ***service*** and can be included in rate base. *Sections 69-3-109* and [*45] *69-3-201, MCA*.

Order

1. NWE's acquisitions of the Battle Creek natural gas production assets from Helis and Energy Consultants were prudent and in the ***public*** interest.

2. NWE is authorized to include the Battle Creek properties in rate base. The purchase consists of the Helis acquisition at a price of $ 11,374,123 and the Energy Consultants acquisition at a price of $ 997,730, for a total amount to be included in rate base of $ 12,371,854.

3. NWE will include Battle Creek in its next full general rate case (Docket D2012.9.94), as a known and measurable adjustment in the applicant's rebuttal testimony.

4. The ***Commission*** approves the ROE/Capital Structure Stipulation subject to adjustment in the pending general rate case, and the Unit Cost-Market-Price Crossover Point Stipulation.

5. NWE is authorized to recover the total fixed revenue requirement of $ 2,494,036. The approved fixed-cost unit rate for Battle Creek is $ 0.01252/therm.

6. NWE is authorized to true-up the Battle Creek costs collected in the natural gas tracker to the actual revenue requirement approved herein by the ***Commission***.

7. NWE is authorized to recover variable royalty [*46] gas costs and production tax expenses in the natural gas tracker.

8. In approving NWE's acquisition of the Battle Creek reserves, the ***Commission***'s intent is that all of the reserves be used to serve NWE's natural gas customers until the reserves are entirely depleted. The reserves may not be removed from rate base unless the ***Commission*** finds that customers of the natural gas utility will not be adversely affected. The proper ratemaking treatment of any future gains on any activity involving Battle Creek will be determined by the ***Commission***. In making that determination, the ***Commission*** will recognize that ratepayers have carried the risk of loss since the issuance of this ***Order***, except that risk which results from imprudent operation of the asset.

9. NWE shall file tariffs in compliance with this ***Order*** as soon as practical after issuance of this ***Order***. All tariffs shall comply with the determinations set forth in this ***Order***.

10. This Final ***Order*** is effective for ***service*** rendered on and after December 1, 2012.

DONE IN OPEN SESSION at Helena, ***Montana***, on the 15th day of November 2012 by a vote of 4 to 1.

BY ***ORDER*** OF THE ***MONTANA PUBLIC SERVICE COMMISSION***

TRAVIS KAVULLA, Chairman

GAIL [*47] GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner

BRAD MOLNAR, Commissioner (dissenting)

JOHN VINCENT, Commissioner

EXHIBIT WITHDRAWN FROM HEARING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 61
PARTY: OPC
DESCRIPTION: Forrest/OK Corp.
Commission memo on seismic activities

Commission Order PSC-08-0667-PAA-EI

and Consummating Order PSC-08-0748-CO-EI

EXHIBIT NO. 63

DOCKET NO: 140001-EI Gas Reserve

WITNESS: Forrest

PARTY: FPL

DESCRIPTION: Revised SF-8 Fuel Forecast

DOCUMENTS: FPL's redacted response to OPC's 6th Set of Interrogatories, No. 65, Redacted Revised SF-8 based on FPL's July 2014 Fuel Forecast consisting of interrogatory answer, revised chart as attachment 1, and affidavit.

PROFFERED BY: OPC

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 63
PARTY: OPC
DESCRIPTION: Forest/Revised Redacted SF-8 Fuel forecast

Q.

Please refer to Exhibit SF-8 provided with the testimony of FPL witness Forrest and the response to Staffs 7th Set of Interrogatories, Interrogatory No. 173.

a. Please provide a revised version of Exhibit SF -8 replacing the October 7, 2013 fuel forecast with the July 28, 2014 fuel forecast used in the referenced revision to the 2015 projected fuel costs. This should include a revision to all of the years utilized in SF-8 and not just to the 2015 projected fuel costs.

b. Please provide a revised version of Exhibit SF-8 replacing the October 7, 2013 fuel forecast with the Company's most recent fuel forecast if a new forecast has been prepared since the July 28, 2014 forecast identified in (a), above. This should include a revision to all of the years utilized in SF-8 and not just to the 2015 projected fuel costs.

A.

a. See Attachment I for the updated Exhibit SF-8 using the July 28, 2014 fuel forecast.

b. The latest fuel forecast is the July 28, 2014 fuel forecast, and the updated Exhibit SF-8 is attached in response to part (a) of this question.

Revised SF-8 Based on July 28, 2014 Fuel Forecast
Results of FPL's Economic Evaluation

A	B	C	D	E	F = C + D + E	G = F / B	H	I = B x (H-G)	J	K = I x J
Year	Annual Production (Bcf)	Operating Expenses ($MM)	Depreciation ($MM)	Return Rate(2) ($MM)	Revenue Requirement ($MM)	Effective Cost ($/MMBtu)	FPL Market Price Forecast 7/28/2014 ($/MMBtu)	Undiscounted Customer Savings ($MM)	FPL Discount Factor	Discounted Customer Savings ($MM)
2015	15.6	[redacted]	[redacted]	[redacted]	[redacted]	$3.48	$3.75	$4.2	0.9302	$3.9
2016	16.8	[redacted]	[redacted]	[redacted]	[redacted]	$3.56	$3.94	$6.4	0.8649	$5.5
2017	11.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.00	$4.42	$4.8	0.8043	$3.9
2018	8.7	[redacted]	[redacted]	[redacted]	[redacted]	$4.40	$4.66	$2.3	0.7480	$1.7
2019	7.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.96	$5.23	$1.9	0.6956	$1.3
2020	6.1	[redacted]	[redacted]	[redacted]	[redacted]	$4.79	$5.38	$3.6	0.6468	$2.3
2021	5.3	[redacted]	[redacted]	[redacted]	[redacted]	$4.94	$5.58	$3.4	0.6015	$2.0
2022	4.7	[redacted]	[redacted]	[redacted]	[redacted]	$5.08	$5.78	$3.3	0.5594	$1.8
2023	4.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.21	$5.98	$3.3	0.5202	$1.7
2024	3.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.34	$6.18	$3.3	0.4837	$1.6
2025	3.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.24	$6.33	$3.9	0.4498	$1.8
2026	3.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.32	$6.53	$4.0	0.4183	$1.7
2027	3.1	[redacted]	[redacted]	[redacted]	[redacted]	$5.39	$6.78	$4.3	0.3890	$1.7
2028	2.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.46	$7.03	$4.6	0.3617	$1.7
2029	2.8	[redacted]	[redacted]	[redacted]	[redacted]	$5.52	$7.33	$5.0	0.3364	$1.7
2030	2.6	[redacted]	[redacted]	[redacted]	[redacted]	$5.58	$7.63	$5.3	0.3129	$1.7
2031	2.4	[redacted]	[redacted]	[redacted]	[redacted]	$5.65	$7.81	$5.3	0.2910	$1.5
2032	2.3	[redacted]	[redacted]	[redacted]	[redacted]	$5.71	$8.00	$5.2	0.2705	$1.4
2033	2.2	[redacted]	[redacted]	[redacted]	[redacted]	$5.80	$8.19	$5.2	0.2516	$1.3
2034	2.0	[redacted]	[redacted]	[redacted]	[redacted]	$5.88	$8.39	$5.1	0.2340	$1.2
2035	1.9	[redacted]	[redacted]	[redacted]	[redacted]	$5.97	$8.60	$5.0	0.2176	$1.1
2036	1.8	[redacted]	[redacted]	[redacted]	[redacted]	$6.05	$8.81	$4.9	0.2023	$1.0
2037-65	23.1	[redacted]	[redacted]	[redacted]	[redacted]	$7.88	$11.55	$84.6	0.1008	$8.5
Totals(1)	**137.8**	**$323.2**	**$190.8**	**$195.5**	**$709.4**			**$178.7**		**$51.9**

Notes:

(1) Totals are for 2015-2065, an assumed 50 year project life. Totals may not add due to rounding.

(2) Return rate includes return on the assets and return of financing costs.

(3) Based on discount rate of 7.5%, which reflects FPL's weighted average cost of capital

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 31 day of October, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam Forrest, who is personally known to me, and he acknowledged before me that he co-sponsored the answer to interrogatory number **65** from **OPC'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 65)** in Docket No. 140001-EI, and that the responses are true and correct based on his personal knowledge.

Sam Forrest

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 31 day of October, 2014.

Maritza Miranda-Wise

Notary Public
State of Florida, at Large

My Commission Expires:

MARITZA MIRANDA-WISE
MY COMMISSION # FF 002868
EXPIRES: May 30, 2017
Bonded Thru Notary Public Underwriters

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of November, 2014, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Melissa Linton, who is personally known to me, and she acknowledged before me that she co-sponsored the answer to interrogatory number 65 from **OPC'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 65)** in Docket No. 140001-EI, and that the responses are true and correct based on her personal knowledge.

Melissa Linton

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of November, 2014.

Janet Kelly
Notary Public
State of Florida, at Large

My Commission Expires: 11/24/2017

JANET KELLY
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF072656
Expires 11/24/2017

EXHIBIT NO. 64

DOCKET NO: 140001-EI Gas Reserve

WITNESS: Forrest

PARTY: FPL

DESCRIPTION: 3 Variations on Customer Fuel Savings Sensitivity Matrix

DOCUMENTS: Forrest late filed deposition Exhibit 1 containing 3 variations on customer fuel savings sensitivity matrix, the original matrix contained in Forrest's direct, and FPL's commentary on the new matrices.

PROFFERED BY: OPC

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 64
PARTY: OPC
DESCRIPTION: Forrest/3 Variations on customer fuel savings sensitivity matrix

This late-filed exhibit responds to a request by the Office of Public Counsel for three variants to the matrix of customer savings under sensitivity cases that appears on page 38 of Mr. Forrest's direct testimony, to reflect the following changes in assumptions:

- Change Case 1 -- Changing the range of variability in gas production volume from +/- 10% to +/- 20%, but using the same October 2013 fuel forecast;
- Change Case 2 -- Using FPL's July 2014 fuel forecast instead of its October 2013 fuel forecast, but using the +/- 10% range of variability in gas production volume; and
- Change Case 3 -- Using FPL's July 2014 fuel forecast and a +/- 20% range of variability in gas production volume

The results for the three requested change cases as well as the original table are attached. FPL has several observations about the requested change cases:

- Each of the change cases shows significant base case customer savings ($106.9 MM NPV in Change Case 1 and $51.9 MM in Change Cases 2 and 3). These are the most likely outcomes for customers in each Change Case and are extremely favorable.
- The difference between the October 2013 and July 2014 fuel forecasts illustrates the price volatility that the Woodford Project would mitigate. Decoupling a portion of FPL's fuel purchases from market prices would create a more stably priced source of natural gas for the benefit of FPL's customers.
- Picking a fuel price forecast with lower fuel prices, as OPC has done, and then subjecting it to the same full range of downward fuel price volatility effectively double counts the potential "downside exposure." In other words, the variability that exists between the October 2013 and July 2014 fuel forecasts is accounted for in the 20.9% reduction in fuel prices used for the "low fuel price" sensitivities. Picking a lower fuel forecast as the starting point and then applying the same 20.9% reduction can result in exceptionally low values for the "low fuel price" sensitivity case.
- Finally, while FPL consented to run change cases using a +/- 20% range of variability in gas production volume, FPL does not believe that this range is realistic or relevant. As described by FPL witness Taylor in his direct testimony, the AMI has an established production history with a robust amount of operational performance data. Given this extensive base of production history and knowledge, Dr. Taylor expects that the aggregate volume of gas produced from the wells in the Woodford Project will not vary outside a +/- 10% band. While it is possible that the output of a single well could vary by +/- 20%, the variability for the Woodford Project in the aggregate should not exceed +/- 10%.

Pricing and Production Sensitivities[(1) / (2)]

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($38.2)	$39.1	$116.4
Base Production	$10.3	**$106.9**	$203.5
High Production	$59.8	$175.7	$291.7

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: October 2013

Pricing and Production Sensitivities[1] / [2]

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($50.7)	$23.1	$97.0
Base Production	($30.0)	**$51.9**	$134.0
High Production	($10.2)	$79.9	$170.2

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Pricing and Production Sensitivities(1) / (2)

(July 2014 Fuel Curve; Pricing: +/-20.9% per MMBtu; Production: +/-20% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($70.5)	($4.9)	$60.8
Base Production	($30.0)	$\boxed{\textbf{\$51.9}}$	$134.0
High Production	$11.4	$109.7	$208.3

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 20.9% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 20%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: July 2014

Pricing and Production Sensitivities(1) / (2)

(October 2013 Fuel Curve; Pricing: +/-21.6% per MMBtu; Production: +/-10% monthly production)

	Pricing		
	Low Fuel	Base Fuel	High Fuel
Low Production	($14.4)	$72.6	$159.5
Base Production	$10.3	**$106.9**	$203.5
High Production	$34.1	$140.4	$246.7

Notes

For illustrative purposes, the following sensitivities were assumed:

(1) Pricing sensitivity assumes +/- 21.6% per MMBtu around the NYMEX Henry Hub. This is based on 8 year historical volatility from 2005-2012.

(2) Assumes **+/- 10%** of monthly production (MMcf) for project PDPs and PUDs.

(3) Fuel curve date: October 2013

EXHIBIT NO. 65

DOCKET NO: 140001-EI

WITNESS: Deason & Ousdahl

PARTY: Florida Power & Light Company

DESCRIPTION: Order No. 14546

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 65
PARTY: OPC
DESCRIPTION: Ousdahl and Deason/Fuel Order 14546

7167

BUREAU OF ELECTRIC ACCOUNTING
DIVISION OF ELECTRIC & GAS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Cost Recovery Methods for Fuel-Related Expenses.	DOCKET NO. 850001-EI-B ORDER NO. 14546 ISSUED: 7-8-85

The following Commissioners participated in the disposition of this matter:

JOHN R. MARKS, Chairman
JOSEPH P. CRESSE
GERALD L. GUNTER

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING COST RECOVERY METHODS FOR
FUEL-RELATED EXPENSES

BY THE COMMISSION:

Background

As a result of issues raised by Staff in the February, 1985 fuel adjustment hearing, this docket was created to consider the proper means of recovery of fossil fuel-related expenses. In Order No. 14222, the final order establishing the April-September, 1985 Fuel and Purchased Power Cost Recovery Factors, we instructed Staff, the four investor owned electric utilities and any other interested parties to provide information necessary for the Commission to be able to consider at the August, 1985 fuel adjustment hearing whether the utilities were passing appropriate fixed and variable costs associated with fuel receipts through their fuel adjustment clauses.

Pursuant to the Commission's directive, a workshop concerning the cost recovery methods of fossil fuel-related expenses was noticed for and held on May 2, 1985. As a result of the information exchanged at that workshop and subsequent discussions, the parties to the proceeding, which include Staff, the Office of Public Counsel, Florida Power and Light Company (FPL), Florida Power Corporation (FPC), Gulf Power Company (Gulf), and Tampa Electric Company (TECO), identified the fossil fuel-related costs currently being recovered through the utilities' fuel adjustment clauses and agreed to a policy addressing the appropriate prospective means of recovering such fossil fuel-related expenses. The Florida Industrial Power Users Group (FIPUG) has not intervened in this proceeding but was informed of the parties' stipulation and stated that they took no position.

On June 21, 1985, the parties submitted to the Commission a stipulation evidencing their agreement. Attached to the stipulation was a draft Notice of Proposed Agency Action which the parties requested be adopted in the disposition of this proceeding. The draft Notice of Proposed Agency Action was endorsed by Staff's recommendation of June 20, 1985. In the stipulation the parties identified the fossil fuel-related costs currently being incurred and how each of the utilities are treating those expenses for cost recovery. A copy of that information is attached as Appendix A. As can be seen on Appendix A, each of the utilities do not incur all of the same types of fossil fuel-related expenses, and even in instances where the same types of expenses are incurred, utilities may recover them differently.

In addition to identifying fossil fuel-related costs and their current means of recovery, the parties reached an agreement in their stipulation as to whether these cots should be recovered prospectively through base rates or through fuel adjustment clauses. The agreement regarding specific costs reflects a broader policy consensus for the recovery of fossil fuel-related costs. The policy agreed to among the parties and recommended to the Commission consisted of two essential points which appear to reflect the Commission's practical application of fuel adjustment clauses:

1. When similar circumstances exist, the Commission should attempt to treat, for cost recovery purposes, specific types of fossil fuel-related expenses in a uniform manner among the various electric utilities. At times, however, it may be appropriate to treat similar types of expenses in dissimilar ways.

* 2. Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause. The volatility of fossil fuel-related costs may be due to a number of factors including, but not necessarily limited to: price, quantity, number of deliveries, and distance. Except as noted below, these volatile fossil fuel-related charges are incurred by the utility for goods obtained or services provided prior to the delivery of fuel to the electric utility's dedicated storage facilities. (Dedicated storage facilities mean storage facilities which are used solely to serve the affected electric utility.) All other fossil fuel-related costs should be recovered through base rates.

In the specific application of this policy, the parties recommended the following treatment of fossil fuel-related charges:

Invoiced Fuel Charges. The invoiced cost of fuel is dependent upon market conditions and the quantity of fuel purchased. The invoiced cost of fuel should be considered to include all price revisions and adjustments relating to the volume and/or quality of fuel delivered. This component of a utility's fossil fuel-related expenses is the most volatile in nature and is most appropriately recovered through the fuel adjustment clause.

Transportation Charges. The costs associated with moving fuel to fuel storage locations and terminals dedicated to the supply of a utility's generating facility are subject to significant changes due to fluctuations in distances, deliveries, volume and price. Consequently, such costs should be recovered through fuel adjustment clauses. However, transportation charges for moving fuel between dedicated storage facilities and generating plant sites appear to be more stable and predictable, due in part to many of these costs occuring under longer-term arrangements. Therefore, these transportation costs are more appropriately recovered through base rates.

Taxes and Purchasing Agents' Commissions. These charges vary with each transaction and are affected by both price and volume. These costs are most appropriately recovered through fuel adjustment clauses.

Port Charges. These charges include dockage, the fee paid to a port facility for the use of a pier, wharfage, the fee paid to a port facility for the right to receive products through a port facility, harbormaster fees, pilot fees and charges for assist tugs. These fees, which are transportation costs, are incurred prior to delivery to the utility's dedicated inventory storages facilities and vary with the number and volume of deliveries and are more properly recovered through fuel adjustment clauses.

Inspection Fees. Volume and quality inspection charges are often incurred several times in bringing fuel to a utility's generating plant sites. The charges for these inspections, which are critical to assuring that the utilities receive the proper amount of fuel consistent with contract specifications, vary with the number and size of deliveries and are essential to the determination of whether there should be adjustments to the invoice price of fuel. These charges are incurred prior to and during delivery to the utility and are appropriate for recovery through the fuel adjustment clauses.

O&M Expenses at Plants, Storage Facilities and Terminals. These costs are relatively fixed and do not tend to fluctuate significantly even with changes in the number and sizes of deliveries. As these costs are closely akin to other O&M expenses, they are more properly recovered through base rates. These expenses include unloading and handling costs at storage facilities and generating plants.

Additives. Several of the utilities blend additives with their fuel prior to burning or inject additives directly into boiler firing chambers along with fuel being burned. The price of these additives is subject to swings, and of course, the amount of additives is related to the volume and type of fuel burned. Therefore, the costs of these types of additives should be recovered through fuel adjustment clauses. Fuel additives neither blended with fuel prior to its burning nor injected into the boiler firing chamber along with fuel will be recovered through base rates.

Fuel Procurement Administrative Charges. Each of the utilities have staffs responsible for fuel procurement, and the costs associated with fuel procurement and administration do not bear a significant relationship to the volume or price of fuel purchases. These costs are relatively fixed and are not volatile; they are more appropriately recovered through base rates.

Inventory Adjustments. From time to time adjustments are made to the volume and/or value of fuel inventory maintained for system generation. Most frequently, these adjustments relate to coal inventory and result from survey evaluations of coal sites maintained at the generating facilities. Differences between the survey results and per book volumes result due to the inaccuracy inherent in the measuring devices utilized. Coal inventory adjustments shall continue to be afforded the accounting treatment specified in the Florida Public Service Commission Staff Advisory Bulletin No. 3 dated April 9, 1982. From time to time adjustments to the volume and/or value of inventory may result from Commission decisions. The impact of these adjustments are appropriately recognized in the computation of the fuel cost recovery factors.

In addition to stipulating to the foregoing applications of policy, the parties also recommended to the Commission that the policy it adopts be flexible enough to allow for recovery through fuel adjustment clauses of expenses normally recovered
*
through base rates when utilities are in a position to take advantage of a cost-effective transaction, the costs of which were not recognized or anticipated in the level of costs used to establish the utility's base rates. One example raised was the cost of an unanticipated short-term lease of a terminal to allow a utility to receive a shipment of low cost oil. The parties suggest that this flexibility is appropriate to encourage utilities to take advantage of short-term opportunities not reasonably anticipated or projected for base rate recovery. In these instances, we will require that the affected utility shall bring the matter before the Commission at the first available fuel adjustment hearing and request cost recovery through the fuel adjustment clause on a case by case basis. The Commission shall rule on the appropriate method of cost recovery based upon the merits of each individual case.

Finally, the parties recognize that the Commission, during its most recent fuel adjustment hearing, voted to determine in a single proceeding which items of fossil fuel-related costs should be transferred from fuel adjustment recovery to base rate recovery and to effect such changes at one time. While recognizing that this was the vote of the Commission, Public Counsel disagrees with such approach.

Commission's Findings

Having considered the stipulation of all the parties in this proceeding and recognizing the need for a further elaboration upon how fossil fuel-related costs should be treated for purposes of cost recovery, the Commission approves the stipulation of the parties and adopts the provisions therein, as its own. We find the policy outlined and specified in the stipulation to be an appropriate extension of the prior determinations regarding fuel costs to be recovered through fuel clauses made by the Commission in Order No. 6357.

In that earlier decision the Commission found that "the delivered cost of fuel to the generating plant site be used in determining a utility's fuel adjustment charge." That language has given rise to the recovery through the fuel adjustment clauses of unloading expenses, terminal operating expenses for terminals removed from plant sites, and transportation costs for moving oil from terminals to plant sites. While we recognize that the recovery of such costs through fuel clauses is consistent with the language in Order No. 6357, we feel further refinement is necessary since it is clear that these costs are not volatile.

Another expense which has come to be passed through the utilities' fuel clauses as a part of the cost of fuel is the cost of additives which are not added to fuel prior to burn or to boilers during burn. These additives are added after fuel is burned, generally to improve emissions control. We find that the cost of these "non-fuel additives" is more appropriately recovered through base rates.

As a result of our determinations in this proceeding, prospectively, the following charges are properly considered in the computation of the average inventory price of fuel used in the development of fuel expense in the utilities' fuel cost recovery clauses:

1. The invoice price of fuel.
2. Any revisions to the invoice price.
3. Any quality and/or quantity adjustments to the invoice price.
4. Transportation costs to the utility system, including detention or demurrage.
5. Federal and state taxes and purchasing agents' commissions.
6. Port charges.
7. All quantity and/or quality inspections performed by independent inspectors.
8. All additives blended with fuel prior to burning or injected into the boiler firing chamber along with fuel.

9. Inventory adjustments due to volume and/or price adjustments.

10. Fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers. Recovery of such costs should be made on a case by case basis after Commission approval.

It is not the Commission's intent to require the restatement of the average cost of fossil fuel inventory computed prior to the revision of rates necessitated by this Order.

The following types of fossil fuel-related costs are more appropriately considered in the computation of base rates:

1. Operations and maintenance expenses at generating plants or system storage facilities. This includes unloading and fuel handling costs at the generating plant or storage facility.

2. Transportation charges between dedicated storage facilities and generating plants.

3. Fuel procurement administrative functions.

4. Fuel additives neither blended with fuel prior to burning nor injected into the boiler firing chamber along with fuel.

While it is the Commission's intent in this Order to establish comprehensive guidelines for the treatment of fossil fuel-related costs, it is recognized that certain unanticipated costs may have been overlooked. If any utility incurs or will incur a fossil fuel-related cost which is not addressed in this order and the utility seeks to recover such cost through its fuel adjustment clause, the utility should present testimony justifying such recovery in an appropriate fuel adjustment hearing.

Consistent with the determinations previously made herein, the Commission finds that the base rates and fuel and purchased power cost recovery factors for the following investor owned electric utilities in this state will require revisions. Tampa Electric Company is currently recovering unloading expenses through its fuel clause which should be recovered through base rates. Similarly, Florida Power & Light Company and Florida Power Corporation are recovering expenses of terminal operations and of transportation of fuel between terminals and plant sites through their fuel adjustment clauses which should be recovered through their base rates. Gulf Power Company is recovering the cost of a contract tugboat used to shift coal barges at a plant site through its fuel clause which expense is more appropriately recovered through its base rates. It is the Commission's intent that any revisions to fuel and purchased power cost recovery factors and base rates only reflect a change in the means of recovery of these items. So that the Commission can be assured of the accuracy and fairness of these necessary rate changes, they will be considered during the course of the August 1985 fuel adjustment hearings and become effective for billings on or after October 1, 1985.

Therefore, the stipulation of the parties to this proceeding is accepted, and it is,

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law herein be and the same are hereby approved in every respect. It is further

ORDERED that the fuel and fossil fuel-related expenses discussed herein shall be treated in the fashion approved in the computation of fuel and purchased power cost recovery factors. It is further

ORDERED that the revisions to base rates being charged by Florida Power Corporation, Florida Power & Light Company, Gulf Power Company and Tampa Electric Company necessary to implement the determinations in this proceeding shall be considered at the August, 1985 fuel adjustment hearings and shall become effective for billings made on and after October 1, 1985. It is further

ORDERED that the action proposed herein is preliminary in nature and will not become effective or final, except as provided by Florida Administrative Code Rule 25-22.29. It is further

ORDERED that any person adversely affected by the action proposed herein may file a petition for a formal proceeding, as provided by Florida Administrative Code Rule 25-22.29. Said petition must be received by the Commission Clerk on or before July 29, 1985, in the form provided by Florida Administrative Code Rule 25-22.36(7)(a) and (f). It is further

ORDERED that in the absence of such a petition, this order shall become effective on July 30, 1985 as provided by Florida Administrative Code Rule 25-22.29(6). It is further

ORDERED that if this order becomes final and effective on July 30, 1985, any party adversely affected may request judicial review by the Florida Supreme Court by the filing of a notice of appeal with the Commission clerk and the filing of a copy of the notice and the filing fee with the Supreme Court. This filing must be completed within 30 days of the effective date of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

By Order of the Florida Public Service Commission, this 8th day of July, 1985.

Steve Tribble

STEVE TRIBBLE
Commission Clerk

(S E A L)

MRC

APPENDIX A

FUEL COST RECOVERY COMPARISON

Expense Item	TECO Recovery Method	FPL Recovery Method	FPC Recovery Method	GULF Recovery Method
01. Purchase Price of Fuel	FAC	FAC	FAC	FAC
02. Quality / Quantity Adj.	FAC	FAC	FAC	FAC
03. Retroactive Price Adj.	FAC	FAC	FAC	FAC
04. Transp. to Plant or Term.	FAC	FAC	FAC	FAC
05. Unloading Expenses	FAC-->BR	BR	BR	FAC-->BR
06. Labor (Rail Car Maint.)	--	--	--	FAC
07. Ad Valorem Taxes (Rail Car)	--	--	--	FAC
08. Rail Car Depreciation	--	--	--	FAC
09. Stores (Spare Parts)	--	--	--	FAC
10. Terminal Operating Expenses	--	FAC-->BR	FAC-->BR	--
11. Transp. from Term. to Plant	--	FAC-->BR	FAC-->BR	--
12. Handling Costs at Plant	BR	BR	BR	BR
13(a). Volume Insp's--In-House	--	BR	BR	--
13(b). Volume Insp's--Outside	--	FAC	BR-->FAC	--
14(a). Quality Insp's--In-House	BR	BR	BR	BR
14(b). Qual. Insp's--Outside	BR-->FAC	FAC	BR-->FAC	BR-->FAC
15. Limestone	FAC	--	--	--
16. Limestone Freight	FAC	--	--	--
17. Fuel Additives	FAC	FAC	FAC	FAC
18. Non-fuel Additives	FAC-->BR	BR	BR	--
19. Detention / Demurrage	FAC	FAC	--	FAC
20. Inventory Adjustments	FAC	FAC	FAC	FAC
21. Wharfage / Dockage	FAC	FAC	--	FAC
22. Tug / Pilot Fees	FAC	FAC	--	FAC
23. Port Charges	FAC	FAC	--	FAC
24. EPA Charges	FAC	--	--	--
25. Lost Coal	FAC	--	--	FAC
26. Fuel Administration	BR	BR	BR	BR
27. Outside Services	BR	BR	BR	BR
28. Admin. & General	BR	BR	BR	BR
29. Residuals	BR	--	BR	BR

LEGEND: FAC-->BR = To be removed from Fuel Adj. and put in Base Rates
BR-->FAC = To be removed from Base Rates and put in Fuel Adj.
FAC = Fuel Adjustment Clause
BR = Base Rates
-- = Category does not exist.

EXHIBIT NO. 66

DOCKET NO: 140001-EI Gas Reserve

WITNESS: Tim Taylor

PARTY: FPL witness and executive

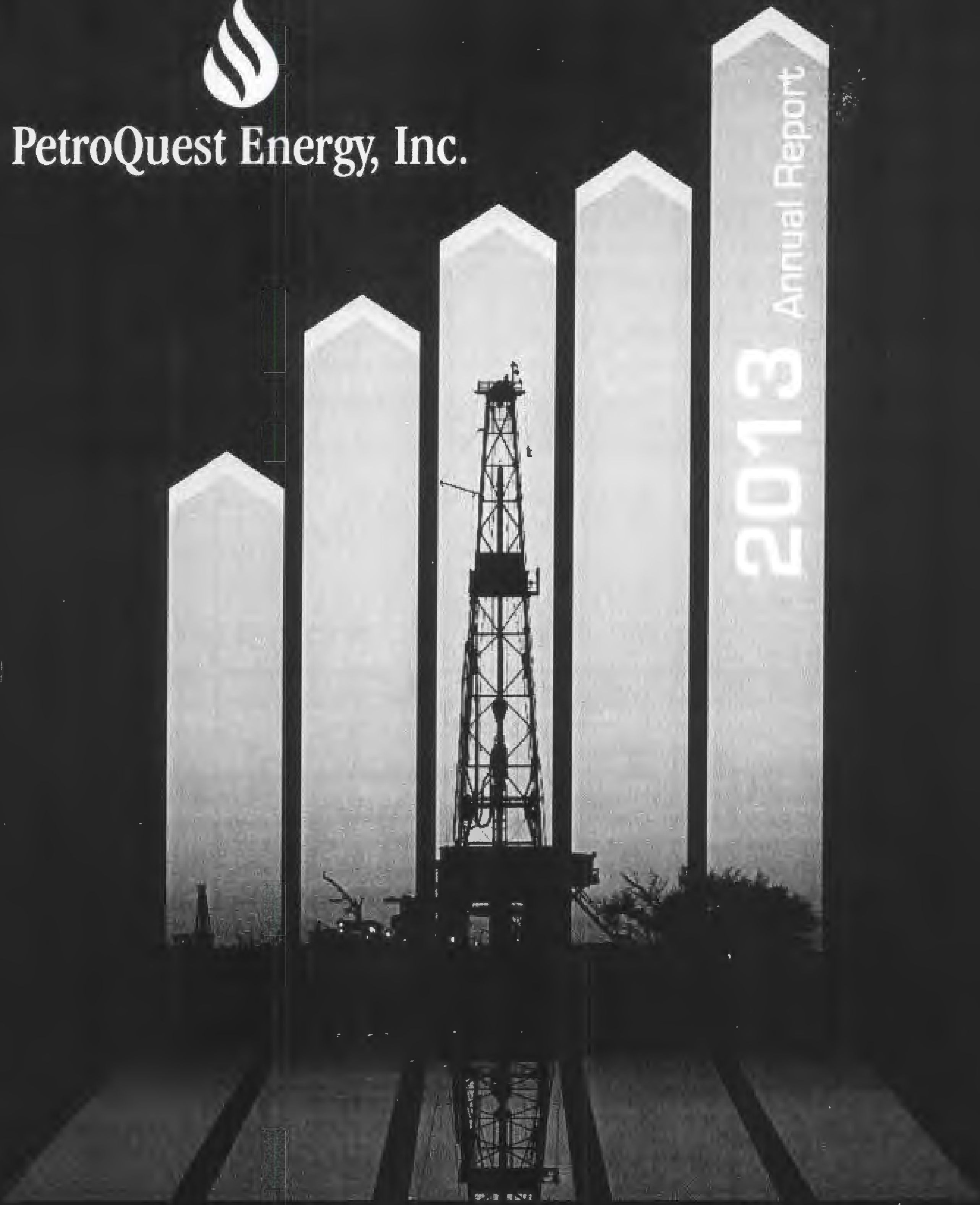
DESCRIPTION: Excerpt of PetroQuest 2013 Annual Report

DOCUMENTS: 14 page excerpt

PROFFERED BY: FIPUG

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 66
PARTY: FIPUG
DESCRIPTION: Taylor/Excerpt PetroQuest 2013 Annual Report

PetroQuest Energy, Inc.



RESOURCES. RETURNS. GROWTH.

Management believes that we are in substantial compliance with current applicable environmental laws and regulations described above and that continued compliance with existing requirements will not have a material adverse impact on us.

Corporate Offices

Our headquarters are located in Lafayette, Louisiana, in approximately 49,200 square feet of leased space, with exploration offices in The Woodlands, Texas and Tulsa, Oklahoma, in approximately 13,100 square feet and 11,800 square feet, respectively, of leased space. We also maintain owned or leased field offices in the areas of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available.

Employees

We had 126 full-time employees as of February 5, 2014. In addition to our full time employees, we utilize the services of independent contractors to perform certain functions. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement.

Available Information

We make available free of charge, or through the "Investors—SEC Documents" section of our website at www.petroquest.com, access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed or furnished to the Securities and Exchange Commission. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and the charters of our Audit, Compensation and Nominating and Corporate Governance Committees are also available through the "Investors—Corporate Governance" section of our website or in print to any stockholder who requests them.

Item 1A. **Risk Factors**

Risks Related to Our Business, Industry and Strategy

Oil and natural gas prices are volatile, and an extended decline in the prices of oil and natural gas would likely have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our future financial condition, revenues, results of operations, profitability and future growth, and the carrying value of our oil and natural gas properties depend primarily on the prices we receive for our oil and natural gas production. Our ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms also substantially depends upon oil and natural gas prices. Historically, the markets for oil and natural gas have been volatile. For example, for the four years ended December 31, 2013, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $68.01 per Bbl, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.01 per MMBtu to a low of $1.91 per MMBtu. These markets will likely continue to be volatile in the future. The prices we will receive for our production, and the levels of our production, will depend on numerous factors beyond our control.

These factors include:

- relatively minor changes in the supply of or the demand for oil and natural gas;
- the condition of the United States and worldwide economies;
- market uncertainty;
- the level of consumer product demand;
- weather conditions in the United States, such as hurricanes;
- the actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulation and taxes, including price controls adopted by the FERC;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;

- the price and level of foreign imports of oil and natural gas; and

- the price and availability of alternate fuel sources.

We cannot predict future oil and natural gas prices and such prices may decline. An extended decline in oil and natural gas prices may adversely affect our financial condition, liquidity, ability to meet our financial obligations and results of operations. Lower prices have reduced and may further reduce the amount of oil and natural gas that we can produce economically and has required and may require us to record additional ceiling test write-downs and may cause our estimated proved reserves at December 31, 2014 to decline compared to our estimated proved reserves at December 31, 2013. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices. Our sales are not made pursuant to long-term fixed price contracts.

To attempt to reduce our price risk, we periodically enter into hedging transactions with respect to a portion of our expected future production. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition, liquidity, ability to meet our financial obligations and results of operations.

Our outstanding indebtedness may adversely affect our cash flow and our ability to operate our business, which in turn may limit our ability to remain in compliance with debt covenants and make payments on our debt.

The aggregate principal amount of our outstanding indebtedness net of cash on hand as of December 31, 2013 was $416 million. We have $75 million of additional availability under our bank credit facility, subject, however, to limitations on incurrence of indebtedness under the indenture governing our 10% senior notes. In addition, we may also incur additional indebtedness in the future. Specifically, our high level of debt could have important consequences for you, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our outstanding indebtedness, including our 10% senior notes, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the agreements governing such indebtedness;

- the covenants contained in our debt agreements limit our ability to borrow money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations and may limit our flexibility in operating our business;

- we will need to use a substantial portion of our cash flows to pay interest on our debt, approximately $35 million per year for interest on our 10% senior notes alone, and to pay quarterly dividends, if declared by our Board of Directors, on our 6.875% Series B Cumulative Convertible Perpetual Preferred Stock (the "Series B Preferred Stock") of approximately $5.1 million per year, which will reduce the amount of money we have for operations, capital expenditures, expansion, acquisitions or general corporate or other business activities;

- the amount of our interest expense may increase because certain of our borrowings in the future may be at variable rates of interest, which, if interest rates increase, could result in higher interest expense;

- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;

- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially extended or further declines in oil and natural gas prices; and

- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow from operations will be sufficient to allow us to pay the principal and interest on our debt, including our 10% senior notes, and meet our other obligations. If we do not have enough cash to service our debt, we may be required to refinance all or part of our existing debt, including our 10% senior notes, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our 10% senior notes, and to fund planned capital expenditures will depend on our ability to generate sufficient cash flow from operations in the future. To a certain extent, this is subject to general economic, financial, competitive, legislative and regulatory conditions and other factors that are beyond our control, including the prices that we receive for our oil and natural gas production.

We cannot assure you that our business will generate sufficient cash flow from operations or that future borrowings will be available to us under our bank credit facility in an amount sufficient to enable us to pay principal and interest on our indebtedness, including our 10% senior notes, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on our 10% senior notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and could impair our liquidity.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis and the United States financial market have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, future hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. These factors, combined with volatile prices of oil and natural gas, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

We may not be able to obtain adequate financing when the need arises to execute our long-term operating strategy.

Our ability to execute our long-term operating strategy is highly dependent on having access to capital when the need arises. We historically have addressed our long-term liquidity needs through bank credit facilities, second lien term credit facilities, issuances of equity and debt securities, sales of assets, joint ventures and cash provided by operating activities. We will examine the following alternative sources of long-term capital as dictated by current economic conditions:

- borrowings from banks or other lenders;
- the sale of non-core assets;
- the issuance of debt securities;
- the sale of common stock, preferred stock or other equity securities;
- joint venture financing; and
- production payments.

The availability of these sources of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, oil and natural gas prices, our credit ratings, interest rates, market perceptions of us or the oil and gas industry, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these sources when the need arises.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our bank credit facility and the indenture governing our 10% senior notes contain a number of significant covenants that, among other things, restrict or limit our ability to:

- pay dividends or distributions on our capital stock or issue preferred stock;
- repurchase, redeem or retire our capital stock or subordinated debt;
- make certain loans and investments;
- place restrictions on the ability of subsidiaries to make distributions;
- sell assets, including the capital stock of subsidiaries;
- enter into certain transactions with affiliates;
- create or assume certain liens on our assets;
- enter into sale and leaseback transactions;
- merge or to enter into other business combination transactions;
- enter into transactions that would result in a change of control of us; or
- engage in other corporate activities.

Also, our bank credit facility and the indenture governing our 10% senior notes require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our bank credit facility and the indenture governing our 10% senior notes impose on us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our bank credit facility and our 10% senior notes. A default, if not cured or waived, could result in all indebtedness outstanding under our bank credit facility and our 10% senior notes to become immediately due and payable. If that should occur, we may not be able to pay all such debt or borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us. If we were unable to repay those amounts, the lenders could accelerate the maturity of the debt or proceed against any collateral granted to them to secure such defaulted debt.

Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.

As is generally the case in the Gulf Coast Basin where approximately 40% of our current production is located, many of our producing properties are characterized by a high initial production rate, followed by a steep decline in production. In order to maintain or increase our reserves, we must constantly locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. We must do this even during periods of low oil and natural gas prices when it is difficult to raise the capital necessary to finance our exploration, development and acquisition activities. Without successful exploration, development or acquisition activities, our reserves and revenues will decline rapidly. We may not be able to find and develop or acquire additional reserves at an acceptable cost or have access to necessary financing for these activities, either of which would have a material adverse effect on our financial condition.

Approximately 40% of our production is exposed to the additional risk of severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise.

At December 31, 2013, approximately 40% of our production and approximately 20% of our estimated proved reserves are located in the Gulf of Mexico and along the Gulf Coast Basin. Operations in this area are subject to severe weather, including hurricanes and tropical storms, as well as flooding, coastal erosion and sea level rise. Some of these adverse conditions can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, certain of our Gulf Coast Basin properties have experienced damages and production downtime as a result of storms including Hurricanes Katrina and Rita, and more recently Hurricanes Gustav and Ike. In addition, according to certain scientific studies, emissions of carbon dioxide, methane, nitrous oxide and other gases commonly known as greenhouse gases may be contributing to global warming of the earth's atmosphere and to global climate change, which may exacerbate the severity of these adverse conditions. As a result, such conditions may pose increased climate-related risks to our assets and operations.

In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks; however, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial condition and operations.

We maintain several types of insurance to cover our operations, including worker's compensation, maritime employer's liability and comprehensive general liability. Amounts over base coverages are provided by primary and excess umbrella liability policies. We also maintain operator's extra expense coverage, which covers the control of drilling or producing wells as well as redrilling expenses and pollution coverage for wells out of control.

We may not be able to maintain adequate insurance in the future at rates we consider reasonable, or we could experience losses that are not insured or that exceed the maximum limits under our insurance policies. If a significant event that is not fully insured or indemnified occurs, it could materially and adversely affect our financial condition and results of operations.

Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.

We use the full cost method of accounting to account for our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and natural gas properties. Under full cost accounting rules, the net capitalized costs of oil and natural gas properties may not exceed a "full cost ceiling" which is based upon the present value of estimated future net cash flows from proved reserves, including the effect of hedges in place, discounted at 10%, plus the lower of cost or fair market value of unproved properties. If at the end of any fiscal period we determine that the net capitalized costs of oil and natural gas properties exceed the full cost ceiling, we must charge the amount of the excess to earnings in the period then ended. This is called a "ceiling test write-down." This charge does not impact cash flow from operating activities, but does reduce our net income and stockholders' equity. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

We review the net capitalized costs of our properties quarterly, using a single price based on the beginning of the month average of oil and natural gas prices for the prior 12 months. We also assess investments in unproved properties periodically to determine whether impairment has occurred. The risk that we will be required to further write down the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our unproved property values, or if estimated future development costs increase. As a result of the decline in commodity prices, we recognized ceiling test write-downs totaling $137.1 million and $18.9 million during the years ended December 31, 2012 and December 31, 2011, respectively. While no such write-downs occurred during 2013, we may experience further ceiling test write-downs or other impairments in the future. In addition, any future ceiling test cushion would be subject to fluctuation as a result of acquisition or divestiture activity.

Factors beyond our control affect our ability to market oil and natural gas.

The availability of markets and the volatility of product prices are beyond our control and represent a significant risk. The marketability of our production depends upon the availability and capacity of natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Our ability to market oil and natural gas also depends on other factors beyond our control. These factors include:

- the level of domestic production and imports of oil and natural gas;
- the proximity of natural gas production to natural gas pipelines;
- the availability of pipeline capacity;

- the demand for oil and natural gas by utilities and other end users;
- the availability of alternate fuel sources;
- the effect of inclement weather, such as hurricanes;
- state and federal regulation of oil and natural gas marketing; and
- federal regulation of natural gas sold or transported in interstate commerce.

If these factors were to change dramatically, our ability to market oil and natural gas or obtain favorable prices for our oil and natural gas could be adversely affected.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly increase our risks, costs and delays.

The explosion and sinking of the Deepwater Horizon drilling rig in the Gulf of Mexico in April 2010 and the resulting oil spill may significantly impact the risks we face. The Deepwater Horizon incident and resulting legislative, regulatory and enforcement changes, including increased tort liability, could increase our liability if any incidents occur on our offshore operations. We cannot predict the ultimate impact the Deepwater Horizon incident and resulting changes in regulation of offshore oil and natural gas operations will have on our business or operations.

In response to the spill, and during a moratorium on deepwater (below 500 feet) drilling activities implemented between May 30, 2010 and October 12, 2010, the BOEMRE issued a series of active "Notices to Lessees and Operators", or NTLs, and adopted changes to its regulations to impose a variety of new measures intended to help prevent a similar disaster in the future.

Offshore operators, including those operating in deepwater, OCS waters and shallow waters, where we have substantial operations, must comply with strict new safety and operating requirements. For example, permit applications for drilling projects must meet new standards with respect to well design, casing and cementing, blowout preventers, safety certification, emergency response, and worker training. Operators of all offshore waters are also required to demonstrate the availability of adequate spill response and blowout containment resources. In addition, the BSEE imposed, for the first time, requirements that offshore operators maintain comprehensive safety and environmental programs. Such developments have the potential to increase our costs of doing business.

We may need to obtain bonds or other surety in order to maintain compliance with applicable regulations, which, if required, could be costly and reduce borrowings available under our bank credit facility or any other credit facilities we may enter into in the future.

Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS of the Gulf of Mexico and removal of facilities. Lessees subject to these regulations are generally required to have substantial net worth or post bonds or other acceptable assurances so that the various obligations of lessees on the Gulf of Mexico shelf will be met. While we have been exempt from such supplemental bonding requirements in the past, the BOEM has recently notified us that beginning in 2014 we will need to post supplemental bonding or some form of collateral for certain of our offshore properties. We are currently evaluating the cost of compliance with these supplemental bonding requirements and the potential collateral that would need to be provided. We believe that we will be able to satisfy the collateral requirements using a combination of our existing cash on hand and letters of credit available under our bank credit facility. Our borrowings available under our bank credit facility will be reduced to the extent we issue letters of credit to support the issuance of these bonds or other surety. The cost of compliance with these supplemental bonding requirements is not expected to be material.

Federal and state legislation and regulatory initiatives relating to oil and natural gas development and hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to enhance oil and natural gas production. Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the USEPA is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The USEPA published a progress report on this study in December 2012, and the final draft report is scheduled for completion during 2014. The USEPA has also promulgated rules to limit air emissions from many hydraulically fractured natural gas wells. The new regulations will require use of equipment to capture gases that come from the well during the drilling process (so-called green completions) after January 1, 2015. Other new requirements mandate tighter standards for emissions associated with gas production, storage and transport. Additionally, in May 2012, the BLM proposed rules to regulate the use of hydraulic fracturing on federal and tribal lands, but following extensive public comment on the proposals, issued a revised proposal in May 2013. The revised proposal which also addresses disclosure of fluids used in the fracturing process, integrity of well construction, and the management and disposal of wastewater that flows back from the drilling process, has also generated substantial public comment and no final rule has yet been promulgated.

A number of states, including Louisiana and Texas, have required operators or service companies to disclose chemical components in fluids used for hydraulic fracturing. Some states have also imposed, or are considering, more stringent regulation of oil and natural gas exploration and production activities involving hydraulic fracturing by, among other things, promulgating well completion requirements, imposing controls on storage, recycling and disposal of flowback fluids, and increasing reporting obligations. In addition, concerns related to the impacts from hydraulic fracturing have led several states to ban new natural gas development or to impose moratoria on use of hydraulic fracturing in various sensitive areas, including some areas overlying the Marcellus Shale. Similar action could be taken to preclude or limit natural gas development in other locations.

Recent seismic events have been observed in some areas (including Oklahoma, Ohio and Texas) where hydraulic fracturing has taken place. Some scientists believe the increased seismic activity may result from deep well fluid injection associated with use of hydraulic fracturing. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

Concerns regarding climate change have led the Congress, various states and environmental agencies to consider a number of initiatives to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane. Among other things, in the absence of new federal legislation, the USEPA promulgated regulations imposing reporting and other requirements on sources of significant emissions of greenhouse gases. Stricter regulations of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, or could adversely affect demand for the oil and natural gas we produce. In addition, climate change that results in physical effects such as increased frequency and severity of storms, floods and other climatic events, could disrupt our exploration and production operations and cause us to incur significant costs in preparing for and responding to those effects.

Although it is not possible at this time to predict the final outcome of the USEPA's study or the requirements of any additional federal or state legislation or regulation regarding hydraulic fracturing, management of drilling fluids, well integrity requirements or climate change, any new federal or state restrictions imposed on oil and gas exploration and production activities in areas in which we conduct business could significantly increase our operating, capital and compliance costs as well as delay our ability to develop oil and natural gas reserves. In addition to increased regulation of our business, we may also experience an increase in litigation seeking damages as a result of heightened public concerns related to air quality, water quality, and other environmental impacts.

The adoption of derivatives legislation by Congress, and implementation of that legislation by federal agencies, could have an adverse impact on our ability to mitigate risks associated with our business.

On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Reform Act, which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation required the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation, which they have done since late 2010. The CFTC has introduced dozens of proposed rules coming out of the Dodd-Frank Reform Act, and has promulgated numerous final rules based on those proposals. The effect of the proposed rules and any additional regulations on our business is not yet entirely clear, but it is increasingly clear that the costs of derivatives-based hedging for commodities will likely increase for all market participants. Of particular concern, the Dodd-Frank Reform Act does not explicitly exempt end users from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Act to require margin from end users, the exemption is not in the Act. While rules proposed by the CFTC and federal banking regulators appear to allow for non-cash collateral and certain exemptions from margin for end users, the rules are not final and uncertainty remains. The full range of new Dodd-Frank requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to mitigate and otherwise manage our financial and commercial risks related to fluctuations in oil and natural gas prices. In addition, final rules were promulgated by the CFTC imposing federally-mandated position limits covering a wide range of derivatives positions, including non-exchange traded bilateral swaps related to commodities including oil and natural gas. These position limit rules were vacated by a Federal court in September 2012, and the CFTC has appealed that decision and could re-promulgate the rules in a manner that addresses the defects identified by the court. If these position limits rules go into effect in the future, they are likely to increase regulatory monitoring and compliance costs for all market participants, even where a given trading entity is not in danger of breaching position limits. These and other regulatory developments stemming from the Dodd-Frank Reform Act, including stringent new reporting requirements for derivatives positions and detailed criteria that must be satisfied to continue to enter into uncleared swap transactions, could have a material impact on our derivatives trading and hedging activities in the form of increased transaction costs and compliance responsibilities. Any of the foregoing consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

From time to time legislative proposals are made that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included, among others, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. Such proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.

We operate in the highly competitive areas of oil and natural gas exploration, development and production. Factors that affect our ability to compete successfully in the marketplace include:

- the availability of funds and information relating to a property;
- the standards established by us for the minimum projected return on investment; and
- the transportation of natural gas.

Our competitors include major integrated oil companies, substantial independent energy companies, affiliates of major interstate and intrastate pipelines and national and local natural gas gatherers, many of which possess greater financial and other resources than we do. If we are unable to successfully compete against our competitors, our business, prospects, financial condition and results of operations may be adversely affected.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year time frame. We removed approximately 4.3 Bcfe and 5.5 Bcfe of proved undeveloped reserves in 2013 and 2012, respectively, as a result of the five year rule. These write-downs represented approximately 1% and 2% of the respective total year-end proved reserves at December 31, 2013 and 2012.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

Although the estimates of our oil and natural gas reserves and future net cash flows attributable to those reserves were prepared by Ryder Scott Company, L.P., our independent petroleum and geological engineers, we are ultimately responsible for the disclosure of those estimates. Reserve engineering is a complex and subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and work-over and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil and natural gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Historically, the difference between our actual production and the production estimated in a prior year's reserve report has not been material. Our 2013 production, excluding the impact from the Gulf of Mexico Acquisition, was approximately 8% greater than amounts projected in our 2012 reserve report. We cannot assure you that these differences will not be material in the future.

Approximately 33% of our estimated proved reserves at December 31, 2013 are undeveloped and 8% were developed, non-producing. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop and produce our reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated. In addition, the recovery of undeveloped reserves is generally subject to the approval of development plans and related activities by applicable state and/or federal agencies. Statutes and regulations may affect both the timing and quantity of recovery of estimated reserves. Such statutes and regulations, and their enforcement, have changed in the past and may change in the future, and may result in upward or downward revisions to current estimated proved reserves.

You should not assume that the standardized measure of discounted cash flows is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the standardized measure of discounted cash flows from proved reserves at December 31, 2013 are based on twelve-month average prices and costs as of the date of the estimate. These prices and costs will change and may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by oil and natural gas purchasers or in governmental regulations or taxation may also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor we use when calculating standardized measure of discounted cash flows for reporting requirements in compliance with accounting requirements is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our operations or the oil and natural gas industry in general will affect the accuracy of the 10% discount factor.

We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.

Acquisitions of oil and gas businesses and properties have been an important element of our business, and we will continue to pursue acquisitions in the future. In the last several years, we have pursued and consummated acquisitions that have provided us opportunities to grow our production and reserves. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition or, if the acquisition occurs, effectively integrate the acquired business into our existing business. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate revenues comparable to our existing business, the anticipated cost efficiencies or synergies may not be realized and these businesses may not be integrated successfully or operated profitably. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and to assess possible environmental liabilities. Our inability to successfully identify, execute or effectively integrate future acquisitions may negatively affect our results of operations.

Even though we perform due diligence reviews (including a review of title and other records) of the major properties we seek to acquire that we believe is consistent with industry practices, these reviews are inherently incomplete. It is generally not feasible for us to perform an in-depth review of every individual property and all records involved in each acquisition. However, even an in-depth review of records and properties may not necessarily reveal existing or potential problems or permit us to become familiar enough with the properties to assess fully their deficiencies and potential. Even when problems are identified, we may assume certain environmental and other risks and liabilities in connection with the acquired businesses and properties. The discovery of any material liabilities associated with our acquisitions could harm our results of operations.

In addition, acquisitions of businesses may require additional debt or equity financing, resulting in additional leverage or dilution of ownership. Our bank credit facility contains certain covenants that limit, or which may have the effect of limiting, among other things acquisitions, capital expenditures, the sale of assets and the incurrence of additional indebtedness.

Hedging production may limit potential gains from increases in commodity prices or result in losses.

We enter into hedging arrangements from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2013 are in the form of swaps placed with the commodity trading branches of JPMorgan Chase Bank and Wells Fargo Bank, N.A., both of which participate in our bank credit facility. We cannot assure you that these or future counterparties will not become credit risks in the future. Hedging arrangements expose us to risks in some circumstances, including situations when the counterparty to the hedging contract defaults on the contractual obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. Oil and natural gas hedges increased our total oil and gas sales by approximately $0.9 million, $9.1 million and $2.4 million during 2013, 2012 and 2011, respectively. We cannot assure you that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in oil and natural gas prices.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand for oil and natural gas. In accordance with customary industry practice, we rely on independent third-party service providers to provide most of the services necessary to drill new wells. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, drilling rig crews and other personnel, trucking services, tubulars, fracking and completion services and production equipment, including equipment and personnel related to horizontal drilling activities, could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

The loss of key management or technical personnel could adversely affect our ability to operate.

Our operations are dependent upon a diverse group of key senior management and technical personnel. In addition, we employ numerous other skilled technical personnel, including geologists, geophysicists and engineers that are essential to our operations. We cannot assure you that such individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of any of these key management or technical personnel could have an adverse effect on our operations.

Operating hazards may adversely affect our ability to conduct business.

Our operations are subject to risks inherent in the oil and natural gas industry, such as:

- unexpected drilling conditions including blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- equipment failures, fires or accidents;
- pollution and other environmental risks; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

These risks could result in substantial losses to us from injury and loss of life, damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions and more extensive governmental regulation. These regulations may, in certain circumstances, impose strict liability for pollution damage or result in the interruption or termination of operations.

Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.

Our operations are subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may:

- require the acquisition of permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment from drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from our operations.

The trend toward stricter requirements and standards in environmental legislation and regulation is likely to continue. Our drilling plans may be delayed, modified or precluded as a result of new or modified environmental mandates, including those imposed to protect the American Burying Beetle and other endangered species that may be present in the vicinity of our operations. The enactment of stricter legislation or the adoption of stricter regulations could have a significant impact on our operating costs, as well as on the oil and natural gas industry in general.

Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could also be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden and accidental environmental damages, but this insurance may not extend to the full potential liability that could be caused by sudden and accidental environmental damages and further may not cover environmental damages that occur over time. Accordingly, we may be subject to liability or may lose the ability to continue exploration or production activities upon substantial portions of our properties if certain environmental damages occur.

We cannot control the activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of drilling and development activities on our partially owned properties operated by others therefore will depend upon a number of factors outside of our control, including the operator's:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

As a result of any of the above or an operator's failure to act in ways that are in our best interest, our allocated production revenues and results of operations could be adversely affected.

Ownership of working interests and overriding royalty interests in certain of our properties by certain of our officers and directors potentially creates conflicts of interest.

Certain of our executive officers and directors or their respective affiliates are working interest owners or overriding royalty interest owners in certain properties. In their capacity as working interest owners, they are required to pay their proportionate share of all costs and are entitled to receive their proportionate share of revenues in the normal course of business. As overriding royalty interest owners they are entitled to receive their proportionate share of revenues in the normal course of business There is a potential conflict of interest between us and such officers and directors with respect to the drilling of additional wells or other development operations with respect to these properties.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Outstanding Common Stock

Our stock price could be volatile, which could cause you to lose part or all of your investment.

The stock market has from time to time experienced significant price and volume fluctuations that may be unrelated to the operating performance of particular companies. In particular, the market price of our common stock, like that of the securities of other energy companies, has been and may continue to be highly volatile. During 2013, the sales price of our stock ranged from a low of $3.55 per share (on February 28, 2013) to a high of $5.39 per share (on January 23, 2013). Factors such as announcements concerning changes in prices of oil and natural gas, the success of our acquisition, exploration and development activities, the availability of capital, and economic and other external factors, as well as period-to-period fluctuations and financial results, may have a significant effect on the market price of our common stock.

From time to time, there has been limited trading volume in our common stock. In addition, there can be no assurance that there will continue to be a trading market or that any securities research analysts will continue to provide research coverage with respect to our common stock. It is possible that such factors will adversely affect the market for our common stock.

Issuance of shares in connection with financing transactions or under stock incentive plans will dilute current stockholders.

We have issued 1,495,000 shares of Series B Preferred Stock, which are presently convertible into 5,147,734 shares of our common stock. In addition, pursuant to our stock incentive plan, our management is authorized to grant stock awards to our employees, directors and consultants. You will incur dilution upon the conversion of the Series B Preferred Stock, the exercise of any outstanding stock awards or the grant of any restricted stock. In addition, if we raise additional funds by issuing additional common stock, or securities convertible into or exchangeable or exercisable for common stock, further dilution to our existing stockholders will result, and new investors could have rights superior to existing stockholders.

The number of shares of our common stock eligible for future sale could adversely affect the market price of our stock.

At December 31, 2013, we had reserved approximately 1.9 million shares of common stock for issuance under outstanding options and approximately 5.1 million shares issuable upon conversion of the Series B Preferred Stock. All of these shares of common stock are registered for sale or resale on currently effective registration statements. We may issue additional restricted securities or register additional shares of common stock under the Securities Act in the future. The issuance of a significant number of shares of common stock upon the exercise of stock options, the granting of restricted stock or the conversion of the Series B Preferred Stock, or the availability for sale, or sale, of a substantial number of the shares of our common stock eligible for future sale under effective registration statements, under Rule 144 or otherwise, could adversely affect the market price of the common stock.

Provisions in our certificate of incorporation and bylaws could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders.

Certain provisions of our certificate of incorporation and bylaws may delay, discourage, prevent or render more difficult an attempt to obtain control of our company, whether through a tender offer, business combination, proxy contest or otherwise. These provisions include:

- the charter authorization of "blank check" preferred stock;

- provisions that directors may be removed only for cause, and then only on approval of holders of a majority of the outstanding voting stock;
- a restriction on the ability of stockholders to call a special meeting and take actions by written consent; and
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders.

We do not intend to pay dividends on our common stock and our ability to pay dividends on our common stock is restricted.

We have not paid dividends on our common stock, in cash or otherwise, and intend to retain our cash flow from operations for the future operation and development of our business. We are currently restricted from paying dividends on our common stock by our bank credit facility, the indenture governing the 10% senior notes and, in some circumstances, by the terms of our Series B Preferred Stock. Any future dividends also may be restricted by our then-existing debt agreements.

Item 1B **Unresolved Staff Comments**

None

Item 3. **Legal Proceedings**

PetroQuest is involved in litigation relating to claims arising out of its operations in the normal course of business, including worker's compensation claims, tort claims and contractual disputes. Some of the existing known claims against us are covered by insurance subject to the limits of such policies and the payment of deductible amounts by us. Management believes that the ultimate disposition of all uninsured or unindemnified matters resulting from existing litigation will not have a material adverse effect on PetroQuest's business or financial position.

Item 4. **Mine Safety Disclosures**

Not applicable.

EXHIBIT NO. 67

DOCKET NO: 140001-EI

WITNESS: Deason

PARTY: Florida Power & Light Company

DESCRIPTION: Bloomberg Article: "Duke Energy Sees Potential Shale Gas Investment"

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 67
PARTY: OPC
DESCRIPTION: Deason/ "Duke Energy Sees Potential Shale Gas Investment" Bloomberg Article

Bloomberg

Duke Energy Sees Potential Shale Gas Investment

By Mark Chediak and Harry R. Weber - Nov 11, 2014

Duke Energy Corp. (DUK) is interested in making its first investment in the production of shale gas as its power plants become more dependent on the fossil fuel.

"Gas prices have some volatility and investments in gas reserves might make sense," Chief Financial Officer Steve Young said in an interview at Edison Electric Institute's Financial Conference in Dallas today.

The largest U.S. utility owner plans to use more gas in its plants in part because of proposed U.S. Environmental Protection Agency carbon-dioxide regulations that will force it to shut some coal-fired facilities. About a third of Duke's plants burn coal, a third burn gas and a third is nuclear, Young said.

Duke now buys gas in the open market, leaving it subject to price swings that are passed through to customer bills. By investing at the wellhead, Duke would lock-in prices for customers, he said. In exchange, it would seek state regulators' approval to earn a guaranteed profit on the investment.

The company is watching a proposal by NextEra Energy Inc. under which its Florida subsidiary would invest in Oklahoma gas production to reduce fuel costs. NextEra expects a decision by state regulators this year or early next on its request, Chief Financial Officer Moray Dewhurst told investors on an Oct. 31 call.

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EXHIBIT NO. 68

DOCKET NO: 140001-EI Gas Reserve

WITNESS: Sam Forrest ~~Kim Ousdahl~~

PARTY: FPL witness and executive

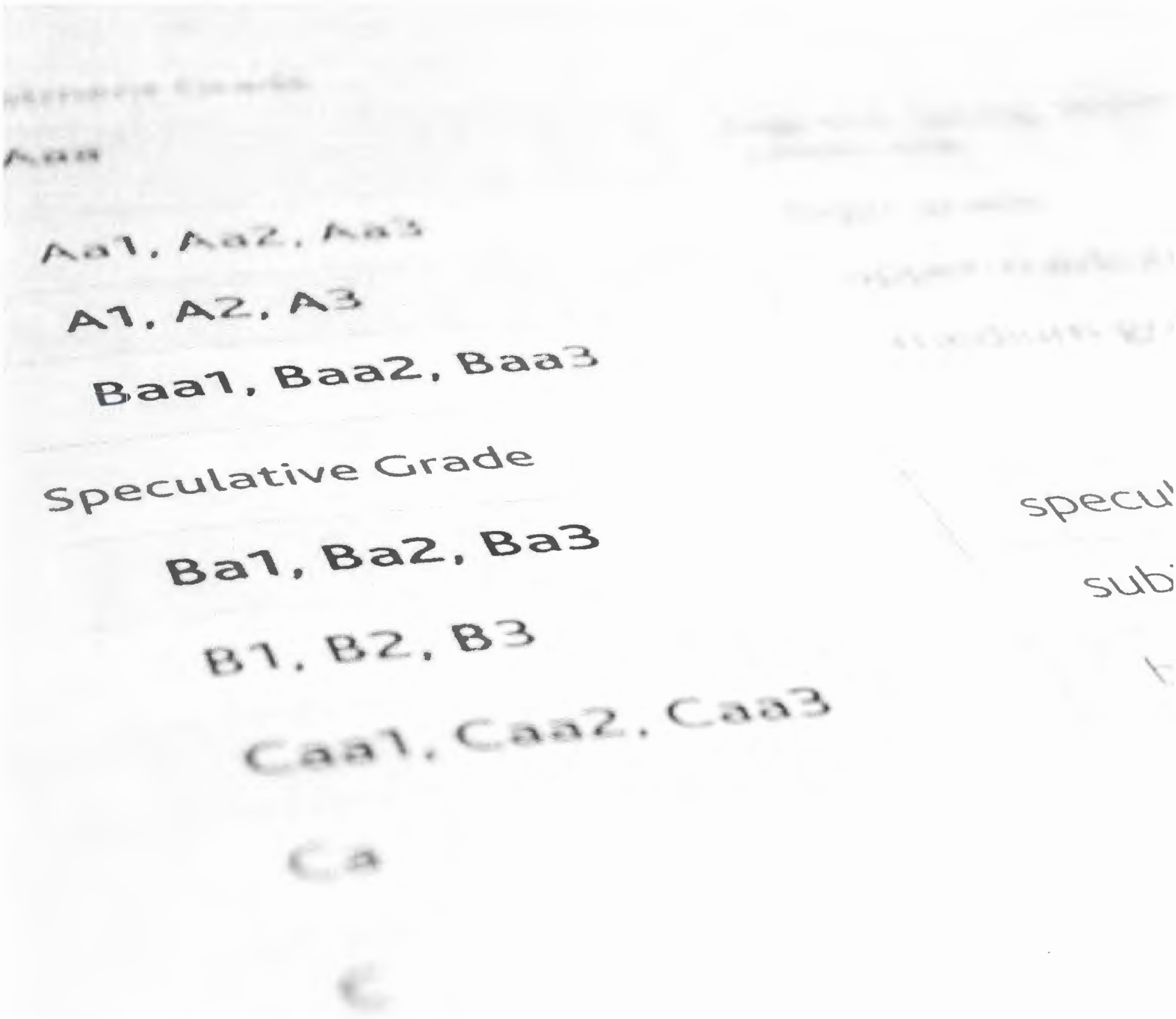
DESCRIPTION: Excerpt of Moody's Investor Services

DOCUMENTS: 7 page excerpt

PROFFERED BY: FIPUG

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 140001-EI EXHIBIT: 68
PARTY: FIPUG
DESCRIPTION: Forrest/Excerpt Moody's Investor Services

Moody's
INVESTORS SERVICE



Rating Symbols and Definitions

AUGUST 2014

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Preface

In the spirit of promoting transparency and clarity, Moody's Standing Committee on Rating Symbols and Definitions offers this updated reference guide which defines Moody's various ratings symbols, rating scales and other ratings-related definitions.

Since John Moody devised the first bond ratings almost a century ago, Moody's rating systems have evolved in response to the increasing depth and breadth of the global capital markets. Much of the innovation in Moody's rating system is a response to market needs for clarity around the components ofcredit risk or to demands for finer distinctions in rating classifications.

The Standing Committee on Rating Symbols and Definitions, one of several at Moody's that focuses on credit policy issues, is comprised of structured finance, corporate finance, public finance, and financial institutions credit analysts, as well as representatives from the Credit Policy group. The names, direct telephone numbers and e-mail addresses of the members of the Standing Committee are listed below.

I invite you to contact us with your comments.

Ken Emery
Chair, Standing Committee on Rating Symbols and Definitions

Moody's Standing Committee on Rating Symbols and Definitions

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Credit Rating Services

Moody's Global Rating Scales

Ratings assigned on Moody's global long-term and short-term rating scales are forward-looking opinions of the relative credit risks of financial obligations issued by non-financial corporates, financial institutions, structured finance vehicles, project finance vehicles, and public sector entities. Long-term ratings are assigned to issuers or obligations with an original maturity of one year or more and reflect both on the likelihood of a default on contractually promised payments and the expected financial loss suffered in the event of default.[1] Short-term ratings are assigned to obligations with an original maturity of thirteen months or less and reflect the likelihood of a default on contractually promised payments.[2]

Moody's differentiates structured finance ratings from fundamental ratings (i.e., ratings on nonfinancial corporate, financial institution, and public sector entities) on the global long-term scale by adding (sf) to all structured finance ratings. The (sf) indicator was introduced on August 11, 2010 and explained in a special comment entitled, "Moody's Structured Finance Rating Scale." The addition of (sf) to structured finance ratings should eliminate any presumption that such ratings and fundamental ratings at the same letter grade level will behave the same. The (sf) indicator for structured finance security ratings indicates that otherwise similarly rated structured finance and fundamental securities may have different risk characteristics. Through its current methodologies, however, Moody's aspire to achieve broad expected equivalence in structured finance and fundamental rating performance when measured over a long period of time.

1 For certain structured finance, preferred stock and hybrid securities in which payment default events are either not defined or do not match investors' expectations for timely payment, the ratings reflect the likelihood of impairment (as defined below in this publication) and the expected financial loss in the event of impairment.

2 For certain structured finance, preferred stock and hybrid securities in which payment default events are either not defined or do not match investors' expectations for timely payment, the ratings reflect the likelihood of impairment (as defined below in this publication).

Global Long-Term Rating Scale

Aaa	Obligations rated Aaa are judged to be of the highest quality, subject to the lowest level of credit risk.
Aa	Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.
A	Obligations rated A are judged to be upper-medium grade and are subject to low credit risk.
Baa	Obligations rated Baa are judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics.
Ba	Obligations rated Ba are judged to be speculative and are subject to substantial credit risk.
B	Obligations rated B are considered speculative and are subject to high credit risk.
Caa	Obligations rated Caa are judged to be speculative of poor standing and are subject to very high credit risk.
Ca	Obligations rated Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.
C	Obligations rated C are the lowest rated and are typically in default, with little prospect for recovery of principal or interest.

Note Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. Additionally, a "(hyb)" indicator is appended to all ratings of hybrid securities issued by banks, insurers, finance companies, and securities firms.*

Note: For more information on long-term ratings assigned to obligations in default, please see the definition "Long-Term Credit Ratings for Defaulted or Impaired Securities" in the Other Definitions section of this publication

* *By their terms, hybrid securities allow for the omission of scheduled dividends, interest, or principal payments, which can potentially result in impairment if such an omission occurs Hybrid securities may also be subject to contractually allowable write-downs of principal that could result in impairment. Together with the hybrid indicator, the long-term obligation rating assigned to a hybrid security is an expression of the relative credit risk associated with that security*

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Standard & Poor's Ratings Definitions

20-Nov-2014

Table of Contents

(**Editor's note:** We've republished the ratings definitions to add mid-market evaluation ratings and national scale insurer financial strength ratings definitions. We also added a tab ratings definitions for the Standard & Poor's Maalot (Israel) national scale.)

1. This document contains Standard & Poor's rating definitions. The definitions are classified into two types; general-purpose credit ratings and special-purpose ratings. Standard to summarize the opinion. The rating definition provides the meaning of the letters, numbers and/or words. Additionally, some ratings are expressed with qualifiers, suffixes and/or information are included.

2. Section I describes the general-purpose credit rating, both issue and issuer credit ratings, and the long-term and short-term credit ratings. Section II provides information on Cre currency ratings. Special-purpose ratings are detailed in section III. Qualifiers are covered in section IV. Section V details national and regional scale ratings. Other credit related c seven identifiers. Section IX includes a list of contacts for further information.

3. Standard & Poor's provides other services not covered in this ratings definitions document. Information about other products and services is located on Standard & Poor's Web s

I. GENERAL-PURPOSE CREDIT RATINGS

4. The following sets of rating definitions are for long-term and short-term credit ratings for both issuer and issue ratings. These types of credit ratings cover the broadest set of crec these as the "traditional" credit ratings.

A. Issue Credit Ratings

5. A Standard & Poor's issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of finai ratings on medium-term note programs and commercial paper programs). It takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancem in which the obligation is denominated. The opinion reflects Standard & Poor's view of the obligor's capacity and willingness to meet its financial commitments as they come due, a subordination, which could affect ultimate payment in the event of default.

6. Issue credit ratings can be either long-term or short-term. Short-term ratings are generally assigned to those obligations considered short-term in the relevant market. In the U.S. maturity of no more than 365 days—including commercial paper. Short-term ratings are also used to indicate the creditworthiness of an obligor with respect to put features on long term ratings.

1. Long-Term Issue Credit Ratings

7. Issue credit ratings are based, in varying degrees, on Standard & Poor's analysis of the following considerations:

- Likelihood of payment—capacity and willingness of the obligor to meet its financial commitment on an obligation in accordance with the terms of the obligation;
- Nature of and provisions of the obligation;, and the promise we impute.
- Protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws aff

8. Issue ratings are an assessment of default risk, but may incorporate an assessment of relative seniority or ultimate recovery in the event of default. Junior obligations are typical priority in bankruptcy, as noted above. (Such differentiation may apply when an entity has both senior and subordinated obligations, secured and unsecured obligations, or opera

Table 1 | Download Table

Category	Definition
AAA	An obligation rated 'AAA' has the highest rating assigned by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is extremely strong.
AA	An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitment on the obligation is very strong.
A	An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, t obligation is still strong.
BBB	An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of t
BB; B; CCC;	Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'C' the highest. While such characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.

CC; and C	
BB	An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or ecor capacity to meet its financial commitment on the obligation.
B	An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse b obligor's capacity or willingness to meet its financial commitment on the obligation.
CCC	An obligation rated 'CCC' is currently vulnerable to nonpayment, and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitr or economic conditions, the obligor is not likely to have the capacity to meet its financial commitment on the obligation.
CC	An obligation rated 'CC' is currently highly vulnerable to nonpayment. The 'CC' rating is used when a default has not yet occurred, but Standard & Poor's expects default to be a virtual ce
C	An obligation rated 'C' is currently highly vulnerable to nonpayment,and the obligation is expected to have lower relative seniority or lower ultimate recovery compared to obligations that a
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are not made or payments will be made within five business days in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will be use action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exchange
NR	This indicates that no rating has been requested, or that there is insufficient information on which to base a rating, or that Standard & Poor's does not rate a particular obligation as a matt

*The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

2. Short-Term Issue Credit Ratings

Table 2 | Download Table

Category	Definition
A-1	A short-term obligation rated 'A-1' is rated in the highest category by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is strong. Within this cate indicates that the obligor's capacity to meet its financial commitment on these obligations is extremely strong.
A-2	A short-term obligation rated 'A-2' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories on the obligation is satisfactory.
A-3	A short-term obligation rated 'A-3' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened cap obligation.
B	A short-term obligation rated 'B' is regarded as vulnerable and has significant speculative characteristics. The obligor currently has the capacity to meet its financial commitments; howev obligor's inadequate capacity to meet its financial commitments.
C	A short-term obligation rated 'C' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial cc
D	A short-term obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are nc such payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' rating also wil similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exc

B. Issuer Credit Ratings

9. A Standard & Poor's issuer credit rating is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness t not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory prefer

10. Counterparty credit ratings, corporate credit ratings and sovereign credit ratings are all forms of issuer credit ratings.

11. Issuer credit ratings can be either long-term or short-term.

1. Long-Term Issuer Credit Ratings

Table 3 | Download Table

Category	Definition
AAA	An obligor rated 'AAA' has extremely strong capacity to meet its financial commitments. 'AAA' is the highest issuer credit rating assigned by Standard & Poor's.
AA	An obligor rated 'AA' has very strong capacity to meet its financial commitments. It differs from the highest-rated obligors only to a small degree.
A	An obligor rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions
BBB	An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakenec
BB; B; CCC; and CC	Obligors rated 'BB', 'B', 'CCC', and 'CC' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'CC' the highest. While such oblig these may be outweighed by large uncertainties or major exposures to adverse conditions.
BB	An obligor rated 'BB' is less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or ecc capacity to meet its financial commitments.
B	An obligor rated 'B' is more vulnerable than the obligors rated 'BB', but the obligor currently has the capacity to meet its financial commitments. Adverse business, financial, or economic c meet its financial commitments.
CCC	An obligor rated 'CCC' is currently vulnerable, and is dependent upon favorable business, financial, and economic conditions to meet its financial commitments.
CC	An obligor rated 'CC' is currently highly vulnerable. The 'CC' rating is used when a default has not yet occurred, but Standard & Poor's expects default to be a virtual certainty, regardless
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' is in default on one or more of its financial obligations including rated and unrated financial obligations but excluding hybrid instruments classi An obligor is considered in default unless Standard & Poor's believes that such payments will be made within five business days of the due date in the absence of a stated grace period,o A 'D' rating is assigned when Standard & Poor's believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due the obligor has selectively defaulted on a specific issue or class of obligations but it will continue to meet its payment obligations on other issues or classes of obligations in a timely mann distressed exchange offer.
NR	An issuer designated 'NR' is not rated.

*The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

2. Short-Term Issuer Credit Ratings

Table 4 | Download Table

Category	Definition
A-1	An obligor rated 'A-1' has strong capacity to meet its financial commitments. It is rated in the highest category by Standard & Poor's. Within this category, certain obligors are designated v meet its financial commitments is extremely strong.

A-2	An obligor rated 'A-2' has satisfactory capacity to meet its financial commitments. However, it is somewhat more susceptible to the adverse effects of changes in circumstances and eco
A-3	An obligor rated 'A-3' has adequate capacity to meet its financial obligations. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened ca
B	An obligor rated 'B' is regarded as vulnerable and has significant speculative characteristics. The obligor currently has the capacity to meet its financial commitments; however, it faces m inadequate capacity to meet its financial commitments.
C	An obligor rated 'C' is currently vulnerable to nonpayment that would result in a 'SD' or 'D' issuer rating, and is dependent upon favorable business, financial, and economic conditions for
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' has failed to pay one or more of its financial obligations (rated or unrated), excluding hybrid instruments classified as regulatory capital or in considered in default unless Standard & Poor's believes that such payments will be made within any stated grace period. However, any stated grace period longer than five business day when Standard & Poor's believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. An 'SD' rating is assig selectively defaulted on a specific issue or class of obligations, excluding hybrid instruments classified as regulatory capital, but it will continue to meet its payment obligations on other iss rating is lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.
NR	An issuer designated 'NR' is not rated.

II. CREDITWATCH, RATING OUTLOOK , LOCAL CURRENCY AND FOREIGN CURRENCY RATINGS

12. The following section explains CreditWatch and rating outlooks and how they are used. Additionally, this section explains local currency and foreign currency ratings.

A. CreditWatch

13. CreditWatch highlights our opinion regarding the potential direction of a short-term or long-term rating. It focuses on identifiable events and short-term trends that cause ratings Poor's analytical staff. Ratings may be placed on CreditWatch under the following circumstances:

- When an event has occurred or, in our view, a deviation from an expected trend has occurred or is expected and when additional information is necessary to evaluate the cur mergers, recapitalizations, voter referendums, regulatory actions, performance deterioration of securitized assets, or anticipated operating developments.
- When we believe there has been a material change in performance of an issue or issuer, but the magnitude of the rating impact has not been fully determined, and we believe
- A change in criteria has been adopted that necessitates a review of an entire sector or multiple transactions and we believe that a rating change is likely in the short-term.

14. A CreditWatch listing, however, does not mean a rating change is inevitable, and when appropriate, a range of potential alternative ratings will be shown. CreditWatch is not ir changes may occur without the ratings having first appeared on CreditWatch. The "positive" designation means that a rating may be raised; "negative" means a rating may be low lowered, or affirmed.

B. Rating Outlooks

15. A Standard & Poor's rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a ra economic and/or fundamental business conditions. An outlook is not necessarily a precursor of a rating change or future CreditWatch action.

- Positive means that a rating may be raised.
- Negative means that a rating may be lowered.
- Stable means that a rating is not likely to change.
- Developing means a rating may be raised or lowered.
- N.M. means not meaningful.

C. Local Currency and Foreign Currency Ratings

16. Standard & Poor's issuer credit ratings make a distinction between foreign currency ratings and local currency ratings. An issuer's foreign currency rating will differ from its loca to meet its obligations denominated in its local currency, vs. obligations denominated in a foreign currency.

III. SPECIAL-PURPOSE RATINGS

17. Section III includes a description of different types of special-purpose ratings. Special-purpose ratings can be for capital market transactions or entities. Such a rating type can companies). Another type of special-purpose rating is a recovery rating which is very different than a traditional issuer credit rating. Some ratings are limited by the type of credit su special-purpose ratings are for the specific types of transaction structures, such as those with embedded put options.

A. Dual Ratings

18. Dual ratings may be assigned to debt issues that have a put option or demand feature. The first component of the rating addresses the likelihood of repayment of principal and addresses only the demand feature. The first component of the rating can relate to either a short-term or long-term transaction and accordingly use either short-term or long-term ra to the put option and is assigned a short-term rating symbol (for example, 'AAA/A-1+' or 'A-1+/A-1'). With U.S. municipal short-term demand debt, the U.S. municipal short-term note rating (for example, 'SP-1+/A-1+').

B. Fund Credit Quality Ratings

19. Fund credit quality ratings, identified by the 'f' suffix, are assigned to fixed-income funds and other actively managed funds that exhibit variable net asset values. These ratings of a fund's portfolio. The ratings reflect the level of protection against losses from credit defaults and are based on an analysis of the credit quality of the portfolio investments and t

Table 5 | Download Table

Category	Definition
AAAf	The fund's portfolio holdings provide extremely strong protection against losses from credit defaults.
AAf	The fund's portfolio holdings provide very strong protection against losses from credit defaults.
Af	The fund's portfolio holdings provide strong protection against losses from credit defaults.
BBBf	The fund's portfolio holdings provide adequate protection against losses from credit defaults.
BBf	The fund's portfolio holdings provide uncertain protection against losses from credit defaults.
Bf	The fund's portfolio holdings exhibit vulnerability to losses from credit defaults.
CCCf	The fund's portfolio holdings make it extremely vulnerable to losses from credit defaults.

*The ratings from 'AAf' to 'CCCf' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

C. Fund Volatility Ratings

20. A fund volatility rating is a forward-looking opinion about a fixed-income investment fund's sensitivity to changing market conditions relative to the risk of a portfolio composed ‹ currency of the fund. (Government securities (for S1 through S4 categories) are intended to signify the most liquid, highest quality securities issued by a sovereign government.) V‹ sensitivity to interest rate movements, credit risk, investment diversification or concentration, liquidity, leverage, and other factors. Different symbology is used to distinguish the fur or issuer credit ratings.

Table 6 | Download Table

Fund Volatility Ratings

Category	Definition
S1	Funds that possess low sensitivity to changing market conditions are rated S1. These funds possess an aggregate level of risk that is less than or equal to that of a portfolio comprised o denominated in the base currency of the fund. Within this category, certain funds are designated with a plus sign (+). This indicates the fund's extremely low sensitivity to changing marke is less than or equal to that of a portfolio comprising the highest quality fixed-income instruments with an average maturity of 12 months or less.
S2	Funds that possess low to moderate sensitivity to changing market conditions are rated S2. These funds possess an aggregate level of risk that is less than or equal to that of a portfolio years and denominated in the base currency of the fund.
S3	Funds that possess moderate sensitivity to changing market conditions are rated S3. These funds possess an aggregate level of risk that is less than or equal to that of a portfolio compr and denominated in the base currency of the fund.
S4	Funds that possess moderate to high sensitivity to changing market conditions are rated S4. These funds possess an aggregate level of risk that is less than or equal to that of a portfolic and denominated in the base currency of the fund.
S5	Funds that possess high sensitivity to changing market conditions are rated S5. These funds may be exposed to a variety of significant risks including high concentration risks, high leve securities.
S6	Funds that possess the highest sensitivity to changing market conditions are rated S6. These funds include those with highly speculative investment strategies with multiple forms of sign

D. Insurance Financial Enhancement Ratings

21. A Standard & Poor's insurer financial enhancement rating is a forward-looking opinion about the creditworthiness of an insurer with respect to insurance policies or other finan enhancement and/or financial guarantees. When assigning an insurer financial enhancement rating, Standard & Poor's analysis focuses on capital, liquidity, and company commi financial guaranty business.

22. Insurer financial enhancement ratings are based, in varying degrees, on Standard & Poor's analysis of the following considerations:

- Likelihood of payment--capacity and willingness of the insurer to meet its financial commitment on an obligation in accordance with the terms of the obligation;
- Nature of and provisions of the obligations; and
- Protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws aff

Table 7 | Download Table

Insurer Financial Enhancement Ratings*

Category	Definition
AAA	An insurer rated 'AAA' has extremely strong capacity to meet its financial commitments. 'AAA' is the highest insurer financial enhancement rating assigned by Standard & Poor's.
AA	An insurer rated 'AA' has very strong capacity to meet its financial commitments. It differs from the highest-rated insurers only to a small degree.
A	An insurer rated 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditi
BBB	An insurer rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weake
BB; B; CCC; and CC	Insurers rated 'BB', 'B', 'CCC', and 'CC' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'CC' the highest. While such in characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.
BB	An insurer rated 'BB' is less vulnerable in the near term than other lower-rated insurers. However, it faces major ongoing uncertainties and exposure to adverse business, financial, or capacity to meet its financial commitments.
B	An insurer rated 'B' is more vulnerable than the insurers rated 'BB', but the insurer currently has the capacity to meet its financial commitments. Adverse business, financial, or econon to meet its financial commitments.
CCC	An insurer rated 'CCC' is currently vulnerable, and is dependent upon favorable business, financial, and economic conditions to meet its financial commitments.
CC	An insurer rated 'CC' is currently highly vulnerable.
R	An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision the regulators may have the power to favor one c others.
SD	An insurer rated 'SD' has failed to pay one or more of its financial obligations when it came due. An 'SD' rating is assigned when Standard & Poor's believes that the obligor has selectiv continue to meet its payment obligations on other issues or classes of obligations. A selective default includes the completion of a distressed exchange offer.
NR	An issuer designated 'NR' is not rated.

*Ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

E. Insurer Financial Strength Ratings

23. A Standard & Poor's insurer financial strength rating is a forward-looking opinion about the financial security characteristics of an insurance organization with respect to its abil accordance with their terms. Insurer financial strength ratings are also assigned to health maintenance organizations and similar health plans with respect to their ability to pay un terms.

24. This opinion is not specific to any particular policy or contract, nor does it address the suitability of a particular policy or contract for a specific purpose or purchaser. Furthermoı surrender or cancellation penalties, timeliness of payment, nor the likelihood of the use of a defense such as fraud to deny claims.

25. Insurer financial strength ratings do not refer to an organization's ability to meet nonpolicy (i.e., debt) obligations. Assignment of ratings to debt issued by insurers or to debt iss policies, contracts, or guarantees is a separate process from the determination of insurer financial strength ratings, and follows procedures consistent with those used to assign ar not a recommendation to purchase or discontinue any policy or contract issued by an insurer.

1. Long-Term Insurer Financial Strength Ratings

Table 8 | Download Table

Category	Definition

AAA	An insurer rated 'AAA' has extremely strong financial security characteristics. 'AAA' is the highest insurer financial strength rating assigned by Standard & Poor's.
AA	An insurer rated 'AA' has very strong financial security characteristics, differing only slightly from those rated higher.
A	An insurer rated 'A' has strong financial security characteristics, but is somewhat more likely to be affected by adverse business conditions than are insurers with higher ratings.
BBB	An insurer rated 'BBB' has good financial security characteristics, but is more likely to be affected by adverse business conditions than are higher-rated insurers.
BB; CCC; and CC	An insurer rated 'BB' or lower is regarded as having vulnerable characteristics that may outweigh its strengths. 'BB' indicates the least degree of vulnerability within the range; 'CC' the h
BB	An insurer rated 'BB' has marginal financial security characteristics. Positive attributes exist, but adverse business conditions could lead to insufficient ability to meet financial commitme
B	An insurer rated 'B' has weak financial security characteristics. Adverse business conditions will likely impair its ability to meet financial commitments.
CCC	An insurer rated 'CCC' has very weak financial security characteristics, and is dependent on favorable business conditions to meet financial commitments.
CC	An insurer rated 'CC' has extremely weak financial security characteristics and is likely not to meet some of its financial commitments.
R	An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one cl others. The rating does not apply to insurers subject only to nonfinancial actions such as market conduct violations.
SD or D	An insurer rated 'SD' (selective default) or 'D' is in default on one or more of its insurance policy obligations but is not under regulatory supervision that would involve a rating of 'R'. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action if payments on a policy obligation are at risk. A 'D' rating is assigned when Standard & the obligor will fail to pay substantially all of its obligations in full in accordance with the policy terms. An 'SD' rating is assigned when Standard & Poor's believes that the insurer has selectively defaulted on a specific class of policies but it will continue to meet its payment obligations on completion of a distressed exchange offer. Claim denials due to lack of coverage or other legally permitted defenses are not considered defaults.
NR	An insurer designated 'NR' is not rated.

*Ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

F. Municipal Short-Term Note Ratings

26. A Standard & Poor's U.S. municipal note rating reflects Standard & Poor's opinion about the liquidity factors and market access risks unique to the notes. Notes due in three ye original maturity of more than three years will most likely receive a long-term debt rating. In determining which type of rating, if any, to assign, Standard & Poor's analysis will revie

- Amortization schedule—the larger the final maturity relative to other maturities, the more likely it will be treated as a note; and
- Source of payment—the more dependent the issue is on the market for its refinancing, the more likely it will be treated as a note.

Table 9 | Download Table

Municipal Short-Term Note Ratings

Category	Definition
SP-1	Strong capacity to pay principal and interest. An issue determined to possess a very strong capacity to pay debt service is given a plus (+) designation.
SP-2	Satisfactory capacity to pay principal and interest, with some vulnerability to adverse financial and economic changes over the term of the notes.
SP-3	Speculative capacity to pay principal and interest.

G. Principal Stability Fund Ratings

27. A Standard & Poor's principal stability fund rating, also known as a "money market fund rating," is a forward-looking opinion about a fixed income fund's capacity to maintain st stability rating to a fund, Standard & Poor's analysis focuses primarily on the creditworthiness of the fund's investments and counterparties, and also its investments' maturity struct fund's stable net asset value. Principal stability fund ratings are assigned to funds that seek to maintain a stable or an accumulating net asset value.

28. Generally, when faced with an unanticipated level of redemption requests during periods of high market stress, the manager of any fund may suspend redemptions for up to fi payments in-kind in lieu of cash.

29. Principal stability fund ratings, or money market fund ratings, are identified by the 'm' suffix (e.g., 'AAAm') to distinguish the principal stability rating from a Standard & Poor's tra ratings are not commentaries on yield levels.

Table 10 | Download Table

Principal Stability Fund Ratings

Category	Definition
AAAm	A fund rated 'AAAm' demonstrates extremely strong capacity to maintain principal stability and to limit exposure to principal losses due to credit risk. 'AAAm' is the highest principal stabilit
AAm	A fund rated 'AAm' demonstrates very strong capacity to maintain principal stability and to limit exposure to principal losses due to credit risk. It differs from the highest-rated funds only to
Am	A fund rated 'Am' demonstrates strong capacity to maintain principal stability and to limit exposure to principal losses due to credit risk, but is somewhat more susceptible to the adverse than funds in higher-rated categories.
BBBm	A fund rated 'BBBm' demonstrates adequate capacity to maintain principal stability and to limit exposure to principal losses due to credit risk. However, adverse economic conditions or c capacity to maintain principal stability.
BBm	A fund rated 'BBm' demonstrates speculative characteristics and uncertain capacity to maintain principal stability. It is vulnerable to principal losses due to credit risk. While such funds w may be outweighed by large uncertainties or major exposures to adverse conditions.
Dm	A fund rated 'Dm' has failed to maintain principal stability resulting in a realized or unrealized loss of principal.

*The ratings from 'AA' to 'BB' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the rating categories.

H. Mid-Market Evaluation Rating

30. A Mid-Market Evaluation rating (MME rating) is Standard & Poor's forward-looking opinion about the creditworthiness of a mid-market company relative to other mid-market co capacity and willingness to meet its financial commitments as they come due. We assign the MME rating at an obligor level, but can assign it at a debt instrument level as well. In c instrument, we may modify the MME rating with the symbols '+' or '-' to indicate our opinion about recovery prospects in case of default (including our opinion of the collateral secu

31. MME ratings are derived from a specific MME methodology and use a specific credit rating scale ranging from 'MM1' (highest) to 'MM8' and 'MMD' (default). We apply the MME rating with respect to a company's overall capacity to meet its financial commitments, or to assign an issue-level MME rating with respect to a company's capacity to meet its financ the MME rating scale on the issue level is only for long-term debt instruments. The symbols '+' and '-' apply only to debt instruments. For instance, a debt instrument could receive a expectations of particularly high or low recovery.

Table 11 | Download Table

Category	Definition

MM1	The company has a very strong capacity to meet its financial commitments relative to other mid-market companies. Companies rated at this level are less susceptible to the adverse effe other mid-market companies.
MM2	The company has a strong capacity to meet its financial commitments relative to other mid-market companies. However, the company is somewhat more susceptible to the adverse effe other mid-market companies in the higher category.
MM3	The company has a good capacity to meet its financial commitments relative to other mid-market companies. However, adverse economic conditions or changing circumstances are mo its financial commitments.
MM4	The company has an adequate capacity to meet its financial commitments relative to other mid-market companies. However, it is more exposed to adverse economic conditions or chan higher MME Rating.
MM5	The company has reasonably adequate capacity to meet its financial commitments relative to other mid-market companies. It faces ongoing uncertainties or exposure to adverse busine inadequate capacity on the part of the company to meet its financial commitments.
MM6	The company has a weak capacity to meet financial commitments, although it is less vulnerable relative to other mid-market companies with a lower MME Rating. Adverse business, fina capacity or willingness to meet its financial commitments.
MM7	The company is currently vulnerable to defaulting and is dependent upon favorable business and financial conditions to meet financial commitments. In the event of adverse business, fin the capacity to meet its financial commitments.
MM8	The company is currently highly vulnerable to defaulting and is dependent upon favorable business and financial conditions to meet its financial commitments We expect default to be a vi exchange, or similar debt restructuring, or a bankruptcy filing.
MMD	The company has either failed to pay one or more of its financial obligations when due, or it has been placed into bankruptcy, or it has completed a distressed exchange or similar debt re
NR	An issuer designated 'NR' is not rated. For an obligation, an NR designation indicates that no rating has been requested, or that there is insufficient information on which to base a rating, matter of policy.

I. Recovery Ratings

32. Recovery ratings focus solely on expected recovery in the event of a payment default of a specific issue, and utilize a numerical scale that runs from 1+ to 6. The recovery ratin any other rating, and provides a specific opinion about the expected recovery.

Table 12 | Download Table

Recovery Ratings

Category	Definition
1+	A recovery rating of '1+' denotes the highest expectation of full recovery in the event of default.
1	A recovery rating of '1' denotes an expectation of very high (i.e., 90%-100%) recovery in the event of default.
2	A recovery rating of '2' denotes an expectation of substantial (i.e., 70%-90%) recovery in the event of default.
3	A recovery rating of '3' denotes an expectation of meaningful (i.e., 50%-70%) recovery in the event of default.
4	A recovery rating of '4' denotes an expectation of average (i.e., 30%-50%) recovery in the event of default.
5	A recovery rating of '5' denotes an expectation of modest (i.e., 10%-30%) recovery in the event of default.
6	A recovery rating of '6' denotes an expectation of negligible (i.e., 0-10%) recovery in the event of default.

J. SPUR (Standard & Poor's Underlying Rating)

33. A SPUR rating is an opinion about the stand-alone capacity of an obligor to pay debt service on a credit-enhanced debt issue, without giving effect to the enhancement that ap of the debt issuer/obligor with the designation SPUR to distinguish them from the credit-enhanced rating that applies to the debt issue. Standard & Poor's maintains surveillance o

K. Swap Risk Ratings

34. A Standard & Poor's Swap Risk Rating is a forward-looking opinion about the likelihood of loss associated with a specific swap transaction (the "Swap Transaction") entered ir

35. A swap risk rating takes into consideration Standard & Poor's view on the terms of the Swap Transaction including, without limitation, the creditworthiness of one or more refere above a certain specified threshold percentage/amount, termination events, and potential recovery percentage or amount on the Portfolio. All swap risk ratings take into considera

36. A swap risk rating may be modified by the designation "Portfolio," "Single Counterparty--Protection Buyer" and "Single Counterparty--Protection Seller." A Swap Risk Rating (P view on the creditworthiness of the credit default swap Portfolio. A Swap Risk Rating (Single Counterparty--Protection Buyer) takes into consideration Standard & Poor's view on t protection under the Swap Transaction. A Swap Risk Rating (Single Counterparty--Protection Seller) takes into consideration Standard & Poor's view on the creditworthiness of th Transaction. Because the terms of each Swap Transaction are highly customized, a swap risk rating may address different risks; therefore the swap risk ratings should not be view swap transactions.

37. Swap risk ratings will be modified by a suffix that identifies the type of swap risk rating assigned. The letter ratings will be followed by the designations 'srp,' 'srb,' and 'srs' to cor

- Portfolio ('srp') ratings only take into consideration the creditworthiness of the reference portfolio of the credit default swap;
- Single counterparty--Protection Buyer ('srb') ratings take into consideration the creditworthiness of the reference portfolio and the buyer of protection under the swap transacti
- Single counterparty--Protection Seller ('srs') ratings take into consideration the creditworthiness of the reference portfolio and the seller of protection under the swap transactic

38. A Swap Risk Rating (Portfolio) does not address either counterparty risk (including risk of periodic payments). Each of Swap Risk Ratings (Single Counterparty--Protection Bu the counterparty risk of one of the Counterparties to the Swap Transaction, respectively. None of the swap risk ratings address the specific amount of termination payments that wc risks addressed by each swap risk rating are stated in the rating letter and the terms and conditions issued for each rated Swap Transaction.

Table 13 | Download Table

Category	Definition
AAA	A Swap Transaction with a swap risk rating of 'AAA' has the highest rating assigned by Standard & Poor's. The likelihood of loss under the Swap Transaction is extremely low.
AA	A Swap Transaction with a swap risk rating of 'AA' differs from the highest-rated Swap Transaction only to a small degree. The likelihood of loss under the Swap Transaction is very
A	A Swap Transaction with a swap risk rating of 'A' is somewhat more susceptible to the adverse effects or changes in circumstances and economic conditions than Swap Transacti under the Swap Transaction is still low.
BBB	A Swap Transaction with a swap risk rating of 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to Transaction.
BB; B; CCC; and CC	A Swap Transaction with a swap risk rating of 'BB', 'B', 'CCC', and 'CC' is regarded as having significant speculative characteristics.
	A Swap Transaction with a swap risk rating of 'BB' indicates less vulnerability to a risk of loss than other speculative issues. However, major ongoing uncertainties or exposure to a

BB	substantial increase in the likelihood of loss under the Swap Transaction.
B	A Swap Transaction with a swap risk rating of 'B' is more vulnerable to a risk of loss than a Swap Transaction with a swap risk rating of 'BB'. However, major ongoing uncertainties conditions will likely lead to a substantial increase in the likelihood of loss under the Swap Transaction.
CCC	A Swap Transaction with a swap risk rating of 'CCC' is currently vulnerable to a risk of loss. In the event of adverse business, financial or economic conditions, the Swap Transacti
CC	A Swap Transaction with a swap risk rating of 'CC' is currently highly vulnerable to loss.
D	A Swap Transaction with a swap risk rating of 'D' has incurred or experienced loss.
NR	A Swap Transaction designated 'NR' is not rated, which implies no opinion about its swap risk rating, including without limitation, that a swap risk rating has not been requested or th

*A swap risk rating from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major swap risk rating categories.

IV. QUALIFIERS

39. Standard & Poor's assigns qualifiers to ratings when appropriate. This section details active and inactive qualifiers.

A. Active Qualifiers

40. Standard & Poor's uses six qualifiers that limit the scope of a rating. The structure of the transaction can require the use of a qualifier such as a 'p' qualifier, which indicates the Likewise, the qualifier can indicate a limitation on the type of information used, such as "pi" for public information. A qualifier appears as a suffix and is part of the rating.

Federal deposit insurance limit: 'L' qualifier

41. Ratings qualified with 'L' apply only to amounts invested up to federal deposit insurance limits.

Principal: 'p' qualifier

42. This suffix is used for issues in which the credit factors, the terms, or both, that determine the likelihood of receipt of payment of principal are different from the credit factors, ter on the obligation. The 'p' suffix indicates that the rating addresses the principal portion of the obligation only and that the interest is not rated.

Public Information Ratings: 'pi' qualifier

43. Ratings with a 'pi' suffix are based on an analysis of an issuer's published financial information, as well as additional information in the public domain. They do not, however, r therefore may be based on less comprehensive information than ratings without a 'pi' suffix. Ratings with a 'pi' suffix are reviewed annually based on a new year's financial statem event occurs that may affect the issuer's credit quality.

Preliminary Ratings: 'prelim' qualifier

44. Preliminary ratings, with the 'prelim' suffix, may be assigned to obligors or obligations, including financial programs, in the circumstances described below. Assignment of a fin of appropriate documentation. Standard & Poor's reserves the right not to issue a final rating. Moreover, if a final rating is issued, it may differ from the preliminary rating.

- Preliminary ratings may be assigned to obligations, most commonly structured and project finance issues, pending receipt of final documentation and legal opinions.
- Preliminary ratings are assigned to Rule 415 Shelf Registrations. As specific issues, with defined terms, are offered from the master registration, a final rating may be assigne
- Preliminary ratings may be assigned to obligations that will likely be issued upon the obligor's emergence from bankruptcy or similar reorganization, based on late-stage reor obligor. Preliminary ratings may also be assigned to the obligors. These ratings consider the anticipated general credit quality of the reorganized or post-bankruptcy issuer as
- Preliminary ratings may be assigned to entities that are being formed or that are in the process of being independently established when, in Standard & Poor's opinion, docun assigned to the obligations of these entities.
- Preliminary ratings may be assigned when a previously unrated entity is undergoing a well-formulated restructuring, recapitalization, significant financing or other transformat commitments are invited. The preliminary rating may be assigned to the entity and to its proposed obligation(s). These preliminary ratings consider the anticipated general cre anticipated obligation(s), assuming successful completion of the transformative event. Should the transformative event not occur, Standard & Poor's would likely withdraw the
- A preliminary recovery rating may be assigned to an obligation that has a preliminary issue credit rating.

Termination Structures: 't' qualifier

45. This symbol indicates termination structures that are designed to honor their contracts to full maturity or, should certain events occur, to terminate and cash settle all their contr

B. Inactive Qualifiers

46. Inactive qualifiers are no longer applied or outstanding.

Contingent upon final documentation: '*' inactive qualifier

47. This symbol that indicated that the rating was contingent upon Standard & Poor's receipt of an executed copy of the escrow agreement or closing documentation confirming in 1998.

Termination of obligation to tender: 'c' inactive qualifier

48. This qualifier was used to provide additional information to investors that the bank may terminate its obligation to purchase tendered bonds if the long-term credit rating of the i and/or the issuer's bonds were deemed taxable. Discontinued use in January 2001.

U.S. direct government securities: 'G' inactive qualifier

49. The letter 'G' followed the rating symbol when a fund's portfolio consisted primarily of direct U.S. government securities.

Provisional Ratings: 'pr' inactive qualifier

50. The letters 'pr' indicate that the rating was provisional. A provisional rating assumed the successful completion of a project financed by the debt being rated and indicates that p entirely dependent upon the successful, timely completion of the project. This rating, however, while addressing credit quality subsequent to completion of the project, made no co of such completion.

Quantitative Analysis of public information: 'q' inactive qualifier

51. A 'q' subscript indicates that the rating is based solely on quantitative analysis of publicly available information. Discontinued use in April 2001.

Extraordinary risks: 'r' inactive qualifier

52. The 'r' modifier was assigned to securities containing extraordinary risks, particularly market risks, which are not covered in the credit rating. The absence of an 'r' modifier shou not exhibit extraordinary non-credit related risks. Standard & Poor's discontinued the use of the 'r' modifier for most obligations in June 2000 and for the balance of obligations (ma

V. NATIONAL AND REGIONAL SCALE RATINGS

53. National and regional scale ratings are special-purpose ratings that only apply to issues/issuers in a specific country or region.

A. National And Regional Scale Ratings

54. Standard & Poor's national scale credit ratings are an opinion of an obligor's creditworthiness (issuer, corporate, or counterparty credit rating) or overall capacity to meet speci issuers and issues in a given country or region. National scale credit ratings provide a rank ordering of credit risk within the country. Given the focus on credit quality within a singl between countries. Standard & Poor's also assigns regional scale credit ratings for certain groups of countries. Regional scale credit ratings have the same attributes as national s national or regional scales, and are a relative rank order within the region. The national and regional scale credit ratings use Standard & Poor's global rating symbols with the add Table 14 notes three countries where prefixes are not used. The regional scale rating definitions are the same as the national scale rating definitions but with the word "national" r

55. Table 14 lists the national or regional scales, the country or regional prefixes and the associated countries or regions.

Table 14 | Download Table

Scale Name	Prefix	Countries
Argentina National Scale	ra	Argentina
ASEAN Regional Scale	ax	Association of South-East Asian Nations (Indonesia, Malaysia, Philippines, Singapore, Thailand, Brunei Darussalam, Vietnam, Lao People's Den
Brazil National Scale	br	Brazil
Canada National Scale	no prefix	Canada
CaVal (Mexico) National Scale	mx	Mexico
Greater China Regional Scale	cn	China, Hong Kong, Macau and Taiwan
Gulf Cooperation Council Regional Scale	gc	Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and United Arab Emirates
Japan SME National Scale	no prefix	Japan
Kazakhstan National Scale	kz	Kazakhstan
Maalot (Israel) National Scale	il	Israel
Nigeria National Scale	ng	Nigeria
Nordic Regional Scale	no prefix	Denmark, Finland, Sweden
Russia National Scale	ru	Russia
South Africa National Scale	za	South Africa
Taiwan Ratings National Scale	tw	Taiwan
Turkey National Scale	tr	Turkey
Ukraine National Scale	ua	Ukraine
Uruguay National Scale	uy	Uruguay

56. Fourteen national and regional scales use an identical set of rating definitions. Tables 15-18 detail the set of definitions applied to the 14 national or regional scales. Canada, regional short-term scale is also a different scale. In addition, the Taiwan Ratings fund credit quality ratings use a separate scale. These unique five scales appear after the genera

57. The national scale credit rating definitions include a country prefix denoted as 'xx' See table 14 for a list of country prefixes, the scale name and the associated countries. For e entities/obligations in Brazil.

B. General National And Regional Scale Ratings

1. National Scale Issue Credit Ratings

58. A Standard & Poor's national scale issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific debt, bond, lease, comme instrument ("obligation") relative to the creditworthiness of other national obligors with respect to their own financial obligations. National obligors include all active borrowers, gua enhancement residing in the country, as well as any foreign obligor active in country's financial markets.

59. Standard & Poor's national scale issue credit ratings are based, in varying degrees, on the analysis of the following considerations:

- The relative likelihood of payment–the rating assesses the obligor's capacity and willingness to meet its financial commitments in accordance with the terms of the obligation,
- The obligation's nature and provisions; and
- Protection afforded to, and the relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under bankruptcy laws and other laws affect

2. National Scale Long-Term Issue Credit Ratings

Table 15 | Download Table

Category	Definition
xxAAA	An obligation rated 'xxAAA' has the highest credit rating assigned on Standard & Poor's national scale. The obligor's capacity to meet its financial commitments on the obligation, relative
xxAA	An obligation rated 'xxAA' differs from the highest-rated debt only to a small degree. The obligor's capacity to meet its financial commitments on the obligation, relative to other national c
xxA	An obligation rated 'xxA' is somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than higher-rated debt. Still, the obligor's capacity to n national obligors, is strong.
xxBBB	An obligation rated 'xxBBB' exhibits adequate protection parameters relative to other national obligations. However, adverse economic conditions or changing circumstances are more meet its financial commitments on the obligation.
xxBB; xxB; xxCCC, xxCC; and xxC	Obligations rated 'xxBB', 'xxB', 'xxCCC', 'xxCC', and 'xC' on the Standard & Poor's national credit rating scale are regarded as having high risk relative to other national obligations Wh characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions relative to other national obligations.
xxBB	An obligation rated 'xxBB' denotes somewhat weak protection parameters relative to other national obligations. The obligor's capacity to meet its financial commitments on the obligatior exposure to adverse business, financial, or economic conditions.
xxB	An obligation rated 'xxB' is more vulnerable than obligations rated 'xxBB' relative to other national obligations. The obligor currently has a weak capacity to meet its financial obligations would likely impair capacity or willingness of the obligor to meet its financial commitments on the obligation.

xxCCC	An obligation rated 'xxCCC' is currently vulnerable to nonpayment, relative to other national obligations, and is dependent upon favorable business and financial conditions for the obligo of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitment on the obligation.
xxCC	An obligation rated 'xxCC' is currently highly vulnerable to nonpayment relative to other national obligations. The 'xxCC' rating is used when a default has not yet occurred, but Standar the anticipated time to default.
xxC	An obligation rated 'xxC' is currently highly vulnerable to nonpayment, and the obligation is expected to have lower relative seniority or lower ultimate recovery compared to obligations
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are not made payments will be made within five business days in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will be u action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exchang

*The credit ratings from 'xxAA' to 'xxCCC' may be modified by the addition of a plus (+) or minus (-) to show relative strength with the rating category.

3. National Scale Short-Term Issue Credit Ratings

Table 16 | Download Table

National Scale Short-Term Issue Credit Ratings*

Category	Definition
xxA-1	A short-term obligation rated 'xxA-1' is rated in the highest category on Standard & Poor's national scale. The obligor's capacity to meet its commitments on the obligation, relative to othe obligations are designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations, relative to other national obligors, is extreme
xxA-2	A short-term obligation rated 'xxA-2' is slightly more susceptible to adverse changes in circumstances and economic conditions than obligations rated 'xxA-1'. The obligor's capacity to m national obligors, is satisfactory.
xxA-3	A short-term obligation rated 'xxA-3' denotes adequate protection parameters relative to other short-term national obligations. It is, however, more vulnerable to adverse effects of change designations.
xxB	A short-term obligation rated 'xxB' denotes weak protection parameters relative to other short-term national obligations. It is vulnerable to adverse business, financial, or economic conditi
xxC	A short-term obligation rated 'xxC' denotes doubtful capacity for payment.
D	A short-term obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are nc such payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' rating also wil similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exc

*Apply to obligations with an original maturity of less than one year.

4. National Scale Issuer Credit Ratings

60. A Standard & Poor's national scale issuer credit rating is a forward-looking opinion about the overall creditworthiness of a debt issuer, guarantor, insurer, or other provider of c obligations as they come due, relative to other national obligors. Such national obligors include all active borrowers, guarantors, insurers, and other providers of credit enhancem in national financial markets.

61. Issuer credit ratings do not apply to specific obligations, as they do not take into account the nature and provisions of the obligation, its standing in bankruptcy or liquidation, st obligation. In addition, they do not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation.

5. National Scale Long-Term Issuer Credit Ratings

Table 17 | Download Table

National Scale Long-Term Issuer Credit Ratings*

Category	Definition
xxAAA	An obligor rated 'xxAAA' has an extremely strong capacity to meet its financial commitments relative to that of other national obligors. 'xxAAA' is the highest issuer credit rating assigned a
xxAA	An obligor rated 'xxAA' differs from the highest-rated obligors only to a small degree, and has a very strong capacity to meet its financial commitments relative to that of other national obli
xxA	An obligor rated 'xxA' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher-rated obligors. Still, the obligor has a strong other national obligors.
xxBBB	An obligor rated 'xxBBB' has an adequate capacity to meet its financial commitments relative to that of other national obligors. However, adverse economic conditions or changing circum obligor to meet its financial commitments.
xxBB;, xxB; xxCCC; and xxCC	Obligors rated 'xxBB', 'xxB', 'xxCCC', and 'xxCC' on the Standard & Poor's national credit rating scale are regarded as having high risk relative to other national obligors. While such oblig these may be outweighed by large uncertainties or major exposure to adverse conditions relative to other national obligors.
xxBB	An obligor rated 'xxBB' denotes somewhat weak capacity to meet its financial commitments, although it is less vulnerable than other lower-rated national obligors. However, it faces ongoi economic conditions, which could result in an inadequate capacity on the part of the obligor to meet its financial commitments.
xxB	An obligor rated 'xxB' is more vulnerable than obligors rated 'xxBB'. The obligor currently has a weak capacity to meet its financial commitments relative to other national obligors. Advers the obligor's capacity or willingness to meet its financial commitments.
xxCCC	An obligor rated 'xxCCC' is currently vulnerable relative to other national obligors and is dependent upon favorable business and financial conditions to meet its financial commitments.
xxCC	An obligor rated 'xxCC' is currently highly vulnerable to defaulting on its financial commitments relative to other national obligors. The 'xxCC' rating is used when a default has not yet occu certainty, regardless of the anticipated time to default.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' is in default on one or more of its financial obligations including rated and unrated financial obligations but excluding hybrid instruments classi An obligor is considered in default unless Standard & Poor's believes that such payments will be made within five business days of the due date in the absence of a stated grace period,o A 'D' rating is assigned when Standard & Poor's believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due the obligor has selectively defaulted on a specific issue or class of obligations but it will continue to meet its payment obligations on other issues or classes of obligations in a timely mann distressed exchange offer.

*The credit ratings from 'xxAA' to 'xxCCC' may be modified by the addition of a plus (+) or minus (-) to show relative strength with the rating category.

6. National Scale Short-Term Issuer Credit Ratings

Table 18 | Download Table

Category	Definition
xxA-1	An obligor with a 'xxA-1' short-term credit rating has a strong capacity to meet financial commitments relative to that of other national obligors. Within this category, certain obligations are capacity to meet its financial commitment on these obligations, relative to that of other obligors in the national market, is extremely strong.
xxA-2	An obligor with a 'xxA-2' short-term credit rating has a satisfactory capacity to meet financial obligations relative to that of other national obligors.
xxA-3	An obligor with a 'xxA-3' short-term credit rating has an adequate capacity to meet financial commitments relative to that of other national obligors. However, the obligor is more vulnerabl conditions than higher-rated obligors.

xxB	An obligor with a 'xxB' short-term credit rating has a weak capacity to meet financial commitments, relative to that of other national obligors, and is vulnerable to adverse business, financi
xxC	An obligor with a 'xxC' short-term credit rating has a doubtful capacity to meet financial commitments.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' has failed to pay one or more of its financial obligations (rated or unrated), excluding hybrid instruments classified as regulatory capital or in considered in default unless Standard & Poor's believes that such payments will be made within any stated grace period. However, any stated grace period longer than five business day when Standard & Poor's believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. An 'SD' rating is assig selectively defaulted on a specific issue or class of obligations, excluding hybrid instruments classified as regulatory capital, but it will continue to meet its payment obligations on other iss rating is lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.

*Apply to an obligor's capacity to meet financial commitments over a time horizon of less than one year.

C. National Scale Insurer Financial Strength Ratings

62. A national scale insurer financial strength rating is a forward-looking opinion about the financial security characteristics of an insurance organization with respect to its ability t accordance with their terms, relative to other insurers in the national market.

63. This opinion is not specific to any particular policy or contract, nor does it address the suitability of a particular policy or contract for a specific purpose or purchaser. Furthermo surrender or cancellation penalties, timeliness of payment, nor the likelihood of the use of a defense such as fraud to deny claims.

64. Insurer financial strength ratings do not refer to an organization's ability to meet nonpolicy (i.e., debt) obligations. Assignment of ratings to debt issued by insurers or to debt iss policies, contracts, or guarantees is a separate process from the determination of insurer financial strength ratings, and follows procedures consistent with those used to assign ar

Table 19 | Download Table

Category	Definition
nsAAA	An insurer rated 'nsAAA' has extremely strong financial security characteristics, relative to other insurers in the national market. 'nsAAA' is the highest insurer financial strength r
nsAA	An insurer rated 'nsAA' has very strong financial security characteristics, relative to other insurers in the national market, differing only slightly from those rated higher.
nsA	An insurer rated 'nsA' has strong financial security characteristics, relative to other insurers in the national market but is somewhat more likely to be affected by adverse busines
nsBBB	An insurer rated 'nsBBB' has good financial security characteristics, relative to other insurers in the national market but is more likely to be affected by adverse business conditio
nsBB, nsB, nsCCC, and nsCC	An insurer rated 'nsBB' or lower is regarded as having vulnerable financial security characteristics, relative to other insurers in the national market that may outweigh its strength range; 'nsCC' the highest.
nsBB	An insurer rated 'nsBB' has marginal financial security characteristics, relative to other insurers in the national market. Positive attributes exist, but adverse business conditions c
nsB	An insurer rated 'nsB' has weak financial security characteristics, relative to other insurers in the national market. Adverse business conditions will likely impair its ability to meet f
nsCCC	An insurer rated 'nsCCC' has very weak financial security characteristics, relative to other insurers in the national market, and is dependent on favorable business conditions to
nsCC	An insurer rated 'nsCC' has extremely weak financial security characteristics, relative to other insurers in the national market and is likely not to meet some of its financial commi
R	An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor not others. The rating does not apply to insurers subject only to nonfinancial actions such as market conduct violations.
SD and D	An insurer rated 'SD' (selective default) or 'D' is in default on one or more of its insurance policy obligations but is not under regulatory supervision that would involve a rating of 'F The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action if payments on a policy obligation are at risk. A 'D' rating is assigned when Sta and that the obligor will fail to pay substantially all of its obligations in full in accordance with the policy terms. An 'SD' rating is assigned when Standard & Poor's believes that the insurer has selectively defaulted on a specific class of policies, but it will continue to meet its payment obligati the completion of a distressed exchange offer. Claim denials due to lack of coverage or other legally permitted defenses are not considered defaults.
NR	An insurer designated 'NR' is not rated.

*Ratings from 'nsAA' to 'nsCCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

D. Canada National Scale Ratings

65. Canadian national scale ratings use a unique set of rating definitions detailed in paragraphs 66-71 and tables 20-22.

1. Canadian Commercial Paper Ratings

66. A Canadian commercial paper rating is a forward-looking opinion about the capacity of an obligor to meet the financial commitments associated with a specific commercial pa ("obligation") relative to the debt servicing and repayment capacity of other obligors active in the Canadian domestic financial markets ("obligors") with respect to their own financi

Table 20 | Download Table

Category	Definition
A-1(High)	A short-term obligation rated 'A-1(High)' is rated in the highest category by Standard & Poor's. The obligor's capacity to meet its financial commitment on the obligation is extremely stron rating scale would qualify for a rating of 'A-1+' on Standard & Poor's global short-term rating scale.
A-1(Mid)	Short-term obligations rated 'A-1(Mid)' reflect a strong capacity for the obligor to meet its financial commitment on the obligation. Obligations rated 'A-1(Mid)' on the Canadian commercial Poor's global short-term rating scale.
A-1(Low)	A short-term obligation rated 'A-1(Low)' is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categori commitment on the obligation is satisfactory. Obligations rated 'A-1(Low)' on the Canadian commercial paper rating scale would qualify for a rating of 'A-2' on Standard & Poor's global sh
A-2	Obligations rated 'A-2' reflect a satisfactory capacity of the obligor to fulfill its financial commitment on the obligation, while exhibiting higher susceptibility to changing circumstances or ec rated 'A-2' on the Canadian commercial paper rating scale would qualify for a rating of 'A-2' on Standard & Poor's global short-term rating scale.
A-3	A short-term obligation rated 'A-3' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened ca obligation. Obligations rated 'A-3' on the Canadian commercial paper rating scale would qualify for a rating of 'A-3' on Standard & Poor's global short-term rating scale.
B	A short-term obligation rated 'B' is regarded as having significant speculative characteristics. The obligor currently has the capacity to meet its financial commitment on the obligation; ho obligor's inadequate capacity to meet its financial commitment on the obligation.
C	A short-term obligation rated 'C' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial c
D	A short-term obligation rated 'D' is in payment default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligat believes that such payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' the taking of a similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a

2. Canadian Fund Sensitivity Ratings

67. A fund sensitivity rating is a forward-looking opinion about a fund's inherent share price and return sensitivity to changing market conditions, as measured by the variability of

Value at Risk (VaR; see paragraph 68) relative to a 1-year risk free benchmark. For each sensitivity rating category, risk limits are established that are based on a multiple of VaR

Table 21 | Download Table

Category	Definition
Low Sensitivity	Funds that possess low share price and return variability compared to a 1-year risk free benchmark are rated 'Low Sensitivity.' Within the category, certain funds are ra sensitivity to changing market conditions.
Low to Moderate Sensitivity	Funds that possess low to moderate share price and return variability compared to a 1-year risk free benchmark are rated 'Low to Moderate Sensitivity.'
Moderate Sensitivity	Funds that possess moderate share price and return variability compared to a 1-year risk free benchmark are rated 'Moderate Sensitivity.'
Moderate to High Sensitivity	Funds that possess moderate to high share price and return variability compared to a 1-year risk free benchmark are rated 'Moderate to High Sensitivity.'
High Sensitivity	Funds that possess high share price and return variability compared to a 1-year risk free benchmark are rated 'High Sensitivity.'
Extremely High Sensitivity	Funds that possess extremely high share price and return variability compared to a 1-year risk free benchmark are rated 'Extremely High Sensitivity.'

68. Value at Risk (VaR) is a probability-based metric for quantifying the market risk of assets and portfolios. VaR is often used as an approximation of the "maximum reasonable lo sensitivity rating profile, Standard & Poor's utilizes the 250-day historical 99% VaR of the fund's return versus the same VaR of the benchmark.

69. Risk free benchmark for the country of domicile for each rated fund. Where no risk free benchmark is available, Standard & Poor's utilizes the most appropriate benchmark for t

Below is a list of the benchmarks used in the analysis:

- United States: 1-Year T-Bill Index
- Canada: Scotia 1-Year Canadian T-Bill Index

3. Canadian Preferred Share Scale Ratings

70. The Standard & Poor's Canadian preferred share rating scale serves issuers, investors, and intermediaries in the Canadian financial markets by expressing preferred share ra in terms of rating symbols that have been actively used in the Canadian market over a number of years. A Standard & Poor's preferred share rating on the Canadian scale is a forv obligor with respect to a specific preferred share obligation issued in the Canadian market, relative to preferred shares issued by other issuers in the Canadian market. There is a assigned on the Canadian preferred share scale and the various rating levels on the global debt rating scale of Standard & Poor's. The Canadian scale rating is fully determined t additional analytical criteria associated with the determination of ratings on the Canadian scale. It is the practice of Standard & Poor's to present an issuer's preferred share ratings national scale when listing the ratings for a particular issuer.

71. The following table shows the national scale preferred share ratings and the corresponding global scale preferred share ratings:

Table 22 | Download Table

National Scale Preferred Share Rating	Global Scale Preferred Share Rating	National Scale Preferred Share Rating	Global Scale Preferred Share Rating
P-1(High)	AA	P-3(Low)	BB-
P-1	AA-	P-4(High)	B+
P-1	A+	P-4	B
P-1(Low)	A	P-4(Low)	B-
P-1(Low)	A-	P-5(High)	CCC+
P-2(High)	BBB+	P-5	CCC
P-2	BBB	P-5(Low)	CCC-
P-2 Low	BBB-	CC	CC
P-3(High)	BB+	C	C
P-3	BB	D	D

E. Nordic Regional Scale Short-Term Ratings

72. Nordic regional scale ratings use a unique set of rating definitions detailed in paragraph 73 and tables 23 and 23.

73. The following is the Nordic Regional Scale that applies to short-term obligations. The Nordic regional scale that applies to short-term issue credit ratings appears in table 23. T credit ratings appears in table 24.

Table 23 | Download Table

Category	Definition
K-1	A short-term obligation rated 'K-1' exhibits strong protection parameters. This indicates that the obligor's capacity to meet its financial commitment on these obligations is strong.
K-2	A short-term obligation rated 'K-2' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories on the obligation is satisfactory.
K-3	A short-term obligation rated 'K-3' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened cap obligation.
K-4	A short-term obligation rated 'K-4' has speculative characteristics but is less vulnerable in the near term than other lower-rated obligations. However, it faces major ongoing uncertainties conditions which could lead to the obligor's inadequate capacity to meet its financial commitments.
K-5	A short-term obligation rated 'K-5' is regarded as vulnerable and has significant speculative characteristics, but the obligor currently has the capacity to meet its financial commitments. A impair the obligor's capacity or willingness to meet its financial commitments.
K-6	A short-term obligation rated 'K-6' is currently vulnerable to nonpayment, and the obligor is dependent upon favorable business, financial, and economic conditions to meet its financial coi
D	A short-term obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are nc such payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' rating also wil similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exc

Table 24 | Download Table

Nordic Regional Scale Short-Term Issuer Credit Ratings

Category	Definition
K-1	An obligor rated 'K-1' is regarded as having a strong capacity to meet its financial commitments.
K-2	An obligor rated 'K-2' is regarded as having a satisfactory capacity to meet its financial commitments. However, it is somewhat more susceptible to the adverse effects of changes in circ
K-3	An obligor rated 'K-3' is regarded as having an adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely t commitments.
K-4	An obligor rated 'K-4' has speculative characteristics but is less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure t could lead to the obligor's inadequate capacity to meet its financial commitments.
K-5	An obligor rated 'K-5' is regarded as vulnerable and has significant speculative characteristics, but the obligor currently has the capacity to meet its financial commitments. Adverse busin obligor's capacity or willingness to meet its financial commitments.
K-6	An obligor rated 'K-6' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions to meet its financial commitments.
D/SD	An obligor rated 'SD' (selective default) or 'D' has failed to pay one or more of its financial obligations (rated or unrated), excluding hybrid instruments classified as regulatory capital or in considered in default unless Standard & Poor's believes that such payments will be made within any stated grace period. However, any stated grace period longer than five business day when Standard & Poor's believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. An 'SD' rating is assig selectively defaulted on a specific issue or class of obligations, excluding hybrid instruments classified as regulatory captial, but it will continue to meet its payment obligations on other iss rating is lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.

F. Standard & Poor's Maalot (Israel) National Scale Ratings

74. Standard & Poor's Maalot (Israel) national scale uses a unique set of rating definitions detailed in paragraphs 75-82 and tables 25-29.

75. The Standard & Poor's Maalot (Israel) national scale serves issuers, insurers, counterparties, intermediaries, and investors in the financial markets of the State of Israel by prov instrument, and issuer credit ratings, which apply to an obligor (i.e., borrower, guarantor, bank, insurer, or other provider of credit enhancement). The Standard & Poor's Maalot na with the addition of an 'il' prefix to denote "Israel" and the scale's focus on Israeli financial markets. For the most part, the criteria employed for determining ratings on the Standard employed on the Standard & Poor's global scale. Standard & Poor's Maalot national scale credit ratings provide a rank ordering of credit risk within the country. As a result, the Sta comparable to Standard & Poor's global scale or to any other national rating scale.

1. Debt Credit Ratings

76. A Standard & Poor's Maalot national scale debt credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific debt, bond, lease, c financial instrument ("obligation") relative to the creditworthiness of other Israeli obligors with respect to their own financial obligations. Israeli obligors include all active borrowers enhancement residing in Israel, as well as any foreign obligor active in Israeli financial markets.

2. Long-Term Debt Credit Ratings

77. Standard & Poor's Maalot national scale debt credit ratings are based, in varying degrees, on the analysis of the following considerations:

- The relative likelihood of payment--the rating assesses the obligor's capacity and willingness to meet its financial commitments in accordance with the terms of the obligation,
- The obligation's nature and provisions; and
- Protection afforded to, and the relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under bankruptcy laws and other laws affect

78. Obligation ratings are an assessment of default risk, but may incorporate an assessment of relative seniority or ultimate recovery in the event of default. Junior obligations are lower priority in bankruptcy, as noted above. (Such differentiation may apply when an entity has both senior and subordinated obligations, secured and unsecured obligations, or

Table 25 | Download Table

Standard & Poor's Maalot (Israel) National Scale Long-Term Issue Ratings*

Category	Definition
ilAAA	An obligation rated 'ilAAA' has the highest rating assigned on Standard & Poor's Maalot national scale. The obligor's capacity to meet its financial commitments on the obligation, relative to
ilAA	An obligation rated 'ilAA' differs from the highest-rated debt only to a small degree. The obligor's capacity to meet its financial commitments on the obligation, relative to other Israeli obligor
ilA	An obligation rated 'ilA' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher –rated obligors. Still, the obligor has a moc obligation, relative to other Israeli obligors.
ilBBB	An obligation rated 'ilBBB' exhibits reasonably adequate protection parameters relative to other Israeli obligations. However, adverse economic conditions or changing circumstances are obligor to meet its financial commitments on the obligation.
ilBB; ilB; ilCCC; ilCC; and ilC	Obligations rated 'ilBB', 'ilB', 'ilCCC', 'ilCC', and 'ilC' on the Standard & Poor's Maalot national rating scale are regarded as having high risk relative to other Israeli obligations. While such ot characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions relative to other Israeli obligations.
ilBB	An obligation rated 'ilBB' denotes somewhat weak protection parameters relative to other Israeli obligations. The obligor's capacity to meet its financial commitments on the obligation is sc exposure to adverse business, financial, or economic conditions.
ilB	An obligation rated 'ilB' is more vulnerable than obligations rated 'ilBB' relative to other Israeli obligations. The obligor currently has a weak capacity to meet its financial obligations. Advers likely impair capacity or willingness of the obligor to meet its financial commitments on the obligation.
ilCCC	An obligation rated 'ilCCC' is currently vulnerable to nonpayment, relative to other Israeli obligations, and is dependent upon favorable business and financial conditions for the obligor to m adverse business, financial, or economic conditions, the obligor is unlikely to have the capacity to meet its financial commitment on the obligation.
ilCC	An obligation rated 'ilCC' is currently highly vulnerable to nonpayment relative to other Israeli obligations. The 'ilCC' rating is used when a default has not yet occurred, but Standard & Poo the anticipated time to default.
ilC	An obligation rated 'ilC' is currently highly vulnerable to nonpayment, and the obligation is expected to have lower relative seniority or lower ultimate recovery compared to obligations that
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are not made on such payments will be made within five business days in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will b similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exc

*The ratings from 'ilAA' to 'ilCCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative strength within the rating category.

3. Short-Term Ratings

79. Apply to obligations with an original maturity of less than one year.

Table 26 | Download Table

Category	Definition
ilA-1	A short-term obligation rated 'ilA-1' is rated in the highest category on Standard & Poor's Maalot Israeli national scale. The obligor's capacity to meet its commitments on the obligation, rel certain obligations are designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations, relative to that of other obligors in the
ilA-2	A short-term obligation rated 'ilA-2' is slightly more susceptible to adverse changes in circumstances and economic conditions than obligations rated 'ilA-1'. The obligor's capacity to meet Israeli obligors, is satisfactory.
ilA-3	A short-term obligation rated 'ilA-3' denotes adequate protection parameters relative to other short-term Israeli obligations. It is, however, more vulnerable to adverse effects of changes i designations.
ilB	A short-term obligation rated 'ilB' denotes weak protection parameters relative to other short-term Israeli obligations. It is vulnerable to adverse business, financial, or economic conditions
ilC	A short-term obligation rated 'ilC' denotes doubtful capacity for payment.
D	A short-term obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are nc believes that such payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' the taking of a similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a

4. Issuer Credit Ratings

80. A Standard & Poor's Maalot national scale issuer credit rating is a forward-looking opinion about the overall creditworthiness of a debt issuer, guarantor, bank, insurer, or othe financial obligations as they come due, relative to other Israeli obligors. Such Israeli obligors include all active borrowers, guarantors, banks, insurers, and other providers of credi active on Israeli financial markets. A counterparty credit rating is a form of issuer credit rating.

81. Issuer credit ratings do not apply to specific obligations, as they do not take into account the nature and provisions of the obligation, its standing in bankruptcy or liquidation, st obligation. In addition, they do not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation.

5. Long-Term Issuer Credit Ratings

Table 27 | Download Table

Category	Definition
ilAAA	An obligor rated 'ilAAA' has a very strong capacity to meet its financial commitments relative to that of other Israeli obligors. 'ilAAA' is the highest issuer credit rating assigned according to
ilAA	An obligor rated 'ilAA' differs from the highest-rated obligors only to a small degree, and has a strong capacity to meet its financial commitments relative to that of other Israeli obligors.
ilA	An obligor rated 'ilA' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher-rated obligors. Still, the obligor has a modera that of other Israeli obligors.
ilBBB	An obligor rated 'ilBBB' has a reasonably adequate capacity to meet its financial commitments relative to that of other Israeli obligors. However, adverse economic conditions or changing the obligor to meet its financial commitments.
ilBB; ilB; ilCCC; and ilCC	Obligors rated 'ilBB', 'ilB', 'ilCCC', and 'ilCC' on the Standard & Poor's Maalot national rating scale are regarded as having high risk relative to other Israeli obligors. While such obligors will may be outweighed by large uncertainties or major exposure to adverse conditions relative to other Israeli obligors.
ilBB	An obligor rated 'ilBB' denotes somewhat weak capacity to meet its financial commitments, although it is less vulnerable than other lower-rated Israeli obligors. However, it faces ongoing economic conditions, which could result in an inadequate capacity on the part of the obligor to meet its financial commitments.
ilB	An obligor rated 'ilB' is more vulnerable than obligors rated 'ilBB'. The obligor currently has a weak capacity to meet its financial commitments relative to other Israeli obligors. Adverse bus obligor's capacity or willingness to meet its financial commitments.
ilCCC	An obligor rated 'ilCCC' is currently vulnerable relative to other Israeli obligors and is dependent upon favorable business and financial conditions to meet its financial commitments.
ilCC	An obligor rated 'ilCC' is currently highly vulnerable to defaulting on its financial commitments relative to other Israeli obligors. The 'ilCC' rating is used when a default has not yet occurred certainty, regardless of the anticipated time to default.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' is in default on one or more of its financial obligations including rated and unrated financial obligations but excluding hybrid instruments classi An obligor is considered in default unless Standard & Poor's Maalot believes that such payments will be made within five business days of the due date in the absence of a stated grace p calendar days. A 'D' rating is assigned when Standard & Poor's Maalot believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obliga Standard & Poor's Maalot believes that the obligor has selectively defaulted on a specific issue or class of obligations but it will continue to meet its payment obligations on other issues or lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.

*The ratings from 'ilAA' to 'ilCCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative strength within the rating category.

6. Short-Term Issuer Credit Ratings

82. Apply to obligors' capacity to meet financial commitments over a time horizon of less than one year.

Table 28 | Download Table

Category	Definition
ilA-1	An obligor with an 'ilA-1' short-term rating has a strong capacity to meet financial commitments relative to that of other Israeli obligors. Within this category, certain obligations are designa to meet its financial commitment on these obligations, relative to that of other obligors in the Israeli market, is very strong.
ilA-2	An obligor with an 'ilA-2' short-term rating has a satisfactory capacity to meet financial obligations relative to that of other Israeli obligors.
ilA-3	An obligor with an 'ilA-3' short-term rating has an adequate capacity to meet financial commitments relative to that of other Israeli obligors. However, the obligor is more vulnerable to adve than higher-rated obligors.
ilB	An obligor with an 'ilB' short-term rating has a weak capacity to meet financial commitments, relative to that of other Israeli obligors, and is vulnerable to adverse business, financial, or ec
ilC	An obligor with an 'ilC' short-term rating has a doubtful capacity to meet financial commitments.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' has failed to pay one or more of its financial obligations (rated or unrated), excluding hybrid instruments classified as regulatory capital or in considered in default unless Standard & Poor's Maalot believes that such payments will be made within any stated grace period. However, any stated grace period longer than five busine assigned when Standard & Poor's Maalot believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. An 'S that the obligor has selectively defaulted on a specific issue or class of obligations, excluding hybrid instruments classified as regulatory capital, but it will continue to meet its payment obl manner. An obligor's rating is lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.

7. Insurer Financial Strength Ratings

83. A Standard & Poor's Maalot (Israel) national scale insurer financial strength rating is a forward-looking opinion about the financial security characteristics of an insurance orga policies and contracts in accordance with their terms, relative to other insurers in the national market.

84. This opinion is not specific to any particular policy or contract, nor does it address the suitability of a particular policy or contract for a specific purpose or purchaser. Furthermo

surrender or cancellation penalties, timeliness of payment, nor the likelihood of the use of a defense such as fraud to deny claims.

85. Insurer financial strength ratings do not refer to an organization's ability to meet nonpolicy (i.e., debt) obligations. Assignment of ratings to debt issued by insurers or to debt iss policies, contracts, or guarantees is a separate process from the determination of insurer financial strength ratings, and follows procedures consistent with those used to assign ar

Table 29 | Download Table

Category	Definition
ilAAA	An insurer rated 'ilAAA' has extremely strong financial security characteristics, relative to other insurers in the Israel market. 'ilAAA' is the highest insurer financial strength rating assi
ilAA	An insurer rated 'ilAA' has very strong financial security characteristics, relative to other insurers in the Israel market, differing only slightly from those rated higher.
ilA	An insurer rated 'ilA' has strong financial security characteristics, relative to other insurers in the Israel market but is somewhat more likely to be affected by adverse business condit
ilBBB	An insurer rated 'ilBBB' has good financial security characteristics, relative to other insurers in the Israel market but is more likely to be affected by adverse business conditions than
ilBB, ilB ilCCC, and ilCC	An insurer rated 'ilBB' or lower is regarded as having vulnerable financial security characteristics, relative to other insurers in the Israel market that may outweigh its strengths. 'ilBB' i the highest.
ilBB	An insurer rated 'ilBB' has marginal financial security characteristics, relative to other insurers in the Israel market. Positive attributes exist, but adverse business conditions could lea
ilB	An insurer rated 'ilB' has weak financial security characteristics, relative to other insurers in the Israel market. Adverse business conditions will likely impair its ability to meet financial
ilCCC	An insurer rated 'ilCCC' has very weak financial security characteristics, relative to other insurers in the Israel market, and is dependent on favorable business conditions to meet fin
ilCC	An insurer rated 'ilCC' has extremely weak financial security characteristics, relative to other insurers in the Israel market and is likely not to meet some of its financial commitments.
R	An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one others. The rating does not apply to insurers subject only to nonfinancial actions such as market conduct violations.
SD and D	An insurer rated 'SD' (selective default) or 'D' is in default on one or more of its insurance policy obligations but is not under regulatory supervision that would involve a rating of 'R'. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action if payments on a policy obligation are at risk. A 'D' rating is assigned when Standar that the obligor will fail to pay substantially all of its obligations in full in accordance with the policy terms. An 'SD' rating is assigned when Standard & Poor's believes that the insurer has selectively defaulted on a specific class of policies, but it will continue to meet its payment obligations completion of a distressed exchange offer. Claim denials due to lack of coverage or other legally permitted defenses are not considered defaults.
NR	An insurer designated 'NR' is not rated.

*Ratings from 'ilAA' to 'ilCCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

G. Taiwan Ratings National Scale Ratings

86. Taiwan Ratings Corporation (Taiwan Ratings) is a majority owned subsidiary of Standard & Poor's operating as Taiwan Ratings Corporation (Taiwan Ratings). Taiwan Rating intermediaries, and investors in Taiwan's financial markets providing:

- issue credit ratings, which apply to a specific obligation,
- issuer credit ratings, which apply to an obligor (i.e. borrower, guarantor, bank, insurer, or other provider of credit enhancement),
- insurer financial strength ratings, which apply to an insurer's ability to pay under its insurance policies and contracts in accordance with their terms, and
- fixed-income fund credit quality ratings identified with an 'f' suffix to denote funds that exhibit variable net asset values.

87. Taiwan Ratings national scale uses Standard & Poor's global rating symbols with the addition of a 'tw' prefix to denote "Taiwan" and the scale's focus on the Taiwanese financi on Taiwan Ratings national scale are comparable to those employed on the Standard & Poor's global scale, and the mapping of Taiwan Ratings national scale ratings to Standar be found at www.taiwanratings.com.

88 Taiwan Ratings' long-term and short-term issue and issuer credit rating definitions outlined in tables 30-33 are the same as those in tables 15-19 except they apply to Taiwan F insurer financial strength ratings definitions are set out in table 34 and fixed-income fund credit quality ratings definitions are described in table 35.

Taiwan Ratings Issue Credit Ratings

89. A Taiwan Ratings issue credit rating is a forward-looking opinion about the creditworthiness of an obligor with respect to a specific debt, bond, lease, commercial paper progra ("obligation") relative to the creditworthiness of other Taiwanese obligors with respect to their own financial obligations. Taiwanese obligors include all active borrowers, guaranto residing in Taiwan, as well as any foreign obligor active in Taiwan's financial markets.

90. Taiwan Ratings issue credit ratings are based, in varying degrees, on the analysis of the following considerations:

- The relative likelihood of payment–the rating assesses the obligor's capacity and willingness to meet its financial commitments in accordance with the terms of the obligation,
- The obligation's nature and provisions; and
- Protection afforded to, and the relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under bankruptcy laws and other laws affect

Taiwan Ratings Long-Term Issue Credit Ratings

Table 30 | Download Table

Category	Definition
twAAA	An obligation rated 'twAAA' has the highest credit rating assigned on Taiwan Ratings national scale. The obligor's capacity to meet its financial commitments on the obligation, relative to
twAA	An obligation rated 'twAA' differs from the highest-rated debt only to a small degree. The obligor's capacity to meet its financial commitments on the obligation, relative to other Taiwans
twA	An obligation rated 'twA' is somewhat more susceptible to adverse effects of changes in circumstances and economic conditions than higher-rated debt. Still, the obligor's capacity to r Taiwanese obligors, is strong.
twBBB	An obligation rated 'twBBB' exhibits adequate protection parameters relative to other Taiwanese obligations. However, adverse economic conditions or changing circumstances are m to meet its financial commitments on the obligation.
twBB; twB; twCCC; twCC; and twC	Obligations rated 'twBB', 'twB', 'twCCC', 'twCC', and 'twC' on the Taiwan Ratings national credit rating scale are regarded as having high risk relative to other national obligations. While characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions relative to other Taiwanese obligations.
twBB	An obligation rated 'twBB' denotes somewhat weak protection parameters relative to other Taiwanese obligations. The obligor's capacity to meet its financial commitments on the obliga or exposure to adverse business, financial, or economic conditions.

twB	An obligation rated 'twB' is more vulnerable than obligations rated 'twBB' relative to other Taiwanese obligations. The obligor currently has a weak capacity to meet its financial obligatio however, would likely impair capacity or willingness of the obligor to meet its financial commitments on the obligation.
twCCC	An obligation rated 'twCCC' is currently vulnerable to nonpayment, relative to other Taiwanese obligations, and is dependent upon favorable business and financial conditions for the ob event of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitment on the obligation.
twCC	An obligation rated 'twCC' is currently highly vulnerable to nonpayment relative to other Taiwanese obligations. The 'twCC' rating is used when a default has not yet occurred, but Taiwa the anticipated time to default.
twC	An obligation rated 'twC' is currently highly vulnerable to nonpayment, and the obligation is expected to have lower relative seniority or lower ultimate recovery compared to obligations
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid instruments, the 'D' rating category is used when payments on an obligation are not made on the will be made within five business days, in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will be used upon and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' upon completion of a distressed exchange

*The credit ratings from 'twAA' to 'twCCC' may be modified by the addition of a plus (+) or minus (-) to show relative strength with the rating category.

Taiwan Ratings Short-Term Issue Credit Ratings

Table 31 | Download Table

Taiwan Ratings Short-Term Issue Credit Ratings

Category	Definition
twA-1	A short-term obligation rated 'twA-1' is rated in the highest category on Taiwan Ratings national scale. The obligor's capacity to meet its commitments on the obligation, relative to other Ta obligations are designated with a plus sign (+). This indicates that the obligor's capacity to meet its financial commitment on these obligations, relative to other Taiwanese obligors, is extre
twA-2	A short-term obligation rated 'twA-2' is slightly more susceptible to adverse changes in circumstances and economic conditions than obligations rated 'twA-1'. The obligor's capacity to me Taiwanese obligors, is satisfactory.
twA-3	A short-term obligation rated 'twA-3' denotes adequate protection parameters relative to other short-term Taiwanese obligations. It is, however, more vulnerable to adverse effects of cha designations.
twB	A short-term obligation rated 'twB' denotes weak protection parameters relative to other short-term Taiwanese obligations. It is vulnerable to adverse business, financial, or economic cor
twC	A short-term obligation rated 'twC' denotes doubtful capacity for payment.
D	A short-term obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid instruments, the 'D' rating category is used when payments on an obligation are not made payments will be made within any stated grace period. However, any stated grace period longer than five business days will be treated as five business days. The 'D' rating also will be u similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exc

*Apply to obligations with an original maturity of less than one year.

Taiwan Ratings Issuer Credit Ratings

91. A Taiwan Ratings issuer credit rating is a forward-looking opinion about the overall creditworthiness of a debt issuer, guarantor, insurer, or other provider of credit enhanceme due, relative to other Taiwanese obligors. Such Taiwanese obligors include all active borrowers, guarantors, insurers, and other providers of credit enhancement residing in Taiwa markets.

92. Issuer credit ratings do not apply to specific obligations, as they do not take into account the nature and provisions of the obligation, its standing in bankruptcy or liquidation, st obligation. In addition, they do not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation.

93. Counterparty credit ratings and corporate credit ratings are all forms of issuer credit ratings.

Taiwan Ratings Long-Term Issuer Credit Ratings

Table 32 | Download Table

Taiwan Ratings Long-Term Issuer Credit Ratings

Category	Definition
twAAA	An obligor rated 'twAAA' has an extremely strong capacity to meet its financial commitments relative to that of other Taiwanese obligors. 'twAAA' is the highest issuer credit rating assigne
twAA	An obligor rated 'twAA' differs from the highest-rated obligors only to a small degree, and has a very strong capacity to meet its financial commitments relative to that of other Taiwanese
twA	An obligor rated 'twA' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher-rated obligors. Still, the obligor has a strong other Taiwanese obligors.
twBBB	An obligor rated 'twBBB' has an adequate capacity to meet its financial commitments relative to that of other Taiwanese obligors. However, adverse economic conditions or changing circ obligor to meet its financial commitments.
twBB; twB; twCCC; and twCC	Obligors rated 'twBB', 'twB', 'twCCC', and 'twCC' on the Taiwan Ratings credit rating scale are regarded as having high risk relative to other Taiwanese obligors. While such obligors will li be outweighed by large uncertainties or major exposure to adverse conditions relative to other Taiwanese obligors.
twBB	An obligor rated 'twBB' denotes somewhat weak capacity to meet its financial commitments, although it is less vulnerable than other lower-rated Taiwanese obligors. However, it faces on or economic conditions, which could result in an inadequate capacity on the part of the obligor to meet its financial commitments.
twB	An obligor rated 'twB' is more vulnerable than obligors rated 'twBB'. The obligor currently has a weak capacity to meet its financial commitments relative to other Taiwanese obligors. Adve impair the obligor's capacity or willingness to meet its financial commitments.
twCCC	An obligor rated 'twCCC' is currently vulnerable relative to other Taiwanese obligors and is dependent upon favorable business and financial conditions to meet its financial commitments.
twCC	An obligor rated 'twCC' is currently highly vulnerable to defaulting on its financial commitments relative to other Taiwanese obligors. The 'twCC' rating is used when a default has not yet o certainty, regardless of the anticipated time to default.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' is in default on one or more of its financial obligations including rated and unrated financial obligations but excluding hybrid instruments classi An obligor is considered in default unless Taiwan Ratings believes that such payments will be made within five business days, or within the earlier of the stated grace period or 30 calenda that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. A 'SD' rating is assigned when Taiwan Ratings believes class of obligations but it will continue to meet its payment obligations on other issues or classes of obligations in a timely manner. An obligor's rating is lowered to 'D' or 'SD' if it is conduc
NR	An issuer designated 'NR' is not rated.

*The credit ratings from 'twAA' to 'twCCC' may be modified by the addition of a plus (+) or minus (-) to show relative strength with the rating category.

Taiwan Ratings Short-Term Issuer Credit Ratings

Table 33 | Download Table

Category	Definition

twA-1	An obligor with a 'twA-1' short-term credit rating has a strong capacity to meet financial commitments relative to that of other Taiwanese obligors. Within this category, certain obligations a obligor's capacity to meet its financial commitment on these obligations, relative to that of other obligors in the Taiwanese market, is extremely strong.
twA-2	An obligor with a 'twA-2' short-term credit rating has a satisfactory capacity to meet financial obligations relative to that of other Taiwanese obligors.
twA-3	An obligor with a 'twA-3' short-term credit rating has an adequate capacity to meet financial commitments relative to that of other Taiwanese obligors. However, the obligor is more vulner conditions than higher-rated obligors.
twB	An obligor with a 'twB' short-term credit rating has a weak capacity to meet financial commitments, relative to that of other Taiwanese obligors, and is vulnerable to adverse business, fina
twC	An obligor with a 'twC' short-term credit rating has a doubtful capacity to meet financial commitments.
R	An obligor rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favor one clas others.
SD and D	An obligor rated 'SD' (selective default) or 'D' has failed to pay one or more of its financial obligations (rated or unrated), excluding hybrid instruments classified as regulatory capital or tha obligor is considered in default unless Taiwan Ratings believes that such payments will be made within any stated grace period. However, any stated grace period longer than five busine is assigned when Taiwan Ratings believes that the default will be a general default and that the obligor will fail to pay all or substantially all of its obligations as they come due. A 'SD' credit has selectively defaulted on a specific issue or class of obligations, excluding hybrid instruments classified as regulatory capital, but it will continue to meet its payment obligations on othe rating is lowered to 'D' or 'SD' if it is conducting a distressed exchange offer.
NR	An issuer designated 'NR' is not rated.

*Apply to an obligor's capacity to meet financial commitments over a time horizon of less than one year.

Taiwan Ratings Insurer Financial Strength Ratings

94. A Taiwan Ratings' insurer financial strength rating is a forward-looking opinion about the financial security characteristics of an insurance organization with respect to its ability accordance with their terms, relative to other insurers in the Taiwan market.

95. This opinion is not specific to any particular policy or contract, nor does it address the suitability of a particular policy or contract for a specific purpose or purchaser. Furthermo surrender or cancellation penalties, timeliness of payment, nor the likelihood of the use of a defense such as fraud to deny claims.

96. Insurer financial strength ratings do not refer to an organization's ability to meet nonpolicy (i.e., debt) obligations. Assignment of ratings to debt issued by insurers or to debt iss policies, contracts, or guarantees is a separate process from the determination of insurer financial strength ratings, and follows procedures consistent with those used to assign ar

Table 34 | Download Table

Taiwan Ratings Insurer Financial Strength Ratings

Category	Definition
twAAA	An insurer rated 'twAAA' has extremely strong financial security characteristics, relative to other insurers in the Taiwan market. 'twAAA' is the highest insurer financial strength r
twAA	An insurer rated 'twAA' has very strong financial security characteristics, relative to other insurers in the Taiwan market, differing only slightly from those rated higher.
twA	An insurer rated 'twA' has strong financial security characteristics, relative to other insurers in the Taiwan market but is somewhat more likely to be affected by adverse busines
twBBB	An insurer rated 'twBBB' has good financial security characteristics, relative to other insurers in the Taiwan market but is more likely to be affected by adverse business conditic
twBB, twB, twCCC, and twCC	An insurer rated 'twBB' or lower is regarded as having vulnerable financial security characteristics, relative to other insurers in the Taiwan market, which may outweigh its stren range; 'twCC' the highest.
twBB	An insurer rated 'twBB' has marginal financial security characteristics, relative to other insurers in the Taiwan market. Positive attributes exist, but adverse business conditions
twB	An insurer rated 'twB' has weak financial security characteristics, relative to other insurers in the Taiwan market. Adverse business conditions will likely impair its ability to meet
twCCC	An insurer rated 'twCCC' has very weak financial security characteristics, relative to other insurers in the Taiwan market, and is dependent on favorable business conditions to
twCC	An insurer rated 'twCC' has extremely weak financial security characteristics, relative to other insurers in the Taiwan market and is likely not to meet some of its financial comm
R	An insurer rated 'R' is under regulatory supervision owing to its financial condition. During the pendency of the regulatory supervision, the regulators may have the power to favc and not others. The rating does not apply to insurers subject only to nonfinancial actions such as market conduct violations.
SD and D	An insurer rated 'SD' (selective default) or 'D' is in default on one or more of its insurance policy obligations but is not under regulatory supervision that would involve a rating of ' The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action if payments on a policy obligation are at risk. A 'D' rating is assigned when Ta that the obligor will fail to pay substantially all of its obligations in full in accordance with the policy terms. An 'SD' rating is assigned when Taiwan Ratings believes that the insurer has selectively defaulted on a specific class of policies, but it will continue to meet its payment obligatior completion of a distressed exchange offer. Claim denials due to lack of coverage or other legally permitted defenses are not considered defaults.
NR	An insurer designated 'NR' is not rated.

*Ratings from 'twAA' to 'twCCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Taiwan Ratings Fund Credit Quality Ratings

97. Taiwan Ratings Fund Credit Quality Ratings, identified by the 'f' suffix, are assigned to fixed-income funds and other actively managed funds that exhibit variable net asset valu the Taiwan Ratings rating scale. A fund credit quality rating is not directly comparable to a debt rating because of differences in rating criteria.

98. These ratings are forward-looking opinions about the overall credit quality of a fund's portfolio. The ratings reflect the level of protection against losses from credit defaults.

Table 35 | Download Table

Category	Definition
twAAAf	The fund's portfolio holdings provide extremely strong protection against losses from credit defaults on the Taiwan Ratings' ratings scale.
twAAf	The fund's portfolio holdings provide very strong protection against losses from credit defaults on the Taiwan Ratings' ratings scale.
twAf	The fund's portfolio holdings provide strong protection against losses from credit defaults on the Taiwan Ratings' ratings scale.
twBBBf	The fund's portfolio holdings provide adequate protection against losses from credit defaults on the Taiwan Ratings' ratings scale.
twBBf	The fund's portfolio holdings provide uncertain protection against losses from credit defaults on the Taiwan Ratings' ratings scale.
twBf	The fund's portfolio holdings exhibit vulnerability to losses from credit defaults on the Taiwan Ratings' ratings scale.
twCCCf	The fund's portfolio holdings make it extremely vulnerable to losses from credit defaults on the Taiwan Ratings' ratings scale.

*The ratings from 'twAAf' to 'twCCCf' can be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

H. Japan SME National Scale Ratings

99. The Standard & Poor's Japan Small and Medium-Sized Enterprise (SME) national scale serves Japanese SMEs, lenders, suppliers, and other parties that have an interest in S

A Standard & Poor's Japan SME rating reflects Standard & Poor's opinion of the overall financial capacity of a Japanese SME to meet its financial obligations as they come due, re Poor's Japan SME rating is a quantitatively derived indicator of creditworthiness. Calculations differ significantly from Standard & Poor's rating criteria and do not include subjectiv analysts. Japan SME ratings are expressed using Standard & Poor's traditional credit rating symbols, but in lower case (e.g., 'bbb') to highlight that they are quantitatively derived.

100. Standard & Poor's Japan SME national scale is not directly comparable to Standard & Poor's global scale, to any other national rating scale or to scales for any quantitatively to small and medium-sized enterprises in Japan. For every rating category, firms with a Japan SME rating are typically smaller than firms with an "equivalent" Standard & Poor's cr analysts do not determine Japan SME ratings and, if Standard & Poor's ratings criteria were applied, it is unlikely that analysts would rate companies as indicated by the Japan SN

101. A Japan SME rating does not apply to any specific obligation, as it does not take into account the nature and provisions of the obligation, its standing in bankruptcy or liquidat of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation.

Table 36 | Download Table

Japan SME National Scale Ratings

Category	Definition
aaa	An obligor rated 'aaa' has a very strong capacity to meet its financial commitments relative to that of other Japanese SMEs. 'aaa' is the highest credit rating assigned on the Standard & P
aa	An obligor rated 'aa' differs from the highest-rated obligors only to a small degree, and has a strong capacity to meet its financial commitments relative to that of other Japanese SMEs.
a	An obligor rated 'a' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than higher-rated obligors. Still, the obligor has a moderat that of other Japanese SMEs.
bbb	An obligor rated 'bbb' has a reasonably adequate capacity to meet its financial commitments relative to that of other Japanese SMEs. However, adverse economic conditions or changing financial commitments.
bb	An obligor rated 'bb' has somewhat weak capacity to meet its financial commitments relative to that of other Japanese SMEs. However, it faces ongoing uncertainties or exposure to adv result in an inadequate capacity to meet its financial commitments.
b	An obligor rated 'b' has a weak capacity to meet its financial commitments relative to that of other Japanese SMEs. Adverse business, financial, or economic conditions will likely impair th
ccc	An obligor rated 'ccc' is currently vulnerable to nonpayment relative to other Japanese SMEs, and is dependent upon favorable business and financial conditions to meet its financial com conditions, the obligor is not likely to have the capacity to meet its financial commitments.

VI. OTHER CREDIT RELATED OPINIONS

A. Credit Estimates

102. A credit estimate is an indication, provided to a third party, of the likely Standard & Poor's issue or issuer credit rating on an unrated obligation or obligor. The estimate is base models, where applicable, and draws on analytical experience and sector knowledge of Standard & Poor's analysts. These estimates do not involve direct contact with the obligor or strategic issues that such contact may allow. Standard & Poor's does not maintain ongoing surveillance on credit estimates, but periodic updates may be provided. A credit estir expressed using Standard & Poor's traditional credit rating symbols, but in lower case (e.g., 'bbb').

B. Credit Assessments

103. A credit assessment is an indicator of Standard & Poor's opinion of creditworthiness that may be expressed in descriptive terms, a broad rating category or with the addition o within the category. It reflects our view of the general credit strengths and weaknesses of an issuer, obligor, a proposed financing structure, or elements of such structures. It may a elements of a credit that would ordinarily be taken into account in a credit rating. A credit assessment usually represents a point-in-time evaluation and Standard & Poor's generall assessments. A credit assessment is generally confidential. Credit assessments are expressed using Standard & Poor's traditional credit rating symbols, but in lower case (e.g., 'b

VII. OTHER IDENTIFIERS

A. Active Identifiers

104. Standard & Poor's currently uses seven other identifiers. These words or symbols provide additional information but do not change the definition of a rating or our opinion ab are often required by regulation.

Unsolicited: 'unsolicited' and 'u' identifier

105. The 'u' identifier and 'unsolicited' designation are unsolicited credit ratings assigned at the initiative of Standard & Poor's and not at the request of the issuer or its agents.

Structured finance: 'sf' identifier

106. The 'sf' identifier shall be assigned to ratings on "structured finance instruments" when required to comply with applicable law or regulatory requirement or when Standard & I identifier to a rating does not change that rating's definition or our opinion about the issue's creditworthiness. For detailed information on the instruments assigned the 'sf' identifier Instruments Carrying The Structured Finance Identifier" in Section VIII, "Related Research."

Japan: 'jr' identifier

107. The 'JR' identifier is assigned to all issues and issuers ratings assigned by either Standard & Poor's Ratings Japan K.K. or Nippon Standard & Poor's K.K., each of which is a registered under the Japanese regulation. The addition of the identifier does not change the definition of that rating or our opinion about the issue's or issuer's creditworthiness.

European Union: 'EU' identifier

108. Standard & Poor's assigns the 'EU' identifier to global scale ratings assigned by Standard & Poor's rating entities (or branches thereof) regulated in the European Union. The that rating's definition or our opinion about the issue's or issuer's creditworthiness.

European Endorsed: 'EE' identifier

109. Standard & Poor's assigns the 'EE' identifier to global scale ratings assigned by Standard & Poor's rating entities established outside the European Union which are endorse European Union. The addition of the 'EE' identifier to a rating does not change that rating's definition or our opinion about the issue's or issuer's creditworthiness.

Nippon KK: 'XN' identifier

110. Nippon Standard & Poor's K.K. (Nippon KK) assigns the 'XN' identifier to credit ratings assigned by Nippon KK. Nippon KK is not a Nationally Recognized Statistical Rating O does not change that rating's definition or our opinion about the issue's or issuer's creditworthiness.

Under criteria observation 'UCO' identifier

111. The 'UCO' identifier may (or shall, if an EU regulatory requirement) be assigned to credit ratings under review as a result of a criteria revision. The addition of the 'UCO' identi opinion about the issue's or issuer's creditworthiness.

B. Inactive Identifiers

112. Inactive identifiers are no longer applied or outstanding.

1. European Endorsement : 'EX' identifier

113. Standard & Poor's provisionally assigned the 'EX' identifier during a transitional period ending on April 30, 2012, to global scale ratings assigned by Standard & Poor's rating Union (EU) that were not recognized by EU regulators as endorsable, but which nevertheless were recognized for certain EU regulatory purposes. Before the transitional period e certain ratings with 'EE' identifiers following determinations by EU regulators that such ratings were endorsable. However, following the end of the transitional period, any ratings s certain EU regulatory purposes. With certain exceptions, Standard & Poor's no longer assigns the 'EX' identifier and may remove the 'EX' identifier from existing ratings. The additi the definition of that rating. Discontinued use in June 2012.

VIII. RELATED RESEARCH

- **National And Regional Scale Credit Ratings**, Sept. 22, 2014
- **S&P Announces Changes To The List Of Instruments Carrying The Structured Finance Identifier**, March 21, 2014
- **Principles Of Credit Ratings**, Feb. 16, 2011
- **The Time Dimension of Standard & Poor's Ratings**, Sept. 22, 2010
- **Methodology: Credit Stability Criteria**, May 3, 2010
- **Understanding Standard & Poor's Ratings Definitions**, June 3, 2009

IX. CONTACT INFORMATION

Table 37 | Download Table

Criteria Group Contacts

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