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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	Docket No. 150001-EI Docket No. 140001-EI Filed: January 23, 2015

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THE FLORIDA INDUSTRIAL POWER USERS GROUP'S
NOTICE OF FILING

The Florida Industrial Power Users Group (FIPUG) hereby files for record purposes documents that the Florida Public Service Commission previously produced to FIPUG pursuant to a public records request. These documents relate to the Florida Power and Light Company's oil and gas exploration and production petition which is addressed in the above-referenced dockets. The public records request and the documents produced in response to the request are attached to this Notice of Filing.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of FIPUG's Notice of Filing, was furnished to the following by Electronic Mail, on this 23rd day of January, 2015:

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/s/ Jon C. Moyle
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Myndi Qualls

To: Jon Moyle
Subject: RE: Public Records Request

From: Jon Moyle
Sent: Thursday, December 18, 2014 10:39 AM
To: Jennifer Crawford
Cc: Martha Barrera; Mary Anne Helton
Subject: Public Records Request

Jennifer: I am sitting in the agenda conference listening to the Commission discuss the FPL oil and gas reserve issue. During the discussion, there has been reference to certain materials provided to the Commission. (For example, Commissioner Brown just referenced a pamphlet that was handed out by staff to Commissioner that had a reference to liability.). I would like to make a public records request for all documents used or provided to the Commission regarding the FPL gas reserve petition that were not admitted into evidence in the proceeding. Thanks for your attention to this matter. Regards, Jon

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Sent from my iPhone

Post Hearing Information Sheet – Docket No. 140001-EI

For the Gas Reserves Decision
(Issues 1, 2, 3, 6, and 8)

ISSUE 1: **Should the Commission approve Florida Power & Light Company's request to recover the amounts it would pay to its subsidiary for gas obtained from the PetroQuest joint venture through the fuel cost recovery clause on the basis and in the manner proposed by FPL in the June 25 Petition?**

Paraphrased Arguments

FPL: Yes. FPL's investment in the PetroQuest joint venture is projected to provide fuel savings over the life of the project. In addition, the PetroQuest joint venture will provide for fuel price stability, effectively acting as a long-term hedge. Because it is designed to reduce the delivered price of fossil fuel (natural gas) and the costs for the PetroQuest joint venture were not recognized or anticipated in the cost levels used to determine FPL's current base rates, the costs associated with the PetroQuest joint venture are appropriate for recovery through the Fuel Clause.

OPC, FRF, and FIPUG: No. The Commission should not approve the recovery of costs associated with the Woodford Project. The Woodford Project does not satisfy the criteria for Fuel Clause recovery because its costs are not capital costs normally recovered through base rates, and go beyond the policy adopted by the Commission for dealing with fossil fuel-related costs normally recovered through base rates that will result in fuel savings to customers.

In addition, the Commission prohibits utilities from profiting (or earning a return) on fuel purchases recovered through the Fuel Clause. Under FPL's proposal, FPL would "purchase" (or acquire) fuel from the Woodford Project at production costs, and would then allow FPL shareholders to profit (earn a return) on the gas that the Company acquires at production costs.

Options before the Commission

1. Approve the Woodford Project as filed.
2. Approve the Woodford Project but require greater customer protections (i.e., sharing mechanism for costs and benefits, capping recovery at the market price of gas, etc.).
3. Deny the Woodford Project.

Considerations for approving the Woodford Project

A. FPL's customers are expected to receive fuel savings and reduced volatility of gas prices.

B. The type of projects eligible for recovery through the Fuel Clause has evolved since the issuance of Order No. 14546.

C. Approval of this project could encourage other innovative strategies for reducing the effective cost of natural gas, which is important given that FPL purchases more natural gas than any other electric utility in the country and given Florida's significant and growing dependence on natural gas for generation.

D. FPL's natural gas price forecasts prepared in October 2013 and July 2014 presented in this case are consistent with the forecast assumptions and forecast methodology used in other proceedings before the Commission.

E. FPL's natural gas price forecasts of October 2013 and July 2014 indicate that the project will likely produce positive customer fuel savings over the life of the project based on the combination of two factors: well productivity and natural gas market price. Under the July 2014 natural gas price forecast, 6 of 9 sensitivities produce positive customer savings (see Table 1), and the base case indicates savings of $51.9M. Also, the sensitivities show that the magnitude of potential positive savings ($170.2M assuming high fuel price and high productivity) exceeds the magnitude of potential losses (-$50.7M assuming low fuel price and low productivity).

Table 1 Pricing and Production Sensitivities
(Savings (losses) in Millions $)

	Low Fuel Pricing	Base Fuel Pricing	High Fuel Pricing
Low Production	($50.7)	$23.1	$97.0
Base Production	($30.0)	$51.9	$134.0
High Production	($10.2)	$79.9	$170.2

Based on 1. July 2014 Fuel Curve; 2. Pricing: +/- 20.9% per MMBtu around NYMEX Henry Hub based on 8 year historical volatility from 2005-2012; and 3. Production: +/-10% monthly production.
Source: Exhibit 64, Attachment 2

F. Historically, production costs have been less volatile than market prices. By decoupling production costs from market prices, the Woodford Project may act as a long-term physical hedge.

G. The Woodford Project will have a small effect on FPL's overall cost of natural gas and on price hedging. This project may act as a long-term physical hedge (30 – 50 years in duration) compared to financial hedges, which typically lock in prices for 12 – 24 months.

H. The Woodford Project revenue requirement recovered through the Fuel Clause will be limited to FPL's mid-point ROE. FPL has the opportunity to earn up to 100 basis points above the mid-point ROE on rate base items recovered through base rates. FPL currently earns above the mid-point ROE on its rate base.

I. Recovery of investments in gas reserve projects have been approved by three other state regulatory commissions.

J. Customers currently bear certain drilling, production, and shale gas risks (earthquakes, environmental issues, etc.) as these factors are embedded in the market price of gas.

<u>Considerations for not approving the Woodford Project</u>

K. Approving the Woodford Project as proposed by FPL represents a change from past regulatory policy by including non-regulated investments in rate base. This investment will involve FPL and its customers directly in a competitive industry. Participation in such non-regulated projects could increase FPL's risk and cost of capital.

L. Fuel savings for customers will depend on the level of market prices and the actual results of the drilling and production operations. If the Woodford Project investment is found prudent at the outset as requested by FPL, the Company's recovery of its costs and return on investment is assured through the Fuel Clause independent of the level of market prices or the results of the drilling and production operation.

M. Customers bear the risk that fuel savings expected from the Woodford Project might not materialize. In addition, there is the loss of opportunity for greater fuel savings had the investment never been made.

N. FPL's Pricing and Production Sensitivities matrix (Table 1 above) shows that 3 of the 9 sensitivities produce losses, and the losses could be as much as $50.7M. FPL bases its estimate of customer savings on its October 2013 natural gas price forecast which was prepared over a year ago. FPL's July 2014 natural gas price forecast reflects significantly lower projected prices for all years compared to the Company's October 2013 natural gas price forecast. The likelihood of fuel savings resulting from the Woodford Project is less certain than at the time FPL filed its petition. In addition, the expected savings of $107M based on FPL's October 2013 base case natural gas price forecast has dropped to $52M based on FPL's July 2014 base case natural gas price forecast. The more current forecast should be recognized as the most relevant forecast to be used to analyze the cost effectiveness of the project.

O. All previous gas reserve investment programs approved for recovery by other state regulatory commissions involve gas utilities. FPL's proposal is the only example involving an electric utility. In addition, the program in Montana was approved pursuant to statutory authority and the program in Oregon was approved through a stipulation.

P. The Woodford Project is a much larger capital project than the capital projects previously approved for recovery through the Fuel Clause. The potential fuel savings associated with the Woodford Project are less certain than in other examples of capital substitution previously approved for recovery through the Fuel Clause.

Q. The Woodford Project is not a true fixed price hedge. Production costs are not fixed and some degree of price volatility will remain. In addition, there have been times when production costs in the Woodford Shale area have exceeded concurrent market prices.

R. Drilling, production, and project-specific risks will be borne by FPL customers. The record indicates there are additional risks as an investor in gas reserves that are not currently being borne by FPL as a purchaser of gas. FPL's proposal calls for the liability, if any, associated with these additional risks to be recovered from customers through the Fuel Clause.

Other Considerations

S. For auditing purposes, the Commission will only have access to invoices from PetroQuest. FPL will be responsible for auditing PetroQuest's actual costs.

T. Commission auditors will need the subaccount detail that correlates the "industry standard chart of accounts" used by FPL for the Gas Reserve Company to the FERC natural gas chart of accounts to more efficiently audit the amounts and transactions related to the Woodford Project investment.

U. Approval of the Woodford Project for recovery through the Fuel Clause may become a precedent for growing rate base through the various cost recovery clauses. Requests for approval of clause recovery of similar investments by other investor-owned utilities (IOUs) in the state may follow.

V. Although for different reasons, neither FPL nor OPC support a sharing mechanism for recovery of the Woodford Project.

W. The Florida Legislature sets policy. An argument can be made that a proposal such as this, with such significant policy implications for not just FPL but for all IOUs in the state, is best addressed by the Legislature.

ISSUE 6: **Is FPL contractually precluded by paragraph 6 of the Stipulation and Settlement Agreement dated December 12, 2012 and approved by the Commission in Order No. PSC-13-0023-S-EI from seeking to increase rates as it proposes?**

Paraphrased Arguments

FPL: No. The first sentence of paragraph 6 in the Stipulation and Settlement Agreement provides expressly that "[n]othing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges ...." FPL's request to recover costs associated with the PetroQuest joint venture through the Fuel Clause is projected to provide net savings for customers and would serve as a valuable longer term physical hedge.

OPC, FRF: Yes. By the terms of the agreement, FPL is barred from recovering base rate costs through the fuel clause. The provision in the agreement that "It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover though cost recovery clauses increases in the magnitude of costs of types or categories ....that have been and traditionally, historically and ordinarily would be recovered through base rates," is controlling and restricts what, if any, costs can be recovered. The Woodford Project costs are not a hedge and not costs that are traditionally and historically recovered through the fuel clause.

FIPUG: Yes. The parties to the December 12, 2013 Stipulation and Settlement Agreement negotiated a resolution to a litigated rate case that provided rate stability and predictability for the duration of the Settlement. Language was included in the Agreement to prevent "end runs" around the Agreement, and the associated rate stability and predictability. Oil and gas exploration and production costs are more analogous to base rate type expenditures that would be "ordinarily" recovered in base rates. Large capital expenditures expended on things like drilling wells and related equipment would be the type of expenditures that would ordinarily be recovered in base rates. the settlement agreement contractual language precludes the recovery of such costs through the fuel clause, at least until the term of the current settlement agreement expires.

Background

The relevant portions of Paragraph 6 of the Stipulation and Settlement Agreement (2012 Settlement), approved in Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light states:

> Nothing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges,

* * * * * * * * * * * *

It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example: investment in and maintenance of transmission assets) that have been and traditionally, historically, and ordinarily would be recovered through base rates.

Relevant Orders

Order No. **12645**, issued November 3, 1983, in Docket No. 830001-EU, In re: Investigation of Fuel Adjustment Clauses of Electric Utilities.

- Established guidelines for fuel procurement
- The utility should have the flexibility to employ any means to achieve this result.
- All utility transaction with affiliated companies which provide fuel or fuel related services should be based on costs which are consistent with or lower than the costs a utility would incur if the utility received the fuel or services from an independent supplier in the competitive market obtained through competitive bidding.

Order No. **14546,** issued July 8, 1985, in Docket No. 850001-EI-B, In re: Cost recovery Methods for Fuel-Related Expenses.

- Fuel related costs which are subject to volatile changes are recoverable through the fuel clause
- Fuel related costs recovered through base rates but which were not recognized or anticipated and which if expended result in fuel savings to customers were to be considered for recovery through the fuel clause on a case by case basis.

Order No. PSC-02-**1484**-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management policies and procedures.

- Hedging maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time
- Hedging removes the disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.

Order No. PSC-06-**1057**-FOF-EI, issued December 22, 2006, in Docket No. 060001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

- the objective of the hedging programs is to minimize price volatility, and that prices are uncertain and volatile, particularly for natural gas, so there will be periods when the companies have hedging gains and other periods where the companies will have hedging losses.
- minimizing price volatility produces customer benefits.

Order No. PSC-08-**0667**-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

- Sets hedging guidelines
- Reduce the volatility of fuel adjustment charges
- "Hedging Activities" that are appropriately reported by IOUs in their hedging information reports are defined to be natural gas and fuel oil fixed price financial or physical transactions
- primary purpose is not to reduce an IOU's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs paid by customers over time.
- an IOU is not expected to predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.

Considerations

A. The first question the Commission should determine is whether the cost of the PetroQuest joint venture should be recovered.

B. If the answer is yes, the Commission should determine where these costs are recovered: base rates or Fuel Clause.

C. The 2012 Settlement precludes FPL from requesting an increase in base rates to take effect before January 1, 2017.

D. If the Commission determines that the costs should be recovered through base rates, FPL would be precluded from seeking to recover those costs until 2017. Thus, the petition should be denied.

E. Paragraph 6 of the 2012 Settlement states that FPL may recover costs that "are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges."

F. For the Commission to determine that the costs are appropriate for recovery through the Fuel Clause, the Commission must first decide whether the costs of the PetroQuest joint venture are the type of costs traditionally and historically recovered through the Fuel Clause.

G. If the Commission decides that the nature of the costs are traditionally recovered through the Fuel Clause, the 2012 Settlement would not preclude the granting of the petition.

H. If the Commission determines that the PetroQuest joint venture is in fact a long-term physical hedge, the costs may be recoverable through the Fuel Clause and the 2012 Settlement would not preclude FPL from recovering the costs.

<u>ISSUE 2</u>: **If the Commission answers Issue 1 in the negative, what standard should the Commission apply to a request by FPL to recover the price that FPL pays to its subsidiary/affiliate for gas obtained through the joint venture with PetroQuest?** *(This is a fall-out Issue.)*

<u>Paraphrased Arguments</u>

<u>FPL</u>: FPL believes this issue is effectively moot. If the Commission rejects FPL's Petition, FPL will not pursue the PetroQuest joint venture. Instead, FPL's unregulated affiliate, USG, will retain all rights and responsibilities associated with the joint venture with PetroQuest. Thus, the question is hypothetical and need not be addressed.

<u>OPC, FRF, and FIPUG</u>: Cost recovery of any gas purchased under the arrangement described in this issue should be no more than the market price of gas.

<u>Considerations</u>

A. If the Commission does not approve the joint venture proposal in Issue 1, FPL's non-regulated affiliate, USG, will be involved in the joint venture with PetroQuest. If FPL were to purchase gas from USG, the price of gas FPL pays to USG would undergo the same level of scrutiny as all other gas purchases FPL makes from any other producer. Staff would analyze FPL's gas costs against the market price of gas.

B. If the Commission approves the joint venture proposal in Issue 1, the joint venture agreement between FPL and PetroQuest addresses cost recovery.

ISSUE 3: **What amount, if any, associated with the transactions proposed in FPL's June 25 Petition should be included for recovery through FPL's 2015 fuel cost recovery factor?** *(This is a fall-out issue.)*

Paraphrased Arguments

FPL: For 2015, the amount to be recovered is projected to be $45,473,295, which is based on FPL's share of the costs to be incurred in 2015 for the PetroQuest joint venture. The recovery amount will be recovered through the normal Fuel Clause actual/estimated and final true-up mechanisms as actual 2015 costs are known.

OPC, FRF, and FIPUG: Zero. Nevertheless, if FPL's subsidiary goes forward with the transaction, then any natural gas obtained by FPL from such subsidiary should be recovered through FPL's 2015 fuel cost recovery factor based on the market price of gas, consistent with how fossil fuel costs obtained from affiliated entities are recovered. However, if the Commission finds that the transaction falls within its regulatory jurisdiction, despite OPC's strong contention that it does not have such authority, then the amount recovered through the 2015 fuel cost recovery factor should be based on the lower of cost or market for the gas obtained from the subsidiary.

Considerations

A. FPL's 2015 fuel cost recovery factors were set at the October 22, 2014 Fuel Hearing without including any amount of estimated costs associated with the Woodford Project.

B. If the vote on Issue 1 approves FPL's proposal, FPL will not change its 2015 factors. Instead, FPL will file for cost recovery of actual expenses in its actual/estimated and final true-up filings for 2015 (to be implemented in the first billing cycle of 2016).

C. If the vote on Issue 1 denies FPL's proposal, this issue is moot.

D. In either scenario, FPL will not change its 2015 fuel factors during 2015 as a result of the Woodford Project.

<u>ISSUE 8</u>: **What effect, if any, does Commission's decision on Issue 3 have on the fuel cost recovery factor and GPIF targets/ranges for the period January 2015 through December 2015?** *(This is a fall-out issue.)*

<u>Paraphrased Arguments</u>

<u>FPL</u>: By stipulation, the Commission approved the 2015 Targets without recognition of the Woodford Project. If the Woodford Project is approved, the 2015 GPIF targets/ranges would change slightly. As noted in Issue 3, FPL does not propose to revise the 2015 fuel factors. Rather, FPL would reflect both the costs and the fuel savings associated with the Woodford Project in the actual/estimated and final true-up filings for 2015.

<u>OPC, FRF, and FIPUG</u>: No position. (OPC and FRF) As the Commission should not permit natural gas drilling and production costs to be recovered through the Fuel Clause, no change to the GPIF targets/ranges is necessary. (FIPUG)

<u>Considerations</u>

A. The record in the 2014 Fuel Clause proceeding includes the GPIF targets/ranges both with and without the impact of the Woodford Project. The GPIF results for 2015 will be calculated by comparing actual performance measures against the appropriate targets/ranges.

If you **deny** the petition because it is **barred by the settlement**, you do not need to decide the remaining issues, including the guidelines.

If you **deny** the petition on the **merits**, my recommendation is that you do not need to decide the remaining issues. If there is interest in pursuing the guidelines, my recommendation is to hold a workshop or generic proceeding to gather information from all stakeholders, including the other investor-owned utilities.

If you **grant** the petition on the **merits**, you must set the schedule for the remaining guidelines issues. At the end of the hearing on December 2 you set a briefing date of January 5, 2015. My recommendation is to extend that date by one week and shoot for the March 3 Agenda.

Staff's Preferred Schedule for the Guideline Issues (4, 5 & 7):
Briefs Due -- January 12
Staff Recommendation – February 19
Agenda – March 3
Final Order – March 23

Briefing Schedule Announced at Hearing for the Guideline Issues (4, 5 & 7):
Briefs Due: January 5 (the only date announced, staff would still prefer the March 3 Agenda as set out above, but if not....)
Staff Recommendation – January 22
Agenda – February 3
Final Order – February 23

Agenda Conference
Thursday, December 18, 2014, 9:30 a.m.

I. Invocation.

II. Call the meeting to order.

III. Item 14 is withdrawn.

14 140038-SU – Majority control of Crooked Lake Park Sewerage Co. / name change to Glenbrook Properties

IV. Ask for motions for the move staff list.
(Items 1, 2, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13 and 14 are on the move staff list)

2 110013-TP – Proposals for relay service, Telecommunications Access System Act of 1991
140029-TP – Proposals for relay service, Telecommunications Access System Act of 1991
4 110260-WS – Staff-assisted race case in Lee Co. by Useppa Island Utilities Co., Inc.
5 130223-EI -- Optional non-standard meter rider by Florida Power & Light Company
6 140204-GU – Flexible gas service tariff by FPUC, FPUC-Fort Meade and FPUC-Indiantown Division
7 140190-GU – Transportation service extension in Palm Beach Co. w/FPUC by Peninsula Pipeline Co.
8 140189-GU – Transportation service extension in Nassau Co. with FPUC by Peninsula Pipeline Co.
9 140210-EU – Territorial agreement in Charlotte, Lee & Collier Counties by FPL and Lee Co. Electric
10 140007-EI – Environmental cost recovery clause
11 140180-EQ – Renewable energy power purchase contract w/Rayonier Performance Fibers, LLC by FPUC
12 140185-EQ – Power purchase contract w/Eight Flags Energy, LLC by FPUC

V. Move to Item #3.

3 140001-EI – Fuel and purchased power cost recovery clause w/generating performance incentive factor

Andrew Maurey will introduce the item.

Participation: Post-hearing recommendation; participation limited to Commissioners and Staff.

Legal: Martha Barrera
Staff: AFD: Andrew Maurey, Pete Lester, Michael Barrett
IDM: Mark Laux

Discussion, call for motion(s), and vote on all issues.

Move to Item #15.

15 140205-WS – Adoption of Rule 25-30.091, F.A.C and amendment of Rule 25-30.440, F.A.C.

Rosanne Gervasi will introduce the item.

Participation: Interested persons may participate.

Legal: Rosanne Gervasi
Staff: IDM: Kevin Bloom, David Dowds, Mark Futrell
ENG: Stan Rieger, Adam Hill, Laura King
ECO: Don Rome

Utilities, Inc.: Marty Friedman
U.S. Water Corp.: Troy Rendell
Office of Public Counsel: Patty Christensen or Erik Sayler

Discussion, call for motion(s), and vote on all issues.

VI. Adjourn the conference and announce time certain for Internal Affairs.

12/18/14 (Thur.) 8:25 a.m.

December 18, 2014

PLEASE NOTE: This list is assembled for the administrative convenience of the Commission personnel, and for no other purpose. It represents neither decision nor vote by any Commissioner. Persons who rely on this list for any purpose do so at their own risk.

Issued 8:00 p.m., December 17, 2014

MS	1	**Consent Agenda**
MS	2	**Docket No. 110013-TP** – Request for submission of proposals for relay service, beginning in June 2012, for the deaf, hard of hearing, deaf/blind, or speech impaired, and other implementation matters in compliance with the Florida Telecommunications Access System Act of 1991. **Docket No. 140029-TP** – Request for submission of-proposals for relay service, beginning in June 2015, for the deaf, hard of hearing, deaf/blind, or speech impaired, and other implementation matters in compliance with the Florida Telecommunications Access System Act of 1991.
--	3	**Docket No. 140001-EI** – Fuel and purchased power cost recovery clause with generating performance incentive factor.
MS	4	**Docket No. 110260-WS** – Application for staff-assisted rate case in Lee County by Useppa Island Utilities Co., Inc.
MS	5	**Docket No. 130223-EI** – Petition for approval of optional non-standard meter rider, by Florida Power & Light Company.
MS	6	**Docket No. 140204-GU** – Joint petition for approval of flexible gas service tariff by Florida Public Utilities Company, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.
MS	7	**Docket No. 140190-GU** – Petition for approval of transportation service agreement for an extension in Palm Beach County with Florida Public Utilities Company, by Peninsula Pipeline Company, Inc.
MS	8	**Docket No. 140189-GU** – Petition for approval of transportation service agreement for an extension in Nassau County with Florida Public Utilities Company, by Peninsula Pipeline Company, Inc.
MS	9	**Docket No. 140210-EU** – Joint petition for approval of amendment to territorial agreement in Charlotte, Lee, and Collier Counties, by Florida Power & Light Company and Lee County Electric Cooperative.
MS	10	**Docket No. 140007-EI** – Environmental cost recovery clause.
MS	11	**Docket No. 140180-EQ** – Petition for approval of amendment to extend term of negotiated renewable energy power purchase contract with Rayonier Performance Fibers, LLC, by Florida Public Utilities Company.
MS	12	**Docket No. 140185-EQ** – Petition for approval of negotiated power purchase contract with Eight Flags Energy, LLC, by Florida Public Utilities Company.
MS	13	**Docket No. 140113-EI** – Petition for approval to construct an independent spent fuel storage installation and an accounting order to defer amortization pending recovery from the Department of Energy, by Duke Energy Florida, Inc.
MS	14	**Docket No. 140038-SU** – Application for transfer of majority organizational control of Crooked Lake Park Sewerage Co. in Polk County, and for name change on Certificate No. 517-S to Glenbrook Properties, LLC, a Florida limited liability company.
--	15	**Docket No. 140205-WS** – Proposed adoption of Rule 25-30.091, F.A.C., Petition to Revoke Water Certificate of Authorization, and proposed amendment of Rule 25-30.440, F.A.C., Additional Engineering Information Required of Class A and B Water and Wastewater Utilities in an Application for Rate Increase.

Informational Packet

Docket No.	140001-EI, Fuel and purchased power cost recovery clause with generating performance incentive factor.
In re:	Item 3 for the December 18, 2014 Agenda Conference, the post-hearing decision for the Florida Power & Light's (FPL) Gas Reserves project.
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Staff's Analysis

- All things being equal, the impact would be equal for a $1 move in either direction (i.e., a $1 rise in the price of natural gas would add $6.00 on a customer bill for fuel charges, and a $1 fall in the price of natural gas would reduce the customer bill for fuel charges by $6.00).

- Importantly, a significant volume of gas will likely be purchased *with hedges in place,* so the impact of a $1 rise in the price of natural gas would only be applicable for the unhedged volumes. [Note that the volume of natural gas hedged is a confidential number that is disclosed in FPL's "Risk Management Plan For Fuel Procurement."]

- As a hypothetical example, if the hedged volume was 55%, the unhedged volume would be 45%, and using the rule of thumb expressed by witness Forrest, the impact of a $1 rise in the price of natural gas would be a $2.70 increase on customer bills for fuel charges (45% of the $600 million is $270 million, roughly translating to $2.70).

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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, 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 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.

Florida Power & Light Company
Docket No. 140001-EI
Staff's 2nd Set of Interrogatories
Interrogatory No. 35
Page 1 of 1

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.

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 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.

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.

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.

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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.

SCHEDULE: E10

FLORIDA POWER & LIGHT COMPANY
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.

SCHEDULE: E10

FLORIDA POWER & LIGHT COMPANY
ASSUMING $125 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	$30.94	-$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 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 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.

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.

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Docket No. 140001-EI
Staff's 8th Set of Interrogatories
Interrogatory No. 176
Page 1 of 1

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.

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

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.

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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

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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	[redacted]				$3.56	$3.94	$6.4	0.8649	$5.5
2017	11.3	[redacted]				$4.00	$4.42	$4.8	0.8043	$3.9
2018	8.7	[redacted]				$4.40	$4.66	$2.3	0.7480	$1.7
2019	7.1	[redacted]				$4.96	$5.23	$1.9	0.6956	$1.3
2020	6.1	[redacted]				$4.79	$5.38	$3.6	0.6468	$2.3
2021	5.3	[redacted]				$4.94	$5.58	$3.4	0.6015	$2.0
2022	4.7	[redacted]				$5.08	$5.78	$3.3	0.5594	$1.8
2023	4.3	[redacted]				$5.21	$5.98	$3.3	0.5202	$1.7
2024	3.9	[redacted]				$5.34	$6.18	$3.3	0.4837	$1.6
2025	3.6	[redacted]				$5.24	$6.33	$3.9	0.4498	$1.8
2026	3.3	[redacted]				$5.32	$6.53	$4.0	0.4183	$1.7
2027	3.1	[redacted]				$5.39	$6.78	$4.3	0.3890	$1.7
2028	2.9	[redacted]				$5.46	$7.03	$4.6	0.3617	$1.7
2029	2.8	[redacted]				$5.52	$7.33	$5.0	0.3364	$1.7
2030	2.6	[redacted]				$5.58	$7.63	$5.3	0.3129	$1.7
2031	2.4	[redacted]				$5.65	$7.81	$5.3	0.2910	$1.5
2032	2.3	[redacted]				$5.71	$8.00	$5.2	0.2705	$1.4
2033	2.2	[redacted]				$5.80	$8.19	$5.2	0.2516	$1.3
2034	2.0	[redacted]				$5.88	$8.39	$5.1	0.2340	$1.2
2035	1.9	[redacted]				$5.97	$8.60	$5.0	0.2176	$1.1
2036	1.8	[redacted]				$6.05	$8.81	$4.9	0.2023	$1.0
2037-65	23.1	[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

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"

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)	$\boxed{\textbf{\$51.9}}$	$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"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 120015-EI ORDER NO. PSC-13-0023-S-EI ISSUED: January 14, 2013

The following Commissioners participated in the disposition of this matter:

RONALD A. BRISÉ, Chairman
LISA POLAK EDGAR
ART GRAHAM
EDUARDO E. BALBIS
JULIE I. BROWN

ORDER APPROVING REVISED STIPULATION AND SETTLEMENT

BY THE COMMISSION:

Background

On March 19, 2012, pursuant to Section 366.06, Florida Statutes (F.S.), and Rules 25-6.0425 and 25-6.043, Florida Administrative Code (F.A.C.), Florida Power & Light Company (FPL) filed a petition for approval of permanent increase of its base rates and charges. In its petition, FPL requested a base rate increase of $528 million with a Return on Equity (ROE) of 11.25%, plus a .25% performance adder to remain as long as it maintained the lowest electrical rates in the state compared to the other 4 Investor Owned Utilities. Twelve parties were granted intervention in the docket.[1] However, several parties were dismissed from the docket for various reasons.[2] By the Order Establishing Procedure, Order No. PSC-12-0143-PCO-EI, issued March 26, 2012, the hearing was set to commence on August 20, 2012. In May, June and August, 2012, nine Commission service hearings were held throughout FPL's service territory. On August 15, 2012, FPL and three of the eleven intervening parties filed a Motion to Approve Settlement

[1] Office of Public Counsel (OPC), South Florida Hospital and Healthcare Association (SFHHA), Florida Retail Federation (FRF), Thomas Saporito (Saporito), Florida Industrial Power Users Group (FIPUG), Village of Pinecrest, Federal Executive Agencies (FEA), Glen Gibellina, Larry Nelson, John Hendricks, Algenol Biofuels Inc., and Daniel and Alexandria Larson.

[2] Mr. and Mrs. Larson and Mr. Nelson were dismissed as parties from the docket and their positions on the issues were stricken pursuant to Section VII(a) of Order No. PSC-12-0143-PCO-EI, the Order Establishing Procedure. Section VII(a) provides "[U]nless excused by the Presiding Officer for good cause shown, each party (or designated representative) shall personally appear at the hearing. Failure of a party, or that party's representative, to appear shall constitute waiver of that party's issues, and that party may be dismissed from the proceeding." Both Mrs. Larson and Mr. Nelson subsequently filed Petitions to Re-intervene and Intervene respectively in the supplemental portion of the hearing, and those petitions were denied. Mr. Gibellina was dismissed from the docket for failure to appear at the Prehearing Conference.

Agreement (Settlement Agreement) and a Motion to Suspend the Procedural Schedule.[3] The Motion to Suspend the Procedural Schedule was denied by Order No. PSC-12-0430-PCO-EI, issued August 17, 2012. The technical hearing commenced on August 20, 2012, and lasted 10 days.

On August 27, 2012, Order No. PSC-12-0440-PCO-EI, the Second Order Revising Order Establishing Procedure (Second Order) was issued establishing a procedural schedule for further actions necessary for us to consider the proposed Settlement Agreement. The Second Order stated that upon conclusion of the evidentiary portion of the hearing, a date and time would be set for the sole purpose of taking up the proposed Settlement Agreement. Also, the Second Order gave all parties an opportunity to conduct informal discovery on the proposed Settlement Agreement. On August 31, 2012, we announced that the hearing would reconvene on September 27, 2012, and continue on September 28, 2012, if necessary, to consider the proposed Settlement Agreement. On September 27, 2012, we voted to take additional testimony limited to specific issues that were part of the proposed Settlement Agreement, but supplemental to the issues in the rate case. Accordingly, in compliance with Sections 120.569 and 120.57, F.S., the administrative hearing was continued to November 19-20, 2012.

On October 3, 2012, Order No. PSC-12-0529-PCO-EI, the Third Revised Order Establishing Procedure was issued establishing the necessary procedures for discovery and setting dates for filing prefiled testimony, the Prehearing Conference, and supplemental hearing dates. On November 19 and 20, 2012, the supplemental hearing was held, and on November 30 parties filed post-hearing briefs. On December 13, 2012, we convened a Special Agenda Conference to consider the proposed Settlement Agreement filed by FPL, FIPUG, SFHHA, and FEA. At the Special Agenda we expressed our concerns with the proposed Settlement Agreement. We engaged in an extensive discussion of the benefits and detriments associated with the provisions of the proposed Settlement Agreement, and whether the agreement as filed was in the public interest. Upon completion of our discussion, all the parties (signatories and non-signatories) were given an opportunity to engage in further settlement negotiations. Upon reconvening the Special Agenda Conference, the signatories filed a revised Stipulation and Settlement and the non-signatories reiterated their continued objections to our consideration of the proposed or modified agreement.

By this Order, we approve the revised Stipulation and Settlement (Attachment A). We have jurisdiction over these matters pursuant to Chapter 366, F.S., including Sections 366.04, 366.05, 366.06, 366.07, and 366.076, F.S.

<u>The August 15, 2012 Proposed Settlement Agreement</u>

The major elements of the August 15, 2012 proposed agreement included the following:

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[3] FPL, FIPUG, FEA, and SFHHA are the signatories to the Settlement Agreement. While Algenol did not execute the Settlement Agreement or join in the motion, it did express its support for the Settlement Agreement. Algenol subsequently withdrew from the proceeding.

- The Term would begin with the first billing cycle of January 2013 and continue through the last billing cycle in December 2016.

- FPL's authorized Return on Equity would be set at 10.70 percent (9.70-11.70 percent range) for all purposes.

- FPL would be authorized to implement a revenue increase of $378 million effective January 1, 2013. The increase would be based on the projected 2013 test year billing determinants contained in FPL's filed Minimum Filing Requirements.

- FPL's proposed minimum late payment charge of $5.00 would be increased to $6.00.

- Demand credits for large commercial and industrial customers in the new CILC and CDR rates would be increased from the credits filed in FPL's MFRs. The increased CILC and CDR credits would be recovered through the energy conservation cost recovery clause (ECCR).

- FPL would not be precluded from petitioning the Commission to seek recovery of costs associated with any storms. Storm cost recovery would begin, on an interim basis, 60 days from the filing of a storm cost recovery petition and associated tariff. Storm cost recovery charges would be assessed over a 12-month period if the costs do not exceed $4.00/1,000 kWh on a monthly residential customer bill. Storm cost recovery in excess of $4.00/1,000 kWh would be recovered in a subsequent year or years as determined by the Commission.

- FPL would continue to recover the annual non-fuel revenue requirements for West County Unit 3 through the capacity cost recovery clause in the same manner provided in the 2010 Rate Case Settlement, except that upon the implementation date of the proposed settlement, recovery would no longer be limited to the projected fuel cost savings.

- The revenue requirements associated with West County Unit 3 would be allocated to customer classes based on the cost of service and rate design methodology reflected in FPL's filed MFRS in the current case. Recovery of West County Unit 3's revenue requirements would survive termination of the proposed settlement and would continue until such time as new base rates are authorized for FPL.

- FPL would be allowed three generation base rate increases (GBRA): June 2013 – Canaveral; June 2014 – Riviera; and June 2016 – Port Everglades. FPL would file for each GBRA through the Capacity clause. Each GBRA would be calculated using a 10.70 percent ROE and the capital structure reflected in FPL's MFRs for the Canaveral Step Increase. The proposed settlement provides for a true up to actual capital expenditures if capital costs are lower than projected. FPL would provide any refund through the Capacity Clause and base rates would be adjusted going forward. FPL would be required to initiate a limited proceeding if it chooses to pursue a revenue increase for higher capital costs. For the Canaveral Modernization Project, the revenue requirement would be based on FPL's current rate petition and MFRs. The Riviera and Port Everglades revenue requirements would be based on the cumulative present value of revenue requirements reflected in the respective need determinations. Each GBRA would be reflected in FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously.

- If FPL's achieved ROE falls below 9.70 percent during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, FPL could petition the Commission to amend its base rates and may seek interim relief. If FPL's achieved ROE exceeds 11.70 percent during the settlement term on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, any other Party could petition the Commission to amend its base rates and may seek interim relief. This Agreement would terminate upon the effective date of any final order issued in any rate relief proceeding.

- FPL would amortize its projected depreciation reserve surplus and a portion of its fossil dismantlement reserve (termed the "Reserve Amount") over the period of the Agreement, not to exceed $400 million.

- No depreciation or dismantlement studies would be required to be filed during the Term of the Agreement.

- An Incentive Mechanism would become effective on the implementation date of the Settlement. The Incentive Mechanism involves the sharing of gains resulting from electric wholesale purchases and sales, and asset optimization. Asset optimization involves: gas storage utilization; city-gate gas sales using existing transport; production area gas sales; capacity release of gas transport and electric transmission; and the outsourcing of the optimization function. Annually, as part of the fuel cost recovery clause, FPL would file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. FPL customers would receive 100 percent of the gain from electric wholesale sales and purchases and asset optimization up to a threshold of $36 million ("Customer Savings Threshold.") FPL customers would also receive 100 percent of the gain for the first $10 million above the Customer Savings Threshold (termed "Additional Customer Savings"). Incremental gains above the Customer Savings Threshold and the Additional Customers Savings (totaling $46 million) would be shared between FPL and customers as follows:

    1. Between $46 million and $75 million, customers receive 30 percent of the incremental gains;
    2. Between $75 and $100 million, customers receive 40 percent of the incremental gains.

3. Over $100 million, customers receive 50 percent of the incremental gains.

The customers' portion of all gains would be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL would be entitled to recover through the Fuel Clause reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs and asset optimization measures. Such costs include: incremental personnel costs, software and associated hardware costs. In addition, variable power plant O&M costs incurred to generate additional output in order to make wholesale sales, if the level of sales exceeds 514,000 MWh.

Decision

At the Special Agenda Conference, we expressed our concerns with the proposed Settlement Agreement. We engaged in an extensive discussion of the benefits and detriments associated with provisions of the proposed Settlement Agreement, and whether the agreement as filed was in the public interest. Upon completion of our discussion, all parties were given an opportunity to engage in further settlement negotiations. Upon reconvening the Special Agenda Conference, the signatories filed a revised Stipulation and Settlement and the non-signatories reiterated their continued objections to our consideration of the proposed and modified agreements. The modified agreement incorporates changes based upon our extensive discussion. The changes are discussed below.

- FPL's authorized Return on Equity was reduced to 10.50 percent from 10.70 percent for all purposes.

- The revenue increase was reduced from $378 million to $350 million effective January 1, 2013. The increase is based on the projected 2013 test year billing determinants contained in FPL's filed Minimum Filing Requirements. We note that $18 million of the reduction in the requested revenue shall be allocated directly to the base customer and energy charges for the residential rate class only.

- FPL's minimum late payment charge was reduced from $6.00 to $5.00 as originally requested in FPL's MFRs.

- FPL shall be allowed three generation base rate increases (GBRA): June 2013 – Canaveral, June 2014 – Riviera, and June 2016 – Port Everglades. FPL will file for each GBRA through the Capacity clause. Each GBRA will be calculated using a 10.50 percent ROE, instead of 10.70 as originally proposed, and using the capital structure reflected in FPL's MFRs for the Canaveral Step Increase. The settlement provides for a true up to actual capital expenditures if capital costs are lower than projected. FPL will provide any refund through the Capacity Clause and base rates will be adjusted going forward. It will be FPL's obligation to initiate a limited proceeding if it chooses to pursue a revenue increase for higher capital costs. For the Canaveral Modernization Project, the revenue requirement will be based on FPL's current rate petition and MFRs. The Riviera and Port Everglades revenue requirements will be based on the cumulative present value of revenue requirement reflected in the respective need determinations. Each GBRA will be reflected in FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously. FPL shall calculate and submit for our staff's administrative approval the amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that each modernization plant is to go into service. These filing shall include revised tariff sheets for the year that each modernization plant is to go into commercial service.

- If FPL's achieved ROE falls below 9.50 percent, instead of 9.70 percent as originally proposed, during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the Commission to amend its base rates and may seek interim relief. If FPL's achieved ROE exceeds 11.50 percent during the term of the settlement on an FPL monthly earning surveillance report stated on an FPSC actual, adjusted basis, any other Party may petition the Commission to amend its base rates and may seek interim relief. This Agreement terminates upon the effective date of any final order issued in any rate relief proceeding.

- An Incentive Mechanism will become effective on the implementation date of the revised Stipulation and Settlement. This is a four-year pilot program. The Commission has the option to review this pilot program after two years. Upon review, if the Commission determines that the pilot program is not providing the kinds of benefits that it anticipated or if the Commission determines the pilot program is not satisfactory, the Commission may terminate this pilot program. The Incentive Mechanism involves the sharing of gains resulting from electric wholesale purchases and sales, and asset optimization. Asset optimization involves: gas storage utilization; city-gate gas sales using existing transport; production area gas sales; capacity release of gas transport and electric transmission; and the outsourcing of the optimization function. Annually, as part of the fuel cost recovery clause, FPL will file a final true-up schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases, and all forms of asset optimization it undertook in that calendar year. FPL customers will receive 100 percent of the gain from electric wholesale sales and purchases and asset optimization up to a threshold of $36 million ("Customer Savings Threshold"). FPL customers will also receive 100 percent of the gain for the first $10 million above the Customer Savings Threshold (termed "Additional Customer Savings"). Incremental gains above the Customer Savings Threshold and the Additional Customers Savings (totaling $46 million) will be shared between FPL and customers as follows:

1. Between $46 million and $100 million, customers receive 40 percent of the incremental gains.
2. Over $100 million, customers receive 50 percent of the incremental gains.

The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL will be entitled to recover through the Fuel Clause reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs and asset optimization measures. Such costs include: incremental personnel costs, software, and associated hardware costs. In addition, variable power plant O&M costs incurred to generate additional output in order to make wholesale sales will be included if the level of sales exceeds 514,000 MWh.

We note that with respect to the GBRA, we find that it is the public interest because it provides a benefit to both FPL's customers and FPL. We already approved the need for the Canaveral, Riviera, and Port Everglades Modernization Projects when we considered FPL's need determination petitions. The GBRA provides the mechanism for FPL to recover the costs to modernize these plants and bring them into commercial service. We also find that the pilot incentive mechanism is in the public interest. The pilot incentive mechanism is beneficial to both FPL's customers and FPL. We note that this is a four-year pilot program and we have the option to review it after two years. If we determine that the program is not providing the kinds of benefits that are anticipated, or if we determine the pilot program is otherwise unsatisfactory, we may terminate the program.

Settlement agreements are approved if we determine that they are in the public interest.[4] The public interest standard that we apply in approving the revised Stipulation and Settlement requires a fact-intensive, case-specific analysis. Having carefully reviewed the evidence in the record, and having discussed the benefits and detriments associated with the revised Stipulation and Settlement, we find that as a whole the settlement is in the public interest. It provides a reasonable resolution of all the issues in this proceeding regarding FPL's rates and charges. It also provides FPL's customers with stability and predictability with respect to their electricity rates, while allowing FPL to maintain the financial strength to make investments necessary to

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[4] Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

provide customers with safe and reliable power. All stipulated issues that were approved in this docket on August 31, 2012, are superseded by our approval of the revised Stipulation and Settlement.

We find, therefore, consistent with our ongoing authority and obligation, that the revised Stipulation and Settlement establishes rates that are fair, just, and reasonable in the public interest. We have a long history of encouraging settlements that are in the public interest, and we believe it is appropriate to do so in this case as well.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the revised Stipulation and Settlement filed December 13, 2013, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that FPL shall file for our staff's administrative approval revised tariff sheets to reflect the terms of the revised Stipulation and Settlement. It is further

ORDERED that FPL shall calculate and submit for our staff's administrative approval the amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that each modernization plant is to go into commercial service. These filing shall include revised tariff sheets for the year that each modernization plant is to go into commercial service. It is further

ORDERED that Docket No. 120015-EI shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of January, 2013.

/s/ Ann Cole
ANN COLE
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance 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.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	)))	Docket No. 120015-EI

STIPULATION AND SETTLEMENT

WHEREAS, Florida Power & Light Company ("FPL" or the "Company"), the Florida Industrial Power Users Group ("FIPUG"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Federal Executive Agencies ("FEA") have signed this Stipulation and Settlement (the "Agreement"; unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement); and

WHEREAS, on February 1, 2011, the Florida Public Service Commission ("FPSC" or "Commission") entered Order No. PSC-11-0089-S-EI approving a stipulation and settlement of FPL's rate case in Docket Nos. 080677-EI and 090130-EI, which continues in effect through the last billing cycle in December 2012 (the "2010 Rate Case Stipulation"); and

WHEREAS, on March 19, 2012, FPL petitioned the Commission for an increase in base rates of approximately $516.5 million to be effective on January 1, 2013 following the expiration of the 2010 Rate Case Stipulation, for a step increase of $173.9 million to be effective upon the commercial in-service date of the Canaveral Modernization Project (scheduled to be June 1, 2013), and for other related relief (the "2012 Rate Petition"); and

WHEREAS, the Parties have filed voluminous prepared testimony with accompanying exhibits and conducted extensive discovery; and

WHEREAS, the Parties recognize that this is a period of substantial economic uncertainty, in which economic development and job creation are vitally important to the state of Florida; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability and predictability with respect to FPL's base rates and charges, as well as to promote economic development, job creation and stability;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement will become effective on the first billing cycle of January 2013 (the "Implementation Date") and continue through the last billing cycle in December 2016 (the period from the Implementation Date through the last billing cycle in December 2016 may be referred to herein as the "Term").

2. FPL's authorized rate of return on common equity ("ROE") shall be a range of 9.50% to 11.50%, with a mid-point of 10.50%. FPL's authorized ROE range and mid-point shall be used for all purposes during the Term.

3. (a) Upon the Implementation Date and effective with the first billing cycle in January 2013, FPL shall increase its base rates and service charges by an amount that is intended to generate an additional $350 million of annual revenues, based on the projected 2013 test year billing determinants reflected in the Minimum Filing Requirements ("MFRs")

filed with the 2012 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(b) Attached hereto as Exhibit B are tariff sheets for new base rates and service charges that implement the $350 million rate increase described in Paragraph (3)(a) above, which tariff sheets shall become effective on the first billing cycle of January 2013. The new base rates reflected in the attached tariff sheets are based on the billing determinants, cost of service allocations and rate design in the MFRs accompanying the 2012 Rate Petition and include additional adjustments, all of which are reflected in Exhibit A; provided, however, that: (i) the allocation of revenue responsibility for the base customer and energy charges for the residential rate class (i.e., RS(T)-1) shall be reduced by an additional $18 million; (ii) the minimum late payment charge shall be $5.00; and (iii) consistent with FPL's recently approved revised Economic Development Rider and to promote further economic development and job creation, (A) the energy and demand charges for business and commercial rates are adjusted as shown in Exhibit B, and (B) the utility-controlled demand credits for large commercial and industrial customers in the new CILC and CDR rates are greater than the credits reflected in such MFRs, and the relationship between the non-fuel energy and demand charges in the CILC rates are revised. FPL shall be entitled to recover the increased CILC and CDR credits through the energy conservation cost recovery ("ECCR") clause.

(c) Base rates set in accordance with this Paragraph 3 shall not be changed during the Term except as otherwise permitted in this Agreement.

4. Nothing in this Agreement shall preclude FPL from requesting the Commission to approve the recovery of costs that are recoverable through base rates under the nuclear cost recovery statute, Section 366.93, Florida Statutes, and Commission Rule 25-6.0423, F.A.C. Parties may participate in nuclear cost recovery proceedings and proceedings related thereto and may oppose FPL's requests.

5. (a) Nothing in this Agreement shall preclude FPL from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or level of theoretical depreciation reserve. Consistent with the rate design method set forth in Order No. PSC-06-0464-FOF-EI, the Parties agree that recovery of storm costs from customers will begin, on an interim basis, sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed \$4.00/1,000 kWh on monthly residential customer bills. In the event the storm costs exceed that level, any additional costs in excess of \$4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission. All storm related costs subject to interim recovery under this Paragraph 5 shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, to the estimate of incremental costs above the level of storm reserve prior to the storm and to the replenishment of the storm reserve to the level as of the Implementation Date. The Parties to this Agreement are not precluded from participating in any such proceedings and opposing the amount of FPL's claimed

costs but not the mechanism agreed to herein.

(b) The Parties agree that the \$4.00/1,000 kWh cap in this Paragraph 5 will apply in aggregate for a calendar year; provided, however, that FPL may petition the Commission to allow FPL to increase the initial 12 month recovery beyond \$4.00/1,000 kWh in the event FPL incurs in excess of \$800 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to the level that existed as of the Implementation Date. All Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of theoretical depreciation reserve.

6. Nothing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically, and ordinarily would be

recovered through base rates. It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or atypical kinds of costs (including but not limited to, for example, requirements related to cybersecurity or the requirements for seismic and flood protection at nuclear plants arising out of the Fukushima Daiichi event), and concurrently or in connection with the imposition of such requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause. Nothing in this Agreement shall affect the shifts from clause to base rate recovery and from base rate to clause recovery that were set forth in the 2012 Rate Petition and accompanying MFRs.

7. (a) FPL will continue throughout the Term to recover the annual non-fuel revenue requirements for West County Unit 3 via its capacity cost recovery clause (the "Capacity Clause") in the manner provided in the 2010 Rate Case Stipulation; provided, however, that commencing upon the Implementation Date, such recovery shall not be limited to the projected fuel cost savings for West County Unit 3.

(b) The revenue requirements associated with West County Unit 3 quantified pursuant to this paragraph shall be allocated to customer classes utilizing the same cost of service and rate design methodology reflected in the MFRs accompanying the 2012 Rate Petition.

(c) FPL's right to recover the non-fuel revenue requirements for West County Unit 3 pursuant to this Paragraph 7 shall survive termination of this Agreement and shall continue until such time as new base rates are authorized for FPL that are based on a test year that reflects the then applicable non-fuel revenue requirements for West County Unit 3.

8. (a) FPL projects that the following three power plant modernization projects will enter commercial service while this Agreement is in effect: the Canaveral Modernization Project (projected to go into service June 2013), the Riviera Modernization Project (projected to go into service June 2014), and the Port Everglades Modernization Project (projected to go in service June 2016). For each of these three modernization projects, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). For the Canaveral Modernization Project, the Annualized Base Revenue Requirement shall be as reflected in the 2012 Rate Petition and accompanying MFRs; for the Riviera and Port Everglades Modernization Projects, the Annualized Base Revenue Requirement shall reflect the costs upon which the cumulative present value of revenue requirements was predicated, and pursuant to which a need determination was granted by the Commission. Each such base rate adjustment will be referred to as a Generation Base Rate Adjustment ("GBRA").

(b) Each GBRA is to be reflected on FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity (excluding West County Unit 3 revenues) during the first twelve months of operation.

FPL will begin applying the incremental base rate charges and base credits for each of the three modernization projects to meter readings made on and after the commercial in-service date of that modernization project.

(c) Each GBRA will be calculated using a 10.50% ROE and the capital structure reflected in the Canaveral Step Increase MFRs accompanying the 2012 Rate Petition. FPL will calculate and submit for Commission confirmation that amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that modernization project is to go into service.

(d) In the event that the actual capital expenditures are less than the projected costs used to develop the initial GBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the Capacity Clause. In order to determine the amount of this credit, a revised GBRA Factor will be computed using the same data and methodology incorporated in the initial GBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going forward basis, base rates will be adjusted to reflect the revised GBRA factor. The difference between the cumulative base revenues since the implementation of the initial GBRA factor and the cumulative base revenues that would have resulted if the revised GBRA factor had been in-place during the same time period will be credited to customers through the Capacity Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(e) In the event that actual capital costs for a modernization project are higher than the projection on which the Annualized Base Revenue Requirement was based, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall increase the GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Any Party may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15).

(f) Upon expiration or termination of this Agreement, FPL's base rate levels, including the effects of the GBRAs as implemented in this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues) for each of the modernization projects that achieved commercial in-service operation during the term of this Agreement, shall continue in effect until next reset by the Commission.

9. (a) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity falls below 9.50% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the FPSC to amend its base rates, either as a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, and/or as a limited proceeding under Section 366.076, Florida Statutes. (Throughout this Agreement, "FPSC actual, adjusted basis" and "actual adjusted earned return" shall mean

results reflecting all adjustments to FPL's books required by the Commission by rule or order, but excluding pro forma, weather-related adjustments.) If FPL files a petition to initiate a general rate proceeding pursuant to this provision, FPL may request an interim rate increase pursuant to the provisions of Section 366.071, Florida Statutes. The other Parties to this Agreement shall be entitled to participate in any proceeding initiated by FPL to increase base rates pursuant to this paragraph, and may oppose FPL's request.

(b) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity exceeds 11.50% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, any other Party shall be entitled to petition the Commission for a review of FPL's base rates. In any case initiated by FPL or any other Party pursuant to this paragraph, all parties will have full rights conferred by law.

(c) Notwithstanding Paragraph 3 above, this Agreement shall terminate upon the effective date of any final order issued in any such proceeding pursuant to this Paragraph 9 that changes FPL's base rates prior to the last billing cycle of December 2016.

(d) This Paragraph 9 shall not (i) be construed to bar or limit FPL to any recovery of costs otherwise contemplated by this Agreement; (ii) apply to any request to change FPL's base rates that would become effective after this Agreement terminates; or (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the termination of this Agreement to argue that FPL's authorized ROE range should be different than 9.50% to 11.50%.

10. (a) In Order No. PSC-10-0153-FOF-EI, the Commission determined a net theoretical depreciation reserve surplus in the total amount of $894 million (the "Total Depreciation

Reserve Surplus"). The Commission directed FPL to amortize the Total Depreciation Reserve Surplus over four years, ending in 2013. Pursuant to the 2010 Rate Case Stipulation, the Parties therein agreed that in each year during the term of that agreement, FPL would have discretion to vary the amount of amortization of Total Depreciation Reserve Surplus taken in that year, subject to certain limitations. As a result of FPL's actual and projected discretionary amortization during 2010-2012, the 2012 Rate Petition and accompanying MFRs projected that FPL would have $191 million of Total Depreciation Reserve Surplus remaining at the end of 2012 and would amortize that amount in 2013. The actual remaining amount may differ from the projected amount of $191 million.

(b) Notwithstanding Order No. PSC-10-0153-FOF-EI or the 2010 Rate Case Stipulation, the Parties agree that over the Term of this Agreement, FPL may amortize the Total Depreciation Reserve Surplus remaining at the end of 2012, plus a portion of FPL's Fossil Dismantlement Reserve (together the "Reserve Amount") with the amounts to be amortized in each year of the Term left to FPL's discretion subject to the following conditions: (i) the amount of Total Depreciation Reserve Surplus that FPL may amortize during the term shall not be less than $191 million (or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012) and the total Reserve Amount amortized during the Term shall not exceed $400 million[1] subject to (iii) below; (ii) for any surveillance reports submitted by FPL during the Term on which its return on equity (measured on an FPSC actual, adjusted basis) would otherwise fall below 9.50%,

[1] The Company would record the $191 million of net surplus amortization or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012, to the cost of removal component of the depreciation reserve to ensure that the amount of net surplus amortization on the financial statements equals the amount of net surplus amortization reflected in rates.

FPL must amortize at least the amount of the available Reserve Amount necessary to maintain in each such 12-month period a return on equity of 9.50% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize Reserve Amount in an amount that results in FPL achieving a return on equity of greater than 11.50% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL during the Term. FPL shall not satisfy the requirement of Paragraph 9 that its actual adjusted earned return on equity must fall below 9.50% on a monthly surveillance report before it may initiate a petition to increase base rates during the Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned return on equity to at least 9.50% for the period in question.

11. Notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., FPL shall not be required during the Term to file any depreciation study or dismantlement study. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect throughout the Term. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364 pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL during the Term.

12. (a) In order to create additional value for customers by FPL engaging in both wholesale power purchases and sales, as well as all forms of asset optimization, the Parties agree that FPL will be subject to the following mechanism, effective on the Implementation Date (the "Incentive Mechanism"):

(i) FPL will file each year as part of its fuel cost recovery clause ("Fuel Clause") final true-up filing a schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization that it undertook in that year (the "Total Gains Schedule").[2] FPL's final true-up filing will include a description of each asset optimization measure for which gain is included on the Total Gains Schedule for the prior year, and such measures shall be subject to review by the Commission to determine that they are eligible for inclusion in the Incentive Mechanism.

(ii) For the purposes of the Incentive Mechanism, "asset optimization" includes but is not limited to:

- Gas storage utilization (FPL could release contracted storage space or sell stored gas during non-critical demand seasons);
- Delivered city-gate gas sales using existing transport (FPL could sell gas to Florida customers, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);
- Production (upstream) area sales (FPL could sell gas in the gas-production areas, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);

[2] For the purpose of this Agreement, "short-term" is intended to refer to non-separated wholesale sales and purchases. Order No. PSC-97-0262-FOF-EI defined "non-separated" sales as "sales that are non-firm or less than one year in duration."

- Capacity Release of gas transport and electric transmission (FPL could sell idle gas transportation and/or electric transmission capacity for short periods when it is not needed to serve FPL's native load;
- Asset Management Agreement ("AMA") (FPL could outsource optimization function such as those described above to a third party through assignment of transportation and/or storage rights in exchange for a premium to be paid to FPL).

(iii) On an annual basis, FPL customers will receive 100% of the gain described in Paragraph 12(a)(i), up to a threshold of $36 million ("Customer Savings Threshold"). In addition, FPL customers will receive 100% of the gain described in Paragraph 12(a)(i) for the first $10 million above the Customer Savings Threshold ("Additional Customer Savings"). Incremental gains above the total of the Customer Savings Threshold and the Additional Customer Savings (i.e., above a gain of $46 million) will be shared between FPL and customers as follows: FPL will retain 60% and customers will receive 40% of incremental gains between $46 million and $100 million; and FPL will retain 50% and customers will receive 50% of all incremental gains in excess of $100 million. The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL agrees that it will not require any native load customer to be interrupted in order to initiate or maintain an economy sale, whether that sale is firm or non-firm.

(b) FPL will be entitled to recover through the Fuel Clause the following types of reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs as well as the asset optimization measures (the "Incremental Optimization Costs"):

(i) incremental personnel, software and associated hardware costs incurred by FPL to manage the expanded short-term wholesale purchases and sales programs and the asset optimization measures; and

(ii) variable power plant O&M costs[3] incurred by FPL to generate additional output in order to make wholesale sales, to the extent that the level of such sales exceed 514,000 MWh (*i.e.,* the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), with such costs determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs.

FPL's final true-up filing will separately state and describe the Incremental Optimization Costs that it incurred in the prior year, and such costs shall be subject to review and approval by the Commission.

(c) On or after January 2, 2015 (*i.e.,* two years after the Implementation Date), the Commission may review and, if continuing the Incentive Mechanism is deemed not to be in the public interest, terminate the Incentive Mechanism for the remainder of the Term.

13. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 9, a Party to this Agreement will neither seek nor support any reduction in FPL's base rates, including limited, interim or any other rate decreases, that would take effect prior to the first billing

[3] For the purpose of this Agreement, "variable power plant O&M costs" includes non-fuel O&M expenses and costs for capital replacement parts that vary as a function of a power plant's output.

cycle for January 2017, except for any such reduction requested by FPL or as otherwise provided for in this Agreement. FPL shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraph 9 of this Agreement. FPL is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2017, nor are the Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2017, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this Agreement.

14. Nothing in this Agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the Term unless the application of such new or revised tariff or rate schedule is optional to FPL's customers.

15. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof; provided, however, that nothing in this Agreement shall affect FIPUG's right to continue its appeal of Order No. PSC-12-0187-FOF-EI granting an affirmative determination of need for the Port

Everglades Modernization Project or FPL's right to oppose that appeal. No party will assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value. Approval of this Agreement in its entirety will resolve all matters in Docket No. 120015-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes. This docket will be closed effective on the date the Commission Order approving this Agreement is final, and no Party shall seek appellate review of any order issued in these Dockets.

16. This Agreement is dated as of August 15, 2012. It may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party(ies) shall not disturb or diminish the benefits of this Agreement to any current Party.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

By:____________________
Eric E. Silagy

LEXSEE 1983 FLA PUC LEXIS 163

In re: Investigation of Fuel Adjustment Clauses of Electric Utilities

DOCKET NO. 830001-EU; **ORDER NO. 12645**

Florida Public Service Commission

1983 Fla. PUC LEXIS 163

83 FPSC 12

November 3, 1983; Partial Publication Only

CORE TERMS: fuel, staff, true-up, inventory, prudence, oil, coal, guidelines, procurement, generic, transportation, nonrecoverable, long-term, monthly, supplier, plant, expenditure, recommends, audit, tank, rate case, confidential, retroactive, expensed, reporting, subject to refund, ratepayer, normally, invoice, fuel oil

Matthew M. Childs, Esquire, 315 Calhoun Street, Tallahassee, Florida 32301, for Florida Power and Light Company.

C. Roger Vinson, Esquire, and Edison Holland, Esquire, Post Office Box 12950, Pensacola, Florida 32576, for Gulf Power Company.

Joseph A. McGlothlin, Esquire, Post Office Box 3350, Tampa, Florida 33601, The Florida Industrial Power Users Group.

Stephen Fogel, Esquire, Office of Public Counsel, Room 4, Holland Building, Tallahassee, Florida 32301, for the Citizens of the State of Florida.

Kent R. Putnam, Esquire, Post Office Box 1876, Tallahassee, Florida 32302, for Florida Public Utilities Company.

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Paul Sexton, Esquire, M. Robert Christ, Esquire and Charles L. Shelfer, Esquire, 101 East Gaines Street, Tallahassee, Florida 32301, for the Commission staff.

Prentice P. Pruitt, Esquire, Kathleen Villacorta, Esquire and Patrick K. Wiggins, Esquire, [*2] 101 East Gaines Street, Tallahassee, Florida 32301, Counsel to the Commissioners.

PANEL:

The following Commissioners participated in the disposition of this matter: Gerald L. Gunter, Chairman; Joseph P. Cresse, Susan W. Leisner, John R. Marks, III, Katie Nichols

OPINION: Pursuant to notice, a public hearing on the above matter was held before the Florida Public Service Commission on June 1, 2, 3 and 24, 1983, in Tallahassee, Florida.

ORDER CONCERNING GENERIC ISSUES

BY THE COMMISSION:

Background

During the June, 1983, true-up hearings certain "generic" issues were raised for consideration. The time alotted for hearing was insufficient and a second hearing on these issues was

Issues Presented

The following issues were raised in this proceeding: n1

1. Whether the Commission should require that all company inventory policies be supported and justified to the Commission's satisfaction by a comprehensive and systematic inventory study?

2. Whether or not a generic inventory policy should be adopted by the Commission on a standby basis and be applied by the Commission for ratemaking purposes in cases where a utility fails the justify an alternative inventory policy? [*3]

3. Whether fuel oil that cannot be burned for generation should be maintained in inventory and, if not, how should it be taken off the books.

4. Whether base coals that are nonrecoverable for operating purposes should remain a component of coal inventory?

5. When should a transfer of nonrecoverable base coal to Account 312 be effectuated and what ratemaking treatment should be used to recognize the transfer?

6. Should the Commission adopt specific standards for new long-term fuel contracts?

7. What, if any, should be the Commission standards for new long-term fuel contracts?

8. Should compliance with Commission standards be a prerequisite to recovery of new long-term fuel contract costs?

9. Whether affiliates and subsidiaries of utilities or utility holding companies engaged in procurement of fuel or services for a utility should be required to conduct such activities under the same standard as a utility would be required to meet had it purchased the same fuel or service.

10. Whether the Commission should require that all ulilities file a monthly report detailing all purchases of fuel, transportation and/or fuel handling services as proposed by staff.

11. Whether [*4] the proposed monthly reporting forms should be accorded specified confidential treatment.

12. Whether the Commission should change the operation of the clause to place a jurisdictional limitation on the review of prudence rather than treat prudence at the end of each six month period and explicitly make revenues subject to refund.

13. What is the Commission's current power to review expenditures during prior true-up periods?

14. What is the proper legal procedure for the Commission to adopt a conservation reward/penalty methodology and to grant a reward or impose a penalty?

15. Would the Commission deny due process if it were to grant conservation rewards or impose conservation penalties during the June true-up hearings.

16. Whether costs to be recovered by FPL should be calculated using the original or the current version of the rule. (This issue is being preserved pending appeal by Public Counsel)

17. Are net savings to be calculated on a monthly or six month basis? (This issue is being preserved pending a petition for reconsideration by Public Counsel)?

n1 These issues were commingled with other issues in the Prehearing Order (Order No. 11999) and are not numbered the same as in that order.

[*5]

Of these seventeen issues, the first twelve involve questions of fact and policy, while the last five involve questions of law.

Findings of Fact

Fuel Inventory Policies (Issues 1 and 2)

In recent rate cases we have reviewed the inventory policies of each of the four large generating utilities as part of our analysis of working capital requirements. Each utility's inventory policy effects the level of fuel held in inventory, which effects in turn the utility's working capital requirements under the balance sheet approach. In each case we encountered difficulties in analyzing each company's policy and in Order No. 11498 and we found that Gulf Power Company's inventory policy was not justified.

The staff has proposed that we require each utility to support and justify its inventory policy by a comprehensive and systematic study. The staff envisions a proceeding separate from a rate case wherein we would review the results of each utility's study and rule on the reasonableness of its inventory policy. FPL and FPC agree that further study of inventory policies is appropriate. TECO and Gulf, however, maintain that any review of inventory policy should fall within a [*6] rate case.

We agree that further study of fuel inventory policies is needed. However, we will not order special studies to be performed for approval separate from rate cases. Instead, we expect each utility to fully document its inventory policy in its next rate case.

The staff has proposed a "generic" fuel inventory policy to be applied in a rate case if a utility fails to fully justify its own policy. The staff's proposed policy is as follows:

1. Heavy Oil - 45 days projected burn plus normally unavailable oil.

2. Light Oil - 30 days burn at the lighest average monthly rate during the most current and five year period plus normally unavailable oil.

3. Coal - 90 days projected burn plus base coal volumes.

All other parties objected to the adoption of a generic policy. Each utility proposed that we rely on the record of each case to identify the proper inventory level if the utility's policy is not justified. Public Counsel also preferred a case-by-case analysis.

If a utility fails to justify its own inventory policy in a rate proceeding the Commission should have a generic policy available in order to evaluate the reasonableness of the dollar amount of inventory requested [*7] in working capital. The generic policy will not be used automatically in the event that the utility's policy is not justified, rather, we will strive to determine an optimum policy from the evidence presented in the rate case. If we cannot determine an optimum policy from the record, we would have the option of using the generic policy, or the generic policy modified by evidence of record. In such a case, the utility would be free to demonstrate that the generic policy would not provide acceptable inventory levels for its operation or the utility could build an alternative inventory based on the generic policy with modification to meet its operational requirements.

The generic policy recommended by staff is not represented to be the most optimal policy. Staff witness Foxx stated that it is not possible to create one generic inventory policy which is equally fair to all utilities. This is due to the differences in the system generating characteristics of the utilities.However, staff's proposed generic policy was shown to be reasonable by Mr. Foxx's testimony, which showed utility inventory levels throughout the nation in relation to burn levels.Although the levels specified [*8] by staff's generic policy are not equal to the national averages, we find the proposed generic policy to be reasonable. We therefore adopt the staff's proposed generic inventory policy for the purposes set forth above.

Nonrecoverable Oil (Issue 3)

Each utility that maintains an oil inventory holds a certain amount of "nonrecoverable oil" in inventory. The point of discharge in an oil storage tank is above the bottom, allowing water and sediment to fall below the level from which oil is pumped. Nonrecoverable oil represents the volume of oil below the discharge pipes at the bottom of oil storage tanks. This nonrecoverable oil typically contains a certain amount of noncombustible oil which must be processed before use as fuel oil. It also contains a certain amount of combustible oil, but this oil cannot be removed for use without special equipment.

The staff had originally proposed that each company estimate the amount of combustible oil when filling its tanks and expense that oil at the then current price of oil.The staff has modified that approach and now proposes that the value of all nonrecoverable oil below the discharge value be expensed at average unit cost at the [*9] next fuel adjustment true-up and thereafter expensed after each tank cleaning and refill at the then prevailing cost. FPL and TECO propose to retain all nonrecoverable oil in inventory and expense it out at tank cleaning. Public Counsel proposes that all nonrecoverable oil be removed from inventory and be amortized over the expected period between tank cleanings.

We find that the value of all heavy and light oil which normally resides in the storage tanks below the normal operating intake pipe and is normally unavailable should be expensed at the end of the next fuel adjustment true-up hearing. This oil should be expensed at the average unit cost of oil residing in the tanks on the day expensed. If a tank is emptied and refilled, the nonrecoverable oil should be expensed when the tank is refilled.

In recent rate cases nonavailable oil has been included in working capital for utilities and those utilities' rates currently allow a recovery on the investment in that nonrecoverable oil. If that oil is expensed off the utility should no longer receive a return on it. Therefore, when each utility calculates the expense of its nonrecoverable oil it should likewise calculate the revenue [*10] effect of removing that oil from rate base. The adjustment to the fuel adjustment clause to expense the oil would reflect the offset of the rate base reduction. After the nonrecoverable oil has been expensed through the fuel adjustment clause the clause would thereafter reflect an adjustment to recognize the rate base reduction until the utility's next rate case.

Base Coal (Issues 4 and 5)

Each coal pile maintained by a utility contains a certain amount of "base coal" used to support the pile. This coal is normally low grade coal and is not expected to be burned as part of normal utility operations. Except for TECO, this coal is maintained in inventory in spite of the fact that it is not expected to be burned. All parties (except FPL, which uses no coal) have agreed that base coal should be capitalized in Account 312 and depreciated over the life of the plant. TECO currently accounts for its base coal in this manner. We find that the proper treatment of investment in base coal is to capitalize it in account 312 as proposed. Normally, plant items such as base coal would be depreciated over the life of the plant to which it relates. However, we find that a [*11] shorter period of five years is more appropriate for the depreciation of base coal.

The staff proposes that we require the transfer of base coal to account 312 in the next true-up and allow recovery of depreciation through the fuel adjustment until each company's next rate case. FPC, Gulf and Public Counsel propose that no change occur until the next rate case. We agree with FPC, Gulf and Public Counsel. There is no need for extraordinary measures in correcting the accounting for base coal. A delay until each company's next rate case is appropriate.

Commission Standards for New Long Term Fuel Contracts (Issues 6-9)

The staff had proposed that we adopt specific detailed guidelines for new long-term contracts. The original staff proposal envisioned a set of specific guidelines that a utility should meet in obtaining new contracts. These guidelines would cover solicitation and negotiation of new contracts. FPL, FPC, TECO and GULF all opposed the adoption of detailed standards governing fuel contracts. Each expressed a concern that detailed standards would not be flexible enough to encompass all reasonable procurement decisions. In response to the positions of the other [*12] parties, the staff modified its proposal to involve a set of broad guidelines to be adopted by the Commission. More detailed guidelines would be approved for use by the staff, but would not be adopted for direct application by the Commission to each utility. We agree that we should adopt broad guidelines, as proposed by staff. Utilities will then be placed on notice as to the basic procurement standards we intend to apply.

We next must determine what broad guidelines should be adopted. The staff, in its final recommendation, broadened the standards that it has originally proposed. We view these revised standards as appropriate and adopt them as our central policy on new long term fuel contracts. The approved guidelines are set forth on Appendix A of this Order. These broad guidelines will be augmented by more specific guidelines that we will approve for internal staff use.

The staff proposed that compliance with the broadened guidelines be a prerequisite to cost recovery through the fuel adjustment. Again, the four utilities opposed the application of preset criteria as a condition for cost recovery. We find that compliance with our central guidelines should not be a prerequisite [*13] to fuel cost recovery. However, should a utility fail to comply with the our central guidelines it would have a special burden to show that non-compliance was justified.In addition, staff's detailed guidelines would be considered in any fuel adjustment proceeding where staff sought to apply them to utility's purchases. We would then formally determine whether compliance with staff's guidelines is also appropriate.

The staff has also proposed that our guidelines be applied to affiliates and subsidiaries of utilties or utility holding companies engaged in the procurement of fuel or services for a utility. Public Counsel agrees with the staff, stating that a utility should show that its affiliated companies are the most cost-effective providers of fuel and services.

We agree with the staff and Public Counsel. Given the broad standards that we have adopted, we consider it reasonable to expect purchases by affiliated companies for a utility to meet the same standards as purchases by the utility itself.

Monthly Fuel Reports (issues 10 and 11)

The staff has proposed that we reguire all utilities to file a monthly report detailing all purchases of fuel, transportation [*14] and fuel handling services and has recommended the form and content of the report.

FPL is willing to provide the information but suggests that guality adjustments need not be included because they are not made on an invoice by invoice basis. FPC has no objection to providing the information if we determine that the information cannot be adequately reviewed by our monthly field audits. TECO states that the requested information is being compiled and submitted at the audit staff's request. Gulf has no objection to filing the information, as long as it is done concurrently with the filing of FERC's Form 423. All of the utilities stressed the need to protect the confidentiality of information filed on the forms. Public Counsel supports the staff's proposed reporting forms.

We agree with the staff and Public Counsel that the information requested by the proposed forms is a valuable and useful tool in analyzing the prudence of utility fuel purchases and related transactions.We find that the information requested by staff should be provided on a monthly basis, to be filed with the Commission Clerk within 30 days after the end of the reporting month unless the utility demonstrates [*15] a need for an extension. The monthly reporting forms are to be completed on a plant specific and supplies specific basis.

The first form proposed by staff is the Coal Receipt Analysis form. One form would be completed for each plant. This form includes information on the delivered price and quality of coal received in each month from each supplier for each plant. The point of receipt is usually at a river loading facility or rail tipple where the coal is loaded into river barges or rail cars. Separate invoices from a given supplier may be combined into one entry if the coal was purchased under the same contract and invoiced at the same price. Any retroactive or quality adjustments known at the time of filing should be included in the appropriate columns. Retroactive and quality adjustments for coal from previous reporting periods would be attached as an addendum to this form which already documents the time period involved, the specific previously reported entries to revise, the revision (in total dollars and in dollars per ton) to each previously reported entry, and the nature or cause of the revision. If quality reports are not available at the time of filing, they would [*16] be updated in a similar fashion.

The second form proposed by staff is the Fuel Oil Receipt Analysis which reflects the invoice information of oil delivered to generating facilities or terminals. One form would be completed for each plant or terminal. One entry would be made for each supplier for each grade of fuel. Residual fuel oil of different sulfur grades must be reported separately.Multiple invoices may be reported as one entry so long as the above criteria are met. In the event multiple invoices are reported as one entry, the weighted average price would be reported. Retroactive price changes and quality adjustments would be reported as an attachment which documents the previously reported entry to revise, the nature of the revision, ad the revision in total dollars and dollars per barrel.

The third form proposed by staff is the Coal Rail Transportation Cost Analysis form which documents the rail transportation costs for coal shipped from each supplier to each plant. One form would be completed for each plant. Retroactive adjustments to this form would be reported in a similar manner as above. The entries would be on a date shipped basis.

The fourth form [*17] proposed by staff is the Coal Waterborne Transportation Cost Analysis form which documents the costs of the various components in the waterborne coal transportation network. One form would be completed for each plant. The entries would be on a date shipped basis. Retroactive adjustments would be made in a similar manner as the first two forms.

The staff proposed that retroactive revisions or adjustments to transactions previously reported would be included in the form of an addendum which would be specific enough in nature to enable the staff to revise the original filing of the form. The forms would be required to be filed in a timely manner. We find that the content of the forms proposed by the staff is reasonable and except for reformatting to isolate confidential material (see below), we approve the format of the forms as well.

Next, we must determine whether any portion of the monthly reports should be accorded confidential treatment. We agree that certain portions of the monthly reports will contain proprietary confidential business information. However, many portions of the monthly reports will not. The proprietary information for all types of fuel is transportation. [*18] Any breakout of transportation costs must be treated confidentially. In addition, F.O.B. mine prices for coal is proprietary in nature as is the price of fuel oil. Disclosure of separate transportation or F.O.B. mine prices would have a direct impact on a utility's future fuel and transportation contracts by informing potential bidders of current prices paid for services. Disclosure of fuel oil prices would have an indirect effect upon bidding suppliers. Suppliers would be reluctant to provide significant price concessions to an individual utility if prices were disclosed because other purchasers would seek similar concessions.

As proposed, staff's reporting forms commingle confidential and non confidential information.By segregating transportation and base fuel price information to separate parts of the form, confidential material can be separate from non confidential material. Revised forms to accomplish this purpose are shown on Appendix B of this order. Each utility participating in the fuel adjustment clause should file these forms monthly. Forms 423-1 and 423-2 would be public record. Forms 423-1(a), 423-2(a) and 423-2(b) would be confidential and exempt from public [*19] access.

Change in the Operation of the Fuel Adjustment Clause (Issue 12)

The staff has proposed that we change the operation of the fuel adjustment clause so as to clarify the nature of our jurisdiction over amounts passed through the clause. As proposed by the staff, this change is to be prospective in nature. We will discuss our jurisdiction over amounts previously passed through the clause as currently structured at a later point in this order.

As currently structured, the clause provides that utilities are to justify their expenditures at a true-up hearing immediately following each six month period. The staff proposed that we change the clause so that, instead of requiring proof of prudence at the true-up immediately following a six month period, we simply limit our jurisdiction over all transactions passed through the fuel clause for a period of three years from the date we approve the amount at the true-up hearing. Under the staff proposal, if before the end of the three year period the Commission indicates a need for further review for any specific transaction, the Commission would explicitly retain jurisdiction over amounts passed through the fuel clause [*20] relating to that transaction. The Commission may then continue jurisdiction over those amounts until a final order is issued. Once a specific transaction which has been explicitly set aside for review has been ruled upon by the Commission, the Commission would lose jurisdiction over that transaction for the period reviewed by the Commission. The above jurisdictional limitations would not apply for transactions when fraud or other such irregularities can be shown.

Each of the parties responded to the staff proposal in different ways.

FPL proposed that unless a utility has fraudulently or through error provided incorrect or incomplete information, or the amounts paid have changed due to litigation or dispute, Commission jurisdiction should cease after one year from the date of the transaction, unless the Commission identifies a problem and retains jurisdiction over a specific transaction.

FPC agreed that the current six month may not be adequate for proper review, but stated that the Commission may not lawfully extend its jurisdiction beyond a reasonably determined review period in order to provide a catch-all for the possibility that it may have overlooked something.

According [*21] to TECO, the Commission should first enter a provisional true-up order within sixty days of the end of the six month period under review. The Commission should then provide for a further true-up followed by a final order after a reasonable length of time. TECO submits that such final order should be entered within one year of the end of the six month period under review.

Gulf's position is that unless the Commission specifically reserves jurisdiction to allow further study of expenditures, jurisdiction lapses on approval of the true-up. The exception to this limitation of jurisdiction are instances of fraud or misrepresentations.

Public Counsel supported staff's approach.

The current structure of the clause creates two problems. First, although under the current clause prudence is to be reviewed at the true-up hearing after each six-month period, varying positions have been stated as to our jurisdiction to look at the prudence of transactions after a true-up order has been issued. Although we have now resolved the issue, a second problem was caused by our prior practice of identifying questionable transactions and placing the associated revenues subject to refund. In recent [*22] periods, utilities have preferred to stipulate to continuing jurisdiction rather than have their revenues explicitly made subject to refund. According to the utilities, making revenues subject to refund creates a financial uncertainty about those revenues, adversely affecting a utility's financial position.

The staff's proposal achieves two goals. It resolves all uncertainty as to our jurisdiction over amounts passed through the clause by explicitly retaining the power to review prior transactions. Thus, the complex factual and legal problem engendered by the structure of the current clause is avoided. It also obviates any desire or need to explicitly declare revenues subject to refund, as jurisdiction continues without question. The financial uncertainty that arises when revenues are declared subject to refund is avoided. We therefore agree with the staff's proposal that the operation of the clause should be changed.

Staff's proposal to place a time limit on our jurisdiction, however, is inappropriate. We see no justification in limiting our ability to scrutinize past transactions. We fully intend to review a utility's procurement decisions solely in light of the [*23] facts known or knowable at the time a decision was made. The appropriate limitation of our jurisdiction is based on whatever statute of limitations or other jurisdictional limitations applies to our actions as a matter of law.

Under the new structure, rather than explicitly considering prudence at the end of each six month period, we will consider only the question of comparing projected to actual results. Questions of prudence require careful and often prolonged study. When a question arises as to the prudence of a utility's expenditures, proper time should be taken to fully analyze the question and resolve the matter on all of the facts available. Often, a full staff analysis should be made before the matter is formally included within the fuel adjustment proceeding.

From now on, each utility will be required at true-up only to demonstrate how the amounts actually expended for fuel and purchased power compare with the amounts projected for the prior six month period. The true-up approved at that time will reflect the reconciliation of projected to actual results (with the appropriate calculation of interest, other true-up amounts, etc.). Although the burden of proving the [*24] prudence of its actions will remain with the utility, the question of prudence will arise only as facts regarding fuel procurement justify scrutiny. Hopefully, we will be presented with complete analyses of procurement decisions in a timely manner.

At the true-up hearing that follows a six month period a utility will still be free to present whatever evidence of prudence it chooses to provide. We note that certain utilities have periodically presented broad statements as to the prudence of their fuel procurement activities.Such prsentations are not inappropriate, but they hardly elucidate the subject matter. Fuel procurement is an exceedingly complex matter and a determination of the prudence of procurement decisions requires a complex analysis.

While a utility may feel satisfied that it has properly met its burden by such a presentation, we expect the quality and quantity of evidence to be presented in support of the prudence of fuel procurement decisions to match the complexity of the subject matter. We will therefore accept any relevant proof a utility chooses to present a true-up, but we will not adjudicate the question of prudence, nor consider ourselves bound to do so [*25] until all relevant facts are analyzed an placed before us. We will be free to revisit any transaction until we explicitly determine the matter to be fully and finally adjudicated.

Although this order is being issued after the true-up order for the October, 1982 - March 1983 period, the restructuring of the clause is effective as of that true-up hearing. Except for the delay engendered by an extended hearing on the generic issues, we would have decided this issue in conjunction with the final true-up decision for that period. Therefore, all fuel transactions, beginning October 1, 1982, are subject to the newly structured clause and Order No. 12172, the true-up order for the October, 1982 - March, 1983 period is the first true-up order under the new structure.

Future Rulemaking

Having resolved the above policy issues within an adjudicatory framework, we consider it appropriate to move toward rulemaking and codify our policy. The staff is directed to begin drafting rules to encompass the policy decisions made in this order.

Conclusions of Law

Review of Prior True-up Periods (Issue 13)

Periodically, we find it necessary to review the prudence of certain [*26] utility fuel procurement actions. Often the transactions in question extend into prior six-month periods. From time to time questions have arisen as to our authority to review transactions in prior true-up periods. We find it appropriate to fully resolve the issue at this time.

According to the staff, absent an allegation of prudence, evidence of record thereon and an order making a finding of prudence, the Commission may review expenditures made during prior true-up periods. According to staff, however, where a particular transaction has been called into question by the Commission, evidence in support of its reasonableness has been presented by the utility, and the expense has not been disallowed, the Commission should consider the prudence of that transaction to have been ruled on, even if the order did not make an explicit finding of prudence. In addition, the staff asserts that the nature of the six-month clause and the manner in which costs flow through the clause shows that a true-up order is not truly final as to prudence.

FPL, FPC, Gulf and TECO all assert that Commission jurisdiction over fuel transactions lapses at true-up unless the Commission explicitly reserves [*27] jurisdiction to allow further study.

Public Counsel's position is that the Commission may review any expenditure that has previously passed through the clause and disallow those costs that were imprudently incurred. According to Public Counsel, the utilities are relieved of regulatory lag by the operation of the clause and, in exchange, the Commission and ratepayers must have assurances that the costs collected are proper.

We conclude that the staff's view is proper. The question of whether we may review the prudence of expenditures made during prior true-up periods is governed by whether the prudence regarding of expenditures has been adjudicated. The issuance of a true-up order does not adjudicate the question of prudence per se. As pointed out by staff, the true-up hearings have never been relied upon by the Commission or any other party as the point at which prudence is actually reviewed. With rare exception, prudence has not been alleged, proven nor ruled upon during those proceedings. An actual adjudication of prudence depends on whether an allegation of prudence was made, evidence was presented thereon and a ruling made. Where an expenditure has been disputed and [*28] its prudence examined on the record, a ruling in favor of prudence should be inferred even if none is explicitly made.

This approach to jurisdiction over prior true-up periods naturally involves a review of the record of prior proceedings. Since several hearings are held each year, this process is necessarily complex. We will defer such a review until such time as we must face the question for a particular utility.

Staff is also correct in stating that the nature of the clause and the way costs are passed through it belies any finality to a true-up order. As stated in Order No. 11572, the effect of expenditures during any six month period extend beyond that period and utilities frequently pass retroactive price adjustments through the clause.

The nature of the fuel adjustment is continuous and the segregation of charges to fuel cost into 6-month periods is for ease of administration only.Indeed, fuel purchases in any one period will affect future periods, as fuel cost is charged on an "as burned" basis at weighted average inventory cost. Thus, instead of fuel costs collected in any one period reflecting only fuel purchased during that period, those costs reflect the [*29] weighted average cost of purchases during and prior to that period. In addition, it is quite common for utilities to receive retroactive adjustments to fuel price and transportation costs well after the close of the original transaction to which they relates.

Conservation Penalty/Reward (Issues 27 and 28)

Since we have declined to adopt any penalties or rewards at this time these issues are moot.

Proper Version of Oil Backout Rule (Issue 29)

Public Counsel has raised this issue in order to preserve its pending appeal. No ruling is necessary.

Calculation of Net Savings on Six-Month or Monthly Basis (Issue 30)

Public Counsel has raised this issue in order to preserve it pending a motion for reconsideration. No ruling is necessary.

Other Conclusions of Law

The findings of fact and policy decisions made in this order are supported by the weight of the evidence of record and are within the range of the discretion granted to the Commission by the legislature under Chapter 366, Florida Statutes.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the issues of fact and law set forth on pages 2 and 3 of this order be and [*30] the same are resolved as set forth in the body of this order. It is further

ORDERED that each electric utility seeking to recover the cost of fuel through the fuel adjustment clause shall file monthly reports in the form of Appendix B to this order, each report to be submitted within 30 days after the end of the reporting month.

By Order of the Florida Public Service Commission this 3rd day of November, 1983.

APPENDIX A

FLORIDA PUBLIC SERVICE COMMISSION FUEL PROCUREMENT POLICY

I. General

A. The Public Service Commission requires that all expense associated with the procurement of fuel, fuel related handling services and fuel transportation which are recovered through the Fuel Adjustment Clause be prudently incurred, result from competitive procurement procedures, be reasonably competitive in cost or value relative to what other buyers are paying under similar terms and conditions for fuel or services of comparable quality or specifications and result from sound administration of fuel supply agreements.

B. To accomplish the objectives expressed in (A), the Commission establishes the following guidelines that it recommends to electric utilities seeking fuel [*31] expense recovery through the Fuel Adjustment Clause. The Commission fully recognizes that differing fuel mixes and plant locations will necessarily result in vastly different fuel procurement strategies. However, the Commission also believes that there are certain fundamental, common procedures which, when employed, will result in the lowest, long run overall fuel expense to the companies and their ratepayers.

C. While the Commission believes that compliance with the guidelines expressed in this policy will achieve the lowest system fuel cost, the utility's management has sole responsibility to procure fuel in the most cost efficient manner possible and therefore it should have the flexibility to employ any means to achieve this result. In consideration of the above, departures from Commission policy are authorized when such departures can be justified and shown to be in the best interest of the utility and its ratepayers.

D. Departures from Commission policy which through Commission audit, investigation and hearing can be shown to have resulted in unjustified additional fuel expense are inappropriate for recovery through the Fuel Adjustment Clause and such expense will be [*32] disallowed.

E. If the Commission determines, based upon Staff audit and/or investigation, that a utility's unjustified departure from recommended Commission policy has resulted in unnecessary fuel expense, then the utility shall be required to apply credits against the clause or to make refunds to its customers.

F. The Commission's guidelines are intentionally broad to allow utility management the flexibility to tailor procurement procedures to fit a broad range of contingencies and adapt to changes in fuel markets.

G. The burden of proof rests solely with the utility to document the reasonableness of its procurement practices and the resultant expenses from such practices.

H. General overall compliance with Commission policy in no way removes the responsibility of a utility to justify and pay particular transaction the Commission may require the specifically justified.

II. Long-Term Agreements for Fuel, Fuel Handling Services, Fuel Transportation, Spot Purchases and Affiliate Transaction.

A. The Commission recommends that the majority of a utility's requirements for fuel, fuel handling services and/or transportation be procured under the terms of a long-term contract. [*33] Primary reliance upon long-term contracts will ensure that fuel or services will be available when required at reasonable, stable costs to the utility and its ratepayers.

B. The Commission recommends that, to the extent practicable, such long-term contracts be negotiated in a competitive environment. It is recommended that the primary method employed should be an open competitive bidding process or some comparable alternative which produces the same result.

C. All aspects of the procurement process employed in acquiring a long-term fuel or services supply contract should be documented and available to the Commission upon request.

D. Vendors should be selected on the basis of a formal evaluation system which is neutral in its application and capable of producing quantifiable ratings of individual suppliers. Considerations other than delivered price, fuel quality and vendor performance should be thoroughly documented.

E. The Commission recommends that all fuel agreements incorporate clear specification for the fuel or service to be provided and bonus/penalty provisions to ensure that the fuel or services contracted for are provided in accordance with contract terms.

F. [*34] The Commission recommends that the utility arrange for adequate fuel sampling techniques and equipment to be deployed at the point of receipt from the fuel supplier and the point of delivery, if different. Such a procedure will ensure that the quality of the fuel received at the unloading facility is consistent with that of the fuel as loaded, the invoiced priced and the contract specifications. To the extent possible, all such arrangements should be clearly written in the contract.

G. Utilities subject to the Commission's jurisdiction should not pay for or agree to pay for fuel or services at prices in excess of that dictated by the negotiated price terms of executed contracts existing between such utilities and providers of such fuel or services.

H. The Commission recommends that long term fuel or service contracts be based upon a base price plus well defined escalators, public tariffs or public postings unless a benefit to the ratepayer can be demonstrated by using some other pricing arrangement.

I. The Commission recommends that all utilities seek to incorporate a "right to audit" clause in any contract which utilizes escalators. The right to audit clause should give the [*35] utility the authority to audit specific records of the supplier.

J. The Commission recommends that all utilities enforce the right to audit through the annual use of its own audit staff or an independent accounting firm. Any refunds or adjustments due, as identified by audit, should be promptly resolved and credited to fuel expense.

K. The Commission recommends that any escalation methodology to be employed in a long-term contract be tied as closely as possible to actual changes in a suppliers verifiable costs.

L. The Commission recommends that all utilities seek to incorporate adequate well defined remedies in all long-term contracts for substandard quality performance unreliable volume or quality performance and unacceptable high price over protracted periods of time.

N. It is recommended that all contracts and the individual terms of each contract be reviewed and approved by the legal office of the utility.

O. All utility personnel having any interest in a particular firm seeking a long term fuel or services contract with a utility should be removed from any selection process, contract negotiation or administration of a contract with the firm. All personnel [*36] having any potential conflict of interest should be prevented from having any impact upon the contracting process.

P. All utility transaction with affiliated companies which provide fuel or fuel related services should be based on costs which are consistent with or lower than the costs a utility would incur if the utility received the fuel or services from an independent supplier in the competitive market obtained through competitive bidding.

Q. All spot transactions should be priced at, or below, the market price at the time of purchase and should not exceed the normal contract price for similar fuel or fuel related services unless required for reliability purposes.

R. The Commission expects, to the extent possible, that each utility utilize the terms of their long-term contracts relating to minimum and maximum volumes of fuel required to be delivered in order to take advantage of lower prices in the spot market when they exist.

S. The Commission expects that any utility which has a contract with an affiliated organization shall administer that contract in a manner identical to the administration of a contract with an independent organization.

T. Any fuel or fuel related [*37] transaction which does not meet the above criteria shall be denied recovery through the fuel clause by the Commission, unless the utility, which has the full burden of proof, can demonstrate that the transaction is in the best interest of the ratepayer.

In re: Cost Recovery Methods for Fuel-Related Expenses
DOCKET NO. 850001-EI-B; ORDER NO. 14546
Florida Public Service Commission
1985 Fla. PUC LEXIS 531
85 FPSC 67
July 8, 1985

PANEL:

The following Commissioners participated in the disposition of this matter: JOHN R. MARKS, Chairman; JOSEPH P. CRESSE, GERALD L. GUNTER

OPINION: 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.

APPENDIX A

FUEL COST RECOVERY COMPARISON

Expense Item	TECO Recovery Method	FPLL 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

In re: Review of investor-owned electric utilities' risk management policies and procedures.

DOCKET NO. 011605-EI; ORDER NO. PSC-02-1484-FOF-EI
Florida Public Service Commission
2002 Fla. PUC LEXIS 878
02 FPSC 10:400
October 30, 2002, Issued

DISPOSITION: [*1] ORDER APPROVING PROPOSED RESOLUTION OF ISSUES

OPINION: By Order No. PSC-01-1829-PCO-EI, issued September 11, 2001, issues were established for resolution at the November 20-21, 2001, hearing in Docket No. 010001-EI. On November 2, 2001, the Office of Public Counsel (OPC) filed a motion to defer consideration of several of the issues listed in that Order to allow the parties additional time to explore those issues. Those issues generally concerned risk management by investor-owned electric utilities (IOU) with respect to fuel procurement. By Order No. PSC-01-2273-PHO-EI, issued November 19, 2001, OPC's motion was granted. This docket was opened November 26, 2001, for the purpose of addressing the deferred issues, and an evidentiary, administrative hearing was scheduled in this docket for August 12-13, 2002.

Two of the issues deferred for consideration in this docket were resolved by proposed agency action which, because no request for hearing was filed, became final and effective. (Order Nos. PSC-02-0793-PAA-EI and PSC-02-0919-PAA-EI) As to all of the issues remaining for hearing, the parties engaged in settlement discussions. At the start of the administrative hearing scheduled in this docket, [*2] we were presented with a Proposed Resolution of Issues which was intended to resolve all issues that remained for hearing in this docket. The Proposed Resolution of Issues, attached hereto as Attachment A and incorporated herein by reference, was signed and supported by Florida Power Corporation, Florida Power & Light Company, Tampa Electric Company, the Florida Industrial Power Users Group, and OPC.

Based on a modification made in discussions at the start of the hearing, Gulf Power Company agreed to the Proposed Resolution of Issues. That modification amended the first sentence in paragraph 6 of the Proposed Resolution of Issues to include Gulf Power Company and amended the second sentence in paragraph 6 to read as follows: "No party to this docket shall seek approval of a hedging incentive program earlier than six months after the projection filing for the 2003 fuel and purchased power cost recovery period."

We find that the Proposed Resolution of Issues, modified as set forth above, provides a reasonable resolution of all issues in the docket. The Proposed Resolution of Issues establishes a framework and direction for the Commission and the parties to follow with respect to risk [*3] management for fuel procurement. It provides for the filing of information in the form of risk management plans and as part of each IOU's final true-up filing in the fuel and purchased power cost recovery docket, which will allow the Commission and the parties to monitor each IOU's practices and transactions in this area. In addition, it maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Further, the Proposed Resolution of Issues appears to remove disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs. For these reasons, we approve the attached Proposed Resolution of Issues, as modified above.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission [*4] that the Proposed Resolution of Issues, attached hereto as Attachment A and incorporated herein by reference, and modified as set forth in the body of this Order, is hereby approved to resolve all outstanding issues in this docket. It is further

ORDERED that this docket shall be closed.

By ORDER of the Florida Public Service Commission this 30th day of October, 2002.

BLANCA S. BAYO, Director

Division of the Commission Clerk and Administrative Services

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 060001-EI ORDER NO. PSC-06-1057-FOF-EI ISSUED: December 22, 2006

The following Commissioners participated in the disposition of this matter:

LISA POLAK EDGAR, Chairman
J. TERRY DEASON
ISILIO ARRIAGA
MATTHEW M. CARTER II
KATRINA J. TEW

APPEARANCES:

R. WADE LITCHFIELD, ESQUIRE, and JOHN T. BUTLER, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408
On behalf of Florida Power & Light Company (FPL).

NORMAN H. HORTON, JR., ESQUIRE, Messer, Caparello & Self, P. A., P. O. Box 15579, Tallahassee, Florida 32317
On behalf of Florida Public Utilities Company (FPUC).

JEFFREY A. STONE, ESQUIRE, RUSSELL A. BADDERS, ESQUIRE, and STEVEN R. GRIFFIN, ESQUIRE, Beggs & Lane, P. O. Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF).

R. ALEXANDER GLENN, ESQUIRE, and JOHN T. BURNETT, ESQUIRE, Progress Energy Service Company, LLC, 100 Central Avenue, St. Petersburg, Florida 33701-3323
On behalf of Progress Energy Florida, Inc. (PEF).

JAMES D. BEASLEY, ESQUIRE, and LEE L. WILLIS, ESQUIRE, Ausley & McMullen, P. O. Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

MICHAEL B. TWOMEY, SR., ESQUIRE, P. O. Box 5256, Tallahassee, Florida 32314-5256
On behalf of AARP (AARP).

DAMUND E. WILLIAMS, CAPTAIN, KAREN WHITE, LIEUTENANT COLONEL, AFLSA/JACL-ULT, 139 Barnes Drive, Suite 1, Tyndall Air Force Base, FL 32403-5319
On behalf of Federal Executive Agencies, (FEA).

JOHN W. MCWHIRTER, JR., ESQUIRE, McWhirter, Reeves & Davidson, P. A., 400 North Tampa Street, Suite 2450, Tampa, Florida 33601-3350
On behalf of Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT, ESQUIRE and JOHN T. LAVIA, III, ESQUIRE, Young van Assenderp, P. A., 225 South Adams Street, Suite 200, Tallahassee, Florida 32301
On behalf of Florida Retail Federation (FRF).

JAMES W. BREW, ESQUIRE, Brickfield, Burchette, Ritts & Stone, P. C., 1025 Thomas Jefferson Street, NW, Eighth Floor, West Tower, Washington, D.C. 20007-5201
On behalf of White Springs Agricultural Chemicals, Inc., d/b/a PCS Phosphate White Springs (White Springs).

CHARLES J. CRIST, JR., ESQUIRE, JACK SHREVE, ESQUIRE, and CECILIA BRADLEY, ESQUIRE, Office of the Attorney General, The Capitol – PL01, Tallahassee, Florida 32399-1050
On behalf of the Citizens of Florida (AG).

PATRICIA A. CHRISTENSEN, ESQUIRE, JOSEPH A. MCGLOTHLIN, ESQUIRE, and CHARLES J. BECK, ESQUIRE, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

LISA C. BENNETT, ESQUIRE, and WM. COCHRAN KEATING, IV, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS' AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

As part of this Commission's continuing fuel and purchased power cost recovery and generating performance incentive factor proceedings, a hearing was held on November 6-8, 2006, in this docket, and continued to December 8, 2006. The hearing addressed the issues set out in Order No. PSC-06-0920-PHO-EI, issued November 2, 2006, in this docket (Prehearing Order). Several of the positions on these issues were stipulated or not contested by the parties and presented to us for approval, but some contested issues remained for our consideration. As set forth fully below, we approve each of the stipulated and uncontested positions presented. Our rulings on the remaining issues are also discussed below.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

I. GENERIC FUEL COST RECOVERY ISSUES

A. Shareholder Incentive Benchmarks

The parties stipulated that the actual benchmark levels for calendar year 2006 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI are as follows:

FPL: $19,136,028
GULF: $3,546,453
PEF: $5,626,264
TECO: $787,027

We approve this stipulation as reasonable.

The parties also stipulated that the estimated benchmark levels for the calendar year 2007 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI are as follows:

FPL: $19,849,221
GULF: $3,092,606
PEF: $3,005,206
TECO: $946,443

We approve this stipulation as reasonable.

B. Over or Under Recovery Calculations and Notifications.

The parties stipulated that an informal meeting to discuss the correct methodology for calculating over and under recoveries of projected fuel costs pursuant to Order No. 13694, issued September 20, 1984, in Docket No. 840001-EI, and Order No. PSC-98-0691-EI, issued May 19, 1998, in Docket No 980269-PU, be held between all parties to this proceeding and Commission staff. Once that meeting has been conducted, the Commission staff will bring a proposed agency action recommendation to this Commission for our consideration. Included in the informal meeting and subsequent discussion will be a recommendation on the appropriate timing of notification to the Commission for costs which are more than 10% over or under the utility's projections. We approve this stipulation as reasonable.

C. Appropriate Credits for Emissions Allowances for 2005, 2006, 2007

The parties stipulated that the appropriate credits for emissions allowances for power sales for each investor owned utility for the years 2005 through 2007 are as follows:

FPL: For power sales reported on Schedule A6, all related emission allowances shall be reported separately from other fuel expenses in the future and made available to our staff upon request.

GULF: 2005 $10,229,597
2006 $19,580,767 (Jan-Jul. actual; Aug.-Dec. estimated)
2007 $29,645,000 (Projected)

PEF: For power sales reported on Schedule A6, all related emission allowances shall be reported separately from other fuel expenses in the future and made available to our staff upon request.

TECO: 2005 $6,593
2006 $35,443
2007 $40,100

We approve this stipulation as reasonable.

II. COMPANY-SPECIFIC FUEL COST RECOVERY ISSUES

A. Progress Energy Florida

Hedging Activities for Years 2005 through 2007

By Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, this Commission authorized the recovery of hedging costs by investor owned electric utilities. The purpose of the resolution which was adopted by the order was to manage price volatility of fuel and purchased power for each investor owned utility. While allowing recovery of prudently incurred hedging costs and incremental operation and maintenance expenses associated with hedging, the Commission reserved its ability to review those costs annually during the fuel hearing.

In accordance with Order No. PSC-02-1484-FOF-EI, Progress submitted its risk management plan and its hedging costs. Mr. Joseph McAllister and Javier Portuondo presented testimony that PEF executes physical and financial natural gas hedging in accordance with the

Company's approved natural gas hedging strategy. PEF has in the past and will continue to utilize physical fixed price agreements and financial products, including fixed price swaps and options to hedge natural gas prices. PEF also hedges, using financial products, the prices it pays for residual oil. PEF's hedging activities, according to the testimony presented, has produced customer savings of approximately $87.7 million for its purchases of natural gas and heavy oil for 2006.

In its prehearing statement and in its opening statement, FIPUG argued that insufficient evidence of customer benefit had been presented in light of the fact that the utilities' 2006 fuel costs passed through to customers exceeded market price. According to FIPUG, it was seeking to understand each utility's plans on a going forward basis to show how customer's benefit from the hedging plans. According to FIPUG, fuel volatility is already avoided by annualizing fuel costs in the annual fuel proceedings and there needs to be some proof that the hedging programs are working. Counsel for FIPUG extensively cross-examined Javier Portuondo for Progress. The witness concluded that PEF's hedging program was successful because it met the objective, to minimize price volatility and create stability for its customers.

After evaluating the exhibits and testimony filed by PEF, staff recommended that the Commission find that Progress, through its hedging activities, has adequately mitigated the price risk for natural gas, residual and purchased power through September 1, 2006. Staff summarized that each utility presented testimony that the objective of the hedging programs is to minimize price volatility, and that prices are uncertain and volatile, particularly for natural gas, so there will be periods when the companies have hedging gains and other periods where the companies will have hedging losses. Staff also found that the utilities follow risk management plans to avoid speculation. Staff's belief is that minimizing price volatility produces customer benefits.

Based upon the evidence in the record, we agree with staff that Progress has adequately mitigated the price risk for natural gas, residual oil, and purchased power through September 1, 2006. We are of the opinion that the purpose of Order No. PSC-02-1484-FOF-EI continues to be viable. Reducing price volatility by participating in hedging programs continues to be a benefit to customers. We will continue to monitor each utilities' hedging and risk management policies.

B. Florida Power and Light

Hedging Activities for Years 2005 through 2007

In accordance with Order No. PSC-02-1484-FOF-EI, FPL also submitted its risk management plan and hedging costs. FPL witness Gerard Yupp testified that FPL's policy of maintaining price stability and avoiding volatility was met by its hedging and risk management plans.

After evaluating the exhibits and testimony filed by FPL, staff recommended that the Commission find that FPL has adequately mitigated the price risk for natural gas, residual and purchased power through September 1, 2006. Based upon the evidence in the record, we agree with staff that FPL has adequately mitigated the price risk for natural gas, residual oil and purchased power through September 1, 2006, for the same reasons identified above for Progress. We will continue to monitor each utility's hedging and risk management policies.

Southeast Supply Header Pipeline

FPL requested that the Commission approve recovery of its costs associated with its proposed participation in the Southeast Supply Header Pipeline (SESH) through the fuel clause. FPL testified that the costs are all gas transportation costs which are recoverable by Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B. The main goal for the project is supply reliability. The project will connect FPL to two new supply basins in east Texas and north Louisiana. It is appropriate to diversify by supply basin and to pick up additional supply basins given the current dependence by Florida utilities on the Gulf of Mexico and Mobile Bay area for supply, because those two areas are showing a decline in production. There is an additional cost to get the gas from Texas and Louisiana down to Mobile Bay, but there is also a potential for savings in that SESH may reduce the premium FPL now pays for gas in the Mobile Bay area by bringing in more supply and hence more competition.

An additional reason for this project is to meet new demand. The project will come on-line in 2008. FPL will have increased demand for natural gas beginning in 2007 and continuing through 2010. FPL did consider alternatives to this project such as liquefied natural gas and other pipelines, and after deliberation, chose SESH as its best alternative.

Although FPL presented its Precedent Agreement to give evidence of the costs associated with its participation in the SESH project, we note that we are not being asked to affirm or approve the contract. The costs associated with FPL's participation in the SESH project will come to us each year during our annual fuel adjustment proceeding and will be subject to audits and true-ups similar to the audits and true-ups of our ongoing annual review of Gulfstream and FGT transportation costs. In addition, the administration of the contract and all costs associated with the SESH project will be subject to a prudence review by us. We retain our jurisdiction to review the prudence for all costs that come before us, whether they are associated with participation in this pipeline project or other such project.

Based upon our review of the evidence in the record, and the fact that historically, transportation costs for natural gas have been eligible for cost recovery through the fuel clause, there is nothing in this record to indicate that FPL's participation in the SESH project is not a wise or strategic move. By making this finding, we specifically retain our oversight of the administration of the contract and the recovery of all costs associated with participation in the project for review annually during the fuel clause hearings and any subsequent review for prudence. Thus, we approve the costs associated with FPL's participation in the Southeast Supply Header Pipeline project as appropriate for recovery through the fuel cost-recovery clause beginning in 2008, subject to the oversight discussed above.

Fuel Savings Associated with Turkey Point Unit 5

In May 2007, FPL will bring on line a new generating unit known as Turkey Point Unit 5, which is a gas-fired generating unit that will operate very efficiently compared to other FPL gas-fired generating units. The record demonstrates that there will be 2007 fuel savings in the amount of $73,493,954, associated with the commencement of commercial operation of Turkey Point Unit 5, with the anticipated in-service date of May 2007. Based on the evidence in the record, we find that FPL's calculation of $73,493,954 in fuel savings for FPL's customers from May through December 2007 is reasonable, with the understanding that the fuel savings are subject to audit and true-up through the normal course of our fuel and purchased power cost recovery clause proceedings. We find that these fuel savings are properly credited to FPL customers in the 2007 fuel factors, as discussed below.

<u>Levelization of Bills for 2007 Caused by Fuel Savings Associated with Turkey Point Unit 5</u>

Construction of the new generating unit, Turkey Point Unit 5, was the subject of a prior base rate proceeding involving FPL. During that proceeding, FPL entered into a stipulation with intervenors providing for an adjustment to FPL's base rates upon commencement of commercial operation of Turkey Point Unit 5. In Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, we approved the stipulation. As stated above, Turkey Point Unit 5 will be commercially operational in May 2007, and accordingly, the generation base rate adjustment (GBRA) will go into effect. FPL proposed to levelize the residential 1000 kWh bill by offsetting GBRA with fuel savings attributable to the new Turkey Point Unit 5 generation facility as well as a portion of fuel savings attributable to the overall reduction in 2007 fuel costs. The purpose of levelization is to provide all customer classes with a more stable bill in 2007. If we did not approve FPL's levelization proposal, bills would decrease in January 2007. Then, in May 2007, when Turkey Point Unit 5 begins commercial operations, the GBRA would become effective and would result in an increase in base rates and thus customer bills.

FPL's current 1000 kWh residential bill is $108.61. Absent FPL's proposal to levelize the bill, the bill would decrease to $102.61 in January 2007 as a result of the lower fuel costs, and increase in May 2007 to $103.89, as a result of the GBRA increase in base rates. Under FPL's proposal to levelize bills, the 1000 kWh residential bill for January through December 2007 will be $103.51.

Under the standard methodology to calculate fuel factors for a 12-month period, fuel costs, including savings, are levelized over the projected 12 month period, resulting in a levelized fuel factor for 12 months. However, in order to offset the impact of the GBRA on customer bills from May through December 2007, FPL proposed one set of fuel factors for January through April 2007 and a different set of fuel factors for May through December 2007. Only the May through December fuel factors include the fuel savings of the new unit. The May through December factors also include some additional fuel savings attributable to the overall reduction in 2007 fuel costs. The May through December fuel factors are lower than the January through April fuel factors under FPL's proposal. The lower May through December fuel factors are designed to offset the increase in GBRA.

We are reluctant to deviate from the standard methodology of levelizing fuel costs over the full 12-month period, but we also believe that, in this particular instance, the price stability offered by FPL's proposal would send customers a more consistent price signal through 2007. Based on the evidence in the record, we find that in this instance FPL's proposal to levelize the 1000 kWh residential bill by offsetting GBRA with fuel savings is appropriate.

Additional Fuel Cost Incurred for Turkey Point Unit 3 Outage

FPL, OPC, and our staff stipulated that the additional fuel cost incurred as a result of the outage extension at Turkey Point Unit 3 in March and April 2006 was $6,163,000. Based on the evidence in the record, we agree.

While FPL and OPC agreed to the dollar amount of the costs associated with the extended outage, they did not agree on the recovery of the amount. OPC raised an issue in this docket regarding the prudence of the additional fuel costs associated with the outage extension at Turkey Point Unit 3. FPL requested that the issue be heard at a later date because the cause of the outage is still subject to criminal investigation by the FBI and other agencies. FPL stated it has been requested by the investigating agencies not to disclose the results of the investigation. Because of this request, it would be difficult to hold hearings on the facts associated with the on-going investigation. The prehearing officer agreed and so ordered. In the meantime, FPL requested that it be allowed to recover the additional fuel cost of the Turkey Point Unit 3 outage beginning in 2007, subject to refund with interest, if the Commission were to subsequently determine that the outage was due to imprudence on the part of FPL. OPC urged the Commission to disallow the costs associated with the outage and if the Commission were to later deem them prudent, FPL could collect the costs (including interest) from ratepayers in 2008. The parties presented the Commission with legal argument in support of their positions. Upon review of the arguments presented, we determine that FPL shall be allowed to recover the costs, subject to refund with interest, if the costs are deemed imprudent by us. We are mindful that if recovery is postponed, there is a possibility that customers will pay interest to FPL. Thus, the additional fuel cost incurred as a result of the outage extension at Turkey Point Unit 3 in March and April 2006 of $6,163,000 shall be recovered by FPL in 2007, subject to interest, with a prudence review by us in a subsequent fuel proceeding.

C. Florida Public Utilities

Prudence of Purchased Power Contracts

FPUC has a purchased power contract with Jacksonville Electric Authority (JEA) to serve customers in its Fernandina Beach Division, and a purchased power contract with Gulf Power Company (GULF) to serve customers in its Marianna Division. Both contracts were scheduled to expire at the end of 2007, and FPUC hired consultant Robert Camfield to assist in obtaining new, favorable, long-term contracts. As Mr. Camfield testified at the hearing, FPUC began its search for replacement contracts in 2005. Mr. Camfield testified about the steps FPUC took to procure a reasonable replacement contracts. In 2005, FPUC began looking for the replacement contracts. It conducted a request for proposal (RFP) process but the successful bidder was not able to serve the Fernandina Beach Division because of transmission constraints. After determining that transmission constraints required a different provider, FPUC negotiated a new contract with JEA for the Fernandina Beach Division. The new contract is an embedded cost agreement and commences January 1, 2007, thus terminating the existing contract one year early. The benefit to the early termination is a more favorable long-term, ten year contract with JEA. According to the testimony, the contract with GULF for the Marianna Division will remain in effect until the end of December 2007. Although, FPUC is currently negotiating a new long-term contract with GULF, the 2007 purchased power prices for the Marianna Division will still be governed by the existing contract with GULF.

FPUC has asked this Commission to determine that the costs associated with its purchased power contracts for both its Fernandina Beach and Marianna Divisions are reasonable and prudent for 2007. Based on the evidence in the record, we find that FPUC's purchased power costs for Marianna and Fernandina Beach, as proposed for recovery in its 2007 fuel factors and as reflected in its purchased power agreements are prudent and reasonable for 2007.

D. Gulf

Hedging Activities for Years 2005 through 2007

In accordance with Order No. PSC-02-1484-FOF-EI, GULF submitted its risk management plan and its hedging costs. Witness H. R. Ball testified that GULF's hedging policy is a benefit to the customer because it helps avoid extreme price increases. The benefits must be looked at on a long term basis. Mr. Ball also testified that GULF has presented proof that the hedging program has saved its customers' money in the past and is a proven benefit to GULF customers. GULF has protected its customers from large price increases and expects to do so in the future.

After evaluating the exhibits and testimony filed by GULF, staff recommended that the Commission find that GULF has adequately mitigated the price risk for natural gas, residual and purchased power through September 1, 2006. Based upon the evidence in the record, for the same reasons identified for FPL and Progress, we find that GULF has adequately mitigated the price risk for natural gas, residual oil and purchased power through September 1, 2006. We will continue to monitor each utilities hedging and risk management policies.

Operation and Maintenance Expenses for Hedging for 2007

Prior to the hearing, our staff agreed with GULF concerning the utility's total fuel clause projected recovery request for 2007. However, during cross examination by FIPUG, we learned that GULF included in its request, $98,402 in incremental operation and maintenance expenses for hedging for the year 2007. Thus, our staff recommended an adjustment be made to exclude GULF's incremental operation and maintenance expenses from GULF's fuel factors for 2007.

Staff's recommendation was based on its reading of Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605, which staff believes prohibits recovery of any hedging-related operation and maintenance expenses after December 31, 2006.

Based on the recommendation of staff that operation and maintenance expenses are not recoverable under Order No. PSC-02-1484-FOF-EI, we disallow the recovery of 2007 operation and maintenance expenses for hedging, but we specifically reserve the right to hear evidence from GULF and other interested parties regarding the reinstatement of the disallowed costs in the next year's fuel proceeding. We are concerned that this issue was not raised sufficiently to allow all viewpoints to be expressed and to allow evidence to be taken and, accordingly will, if brought before us in 2007, hear testimony and arguments in support of recovery and after consideration, may reinstate recovery of those costs.

E. <u>Tampa Electric Company</u>

<u>Hedging Activities for Years 2005 through 2007</u>

In accordance with Order No. PSC-02-1484-FOF-EI, TECO also submitted its risk management plan and its hedging costs. Witness Joann Wehle testified that TECO's policy of maintaining price stability and avoiding volatility was implemented through its hedging and risk management plans.

After evaluating the exhibits and testimony filed by TECO, our staff recommended that the Commission find that TECO has adequately mitigated the price risk for natural gas, residual and purchased power through September 1, 2006. Based upon the evidence in the record, for the same reasons identified for the other utilities, we agree with staff that TECO has adequately mitigated the price risk for natural gas, residual oil and purchased power through September 1, 2006. We will continue to monitor each utilities hedging and risk management policies.

III. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL COST RECOVERY FACTORS

Based on the evidence in the record, we approve the following as the appropriate final fuel adjustment true-up amounts for the period of January 2005 through December 2005:

<u>FPL:</u>	$307,437,600 under-recovery.	
<u>FPUC:</u>	Marianna:	$53,882 under-recovery
	Fernandina Beach:	$153,867 under-recovery
<u>GULF:</u>	$20,174,117 under-recovery.	
<u>PEF:</u>	$385,055 under-recovery.	
<u>TECO:</u>	$106,516,837 under-recovery.	

Based on the evidence in the record, we approve the following as the appropriate estimated/actual fuel adjustment true-up amounts for the period of January 2006 through December 2006:

FPL:	$216,430,642 over-recovery	
FPUC:	Marianna:	$262,709 under-recovery
	Fernandina Beach:	$738,815 under-recovery
GULF:	$26,505,347 under-recovery.	
PEF:	$46,865,312 over-recovery.	
TECO:	$51,260,142 under-recovery.	

Based on the evidence in the record, we approve the following as the appropriate fuel adjustment true-up amounts to be collected/refunded from January 2007 through December 2007:

FPL:	$91,006,958 under-recovery	
FPUC:	Marianna:	$316,591 under-recovery.
	Fernandina Beach:	$892,682 under-recovery.
GULF:	$46,679,464 under-recovery.	
PEF:	$46,480,257 over-recovery	
TECO:	$157,776,979 under-recovery.	

Based on the evidence in the record and stipulation of the parties we approve the following as the appropriate revenue tax factors to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2007 through December 2007:

1.00072 for each investor-owned electric utility.

Based on the evidence in the record, we approve the following as the appropriate projected net fuel and purchased power cost recovery amounts to be included in the fuel cost recovery factors for the period January 2007 through December 2007:

FPL:	$6,106,351,832	
FPUC:	Marianna:	$13,920,307
	Fernandina Beach:	$$22,203,752
GULF:	$454,168,401	
PROGRESS:	$2,095,303,822	
TECO:	$1,177,662,727	

Based on the evidence in the record and the resolution of the generic and company–specific fuel cost recovery issues discussed above, we approve the following as the appropriate levelized fuel cost recovery factors for the period January 2007 through December 2007:

FPL:	5.763 cents/kWh for January through April 2007; and 5.638 cents/ kWh for May through December 2007.	
GULF:	3.938 cents/kWh	
FPUC:	Marianna:	2.709¢/kwh

	Fernandina Beach: 3.412¢/kwh
PEF:	5.132 cents per kWh
TECO:	5.897 cents per kWh

Based on the evidence in the record and stipulation of/ the parties, we approve the following as the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class:

FPL: JANUARY 2007 – DECEMBER 2007 –

GROUP	RATE SCHEDULE	LINE LOSS MULTIPLIER
A	RS-1 first 1,000 kWh All additional kWh	1.00194 1.00194
A	GS-1,SL-2, GSCU-1	1.00194
A-1*	SL-1,OL-1,PL-1	1.00194
B	GSD-1	1.00187
C	GSLD-1 & CS-1	1.00077
D	GSLD-2,CS-2,OS-2 & MET	.99464
E	GSLD-3 & CS-3	.95644
	TIME OF USE RATES	
A	RST-1,GST-1 ON-PEAK OFF-PEAK	 1.00194 1.00194
B	GSDT-1,CILC-1(G),HLTF(21-499 kW) ON-PEAK OFF-PEAK	 1.00187 1.00187
C	GSLDT-1 & CST-1, HLTF(500-1,999 kW) ON-PEAK OFF-PEAK	 1.00077 1.00077
D	GSLDT-2 & CST-2, HLTF (2,000+ kW) ON-PEAK OFF-PEAK	 .99571 .99571
E	GSLDT-3,CST-3 CILC-1(T)&ISST-1(T) ON-PEAK OFF-PEAK	 .95644 .95644
F	CILC-1(D) & ISST-1(D) ON-PEAK	 .99298

	OFF-PEAK	.99298
* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK		

FPUC: Marianna: 1.0000 - All Rate Schedules
Fernandina Beach: 1.0000 - All Rate Schedules

GULF:

GROUP	RATE SCHEDULE	LINE LOSS MULTIPLIER
A	RS, RSVP, GS, GSD, GSDT, GSTOU, SBS(1), OSIII	1.00526
B	LP, LPT, SBS(2)	0.98890
C	PX, PXT, RTP, SBS(3)	0.98063
D	OSI/II	1.00529

PEF:

Group	Delivery Voltage Level	Line Loss Multiplier
A.	Transmission	0.9800
B.	Distribution Primary	0.9900
C.	Distribution Secondary	1.0000
D.	Lighting Service	1.0000

TECO:

Rate Schedule	Fuel Recovery Loss Multiplier
RS, GS and TS	1.0042
RST and GST	1.0042
SL-2, OL-1 and OL-3	N/A
GSD, GSLD, and SBF	1.0004
GSDT, GSLDT, and SBFT	1.0004
IS-1, IS-3, SBI-1, SBI-3	0.9742
IST-1, IST-3, SBIT-1, SBIT-3	0.9742

Based on the evidence in the record and the resolution of the generic and company-specific fuel cost recovery issues discussed above, we approve the following as the appropriate fuel recovery factors for each rate class/delivery voltage level class adjusted for line losses:

FPL:

JANUARY 2007 – APRIL 2007

GROUP	RATE SCHEDULE	FUEL RECOVERY FACTOR
		(¢/kWh)
A	RS-1 first 1,000 kWh All additional kWh	5.420 6.420
A	GS-1,SL-2, GSCU-1	5.774
A-1*	SL-1,OL-1,PL-1	5.634
B	GSD-1	5.774
C	GSLD-1 & CS-1	5.768
D	GSLD-2,CS-2,OS-2 & MET	5.732
E	GSLD-3 & CS-3	5.512
A	RST-1,GST-1 ON-PEAK OFF-PEAK	 6.422 5.484
B	GSDT-1,CILC-1(G),HLFT(21-499 kW) ON-PEAK OFF-PEAK	 6.422 5.484
C	GSLDT-1 & CST-1, HLFT(500-1,999 kW) ON-PEAK OFF-PEAK	 6.415 5.478
D	GSLDT-2, CST-2, HLFT (2,000+ kW) ON-PEAK OFF-PEAK	 6.383 5.450
E	GSLDT-3,CST-3 CILC-1(T)&ISST-1(T) ON-PEAK OFF-PEAK	 6.131 5.235

F	CILC-1(D) & ISST-1(D) ON-PEAK OFF-PEAK	 6.365 5.435
*WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK		

MAY 2007 – DECEMBER 2007

GROUP	RATE SCHEDULE	FUEL RECOVERY FACTOR
		(¢/kWh)
A	RS-1 first 1,000 kWh All additional kWh	5.295 6.295
A	GS-1,SL-2, GSCU-1	5.649
A-1*	SL-1,OL-1,PL-1	5.510
B	GSD-1	5.649
C	GSLD-1 & CS-1	5.643
D	GSLD-2,CS-2,OS-2 & MET	5.608
E	GSLD-3 & CS-3	5.393
A	RST-1,GST-1 ON-PEAK OFF-PEAK	 6.297 5.359
B	GSDT-1,CILC-1(G),HLFT(21-499 kW) ON-PEAK OFF-PEAK	 6.297 5.359
C	GSLDT-1 & CST-1, HLFT(500-1,999 kW) ON-PEAK OFF-PEAK	 6.290 5.353
D	GSLDT-2 & CST-2, HLFT (2,000+ kW) ON-PEAK OFF-PEAK	 6.258 5.326
E	GSLDT-3,CST-3 CILC-1(T)&ISST-1(T) ON-PEAK OFF-PEAK	 6.011 5.116

F	CILC-1(D) & ISST-1(D) ON-PEAK OFF-PEAK	 6.241 5.311
*WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK		

SEASONAL DEMAND TIME OF USE RIDER (SDTR)
FUEL RECOVERY FACTORS

ON PEAK: JUNE 2007 THROUGH SEPTEMBER 2007 – WEEKDAYS 3:00 PM TO 6:00 PM
OFF PEAK: ALL OTHER HOURS

(1) GROUP	(2) OTHERWISE APPLICABLE RATE SCHEDULE	(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1 ON-PEAK OFF-PEAK	 6.175 5.468	 1.00187 1.00187	 6.186 5.478
C	GSLD(T)-1 ON-PEAK OFF-PEAK	 6.175 5.468	 1.00077 1.00077	 6.180 5.472
D	GSLD(T)-2 ON-PEAK OFF-PEAK	 6.175 5.468	 0.99571 0.99571	 6.148 5.444

Note: All other months served under the otherwise applicable rate schedule.

FPUC: **Marianna:**

Rate Schedule	Fuel Recovery Factor per kWh
RS	$.04420
GS	$.04366
GSD	$.04177
GSLD	$.04001
OL	$.03447
SL	$.03463

Fernandina Beach:

Rate Schedule	Fuel Recovery Factor per kWh
RS	$.05170
GS	$.05056
GSD	$.04812
GSLD	$.04850
OL	$.03684
SL	$.03697

GULF: See table below:

GROUP	RATE SCHEDULE*	FUEL RECOVERY FACTOR(¢/KWH)
A	RS, RSVP, GS, GSD, GSDT, GSTOU, OSIII, SBS(1)	Standard – 3.959 On-Peak – 4.414 Off-Peak – 3.773
B	LP, LPT, SBS(2)	Standard – 3.894 On-Peak – 4.342 Off-Peak –3.712
C	PX, PXT, RTP, SBS(3)	Standard – 3.862 On-Peak – 4.306 Off-Peak – 3.681
D	OSI/II	Standard – 3.937 On-Peak – N/A Off-Peak – N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499KW will use the recovery factor applicable to Rate Schedule GSD;(2) customers with a contract demand in the range of 500 to 7,499KW will use the recovery factor applicable to Rate Schedule LP; and (3) customers with a contract demand over 7,499KW will use the recovery factor applicable to Rate Schedule PX.

PEF:

Fuel Cost Factors (cents/kWh)

					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factor	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	5.036	7.358	3.968
B	Distribution Primary	--	--	5.088	7.434	4.009
C	Distribution Secondary	4.798	5.798	5.139	7.508	4.050
D	Lighting	--	--	4.696	--	--

TECO: The appropriate factors are as follows:

Rate Schedule	Fuel Charge Factor (cents per kWh)
RS, GS and TS	5.922
RST and GST	7.392 (on-peak)
	5.146 (off-peak)
SL-2, OL-1 and OL-3	5.483
GSD, GSLD, and SBF	5.899
GSDT, GSLDT and SBFT	7.364 (on-peak)
	5.126 (off-peak)
IS-1, IS-3, SBI-1, SBI-3	5.745
IST-1, IST-3, SBIT-1, SBIT-3	7.171 (on-peak)
	4.992 (off-peak)

IV. GENERIC CAPACITY COST RECOVERY ISSUES

Credits for Transmission Allowances

The parties did not contest that the appropriate credits for transmissions allowances for power sales for each investor-owned utility for the years 2005 through 2007 were as follows:

FPL: 2005: $3,299,310.
2006: $3,701,913; (actuals through June; July-Dec. estimated)
2007: $3,941,588
GULF: 2005: $200,008
2006: $203,633 (Jan-Jul. actual; Aug-Dec. estimated)
2007: $275,000
PEF: 2005: 348,286
2006: 332,333
2007: 260,281

TECO	2005:	$279,560
	2006:	$665,187
	2007:	$511,000

Based on the evidence in the record , we approve these amounts as reasonable.

V. COMPANY SPECIFIC CAPACITY COST RECOVERY ISSUES

A. PROGRESS ENERGY FLORIDA

Incremental Security Costs

The parties did not contest that PEF's incremental security costs as proposed in its 2007 projection filing are reasonable for capacity cost recovery purposes. Based on the evidence in the record, the amount of $3,235,933 for 2007 is approved as reasonable.

B. FLORIDA POWER AND LIGHT

Generation Base Rate Adjustment for Turkey Point Unit 5

The parties did not contest FPL's proposal to approve the Generation Base Rate Adjustment for Turkey Point Unit 5. Upon review of discovery and the record presented at the hearing, staff recommended that the appropriate Generation Based Rate Adjustment factor is 3.271% to be applied as an equal percentage to base charges and non-clause recoverable credits. Based on the evidence in the record , we approve this factor as reasonable.

Incremental Security Costs

The parties did not contest FPL's proposal to approve incremental security costs projected for 2007 as reasonable for cost recovery purposes. FPL proposed to recover a total of $30,442,387 for 2007, which includes $2,796,363 for security costs associated with the recently issued North American Reliability Council's Cyber Security Standards. Based on the evidence in the record, we approve those projected costs as reasonable for recovery through the capacity cost recovery clause.

CILC-1 Load Control Demands

The Federal Executive Agency (FEA) proposed that CILC-1 load control demands should not be included in developing FPL's capacity cost recovery factors. The CILC rate is an optional nonfirm rate for commercial/industrial customers who agree to let FPL control or interrupt at least a portion of the customer's load during periods of capacity shortage. In return for taking service under a nonfirm rate, CILC customers receive an incentive or a/discount in their base rates. Those incentives are recovered from all ratepayers through the conservation cost recovery clause. Customers have the option to install backup generation, but it is not a requirement to take service under this rate.

FEA's witness, Dr. Goins, proposed that the demand-related production costs for FPL's CILC customers be excluded in the calculation of the capacity cost recovery factors because CILC customers do not cause FPL to incur demand-related purchased power costs. Dr. Goins also testified that FEA customers spend millions to install backup generation.

FPL witness, Dr. Morley, testified that FEA's proposal is unfair and inconsistent with Commission rules. The magnitude of the discount for nonfirm service must meet the requirements of Rule 25-6.0438, F.A.C., one of which is a determination of cost-effectiveness. Cost effective means that the benefits to the ratepayers must exceed the cost to the ratepayers.

CILC customers are compensated for any interruptions through discounted base rate charges that reflect the avoided cost benefits that these nonfirm customers provide to the rate payers. Rule 25-6.0438 requires that nonfirm load be maintained at cost-effective levels. FPL's most recent cost-effectiveness analysis as provided in response to FEA's first set of interrogatories, shows a benefit-cost ratio for the CILC rate of 1.02. Dr. Morley testified that a benefit-cost ratio close to 1 means that the rate is only marginally cost-effective.

The non-CILC ratepayer is already paying for the CILC base rate incentive. If the demands of the CILC customers were excluded in calculating the capacity cost recovery factors, this additional discount of $16.3 million would also be recovered from the remaining ratepayers, including residential customers, further reducing the cost-benefit ratio because there is no corresponding increase in benefits.

The purpose of the capacity clause is to allow the utility to recover the capacity component of purchased power costs. In order to supply the least cost power to all customers, nonutility generation is purchased when it is less costly than power generated by the utility. Dr. Morley stated that these transactions take place to serve all load, including CILC customers.

Based on the evidence presented in the record, we find that it is appropriate to continue to include the full demand responsibility of FPL's CILC customers in determining the appropriate factors. The capacity cost factors as established for FPL shall remain unchanged.

VI. APPROPRIATE PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

Based on the evidence in the record and the resolution of the company-specific capacity cost recovery issues discussed above, we approve the following final capacity cost recovery true-up amounts for the period January 2005 through December 2005:

FPL:	$3,305,688 over- recovery
GULF:	$112,632 over-recovery
PEF:	$581,276 under-recovery
TECO:	$156,806 under-recovery

Based on the evidence in the record and the resolution of the company-specific capacity cost recovery issues discussed above, we approve the following estimated/actual capacity cost recovery true-up amounts for the period January 2006 through December 2006:

FPL:	$18,215,446 under-recovery
GULF:	$223,116 under recovery
PEF:	$4,799,289 under recovery
TECO:	$804,145 under-recovery

Based on the evidence in the record and the resolution of the company specific capacity cost recovery issues discussed above, we approve the following total capacity cost recovery true-up amounts to be collected/refunded during the period January 2007 through December 2007:

FPL:	$14,909,758 under-recovery
GULF:	$110,484 under-recovery
PEF:	$5,380,565 under recovery
TECO:	$960,951 under-recovery

Based on the evidence in the record and the resolution of the generic and company-specific capacity cost recovery issues discussed above, we approve the following projected net purchased power and cost recovery amounts to be included in the recovery factor for the period January 2007 through December 2007:

FPL:	$591,052,906
GULF:	$31,663,132
PEF:	$393,207,153
TECO:	$53,038,052

Based on the evidence in the record and stipulation of the parties, we approve the following jurisdictional separation factors to be applied to determine the capacity costs to be recovered during the period January 2007 through December 2007:

FPL:	FPSC 98.68536%
GULF:	96.64872%
PEF:	Base 93.753% Intermediate 79.046% Peaking 88.979%
TECO:	0.9666743%

Based on the evidence in the record and the resolution of the generic and company-specific capacity cost recovery issues discussed above, we approve the following projected capacity cost recovery factors for each rate class/delivery class for the period January 2007 through December 2007:

FPL:

RATE SCHEDULE	CAPACITY RECOVERY FACTOR ($/KW)	CAPACITY RECOVERY FACTOR ($/KWH)
RS1/RST1	-	.00557
GS1/GST1	-	.00521
GSD1/GSDT1/HLFT(21-499 kW)	1.58	-
OS2	-	.00330
GSLD1/GSLDT1/CS1/CST1/HLFT(500-1,999 kW)	1.96	-
GSLD2/GSLDT2/CS2/CST2/HLFT(2,000+ kW)	1.91	-
GSLD3/GSLDT3/CS3/CST3	1.90	-
CILCD/CILCG	2.09	-
CILCT	2.01	-
MET	2.00	-
OL1/SL1/PL1	-	.00085
SL2, GSCU1	-	.00360
RATE CLASS	CAPACITY RECOVERY FACTOR (RESERVATION DEMAND CHARGE) ($/kW)	CAPACITY RECOVERY FACTOR (SUM OF DAILY DEMAND CHARGE) ($/kW)
ISST1D	.25	.12
ISST1T	.24	.11

RATE SCHEDULE	.CAPACITY RECOVERY FACTOR ($/KW)	CAPACITY RECOVERY FACTOR ($/KWH)
SST1T	.24	.11
SST1D1/SST1D2 /SST1D3	.25	.12

GULF: See table below:

RATE CLASS	CAPACITY COST RECOVERY FACTORS ¢/KWH
RS, RSVP	0.311
GS	0.301
GSD, GSDT, GSTOU	0.267
LP, LPT	0.231
PX, PXT, RTP, SBS	0.193
OS-I/II	0.133
OSIII	0.200

PEF:

Rate Class	CCR Factor
Residential	1.132 cents/kWh
General Service Non-Demand	0.958 cents/kWh
@ Primary Voltage	0.948 cents/kWh
@ Transmission Voltage	0.939 cents/kWh

General Service 100% Load Factor	0.656 cents/kWh
General Service Demand	0.808 cents/kWh
@ Primary Voltage	0.800 cents/kWh
@ Transmission Voltage	0.792 cents/kWh
Curtailable	0.583 cents/kWh
@ Primary Voltage	0.577 cents/kWh
@ Transmission Voltage	0.571 cents/kWh
Interruptible	0.692 cents/kWh
@ Primary Voltage	0.685 cents/kWh
@ Transmission Voltage	0.678 cents/kWh
Lighting	0.161 cents/kWh

TECO:

Rate Schedule	Capacity Cost Recovery Factor (cents per kWh)
RS	0.325
GS, TS	0.311
GSD	0.261
GSLD, SBF	0.222
IS-1, IS-3, SBI-1, SBI-3	0.020
SL-2, OL-1 and OL-3	0.042

VII. GENERATING PERFORMANCE INCENTIVE FACTOR (GPIF) ISSUES

The parties stipulated that the appropriate Generation Performance Incentive Factor (GPIF) rewards/penalties for performance achieved during the period January 2005 through December 2005 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

The parties stipulated that the appropriate GPIF targets/ranges for the period January 2007 through December 2007 are those set forth in Attachment A to this Order, which is incorporated by reference herein. We approve these stipulations as reasonable.

OPC raised two additional issues regarding an amendment to the current GPIF manual. OPC requested and we granted an opportunity to brief the issues regarding whether the Commission should incorporate a "dead band" around the scale of Generating Performance Incentive Points and whether that "dead band," if adopted, should be applied for the current year so that rewards or penalties are applied to the period commencing January 1, 2007. We agreed to allow the parties to further brief this issue and accordingly our decision on these two issues will be the subject of a separate order.

VII. OTHER MATTERS

The parties stipulated that for FPUC, GULF, PEF, and TECO, the new fuel adjustment charges and capacity cost recovery factors approved in this Order should be effective beginning with the first billing cycle for January 2007 and thereafter through the last billing cycle for December 2007. The parties also stipulated that for FPUC, GULF, PEF, and TECO the first billing cycle may start before January 1, 2007, and the last billing cycle may end after December 31, 2007, so long as each customer is billed for 12 months regardless of when the factors became effective. We approve these stipulations as reasonable.

The parties stipulated as to FPL that the new Fuel Cost Recovery factors for January through April 2007 and May through December 2007 should become effective during those periods, respectively. There will be four months of billing on the January through April factor and eight months of billing on the May through December factor, thus providing for a total of 12 months of billing on the new Fuel Cost Recovery factors for all customers. We approve these stipulations as reasonable.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations and finding set forth in the body of this Order are hereby approved. It is further

ORDERED that Florida Power and Light Company, Progress Energy Florida, Inc., Tampa Electric Company, GULF Power Company and Florida Public Utilities Company are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2007 through December 2007. It is further

ORDERED the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power and Light Company, Progress Energy Florida, Inc., Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2007 through December 2007. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up, and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based.

By ORDER of the Florida Public Service Commission this 22nd day of December, 2006.

/s/ Blanca S. Bayó
BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

This is a facsimile copy. Go to the Commission's Web site, http://www.floridapsc.com or fax a request to 1-850-413-7118, for a copy of the order with signature.

(S E A L)

LCB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance 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.

ATTACHMENT A

2005 GPIF Rewards and Penalties

Utility		Reward/Penalty
Florida Power & Light Co.	$8,478,098$	Reward
Gulf Power Co.	- 842,874	Penalty
Progress Energy Florida	-1,547,048	Penalty
Tampa Electric Co.	-99,791	Penalty

ATTACHMENT A
PAGE 2 of 3

FPL:

Equivalent Availability and Heat Rate/NOF 2007 Targets for FPL Units

Unit	FPL EAF/POF/EUOF Targets			FPL HR/NOF Targets
	EAF	POF	EUOF	
Ft. Myers 2	78.9	12.2	8.9	6,814 / 85.9
Lauderdale 4	82.6	13.4	4.0	7,650 / 85.1
Lauderdale 5	92.2	3.8	4.0	7,548 / 88.9
Manatee 1	86.6	7.7	5.7	10,220 /66.2
Martin 1	94.6	0.0	5.4	10,027 / 65.2
Martin 4	94.0	0.0	6.0	6,926 / 95.6
Sanford 4	90.2	5.8	4.0	6,878 /89.2
Sanford 5	91.3	1.9	6.8	6,844 / 90.0
Scherer 4	96.0	0.0	4.0	10,136 / 92.5
St. Lucie 1	84.0	9.6	6.4	10,961 / 97.6
St. Lucie 2	70.3	23.3	6.4	11,002 / 97.4
Turkey Point 3	84.2	8.2	7.6	11,112 / 97.6
Turkey Point 4	90.7	0.0	9.3	11,120 / 97.5

GULF:

Equivalent Availability and Heat Rate/NOF 2007 Targets for Gulf Power Co. Units

Unit	Gulf EAF/POF/EUOF Targets			Gulf HR/NOF Targets
	EAF	POF	EUOF	
Crist 4	98.3	0.0	1.7	10,545 / 99.0
Crist 5	97.1	0.0	2.9	10,422 / 99.2
Crist 6	85.3	8.2	6.5	10,258 / 99.2
Crist 7	83.5	3.3	13.2	10,225 / 99.4
Smith 1	78.6	19.7	1.7	10,259 / 99.6
Smith 2	89.4	0.0	10.6	10,328 / 99.4
Daniel 1	82.5	13.4	4.0	10,046 / 98.8
Daniel 2	93.9	1.9	4.2	9,834 / 99.2

Note: NOF is not used for target setting for GULF.

ATTACHMENT A
PAGE 3 of 3

PEF:

Equivalent Availability and Heat Rate/NOF 2007 Targets for PEF Units

Unit	PEF EAF/POF/EUOF Targets			PEF HR/NOF Targets
	EAF	POF	EUOF	
Anclote 1	90.02	5.75	4.23	10,073 / 51.9
Anclote 2	89.80	5.75	4.45	10,205 / 45.3
Bartow 3	88.38	5.75	5.87	10,311 / 51.2
Crystal River 1	84.46	9.59	5.95	10,195 / 78.8
Crystal River 2	72.99	15.34	11.67	9,766 / 80.3
Crystal River 3	86.86	9.86	3.27	10,304/ 98.4
Crystal River 4	94.10	0.00	5.90	9,421 / 93.0
Crystal River 5	91.95	2.47	5.59	9,445 / 92.9
Hines 1	84.77	11.51	3.72	7,363 / 79.7
Tiger Bay	86.82	9.59	3.59	8,024 / 82.9

Equivalent Availability and Heat Rate/NOF 2007 Targets for Tampa Electric Co. Units

Unit	TEC EAF/POF/EUOF Targets			TEC HR/NOF Targets
	EAF	POF	EUOF	
Big Bend 1	60.7	3.5	35.5	10,971 / 71.1
Big Bend 2	76.5	5.8	17.7	10,484 / 83.8
Big Bend 3	57.4	8.5	34.2	11,090 / 64.2
Big Bend 4	59.5	24.4	16.1	10,828 / 82.6
Polk 1	88.4	3.3	8.4	10,428 / 85.8
Bayside 1	81.0	9.6	9.4	7,378 / 84.7

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor

DOCKET NO. 080001-EI; ORDER NO. PSC-08-0667-PAA-EI

Florida Public Service Commission

2008 Fla. PUC LEXIS 501

08 FPSC 10:130

October 8, 2008, Issued

PANEL: [*1] The following Commissioners participated in the disposition of this matter: MATTHEW M. CARTER II, Chairman; LISA POLAK EDGAR; KATRINA J. McMURRIAN; NANCY ARGENZIANO; NATHAN A. SKOP

OPINION: NOTICE OF PROPOSED AGENCY ACTION ORDER CLARIFYING HEDGING ORDER AND PROVIDING GUIDELINES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule *25-22.029, Florida Administrative Code.*

Background

Our current policy regarding risk management and the hedging of fuel prices is embodied in Order No. PSC-02-1484-FOF-EI (the Hedging Order), issued October 30, 2002, in Docket No. 011605-EI, In re: Review of investor-owned electric utilities' risk management Policies and procedures. The Hedging Order approved a settlement, referred to as the Proposed Resolution of Issues, which established a framework and direction to follow with respect to risk management of fuel procurement by the four largest investor-owned electric utilities (IOUs). [*2] The settlement was entered into by Florida Power & Light Company (FPL or Company), Florida Power Corporation (now Progress Energy Florida, Inc., or PEF), Tampa Electric Company (TECO), the Florida Industrial Power Users Group (FIPUG), and the Office of Public Counsel (OPC). Gulf Power Company (Gulf) agreed to the settlement at the hearing based upon a modification made during the August 12, 2002, hearing. The Hedging Order states:

> It [the Proposed Resolution of Issues] provides for the filing of information in the form of risk management plans and as part of each IOU's final true-up filing in the fuel and purchased power cost recovery docket, which will allow the Commission and the parties to monitor each IOU's practices and transactions in this area. In addition, it maintains flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Further, the Proposed Resolution of Issues appears to remove the disincentives that may currently exist for IOUs to engage [*3] in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and

losses, and incremental operating and maintenance expenses associated with new and expanded hedging programs.

Hedging Order, p. 2.

Following the issuance of the Hedging Order, each of the four largest IOUs developed financial hedging programs. Each IOU now hedges significant portions of their natural gas and/or residual oil purchases. No proposals to modify the terms of the Hedging Order were filed until FPL filed its petition requesting approval of its improved volatility mitigation mechanism (VMM) or its VMM alternative at the beginning of 2008.

We initiated two separate audits of the IOUs' hedging programs following the conclusion of the 2007 fuel adjustment hearing, but prior to FPL's filing of its petition on the VMM. The Commission's Division of Competitive Markets and Enforcement (CMP) conducted a hedging review (Staff Management Audit, or management audit) which involved an assessment of the IOUs' fuel hedging program costs and benefits realized since the issuance of the Hedging Order. The financial Division of Regulatory [*4] Compliance and Consumer Assistance (RCA) conducted an audit of the accounting treatment and results of each IOU's 2007 hedging activities for consistency with each IOU's 2007 hedging plan filed in 2006. The RCA audit was completed on May 5, 2008, and the CMP review was completed in June 2008.

On January 31, 2008, FPL filed a petition requesting that we approve its proposed VMM as an alternative to FPL's financial and physical fuel price hedging programs. The VMM proposal involved FPL collecting under-recoveries of unhedged fuel costs over two years, instead of one year as is the current practice. FPL intended that if the combined final true-up and actual/estimated true-up amounts in any year's fuel proceeding reflects an under-recovery, half of that under-recovery would be collected in the projected year and the remaining half would be collected in the year following the projected year. The Company proposed VMM as a method of achieving our objective of mitigating fuel price volatility while avoiding certain hedging disadvantages. FPL argued that such disadvantages include uncertainty introduced by the uneven reaction shown by certain stakeholders during periods when FPL incurs losses [*5] in its hedging program compared to when FPL achieves gains in its program. FPL was also concerned about the regulatory risk it alleged may be associated with the deferral of prudence determinations of hedging losses, as occurred at the November 2007 fuel adjustment hearing (Order No. PSC-08-0030-FOF-EI, issued January 8, 2008, in Docket No. 070001-EI, In re: Fuel and purchased Dower cost recovery clause with generating performance incentive factor.). Had we approved FPL's VMM petition, FPL would have sought express assurances of recovery and recognition that the Company is prudent in its decision to not acquire physical or financial hedges to mitigate fuel price volatility.

In the alternative, if we determined not to approve the VMM as proposed, FPL requested two changes to the current hedging approach. First, FPL requested that we reduce the uncertainty associated with the current hedging program by approving a set of general and specific hedging guidelines set forth by FPL (see Exhibit 3 of the VMM petition). Secondly, the Company proposed that FPL's regulatory risk be reduced by requiring our staff to conduct reviews of hedging results monthly. FPL made this second request [*6] so that we would be in a position to rule on the prudence of FPL's hedging results at the fuel hearing in November of each year for the twelve months ending September 30th of that year.

Our staff filed a recommendation on April 14, 2008, and recommended that we deny FPL's petition and alternative position, in part because it would be premature to make a decision before our review of the results of ongoing hedging audits by RCA and CMP. FPL concurred with our staff that a decision by us of FPL's petition would be premature, and FPL suggested in a post-recommendation letter that a workshop be held to consider improvements to our hedging process.

At the April 22, 2008, Agenda Conference, we considered FPL's VMM Petition. By Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor, we clarified the Hedging Order. Specifically, we decided that the period of review for utility hedging transactions will be through July 31 of the current year. We will determine the prudence of hedging transactions at the annual fuel clause hearing, typically held every year in November. [*7] To facilitate this review, the four largest IOUs are required to file current year hedging results by August 15. The IOUs are required to provide the same hedging information required in Section 5 of the "Proposed Resolution of Issues" in the Hedging Order. We also decided to defer Issues 2 and 3 of our staff's recommendation regarding the VMM issue and the alternative to the VMM issue to a later time so that the hedging audits underway at the time could be completed and reviewed, and so that we could have the benefit of the information gathered at an informal workshop.

Subsequently, our staff and the parties held two workshops regarding FPL's petition. At the June 9, 2008, workshop, FPL proposed revised hedging guidelines and indicated it now favored pursuing guidelines rather than the VMM. OPC took a position during the workshops that the VMM needed to be more fully analyzed by all four large IOUs as a possible alternative to hedging. At the June 24, 2008, workshop, OPC indicated its objection to portions of the proposed guidelines. The meeting concluded with an understanding that ongoing discussion among the parties would attempt to resolve whether hedging activity contributes to [*8] fuel factor volatility reduction and whether the guidelines as proposed by FPL were acceptable to all parties.

On August 5, 2008, FPL filed its petition for leave to withdraw its January 31, 2008, VMM petition and alternative. With its petition to withdraw, FPL filed a new petition for approval of its proposed hedging guidelines. FPL indicates in its new petition that it proposes the guidelines in response to the asymmetric reactions of certain stakeholders to gains and losses. FPL states that its guidelines are designed to mitigate against this asymmetry by reaffirming and clarifying our support for hedging as an appropriate means of managing the impacts of fuel price volatility. FPL indicated PEF, TECO, and GULF supported the proposed guidelines. Our staff issued a set of data requests regarding FPL's August petition, and all responses were timely filed. In addition, our staff conducted a telephonic meeting with parties on August 27, 2008, to consider FPL's petition. At the meeting, PEF, TECO, and GULF expressed support for the guidelines, but also indicated that they were not proposing the guidelines. OPC indicated it was not ready to stipulate to FPL's proposed hedging guidelines. [*9] Based on our staff comments at the meeting, FPL made several revisions and provided its changes to the guidelines to all parties on August 29, 2008, after confirming PEF, GULF, and TECO's support for the changes.

We have jurisdiction pursuant to *Sections 366.04*, *366.041*, and *366.05, Florida Statutes.*

Voluntary Withdrawal of VMM Petition and Alternative

FPL has requested that it be permitted to withdraw its Improved Volatility Mitigation Mechanism Petition and Alternative that was filed by FPL on January 28, 2008. The law is clear that a plaintiff's right to take a voluntary dismissal is absolute. *Fears v. Lunsford, 314 So.2d 578, 579 (Fla. 1975).* It is also established civil law that once a timely voluntary dismissal is taken, the trial court loses its jurisdiction to act and cannot revive the original action for any reason. *Randle-Eastern Ambulance Service, Inc. v. Vasta, 360 So.2d 68, 69 (Fla. 1978).* Both of these legal principles have been recognized in administrative proceedings. n1 In *Saddlebrook Resorts, Inc. v. Wiregrass Ranch, Inc., 630 So.2d 1123, 1128 (Fla. 2d DCA 1993),* [*10] the court concluded that "the jurisdiction of any agency is activated when the permit application is filed . . . [and] is only lost by the agency when the permit is issued or denied or when the permit applicant withdraws its application prior to completion of the fact-fording process."

n1 *Orange County v. Debra, Inc., 451 So. 2d 868 (Fla. 1st DCA 1983); City of Bradenton v. Amerifirst Development Corporation, 582 So, 2d 166 (Fla. 2d DCA 1991); Saddlebrook Resorts, Inc. v. Wiregrass Ranch. Inc., 630 So. 2d 1123 (Fla. 2d DCA 1993)* aff'd, *645 So. 2d 374 (Fla. 1994).*

In this case, we deferred our decision regarding the petition pending receipt of additional audit information. We had not reached our final decision on FPL's VMM petition. Thus, FPL can dismiss its petition as a matter of right. This is consistent with our past decisions. n2 Accordingly, we approve FPL's voluntary withdrawal of its VMM [*11] petition.

n2 See Order No. PSC-07-0725-FOF-EU, issued September 5, 2007, in Docket No. 060635-EU, In re: Petition for determination of need for electrical power plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and City of Tallahassee; Order No. PSC-07-0877-FOF-EI, issued October 31, 2007, in Docket No. 070467-EI, In re: Petition to determine need for Polk Unit 6 electrical power plant, by Tampa Electric Co.; Order No. PSC-07-0485-FOF-EI, issued June 8, 2007, in Docket Nos. 050890-E1, In re: Complaint of Sears, Roebuck and Company against Florida Power & Light Company and motion to compel FPL to continue electric service and to cease and desist demands for deposit pending final decision regarding complaint and 050891-EI, In re: Complaint of Kmart Corporation against Florida Power & Light Company and motion to compel FPL to continue electric service and to cease and desist demands for deposit pending final decision regarding complaint; Order No. PSC-94-0310-FOF-EQ, issued March 17, 1994, in Docket No. 920977-EQ, In re: Petition for approval of contract for the purchase of firm capacity and energy from General

Peat Resources, L.P. and Florida Power and Light Company; Order No. PSC-97-0319-FOF-EQ, issued March 24, 1997, in Docket No. 920978-EQ, In re: Complaint of Skyway Power Corporation to require Florida Power Corporation to furnish avoided cost data pursuant to Commission Rule *25-17.0832(7), F.A.C.*; Order No. PSC-04-0376-FOF-EU, issued April 7, 2004, in Docket No. 011333-EU, In re: Petition of City of Bartow to modify territorial agreement or, in the alternative, to resolve territorial dispute with Tampa Electric Company in Polk County. But see Order No. PSC-07-0297-FOF-SU, issued April 9, 2007, in Docket No. 020640-SU, In re: Application for certificate to provide wastewater service in Lee County by Gistro, Inc. and Order No. PSC-96-0992-FOF-WS, issued August 5, 1996, in Docket No. 950758-WS, In Re: Petition for approval of transfer of facilities of Harbor Utilities Company, Inc., to Bonita Springs Utilities and cancellation of Certificates Nos. 272-W and 215-S in Lee County (voluntary dismissal cannot be utilized to divest the Commission as an adjudicatory agency of its jurisdiction granted to it by the legislature)

[*12]

Although the effect of the withdrawal of a petition is to divest the agency of jurisdiction over the petition, it does not divest the agency of subject matter jurisdiction. We retain the discretion to review our hedging policy and make changes after affording all stakeholders the appropriate due process.

FPL's Proposed Guidelines

FPL's proposed guidelines are the result of meetings with our staff and parties to the fuel docket after the April 22, 2008, Agenda Conference. FPL's purpose in proposing these guidelines is to reaffirm and clarify our support for hedging as an appropriate means of managing the impacts of fuel price volatility. FPL seeks this reaffirmation of the Commission's support based on its observation that the reaction of certain stakeholders to hedging results has been asymmetric. FPL states in its petition that "[s]upport for hedging has generally been strong during periods of rising fuel prices, when hedging programs are showing gains, but has waned when prices are falling and hedging programs are showing losses." FPL Petition, p. 3.

FPL believes this "observed asymmetry" can increase the perceived financial (regulatory) risk for IOUs and could increase their [*13] cost of capital. FPL believes the proposed guidelines will reduce regulatory risk.

Section I

The proposed guidelines clarify the timing of our annual review of utility hedging programs. The Hedging Order requires the four IOUs to file hedging/risk management plans but does not require such plans to be approved by this Commission. The proposed guidelines would have us approve each utility's risk management plan in advance. For example, in 2008, we would approve utility risk management plans that would describe hedging activities during 2009, affecting activities during 2009 and subsequent years. The risk management plans will be filed in early August with the Estimated/Actual Testimony filing.

The approved risk management plans will be the basis for our review of the performance of utility hedging programs. Under the guidelines, a utility's plan may deviate from one or more of the guiding principles set forth in Section IV, therefore allowing a utility to tailor its plan for its particular circumstances. The guidelines reiterate the timing of our review of hedging results that was approved by Order No. PSC-08-0316-FOF-EI, issued May 14, 2008, in Docket No. 080001-EI, In re: Fuel [*14] and purchased Dower cost recovery clause with generating performance incentive factor. Under the guidelines, the hedging program will apply to both financial and physical hedging transactions for natural gas and fuel oil.

Sections II & III

Section II of the guidelines defines hedging activities, which will primarily involve financial transactions for fuel oil and natural gas, including natural gas provided to generators under purchased power agreements. Section III of the guidelines notes that we will determine the prudence of each IOU's hedging activities for the year ending July 31, as clarified by Order No. PSC-08-0316-FOF-EI. To facilitate the prudence review, the IOUs will file monthly hedging data in two reports: a Hedging Activity True-Up Report filed in April that covers August 1 to December 31 of the prior year (in 2009, the report will cover all of calendar year 2008), and a Hedging Activity Supplemental Report filed by August 15, covering the months of the current year through July 31.

Section IV

Finally, the guidelines set forth guiding principles that we would employ in reviewing utility hedging programs and results. This section states that the purpose of hedging [*15] is to reduce fuel factor volatility, not just fuel price volatility. Section IV notes that hedging does not involve speculation, that fuel prices are volatile, and that hedging can result in lost opportunities for fuel savings. Importantly, Section IV notes that the approved risk management plans will be the controlling document for our review of hedging activities. The plans, with our approval, may deviate from one or more of the guiding principles. The risk management plans would designate a range of volumes to be hedged for natural gas and fuel oil within which the IOU normally will operate.

Parties' Comments

OPC filed comments regarding FPL's proposed hedging guidelines on September 3, 2008, and addressed us at our September 16, 2008, Agenda Conference. OPC states that it opposes FPL's proposed hedging guidelines. OPC argues that hedging activities are of very limited value to customers. OPC argues that we should evaluate the six years' worth of historical hedging information now available to determine whether hedging activities are needed to achieve the purpose of reducing the volatility of fuel price on the retail customer. OPC indicates that the levelized fuel adjustment [*16] charge already has the effect of insulating the customer from the changes in the price of fuel, and that little additional "tempering" of volatility seen and felt by customers through their bills is accomplished by hedging activities. Meanwhile, OPC argues that hedging costs have not been quantified satisfactorily, but notes such costs could be substantial by FPL's own admission.

In addition, OPC argues that the guidelines sacrifice our ability to conduct full, after-the-fact prudence reviews. OPC contends that if we adopt such guidelines, the IOUs would enjoy the benefit of lower regulatory risk and should, as a consequence, be restricted to a lower authorized return on equity. OPC notes that FPL did not include any such quid pro quo proposal in its proposed hedging guidelines petition.

Regarding other parties to the fuel docket, FPL states in its current petition that the Office of Attorney General, AARP, the Florida Retail Federation, and FIPUG have all stated that they take no position at this time on the Hedging Guidelines. n3 These parties reserve their right to take a position at a later time.

n3 "FPL attempted to contact White Springs concerning its petition on the Hedging Guidelines but was unable to do so before filing this petition." Petition, p. 5.

[*17]
PSC Audits Regarding Hedging

Our staff's audits of IOU hedging activities are now complete. Regarding utility hedging practices, the management audit concluded:

> Overall, audit staff believes that the use of financial hedges for fuel purchases provides a benefit to utility customers. Each program is appropriately controlled, efficiently organized, and operates under a non-speculative format. There are areas of improvement, which are outlined later in each company's chapter. Generally, each company has successfully mitigated the price volatility for its customers. There have been years in which each company's hedging program provided a gain on its fuel cost, and years in which each program has incurred losses. This is to be expected. Hedging commodities involves the risk of higher prices at the expense of attempting to reduce price volatility. For each company, there is an acceptable level of risk tolerance between the two. Each utility must continue to gauge its customers' tolerance of the cost associated with hedging versus the benefits of reduced fuel cost volatility and any resulting rate increases.

Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric [*18] Utilities, June 2008, Staff Management Audit, pp. 10-11

The financial audits conducted by RCA did not identify any problems with the IOUs' hedging program. The PSC auditors verified that FPL's hedging transactions are in compliance with our Orders and Rules and with applicable Financial Accounting Standards Board statements.

Analysis

The Hedging Order authorized the IOUs to charge hedging gains and losses to the fuel clause and provided initial support for utility hedging programs. Since 2003, the IOUs have charged or credited large amounts of hedging gains and losses to the clause. However, due to the volatility of fuel prices, this cumulative measurement depends on the period in question and the actual day of fuel price quotes.

The Hedging Order did not and could not address all issues and questions that have arisen concerning hedging. For example, such issues as whether we should approve the risk management plans and the appropriate periods for our review of hedging results are not addressed in the hedging order. FPL proposes answers to these questions and others in its proposed hedging guidelines.

The proposed guidelines also intend to address the issue of regulatory risk. [*19] We note that, at any particular moment in time, IOUs can carry substantial amounts of hedging gains or losses on their books. This introduces the issue of regulatory risk into consideration of hedging as our policy, since those amounts may not have been determined to be prudent for cost recovery purposes.

Below, we address specific sections of the guidelines. We have also analyzed the guidelines with particular attention to regulatory risk and whether hedging is in the public interest.

Section I.c. This section would revise the filing date of the risk management plans. According to the guidelines, each IOU would file an annual Risk Management Plan for Fuel Procurement as part of its Actual/Estimated Fuel Filing each August. In its original guidelines petition, FPL indicated that the risk management plans should continue to be part of the IOU's Fuel Projection Filing each September. At the August 27 meeting, our staff commented that this does not allow sufficient time for regulatory review. Our staff argued that a comprehensive annual review of hedging plans, as contemplated in the proposed guidelines, would require more time for discovery and potential opposing testimony than [*20] the two months afforded by a September filing. The Hedging Order did not state that our prior approval was required, only that the IOUs must file a plan. In its response to a staff data request issued August 14, FPL stated that its future risk management plans will be highly detailed. The IOUs agreed to shift the date of the plan from the Projection Filing Date to the Actual/Estimated Filing Date in accord with our staff's suggestion.

Section III. The petition states that this section codifies the timing of our review of hedging results set forth in Order No. PSC-08-0316-PAA-EI. It clarifies that the period to be reviewed for prudence of each IOU's hedging activities includes August 1 of the prior year through July 31 of the current year. Such clarifying language is helpful and consistent with the order.

The proposed guidelines fail to address the timing mismatch between the period of the hedging plans (calendar year) versus the time period included in hedging reports (August to December and January to July). According to the Hedging Order, the period addressed by hedging plans is January through December of the projection year. Thus, targeted quantitative objectives for hedging [*21] plans are designed for the calendar year. According to Commission Order No. PSC-08-0316-PAA-EI, hedging reports address the quantitative results of hedging activities for August to December and January to July. We believe it is important for purposes of our review that the timing of the plan objectives matches the timing of the information in the reports.

The IOUs can address this matter in their hedging plans and reports. IOUs that establish monthly hedging objectives in their filed hedging plans, such as FPL, are encouraged to bifurcate their hedging objectives into two segments within the calendar year to match the periods of the reported results. Other IOUs that do not establish monthly objectives, such as Gulf, are encouraged to address this timing matter in both their risk management plans and in their hedging reports so that comparability of the targeted hedging objectives and hedging results are achieved.

Section IV. FPL's guiding principal IV-d would clarify that "the Commission does not expect the IOU to predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put [*22] into place." FPL's guiding principal IV-e would clarify that we do not expect the IOU to attempt to "outguess the market." While we are in general agreement with these guidelines, it became clear at the staff and parties' August 27, 2008, meeting that at least one IOU (GULF) did not agree with being precluded from utilizing market timing as part of its hedging strategy. We find that the correctness of whether to exclude market timing in our review is highly dependent upon the approved hedge plan for the IOU in question. Subsequent to the August 27, 2008, meeting, FPL amended its proposed guidelines clarifying that the Commission may approve plans notwithstanding deviations from one or more of the guiding principles. If a plan deviates from the guidelines in some way, and the plan is approved by the Commission, the IOUs recognize that the plan controls for purposes of evaluating hedging actions.

Section IV of the guidelines acknowledges that hedging can reduce the volatility of fuel adjustment charges paid by customers and that a well-managed hedging program does not involve speculation. With fuel price hedging, the expectation is that gains and losses will cancel out over the long-run. [*23] At various times since 2002, FPL has had either cumulative hedging losses or cumulative hedging gains. While price volatility is reduced, hedging is not expected to create long-run profits or losses. Thus the appropriate review of hedging programs requires a balanced, disciplined, and long-term view of hedging transactions. The most recent fuel order, as quoted by FPL in its petition, states that, "[h]edging program[s] are designed to assist in managing the impacts of fuel price volatility. Within any given calendar period, hedging can result in gains or losses. Over time, gains and losses are expected to offset one another." Order No. PSC-08-0030-FOF-EI, p. 4.

The preceding quote demonstrates our support for the long-term view of hedging programs. Further support for utility hedging practices and the long-term view of such practices is stated in the 2006 fuel order:

> After evaluating the exhibits and testimony filed by PEF, staff recommended that the Commission find that Progress, through its hedging activities, has adequately mitigated the price risk for natural gas, residual [oil] and purchased power through September 1, 2006. Staff summarized that each utility presented testimony [*24] that the objective of the hedging programs is to minimize price volatility, and that prices are uncertain and volatile, particularly for natural gas, so there will be periods when the companies have hedging gains and other periods where the companies will have hedging losses. Staff also found that the utilities follow risk management plans to avoid speculation. Staff's belief is that minimizing price volatility produces customer benefits.

Order No. PSC-06-1057-FOF-EI, issued December 22, 2006, Docket No. 060001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor, P. 5.

Further, by Order No. PSC-08-0316-PAA-EI, we clarified the Hedging Order by stating that at the annual fuel clause hearings we will rule on the prudence of utility hedging transactions through July 31 of the current year. This addressed in part FPL's concern regarding regulatory risk.

Section IV of the Guidelines clarifies our support for prudently managed hedging programs and acknowledges the principles in the orders cited above. The guidelines do not compromise our ability to review hedging programs and results, and to make appropriate adjustments where necessary. [*25] As we discussed, and as our staff confirmed at the September 16, 2008, Agenda Conference, the guidelines provide guidance to the parties and the Commission, but are not meant to cover all circumstances. The Guidelines will provide additional clarity regarding the timing and scope of the review of hedging results. However, we must retain our ability to review the prudence of a utility's conduct. In approving the Guidelines, any regulatory risk that could be associated with hedging is minimized.

In its comments, OPC alleges that hedging reduces risk for the company and thereby benefits its shareholders. Any such risk reduction that might occur will be reflected in the company's overall risk profile, which we can consider in the cost of equity issue during a base rate proceeding.

FPL buys more gas than any other electric utility in the nation. In general, Florida IOUs burn large quantities of natural gas, and their use of natural gas will increase over the next five years. Natural gas prices are volatile and are influenced by weather (winter and summer temperatures), industrial demand, power generation demand, the price of alternative fuels, and tropical storms and hurricanes. Global [*26] influences may begin to affect natural gas prices as future gas supply could become more dependent upon the import of liquefied natural gas (LNG). Similarly, FPL buys large quantities of residual fuel oil. The price of this fuel oil depends on the price of crude oil, which, in turn, depends on global supply and demand, the price of alternative fuels, and geopolitical risks. Given these circumstances, having hedging available as part of FPL's fuel procurement strategy is appropriate.

In its comments, OPC states "[w]ith respect to reducing fuel price volatility felt by retail customers, which is the single purpose of hedging identified by the utilities, the hedging activities are of very limited value to customers, while the costs of those activities have never been quantified satisfactorily." In response to a staff data request, FPL stated that hedging reduces the volatility of fuel costs over time and that this reduction generally should reduce the volatility of annual fuel adjustment factors. In support of this contention, FPL provided the following chart.

Residential Fuel adjustment charges with and without hedging

	Hedging 1 year in advance ($/1000 kWh)	W/O Hedging ($/1000 kWh)
2003	37.11	40.63
2004	37.50	33.07
2005	40.09	42.76
2006	58.41	51.43
2007	52.95	48.87
2008 n4	52.27	57.14

[*27]

n4 2008 pre-mid course correction fuel factors.

We note that in the recent 2008 mid-course corrections for PEF, FPL, and GULF hedging gains significantly reduced the projected under-recoveries. In these particular cases, hedging significantly reduced the amount of the mid-course factor increases. Of course, the opposite case can apply as well. Hedging losses, typically in times of declining fuel prices, can reduce the amount of factor reductions. In either case, hedging gains and losses affect fuel factors. FPL notes that hedges have reduced the need for mid-course corrections. In its petition, FPL states, "[d]uring periods of rising prices, the IOUs' fuel costs have risen more slowly than market prices, and hedges have shown gains; during periods of declining prices, the IOUs fuel costs have declined more slowly than market prices, and hedges have shown losses." Petition, page 2.

We have previously found that customers benefit from receiving accurate price signals through cost-based rates, and that customers benefit [*28] from stable rates that allow the customer to budget for electric bills. Hedging has contributed to the stability of fuel factors.

Our staff's Management Audit indicates that direct transaction costs for each of the four IOUs are minimal or nonexistent. Regarding indirect transaction costs, OPC is correct that FPL indicated in its VMM petition that indirect transaction costs have not been, quantified but could be substantial. However, in our staff's April 14, 2008, recommendation regarding FPL's VMM petition, our staff stated that FPL referred to these costs as "potential" costs, and such costs are largely theoretical. The indirect transaction costs noted by FPL include the price differential between the bid-ask range for swap transactions. The bid-ask range is the difference in price from the lowest and highest price for an equivalent daily transaction on the New York Mercantile Exchange (NYMEX) or the Intercontinental Exchange (ICE). According to our staff Management Audit, PEF, GULF, and TECO agree that the bid-ask range does not constitute a transaction cost. Another type of cost associated with hedging is incremental operations and maintenance costs associated with establishing [*29] and maintaining a hedging program. We approved such costs for recovery through the fuel clause in the Hedging Order. We note that such costs are not significant relative to the total fuel costs of the utilities. In addition, three of the. IOUs (PEF, TECO, and GULF) no longer recover these costs via the fuel clause. In sum, the four IOUs' transaction costs (direct or indirect) or incremental costs of maintaining their hedging programs as currently established are not substantial relative to the total fuel costs of the utilities.

Ruling

By approving FPL's proposed guidelines, we demonstrate our support for hedging. We retain our discretion to determine the prudence of hedging results and acknowledge that the guidelines do not bind us in our review of a utility's hedging practices.

We approve FPL's proposed Hedging Order Clarification Guidelines attached hereto as Attachment A. The proposed guidelines clarify the regulatory process regarding utility hedging programs, including the timing and content of filings. In addition, the guidelines allow the utilities flexibility for creating and implementing risk management plans.

We find that utility hedging programs provide benefits to [*30] customers. By approving these guidelines we provide regulatory support and guidance regarding hedging programs.

Evaluation of hedging results can be problematic since they are not reported on a calendar basis similar to the original plans. Therefore, we encourage the IOUs to address the comparability of reported results to their original plans by structuring their plans to match reporting periods, or otherwise show the comparability of objectives and results.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's voluntary dismissal of its Volatility Mitigation Mechanism Petition and Alternative, filed with the Commission on January 31, 2008, is approved. It is further

ORDERED that the Hedging Order Guidelines, proposed by Florida Power & Light Company, and included in Attachment A are approved as set forth herein. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule *28-106.201, Florida Administrative Code* [*31] , is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall remain open.

By ORDER of the Florida Public Service Commission this 8th day of October, 2008.

CONCURBY: ARGENZIANO

CONCURRENCE BY: COMMISSIONER ARGENZIANO

COMMISSIONER NANCY ARGENZIANO, concurring with opinion as follows:

I am writing separately to fully explain my vote to approve the guidelines requested by FPL. I understood that we were not taking a vote on fuel hedging in general, only whether to approve the additional clarifying guidelines regarding hedging programs the electric utilities currently engage in pursuant to prior order of the Commission.

As I made clear at the Agenda Conference, I have two main concerns with the guidelines: first, that we don't "loose the forest for the trees," and second that this Commission retain its full powers to review the prudence of a utility's fuel hedging activities.

Based on the questions I asked and the answers I received, I am confident that the Commission [*32] staff understands the need to not only review the details of a utility's hedging plans and the compliance with that plan, but the need to take a bigger look at a utility's hedging activities, especially whether those activities continue to benefit ratepayers. I would further expect that parties to the docket would raise any issues or concerns they become aware of.

Most importantly, however, the discussion at the agenda conference satisfies me that electric utilities are now fully on notice that this Commission will not allow them to engage in imprudent activities, then attempt to hide behind pre-approval of a fuel hedging plan or compliance with the terms of that plan. While a plan might be prudent when approved in advance, situations and circumstances can and do change rapidly, and I expect electric utility companies to competently and diligently manage their hedging activities for the sole benefit of their ratepayers -- not their stockholders.

Attachment A

EXHIBIT 1

Hedging Order Clarification Guidelines

I. Investor-owned utilities (IOUs) shall file an annual Risk Management Plan for Fuel Procurement (the "Plan") as part of the IOU's Annual Estimated/Actual Fuel Filing. [*33] The Plan would be submitted for Commission approval at the annual Levelized Fuel Cost Recovery and Capacity Cost Recovery. Hearing held in November (the "Annual Fuel Hearing").

a. Each IOU will file a comprehensive Plan as part of its annual Levelized Fuel Cost Recovery and Capacity Cost Recovery Estimated/Actual True-up filing ("Estimated/Actual Filing", which typically occurs in early August) that includes the level of detail the IOU feels is appropriate for the risk management/hedging program to be executed. As has been the case with risk management plans filed to date, the Plan will address Items 1, 2, 3 (to the extent possible), 4-9 and 13-15 of Exhibit TFB-4 (ref. Paragraph 2 of the Proposed Resolution of Issues approved in Order No. PSC-02-1484-FOE-EI, Docket No. 011605-EI, dated October 30, 2002). A copy of Exhibit TFB-4 is Attachment 1 to these Guidelines and is incorporated herein by reference. The Plan will cover the activities to be undertaken during the following calendar year for hedges applicable to subsequent years (e.g., file Plan in August 2008 describing the hedging program to be executed during calendar year 2009 for hedges applicable for ongoing activities [*34] for 2009 and subsequent years included in the hedging program).
b. The Plan may be filed with a request for confidentiality to ensure that an IOU's anticipated hedging activities are not broadcast to the market prior to execution.
c. The Commission will review for approval each IOU's Plan during the Annual Fuel Hearing, which approval is required to proceed with the hedging activities proposed in that Plan. This is consistent with page 18 of the Staff recommendation, dated April 14, 2008, on FPL's VMM proposal: "Staff believes the more appropriate approach is for the Commission to approve in advance company risk management plans that identify ranges for the percentages of volumes to be hedged and the types of hedging instruments. Acting within those guidelines, the Company can rebalance its hedge positions in response to changes in market conditions."

II. "Hedging Activities" that are appropriately reported by IOUs in their hedging information reports are defined to be natural gas and fuel oil fixed price financial or physical transactions; instruments include fixed price swaps, options, etc. If an IOU is responsible under a power purchase agreement for providing the natural gas [*35] or fuel oil required to generate the power purchased thereunder, the IOU will report on any hedging activities that it undertakes with respect to such fuel.

III. At the Annual Fuel Hearing, the Commission will review and determine the prudence of each IOU's hedging activities for the year ending the immediately preceding July 31 (e.g., at the November 2009 Annual Fuel Hearing, the Commission will review and determine the prudence of hedging activities for the period August 1, 2008 though July 31, 2009). To facilitate this review, each IOU will file the following reports each year:

a. A Hedging Activity Final True-Up Report in April, covering August 1 to December 31 of the prior year (in 2009, the Hedging Activity Final True-Up Report will cover all of calendar year 200); and
b. A Hedging Activity Supplemental Report by August 15, covering the period January 1 to July 31 of that year.

Hedging Activity Final True-Up Reports and Hedging Activity Supplemental Reports will present the data on hedging activities by month, for each month covered by the reports.

IV. The Commission will establish the following guiding principles that the Commission recognizes as appropriate and [*36] will follow in reviewing Plans and an IOU's hedging actions; provided, however, that the Commission may approve a Plan notwithstanding deviations from one or more of the guiding principles, and the terms of an approved Plan will control for the purpose of reviewing hedging actions:

a. The Commission finds 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.
b. The Commission finds that a well-managed hedging program does not involve speculation or attempting to anticipate the most favorable point in time to place hedges. Its primary purpose is not to reduce an IOU's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs paid by customers over time.
c. The Commission endorses the goal of controlling volatility of fuel adjustment charges and finds that hedging is a useful tool for this purpose.
d. The Commission acknowledges that hedging can result in significant lost opportunities for savings in the fuel costs to [*37] be paid by customers, if fuel prices actually settle at lower levels than at the time that hedges were placed. The Commission recognizes this as a reasonable trade-off for reducing customers' exposure to fuel cost increases that would result if fuel prices actually settle at higher levels than when the hedges were placed. The Commission does not expect an IOU to predict or speculate on whether markets will ultimately rise or fall and actually settle higher or lower than the price levels that existed at the time hedges were put into place.
e. The Commission recognizes that market prices and forecasts of market prices have experienced significant volatility and are expected to continue to be highly volatile and, therefore, does not intend that an IOU will try to "outguess the market" in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged.
f. In order to balance the goal of reducing customers' exposure to rising fuel prices against the goal of allowing customers to benefit from falling fuel prices, the Commission finds that it is appropriate to hedge a portion of the total expected volume of fuel purchases; the volume and timing of such hedges [*38] will be implemented within the parameters of an approved Plan, subject to any modifications or exceptions to the approved Plan that have been filed with and approved by the Commission.
g. The Commission understands that each respective company's forecast of fuel burns is an ongoing process and forecasts do change over time. As a result, the volume to be hedged within the hedging program is based on a point-in-time forecast and the actual hedge percentages will vary from forecasts.

Attachment B

COMPONENTS OF A UTILITY'S FUEL PROCUREMENT RISK MANAGEMENT PLAN

When a utility files its fuel procurement risk management plan with the Commission, this plan should include information regarding the following components:

1. Identify overall quantitative and qualitative risk management objectives:
2 Identify minimum quantity of fuel to he hedged;
3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement;
4. Describe the utility's oversight of its fuel procurement activities:
5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight;
6. Describe the utility's corporate risk policy regarding [*39] fuel procurement activities;
7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities;
8. Describe the utility's strategy to fulfill its risk management objectives;
9. Verify that the utility has sufficient policies and procedures to implement its strategy;
10. Indicate the number and type of personnel who are responsible for fulfilling the utility's risk management objectives;
11. Verify that the utility has a sufficient Timber and type of personnel who can fulfill its risk management objectives.
12. Describe the utility's cost effective response to each general and specific risk associated with its fuel procurement;
13. Describe the utility's reporting system for fuel procurement activities;
14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities; and
15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and [*40] procedures for acquiring the ability to use effectively the hedging technique.

ORDER 08-0668

IS AVAILABLE UPON REQUEST

Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawAdministrative ProceedingsPublic Utility CommissionsAuthorityEnergy & Utilities LawUtility CompaniesBuying & Selling of PowerEnergy & Utilities LawUtility CompaniesContracts for Service

Florida Public Service Commission

January 31, 2011, Issued; January 31, 2011, Issued

DOCKET NO. 100404-EI; ORDER NO. PSC-11-0080-PAA-EI, 11 FPSC 1:327

Reporter
2011 Fla. PUC LEXIS 67

In re: Petition by Florida Power & Light Company to recover Scherer Unit 4 Turbine Upgrade costs through environmental cost recovery clause or fuel cost recovery clause

Core Terms

fuel, saving, turbine, upgrade, plant, cost recovery, base rate, conversion, oil, fuel-related, electric, eligible, environmental cost, customer, cool, install, fossil, burn, gulf, estimate, tower, environmental regulation, related costs, fossil fuel, coal, rail car, ratepayer, volatile, output, fossil-fuel

Panel: [*1] The following Commissioners participated in the disposition of this matter: ART GRAHAM, Chairman; LISA POLAK EDGAR; RONALD A. BRISE; EDUARDO BALBIS; JULIE I. BROWN

Opinion

NOTICE OF PROPOSED AGENCY ACTION ORDER DENYING PETITION TO RECOVER SCHERER UNIT 4 TURBINE UPGRADE COSTS THROUGH THE ENVIRONMENTAL COST RECOVERY CLAUSE OR THE FUEL COST RECOVERY CLAUSE

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to *Rule 25-22.029*, Florida Administrative Code.

BACKGROUND

Florida Power & Light Company (FPL) has requested approval to recover the costs associated with a turbine upgrade to the Scherer Unit 4 coal generating facility through either the Environmental Cost Recovery Clause (ECRC) or the Fuel Cost Recovery Clause (Fuel Clause). FPL asserts that with the installation of a new high pressure rotor to the Unit 4 turbine-generator, the plant will be able to generate approximately 35 MW of additional electricity output, which, [*2] in turn, will substantially offset the parasitic load imposed by the plant's environmental equipment which is being installed to comply with the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) and the Georgia Multipollutant Rule. The environmental equipment to be installed at Unit 4 includes a baghouse, a scrubber, and a selective catalytic reduction system. FPL expects to incur approximately $ 5-7 million in capital costs for the turbine upgrade, and asserts that the upgrade will result in net present value fuel savings to customers of approximately $.240 million through 2045.

FPL originally planned to perform the turbine upgrade at the same time that the environmental equipment is installed at the unit, scheduled to take place during an outage in 2012. In May 2010, however, the EPA issued a new greenhouse gas tailoring rule that FPL believes may require a New Source Review of Scherer Unit 4 for greenhouse gas emissions unless construction begins on the turbine upgrade prior to July 1, 2011. (*75 Fed. Reg. 31513* et seq). Therefore, FPL is presently planning to arrange for delivery of the high pressure rotor in June 2011, with installation [*3] to commence shortly thereafter.

As explained in detail below, we find that the costs of the turbine upgrade are not eligible for recovery through either the ECRC or the Fuel Clause. We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, 366.06, 366.825, and 366.8255.

DECISION

ECRC Eligibility

The ECRC, established in 1993 by the Florida Legislature, provides an investor-owned utility the opportunity to recover the costs associated with incremental changes in environmental regulations between rate cases. Pursuant to Section 366.8255, F.S., only the utility's prudently incurred environmental compliance costs may be recovered through the ECRC. Environmental compliance costs include "all costs or expenses incurred by an electric utility in complying with environmental laws or regulations . . ." Section 366.825(1)(d), F.S. Environmental laws or regulations include "all federal, state, or local statutes, administrative regulations, orders, ordinances, resolutions, or other requirements that apply to electric [*4] utilities and are designed to protect the environment." Section 366.8255(1)(c), F.S. The statute authorizes us to review and decide whether a utility's environmental compliance costs are recoverable through an environmental cost recovery factor. A utility may submit a petition to us describing its proposed environmental compliance activities and projected costs, and if the activities are approved, we "shall allow recovery of the utility's prudently incurred environmental compliance costs, including the costs incurred in compliance with the Clean Air Act, and any amendments thereto or any change in the application or enforcement thereof. . . ." Section 366.8255(2), F.S. The statute provides that any costs recovered in base rates may not also be recovered in the ECRC. Section 366.8255(5), F.S.

We first implemented the provisions of Section 366.8255, F.S., in Docket No. 930613-EI, In re: Petition to establish an environmental cost recovery clause pursuant to Section 366.8255, Florida Statutes [*5] (Gulf Order). [1] There, we identified the criteria required to demonstrate eligibility for cost recovery under the ECRC. We interpreted the statute to prescribe three requirements for recovery of environmental compliance costs through the clause. In the Gulf Order at page 6, we said:

> Upon petition, we shall allow the recovery of costs associated with an environmental compliance activity if:
>
> 1. such costs were prudently incurred after April 13, 1993;
>
> 2. the activity is legally required to comply with a governmentally imposed environmental regulation enacted, became effective, or whose effect was triggered after the company's last test year upon which rates are based; and,
>
> 3. such costs are not recovered through some other cost recovery mechanism or through base rates.

Beginning with the Gulf Order, and in several other decisions over the years, we have considered proposals for recovery of environmental compliance costs on a case-by-case basis, and with [*6] some flexibility; but, we have required fundamental compliance with the provisions of Section 366.8255, F.S. As the following review of our decisions indicates, and of particular importance to this case, we have consistently enforced the requirement that projects eligible for ECRC cost recovery must be required to comply, or remain in compliance with, a governmentally imposed environmental regulation.

The Gulf Order allowed recovery through the ECRC of Gulf's Environmental Auditing Program because the program ensured the efficient management of approved environmental programs to ensure cost-effective compliance with environmental regulations. [2] It also allowed recovery for general air quality costs and emission monitoring costs associated with changes in the scope of compliance with existing environmental regulations and new environmental regulations. [3] It denied recovery of Gulf's Clean Coal Technology program, however, because the program was a discretionary, voluntary research and development program not needed for compliance with any environmental regulations.

[*7]

In Docket No. 990667-EI, In re: Petition by Gulf Power Company for approval of Plant Smith Sodium Injection System as new program for cost recovery through environmental cost recovery clause, [4] we approved the project both to comply with new Clean Air Act Amendment (CAAA) Phase II requirements and to maintain compliance with existing air permit requirements. In Docket No. 980007-EI, In re: Environmental Cost Recovery Clause, [5] we approved Gulf's additional groundwater monitoring equipment to continue to comply with an existing environmental requirement, because greater treatment

1 Order No. PSC-94-0044-FOF-EI, issued January 12, 1994.

2 Gulf Order at 19.

3 Gulf Order at 17.

4 Order No. PSC-99-1954-PAA-EI, issued October 5, 1999.

5 Order No. PSC-98-1764-FOF-EI, issued December 31, 1998.

capacity was needed. In that docket, we also approved two additional coal crushers that contributed to overall compliance with the CAAA at the Tampa Electric Company (TECO) Gannon station even though it was not clear that the additional crushers had initially been a part of TECO's overall NO[x] compliance strategy for Phase II of the CAAA.

[*8]

In Docket No. 020648-EI, In re: Petition for approval of environmental cost recovery of St. Lucie Turtle Net Project for period of 4/15/02 through 12/31/02 by Florida Power & Light Company, [6] FPL's Nuclear Regulatory Commission (NRC) license to operate the St. Lucie nuclear power plant included Appendix B, which imposed certain requirements on FPL to protect several species of endangered sea turtles from entrapment in the cooling water intake canals of the plant. The NRC requirements included installation and maintenance of a five-inch mesh barrier net across the intake canal. Although the NRC requirements had not changed, FPL requested recovery of the costs for a new turtle net project, which included installation of a new net of sturdier material and support structures, conducting a bottom survey of the intake canal, maintenance dredging the canal in the vicinity of the net, and installing a sand pump near the net. These additional activities were not specifically required by Appendix B, but FPL explained that they were necessary to ensure that the net worked properly so that it could continue to comply with its NRC license. In this year's ECRC docket FPL has requested approval [*9] of additional modifications to its Turtle Net Project, which FPL asserts are necessary to remain in compliance with the requirements of Appendix B.

In Docket No. 050958-EI, In re: Petition for approval of new environmental program for cost recovery through Environmental Cost Recovery Clause by Tampa Electric Company, [7] we approved a new flue gas desulphurization system reliability program to amplify an existing program that we had approved earlier, because the program would allow TECO to comply with additional requirements of its Consent Decree with the EPA, even though the specific project TECO engineered was not required by the Consent Decree.

Finally, in Docket No. 060162-EI, In re: Petition by Progress Energy Florida, Inc. for approval [*10] to recover modular cooling tower costs through environmental cost recovery clause, n8 we approved Progress Energy Florida's (PEF) modular cooling tower project in order to continue compliance with wastewater discharge standards required by the Florida Department of Environmental Protection (DEP). PEF's discharge permit limits the temperature of discharge water into the Gulf of Mexico from the Crystal River plants to 96.5 degrees Fahrenheit. Increased inlet water temperatures from the Gulf during the summers of 2004 and 2005 forced PEF to reduce the output of the plants in order to remain in compliance with its discharge permit. The modular cooling towers along the discharge canal provided additional cooling capacity that allowed PEF to comply with its permit and avoid numerous, expensive derates of its base load generating units.

The Office of Public Counsel (OPC) argued that the cooling towers project was not eligible for cost recovery through the ECRC. OPC [*11] put forth several reasons for its position, but OPC's fundamental concern was that utilities were attempting to inappropriately expand the use of the clause dockets to recover costs that should be addressed in base rate proceedings. In Order No. PSC-07-0722-FOF-EI (Cooling Tower Order), we acknowledged OPC's concern, but asserted the need for flexibility in the application of the ECRC statute, as long as the basic criteria of the statute were met. At page 8 of the Cooling Tower Order, we said:

> We believe that this interpretation is consistent with our prior decisions, and with the intent of *section 366.8255, Florida Statutes*, which permits recovery of a wide variety of costs associated with compliance with governmentally imposed environmental requirements, if the costs were incurred after section 366.8255 was enacted, and if the costs are not being recovered in base rates or another cost recovery mechanism. We understand OPC's concern that utilities have the incentive to pass many costs through cost recovery mechanisms, and we are attuned to that concern, but that cannot lead us to restrict the eligibility of environmental costs beyond [*12] what the statute contemplates. . . . Further, we are not persuaded that a decision to approve the eligibility of the modular cooling towers project would lead to the scenario OPC's witness Hewson describes, as long as we continue to require a direct nexus between the project, its compliance costs, and the relevant environmental requirement.

[6] Order No. PSC-02-1421-PAA-EI, issued October 17, 2002.

[7] Order No. PSC-07-0499-FOF-EI, issued June 11, 2007.

FPL relies heavily on our decision in the Cooling Tower Order to support its request for recovery of the turbine upgrade costs in this case. According to FPL, PEF's modular cooling tower project avoided reductions in generating plant output from discharge temperature requirements, and FPL argues that its turbine uprate project will offset reductions in generating unit output due to the installation and operation of pollution controls at the Scherer plant. FPL does not take into account, however, the critical distinguishing fact between the two cases. The modular cooling tower project was designed to allow PEF to run its Crystal River plants in compliance with a governmentally imposed environmental requirement, DEP's wastewater discharge permit. If PEF did not comply with the temperature requirements, it could not run its plants. FPL's turbine [*13] upgrade is not designed to allow FPL to run Scherer Unit 4 in compliance with a governmentally imposed environmental requirement. Without the turbine upgrade, it can still run its plant. When the baghouse, scrubber, and selective catalytic reduction system, whose costs we have approved for recovery through the ECRC, are installed in 2012, FPL will be in compliance with applicable environmental regulations, with or without the turbine upgrade. In its response to our staff's 4th Set of Interrogatories No. 44 in Docket. No. 100007-EI, FPL agreed that "not proceeding with the upgrade of the steam turbine would not violate any federal, state or local environmental rule or regulation. " Allowing recovery of FPL's turbine upgrade project to offset parasitic load from environmental equipment through the ECRC would open up a whole new, perhaps extensive, subset of recoverable costs. Virtually every pollution control system creates a parasitic load for a generating unit. We find that this new subset of costs is not contemplated by *Section 366.8255, F.S.*, or our orders implementing the statute.

As this review of our ECRC decisions indicates, the facts and [*14] circumstances of environmental compliance projects eligible for cost recovery vary considerably, but the principle that connects them is our consistent insistence that the projects comply with the essential criteria of the statute and the Gulf Order, in particular here, the requirement that the projects be required to comply, or remain in compliance with, a governmentally imposed environmental regulation. FPL's Scherer Unit 4 turbine upgrade is a discretionary, voluntary project, and the costs associated with it are not environmental compliance costs required by any known environmental rule or regulation. Thus there is no "direct nexus between the project, its compliance costs, and the relevant environmental requirement." We find that the proposed project does not meet established criteria for recovery through the ECRC.

Fuel Clause Eligibility

The fuel clause is a regulatory tool designed to pass through to utility customers the costs associated with fuel purchases. The purpose is to prevent regulatory lag, which occurs when a utility incurs expenses but is not allowed to collect offsetting revenues until the regulatory body approves cost recovery. Regulatory lag has historically [*15] been a problem for utilities because of the volatility of fuel costs. It is not as much of a problem, however, when expenses, such as capital improvements, and operations and management costs, can be planned for and included in base rate calculations. Different states have addressed volatile fuel costs and the problem of regulatory lag in differing ways. Several jurisdictions, like Florida, have allowed recovery of fuel costs in a fuel adjustment clause, and in Florida the implementation of the fuel clause has changed and developed over the years.

From 1925 to 1951, before the Legislature granted us jurisdiction over investor-owned electric utilities, Florida's electric utilities benefited from a monthly fuel adjustment clause. Starting in 1951, when we obtained jurisdiction over them, the utilities applied a Commission-approved formula and placed the resulting charge on customers' bills. While some auditing functions were performed by our staff, no formal public hearing was held. In 1973-1974, a foreign oil embargo substantially increased the cost of oil, leading to increased consumer concern over fuel adjustment charges. On October 7, 1974, we opened a docket to fully review the [*16] clause process. [9] Two days later, on October 9, 1974, the Attorney General issued an advisory opinion which stated that the practice of allowing changes in the fuel adjustment charges without a public hearing was illegal under Florida law. 74 Op. Att'y. Gen. Fla. 309 (1974). On October 11, 1974, the first fuel adjustment clause hearing was held, which led to the approval of a stipulation that provided for a monthly hearing format on all fuel adjustment clauses. [10] During the 1974 proceeding, we also considered recommendations on the modification of the clause, and implemented a two-month lag between utilities filing for fuel clause recovery and the decision on cost recovery. The

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9 Order No. 6357, issued November 26, 1974, in Docket No. 74680, In re: General Investigation of Fuel Adjustment Clauses of Electric Companies.

10 Id.

two month lag was intended as an incentive to the utilities to optimize fuel costs.

In 1980, we modified the clause again. [11] In Order No. 9273, we [*17] allowed the utilities to collect fuel and fuel-related expenses on a current basis. We subsequently modified the recovery clauses to allow recovery on the projections of future fuel and fuel-related expenditures subject to a true-up hearing in which the utilities' projected fuel expenditures are adjusted to recover only actual expenditures. From 1980 to 1998, we changed the fuel adjustment hearing schedule from once a month, to every six months, to the current yearly schedule.

In 1985, we amended the fuel clause process to better describe those items that would be recoverable under the fuel clause. Prior to the August 1985 fuel hearing, we instructed the parties and our staff to "provide information necessary for the Commission to be able to consider at the August 1985 fuel adjustment [*18] hearing whether the utilities were passing appropriate fixed and variable costs associated with fuel receipts through their fuel adjustment clauses." [12] Order No. 14546 approved a stipulation between OPC, FPL, TECO, Gulf, and FPC (now PEF) after a workshop exploring the issue. The policy outlined in Order No. 14546 consisted of two essential points regarding the scope and application of the fuel adjustment clause:

> 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 [*19] 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. [13]

Order 14546 then discussed the parties' specific applications of the articulated policy, including, for example, the description of "invoiced fuel charges." It was determined that invoiced fuel charges should include all price revisions and adjustments relating to volume and quality of fuel. After discussing several specific applications of the policy, the parties agreed that our policy on fuel clause recovery should be flexible enough to cover some items that would normally go through base rates, and we approved that position. We discussed this fuel clause exception to base rate recovery as follows:

> In addition to stipulating to the foregoing applications of policy, the parties [*20] 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. [14]

[*21]

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[11] Order No. 9273, issued March 7, 1980, in Docket No. 74680, In re: General Investigation of Fuel Cost Recovery Clause. Consideration of Staff's Proposed Projected Fuel and Purchased Power Cost Recovery Clause with an Incentive Factor.

[12] Order No. 14546, p. 1

[13] Order No. 14546, p. 2

[14] Order No. 14546, p. 3

In Order No. 14546 we approved the stipulation of the parties and adopted them as our own. We found that the stipulated provisions (including the fuel clause exception to base rate recovery), were an appropriate extension of the policy established by Order No. 6357. [15] As a result of the policy determinations, we made two lists. One list included charges properly considered in the computation of the average inventory price of fuel. The other list contained items that were more appropriately considered in the determination of base rates. It should be noted that each item on the lists was a shortened reference to the detailed description of the types of costs discussed earlier in the Order. [16]

[*22]

It is Order No. 14546 that FPL relies upon to contend that the upgrade of the steam turbine (turbine upgrade) at the Plant Scherer Unit 4 coal plant is eligible for recovery through the Fuel Clause. The turbine upgrade will offset the loss in unit output resulting from the installation of required pollution control equipment at the generating unit. Scherer Unit 4's heat rate will also be improved by a rate of more than 400 Btu/kWh as a result of the turbine upgrade, meaning the unit will be able to generate electricity more efficiently in addition to increasing its output. FPL witness T.J. Keith states in FPL's September 1, 2010 testimony, that the turbine upgrade will result in fuel savings of approximately $ 240 million on a net present value basis, compared to a cost of about $ 7 million to upgrade the steam turbine.

As Order No. 14546 states, recovery may be allowed for:

> Fossil fuel-related costs [*23] 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.

We find that the appropriate interpretation of this section of Order No. 14546 is that capital projects eligible for cost recovery through the Fuel Clause should produce fuel savings based on lowering the delivered price of fossil fuel, or otherwise result in burning lower price fuel at the plant. We note that the order discusses a "cost effective transaction," and gives as an example, "the cost of an unanticipated short-term lease of a terminal, to allow a utility to receive a shipment of low cost oil." (Order No. 14546, p. 3) This example clearly connects fuel savings to a project that lowers the delivered price of fossil fuel (i.e., the input price). Similarly, in Order No. PSC-95-1089-FOF-EI, issued on September 5, 1995, [17] we approved FPL's purchase of 462 high capacity aluminum rail cars for delivery of coal to Plant Scherer, a capital project that lowered the delivered price of fuel. [*24] The

[15] In Order No. 6357, we discussed the purpose of the fuel adjustment clause as follows: "A fuel adjustment clause is intended to compensate for day-to-day fluctuations in the cost of fuel which cannot be anticipated in the base rates. It should be constructed and applied so as to reimburse the utility for the increase in the cost of fuel as related to generation. It also operates so as to pass on to the customer any savings realized by the utility from decreased cost of fuel. (Order No. 2515-A, dated April 24, 1959). . . It should be emphasized that a utility does not make a profit on its fuel costs. . . . The charge reflected on a customer's bill each month is designed only to provide for the recovery of fuel costs experienced by the utility in generating the customer's power. Conversely, it can and has resulted in a credit to the customer's bill when the price falls below the base cost of fuel. While some may question the propriety of allowing fuel costs to be recovered through an automatic adjustment clause, recent events underscore the basic reasons why such is done for this particular cost item as opposed to others. First, electric utilities rely largely upon fossil fuels to generate power; only Florida Power and Light Company now has a nuclear unit on the line and in service. Thus, their dependency on purchasing large quantities of fossil fuels will continue to exist for many years. Presently, fuel costs represent a substantial portion of operating costs; in some instances, fuel costs alone comprise more than half of a company's total operating costs. Any fluctuation, then, in fuel costs will have a significant impact on a company's earnings and can work to the detriment of the ratepayer or the utility depending on the direction of the movement unless some means exists to recoup those increased costs or refund those savings as quickly as possible. Rate cases are time consuming and expensive, and do not lend themselves to these objectives. Second, fuel costs are a highly volatile cost item unlike other costs of the utilities, such as wages and maintenance. When the volatility factor is coupled with the magnitude of fuel costs, one can readily conclude that the fuel adjustment clause is both a necessary and proper regulatory tool to insure that both the customer and the utility receive the benefits of responsive recognition to changes in the cost of generating electricity. We do not have the slightest doubt that a type of recovery clause should be retained by the utilities in order to accomplish this goal." Order No. 6357, issued November 26, 1974, in Docket No. 74680-CI, In re: General investigation of fuel adjustment clauses of electric companies.

[16] For instance, the discussion of invoiced fuel charges appears on the approved fuel clause recovery lists as items 1, 2 and 3. The fuel clause exception appears on the list as item number 10.

[17] 18 Docket No. 950001-EI

purchase of the rail cars enabled FPL to obtain favorable transportation rate savings from railroad companies that exceeded the recoverable cost of the purchase. That capital investment provided FPL customers an estimated $ 24 million in fuel savings, in the form of reduced fuel costs to FPL's customers, by lowering the delivered price, or input price, of coal. In contrast, the turbine upgrade increases the output and efficiency of the coal plant, resulting perhaps in less fuel burned per kWh, but it has no effect on the delivered price of coal.

As Order No. 14546 states, projects that request recovery of costs through the Fuel Clause should be "fossil fuel related." The turbine upgrade is a capital project that increases output and efficiency but is not specific to fossil fuel. Such an upgrade could as well be made to a nuclear plant's steam turbine. We do not consider the turbine upgrade to be a "fossil fuel-related cost," and therefore we find that it should not be recovered through [*25] the Fuel Clause.

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. As can be seen from that Attachment, all but two of the orders are consistent with our interpretation of Order 14546. One of these orders deals with incremental security costs incurred by utilities at nuclear power plants following the September 11, 2001 terrorist attacks. This was a unique circumstance, however, and we note that those security costs were subsequently removed from the fuel clause and included in the capacity cost recovery clause. FPL argues that the other order, Order No. PSC-96-1172-FOF-EI, issued on September 19, 1996, [18] supports its position that the turbine upgrade should be included in the fuel cost recovery clause. Order No. PSC-96-1172-FOF-EI did approve recovery through the Fuel Clause of costs associated with the thermal power uprate at FPL's Turkey Point nuclear-powered Units 3 and 4, a "non-fossil fuel-related" project. Order No. 14546 states, however, that a cost must be "fossil fuel-related" to be eligible for Fuel Clause recovery. Order No. 14546 also states that; "recovery [*26] of such costs should be made on a case-by-case basis. . . ." While it is true that we granted recovery of "non-fossil fuel-related" costs through the Fuel Clause in those two discreet instances, we believe that the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are "fossil fuel-related" and that lower the delivered price, or input price, of fossil fuel. At the same time, we reaffirm our practice of reviewing the eligibility of projects for recovery on a case-by-case basis.

The turbine upgrade appears to be a cost effective project that would benefit FPL and its ratepayers, but for the reasons stated above, we find that it is not eligible for recovery through either the ECRC or the Fuel Clause.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that for the reasons set out in the body of this Order, the Petition by Florida Power & Light Company to recover Scherer Unit 4 Turbine Upgrade costs through [*27] the environmental cost recovery clause or the fuel cost recovery clause is denied. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by *Rule 28-106.201*, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 31st day of January, 2011.

Docket No. Order No.	**Project**	**Reasons for approval**
930001-EI PSC-93-1331-FOF-EI	Martin gas pipeline lateral	Commission has the flexibility to review fossil fuel related costs on a case-by-case basis to determine whether those costs are appropriate for recovery through the fuel clause. Martin gas pipeline lateral has reduced costs, or at the very minimum, not resulted in any increased

[18] Docket No. 960001-EI

Docket No. Order No.	Project	Reasons for approval
		costs, and the decision was made with the ratepayers' interest in mind, which is to minimize cost. Recognizing the unique facts and circumstances regarding FPL's decision to construct the lateral, to alleviate regulatory lag, and to encourage utilities to take actions to reduce fuel costs to customers, we find that it is appropriate in this case to recover the depreciation and return on investment in the Martin gas pipeline lateral through the fuel recovery clause until FPL's next rate case.
940391-EI PSC-94-1106-FOF-EI	Conversion by FPL of Manatee units to burn orimulsion	By party stipulation and subject to conditions, Commission allowed fuel clause recovery pursuant to Order 14546 of conversion of Manatee Units 1 and 2 to burn orimulsion. The burning of orimulsion represented the most economical alternative to burning oil. The recovery amount was $ 72 million with a recovery period of the used and useful life of the assets. * The project was never commenced.
951096-EI PSC-95-1299-NOR-EI	Oil Backout Rule	Was repealed because if a utility justifies a project that will result in fuel savings to its ratepayers, those oil backout costs will generally be recoverable through the fuel clause on a case-by-case basis.
950001 PSC-95-1089-FOF-EI	FPL's recovery of rail cars	By stipulation, Commission granted rail cars. Unanticipated fuel-related costs not included in the computation of base rates when economically beneficial to a utility's ratepayers, the cost of purchasing or leasing rail cars. 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. The purchase enabled FPL to obtain favorable transportation rate savings from railroad companies and thus lower the delivered price of fuel.

Docket No. Order No.	Project	Reasons for approval
	FPC conversion of Intercession City combustion turbine units P7 and P9 to burn natural gas.	By stipulation. Order No. 14546 . . . allows a utility to recover fossil-fuel related costs that result in fuel savings, even if those costs were not previously addressed in determining base rates. Each oil CT was converted to gas and the conversion resulted in fuel savings. The conversions were to produce an estimated savings of $ 2.5 million with a recovery amount of $ 20 million over a 5 year recovery period.
950001-EI PSC-95-0450-FOF-EI	FPL modifications to Cape Canaveral Units 1 and 2, Fort Myers Unit 2, Riviera Units 3 and 4, and Sanford Units 3, 4, and 5 to use a more economic grade of residual fuel oil	FPL stated costs would be $ 2,754,502, and estimated savings of $ 80 million. These fuel savings result from the use of a more economic grade of residual fuel oil. In approving the fuel clause exception to base rates for these conversions, Commission quoted from Order 14546. We recognized that certain unanticipated costs may be appropriate for recovery through the fuel clause. Order 14546 allows fuel related expenditures that are not being recovered through a utility's base rates. . . . "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 was 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." We have allowed in the past, when those expenditures result in significant savings to the utility ratepayers.
960001-EI PSC-96-1172-FOF-EI	FPL's uprate of Turkey Point Units 3 and 4	The thermal power uprate was estimated to produce $ 198 million in savings with a

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Docket No. Order No.	Project	Reasons for approval
		recovery amount of $ 10 million over 2 years. The savings are due to the difference between low cost nuclear fuel replacing higher cost fossil fuel.
960001-EI PSC-96-0353-FOF-EI	FPC conversion of Intercession city P8 and P10 turbine units to burn natural gas.	By stipulation. Order 14546 allows a utility to recover fossil-fuel related costs that result in fuel savings, even if those costs were not previously addressed in determining base rates. Each oil CT was converted to gas and the conversion resulted in fuel savings. The conversions were to produce an estimated savings of $ 16 million with a recovery amount of $ 2.6 million over a 5 year recovery period.
970001-EI PSC-97-1045-FOF-EI	FPC's conversion of Debary Unit 9 to burn natural gas	Order 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. The oil CT was converted to gas and the conversion resulted in fuel savings. The conversion was to produce an estimated savings of $ 2.1 million with a recovery amount of $ 734,000 over a 5 year recovery period.
970001-EI PSC-97-0359-FOF-EI	FPC conversion of Debary 7, Bartow 3 and 4, Suwannee 1 to	By stipulation. Order 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. Each oil CT was converted to gas and the conversion resulted in fuel savings. The conversions were to produce an estimated savings of $ 22 million with a recovery amount
970001-EI PSC-97-0359-FOF-EI	FPL's investment on rail cars	By stipulation. Recover the depreciation expense and return on investment for rail cars purchased to deliver coal to the Scherer Plant. Pursuant to Order 14546 unanticipated fuel-related costs not included in the computation of base rates may be considered for recovery

Docket No. Order No.	Project	Reasons for approval
		through a utility's fuel clause. When economically beneficial to a utility's ratepayers, the cost of purchasing or leasing rail cars is considered to be a fuel-related expense that should be recovered through the fuel clause.
	FPL's modifications to generating plants and fuel storage facilities to use low gravity fuel oil.	By stipulation. These modifications will allow FPL to operate these plants and using a heavier more economic grade of residual fuel oil. Order 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. The modifications were to produce an estimated savings of $ 19 million with a recovery amount of $ 2 million over a 3 year recovery period.
980001-EI PSC-98-0412-FOF-EI	FPC's conversion of Suwannee 3 to burn natural gas.	Order 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. The oil CT was converted to gas and the conversion resulted in fuel savings. The conversion was to produce an estimated savings of $ 3.25 million with a recovery amount of $ 2.45 million over a 5 year recovery period.
980001-EI PSC-98-1715-FOF-EI	FPC's conversion of Debary 8 to burn natural gas	Order 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs were not previously addressed in determining base rates. The oil CT was converted to gas and the conversion resulted in fuel savings. The conversion was to produce an estimated savings of $ 3.4 million with a recovery amount of $ 1.8 million over a 5 year recovery period.
010001-EI PSC-01-2516-FOF-EI		By stipulation. Parties restated that regulatory treatment of capital costs that are expected to reduce long-term fuel costs is

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		the treatment prescribed in Order 14546 where we listed the types of costs that are recoverable through the Fuel Cost Recover Clause. . . . capital projects with an in-service date on or after Jan 1, 2002, is the utility's cost of capital based on the midpoint of its authorized return on equity. We approve these stipulations as reasonable.
	Incremental Power Plant Security Costs request by FPL	We find that recovery of this incremental cost through the fuel clause is appropriate in this instance because there is a nexus between protection of FPL's nuclear generation facilities and the fuel cost savings that result from the continued operation of those facilities. Further, we believe that this type of cost is a potentially volatile cost, making it appropriate for recovery through the fuel clause. . . . In addition, we find that recovery of this cost through the fuel clause provides a good match between the timing of the incurrence and recovery of the cost. . . . We believe that approving recovery of this incremental power plant security cost through the fuel clause sends and appropriate message to Florida's investor-owned electric utilities that we encourage them to protect their generation assets in extraordinary, emergency conditions as currently exist. * Incremental Security costs were moved into the capacity clause in Docket No. 020001-EI by Order No. PSC-02-1761-FOF-EI issued on December 13, 2002.
050001-EI PSC-05-1252-FOF-EI	FPL sleeving project at St. Lucie No. 2	By Order 14546 we set forth certain criteria for establishing the types of expenses that are eligible for recovery through the fuel clause. In particular, a utility must show that a cost will not be recognized or is not anticipated to be recovered in

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Docket No. Order No.	Project	Reasons for approval
		current base rates. We believe that FPL knew about the potential to sleeve the tubes when it filed its minimum filing requirements for its most recent rate case. * The FPL sleeving project was denied. The project was anticipated prior to FPL's rate case and should have been requested for recovery in base rates.

[*28]

In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company

DOCKET NO. 130198-EI; ORDER NO. PSC-13-0505-PAA-EI

Florida Public Service Commission

2013 Fla. PUC LEXIS 326

13 FPSC 10:211

October 28, 2013, Issued

PANEL: [*1] The following Commissioners participated in the disposition of this matter: RONALD A. BRISE, Chairman; LISA POLAK EDGAR; ART GRAHAM; EDUARDO E. BALBIS; JULIE I. BROWN

OPINION: PROPOSED AGENCY ACTION ORDER ON FLORIDA POWER & LIGHT COMPANY'S PROPOSED SABAL TRAIL TRANSMISSION, LLC AND FLORIDA SOUTHEAST CONNECTION PIPELINES

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to *Rule 25-22.029*, Florida Administrative Code.

Case Background

On July 26, 2013, Florida Power & Light Company (FPL) filed its petition in this docket requesting a determination by the Florida Public Service Commission (Commission), that its decision to enter into long-term natural gas transportation contracts is prudent, and that the associated costs are eligible for recovery through the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause). The petition included testimony from five witnesses, with exhibits outlining FPL's need for additional firm [*2] natural gas transportation, a description of its request for proposals (RFP) process and the resulting contracts, and a request for approval of its planned cost recovery method. The petition was filed following FPL's selection of two projects to develop new natural gas transportation infrastructure into southern Florida, offering the most cost-effective alternative for its customers. These projects are referred to individually in the petition as the Northern Pipeline Project and the Southern Pipeline Project. The two projects are wholly separate pipelines owned and operated by different entities, and therefore are referred to collectively as a matter of convenience.

The instant docket is the culmination of a process, which began in 2009 when FPL petitioned us to develop, build, and operate the Florida EnergySecure Line. On April 7, 2009, FPL filed its petition in Docket No. 090172-EI requesting a determination of need for its proposed Florida EnergySecure Line, a 280-mile long, 30-inch diameter high pressure natural gas transmission pipeline that FPL sought to own and operate primarily for supplying natural gas to its newly modernized Cape Canaveral and Riviera Beach generating units. [*3] By Order No. PSC-09-0715-FOF-EI, we denied the petition finding that FPL had failed to adequately demonstrate that its Florida EnergySecure Line was the most cost-effective alternative for providing additional natural gas transmission capacity. However, we agreed that additional gas capacity was necessary for assuring the reliability of Florida's electric generating system in the future. In Order No. PSC-09-0715-FOF-EI, we stated, "we agree with the parties that increased gas transportation infrastructure is needed to meet future electricity needs, given the uncertainty surrounding both coal-fired and nuclear generation in the state." n1 Our Order directed FPL to "renew its request for proposals to fulfill its gas transportation capacity needs," and further stated that the "new RFP shall contain a specific, detailed request for proposals for a new pipeline, and specifications of the long term natural gas needs of FPL." n2 In addition, the Order stated that "[t]he RFP shall be provided to our staff for review prior to its issuance to ensure it is clear and complete." n3

n1 Order No. PSC-09-0715-FOF-EI, issued October 28, 2009, in Docket No. 090172-EI, In re: Petition to determine need for Florida EnergySecure Pipeline by Florida Power & Light Company, page 5.
[*4]

n2 Id., page 6.

n3 Id., page 6.

FPL provided the RFP for review on November 13, 2012. A public meeting was held on November 26, 2012 so that our staff and any other interested parties could have an opportunity to discuss and review FPL's RFP document prior to its issuance. In addition to our staff, representatives of the Office of Public Counsel (OPC) as well as potential project participants and other interested groups were present at the meeting. There were no objections to FPL issuing the RFP.

FPL issued its RFP on December 19, 2012. The RFP was noticed three times in *Platt's Gas Daily*, a widely distributed industry publication. FPL provided an internet website where interested persons could gather information and ask questions. FPL also held a workshop to facilitate understanding of the RFP and the bidding process prior to the April 3, 2013 due date for responses. An additional meeting was held on June 13, 2013 to discuss the results of the RFP solicitation, FPL's evaluation of the proposals, and the next steps to be taken in the process. Attendees included our staff, OPC, and representatives [*5] of the Florida Industrial Power Users Group (FIPUG). Based on discussion at the meeting, FPL provided an outline of topics that would be covered in the direct testimony filed with its petition.

FPL is not obligated by law to obtain our approval to enter into a long-term gas transportation contracts for the projects, as both contracts are governed by the Federal Energy Regulatory Commission (FERC). The contracts would only trigger our action at the time FPL seeks recovery of costs in the fuel clause proceeding. However, due to the substantial financial commitments involved, FPL is seeking our determination that FPL's decision to enter into long-term gas transportation contracts is prudent and that the associated costs are eligible for recovery through the fuel clause. FPL included a provision in its precedent agreement with each pipeline that requires our approval of the agreements. The contracts may be terminated without financial penalty if we do not make a prudency determination satisfactory to FPL. We have jurisdiction over the subject matter by the provisions of Chapter 366, Florida Statutes.

A. Additional Firm Natural Gas Transportation

Description of FPL's Existing Pipeline [*6] Capacity

Peninsular Florida is currently served by only two major natural gas pipelines. Florida Gas Transmission Company, LLC (FGT) is the larger of the two pipelines with approximately 3,100 million cubic feet per day (MMcf/day) of total gas deliverability. The second of the two pipelines is owned by Gulfstream Natural Gas System, LLC (Gulfstream) and has a maximum 1,300 MMcf/day of gas deliverability. Currently, FPL has firm contracts with Gulfstream for 53 percent of the design capacity of its system which is 695 MMcf/day. By 2017, FPL will have firm transportation contracts with FGT for 41 percent of its design capacity, a total of 1,274 MMcf/day. The FGT capacity serves approximately 65 percent of FPL's current total gas supply requirements, and Gulfstream serves the remaining 35 percent. However, FPL is not the only firm shipper for either system. The remaining capacity of Gulfstream is currently fully subscribed, and only 6 percent of FGT's capacity (approximately 184 MMcf/day), will *potentially* be available on a long-term firm contractual basis within the 2017 time frame. Additional natural gas transportation capacity will be necessary as FPL's and all of Florida's [*7] electric generation systems continue to grow. Nearly 68 percent of the state's electric generation, and more than 72 percent of FPL's total energy, was fueled by natural gas in 2012.

In general, natural gas pipeline transportation capacity availability is firm or non-firm. Firm transportation capacity is acquired through a contract for reservation of a certain portion of a pipe's daily throughput, which is continuously available to a utility to provide fuel for its generators. Utilities typically acquire non-firm transportation capacity by purchasing pipeline capacity that has been temporarily released by another customer, or by purchasing non-reserved capacity. Released capacity becomes available when another customer's need for gas is below their reserved portion. However, this type of capacity cannot be relied upon as it is not guaranteed. If a sufficient supply of fuel is not available when required to meet load, a utility risks a situation where it may be unable to fully utilize its generating assets, and it could be forced to increase its use of more expensive alternative fuels, demand response, or even load shedding. For this reason, it is important for FPL to have adequate [*8] gas transportation capacity available on a firm basis.

Description of Proposed Pipeline Projects

In its petition, FPL states that 400 MMcf/day of additional firm natural gas transportation capacity is required beginning in 2017. The primary factors driving this increased need are the three modernization projects currently in progress at FPL's Cape Canaveral, Riviera Beach, and Port Everglades natural gas plants to upgrade older, 1960's-era steam combustion turbine generating units to modern, and more efficient combined cycle technology. FPL proposes to meet this need by implementing two new contracts for firm pipeline capacity within the northern and southern portions of the state.

The Northern Pipeline project consists of a joint venture between a subsidiary of Spectra Energy Corporation, called Sabal Trail Transmission, LLC (Sabal Trail) and a newly formed subsidiary of FPL's parent company, Next-Era Energy, called U.S. Southeastern Gas Infrastructure LLC (USSGI). The Southern Pipeline project will be owned by another newly formed affiliate of FPL, called the Florida Southeast Connection (FSC). FPL has signed precedent agreements with these two companies for the initial 400 [*9] MMcf/day beginning in 2017, with options to provide additional increments of 200 MMcf/day in 2020 and beyond.

Our review of FPL's need for additional natural gas transportation capacity began by analyzing its customer load forecast for the period 2013 through 2032. Then we evaluated the planned generation resource portfolio identified to meet customer demand and energy requirements. The resulting natural gas requirement was then compared to both existing pipeline resources and the proposed contracts with Sabal Trail and FSC. In addition to a review of the current proposal, we compared each of the current forecasts with those presented in the request for a determination of need for the Florida EnergySecure Line, which proposed a 600 MMcf/day pipeline with a 2014 in-service date.

Load Forecasting

The load forecast contained in FPL's petition consists of two components: a base case forecast for both net energy for load (NEL) and summer peak demand, and a risk adjustment component for both NEL and summer peak demand that increases FPL's base-case forecast in order to reduce the risk of under forecasting FPL's future load growth.

FPL's base case forecast for NEL and summer peak demand [*10] are based upon three econometric models: a customer forecast model, a net energy for load per customer model, and a summer peak demand per customer model. These three models are the same as those used by FPL in their normal annual planning cycle and are used to produce projections of anticipated load growth for FPL's Ten-Year Site Plans (TYSPs) and other proceedings before the Commission. Our staff analyzed these models, including replicating the estimated model coefficients and associated statistics, and find them to be appropriate for forecasting purposes. Our staff also reviewed the forecast assumptions of anticipated economic and demographic conditions in FPL's service territory. These assumptions are drawn from reputable independent third party sources, including the University of Florida's Bureau of Economic and Business Research, the Florida Legislature's Office of Economic and Demographic Research, and IHS Global Insight. We reviewed these forecast assumptions and find them to be appropriate. Finally, the forecast produced by these models are adjusted to incorporate the effects of incremental wholesale and retail contracts, as well as the incremental load resulting from electric [*11] plug-in vehicles and Economic Development and Existing Facility Riders, which are not otherwise included in FPL's historical load levels.

The second component of FPL's load forecast is a risk adjustment factor designed to reduce the risk of under forecasting future load growth. The company indicated in its petition that because FPL is so highly dependent on natural gas-fired generation, the company's long term system reliability could be jeopardized if actual load growth exceeds forecasted growth. To quantify this risk of under forecasting, FPL analyzed the long term forecasts contained in its TYSPs from 1988 through 2012 and compared these forecasts to actual load growth. In particular, for each year of the ten-year forecast horizon contained in the TYSPs, FPL calculated the differences between the forecasted values of NEL and summer peak demand and their corresponding actual values. From these differences, FPL was able to calculate a confidence interval of forecast accuracy for each of the ten years in the forecast horizon. These ten confidence intervals allow FPL to calculate how much their base case forecasts must be increased so that there is a 75 percent probability that actual [*12] NEL and summer peak demand will be less than or equal to their risk-adjusted forecasts. For the forecasts beyond the ten-year forecast horizon covered by the Ten-Year Site Plans (years 2023 through 2032), FPL utilized a constant adjustment factor associated with the ten-year forecast horizon for its NEL and summer peak demand forecasts. We reviewed the data from which FPL derived its risk adjustment factors and confirmed that the data was correctly taken from prior TYSPs and that the resultant forecast errors, variances, and confidence intervals were appropriately calculated.

In its response to a data request regarding the use of the risk-adjusted forecasting methodology, FPL stated that this project is the first time it has built contingencies into its gas transportation forecasting. FPL responded that "[t]he recent growth in gas usage and FPL's significant dependence on gas as a primary fuel dictate a measure of conservatism is employed in procuring gas transportation as we go forward." n4 FPL further explained that between 2010 and 2012, it exceeded its natural gas consumption forecasts generated that year by 114 MMcf/day, and anticipated this variation to increase to 140 MMcf/day [*13] in 2013.

n4 See Document Number 05759-13, in Docket No. 130198-EI, FPL's response to Staffs Second Data Request, number 7, page 1 of 1, issued September 26, 2013.

Although we are unaware of any prior proceeding in which a risk-adjusted load forecast was utilized, we find that FPL's risk adjustment methodology does reasonably account for and adjust for the risk of under forecasting future load growth. This finding is predicated on two factors. First, the specifications of FPL's three forecasting models discussed above have not significantly changed since 1988. This fact implies that the forecast errors upon which the risk adjustment factors are based must be applicable to the current base case forecasts presented in FPL's petition. Second, FPL's methodology of basing the risk adjustment factors on historical forecast accuracy means that the risk adjustment factors include not only the modeling error (the error associated with reducing the complexities of consumer purchasing decisions regarding electricity to a relatively [*14] simple econometric model), but also the error associated with not being able to specify precisely what future economic/demographic conditions will prevail over the forecast period. FPL's proposed risk-adjusted methodology appropriately accounts for both sources of error, and we find it is a reasonable approach for controlling the risk of under forecasting future load growth.

FPL's choice of selecting a 75 percent confidence interval for its risk adjustment factor is somewhat subjective. For example, FPL could have selected a different confidence interval such as 67 percent confidence interval (with an attendant 33 percent chance of under forecasting), which would lower their risk adjusted forecasts. However, the intuitive appeal of FPL's selection of a 75 percent confidence interval is that it does reduce by half the risk of under forecasting load growth compared to the base case forecasts.

Overall, FPL's base case forecast for summer peak demand is down from that presented in the Florida Energy Secure Line proceeding. As illustrated in Figure 1, the base case forecast for summer peak demand in 2017 is 7.4 percent lower than the risk-adjusted forecast and 3.7 percent lower than the [*15] Florida EnergySecure Line forecast. By 2040, this gap increases to 13.0 percent for the risk-adjusted forecast and 6.3 percent for the Florida EnergySecure Line forecast.

[SEE Figure 1: Summer Peak Demand Forecasts (2013 - 2042) IN ORIGINAL]

Generation Resource Portfolios

After forecasting the increased future system load, the next step in determining FPL's future natural gas requirements was to develop projections of the generation resources that will be required to meet the increased load.

In its petition, FPL prepared two generation resource plans to analyze the effects of a potential delay in the construction of the new Turkey Point nuclear units 6 and 7 on natural gas requirements. The first (or base) case is consistent with FPL's 2013 TYSP and assumes Turkey Point units 6 and 7 enter service in 2022 and 2023, respectively. The second case, called nuclear delay, assumes these two units come into service four years later, in 2026 and 2027. Outside of the ten-year planning horizon, the next planned generating unit is a 3x1 greenfield combined cycle unit, similar in size to the Cape Canaveral, Riviera Beach, and Port Everglades modernized units, with an in-service date of [*16] 2025. The nuclear delay case accelerates the need for this unit, moving its in-service date up to 2022. All further need for new generation is projected to be met by building smaller natural gas-fired combined cycle units. These 'filler' units appear for planning purposes, and do not represent any specific unit planned by FPL. We find the use of filler units and the proposed in-service dates for both cases to be reasonable and we expect the resource plans to meet reserve margin requirements over the period reviewed.

Table 1 illustrates the in-service dates of new generating units under both the base case and nuclear delay case scenarios.

Table 1: Generation Addition Forecasts
(2013 - 2030)

	Planned Generation Additions By Year	
Year	Base Case	Nuclear Delay
2013	Cape Canaveral	Cape Canaveral
2014	Riviera Beach	Riviera Beach
2015		
2016	Port Everglades	Port Everglades
2017		
2018		
2019		
2020		
2021		
2022	Turkey Point unit 6	3x1 CC (2,269 MW)
	Planned Generation Additions By Year	
Year	Base Case	Nuclear Delay
2023	Turkey Point unit 7	
2024		Filler CC (635 MW)
2025	3x1 CC (2,269 MW)	Filler CC
2026	Filler CC (635 MW)	Turkey Point unit 6
2027	Filler CC	Turkey Point unit 7
2028	Filler CC	
2029	Filler CC	Filler CC
2030	Filler CC	Filler CC

[*17]

Natural Gas Transportation Requirement

As discussed above, additional natural gas transportation capacity will be necessary within the next few years as more natural gas-fired generating capacity is added. In 2012, FPL consumed more than 600,000 MMcf of natural gas. By 2017, this figure is expected to increase to at least 718,685 MMcf. The total percentage of FPL's electric power generated by natural gas is expected to be somewhat lower in the next few years, due primarily to increased nuclear production from the recently completed uprate projects of FPL's nuclear units. However, without having additional gas transportation infrastructure available in South Florida, FPL's natural gas-fired generating units will not be able to serve its customers efficiently and reliably.

Using the forecast load cases and generation resource portfolios previously discussed, FPL was able to develop forecasts of the resulting natural gas requirements on both an annual and a peak day basis. As only a finite amount of gas can be transported during any one period and no significant storage capacity for natural gas exists at FPL's plant sites, natural gas pipelines must be sized to meet peak daily loads. [*18]

FPL developed three forecasts for natural gas transportation requirements. We compared the first two forecasts by using the base generation resource plan with the base and risk-adjusted customer load forecasts. As a worst-case scenario for need, we compared the risk adjusted customer load forecast with the nuclear delay generation resource plan. These three scenarios were also compared to the Florida Energy Secure Line base forecast for natural gas requirements. Figure 2 details the peak day natural gas requirements for each of the scenarios.

[SEE Figure 2: Natural Gas Peak Day Requirements (Mmcf/day) IN ORIGINAL]

The base forecast projects a substantial increase in natural gas need in 2017 associated with the addition of the Port Everglades Energy Center and the loss of 375 MW of coal-fired capacity from St. John's River Power Park. The base forecast then indicates a slow increase until 2022, when nuclear generation from Turkey Point unit 6 reduces the need for natural gas. The risk-adjusted case projects a similar trend but gas needs rise to a slightly higher level, about 250 MMcf/day above the base forecast. The risk-adjusted nuclear delay case illustrates the additional fuel that [*19] will be required if Turkey Point units 6 and 7 are delayed by four years. These two forecasts differ by up to 300 MMcf/day in 2024, but become equivalent again in 2028 when both new nuclear units are in-service. The Florida EnergySecure Line gas requirement was included as an additional comparison. The lower rate of natural gas demand for the years 2017 through 2021 seen in the Florida EnergySecure Line forecast is primarily due to the earlier in-service date for Turkey Point units 6 and 7 discussed previously. Excepting the earlier inclusion of nuclear generation, the trends for increasing gas requirements are similar.

As seen in each of these scenarios, FPL's natural gas requirements exceed its existing firm contracted transportation capacity beginning in 2017. Figure 3 provides a closer look at the incremental firm natural gas transportation requirements for the period 2014 through 2030. The proposed contracts match the additional capacity required under the risk adjusted case, with the first optional incremental capacity addition in 2020 matching both risk adjusted cases. This increased gas requirement in 2020 is a result of all three modernization projects (Cape Canaveral, Riviera [*20] Beach, and Port Everglades) being online, as well as the loss of coal-fired generation at St. John's River Power Park.

[SEE Figure 3: Incremental Firm Gas Transportation Requirements (MMcf/day) IN ORIGINAL]

Decision

We reviewed FPL's forecast for customer load, its proposed generation resource portfolios, and the comparison of its resulting natural gas requirements with its existing natural gas transportation contracted capacity. Based on this review, we find that FPL has adequately demonstrated a need for an additional 400 MMcf/day of firm natural gas transmission capacity by 2017.

B. Most Cost-Effective Solution

Following the conclusion of the RFP process, FPL began the evaluation of the proposals it received as a result. In order to determine whether the projects selected by FPL were the most cost-effective, our staff reviewed the RFP and the selection process that resulted in FPL signing precedent agreements with Sabal Trail and FSC.

Evaluation of Project Proposals

The RFP requested that bidders provide proposals for 400,000 MMBtu/day (approximately equal to 400 MMcf/day) n5 of firm gas transportation capacity in 2017 with an incremental 200,000 MMBtu/day of firm [*21] capacity in 2020. In addition, FPL requested that the bidders include an optional incremental capacity of up to 400,000 MMBtu/day beyond the 2020 time period. Bidders could submit pricing on either a fixed or an adjustable demand charge, although FPL expressed its strong preference for fixed pricing in order to obtain pricing security for its customers. Any adjustable pricing had to include a price cap in order to limit exposure to price index volatility.

n5 The quantity "MMBtu/day" is equivalent to one million British thermal units of heat energy per day. Because FPL is ultimately concerned with the energy content of the gas, not the volumetric quantity, the contracts will be for units of MMBtu/day rather than MMcf/day (million cubic feet per day). Although the typical heat energy content of one cubic foot of natural gas is approximately one thousand Btus, consistent with industry practice FPL is requiring a quantity of energy to be delivered in its contracts to ensure the necessary amount of electric power can be generated.

[*22]

FPL received four bids for the Northern pipeline and one joint bid for the Northern and Southern pipelines. No separate bids for the Southern portion were received. The entities submitting bids (some of which were joint proposals from companies bidding as partners) represent all active pipelines in the Southeastern U.S. FPL also considered three self-build alternatives for the Southern pipeline, consisting of three configurations of pipe diameters: all 30-inch pipe (labeled proposal Ai), a combination of 30-inch and 36-inch pipe (labeled proposal Aii), and all 36-inch pipe (labeled proposal Aiii). Although FPL had specified its strong preference for fixed pricing, all proposals except the self-build options were based on adjustable demand charges. However, to meet bid requirements, all adjustable pricing included a price cap. The joint proposal for the Northern and Southern pipelines had significant deficiencies, which the bidder elected not to modify, so FPL eliminated it from further consideration. This situation left four proposals for the Northern pipeline and the three FPL self-build options for the Southern pipeline.

Table 2 illustrates the combined project reference numbers [*23] assigned by FPL during its evaluation of the RFP responses. Each of the four proposals for the Northern pipeline were evaluated using the three configurations of the pipe diameters for the Southern pipeline (proposals Ai, Aii, and Aiii) and assigned reference numbers 1 through 12.

Table 2 - Combined Project Numbers

Combined Project	1	2	3	4	5	6	7	8	9	10	11	12	13
Northern Proposal	1	2	3	4	1	2	3	4	1	2	3	4	1
Southern Proposal		Aii(36"/30")				Ai(30")				Aiii(36")			B

Combined project 13 consists of the Sabal Trail proposal for the Northern pipeline, and the non-compliant bid for the Southern pipeline. It is included for reference purposes only.

The economic evaluation was primarily concerned with a Cumulative Present Value of Revenue Requirements (CVPRR) analysis over a 40-year project term. This type of analysis required that the entire system (including a Northern and a Southern pipeline) be taken into consideration, so FPL created a matrix consisting of each of the four proposals for the Northern pipeline that met the minimum requirements paired with each of the three self-build options submitted by Next-Era Energy for the Southern [*24] system. In order to perform the analysis, FPL evaluated the economics of gas transportation using production-cost simulations of its power supply system, including the costs and volumes of gas.

Because only one proposal received for the Southern pipeline was not an FPL self-build option, in order to ensure that the gas transportation charges for the self-build project were reasonably consistent with market prices, FPL performed an economic analysis of the non-compliant proposal using the indicative, non-firm pricing included in that proposal. The result of this analysis was that the non-compliant bid would be between $ 69 and $ 105 million more expensive than the best of the three compliant proposals.

The simulation model used in the economic analysis employed the same risk-adjusted load forecast utilized for determining the incremental gas transportation capacity requirement. This analysis took into consideration the fixed and variable costs, as well as the volume and timing of the needed gas transportation. After quantifying fuel and other variable costs, a production-cost modeling program was run in order to determine the differences in the CPVRR for each combined project. The [*25] analysis was performed under two different generation resource planning scenarios. The first is the base resource plan, and the second is the nuclear delay resource plan. As previously discussed, the nuclear delay case assumes that the in-service dates of the Turkey Point units 6 and 7 will be delayed by four years, meaning the units will come online in 2026 and 2027 instead of 2022 and 2023, respectively.

The evaluation of FPL's CVPRR analysis concluded that the combination of projects selected by FPL is indeed the most cost-effective. The magnitude of savings between the selected project's cost and that of the other potential projects depends on which resource plan, load forecast, and gas price forecast is utilized in the analysis.

The smallest margin of savings between the selected project and the next-most cost-effective project is $ 34 million (using a 40-year term). This comparison is, however, made using the same Northern pipeline proposal paired with two of the FPL self-build options. In fact, the differences between each of the three FPL self-build options are small enough to be insignificant. When using only the FSC for the Southern pipeline, the net present value cost differential [*26] between Sabal Trail and the next best Northern pipeline is about $ 450 million for a 25-year term and about $ 580 million for a 40-year term. Although the results of the various economic analyses differ widely, the conclusion remains the same: the combination of the Sabal Trail and FSC project is clearly the best alternative in terms of cost.

Cost-Effectiveness of Proposals

Figure 4 shows the cost differentials between the selected combination of projects and the other combined projects for the period 2017 through 2057. The horizontal axis shows the combined project numbers from Table 2. This chart clearly shows the relatively small differences in cost between the three FPL self-build alternatives when compared to the differences between the four Northern project proposals. In general, most of the proposals are also slightly more cost-effective for the nuclear delay case, but the overall difference is small.

[SEE Figure 4: Comparison of the Cost-Effectiveness of the Combined Project Numbers IN ORIGINAL]

Source: FPL's response to our staff's second data request, no. 8

As illustrated above, the most cost-effective proposal is combined project 1, the proposed Sabal Trail and the [*27] FSC hybrid Aii combination. Using figures provided by FPL in a data request, we evaluated the savings for the various Northern pipeline proposals on an annual basis for the initial 25-year contract term, using the same FSC proposal for the southern segment. The baseline for the comparison is combined project 1. Positive values indicate higher costs, and negative values indicate savings. Only combined project 2 shows savings in any year when compared to combined project 1, but it is higher than the other two alternative proposals over the full contract term. Figure 5 shows the differences in total cost between combined projects 2, 3, and 4 using combined project 1 as a baseline.

[SEE Figure 5: Difference in Costs from Combined Project 1 Baseline IN ORIGINAL]

Source: FPL's response to our staff's second data request, no. 8

In addition to the economic evaluation, FPL also conducted a non-economic evaluation based on a comparative analysis of each project with respect to attributes that could not be measured in terms of cost. These attributes, while perhaps not as crucial in the overall evaluation, are also important components of the project and must therefore be taken into consideration. [*28] For example, a project that offers more opportunities for future expansion would offer a non-economic benefit. The selected Sabal Trail and FSC combined project meets FPL's strong preferences for Greenfield infrastructure and increased diversity of natural gas supply. In addition, the throughput volumes of the selected projects are easily increased using compression. However, in light of the considerable margin of cost-effectiveness for the Sabal Trail and FSC combined project, the significance of any non-economic factors was minimal.

Description of the Proposed Pipeline System

The Sabal Trail and FSC projects will provide FPL with approximately 400 MMcf/day additional capacities beginning in 2017, with an expansion to 600 MMcf/day in 2020. Optional expansions, each for an incremental 200 MMcf/day, are available to FPL, but must be elected by 2020 and 2024, respectively. These additions would become available to FPL between four and five years after the options have been taken.

The commencement point specified for the Sabal Trail pipeline system is identical to that designated in FPL's 2009 Florida Energy Secure Line project. Transcontinental Pipe Line Company's Compressor Station [*29] 85 ("Transco Station 85") in Choctaw County, Alabama provides access to non-traditional, onshore suppliers of natural gas, which is an important element to FPL because it introduces supply diversity into the system. Because FPL is currently served by only two natural gas companies, each of which provides gas mostly from Gulf of Mexico and Mobile, Alabama Bay area suppliers, gaining more diversity in its supply is an important component of the project and a primary concern to FPL.

The 2009 Florida EnergySecure Line project specified the "connection point" for the northern and southern parts of the system to be in Bradford County, Florida, near FGT Station 16. However, during the development of the RFP, several interested pipeline companies expressed the opinion that a better option was for a "hub" in the Orlando area due to the large potential customer base for contract opportunities. Therefore, in order to not only meet the primary goal of the RFP to fulfill FPL's increased need for natural gas transportation capacity, but also to further increase the diversity of the supply and to promote competition among suppliers, the chosen termination point is what will become the Central Florida [*30] Hub (CFH). The CFH, which is part of the contract for the Sabal Trail pipeline and will be constructed and operated by the same provider, will be an interconnection point between the Northern and Southern pipelines as well as with existing Gulfstream and FGT systems. The CFH will include facilities needed to provide hub wheeling services to deliver contracted capacities interchangeably between and among each of the pipelines, which further increases the flexibility and possible diversity for all the gas shippers in the area.

The Southern pipeline commences at the CFH and terminates at the existing natural gas yard at FPL's Martin Clean Energy Center (Martin), in Martin County, Florida. This terminus location allows for connectivity with the modernized generation plants at Cape Canaveral and Riviera Beach, and because both FGT and Gulfstream currently serve the Martin plant, the addition of the FSC will increase the supply alternatives available to FPL in the event of a pipeline disruption.

Cost Recovery

In response to its RFP, FPL received a total of four proposals for the Northern Pipeline Project and one joint proposal from two companies for the Southern Pipeline Project. [*31] Based on FPL's economic and non-economic evaluations, the Sabal Trail proposal was selected for the Northern Pipeline Project and the FSC proposal for the Southern Pipeline Project. Next-Era Energy is an equity stakeholder in Sabal Trail, and has agreed to operate Sabal Trail as a joint venture between Spectra and a newly formed Next-Era Energy subsidiary called USSGI. Also, FSC is a wholly owned subsidiary of Next-Era Energy, and an affiliate of FPL. FPL does not anticipate any charges coming from USSGI associated with the Northern Pipeline Project. However, FPL stated in a data request response that any costs incurred by FPL for goods or services provided to USSGI or FSC, will be charged in accordance with FPL's Cost Allocation Manual or through an Affiliate Management Fee, and would be subject to internal company review and audits to ensure compliance with *Rule 25-6.1351* F.A.C. We have the authority to review any transactions with affiliated companies to ensure compliance with *Rule 25-6.1351* F.A.C.

Based on Order Nos. 12645 n6 and 14546 n7, prudent and reasonable transportation charges incurred [*32] in the delivery of fuel are allowable expenses in the fuel and purchased power cost recovery clause. Therefore, pipeline charges associated with the delivery of natural gas to FPL's generating stations are eligible for recovery through the fuel clause. While we find that this project is cost effective relative to alternatives, we retain authority to determine the prudent cost and reasonableness of expenses charged to the fuel clause and will review these expenses annually as part of the fuel clause proceedings.

n6 Order No. 12645, issued November 3, 1983, in Docket No. 830001-EU, In re: Investigation of Fuel Adjustment Clauses of Electric Utilities.

n7 Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI, In re: Cost Recovery Methods for Fuel Related Expenses.

In its response to a data request regarding its plans for dispensing of any unused gas, FPL stated that, in periods of idle capacity due to lower loads, it "can pursue opportunities to release capacity on the new pipelines (or to release capacity [*33] on FGT and/or Gulfstream) to other shippers. All revenues generated from the capacity release transactions would be credited back to the customers through the Fuel Clause." n8

n8 FPL's response to Staff's second data request, no. 5, filed on September 26, 2013.

Decision

Upon review, FPL's decision to enter into long-term natural gas transportation contracts with Sabal Trail and FSC was based on a fair and open RFP process. The contracts are projected to save up to $ 450 million over the term of the contracts when compared to the next most cost-effective proposal. We find that FPL is eligible to seek recovery of costs associated with the firm natural gas transportation contracts with Sabal Trail and FSC in the fuel clause, where they will be reviewed annually. The prudence of the actual transportation costs will be examined in the annual Fuel Docket proceedings.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company has demonstrated a need for 400 MMcf/day [*34] of additional firm natural gas transmission capacity by 2017. It is further

ORDERED that Florida Power & Light is eligible to seek recovery of costs associated with firm natural gas transportation contracts in the fuel clause, where they will be reviewed annually. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by *Rule 28-106.201*, Florida Administrative Code, is received by the Commission Clerk, Division of the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 28th day of October, 2013.

Summary Information
Gas Reserve Action by Other Utilities

- Commissions from three states have approved some form of IOU cost recovery concerning the purchase and or development and production from gas reserves.
    - Montana, North-Western Energy (2010 & 2013)
    - Oregon, NW Natural Gas (2011)
    - Utah, Questar Gas (2013)

- None of these projects or the associated method of cost recovery are entirely similar to that proposed in the FPL petition.

- As found in the Commission orders associated with these programs all were approved, at least in part, to provide the utility with a longer term price or supply hedging tool that are not currently available to them in the market place.

- All of the approved gas reserve programs in these states are being implemented for the benefit of "core gas customers" and do not affect rates to other types of customers. While North-Western Energy is a combined electric and gas utiliy their program has only been approved for use on the gas operation side of the company. Beyond FPL, no other electric IOU utility has requested or had a program approved.

- Methods of cost recovery:

    - North-Western Energy, case by case review, interim inclusion of the investment in ratebase upon a showing that "the transactions provide compelling customer benefits over buying gas at market prices."
    - NW Natural Gas, recovery through the Purchase Gas Adjustment mechanism of "all cost of gas produced and delivered plus a ratebase return on the investment."
    - Questar Gas, "cost of service pricing, however if the combined annual production exceeds 65% of the forecasted annual demand and the cost of service price is greater than the Questar Gas purchased-gas price, an amount equal to the excess production times the excess price will be credited back to Questar Gas customers." In addition, "Wexpro (the company created by Questar to develop the reserves) may also sell production to manage the 65% level and credit back to Questar Gas customer the higher of market price or the cost of service price times the sales volumes." Typically a cost of service price would include some form of a return on investment.

- One municipal utility, Los Angeles Department of Water and Power (DWP), is known to have bought a piece of the Pinedale Natural Gas Reserves located in Wyoming. While pricing information (how it will affect customers' rates) has not been released, DWP stated at the time of purchase that this action was taken "in order to stabilize the single most volatile component in DWP's operating expense."

Legal basis as identified in orders approving investment in gas reserves

In general it seems that only Montana has direct statuary support allowing for the investment in gas reserves by an investor owned utility.

North-Western Energy

> "Since 2009, NWE has been allowed by Montana law to acquire natural gas production and gathering facilities and seek inclusion of them in its rate base. (69-3-1413, et seq. MCA.)",
> Docket # D2012.3.25, Order # 7210b
>
> "Inclusion in the natural gas tracker as an interim cost recovery method. 69-3-201 MCA.", Docket #N2005.6.101, Order # 6683d
>
> "Cost recovery by inclusion in rate base. 69-4-101 and 102 MCA.,
> Docket #D2012.3.25, Order # 7210b

Northwest Natural Gas

> Approved by Stipulation, Docket# UM1520/UG 204 Order #11 140
>
> Support for inclusion in the automatic adjustment clause (their purchase gas clause), ORS 757.210

Questar Gas

> Programs must meet public interest standard Utah Code Ann 54-4-1 et seg.,
> Docket # 12-057-13 Ordered issued March 28, 2013
>
> Cost recovery pricing set using cost of service model Utah Administrative Code R746-100 et seq. Docket # 12-057-13 Ordered issued March 28, 2013

Service Date: November 16, 2012

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

* * * * *

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	))))	REGULATORY DIVISION DOCKET NO. D2012.3.25 ORDER 7210b

FINAL ORDER

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

BEFORE:

TRAVIS KAVULLA, Chairman
GAIL GUTSCHE, Vice Chair
W. A. GALLAGHER, Commissioner
BRAD MOLNAR, Commissioner
JOHN VINCENT, Commissioner

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 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 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 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, 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]

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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.

15. NWE described the ROE/Capital Structure Stipulation 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 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 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 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*.

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 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 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 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 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 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 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, 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 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 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 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. 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 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 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.

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 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 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 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 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 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 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 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. 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 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 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 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 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 ¶48 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 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.

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 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 NWE and MCC." *2011 Comments*, ¶ 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 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 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 today's prices, NWE would want to revisit the terms of the Stipulation with MCC. *Id.* NWE should continue to use a standardized natural 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 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 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 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 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 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 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 GUTSCHE, Vice Chair

W. A. GALLAGHER, Commissioner

BRAD MOLNAR, Commissioner (dissenting)

JOHN VINCENT, Commissioner

ATTEST:

Aleisha Solem
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten (10) days. See 38.2.4806, ARM.

ORDER NO. 11 140

ENTERED APR 28 2011

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1520/UG 204

In the Matters of NORTHWEST NATURAL GAS COMPANY, dba NW Natural Applications for Deferred Accounting Order Regarding Purchase of Natural Gas Reserves (UM 1520) and Proposed Purchase of Natural Gas Reserves (UG 204)	ORDER

DISPOSITION: STIPULATION ADOPTED; PROPOSED TRANSACTION FOUND PRUDENT; SUPPLEMENTAL ORDER TO BE ISSUED

In these dockets, Northwest Natural Gas Company, dba NW Natural (NW Natural or Company) seeks approval of applications related to a proposed joint venture with Encana Oil & Gas (USA) Inc. (Encana) to develop gas reserves for service to NW Natural's customers. In docket UG 204, NW Natural requests an order that the Company's decision to acquire a long-term property interest in specified natural gas reserves negotiated with Encana (the Proposed Transaction) is prudent. In docket UM 1520, NW Natural requests that it be allowed to implement deferred accounting to track related expenses from the date of the Proposed Transaction through October 31, 2011, when the Company proposes to begin to recover its expenses through its purchased gas adjustment (PGA) filings. NW Natural requests that we process these applications on an expedited basis, explaining that it needs a decision by May 1, 2011, to execute the negotiated transaction.

Following the filing of opening testimony and a series of settlement negotiations, the four active parties to this docket, NW Natural, the Citizens' Utility Board of Oregon (CUB), the Northwest Industrial Gas Users (NWIGU), and the Commission Staff (Staff) (collectively, Parties), entered a settlement of all issues and presented a stipulation for Commission adoption.[1] The stipulation is attached as Appendix A and incorporated by reference.

In the stipulation, the Parties agree it is likely that the Proposed Transaction will provide benefits to NW Natural's customers, and that, subject to the terms of the stipulation, the Company's decision to enter into the joint venture is prudent. Under the negotiated terms of the Proposed Transaction, NW Natural would enter into a joint venture with Encana to partially fund the drilling of natural gas wells in the Jonah Field in Sublette County, Wyoming, owned by Encana. In return, NW Natural would earn a working interest in the gas reserves in the Jonah Field. NW Natural will invest about $251 million over 5 years and expects to receive a specified volume of gas over a 30-year term. NW Natural either can take its gas in kind, or it can have Encana sell the gas at market prices, allowing the Company to purchase replacement gas at market prices.

The stipulation also sets forth the Parties' agreed alternative ratemaking treatment for the Proposed Transaction. Among other things, the parties agree that the capitalized costs authorized in rates are capped at $251 million. As an interim matter, the initial rates to cover NW Natural's carrying costs will be calculated at the Company's authorized cost of capital, approved by the Commission in docket UG 152, subject to a retroactive adjustment once the Commission authorizes a new cost of capital for the Company. NW Natural's investment will be amortized over 30 years to match the expected volumes, with the opportunity for the parties to reexamine and recommend adjustments to the amortization schedule in five years.

In addition, the Parties agree that the costs of the Proposed Transaction should be recovered on an ongoing basis through NW Natural's annual PGA mechanism, including the deferral process for the commodity cost of gas. All variances from forecast amounts associated with the costs and volumes are subject to the PGA sharing mechanism, up to the first $10 million of the variance in any annual period. Any variance in excess of $10 million, whether positive or negative, will be passed through to customers through the PGA sharing mechanism at 100 percent. Similarly, any savings or costs resulting from NW Natural's decision to take gas in kind or have Encana sell it will be subject to the PGA sharing mechanism. Where the Company incurs additional costs because it purchases replacement gas at a higher price, the stipulation provides for NW Natural to provide notice to the other parties and later explain the transaction.

Finally, the stipulation contains other terms, including the requirement that NW Natural will file a request for a general rate revision not later than December 31, 2011, and submit various reports associated with the Proposed Transaction to the parties and the Commission.

[1] Cascade Natural Gas Corporation intervened as a party but did not file testimony in the proceedings.

DISCUSSION

For reasons to be provided in a supplemental order in these proceedings, we adopt the uncontested stipulation. Although this matter was presented to us on an extremely expedited basis, we have received sufficient information from the parties and our Staff to determine that NW Natural's proposed purchase of the natural gas reserves, under the negotiated terms of the Proposed Transaction, is prudent. We agree with the parties that the Proposed Transaction is likely to produce benefits for NW Natural's customers, that the risk of the transaction has been reasonably mitigated, and that the remaining risk is appropriately shared between shareholders and ratepayers under the terms of the stipulation.

As stated in the stipulation, the finding of prudence does not prevent the parties from challenging the prudence of the Proposed Transaction if new information arises that demonstrates that NW Natural knew, or should have known, something of consequence to the Proposed Transaction at the time of entering it. Moreover, the finding of prudence at this time applies only to NW Natural's decisions to enter into the Proposed Transaction, and not any subsequent decisions the Company might make in terms of exercising its discretion to manage underlying contracts.

By issuing this order to approve the stipulation and enter a finding of prudence, we provide NW Natural the requisite approval prior to May 1, 2011, to permit the Company to proceed with the transaction. Due to the limited time since the filing of the Parties' stipulation and supporting testimony, however, we have not yet had time to prepare our complete written analysis explaining the bases for our conclusions that support the adoption of this stipulation. We will therefore issue a supplemental order providing a more complete summary of the Proposed Transaction, the stipulation, the Parties' testimony supporting the stipulation, and our compete analysis.

ORDER

IT IS ORDERED that:

1. The stipulation among Northwest Natural Gas Company, dba NW Natural, the Citizens' Utility Board of Oregon, the Northwest Industrial Gas Users, and the Staff of the Public Utility Commission of Oregon, attached as Appendix A to this order, is adopted.

2. The Proposed Transaction between Northwest Natural Gas Company, dba NW Natural, and Encana Oil & Gas (USA) Inc., is prudent as described in the stipulation.

3. The application for deferred accounting regarding the purchase of natural gas reserves, filed by Northwest Natural Gas Company, dba NW Natural, is approved.

4. The revised Schedule P, attached as Exhibit A to the stipulation, is approved.

5. Northwest Natural Gas Company, dba NW Natural, must file compliance tariffs consistent with the terms of this order no later than 10 days from the date of this decision.

Made, entered, and effective APR 28 2011.

John Savage	**Susan K. Ackerman**
Commissioner	Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1520, UG 204

In the Matters of NORTHWEST NATURAL GAS COMPANY, dba NW Natural, Application for Deferred Accounting Order Regarding Purchase of Gas Reserves (UM 1520), and Application for Proposed Purchase of Natural Gas Reserves (UG 204).	STIPULATION

This Stipulation resolves all known issues among the parties to this Stipulation related to Northwest Natural Gas Company's ("NW Natural" or "Company") request in these dockets for approval by the Public Utility Commission of Oregon ("Commission") of its acquisition of natural gas reserves.

I. PARTIES

1. The parties to this Stipulation are Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Northwest Industrial Gas Users ("NWIGU"), and NW Natural (together, the "Parties").

II. BACKGROUND

2. For several years, NW Natural has been investigating opportunities to obtain a long-term fixed-price gas supply for approximately 10 percent of its portfolio. The Company believes that such an arrangement would provide substantial benefits to its customers. The Company has now entered into an agreement intended to provide long-term price stability through a joint venture with Encana Oil & Gas (USA) Inc ("Encana") to

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develop gas reserves (the "Proposed Transaction"). In these consolidated dockets, NW Natural requests Commission approval for the Proposed Transaction.

A. Terms of the Proposed Transaction

3. The Proposed Transaction calls for NW Natural and Encana to enter into a joint venture to develop gas reserves for service to NW Natural's customers. Encana will contribute its interest in certain natural gas leases and wells in the Jonah Field, which is located in the Green River Basin in Sublette County, Wyoming. NW Natural will participate with Encana by paying to Encana a portion of the costs of drilling a specified number of new wells referred to in the agreements as "Carry Wells." For each Carry Well drilled, the Company will receive either a working interest in a section of the field (including existing wells and the Carry Wells) or a working interest in the reserves in the field plus a certain percentage of the output of the drilled well, depending upon the section in which the well is drilled. The details of the Proposed Transaction are described in paragraphs 4 through 6 below.

4. Over five years, NW Natural will invest approximately $251 million in the Proposed Transaction through its commitment to pay a portion of the costs of drilling its Carry Wells. In addition to this initial capital investment, over the life of the agreement the Company will pay a portion of the costs to operate and maintain its wells, and to gather and process the gas from those wells. NW Natural expects to receive 63 percent of the total gas from the Proposed Transaction in the first 10 years, 83 percent in the first 15 years, and 94 percent by the end of year 20. The remaining volumes would be received until the wells are finally capped at the end of their useful life—estimated to be approximately 30 years from the date NW Natural and Encana enter into the agreement as described in Paragraph 2 above. These gas volume amounts are expected to represent

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approximately 10 percent of NW Natural's total annual gas requirements during the first ten years of the agreement, and will taper off over the remaining expected life of the wells.

5. The ownership interest earned by NW Natural in the Jonah Field gas reserves differs depending on where in the Jonah Field the wells are drilled. For each well drilled by NW Natural in the part of the Jonah Field referred to as the Updip Area, NW Natural will earn a percentage interest in the oil and gas lease and all of the wells (and all of the gas produced) in one of three sections in that area, up to a specified maximum interest in each section. For each well drilled by NW Natural in the part of the Jonah Field referred to as the Downdip Area, NW Natural will earn a percentage interest in the individual wellbore, (and the gas produced by that well) in addition to the specified interest in the leases, wells and gas produced in one of the sections in the Updip Area as described above. Under the terms of the agreement, Encana will act as the operator of the wells, subject to the terms of the Joint Operating Agreement (NWN/502). Under the Joint Operating Agreement, NW Natural can elect to take its share of production in kind, to sell the production, or to transport it to NW Natural's distribution system. Alternatively, NW Natural may elect to have Encana sell NW Natural's share of production at market prices, and to receive the proceeds of such sale, minus the appropriate royalty and other costs specified in the Proposed Transaction. Then NW Natural could use the proceeds to purchase quantities of gas (or offset portions of the cost of gas) at Opal or from other locations. Initially, NW Natural has elected to have Encana sell NW Natural's share of production.

6. The Proposed Transaction is specifically conditioned upon NW Natural receiving Commission approval, including a finding of prudence.

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B. **Dockets UM 1520 and UG 204.**

7. Docket UM 1520 was opened on January 31, 2011, when NW Natural filed an Application for Deferred Accounting that sought the deferral of expenses related to the Proposed Transaction from the date of its closing (following Commission approval) through the date that the costs are included in rates through the Company's Purchased Gas Adjustment Mechanism ("PGA") on October 31, 2011.

8. Thereafter, on February 18, 2011, the Company filed Advice No. OPUC 11-2, along with its direct testimony, opening Docket UG 204. This filing requests a Commission order finding the Proposed Transaction is prudent and requests approval of revisions to Schedule P of NW Natural's tariff (see Exhibit A) including provisions that will allow NW Natural to assign to its Oregon customers the benefits and costs associated with the Proposed Transaction.

9. On February 22, 2011, Administrative Law Judge ("ALJ") Patrick Power consolidated these two dockets. On February 25, 2011, ALJ Power granted NWIGU's petition to intervene and took notice of CUB's February 3, 2011, notice of intervention.[1]

10. On March 11, 2011, the Commission held a workshop where the Company presented the Proposed Transaction's details and its analysis outlining its proposed ratemaking treatment and estimated customer benefits. At that workshop, presentations were also made by Encana, and certain consultants that had reviewed the Proposed Transaction for NW Natural and the Parties. Also at that workshop the intervening parties and Staff made comments and explained portions of their positions relative to the Proposed Transaction.

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[1] Cascade Natural Gas Corporation also intervened in this docket, although it has not been an active participant and is not a party to this Stipulation.

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11. At the time that the Company filed its direct testimony, the final transactional documents had not yet been fully executed. Therefore, on March 23, 2011, the Company filed supplemental direct testimony that included final and fully executed copies of all of the primary transactional documents, including the Carry & Earning Agreement (NWN/501) and the Joint Operating Agreement (NWN/502).

12. Pursuant to the procedural schedule, Staff, CUB, and NWIGU filed testimony on March 30, 2011.

13. A settlement conference was held on March 31, 2011, and was followed up with conference calls on April 1 and April 4. All the Parties participated in the conference and the subsequent calls.

14. The timeline for Commission review of the Proposed Transaction is very short – this is an expedited docket. Nonetheless, the Parties did, in short order, conduct an analysis of the terms of the Proposed Transaction and its attendant risks and benefits. Staff and the intervening parties served, and the Company provided responses to (both up to the date of the filing of testimony and thereafter), more than 150 data requests seeking detailed information about the Proposed Transaction. The Company also made available to Staff and the intervening parties and the Commission drafts and final copies of all transactional documents (final documents being made available just before testimony was due and filed), and reports prepared by Netherland and Sewell (regarding volumes of gas reserves in the Jonah Field), draft reports by KPMG (regarding the pricing assumptions and benefits of the Proposed Transaction – final report received after testimony was filed), and Environ (regarding environmental review of Encana's operations at the Jonah Field) as part of the Company's evidence of its due diligence.

15. In addition, the Company agreed to fund the retention of an independent legal counsel to act as special legal counsel to CUB and NWIGU for the purpose of reviewing

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the transactional documents under Wyoming oil and gas law and to independently advise CUB and NWIGU.

III. AGREEMENT

16. The Parties agree that it is likely that the Proposed Transaction, over its life, will provide benefits to NW Natural's customers and that therefore, subject to the terms and conditions set forth in this Stipulation and exhibits hereto, including but not limited to the accompanying supporting testimony, the Company's decision to enter into the Proposed Transaction is prudent. Moreover, the Parties agree that given the unique nature of the Proposed Transaction, the Commission should make a finding of prudence at this time based upon the information the Parties have reviewed. However, the Parties recognize that the review in this case has been expedited and that, if in the future, new information, not made available to Staff and the intervening parties, arises which demonstrates that NW Natural knew, or should have known, something of consequence to the Proposed Transaction at the time of the Proposed Transaction, Staff and the intervening parties can then use that information to challenge the prudence of the Transaction. On this point, the Parties agree that a prudence finding by the Commission at this time should apply only to the Company's decision to enter into the Proposed Transaction, and not to any subsequent decisions the Company might make in terms of exercising its discretion to manage the contract. The Parties specifically agree that a prudence finding by the Commission at this time should not, for example, extend to a future decision by the Company to participate in drilling Elective Wells, as that term is defined in the Carry and Earning Agreement (NWN/501). If the Company does choose to participate in drilling Elective Wells, the Parties agree that such decisions would be subject to separate determinations of prudence in future proceedings. Other decisions in addition to that of the drilling of Elective Wells may also require separate prudence findings.

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17. For ratemaking purposes, the Parties agree that the costs of the Proposed Transaction should be recovered on an ongoing basis only through the Company's annual Purchased Gas Adjustment ("PGA"), including the deferral process for the commodity cost of gas. Each year the Company will re-forecast and will update costs associated with the Proposed Transaction, including depletion rate, volumes, operating costs (including midstream costs and ad valorem and severance taxes), and return (carrying costs). These costs will be included in the Company's PGA filing. To calculate the Proposed Transaction's cost of gas for inclusion in the WACOG for the PGA, the Company will divide the projected annual cost of service by the therms expected to be received under the Proposed Transaction. The cost of service will consist of five components: (1) depletion, (2) operating expenses, (3) midstream costs, (4) severance and ad valorem taxes, and (5) return on the investment (carrying costs). The Parties agree that the operating expense and midstream costs are subject to ongoing prudence reviews in the annual PGA filing as provided in Paragraph 16. For purposes of PGA rate calculations and cost of gas deferrals, items 1 through 5 above will be computed and included as part of the Company's commodity costs. Exhibit B attached hereto provides an example of the development of the rate components for gas related to the transaction. For purposes of recording expenses on its books, and for the earnings test, only items 1 through 4 above will be, and the carrying costs will not be, included as part of the Company's cost of gas. For purposes of any general rate proceeding, NW Natural agrees to remove the amounts associated with carrying costs and rate base, including accumulated depletion and deferred (and accumulated deferred) taxes from its books to avoid the potential for double recovery related to the continual ratemaking for the Proposed Transaction. Also, each year at the same time as the earnings test is filed, the Company will provide a separate

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reporting of the earnings test year with the transaction results removed as they would be for a rate case. Exhibit C attached hereto illustrates this proposed ratemaking treatment.

18. Cost of Capital: To address the dispute that has arisen with respect to the appropriate return on the investment included in rates through the PGA, the Parties have agreed to a retrospective adjustment of the cost of capital portion of rates, i.e. the portion of the rates designed to recover the Company's return on equity ("ROE") and cost of debt. As an interim matter, the initial rates to recover the Company's carrying costs in the Proposed Transaction will be calculated at the Company's authorized cost of capital, as determined by the Commission in Docket UG 152. However, the Parties agree that once the Commission authorizes a new cost of capital in the Company's next general rate case, the Company will calculate the difference between the current cost of capital as it relates to the Proposed Transaction as authorized by the Commission in docket UG 152 and the newly authorized cost of capital. The Company will then refund to (or surcharge) customers 100 percent of that difference through the PGA mechanism. This adjustment will occur whether the newly authorized cost of capital is higher or lower than the UG 152 cost of capital. This adjustment is a onetime event and thereafter the return on this investment will be calculated at the new Commission-authorized cost of capital that applies generally to the Company. The applicable cost of capital would be adjusted each time the Commission authorizes a new cost of capital in the context of a general rate proceeding.

19. Incremental Cost of Capital: The Parties also agree that in future rate cases, no Party will use the Proposed Transaction to argue for a higher or lower cost of capital. This provision prohibits parties from seeking incremental adjustments (higher or lower) to their cost of capital calculated using traditional or prevailing methods based on the effects of the Proposed Transaction.

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20. <u>Cost Sharing:</u> The Parties agree that variances from forecast amounts associated with the costs and volumes related to the Proposed Transaction will be subject to the PGA's normal sharing mechanism, up to the first $10 million of the variance in any annual period, whether that variance is positive or negative. All variance in excess of $10 million (whether positive or negative) will be passed through to customers through the PGA at 100 percent. For instance, in the event that NW Natural has elected 90%/10% sharing in a particular PGA year and in the event variances from forecast amounts associated with the Proposed Transaction in that PGA year come to $11 million, NW Natural will bear $1 million of the variance and customers will bear $10 million ($10 M = (90% x $10 M) + (100% x $1 M)) of the variance. Likewise, if variances result in a benefit of $11 million, then NW Natural will retain $1 million of the savings and customers will realize $10 million in savings (as in the equation above).

21. <u>Amortization:</u> The Parties agree to amortize this investment over 30 years in a manner designed to match the expected volumes. However, the Parties agree to revisit this amortization schedule in five years to determine whether the amortization schedule should be modified for any reason, notwithstanding the annual revisions as specified in paragraph 17 above. Further, for purposes of facilitating the periodic development of amortization rates to be used in recording amortization expense, the Parties specifically request that the Commission, as part of its Order in this proceeding, authorize the company to develop amortization rates assuming the entire investment, net of any cumulative amortization, and the entire remaining volume delivery forecast.

22. <u>Marketing Variances:</u> Under the terms of the Proposed Transaction, the Company has the ability to either take its share of gas production in kind or it can elect to have Encana sell the Company's share of the gas at market prices. If the Company elects to have Encana sell its share, the Company can then purchase replacement gas at Opal

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or another location. The Parties agree that any savings resulting from Encana marketing NW Natural's share of the gas will be subject to the PGA sharing mechanism unless the savings become predictable and are included in the forecasted WACOG. In the event that the Company purchases replacement gas as described under this paragraph at a price higher than the price at which Encana sells the gas under the marketing agreement, the Company agrees to provide written notice to the other Parties within 14 days of the transaction. The Parties also agree that if this occurs, the transaction will be placed on the agenda of the next quarterly meeting of the Gas Portfolio Review meeting, where the Company will explain the facts and provide documentation surrounding the purchase. Notwithstanding anything else in this paragraph, the Parties specifically agree that if the Company does purchase replacement gas at a price higher than the price the Company receives for gas sold by Encana, the purchase of replacement gas will be subject to ongoing prudence reviews as provided in Paragraph 16.

23. **Capital Costs:** The Parties agree that the capital costs authorized in rates are capped at $251 million related to the overall investment per well under the agreement. In addition, transactional costs (the incremental amount needed to produce the transaction, including all due diligence-- of up to $1.5 million) will also be capitalized and will be amortized volumetrically with the investment capital costs.

24. **Additional Reporting:** The Parties agree that NW Natural will provide the following:

a. A report that identifies the Company's contract management duties and responsibilities with respect to the Joint Operating Agreement and the Carry and Earning Agreement. This report must be filed within 30 days of the Commission's order approving this Stipulation.

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b. Prior to the Company's 2016 PGA filing, the Company agrees to file a detailed report that describes the results of the Proposed Transaction. This report will include a comparison of actual results to forecast results and an assessment of the Company's actions with respect to its ongoing duties and responsibilities managing the Joint Operating Agreement and the Carry and Earning Agreement.

c. Each quarter, as part of the regular quarterly portfolio review process, the Company agrees to report on the decisions it has made to manage the Proposed Transaction's investment.

d. The Company agrees to report to the Commission, within 10 days, of (1) any ratings downgrade of Encana; (2) any environmental liability or cleanup by Encana exceeding $20,000; or (3) any event that materially impacts the operations and drilling in the Jonah Field.

25. The Company agrees to file a general rate proceeding no later than December 31, 2011.

26. The Parties agree that the Commission should approve NW Natural's Application for Deferred Accounting, filed in UM 1520, and the revised Schedule P attached hereto as Exhibit A subject to the agreement and conditions set forth in this Stipulation and exhibits attached hereto. The Parties agree that approval of Schedule P will result in just and reasonable rates.

27. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the adjustments and the rates resulting from this Stipulation are fair, just, and reasonable.

28. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation

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at any hearing (if necessary), and recommend that the Commission issue an order adopting the settlements contained herein.

29. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties reserve the right to cross–examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented including the right to raise issues that are incorporated in the settlements embodied in this Stipulation.

30. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

31. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

32. In the event that the Proposed Transaction does not close because NW Natural determines that it has not received an order from the Commission that is satisfactory, no Party shall be bound by any of the terms of this Stipulation.

33. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

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This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF

By: ____________________

Date: 4/19/11

CITIZENS' UTILITY BOARD

By: ____________________

Date: ____________________

NW NATURAL

By: ____________________

Date: ____________________

NWIGU

By: ____________________

Date: ____________________

McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400

This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF	CITIZENS' UTILITY BOARD
By:	By: Bob Jenks
Date:	Date: 4-19-2011
NW NATURAL	NWIGU
By:	By:
Date:	Date:

McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

NW NATURAL

By: [signature]

Date: 4/19/11

NWIGU

By: ______________________

Date: ______________________

McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

This Stipulation is entered into by each Party on the date entered below such Party's signature.

STAFF	CITIZENS' UTILITY BOARD
By: ______________	By: ______________
Date: ______________	Date: ______________
NW NATURAL	NWIGU
By: ______________	By: Paula E Pyron
Date: ______________	Date: 4/19/2011

Exhibit A

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 24 _______ Revision of Sheet P-1
Cancels _________ Revision of Sheet P-1

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS

APPLICABILITY:
This schedule applies to all schedules for natural gas Sales Service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE:
The purpose of this schedule is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to the customer notification requirements as described in OAR 860-022-0017.

DEFINITIONS:

1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of natural gas associated with pipeline imbalances, plus propane costs, plus odorization charges, if applicable, less Net Commodity Off-System Sales Revenues for the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, plus the costs of Gas Reserves,[1] less all transportation demand charges embedded in commodity costs.

2. Net Commodity Off-System Sales Revenues: Revenues from the sale of natural gas to a party other than the Company's Oregon Sales Service customers less costs associated with the sales transactions.

3. Variable Transportation Costs: Variable transportation costs, including Pipeline volumetric charges, and other variable costs related to volumes of commodity delivered to Sales Service customers.

4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual Pipeline refunds or surcharges.

5. Demand Costs: Fixed monthly Pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity costs.

6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full Pipeline rate, and 80% of the capacity release revenues exceeding amounts reflecting full Pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

[1] Per the terms of the Stipulation in Docket UM 1520.

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NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 24

_____ Revision of Sheet P-4
Cancels _________ Revision of Sheet P-4

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

19. Embedded Non-Commodity Cost – MDDV Based Sales Service: The Estimated Non-Commodity Cost per Therm – MDDV Based Firm Sales Service multiplied by the Actual Monthly MDDV Sales Service Volumes.

20. Financial Transactions: Cost of Financial Transactions related to gas supply, including but not limited to, hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.

21. Gas Storage Facilities: The cost of natural gas for injections shall be the actual cost of purchasing gas for storage and the cost of injection of the gas into the storage facility. Withdrawals of natural gas shall be valued at the weighted average cost of gas in the facility plus any variable withdrawal costs. For purposes of annual rate filings, the cost of inventory in storage shall be an overall average cost including existing inventory volumes and costs and refill inventory volumes and costs. Refill volumes will be priced at the expected pricing used in each filing. Only the cost of natural gas withdrawn from Gas Storage Facilities will be included in the Actual Commodity Cost, as defined herein.

22. Seasonalized Fixed Charges: The projected monthly non-Commodity costs of gas recovery, calculated by multiplying the Embedded Non-Commodity Costs by Oregon forecasted sales.

23. Gas Reserves: The volumes of natural gas actually received by the Company through its acquisition of gas reserves through joint venture agreements as authorized by the Commission.[1] For purposes of annual rate filings, the cost of Gas Reserves includes all carrying costs on the rate base investment, amortization, operating expenses, gathering and processing costs, and ad Valorem and severance taxes. The cost of Gas Reserves will be included in Actual Commodity Costs. (N)

(N)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES:
The Company shall maintain sub-accounts of Account 191. Monthly entries into these sub-accounts shall be made to reflect: 1) the difference between the monthly Actual Commodity Cost and the monthly Embedded Commodity Cost, 2) the difference between Actual Non-Commodity Cost and the monthly portion of Estimated Non-Commodity Cost and, 3) the difference between Embedded Non-Commodity Cost and monthly Seasonalized Fixed Charges. The entries shall be calculated each month as follows:

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects.

(continue to Sheet P-5)

[1] See Commission order in UM 1520

Effective with service on
and after May 1, 2011

NORTHWEST NATURAL GAS COMPANY
P.U.C. Or. 24

_______ Revision of Sheet P-5
Cancels _____ Revision of Sheet P-5

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

2. A debit or credit entry shall be made equal to 100% of any monthly difference between Embedded Non-Commodity Costs and Monthly Seasonalized Fixed Charges. The monthly Seasonalized Fixed Charges for the period November 1, 2010 through November 30, 2011 are:

November 2010	$8,508,808
December 2010	$12,783,584
January 2011	$12,472,968
February	$10,224,130
March	$8,795,971
April	$6,322,866
May	$4,126,576
June	$2,703,901
July	$2,166,691
August	$2,157,069
September	$2,417,892
October	$5,432,235
November	$9,197,282
ANNUAL TOTAL	$78,801,165

3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds $10 million, amounts beyond $10 million will be recorded at 100%. (N) (N) (N)

4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.

6. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.

7. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continue to Sheet P-6)

Effective with service on
and after May 1, 2011

Exhibit B

Reserves Acquisition Project
Sample PGA Backup Document

Volume and Rate Per Therm would be Included in the PGA to develop WACOG (Lines 21 and 22)

			Projected November 20XX	Projected December 20XX	Projected January 20XX	Projected February 20XX	Projected March 20XX	Projected April 20XX	Projected May 20XX	Projected June 20XX	Projected July 20XX	Projected August 20XX	Projected September 20XX	Projected October 20XX
1	Therms Delivered (000s)													
2	Total Therms		1,132.0	1,310.8	1,475.7	1,631.5	1,780.3	1,987.6	2,087.5	2,302.5	2,358.1	2,547.4	2,846.6	3,061.7
3	Rate per Therm (Depletion Rate)		0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416	0.2416
4	Delivery Value		274	317	357	394	430	480	504	556	570	616	688	740
5														
6	Opex / Severance / Ad Valorem													
7	Operating Cost		87.2	100.1	113.0	124.9	137.2	154.1	164.0	176.5	182.7	200.5	218.5	230.2
8	Severance and Ad Valorem Taxes		59.95	69.42	86.76	95.91	104.66	116.85	122.72	135.36	138.63	149.76	167.35	180.00
9	Total		147.17	169.48	199.79	220.80	241.86	270.99	286.74	311.87	321.34	350.24	385.89	410.18
10														
11	Average Rate Base		23,154.78	26,198.00	29,226.67	32,262.08	35,270.76	39,078.57	42,857.27	44,945.75	46,179.50	49,051.58	52,706.30	54,648.55
12														
13	Carrying Cost													
14	Equity	10.1588%	98.36	111.29	124.16	137.05	149.83	166.01	182.06	190.93	196.17	208.37	223.90	232.15
15	Equity % of Cap Struct	50.1800%												
16	Equity Pretax	39.9400%	116.58	130.65	138.42	152.68	167.07	184.41	206.71	224.60	230.21	250.53	279.49	290.11
17	Debt	7.0660%	67.93	76.85	85.74	94.64	103.47	114.64	125.72	131.85	135.47	143.90	154.62	160.32
18	Total Carrying Cost		184.50	207.50	224.16	247.32	270.54	299.05	332.44	356.45	365.68	394.42	434.10	450.43
19														
20	Total Cost		605.21	693.72	780.55	862.37	942.60	1,050.33	1,123.62	1,224.72	1,256.84	1,360.24	1,507.88	1,600.47
21	Total Volume		1,132.0	1,310.8	1,475.7	1,631.5	1,780.3	1,987.6	2,087.5	2,302.5	2,358.1	2,547.4	2,846.6	3,061.7
22	Total Rate Per Therm		0.535	0.529	0.529	0.529	0.529	0.528	0.538	0.532	0.533	0.534	0.530	0.523

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Exhibit C

NW Natural
20XX Oregon Earnings Review
12 Months Ended December 31, 20XX Forecast
($000's)

Line No.		OREGON EARNINGS TEST Test Year Results (a)	TYPE I Adjustments (b)	Test Year Adjusted (c)	Gas Reserves (d)	Test Year Results (e)	TYPE II Adjustments (f)	Test Year Adjusted Results (g)
	Operating Revenues							
1	Sale of Gas			$0		$0		$0
2	WARM Revenues			0		0		
3	Revenue & Technical Adjustments			0		0		
4	Transportation			0		0		
5	Miscellaneous Revenues			0		0		
6	SB408 Deferrals			0		0		
7	Total Operating Revenues	0	0	0		0	0	0
	Operating Revenue Deductions							
8	Gas Purchased			0	1/	0		0
9	Uncollectible Accrual for Gas Sales			0		0		0
10	Other Operating & Maintenance Expenses			0		0		0
11	Total Operating & Maintenance Exp.	0	0	0		0	0	0
12	Federal Income Tax			0	1/	0		0
13	State Excise			0	1/	0		0
14	Property Taxes			0		0		0
15	Other Taxes			0		0		0
16	Depreciation & Amortization			0		0		0
17	Total Operating Revenue Deductions	0	0	0		0	0	0
18	Net Operating Revenues	$0	$0	$0	$0	$0		$0
	Average Rate Base							
19	Utility Plant in Service			$0	2/	$0		$0
20	Accumulated Depreciation			0	3/	0		0
21	Net Utility Plant	0	0	0	0	0	0	0
22	Aid in Advance of Construction			0		0		0
23	Materials & Supplies			0		0		0
24	Water Heater Program			0		0		0
25	Leasehold Improvements			0		0		0
26	Accumulated Deferred Income Taxes			0	4/	0		0
27	Total Rate Base	$0	$0	$0	$0	$0	$0	$0
28	Rate of Return							
29	Return on Common Equity							

Adjustments for rate cases and annual reporting of results assuming removal of effects of the gas reserves transaction

1/ The Carrying Cost (return and taxes) will be added back to gas purchased to produce a cost of gas commensurate with revenues
The federal and state income taxes will be adjusted to reflect the add back of carrying costs in addition to the removal of the depletion allowance tax benefit.
2/ The cumulative investment amount will be removed as an item of Utility Plant in Service
3/ The cumulative amortization will be removed as an item of Utility Accumulatied Depreciation
4/ The cumulative deferred income taxes will be removed as an item of Utility Accumulated Deferred Income Taxes

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APPENDIX A
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- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of Questar Gas Company for Approval of the Wexpro II Agreement	)))))	DOCKET NO. 12-057-13 REPORT AND ORDER

ISSUED: March 28, 2013

SHORT TITLE

Wexpro II Agreement

SYNOPSIS

The Commission approves Questar Gas Company's application for approval of the Wexpro II Agreement which establishes terms and conditions for the potential future acquisition and development of certain oil and gas properties.

APPEARANCES

Colleen Larkin Bell, Esq. Questar Gas Company	For	Questar Gas Company
Gregory Monson, Esq. Stoel Rives LLP		
Patricia E. Schmid, Esq. Assistant Utah Attorney General	"	Division of Public Utilities
Jerrold S. Jensen, Esq. Assistant Utah Attorney General	"	Office of Consumer Services

I. INTRODUCTION

This matter is before the Commission upon the application of Questar Gas Company ("Questar") for an order approving the Wexpro II Agreement ("Wexpro II") entered into between Questar, Wexpro Company ("Wexpro"), the Utah Division of Public Utilities ("Division"), and the Wyoming Office of Consumer Advocate ("OCA") (referred to collectively hereinafter as the "Parties"), on September 12, 2012. Questar is a "public utility" and "gas corporation" as defined in Utah Code Ann. § 54-2-1. Questar seeks this order pursuant to Utah Code Ann. § 54-4-1 *et seq.* and Utah Administrative Code R746-100 *et seq.* Section 54-4-1 vests the Commission "with power and jurisdiction to supervise and regulate every public utility in this state, and to supervise all of the business of every such public utility in this state, and to do all things ... necessary or convenient in the exercise of such power and jurisdiction."

II. PROCEDURAL HISTORY

On September 10, 2012, Questar filed a notice of intent to file an application for approval of Wexpro II. On September 18, 2012, Questar filed with the Commission a copy of Wexpro II and the application for its approval with supporting testimony and exhibits ("Application"). In general, Wexpro II sets forth procedures by which Wexpro may purchase new natural gas and oil properties or undeveloped leases at its own risk and submit those properties to the Utah and Wyoming Public Service Commissions for approval. Wexpro will manage and develop approved properties as sources of the natural gas Questar provides its retail customers; the cost of this gas to Questar's customers will reflect Wexpro's cost of service rather than market pricing. Wexpro will allocate 54 percent of oil and natural gas liquids net revenues to Questar and will retain the remaining 46 percent.

On September 21, 2012, the Commission issued notice of a scheduling conference, to be held on October 3, 2012, to determine the procedural schedule for examining the Application.[1] On October 2, 2012, the Utah Office of Consumer Services ("Office") filed a request for a pre-hearing order and schedule ("Pre-hearing Order Request") seeking, among other things, the Commission to direct the Division to provide testimony regarding its evaluation of Wexpro II and its statutory authority as a Wexpro II signatory. On the same day, Questar and the Division filed responses to the Office's Pre-hearing Order Request. On October 3, 2012, the Commission commenced the scheduling conference which was continued to October 4, 2012, to permit parties to present their positions on the Pre-hearing Order Request in a recorded hearing with transcription services.

On October 16, 2012, the Commission issued a scheduling order setting the schedule for briefing on dispositive motions at the request of the Office.[2] On October 22, 2012, the Office notified the Commission via email that it would not file a dispositive motion as provided for in the Commission's October 16, 2012, order and stated its intent "to answer and address the utility rate and regulatory actions proposed by the application and contract at issue through the public hearing process and in testimony."[3] The email also requested the Commission to schedule discovery, the filing of testimony, and a hearing on the Application.

On October 29, 2012, the Commission issued notice of a second scheduling conference to be held on November 7, 2012. That scheduling conference resulted in a

[1] The following parties requested and were granted intervention in this proceeding: Utah Association of Energy Users and PacifiCorp, doing business in Utah as Rocky Mountain Power.
[2] *See* Transcript of Hearing, October 4, 2012, at 8, 10.
[3] Email from Paul H. Proctor, Assistant Utah Attorney General, to David R. Clark, Commission Legal Counsel (with a copy to the parties), (October 22, 2012, 1:40 p.m.).

scheduling order issued November 9, 2012, together with a notice of technical conference to be held on December 5, 2012. On November 28, 2012, the Commission issued an amended notice of technical conference, including discussion items and questions to be addressed at the technical conference.

On December 11, 2012, the Division and Office filed direct testimony. On January 10, 2013, Questar, the Division, and the Office filed rebuttal testimony. On January 17, 2013, the Commission issued a notice of recusal of Commissioner Thad LeVar who recused himself from this proceeding due to his prior involvement in the matter in connection with his former duties as Deputy Director of Commerce for the State of Utah. On January 24, 2013, Questar, the Division, and the Office filed surrebuttal testimony. The Office's January 24th surrebuttal testimony included a suggestion the Commission should accept post-hearing briefs on several legal issues. On January 28, 2013, the Division filed a motion opposing the Office's request for briefing and seeking expedited treatment of the motion. On January 29, 2013, Questar filed a response in support of the Division's motion.

On January 30, 2013, the Commission conducted a duly-noticed hearing in this matter. At the conclusion of the hearing, the Commission determined it would accept a post-hearing brief from the Office and reply briefs from Questar, the Division, and any other interested parties. On January 31, 2013, the Commission held a duly-noticed public witness hearing. Two members of the public appeared: 1) Mr. Lane Beattie, President and CEO of the

Salt Lake Chamber, and 2) Mr. Jeff Edwards, President and CEO of the Economic Development Corporation of Utah. Both offered sworn testimony in support of the Application.[4]

On January 31, 2013, at the Commission's request, Questar filed Late Filed Exhibit 3.0 containing the guideline letters referenced in Section V-15 of Wexpro II. On February 8, 2013, the Office filed a post-hearing brief. On February 14, 2013, in response to questions posed by the Commission at hearing, Questar filed three replacement pages for Wexpro II which correct clerical oversights in the version of Wexpro II filed with the Application. On February 15, 2012, Questar and the Division filed reply briefs. On March 27, 2013, Questar filed three more replacement pages to correct clerical errors in three exhibits attached to Wexpro II as follows: Exhibit A, p.3; Exhibit B, p.2; and Exhibit F, p.1. These corrections conform the exhibits to the terms of Wexpro II.

III. BACKGROUND

A. Wexpro I

In 1976, in response to events and decisions pertaining to its non-utility oil operations, Questar, then known as Mountain Fuel Supply, organized Wexpro as a wholly-owned subsidiary. Effective January 1, 1977, Questar transferred its so-called "oil properties" (as defined by the companies) to Wexpro. Further, Questar and Wexpro executed a joint exploration agreement ("JEA") which defined how exploration costs and revenues would be shared for further exploration and development of undeveloped leases.[5] The Division and the Committee of Consumer Services (the predecessor of the Office) challenged this transfer to

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[4] *See* Transcript of Hearing, January 31, 2013, at 5-12.

[5] *See Department of Administrative Services v. Public Service Commission*, 658 P.2d 601, 604 (Utah 1983). Today, Questar and Wexpro are affiliates under the common ownership of Questar Corporation.

Wexpro, asserting it to be a transfer of valuable utility properties financed by ratepayers to an unregulated company which would be free to use them exclusively to benefit Questar shareholders.[6] Following lengthy proceedings in Docket No. 76-057-14, the Commission approved the transfer of properties and the JEA, concluding this action placed the properties beyond its jurisdiction.[7]

The Division and Office appealed the Commission's decision, and in *Committee of Consumer Services v. Public Service Commission, Utah* ("*Committee*"), the Utah Supreme Court reversed the Commission's decision and remanded the case to the Commission for further proceedings.[8] The Court held that transfers of utility assets should be for fair market value so that ratepayers may receive appropriate benefit. Accordingly, the Court directed the Commission to hold an evidentiary hearing to determine whether transferred properties were utility assets and, if so, whether the transfers were in the public interest.[9]

In order to avoid protracted litigation, negotiations were undertaken to identify a fair and workable resolution. The result of these negotiations was the Wexpro Stipulation and Agreement, executed October 14, 1981(hereinafter referred to as "Wexpro I").[10] The Commission approved Wexpro I on December 31, 1981, in Docket No. 76-057-14.[11]

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[6] *See* id.
[7] *See* id; *see also* Docket No. 76-057-14, Report and Order, issued April 11, 1978, *In the Matter of the Petition of the Division of Public Utilities to Consider the Proposed Transfer of Certain Wells, Leases, Lands and Related Facilities and Interests of Mountain Fuel Supply Company to Wexpro Company.*
[8] *See Committee of Consumer Services v. Public Service Commission, Utah,* 595 P.2d 871 (Utah 1979), *cert. denied,* 444 U.S. 1014, 62 L. Ed. 2d 644, 100 S. Ct. 664 (1980).
[9] *See* id. at 878.
[10] The Wexpro I Stipulation consists of 18 numbered Sections. The Wexpro I Agreement consists of 10 numbered Articles. Hereinafter, references to numbered sections of the Stipulation and Agreement will be preceded by "Section" and "Article," respectively.
[11] *See* Docket No. 76-057-14, Report and Order on Stipulation and Agreement, issued December 31, 1981, *In the Matter of the Petition of the Division of Public Utilities to Consider the Proposed Transfer of Certain Wells, Leases,*

The Commission approved Wexpro I despite opposition from the Utah Department of Administrative Services, among others, which argued that Wexpro I did not confer on customers all of the benefits required by the Utah Supreme Court in *Committee*. The Court addressed these and other contentions in *Utah Department of Administrative Services v. Public Service Commission* ("*Department*") and affirmed the Commission's order approving Wexpro I.[12] The Court found the Commission's decision achieved the results sought by the Court's earlier mandate.[13] Consequently, since the approval of Wexpro I, Questar has been acquiring a significant percentage of its gas supply from Wexpro under the terms and conditions of Wexpro I. Wexpro I is the model for Wexpro II. Because Wexpro I provides important context for evaluating Wexpro II, key Wexpro I provisions are summarized here.[14]

Wexpro I pertains to various types of properties, including Productive Oil Reservoirs ("oil properties") and Productive Gas Reservoirs ("gas properties"). Under Wexpro I, Wexpro owns and operates oil properties and develops them at its own expense and risk.[15] Wexpro sells all natural gas produced from oil properties to Questar at cost of service. The cost-of-service charge for gas produced from oil properties is defined in Exhibit A of Wexpro I and includes Wexpro's reasonable and necessary operating expenses, depreciation, taxes, and a return on investment. Wexpro deducts certain necessary and reasonable expenses, royalties, and a return on investment from the proceeds of the sale of oil and natural gas liquids (from existing

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Lands and Related Facilities and Interests of Mountain Fuel Supply Company to Wexpro Company on Remand from the Utah Supreme Court. Wexpro I also resolved issues in five other dockets: Docket Nos. 77-057-03, 79-057-03, 80-057-01, 81-057-01, and 81-057-04.

[12] *See Department of Administrative Services v. Public Service Commission*, 658 P.2d 601 (Utah 1983).

[13] *See* id. at 612-615.

[14] This summary and other discussions of the terms of Wexpro I in this order are not intended to modify the terms of Wexpro I. The language of Wexpro I controls.

[15] *See* Wexpro I, Article II and Exhibit A.

and future wells).[16] Questar then receives 54 percent of the oil and natural gas liquids net revenues, and Wexpro retains 46 percent.[17] If a development well is unsuccessful, all of its costs are borne by Wexpro.[18]

As to gas properties, Wexpro I specifies Questar retains ownership of producing gas wells and appurtenant facilities that historically had been accounted for in its rate base Account No. 101.[19] The natural gas, natural gas liquids and oil produced from these gas properties belong to Questar and the leaseholds and operating rights are transferred to Wexpro. Wexpro operates the wells and facilities on a service contract basis.[20] As with the oil properties, if a gas property development well is unsuccessful, all of its costs are borne by Wexpro.[21] If it is successful, its cost is capitalized in a manner similar to a rate base account. The service contract cost paid to Wexpro includes a base rate of return (calculated using returns received by a group of regulated utilities), plus an additional risk premium of eight percent for investment in commercial development wells. The proceeds from the sale of oil and natural gas from wells defined in Wexpro I as "prior company wells" are accounted for as Questar revenue. The proceeds from the sale of oil from commercial wells completed after July 31, 1981, on gas properties, i.e., "new oil," are allocated to Questar and Wexpro according to the 54-46 formula defined in Wexpro I.[22]

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[16] See Wexpro I, Article II.
[17] *See* Wexpro I, Article II-4(e), (f), and (g) for a definition of the "54-46 formula."
[18] *See* Wexpro I, Article II-4(a).
[19] *See* Wexpro I, Article III.
[20] *See* id.
[21] *See* Wexpro I, Exhibit E.
[22] *See* Wexpro I, Article II-4(e), (f), and (g) for a definition of the "54-46 formula."

Generally, Questar's duties under Wexpro I are limited to accounting responsibilities, arranging for transportation and delivery of natural gas, compensating Wexpro for its cost of service, responding to any defaults under the agreement, and making decisions pertaining to dry holes and required downstream investments.[23] Questar, in conjunction with Wexpro, is also responsible to provide a report to the Division within 60 days of the end of every calendar quarter setting out production of the oil and gas properties, the financial benefits from the properties, and reporting on the operations of each element of Wexpro I.[24]

Among the provisions in Wexpro I is the "Standard of Operation" which states:

> "Except as specifically provided herein, in all aspects of exploration for and development of oil and natural gas discoveries and production on transferred leaseholds and Account 101/105 leaseholds transferred under this Agreement, the parties will operate in accordance with *prudent, standard and accepted field and reservoir management and engineering practices, and with due regard for the benefits provided the Company's utility operations.*"[25]

Additionally, Wexpro I establishes the Division's role to monitor Questar and Wexpro performance in meeting this standard, including employing the services of the accounting and hydrocarbon monitors, retained by the Division at a cost of not more than $60,000 per year, respectively.[26] Any such monitoring costs are considered to be reasonable Wexpro expenses and are included in its cost of service.

As to dispute resolution, Wexpro I provides that if any party claims another party is in default of its obligations, the defaulting party first has the opportunity to correct the default

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[23] *See* Wexpro I, Articles, I-20, II-5(b), II-8(f), III-8(e), III-5(b) and (c), Exhibit E, and Section 9.
[24] *See* Wexpro I, Section 8.1.
[25] Wexpro I, Article VIII-13 (emphasis added).
[26] *See* Wexpro I, Section 8.

after notification. If the default is not corrected to the satisfaction of the charging party, the matter must be addressed through a defined arbitration procedure.[27]

B. Wexpro II

For over 30 years Wexpro has developed and produced gas, oil, and gas liquids pursuant to the terms of Wexpro I. During this period the subject properties have accounted for a significant percentage of Questar's total retail gas volumes.[28] Questar asserts the gas provided to customers under Wexpro I has generated substantial net savings to date in comparison to market-based sources.[29] To address the finite nature of Wexpro I properties and perpetuate their perceived benefits, Questar initiated discussions with interested parties. According to Questar, these efforts led to the execution of Wexpro II.[30] A copy of Wexpro II, including the replacement pages filed on February 14 and March 27, 2013, is attached to and incorporated in this order.

Unlike Wexpro I, which applies to a defined set of oil and gas properties, Wexpro II creates a process by which new properties can become subject to terms and conditions similar to those in Wexpro I. Notably, the gas produced by Wexpro from such properties also will be sold to Questar at cost of service.[31] Under Wexpro II, Wexpro would acquire oil or gas properties or undeveloped leases at its own expense. The Utah and Wyoming Commissions would have a right of first refusal on all such properties that are within the development drilling

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[27] *See* Wexpro I, Section 9.
[28] *See* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 2.
[29] *See* id.
[30] *See* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 3-4.
[31] *See* Wexpro II, Section III-3.

area established in Wexpro I.[32] Questar would also be permitted, but not required, to seek Wexpro II treatment for oil and gas properties outside of the Wexpro I development drilling area.[33]

Wexpro II establishes procedures for Questar to file applications with the Utah and Wyoming Commissions requesting approval to include proposed properties within the scope of Wexpro II. Wexpro II specifies, among other things, the supporting documentation required in such applications, the application schedule, the hydrocarbon monitor's role in evaluating the properties, Wexpro's duty to facilitate interested parties' analyses, the handling of acquisition costs, the management of gas volumes, and the accounting treatment of Wexpro II properties.[34] If both commissions approve including the proposed properties within the scope of Wexpro II, Wexpro must develop the properties for the benefit of Questar's customers pursuant to the terms of Wexpro II.

Wexpro II has many of the same terms and conditions as Wexpro I. For example, Wexpro will continue to bear the risk of dry holes. Further, under both agreements the Wexpro operating expenses paid by Questar, and ultimately by Questar ratepayers, may only include "reasonable and necessary" expenses in various defined categories.[35] Commercial development drilling wells will earn the same rates of return as specified in Wexpro I. Wexpro's acquisition

[32] *See* Wexpro II, Section IV-1(a); *see also* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 6.
[33] *See* Wexpro II, Section IV-1(b); *see also* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 6.
[34] See Wexpro II, Section IV; *see also* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 6-7.
[35] *See* Wexpro I, Exhibit A and Exhibit E; *see also* Wexpro II, Exhibit A and Exhibit Draph 1.

costs, however, will earn a return calculated using the returns approved for Questar by the Utah and Wyoming Commissions.[36]

Questar's Wexpro II duties are similar to those under Wexpro I with the addition, for example, of responsibilities specified in Wexpro II, Section IV-2 (mentioned above) pertaining to the filing of applications with the Utah and Wyoming Commissions requesting approval to include proposed properties under Wexpro II.[37] In addition, Section IV-8 specifies Wexpro II gas volumes will be managed under the direction of Questar.

Wexpro II, Section V-15 refers to the use of confidential guideline letters in executing and administering Wexpro II. The use of guideline letters began in the course of administering Wexpro I but was never presented to the Commission. Historically, Wexpro used these letters to document the concurrence of the Division's hydrocarbon monitor and/or accounting monitor (and in some cases the Division and the Wyoming Commission Staff) with various actions Wexpro sought to take with respect to Wexpro I. Wexpro II, Section V-15 incorporates all applicable Wexpro I guideline letters by reference, and an index of the letters is included as Wexpro II, Exhibit G. Moreover, Section V-15 contemplates the Parties and the Wyoming Commission Staff will develop future guideline letters, as necessary, in consultation with the independent monitors. New proposed guideline letters must be approved by all Parties and the Wyoming Commission Staff before becoming effective.[38]

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[36] *See* Wexpro II, Section IV-6.

[37] Wexpro II, Sections IV-3(e) and V-12(b) also require Wexpro to make itself available to the parties in these application proceedings; to provide access to its books, accounts and records; and to cooperate with the monitors in attempting to obtain other relevant information.

[38] *See* Wexpro II, Section V-15(b).

While based on Wexpro I, Wexpro II is distinct in several other ways. The fees paid to the Division's hydrocarbon and accounting monitors under Wexpro II do not have a dollar cap and cover monitoring responsibilities addressed in both Wexpro I and Wexpro II. All actual and reasonable fees and expenses for the monitors are considered to be normal business expenses of Wexpro in determining the cost of service. Additionally, although the dispute resolution procedures are similar to those contained in Wexpro I, under Wexpro II, disputes pertaining to Questar's default of its obligations under Wexpro II will be adjudicated before the Utah and Wyoming Commissions. Finally, Wexpro II, Section V-10 (Standard of Operation) requires Wexpro to both "*drill and operate* in accordance with prudent, standard and accepted field and reservoir management and engineering practices, and with due regard for the benefits provided the Company's utility operations *in consultation with the Company* [Questar]" (emphasis added). The Standard of Operation defined in Wexpro I (Article VIII-13) does not specify "drill and operate" and does not require consultation with Questar.

IV. POSITIONS OF THE PARTIES

A. Questar

Questar testifies Wexpro I, since its inception in 1981, has saved its customers about $1.27 billion in gas costs.[39] Additionally, Wexpro I, in Questar's view, has provided a stable source of supply and a long term hedge against gas price volatility.[40] Gas supplies provided pursuant to Wexpro I have ranged between about one-third and one-half of the annual supplies required to meet the needs of Questar's customers. Moreover, gas production subject to

[39] *See* Direct Testimony of Barrie L. McKay, QGC Ex. 1.0, at 2.
[40] *See* id.

Wexpro I is finite, although it is exceeding initial expectations due to technological improvements in drilling and production methods.[41] Questar asserts Wexpro is positioned to expand its exploration and production of gas properties beyond those subject to Wexpro I. Questar believes the current low-gas-price environment makes this a favorable time to consider acquiring new gas reserves for the benefit of Questar's customers.[42]

Beginning in the fall of 2011, Questar began to hold public meetings to discuss conceptually a successor agreement patterned on Wexpro I. Additional meetings were held with the Division, the Office, the Wyoming OCA and the hydrocarbon monitor. According to Questar, Wexpro II was developed and refined with these parties' contributions and input.[43]

Questar believes Commission approval of Wexpro II is in the public interest; Wexpro II will be beneficial to Questar's customers because it affords customers access to gas properties purchased by Wexpro at its own risk. Questar testifies the viability of each property and its potential benefits as a long-term physical hedge against natural gas market price volatility will be fully vetted by Questar, the Division's hydrocarbon monitor, and any other interested parties, before the Commission (as well as the Wyoming Commission) considers whether to include such property within the scope of Wexpro II. Questar asserts such properties that are developed will mitigate risks for customers. "Having long-term access to cost-of-service supplies will lessen the impact of the volatility of the natural gas market on Questar Gas and its customers. Questar Gas' customers will not experience sharp spikes that market-based gas costs

[41] *See* id.
[42] *See* id. at 3.
[43] *See* id. at 4.

have seen. And if history is any indication, Questar Gas' customers should continue to enjoy significant cost savings over time."[44]

Questar testifies it likely would not have sought to expand the cost-of-service arrangements of Wexpro I but for Questar Corporation's[45] recent spin-off of its unregulated exploration and production business.[46] According to Questar, that action and the refocusing of Questar Corporation on its core utility business are reasons for its pursuit of Wexpro II.[47] Questar believes continuation of the asserted benefits of cost-of-service gas through Wexpro II will allow Questar "to continue to provide gas to customers at prices among the lowest in the nation. . . "[48] Questar maintains this outcome is in the public interest for many reasons, including enhancing the state of Utah's competitiveness in economic development and providing a long term source of gas supply for its residents.[49]

B. The Division

The Division supports the Application and believes approval of Wexpro II is in the public interest.[50] The Division views Wexpro II as a no cost option to hedge against future natural gas spot market price volatility. It asserts this is a prudent objective that could benefit, and historically through Wexpro I has benefited, Questar's ratepayers.[51] In the Division's opinion, this objective is accomplished without any change in Questar's current rates and without

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[44] *See* id. at 10.
[45] Questar Corporation is the parent company of Questar and Wexpro.
[46] *See* Rebuttal Testimony of Barrie L. McKay, QGC Ex. 1.0R, at 3.
[47] *See* id.
[48] Id. at 16.
[49] *See* id. at 16-17.
[50] *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Ex. 1.0D, at 2, 7.
[51] *See* id. at 3, 7.

placing any financial obligations on Questar or its customers.[52] Moreover, without this continuing option, the Division believes Questar customers could be unduly exposed to future natural gas spot market volatility and uncertainty.[53]

The Division describes a number of advantages for ratepayers in Wexpro II's approach to providing a continuing option for future hedging of gas prices.[54] According to the Division, when ratepayers are asked to participate in a hedge (i.e., when Questar proposes to include a property under Wexpro II), ratepayers, through the efforts of the hydrocarbon monitor and the other participants in the Commission's application proceeding, will have access to information on the cost of the hedge, expected production, and forward price curves. The Division states these are the relevant measures of whether participating in the hedge is in the public interest, and they will be known to the Commission and the hearing participants at the time of decision, unlike with typical hedging programs.[55] Moreover, capital costs incurred from that point forward will only be included in rates if the newly-drilled wells are determined to be commercial because Wexpro will bear the risk of dry holes. Additionally, in the Division's view, ratepayers are further safeguarded by Questar's ability under Wexpro II to "direct the development and drilling of properties operated by Wexpro."[56] The Division states if Questar exercises that ability imprudently, disallowances are possible under Wexpro II.[57]

Regarding the current market for gas properties, the Division testifies well owners that entered into three to five year sales agreements in 2008 and 2009 secured gas prices that

[52] *See* id. at 8.
[53] *See* id.
[54] *See* id.
[55] *See* Prefiled Rebuttal Testimony of Douglas D. Wheelwright, DPU Ex. 1.0R, at 7.
[56] Id.
[57] *See* id.

were much higher than current prices. Given the current low gas prices and the forecast for relatively stable prices going forward, the Division believes existing well owners may desire to sell their interests in existing wells, rather than making more sales at today's lower prices. These conditions create a potential opportunity for Wexpro to acquire additional wells on favorable terms.[58]

The Division also evaluated the rate of return Wexpro will earn on Wexpro II properties. The Division states Wexpro's actual return on new properties to be a combination of existing wells at the lower rate of return and development wells at the higher rate.[59] The Division refers to examples provided by Questar projecting life cycle returns of 13 percent to 14 percent. The Division projects the blended return for Wexpro II properties will be lower than the return on the developed wells that are subject to Wexpro I.[60]

C. The Office

The Office asserts the expansion of Questar's access to cost-of-service gas supplies could provide additional benefits to customers, if properly designed.[61] While acknowledging Wexpro I has provided net benefits to customers over the past 30 years, the Office raises two primary issues concerning the Application: 1) the Parties must be required to demonstrate Wexpro II is in the public interest; and, 2) certain changes must be made to the oversight provided for in Wexpro II before it can be found to be in the public interest.[62]

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58 *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Ex. 1.0D, at 8.
59 *See supra* discussion of rates of return in Sections II.A and II.B.
60 *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Ex. 1.0D, at 10-11.
61 *See* Direct Testimony of Michele Beck, Ex. OCS 1D Beck, at 2.
62 *See* Transcript of Hearing, January 30, 2013, at 104.

The Office testifies the primary question should be whether the Parties have demonstrated that Commission approval of Wexpro II is in the public interest.[63] The Office maintains the Parties have relied too much on the historical performance of Wexpro I in supporting Wexpro II. "[E]nough facts and circumstances have changed in 30 years that public interest should have been more specifically addressed. In fact, the Office asserts that [Wexpro II] cannot be demonstrated to be in the public interest unless a few minor but fundamental changes are made to the oversight of [Wexpro II]."[64]

Regarding oversight, the Office believes the only method of dispute resolution provided for under Wexpro II is binding arbitration and that this method is inadequate.[65] This method, according to the Office, wrongly removes the Commission from the oversight process.[66] The Office asserts neither the Division, nor the monitors, nor an arbitration panel has the mandate imposed on the Commission to uphold the public interest.[67] Without a change in this oversight structure, in the Office's view, Wexpro II cannot be found to be in the public interest.

In addition to the objections noted, the Office has also expressed concerns regarding incorporation by reference of the guideline letters and perceived lack of access by non-Parties to future operating reports pertaining to the Wexpro II properties. The Office noted during the hearings that these concerns had been alleviated or at least mitigated. Regarding the guideline letters, Questar has committed to identify the specific guideline letters applicable to

[63] *See* id. at 106.
[64] Id. at 107.
[65] *See* id. at 105.
[66] *See* id.
[67] *See* id. at 107.

any property proposed for Wexpro II treatment, as the Office recommends.[68] Regarding access to Wexpro II information, the Office states it feels "some level of comfort" from the Division's assurances of access and notes no other party took the opportunity to intervene and raise this issue.[69]

V. DISCUSSION, FINDINGS AND CONCLUSIONS

In *Department* the Court applied the public interest standard in evaluating the unsuccessful challenges to Wexpro I.[70] Likewise, as noted above, the Parties and the Office present their positions in this case in the context of whether Wexpro II will serve the public interest. We also apply this standard as we evaluate the attributes of Wexpro II.

It is uncontroverted Questar's customers have derived substantial net savings from the operation of Wexpro I over the past 30 years. According to the Division, of the 26 years from 1985 through 2011, there were only five years in which buying gas on the market would have benefited Questar's ratepayers, in comparison to the cost-of-service gas provided via Wexpro I.[71] Questar and the Division testify they have entered into Wexpro II to provide the means by which similar benefits may continue, even after the Wexpro I reserves are exhausted. While the protracted lawsuits and other circumstances which led to Wexpro I are much different from the circumstances applicable today, maintaining the advantages of a cost-of-service gas option is a worthy objective, a perspective the Office shares in common with the Parties.[72] The

[68] *See* Transcript of Hearing, January 30, 2013, at 12.
[69] *See* id. at 117-118.
[70] *See Department of Administrative Services v. Public Service Commission*, 658 P.2d 601, 616-19 (Section IV. "Settlement in Public Interest?").
[71] *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Exhibit 1.0D, at 6.
[72] *See* Direct Testimony of Michele Beck, Exhibit OCS 1D Beck, at 1-2.

central question before us is whether Wexpro II achieves this objective in a manner consistent with the public interest.

We find Questar and the Division have adequately demonstrated Wexpro II to be in the public interest. As the Division testifies, Wexpro II is designed to allow Questar's customers to benefit from a no cost option to participate in future, long-term hedges of natural gas market prices.[73] Wexpro II's structure mitigates ratepayers' future gas price risk in several ways, some of which are consistent with Wexpro I terms and conditions, while others increase ratepayers' protections. For example, Wexpro II standing alone has no financial consequence for ratepayers. Wexpro must make the initial financial commitment to new development properties at its own risk. This feature creates a strong incentive for Wexpro to purchase only properties it is confident will be commercially viable and will demonstrably benefit ratepayers. Moreover, to the extent such properties are purchased within the Wexpro I development drilling area, Wexpro and Questar must offer them for service to ratepayers. This feature affords ratepayers substantial protection against Wexpro retaining the most profitable properties for its own benefit and only passing along those which are of questionable value or more risky.

Additionally, consistent with the Division's testimony, the Commission will not consider including properties under Wexpro II until the actual cost of the property is known, and the expected production levels of the properties and forward price curves are available to be evaluated by the Division, the hydrocarbon monitor, and other interested parties, in a Commission proceeding. The Division states, and we agree, these data are among the appropriate measures for determining whether the approval of the property is in the public

[73] *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Ex. 1.0D, at 3-4.

interest.[74] Moreover, as noted above, capital costs incurred from that point forward will only be included in rates if the newly-drilled wells are determined to be commercial.[75]

Wexpro II, Section IV-2 places on Questar the responsibility to file the applications and supporting information the Commission will consider in determining whether to approve specific properties for Wexpro II treatment. Although not directly stated in Wexpro II, it is certainly implied that Wexpro will participate, as appropriate, in preparing and presenting the requisite information[76] and that such information will be the best information available to Questar. Indeed, Questar testified this will be so.[77]

Section IV-2 outlines various types of information, data and analyses that must accompany Questar's applications. These include, for example: 1) the purchase price and gas pricing assumptions, 2) the forecasted production/reserves for future wells, 3) the estimated drilling (capital) costs per well, 4) the forecasted long term cost of service analysis, 5) the impact on Questar's gas supply, and 6) other data as may be requested or appropriate to an evaluation of the property. Items in this latter category could include analyses of potential alternatives to the proposed property and the potential effect of the proposed property acquisition on Questar's gas management and integrated resource planning. To assure the evaluation of each proposed property is robust, we will convene a technical conference in the near future under the Division's direction to further define the supporting information that should accompany any Questar application proposing property for inclusion under Wexpro II. This technical conference will

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[74] *See* Pre-filed Rebuttal Testimony of Douglas D. Wheelwright, DPU Ex. 1.0R, at 7.
[75] See Wexpro II, Article I-11, for the definition of "commercial well."
[76] *See* Wexpro II, Article IV-3(e); *see also* Transcript of Hearing, January 30, 2013, at 60.
[77] *See* Transcript of Hearing, January 30, 2013, at 40-41.

add specificity and detail to the list of supporting material already outlined in Section IV-2.[78] In sum, in Section IV-2 Questar accepts responsibility to propose and support, with the best information available to it, the inclusion of properties under Wexpro II. These Questar duties provide the Commission appropriate oversight of Questar's reliance on such properties as sources of its gas supply. Moreover, these duties are consistent with the public interest in the prudent acquisition of such supplies.

The evidence of current market conditions for the purchase of gas and oil properties also substantiates the public interest in expanding the properties currently subject to cost-of-service pricing. While the Wexpro I properties have outlived initial expectations and will continue to produce for a number of years, market conditions today strongly suggest additional properties may be available at favorable prices, as the Division testifies.[79] Wexpro II affords ratepayers the option to benefit from these market conditions. The application process Wexpro II establishes will give the Division, the Office, and other consumer advocates the opportunity to examine carefully the attributes of individual properties before the acquisition and development costs of accepted properties are included in rates.

The rates of return available to Wexpro on Wexpro II properties do not overshadow the public benefits of the no cost option Wexpro II will provide. First, as already noted, Wexpro must acquire potential Wexpro II properties at its own risk. Second, prior to development, acquired properties earn only the weighted average of the returns authorized for Questar by the Utah and Wyoming Commissions. Third, only developed facilities earn the risk

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[78] *See* id. at 41, where Questar expresses its support of this approach.
[79] *See* Pre-filed Direct Testimony of Douglas D. Wheelwright, DPU Ex.1.0D, at 8.

premiums specified in Wexpro II, and to qualify, the facilities must achieve commercial status. Otherwise, Wexpro recovers neither actual incurred costs nor a return.[80] Fourth, expected potential returns to an exploration and production company in a similar arrangement with a utility, and approved by another state commission, appear to be much higher than those specified in Wexpro II.[81] Taken together, these factors weigh in favor of Wexpro II approval.

In addition to its general concern that Questar has not carried its burden to prove the public interest, the Office asserts the oversight processes in Wexpro II, and in particular the arbitration provisions, improperly infringe upon the Division's statutory duties and the Commission's jurisdiction. Without changes in these areas, Wexpro II, according to the Office, cannot be found to be in the public interest. Based on Wexpro II's terms, the testimony of the Parties, and the positions expressed in their briefs, we disagree. Questar's duties under Wexpro II, discussed above, and the Division's ability to monitor Questar's performance of those duties provide the Commission adequate opportunity to supervise and regulate Questar's service to the public. Wexpro II's terms will not interfere with the Commission's power and jurisdiction to hold Questar accountable to act prudently in obtaining gas supplies for its customers.

The Office argues that in approving Wexpro II the Commission will give up authority to regulate the rates charged to Questar's customers for the gas Questar purchases from Wexpro.[82] In reality, Wexpro II, standing alone, will have no effect on rates. Rather, it is the individual applications Questar files that potentially impact rates. As previously noted, Wexpro II outlines a variety of types of data and analyses Questar and Wexpro must provide in support of

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[80] *See* Wexpro II, Section II-2(a); *see also* Wexpro II, Exhibit D.
[81] *See* Surrebuttal Testimony of James R. Livsey, Exhibit QGC 2.0SR, at 2-3.
[82] *See* Utah Office of Consumer Services' Post-Hearing Brief, filed February 8, 2013, at 1-2.

these applications. Moreover, these information requirements will be further refined at an upcoming technical conference. Questar testifies the Commission will receive the best information available to Questar when it supplies the required data, forecasts, and analysis relevant to the application.[83] If Questar willfully withholds, misrepresents, or negligently fails to ascertain and present pertinent information, it will breach its duties under Section IV-2. As discussed in more detail below, under Wexpro II, Section V-13, any such default of Questar's contractual obligations would be adjudicated before the Commission.

Similarly, during and after the development of Wexpro II properties, Questar continues to have Wexpro II contractual obligations that protect ratepayers from imprudent actions. Wexpro II, Section IV-8 places on Questar the duty to manage Wexpro II gas volumes. Section V-10, establishes the Standard of Operation, previously mentioned, requiring "prudent, standard and accepted field and reservoir management and engineering practices." This operating standard is not only applicable to Wexpro. It requires Wexpro to act in consultation with Questar, with due regard for the benefits provided to Questar customers. This language makes it incumbent upon Questar to assure drilling and operation of approved properties are conducted in the manner that will benefit Questar customers, consistent with prudent, standard and accepted practices. If Wexpro chooses a different course, Questar's Wexpro II duties require it to take appropriate actions on behalf of its customers. Any claim of Questar's failure to do so would be adjudicated before the Commission.

Questar's duty to assure Wexpro acts with due regard for Questar's customers is reinforced by the provisions of Wexpro II, Exhibit A, "Cost-of-Service Formulation for Gas

[83] *See* Transcript of Hearing, January 30, 2013, at 40-41.

from Oil Reservoirs" and Exhibit D "Operator Service Fee." Each of these exhibits defines the operating expenses Wexpro may charge Questar for drilling and operating Wexpro II oil and gas properties, respectively. As defined, such expenses must be "reasonable and necessary." Accordingly, it would be imprudent and a breach of duty for Questar to pay Wexpro for expenses that were not reasonable and necessary in carrying out prudent, standard and accepted practices. Again, any such default would be adjudicated before the Commission.

The Commission's oversight of Wexpro II performance is further facilitated by the work of the hydrocarbon and accounting monitors who will function at the Division's direction. The Division expects these monitors to have responsibilities similar to those they have carried out under Wexpro I (and without the annual $60,000 budget cap).[84] Both Questar and the Division testify these monitors have the responsibility to monitor, evaluate, and report on whether Wexpro and Questar are performing their contractual duties.[85] The monitors are described as "very interactive" and "at the ground level" in reporting Wexpro's actions and making recommendations to the Division.[86] They conduct investigations in accordance with accepted engineering practices and industry standards.[87] They also issue a report annually that includes a "technical evaluation of special projects, issues, and activities undertaken by Wexpro…" and provide the Division a confidential assessment of the benefits to Utah ratepayers.[88] The Division, in carrying out its statutory responsibilities, will evaluate this information together with the operational reports Wexpro must provide annually.[89]

[84] *See* Transcript of Hearing, January 30, 2013, at 98.
[85] *See* id. at 56-60, 96-98.
[86] *See* id. at 58.
[87] *See* id. at 97-98.
[88] *See* id. at 98.

Given Questar's duties under Wexpro II, the evaluations and reports of the monitors will be important not only in reviewing Wexpro's performance but also in assessing the prudence of Questar's actions in behalf of its customers. Moreover, the Division points to Questar's Account No. 191 pass-through applications as Commission proceedings in which Questar's prudence in acquiring gas is routinely examined.[90] The foregoing evidence clearly establishes the Division will have the means and the path to perform its statutory duties to represent the public interest and to "conduct audits and inspections or take other enforcement actions to assure compliance with commission decisions..."[91] The Division's efforts, in turn, will substantially facilitate the Commission's oversight of Questar's Wexpro II performance.

The Office maintains Wexpro II's arbitration provision seeks to eliminate the Commission's power to supervise the performance of a contract that will directly affect the cost of gas paid by Questar's customers.[92] The Office contends the arbitration provision compels the Division to pursue its obligation to the public interest before an arbitrator who has no duty to uphold it. The Office also argues that, in effect, the arbitration provision delegates the Commission's public authority to judge the prudence of Questar's actions to a private entity. The Office seems to believe that because Wexpro II does not place Parties' disputes with Wexpro before the Commission, the Commission is deprived of its ability to regulate the reasonableness of Questar's rates. The Office's interpretations overlook the plain meaning of the

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[89] *See*, e.g., Wexpro II, Section V-12 (requiring Wexpro and Questar to report annually the "production of the Wexpro II properties, the financial benefits from the Wexpro II properties, and reporting on the operation of each element of the [Wexpro II] Agreement," and to make Wexpro's pertinent books and records available to the Division).
[90] *See* Transcript of Hearing, January 30, 2013, at 102.
[91] U.C.A. § 54-4-1.5(3); *see also* U.C.A. § 54-4a-1(1)(b).
[92] *See* Utah Office of Consumer Services' Post-Hearing Brief, filed February 8, 2013, at 16.

dispute resolution section which reserves to the Commission adjudication of Questar's prudent exercise of its Wexpro II rights and duties. The pertinent Wexpro II language states:

> V-13 Dispute Resolution.
> Parties acknowledge that from time to time disputes may arise regarding the performance of this [Wexpro II] Agreement. **In the event that any Party claims that there is a default by Questar Gas of any of its contractual obligations under the terms or intent of this Agreement, such dispute will be adjudicated before the Commissions.** (Emphasis added.)

Section V-13 also provides a separate process for Parties to address claims of default by Wexpro and describes in detail the mandatory and binding arbitration process for such claims.

Regardless of Wexpro II's terms, the Commission's jurisdiction in this context extends to, and is also limited to, Questar's conduct. The Commission generally does not have jurisdiction over Questar's vendors, contractors or suppliers. The Commission, however, assures Questar's transactions with these entities do not contravene the public interest. The Commission accomplishes this through its oversight of Questar's prudence in entering into, and performing the duties it undertakes in, such transactions. When Questar imprudently incurs costs through such transactions, the Commission may disallow the costs from recovery in rates.

In light of the duties Questar undertakes in Wexpro II, together with Questar's more general duties as a public utility, the Commission finds the Wexpro II dispute resolution process simply makes explicit the Commission's authority to safeguard the public interest through its regulation of Questar. Section V-13, quoted above, specifically references the Commission's authority to adjudicate any alleged default by Questar. Nothing in Wexpro II will interfere with the Commission's oversight of Questar's actions in relation to Wexpro II. As Questar stated in its brief:

> [T]he fact that the Commission may not order Wexpro to take certain actions under the [Wexpro II] Agreement does not deprive the Commission of any jurisdiction to set the rates and charges of Questar Gas and to disallow costs if it finds, based on substantial evidence, that Questar Gas acted imprudently. Indeed, the [Wexpro] Agreement clearly exempts the prudence of Questar Gas's conduct under the Agreement from the binding arbitration provision, recognizing that issue is within the purview of the Commission.[93]
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> ...If Questar Gas is imprudent in its purchases of gas from any supplier, Wexpro included, the Commission may disallow costs incurred to the extent they result from that imprudence. If Questar Gas is imprudent in consulting with Wexpro regarding development of any property included in Wexpro II, the Commission may disallow costs incurred by Questar Gas to the extent those costs arise from [Questar's] imprudence.[94]
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> ...If the Division or the Office believes that the costs paid by Questar Gas to Wexpro under Wexpro II are imprudent, they may make such claims in [Questar's] pass-through [Account No. 191] cases before the Commission.[95]

Moreover, as Questar acknowledges, because under Wexpro II the transactions will involve an affiliate, the Commission will apply a higher level of scrutiny in determining whether Questar acts prudently in exercising its rights and performing its duties.[96] It is clear, therefore, the dispute resolution provision of Wexpro II will not impede the Commission in the exercise of its statutory responsibilities.

Based on the record before us, and the foregoing findings and conclusions, we find approval of Wexpro II to be in the public interest.

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[93] Response of Questar Gas to Office's Post-Hearing Brief, filed February 15, 2013, at 2.
[94] Id. at12-13.
[95] Id. at 13.
[96] *See* id. at 10-11.

VI. ORDER

Wherefore, pursuant to the foregoing discussion, findings and conclusions, we order:

1. The Application of Questar Gas for approval of the Wexpro II Agreement, executed September 12, 2012, incorporating corrected pages filed on February 14 and March 27, 2013, is approved.

2. The Commission will hold a technical conference under the direction of the Utah Division of Public Utilities to further specify the materials, analyses, forecasts, cost estimates, and other data that shall accompany Questar's applications for approval to include proposed oil and gas properties under the Wexpro II Agreement (see Wexpro II Agreement, Section IV-2). Notice of the time and place of the technical conference will be issued separately from this order.

DATED at Salt Lake City, Utah this 28th day of March, 2013.

/s/ Ron Allen, Chairman

/s/ David R. Clark, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
D#243055

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the Commission within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission does not grant a request for review or rehearing within 20 days after the filing of the request, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

ATTACHMENT A - THE WEXPRO II AGREEMENT

As Corrected Pursuant to Correspondence from Questar Gas Company Filed with the Commission on February 14, 2013, and March 27, 2013.

WEXPRO II AGREEMENT

This Wexpro II Agreement (Wexpro II Agreement or Agreement) is entered into on __________________, 2012, between Wexpro Company (Wexpro), Questar Gas Company (Questar Gas or the Company), the Utah Division of Public Utilities (Division), and the Wyoming Office of Consumer Advocate (OCA) (singly a Party and collectively the Parties). This Wexpro II Agreement shall be effective upon the entry of a final order of approval by the Utah Public Service Commission (Utah Commission) and the Wyoming Public Service Commission (Wyoming Commission) (together Commissions) as set forth below.

RECITALS

A. This Wexpro II Agreement derives from the Wexpro Stipulation and Agreement executed October 14, 1981 and approved October 28, 1981 by the Wyoming Public Service Commission and December 31, 1981 by the Utah Public Service Commission (hereinafter Wexpro I or Wexpro I Agreement). The Wexpro I Agreement and accompanying guideline letters provide, among other things, the establishment of terms and conditions for a "self-governing means of encouraging the development of natural gas to be made available to Questar Gas' retail distribution customers" at established contractual prices, subject to the ratemaking and other authority of utility regulatory agencies. Over the past thirty years, Wexpro has drilled, developed and operated properties under the Wexpro I Agreement for the benefit of both Questar Gas' customers and Wexpro.

B. Wexpro I and the accompanying guideline letters govern the rights and obligations of the parties to the Wexpro I Agreement in and with respect to expressly defined and identified oil and gas properties.

C. As the Wexpro I Agreement properties mature and continue to be depleted, the Parties desire to supplement the Wexpro I Agreement properties with new properties that would be developed and operated by Wexpro under terms similar to the Wexpro I Agreement, all as set forth herein.

D. Oil and gas property acquisitions, which if approved by the Utah and Wyoming Commissions, will be identified as Wexpro II Properties subject to this Wexpro II Agreement and are believed to have significant potential value for Questar Gas' retail distribution customers.

E. The intent of this Wexpro II Agreement is to produce additional natural gas for the benefit of both Questar Gas' customers and Wexpro.

Therefore, in order to establish a process by which Wexpro II Properties may be identified, evaluated and submitted for approved development and management, the undersigned Parties agree as follows.

I. DEFINITIONS

For purposes of this Agreement, the following definitions will apply to the indicated terms wherever they appear.

Products

I-1. Natural Gas. A gaseous substance whose major constituent is methane.

I-2. Natural Gas Liquids. All liquids extracted from a natural gas stream except liquids (including condensate) recovered by surface separators.

I-3. Oil. The generic term used to describe all products including minerals and hydrocarbons other than natural gas or natural gas liquids.

I-4. Hydrocarbons. A generic term used to refer to natural gas, natural gas liquids and oil collectively.

Hydrocarbon-Producing Properties and Related Terms

I-5. Well. The well bore and all underground and surface materials and facilities installed in connection with drilling into the earth's surface for the production or injection of hydrocarbons and other substances. The term "well" includes all appurtenant facilities.

I-6. Appurtenant Facilities. Those facilities, downstream from the wellhead, to and including the delivery point, that are necessary to make the products acceptable for delivery including, but not limited to, compression, transportation, gathering, separation, treating and certain processing facilities.

I-7. Delivery Point. That point, under standard industry practice, at which a purchaser of oil or natural gas liquids or natural gas takes delivery from the producer.

I-8. Completed Well. (a) A well ready for and capable of producing hydrocarbons in commercial quantities regardless of whether the necessary equipment and machinery is installed to permit continuous production and marketing of hydrocarbons or (b) a dry hole.

I-9. Development Well. A well drilled under the terms of this Agreement for carrying out development oil or development gas drilling, as those terms are defined in Section I-18 and I-19 .

I-10. Dry Hole. A development well that (i) upon completion is clearly uneconomical to produce and is plugged and abandoned while the drilling rig is in place, or (ii) is otherwise not determined to be a commercial well under the procedures set forth in Section I-11. If a commercial well is completed in a productive reservoir above the total depth drilled, that portion of the well below the lowest productive reservoir to total well depth will be considered a dry hole.

I-11. Commercial Well. A development well that, upon completion, (i) clearly produces sufficient quantities to pay, at market prices for the products, all costs of drilling, development and operation of the well, or (ii) requires further determination for classification as a commercial well or dry hole.

A well will be classified as a commercial well in the latter case under the following procedure:

(a) It will be produced for 30 days after stimulation (or such lesser time as state oil and gas regulatory authority requires).

(b) Using the then-available test data for the last 10 days of the test period and economic analysis methods normally used in the industry, Wexpro will make an economic evaluation of the potential value of hydrocarbon production from the well. If the economic evaluation shows that production from the well, when valued at market prices, will pay the expenses of operating the well, including royalties and taxes, plus 50% of the drilling costs to completion to the wellhead, the well will be deemed a commercial well.

(c) If the well does not meet the test set forth in paragraph (b), Wexpro will notify the Parties and the Staff of the Wyoming Commission of its intent to classify the well as a dry hole and will supply to each Party the economic evaluation and the factual basis for the conclusion. Information that is available at such time will be supplied and will include, if available, drilling costs to date, cost for completion, test data, projected life of the well, the decline curve based on field history, and such other data as would be relevant by industry standards.

(d) Disputes concerning the accuracy, completeness and analysis of the data furnished, or the classification made by Wexpro, under paragraphs (b) and (c) may be the subject of the arbitration procedure set forth in Section V-13 of this Agreement. In no event, however, will wells be subject to reclassification as a result of production and other physical and economic data that become known or available after the analysis performed in paragraph (b) of this Section.

I-12. Wexpro II Property. Any Wexpro II Oil Property or Wexpro II Gas Property.

(a) Wexpro II Oil Property. Any Acquired Wexpro II Oil Property and any well classified as a development oil well.

(b) Acquired Wexpro II Oil Property. An oil property acquired by Wexpro and approved for inclusion in this Agreement.

(c) Wexpro II Gas Property. Any Acquired Wexpro II Gas Property and any well classified as a development gas well.

(d) Acquired Wexpro II Gas Property. A gas property acquired by Wexpro and approved for inclusion in this Agreement.

I-13. Acquired Wexpro II Dry Hole. A dry hole that is included in a Wexpro II Property, which was drilled prior to the acquisition by Wexpro.

I-14. Pool. An underground accumulation of hydrocarbons in a single, separate natural reservoir characterized by a single pressure system. Each zone of a geologic formation which is completely separated from any other zone in the formation is a separate pool.

I-15. Productive Oil Reservoir. All productive oil reservoirs as identified in the Wexpro I Agreement.

I-16. Productive Gas Reservoir. All productive gas reservoirs as identified in the Wexpro I Agreement.

Hydrocarbon Operations and Transactions

I-17. Wexpro II Development Drilling Area.

(a) Wexpro II Development Drilling Area has the same definition as Development Drilling Area used in the Wexpro I Agreement.

I-18. Development Oil Drilling. Any drilling completed or recompleted on a Wexpro II Property; and:

(a) targeted and completed in a productive oil reservoir, or

(b) completed as a commercial well outside a productive oil or gas reservoir that produces primarily oil during the first 30 days of production based on the current product allocation methodology defined in Section I-35.

I-19. Development Gas Drilling. Any drilling completed or recompleted in a Wexpro II Property; and:

(a) Targeted and completed in a productive gas reservoir, or

(b) completed as a commercial well outside a productive oil or gas reservoir that produces primarily gas during the first 30 days of production based on the current product allocation methodology defined in Section I-35.

I-20. Enhanced Oil Recovery Facilities. Such facilities as are necessary in connection with "secondary" and "tertiary" petroleum hydrocarbon recovery techniques. These techniques involve man-induced pressure changes or improved sweep efficiency using injected fluids within a productive oil or gas reservoir, often through injection of foreign materials or injection of natural gas for the purpose of increasing the yield from the reservoir. Such techniques do not refer to stimulation procedures used prior to completion to make a well commercial even if essentially similar procedures used on an already commercial well would be classified as "enhanced recovery procedures."

I-21. Farmout. The common petroleum industry transaction by which an oil and gas lease owner contracts to assign a lease or some portion of it to another who undertakes drilling obligations. The assignor usually retains an interest such as an overriding royalty, production payment or working interest.

Accounting and Ratemaking

I-22. Depreciation. A means by which the capital investment in an asset is recovered over the useful life of the asset. Depreciation is generally an expense deduction for federal and state income tax purposes and is also an element of cost-of-service ratemaking for utilities. As used in this Agreement, depreciation will refer to the standard methods being used by Wexpro, and which are recognized and approved by the accounting profession and agencies having jurisdiction over such procedures, except as otherwise provided in this Agreement.

I-23. Amortization. A means by which intangible capital investments or other sums are recovered over the life of a related tangible asset or otherwise eliminated over a period of time. Standard accounting methods will be used to implement amortization as necessary. For purposes of this Agreement, exploration and development costs associated with dry holes will not be amortized.

I-24. Royalty. Generally, a percentage of the gross revenues generated from production from a lease. The royalty owner or recipient remains legally responsible for its pro-rata share of handling and transportation costs (if taken in kind) and production related taxes, including but not limited to severance, ad valorem, and windfall-profits taxes. For those leases from which production is owned only in part by Wexpro, a royalty provided for in this Agreement will apply only to production attributable to Wexpro's respective net interest, as the case may be.

I-25. Taxes. All exactions resulting from levies by government, including but not limited to taxes on income, property, production, operations, occupation, franchise, license, privilege, excise and payroll.

I-26. AFUDC. Allowance for funds used during construction. AFUDC is an amount equal to the base rate of return (r), as defined in Section I-32, applied to funds used for construction purposes. No AFUDC charges will be included upon expenditures for construction projects that have been abandoned. When only a part of plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service will be treated as investment in Wexpro and AFUDC thereon as a charge to construction will cease. AFUDC on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as otherwise limited in this provision.

I-27. Marginal Composite Income Tax Rate. The tax rate

$$t = tf(1\text{-}ts) + ts,$$

where:

(a) tf is the federal income tax rate for U.S. corporations that would apply to Wexpro's highest level of taxable income if Wexpro were to file a separate tax return, without regard to the actual tax rate (on August 31, 2012, this rate was 35%); and

(b) ts is the weighted state tax rate calculated according to the formula given on Exhibit C. ts will be fixed for each calendar year on the basis of data for the immediately previous calendar year. The rate fixed for the remainder of 2012 is 1.6272%, as shown in the sample calculation on Exhibit C.

I-28. Investment of Wexpro. The investment base, designated portions of which will serve as the base to which various rates of return, as specified in this Agreement, will be applied. All investment in Wexpro II Properties will include acquisition costs and future capital, net of depreciation, invested by Wexpro to produce hydrocarbons from Wexpro II Properties and will be as otherwise provided in this Agreement. This will include all depreciated investment in plant and AFUDC in development well drilling and enhanced recovery facilities. New increments of deferred taxes or other tax "timing" reserves related to investments in Wexpro II Property will be subtracted from those investments prior to inclusion in the investment of Wexpro. New increments of the investment of Wexpro will not include any capitalized dry-hole costs.

I-29. Return. As used in this Agreement, the net from proceeds after they have been reduced by all applicable expenses (but not long-or short-term debt and preferred stock expense), depreciation, amortization and taxes.

I-30. Rate of Return. As a percentage, the return divided by the applicable investment.

I-31. Commission-Allowed Rate of Return. The weighted average of the then current Utah and Wyoming Commission-allowed rates of return will be determined each year as of July 31, using the previous calendar year's volumetric firm sales. (On August 1, 2012, this rate was 8.428%.)

I-32. Base Rate of Return (r). A percentage to be (i) applied to specified investment bases or (ii) used as a basis for determining other rates of return as required in this Agreement. The base rate of return (r) is determined by the following method:

r will be determined as of July 31 each year according to the following formula:

$$r = 16.00 + (i - 14.35),$$

where i is the following index:

The arithmetic average of the rate of return on common equity as authorized by the indicated regulatory agency for the 20 utility and natural gas companies listed on Exhibit E, such rates of return to be those in effect by valid order of the respective agencies on May 31 of the calendar year in which the average is being determined.

To the extent that the companies listed in Exhibit E cease to exist under the corporate names indicated, they will be replaced by the successor or assignee company if that successor or assignee continues to provide the same utility service to the majority of customers served by the previous company in the relevant jurisdiction. Successor state regulatory agencies for those state-regulated utilities listed in Exhibit E will not affect the computation under this provision. If, however, any state-regulated utility becomes federally regulated or unregulated, the Parties will choose a replacement state-regulated utility. (On August 1, 2012, the base rate of return was 12.41%.)

I-33. Market Price. The wellhead price per unit for hydrocarbons produced, as determined by the following provisions:

(a) The price upon which third-party royalty payments are to be made for production from the well, as such royalty price is established from time to time.

(b) If a price is not determinable under paragraph (a) at the time of delivery, the average of the three highest prices (if available) paid by a purchaser to a seller (neither of which is an affiliate of the Company) for a product of comparable quality in the same county of delivery or the same producing field, whichever is larger.

(c) If a price is not determinable under paragraphs (a) or (b) at the time of delivery, the highest price paid for the product of comparable quality in the nearest producing area.

I-34. Cost-of-Service. Economic value determined by the aggregation of the actual costs incurred in producing or providing a product. The cost-of-service formulation to be applied under the terms of this Agreement is set forth in Exhibits A and D.

I-35. Product Allocation. The method to be used for purposes of allocating costs, expenses, depreciation and investments, so that products jointly produced from common facilities can be accounted for separately, each carrying an appropriate allocation of the costs associated with that production. Allocations will be made on the following basis:

(a) The equivalent ratio between natural gas and oil will be established on the basis of market price.

I-36. Overriding Royalty. A royalty interest in oil and gas and other minerals at the wellhead in addition to the usual landowners' royalty reserved to the lessor.

II. WEXPRO II OIL PROPERTIES

II-1. Ownership of Oil, Natural Gas Liquids and Natural Gas. All oil, natural gas liquids and natural gas produced from Wexpro II oil properties will be the property of and be sold or otherwise disposed of by Wexpro.

II-2. Oil and Natural Gas Liquids Proceeds. The total proceeds from the sale of oil and natural gas liquids from Wexpro II oil properties, less royalties, will be subject to the following provisions:

(a) Proceeds will first be used to pay the costs and expenses of holding and operating the Wexpro II oil properties. Such costs and expenses will include an allocation to Wexpro of expenses, depreciation, taxes, royalties and other reasonable business expenses of production. The procedures set forth in Exhibit A will serve as guidelines for this determination. In no event will deductible expenses include any exploration and development expenses associated with dry holes.

(b) As an example of the allocation to be performed under paragraph (a), where Wexpro employees are engaged in the operation and maintenance of producing oil wells and productive oil reservoirs and contemporaneously engaged in other activities of Wexpro, Wexpro will maintain accurate and complete time and other records for properly allocating the time and expenses of employees among such operations. Costs that can be directly assigned, such as investments in fractionating towers which benefit only natural gas liquids products, will be directly accounted for as a cost of producing that product.

(c) The investment of Wexpro and Wexpro's operating expense in Wexpro II oil properties will be allocated to the hydrocarbons produced in accordance with the product allocation method defined in Section I-35.

(d) It is agreed that the investment of Wexpro in Wexpro II oil properties will be depreciated by the unit-of-production method for proven developed reserves only. For purposes of calculating the return provided by paragraph (e) of this Section, this investment will be determined on a monthly basis, after additions and depreciation as provided herein.

(e) From the proceeds of the sale of oil and natural gas liquids (after deduction of expenses and all royalties as provided in this Section), Wexpro will deduct an amount sufficient to provide the applicable return on that portion of the investment of Wexpro allocated to oil and natural gas liquids production. Such returns will be calculated for each monthly income statement and will be the product of one-twelfth of that portion of the investment of Wexpro allocated to oil and natural gas liquids production at the end of that month, multiplied by the applicable rate of return.

(f) Any remaining Wexpro oil and natural gas liquids net revenues will be allocated as follows:

Note: This is a replacement of original page 8 filed with the Commission on February 14, 2013.

(i) 54% of such remainder will be allocated to the Company and placed by the Company in an account used solely for the purposes of reducing natural gas rates, or disposed of otherwise by Commission order.

(ii) The remaining 46% will be retained by Wexpro as its separate property and will not be considered utility income or used to reduce natural gas rates.

(iii) To account appropriately for the income tax impact on the 54% allocation set forth in subparagraph (i) above, the sum paid to the Company by Wexpro will be the 54% described in subparagraph (i) divided by a tax-adjustment factor: 1.0 minus the marginal composite income tax rate, as defined in Section I-27. (See Exhibit B.)

(iv) Wexpro's income statement for purposes of this Agreement will not include the resultant tax-adjusted sum paid to the Company as an expense under this paragraph, although it may so appear for income tax purposes or other purposes not covered by this Agreement.

(g) The royalty, expense and return treatment and the 54%-46% allocation described in this Section will be referred to in this Agreement as the "54-46 formula." The accounting procedure set forth in this Section is illustrated by the sample calculations shown on Exhibit B.

II-3. Pricing of Gas from Oil Wells.

(a) Except for field and repressurization use, any and all natural gas produced by Wexpro from Wexpro II oil properties will be priced at cost-of-service (see Exhibit A) and sold by Wexpro to the Company, subject to such federal law and regulations as may be applicable to such a sale. In the event that the average monthly cost-of-service for all natural gas sold under this paragraph is in excess of average monthly market price for that natural gas, the difference between the average cost of service and the average market price will be treated as an expense of Wexpro for the purposes of the "54-46 formula," and such difference will not be included in the cost-of-service calculation.

(b) The Company may, at its discretion, enter into suitable transportation arrangements with third parties or any Company affiliate for transporting gas produced under this Section to its system.

II-4. Enhanced Recovery Procedures. It may be necessary or desirable to implement enhanced recovery procedures for Wexpro II oil properties in order to maximize the recovery of oil. The investment in such procedures may be substantial and the results of these operations may not always be successful. If the revenues from the additional oil recovered as a result of such procedures do not cover the expenses, royalties and return as they are related to the enhanced recovery procedures, the initiation of such procedures would result in more of the total Wexpro oil production revenues being allocated to a return on this new capital, with less available for the "54-46 formula." To assure that investment for enhanced recovery procedures will be prudently made, the following terms will apply:

(a) The capital investment required for enhanced recovery facilities will be made entirely by Wexpro. In lieu of the base rate of return (r), such enhanced recovery investment will be assigned a rate of return as follows:

(i) If, at the time an authority for expenditure (AFE) for an enhanced recovery project is executed, the total of the amounts described in subparagraphs II-2(f)(i) and (ii) for the prior 12 months have been less than 3.00% of the average investment of Wexpro allocated to oil production for such a 12-month period, the rate of return to apply only to that enhanced recovery investment will be the base rate of return plus a 2.00% risk premium (r + 2.00).

(ii) In all other cases, the base rate of return (r) will apply.

(b) The aggregate enhanced recovery facilities investment will look to all natural gas liquids and oil production for recovery of investment, expenses and return. Each amount invested will be deemed made on the first day of the month closest to the date when it was made and will be depreciated on the basis of individual enhanced recovery projects.

II-5. Uneconomical Production. When any Wexpro II oil property is depleted to a point where, in the prudent judgment of Wexpro, it is no longer economically feasible to produce such a reservoir, production from that reservoir may be terminated, and the investment of Wexpro will be adjusted by the net difference between salvage value and abandonment or dismantling costs.

II-6. Development Oil Drilling. Any development oil drilling will be subject to the following provisions:

(a) If a development well is required in the judgment of Wexpro to produce hydrocarbons more efficiently, Wexpro will drill such a well and assume the total risk of unsuccessful drilling, including dry-hole costs.

(b) If a commercial well results, the investment in such a development oil well will be included in the investment of Wexpro on the first day of the month nearest the date the well is qualified as a commercial well. The rate of return on commercial development oil wells will be equal to the base rate of return plus a risk premium of 5.00% (r + 5.00).

(c) For each development oil well spudded, Wexpro will keep detailed accounts of the funds used during drilling of such a well in accordance with the treatment of AFUDC set forth in Section I-26. Where a well is deemed to be a commercial well, the accumulated AFUDC for that well will be added to the investment of Wexpro along with the capital invested in the well.

(d) If production from any well drilled under the terms of this Section occurs and the well is determined to be a dry hole (as defined in Section I-10), paragraph (b) of this Section will not apply. Wexpro may, at its discretion, plug and abandon the well, or produce the well, and the well and all production from the well will be the sole property of Wexpro to dispose of at its discretion and to retain any proceeds.

(e) Wexpro will use prudent judgment in determining the desirability and necessity of development drilling under this Section as well as the timing and methods to be used in any such drilling.

II-7. Gas for Repressurization. Gas being produced from a Wexpro II oil property may be used to repressure the pool without compensation or obligation to the Company so long as no natural gas is consumed except for field or lease use. When such repressurization ceases and such natural gas is finally produced, it will be delivered to the Company at cost-of-service.

II-8. Delivery. The delivery of natural gas produced under the provisions of this Article II will be at the delivery point (defined in Section I-7), and all costs of receiving the natural gas and all the necessary investment at and downstream from such a point will be the responsibility of the Company.

III. WEXPRO II GAS PROPERTIES

III-1. Wexpro will fund and drill or cause to be funded and drilled all necessary and appropriate development wells on these properties and provide the necessary facilities which in its opinion will be reasonably and prudently necessary to efficiently produce the hydrocarbons in the Wexpro II gas properties.

III-2. Development Gas Drilling. Any investment made in Wexpro II gas properties, will be capitalized by Wexpro, and Wexpro will be compensated for these investments by the Company as provided in Section III-3. Necessary facilities installed downstream from the delivery point will be capitalized in the Company's utility accounts.

III-3. Pricing of Gas from Gas Wells. Any and all natural gas produced by Wexpro from Wexpro II gas properties will be priced at cost-of-service and sold by Wexpro to the Company, subject to such federal law and regulations as may be applicable to such a sale.

III-4. Operator Service Fee.

(a) As operator, Wexpro will bill the Company for the services it performs and for the use of the facilities it has installed to produce natural gas, natural gas liquids and oil from the Wexpro II gas properties.

(b) Billing for services will be on a monthly cost-of-service basis and will follow, to the extent applicable and practicable, the methods and practices employed by the Utah and Wyoming Commissions in determining the Company's cost of service prior to the effective date of this Agreement. Exhibit D sets forth the general guidelines for the cost-of-service charges to be made under this Section.

(c) The monthly billing for services will specifically include a return on investment on approved acquisition costs at the current commission-allowed rate of return.

(d) The monthly billing for services will also include a return on investment for costs incurred for new facilities at the current commission-allowed rate of return, except that investment in commercial development wells will be entitled to a base rate of return plus an additional 8.00% (r + 8.00).

III-5. Depreciation. For purposes of this Agreement, Wexpro's investment in commercial development wells and appurtenant facilities will be depreciated monthly by the unit of production method for proved developed producing reserves only, except as otherwise provided in Section I-22.

III-6. Delivery. The delivery of natural gas and natural gas liquids produced under the provisions of Article III will be at the delivery point (defined in Section I-7), and all costs of receiving, processing and gathering the natural gas and natural gas liquids and all the necessary investment at and downstream from such a point will be the responsibility of the Company.

III-7. Development Gas Drilling.

(a) Wexpro will exercise prudent judgment in determining the desirability and necessity of development gas drilling under this Section, as well as the timing and methods to be used in any such drilling as provided in Section V-10.

(b) It is acknowledged that development drilling for natural gas often involves deep, time consuming drilling that may not result in a commercial well. If any development gas well becomes a commercial well, the investment in the well (and in the appurtenant facilities up to the delivery point) will be capitalized in the investment of Wexpro in the same manner and under the same conditions as for a development oil well.

(c) If production from any well drilled under the terms of this Section occurs and the well is determined to be a dry hole (as defined in Section I-10), Wexpro may, at its discretion, plug and abandon the well or produce the well, and the well and all production from the well will be the sole property of Wexpro to dispose of at its discretion and to retain the proceeds.

III-8. "New Oil" from Development Gas Drilling.

(a) Oil from commercial wells completed on a Wexpro II gas property will be sold by Wexpro, and the resulting revenues will be apportioned between the Company and Wexpro as provided by the "54-46 formula."

(b) Oil produced under this Section will bear a share of the Wexpro II gas properties' expenses and investment, determined by the product allocation method defined in Section I-35.

(c) Any allocated oil investment related to development gas drilling (under Section III-2) will carry with it the entitlement to apply a 5.00% risk premium in the "54-46 formula" as specified for development oil drilling in Article II.

(d) Any facilities that may be installed to separate or treat oil and natural gas liquids downstream from the delivery point will be installed by the Company and will be included in the Company's utility accounts.

III-9. Termination of Production. Should any production from Wexpro II gas properties that is achieved by use of facilities installed by Wexpro be terminated, such investment of Wexpro in Wexpro II gas properties will be adjusted by the net difference between salvage value and abandonment or dismantling costs related to such facilities.

III-10. Off-System Natural Gas Production. If natural gas is developed from Wexpro II gas properties at any time that cannot be economically delivered into the Company's distribution system, or which is being sold to third parties, such natural gas will be sold by Wexpro, and the revenues less expenses will be used solely to reduce natural gas rates or as otherwise directed by Commission order.

IV. WEXPRO II PROPERTY ACQUISITION

IV-1. Property Acquisition. Wexpro will acquire oil and gas properties or undeveloped leases at its own risk.

(a) Questar Gas shall apply to the Utah and Wyoming Commissions for approval to include under this Agreement any oil and gas property that Wexpro acquires within the Wexpro I development drilling areas.

(b) Wexpro may also acquire additional oil and gas properties or undeveloped leases outside the Wexpro I development drilling areas. Questar Gas may apply for Commission approval to include these properties under this Agreement.

IV-2. Application. Questar Gas will file an application with the Utah and Wyoming Commissions requesting approval to include proposed properties under this Agreement. The application shall include the following:

(a) Purchase price and gas pricing assumption;
(b) Locations of current and future wells;
(c) Historical production and remaining reserves of current wells;
(d) Forecasted production/reserves for future wells;
(e) Forecasted decline curves for current and future wells;
(f) Estimated drilling (capital) costs per well;
(g) Estimated operating expenses for current and future wells;
(h) Gross working interest and net revenue interest for current and future wells;

(i) Estimated production tax per Dth for current and future wells;
(j) Estimated gathering/processing cost per Dth for current and future wells;
(k) Description of any land lease, title, and legal issues related to real property, including but not limited to a description of the terms under which the property is acquired by Wexpro and whether there are any time limits, such as option expirations, effecting the availability of the properties for inclusion as a Wexpro II property;
(l) Forecasted long-term cost-of-service analysis;
(m) Impact on Questar Gas' gas supply;
(n) Geologic data;
(o) Future development plan for the proposed properties; and
(p) Other data as requested or as may be appropriate to an evaluation of the property.

The application and supporting information shall be filed by the Company. The Company will seek any confidential protections as may be necessary pursuant to applicable Utah and Wyoming statutes and administrative rules.

IV-3. Application Procedure. The following procedures will govern the procedure for filing and responding to the application.

(a) The application shall be filed as a formal proceeding and may include a request for an initial prehearing and scheduling conference, including a request that the proceeding be expedited. Parties agree that formal or informal discovery may begin immediately upon the filing and service of the application.

(b) At the time the application is filed with the Commissions, a confidential copy shall be served upon the Division and the OCA. A confidential copy shall also be provided to the hydrocarbon monitor/evaluator designated by the Parties under Section V-12.

(c) Within seven business days following receipt of the application, the hydrocarbon monitor/evaluator shall provide Questar Gas, the Division, and the OCA with an evaluation of the application and the properties proposed for treatment as Wexpro II properties.

(d) The Division and the OCA shall respond to the application in the manner consistent with their statutory authority and responsibility by recommending its approval or its rejection, in whole or in part, or by requesting additional evaluation.

(e) In any proceeding upon an application filed pursuant to this Wexpro II Agreement, Wexpro shall not be a named applicant nor may Wexpro intervene as a party. However, Wexpro shall make itself available to any Party for the purpose of evaluating the application.

IV-4. Hydrocarbon Monitor/Evaluator. The independent hydrocarbon monitor will evaluate new properties and within seven business days following the filing of Questar Gas' application, will file an independent review of the assumptions, data, and analysis identified in Section IV-2 above for the proposed properties, but will not provide a recommendation.

IV-5. Withdrawal of Properties. If the proposed properties are not approved by both Commissions within 60 days of the filing of the application, Questar Gas may, in its sole discretion, withdraw the proposed properties from consideration for Wexpro II Agreement inclusion.

IV-6. Acquisition Costs. The acquisition costs for Wexpro II properties will earn the current commission-allowed rate of return approved for Questar Gas in its most recent general rate case. Acquisition costs include the costs of acquiring leasehold interests, mineral rights, and currently producing properties. The acquisition costs will be depreciated on a unit of production method using only the reserves from proved developed producing wells at the time of acquisition.

IV-7. Title. Wexpro will retain title to and associated operating rights of the Wexpro II properties. Wexpro will maintain and update a schedule of Wexpro II properties.

IV-8. Management of Gas Volumes. Wexpro II gas volumes will be managed under the direction of Questar Gas.

IV-9. Accounting and Regulatory Treatment.

(a) The investment base of Wexpro II properties will be recorded separately from Wexpro I Agreement properties and will include capital, net of depreciation, invested by Wexpro to acquire, produce, and deliver hydrocarbons from commercial wells.

(b) All royalties or income received from Wexpro under the Wexpro II Agreement, as well as costs associated with natural gas delivered to the Company by Wexpro, will be accounted for under the Account 191 balancing account adjustment provisions of the Company's tariffs on file with and approved by the Commissions in the same manner as natural gas costs incurred by the Company in the purchase of natural gas from third parties.

(c) If a proposed property is not approved for inclusion in this Wexpro II Agreement by both the Utah and Wyoming Commissions then all direct costs associated with that property will be assigned to that property, and common and/or general and administrative costs will be allocated to the property using the Utah Commission-approved Distrigas formula.

IV-10. Wexpro II Property Approval and Well Determination Process. The Wexpro II property approval process as described above and the Wexpro II well-determination process as described in Articles II and III are illustrated on Exhibit F.

V. MISCELLANEOUS PROVISIONS

V-1. Successor and Assigns. This Agreement will be binding upon the Parties and their successors and assigns. No assignment of any right or obligation under this Agreement will be valid if it operates to relieve the assignee of the obligations so assigned.

V-2. Integrated Provisions. The terms and conditions of this Agreement are to be treated as an integrated whole. To the extent that any singular provision is found to be unenforceable or voidable by a court or agency with proper jurisdiction, it is the intent of the Parties that the remaining terms of this Agreement will remain in force and be enforceable by the Parties. Failure of any part of this Agreement will not cause failure of the entire Agreement unless otherwise agreed to by the Parties.

V-3. Filing Reports. Wexpro and the Company will cooperate in providing, in a timely manner when requested, information necessary for the preparation and filing of reports required by appropriate governmental bodies.

V-4. Remedies. The Parties may seek appropriate remedies at law and equity for breaches of the terms of this Agreement in accordance with Section V-13; except that, rescission will not be sought under any condition (except mutual assent), and no transfer, conveyance, grant or reservation executed under this Agreement may be rescinded.

V-5. Field and Lease Use. Wexpro may consume for field or lease use, without compensation or other obligation to the Company, reasonable quantities of any natural gas produced in connection with the production of hydrocarbons from Wexpro II properties.

V-6. Force Majeure. If Wexpro is rendered unable, wholly or in part, by force majeure to carry out its obligations under this Agreement, other than the obligation to make money payments, then Wexpro will give to the other Parties prompt written notice of the force majeure with reasonably full particulars concerning it. Thereupon, the obligations of Wexpro, so far as it is affected by the force majeure, will be suspended during, but no longer than, the continuance of the force majeure. Wexpro will use all possible diligence to remove the force majeure as quickly as possible.

The requirement that any force majeure will be remedied with all reasonable dispatch will not require the settlement of strikes, lockouts, or other labor difficulty by Wexpro contrary to its wishes. Such difficulties will be handled entirely within prudent and reasonable judgment of Wexpro.

The term "force majeure" means an act of God, strike, lockout, or other industrial disturbance, act of public enemy, war, blockade, public riot, lightning, fire, storm, flood, mechanical breakdown, explosion, governmental restraint, or any other cause, whether of the kind specifically enumerated above or otherwise, which is not reasonably within the control of Wexpro.

V-7. Auditing Costs. Any billing to the Company by Wexpro for services under this Agreement or other determination of expenses may include, as a business expense, the allocated costs of auditing of only the properties and transactions covered by this Agreement by independent certified public accountants and other auditors as such audits may be required under the terms of this Agreement.

V-8. Farmouts. Nothing in this Agreement will be construed to preclude Wexpro from entering into farmout agreements with third parties to explore and develop undrilled properties for the benefit of customers.

V-9. Wexpro II Properties. Unless otherwise herein provided to the contrary, Wexpro agrees at its sole cost, risk, and expense, to perform and comply with any and all legally binding lease or other contractual obligations pertaining to the Wexpro II properties and will comply with all laws, rules, and regulations relating to the production of oil and natural gas from such properties and facilities. However, Wexpro will be at liberty to determine for itself the nature, extent, and applicability of such obligations, whether contractual or otherwise.

V-10. Standard of Operation. Wexpro will drill and operate in accordance with prudent, standard and accepted field and reservoir management and engineering practices, and with due regard for the benefits provided the Company's utility operations in consultation with the Company.

V-11. Functional Accounting. For purposes of carrying out the terms and conditions of this Agreement, Wexpro will maintain appropriate separate functional accounting of the transactions required under this Agreement.

V-12. Monitoring Of Performance Under Agreement.

(a) The OCA and the Division will be entitled to monitor the performance of the Company and Wexpro under the Wexpro II Agreement. To facilitate that monitoring, the books and accounts of Wexpro pertaining to the Wexpro II properties will be made available for examination by the OCA and the Division when requested at reasonable times and places designated by Wexpro. In addition, Wexpro and the Company will provide the OCA and the Division with a report within 60 days of the end of every calendar quarter setting out production of the Wexpro II properties, the financial benefits from the Wexpro II properties, and reporting on the operation of each element of the Agreement. Wexpro will have its accounts with respect to all matters under the Agreement audited annually by a firm of independent certified public accountants. The Division and OCA will receive copies of the audit report when completed. All costs of the audit will be borne by Wexpro and will be considered to be normal business expenses of Wexpro for purposes of the Agreement's formulae. This expense item will be strictly restricted, however, to reflect solely the costs of auditing compliance with the Agreement.

(b) If the OCA or the Division desire further monitoring, they will select two monitors, an independent certified public accountant and an independent hydrocarbon industry consulting firm, to review the performance of the Agreement and to advise all Parties with respect thereto. Any monitor selected will be professionally trained and qualified, and will be nationally recognized as a reputable and independent expert in the subject matter of the function monitored. The two monitors will be paid actual and reasonable fees and expenses incurred in evaluating the proposed properties under Article IV of this Wexpro II Agreement, and monitoring the performance of this Agreement and the Wexpro I Agreement by Wexpro which will be considered to be normal business expenses of Wexpro in determining the cost-of-service of natural gas to be delivered or sold to the Company under the Agreement.

(c) Wexpro will cooperate with the monitors in providing reasonable access to its books, accounts, and records with respect to the Wexpro II Properties and in attempting to obtain other relevant information reasonably requested by the monitors. The monitors will be obligated under their retainer agreements to keep information disclosed to them confidential except in connection with necessary reports made to the Division, the OCA, the Company or Wexpro in performing their duties as monitors or with Wexpro's prior approval.

(d) Monitors may be removed with or without cause by the Division and the OCA acting jointly, and with cause by the Company and Wexpro. For purposes of this paragraph, cause will include, but not be limited to, lack of professional qualification, lack of competence, unauthorized disclosure or use of confidential information, and a pattern of unreasonable, harassing or oppressive conduct by the monitor in performing its responsibilities. If a monitor is removed or is unable to continue to act, the Division and the OCA, may select a successor upon the same terms and conditions as an original monitor could be selected.

V-13. Dispute Resolution.

Parties acknowledge that from time to time disputes may arise regarding the performance of this Agreement. In the event that any Party claims that there is a default by Questar Gas of any of its contractual obligations under the terms or intent of this Agreement, such dispute will be adjudicated before the Commissions. In the event that any Party claims that there is any default by Wexpro of any of its contractual obligations under the terms or intent of this Agreement, the following procedure will be followed:

(a) The charging Party will give notice of the claimed default, and Wexpro will be allowed 30 days or such longer time as the charging and defaulting Parties may stipulate to correct its default.

(b) If the default is not corrected to the satisfaction of the charging Party, the matter will be submitted to arbitration on the following terms:

(i) The charging Party will select a person professionally trained and qualified in the subject matter of the dispute but who has not been employed or retained by the Parties within the previous 12 months, to act as an arbitrator, such selection to be within 60 days of the date upon which notice of default was given or such longer time as the Parties may specify.

(ii) Wexpro will similarly select a person professionally trained and qualified in the subject matter of the dispute to act as an arbitrator under the same restrictions and within the same time limit.

(iii) The two arbitrators selected will together select a third person professionally trained and qualified in the subject matter of the dispute to act as an arbitrator, such selection to be within 15 days of the date the latter of the two arbitrators was selected by the Parties. In the event no agreement can be reached on the selection of the third arbitrator within the time permitted, such selection will be made by the Chief Judge of the United States District Court for the District of Utah upon the application of any Party.

(iv) The three arbitrators will give the Parties reasonable opportunity to present their positions and will thereafter decide the matters in dispute by a majority vote. The arbitrators will not engage in investigations or audits themselves but will render their decision based upon information presented to them by the Parties. It is understood that the arbitrators may request the Parties to prepare and present additional evidence if needed for their decision and that arbitrators will keep information presented to them confidential.

(v) Each Party will bear the costs of its own attorneys and witnesses in the arbitration proceedings. The salary and expenses of the arbitrator selected by each of the Parties will be paid by the Party or Parties selecting the arbitrator. The salary and expenses of the third arbitrator will be paid by Wexpro and considered a normal business expense of Wexpro for purposes of the Agreement's "54-46 formula" unless the formula at that time is not returning to Wexpro the full return provided in the Agreement on its investment base, in which event the charging Party will share the expenses of the third arbitrator equally with Wexpro.

(c) Except as otherwise specifically provided in this Section V-13, the arbitration procedure contemplated by this Agreement will comply with Chapter 11 of Title 78B of the Utah Code or any successor provision of Utah law governing arbitration.

(d) The decision of the arbitrators may be presented by any Party to the Commission in an application for any action by the Commission with respect to the claimed default by the charging Party of the Agreement or to a court of competent jurisdiction for any action with respect to a claimed default by Wexpro of the Agreement. In proceedings before the Commission or court with respect to the arbitrated matter, the decision of the arbitrators will be binding upon the Parties except with respect to matters covered by Utah Code Ann. §78B-11-124 and §78B-11-125 and any other claim of impropriety, irregularity or arbitrariness and capriciousness in the arbitration proceedings.

(e) Among the remedies available under arbitration there is specifically excluded any form of rescission of the terms of property transfer of the Agreement.

(f) The Parties agree that separate arbitration proceedings in Utah and Wyoming or between different Parties will not be initiated on the same subject. All Parties to this Agreement should receive notice of any arbitration proceeding initiated by any Party in either state. Any Party that chooses not to participate in the arbitration proceeding will be bound by the decision of the arbitrators as if it had participated.

(g) In deciding any controversy brought before them, the arbitrators, Commission or other administrative or judicial body may consider, as appropriate, that one Party or the other to the proceeding may have superior knowledge or access to the properties, assets or information which is the subject of the proceeding. They may also consider that the Parties to this Agreement have a duty to perform their respective responsibilities in good faith.

(h) Dispute resolution subparagraphs (a)-(g) shall be limited to claims of breach of contract asserted against Wexpro under this Agreement.

V-14. Confidential Information. The Company and Wexpro are obligated under this Agreement to provide the other Parties, its monitors and arbitrators; with information, reports, and notices regarding Wexpro's exploration and development of the properties, and will comply with applicable Utah and Wyoming statutes and administrative rules to protect such information as confidential. It is understood and agreed that the Parties will keep such information, reports, and notices, including information received from monitors and presented in arbitration proceedings, strictly confidential and will use them only in connection with its review of matters under this Agreement. It is understood that the Parties may utilize such information in arbitration proceedings and pursuant to the confidentiality rules of the respective Commissions.

V-15. Guideline Letters.

(a) The Parties acknowledge that from time to time issues may arise regarding Wexpro's interests in Wexpro II properties that may be addressed by guideline letters. All current confidential Wexpro I guideline letters applicable to Wexpro II shall be incorporated herein. A copy of all guideline letters will be maintained by Wexpro, the Division, and the Wyoming Commission Staff.

(b) Future Wexpro II guideline letters will be developed with the Parties, and Wyoming Commission Staff, and in consultation with the independent monitors, as necessary. All Parties must approve a guideline letter before it becomes effective. A copy of the index of current confidential guideline letters is attached as Exhibit G.

V-16. Nothing in this Wexpro II Agreement is intended, nor shall it be construed, interpreted or argued, to subject Wexpro or Wexpro activities to the public utility regulation of any state.

V-17. Nothing in this Wexpro II Agreement is intended, nor shall it be construed, interpreted or argued, to alter, amend or modify Wexpro I.

V-18. Amendment. The Parties agree that this Wexpro II Agreement may by mutual consent and subject to Utah and Wyoming Commissions' approval, be amended to address, explain, clarify or to accommodate applications, approvals, development or production of and from Wexpro II properties, or to address, explain, clarify or to accommodate appropriate regulation for ratemaking purposes of Questar Gas' rights with respect to Wexpro II properties or other benefits from such properties. In the event such amendment is necessary or requested, Parties shall meet and confer for the purpose of drafting and considering proposed amendments.

V-19. Nothing in this Wexpro II Agreement is intended, nor shall it be construed, interpreted or argued, to restrict the Division and the OCA in the performance of their statutory authorities and responsibilities.

VI. EFFECTIVE DATE

This Agreement will be effective upon the entry of a final order of approval by the Utah Public Service Commission and the Wyoming Public Service Commission.

VII. EXHIBITS

VII-1. Exhibits. Attached to and made a part of this Agreement by reference are the following exhibits:

Exhibit	Title
A	Cost-of-Service Formulation for Gas from Oil Reservoirs
B	Sample Calculation of Productive Oil Reservoir Accounting
C	Marginal Composite Income Tax Rate Calculation
D	Operator Service Fee
E	Base Rate of Return Index Companies
F	Wexpro II Property Approval and Wexpro II Well Determination
G	Index of Wexpro Agreement Guideline Letters

This Wexpro II Agreement has been duly executed by the parties this 12th day of September, 2012.

/s/ Craig C. Wagstaff

Craig C. Wagstaff
Executive Vice President &
Chief Operating Officer
Questar Gas Company

/s/ Chris Parker

Chris Parker
Division Director
Utah Division of Public Utilities

/s/ James R. Livsey

James R. Livsey
Executive Vice President &
Chief Operating Officer
Wexpro Company

/s/ Bryce J. Freeman

Bryce Freeman
Administrator
Wyoming Office
of Consumer Advocate

EXHIBIT A

COST-OF-SERVICE FORMULATION FOR GAS FROM OIL RESERVOIRS

The monthly cost-of-service charge directly attributable to the sale to Questar Gas Company of natural gas provided by Wexpro Company from certain properties as set forth in the Agreement will include the following costs. (Section references are to the relevant portions of the Agreement to which this exhibit is attached.)

1. Operating Expenses. Reasonable and necessary operating expenses incurred by Wexpro and allocated to the production, gathering, treatment and disposition of natural gas. Such expenses will include operating and maintenance expenses, administrative and general expenses, royalties (including compensatory royalties) and fees based on the monthly level of production, and other common business expenses.

2. Depreciation. The allocated monthly depreciation expense as computed by the unit-of-production method for proved developed producing reserves only where applicable or one-twelfth of any annual depreciation expense computed using applicable depreciation methods other than the unit-of-production method as allowed by and computed under the terms of the Agreement.

3. Amortization and Depletion. The allocated monthly accrual recorded for the billing month as amortization and depletion of producing lands and land rights, amortization of intangible gas plant and other amortized expenses.

4. Taxes.

(a) Taxes Other than Income Taxes. Accruals recorded for the billing month with respect to taxes other than federal and state income taxes allocated to natural gas operations, adjustments of such accruals for tax expenses previously billed, and such taxes paid but not previously billed, including any state and local income taxes.

(b) Federal and State Income Taxes. Federal and state income taxes for the billing month attributable to the investment of Wexpro allocated to natural gas production facilities, computed by multiplying the return by the marginal composite income tax rate (Section I-27) divided by 1.0 minus the marginal composite income tax rate.

5. Return. Return is computed using the Commission-allowed rate of return (Section I-31) as adjusted from time to time under the procedure specified in the Agreement. For natural gas that is produced from enhanced recovery facilities to which a base rate of return plus 2% adjustment is applicable (Section II-4(a)(i)), the 2% risk premium applies to those facilities only. For natural gas that is produced from development gas wells to which a base rate of return

plus 5% risk adjustment is applicable (Section II-6(b)), the 5% risk premium applies to those facilities only.

The investment used as a base to which a rate of return is applied will be computed in total for each category of investment subject to (i) Commission-allowed rate of return, (ii) the base rate of return plus 2% risk premium, and (iii) the base rate of return plus 5% risk premium, and will be one-twelfth of the sum of:

(a) The allocated, actual original investment including AFUDC in wells, well facilities and plant facilities utilized or held for future use in connection with the production, gathering, treatment and disposition of natural gas and oil, less accumulated reserves for depreciation and amortization of such plant facilities; plus

(b) A general plant allowance calculated by multiplying the amount in paragraph (a) above by 6.3%; plus

(c) A cash working capital allowance for each category of investment, (Commission-allowed rate of return, the base rate of return, the base rate of return plus 2% risk premium, and the base rate of return plus 5% risk premium) equal to 45/365 of the allocated operating expenses, identified in paragraph 1 above, less royalties and annualized by multiplying the monthly amounts by 12; plus

(d) A credit for the balance of accumulated deferred income taxes and other tax-timing reserves, for each category of investment (Commission-allowed rate of return, base rate of return, the base rate of return plus 2% risk premium, and the base rate of return plus 5% risk premium).

6. Cost Allocation. Costs, expenses and investments will be allocated only when direct assignment cannot be made to specific products. When any cost, expense or investment is related to the production of joint products and direct assignment cannot be made, the product allocation procedure (Section I-35) will be used.

7. Page 3 of this exhibit is an example of the calculations to be used for natural gas that is subject to this cost-of-service determination. The individual numbers are illustrative only and do not represent any actual circumstances.

SAMPLE COST - OF- SERVICE CALCULATION
GAS SOLD BY WEXPRO TO THE COMPANY
FROM PRODUCTIVE OIL RESERVOIRS 1/

		(1)	(2)	(3)	(4)	(5)
				Post Aquired Wexpro II Property Enhanced Recovery Facilities		
		Total	Aquired Wexpro II Oil Property 3/	Base Rate of Return(r)	Enhanced Recovery Facilities (r+2.00%)	Wexpro II Development Drilling Facilities
1	**Investment**					
2	Net Plant Investment in Productive Oil Reservoirs	$57,000	$48,300	$5,060	$1,190	$2,450
3	**Gas production Investment:**					
4	Directly Assignable to Gas Production	1,010	800	100	70	40
5	Alocation Based on Product Allocation (&I-35)	6,200	5,000	460	170	570
6	Net Investment in Gas Production Facilities	$7,210	$5,800	$560	$240	$610
7	Add:					
8	General Plant @ 6.3%	454	365	35	15	38
9	Cash Working Capital: 45/365 X (O&M+A&G) x 12	130	117	6	3	4
10	Deferred Income Tax Accrual	(54)	-			
11	Total Investment Base for Return Calculation	$7,740	$6,282	$601	$258	$653
12	**Cost of Service**					
13	Total Expenses for Month	$2,500	$2,173	$207	$46	$74
14	Directly Assignable Expenses - Oil & Gas	701	618	57	10	16
15	Directly Assignable Expenses - Gas					
16	Operating & Maintenance Expenses	1	-	1	-	-
17	Administrative and General Expenses	-	-	-	-	-
18	Royalties	94	83	6	2	3
19	Other Taxes	1	1	-	-	-
20	Depreciation	1	-	-	-	1
21	Total - Gas Direct Expenses	97	84	7	2	4
22	Allocable Expenses - Oil & Gas	$1,799	$1,555	$150	$36	$58
23	Allocable Expenses - Gas					
24	Operating & Maintenance Expenses	70	64	3	1	2
25	Administrative and General Expenses	18	15	1	1	1
26	Royalties	-	-	-	-	-
27	Other Taxes	79	65	7	2	5
28	Depreciation	93	75	9	2	7
29	Total Gas Allocable Expenses	$260	$219	$20	$6	$15
30	**Return Computation**					
31	Applicable Rate of Return		8.428%	12.41%	14.41%	17.41%
32	Return on Investment (line 11 x line 31)/12	63	44	6	3	9
33	Federal Income Taxes (line 32 x Tax Rate)/(1-Tax Rate) 2/	35	25	4	2	5
34	Total Monthly Cost of Service (lines 21 + 29 + 32 + 33)	$455	$372	$37	$13	$34

1/ All figures are hypothetical and used only for demonstrating the method of calculating the cost of service price for gas sold by Wexpro to the Company.

2/ Current Tax Rate : 36.0567%

3/ Future capital investment on Acquired Wexpro II Oil Property, other than costs as provided in columns 3,4,and 5, will earn the Commission Allowed rate of return.

Note: Exhibit A Page 3 reflects the changes filed by Questar Gas Company on March 27, 2013.

Questar Gas Company
Wexpro II Agreement
Exhibit B
Replacement

EXHIBIT B
SAMPLE CALCULATION
PRODUCTIVE OIL RESERVOIR ACCOUNTING \1

		(1)	(2)	(3)	(4)	(5)	(6)
				Post Aquired Wexpro II Oil Property Enhanced Recovery Facilities			
		Total	Aquired Wexpro II Oil Property \3	Base Rate of Return(r)	Enhanced Recovery Facilties (r+2.00%)	Wexpro II Development Drilling Facilities	Allocated to Cost-of-Service Natural Gas
1 Net Plant Investment in Productive Oil Reservoirs		$57,000	$48,300	$5,000	$1,190	$2,450	
Allocation of Investment							
2 Directly Assignable to Products			12,000	1,500	50	240	1,010
3 Allocated Based on Product Allocation			30,500	3,000	900	1,600	6,200
4 Allocated Investment			$42,500	$4,500	$950	$1,840	$7,210
5 Total Revenues for Month from Sale of Oil		$4,520	$3,700	$540	$95	$185	
6 Total Expenses for Month		$2,500	$2,173	$207	$46	$74	
Allocation of Expenses for Month							
7 Directly Assignable to Products			534	50	8	12	97
8 Allocated based on Product Allocation			1336	130	30	43	260
9 Allocated Expenses			$1,870	$180	$38	$55	$357
10 Operating Income for Month			$1,830	$360	$57	$130	
11 Federal and State Income Taxes at :	36.0567% \2		660	130	21	47	
12 Net Income from Oil after Taxes		$1,520	$1,170	$230	$36	$83	
13 Rate of Return For Investment Recovery			8.428%	12.41%	14.41%	17.41%	
14 Return Allocated to Oil Investments (line4 x line13)/12		$383	$298	$47	$11	$27	
15 Amount to Be Divided Between Company and Wexpro		$1,137	$872	$184	$25	$56	
16 Company Portion at:	54%	614	471	99	14	30	
17 Payments to Company (line16)/(1-Tax Rate)		$960	$736	$155	$21	$48	
18 Restatements of Wexpro's Monthly Oil Net Income							
19 Revenue For Month		$4,520					
Expenses for Month - Oil							
20 Previous Expense - Total	$2,143						
21 Amount to Company	$960						
22 Total Restated Expenses for Month		($3,103)					
23 Restated Operating Income		$1,417					
24 Income Taxes		($511)					
25 Restated Wexpro Net Operating Income After Taxes		$906					

1/ All figures are hypotheticaland used only for demonstrating the method of calculating payment to the Company for oil production oil reservoirs, as provided in Article II of the Agreement.

2/ See Exhibit C.

3/ Future capital investment on Acquired Wexpro II Oil Property, other than costs as provided in columns 3,4,and 5, will earn the Commission Allowed rate of return.

Note: Exhibit B reflects changes filed by Questar Gas Company on February 14 and March 27, 2013.

Exhibit C

Marginal Composite Income Tax Rate Calculation

Rate Calculation

For determining the marginal composite tax rate defined in section I-27, the composite state tax rate t_s is determined as follows:

$$t_s = \sum r_i \times f_i$$

where

r_i is the currently applicable marginal state tax rate applicable in state i.

f_i is a factor based on the statutes and regulations currently in effect for state i.

As of July 31, 2012, r_i, f_i, and t_i for each state in which Wexpro is currently doing business and t_s are as follows:

State	r_i	f_i			$r_i \times f_i$
Utah	5	$(Inv_i + Rcpt_i + W_i)$ /	=	16.6390%	0.8
Wyoming	0	$(Inv_i + Rcpt_i + W_i)$ /	=	N/A	0.0
Colorado	4	$Rcpt_i$	=	17.1702%	0.7
Montana	6	$(Inv_i + Rcpt_i + W_i)$ /	=	0.0001%	0.0
New Mexico	7	$(Inv_i + Rcpt_i + W_i)$ /	=	0.0032%	0.0
Nevada	0	$(Inv_i + Rcpt_i + W_i)$ /	=	N/A	0.0
				=	1.6

where

Inv_i is the percentage of Wexpro's total-company investment in state i

$Rcpt_i$ is the percentage of Wexpro's total-company gross receipts in state i

W_i is the percentage of Wexpro's total-company wages in state i

Note: The marginal composite state income tax rate for each state is based on that state's currently applicable statutes and regulations. See Composite Tax Rate Calculation on page 2 of Exhibit C.

Note: Exhibit C Page 1 reflects changes filed by Questar Gas Company on February 14, 2013.

WEXPRO COMPANY
COMPOSITE STATE INCOME TAX RATE

	State	(a) Average Investment	(b) Gross Revenue	(c) Wages	(d) Percentage	(e) Marginal Tax Rate	(f) Marginal Composite State Rate	
	UTAH							
1	State total	71,576,328	11,287,726	5,277,495				
2	Wexpro total	1,076,183,593	265,912,590	13,524,669	(a+b+c)/3=d		d*e=f	
3		6.6509%	4.2449%	39.0213%	16.6390%	5.00%	0.8320%	(1)
	WYOMING	------------------------	N/A--No Income Tax Imposed	------------------------			0.0000%	(2)
	COLORADO							
4	State total		46,184,300					
5	Wexpro total		268,978,922		(b)/1=d		d*e=f	
6			17.1702%		17.1702%	4.63%	0.7950%	(3)
	MONTANA							
7	State total	1,310	720	0				
8	Wexpro total	1,076,183,593	268,391,234	13,524,669	(a+b+c)/3=d		d*e=f	
9		0.0001%	0.0003%	0.0000%	0.0001%	6.75%	0.0000%	
	NEW MEXICO							
10	State total	62,863	10,592	0				
11	Wexpro total	1,076,183,595	268,978,923	13,524,668	(a+b+c)/3=d		d*e=f	
12		0.0058%	0.0039%	0.0000%	0.0032%	7.60%	0.0002%	
13	NEVADA	------------------------	N/A--No Income Tax Imposed	------------------------			0.0000%	(2)
14	TOTAL						1.6272%	

(1) The standard three factor formula was elected on the Utah return for 2010. In 2011, the sales factor will be weighted by 4 with the denominator being 6; by 10 in 2012 with the denominator being 12; and single-sales-factor in 2013 and beyond.
(2) No income tax imposed by Wyoming or Nevada.
(3) Uses single-sales factor. Colorado began requiring single-sales factor apportionment in 2009.

Combined Federal & State Tax Calculation

$t_s = .016272$
$t = t_f\,(1-t_s) + t_s$
$t = .35\,(.9837) + .016272$
$\mathbf{t = .360567}$

All data is for calendar year 2010

EXHBIT D

OPERATOR SERVICE FEE

The monthly operator service fee to be charged to Questar Gas Company by Wexpro for the production of hydrocarbons from certain properties as set forth in Section III of the Agreement will include the costs detailed below. Any reference to investment and facilities in this determination will be only to Wexpro II Gas Properties. No leasehold carrying costs or exploration and development expenses related to dry holes will be included as costs or expenses in this determination.

1. Operating Expenses. Reasonable and necessary operating expenses incurred by Wexpro and allocated to the production, gathering, treatment and disposition of hydrocarbons. Such expenses will include operating and maintenance expenses, administrative and general expenses, royalties (including compensatory royalties) and fees based on the monthly level of production, and other common business expenses.

2. Depreciation. The allocated monthly depreciation expense as computed by the unit-of-production method for proved developed producing reserves only where applicable or one-twelfth of any annual depreciation expense computed using applicable depreciation methods other than the unit-of-production method as allowed by and computed under the terms of the Agreement.

3. Amortization and Depletion. The allocated monthly accrual recorded for the billing month as amortization and depletion of producing lands and land rights, amortization of intangible gas plant and other amortized expenses.

4. Taxes.

(a) Taxes Other than Income Taxes. Accruals recorded for the billing month with respect to taxes other than federal and state income taxes allocated to natural gas operations, adjustments of such accruals for tax expenses previously billed, and such taxes paid but not previously billed, including any state and local income taxes.

(b) Federal and State Income Taxes. Federal and state income taxes for the billing month attributable to applicable investment in hydrocarbon production facilities, computed by multiplying the return by the marginal composite income tax rate (Section I-27) divided by 1.0 minus the marginal composite income tax rate.

5. Return. Wexpro's investment in Acquired Wexpro II Gas Properties is computed using the Commission-allowed rate of return (Section I-31). For investment in commercial development gas wells, the return is computed on the basis of the base rate of return plus a risk premium of 8.00% (r + 8.00).

The investment used as a base to which a rate of return is applied will be computed in total for each category of investment subject to (i) Commission-allowed rate of return, and (ii) the base rate of return plus a 8% risk premium, and will be one-twelfth of the sum of:

(a) The actual original investment including AFUDC in wells, well facilities and plant facilities utilized or held for future use in connection with the production, gathering, treatment and disposition of natural gas, natural gas liquids and oil, less accumulated reserves for depreciation and amortization of such plant facilities; plus

(b) A general plant allowance of 6.3% times the sum of the amount in paragraph (a);

(d) A cash working capital allowance for each category of investment (no risk premium, and 8% risk premium) equal to 45/365 of the allocated operating expenses, identified in paragraph 1 above, less royalties and annualized by multiplying the monthly amounts by 12; plus

(c) A credit for the balance of accumulated deferred income taxes and other tax-timing reserves, for each category of investment (Commission-allowed rate of return, the base rate of return plus 8% risk premium).

6. Costs, expenses and investments will be allocated where appropriate, but only when direct assignment cannot be made.

EXHIBIT E

Base Rate of Return Index Companies

	Company Name	Activity	Regulatory Agency	Authorized BRR on Common Equity on May 31, 1981	Authorized BRR on Common Equity on May 31, 2011	Notes
1.	Idaho Power Company	Electric Services	Idaho PSC	14.50%	10.50%	
2.	Intermountain Gas Co.	Gas Distribution	Idaho PSC	14.50%	14.85%	
3.	Montana Power Company	Electric Services	Montana PSC	13.45%	10.25%	Renamed Northwestern Energy Corp.
4.	Montana-Dakota Utilities Co.	Gas Distribution	Montana PSC	13.50%	12.00%	Renamed MDU Resources
5.	Pacific Power & Light	Electric Services	Wyoming PSC	14.20%	10.60%	Using Replacement Index[1]
6.	Northern Utilities, Inc.	Gas Distribution	Wyoming PSC	13.50%	9.92%	Renamed SourceGas Distribution, LLC
7.	Nevada Power Company	Electric Services	Nevada PSC	15.00%	10.80%	
8.	Southwest Gas Corp.	Gas Distribution	Nevada PSC	15.20%	10.15%	
9.	Utah Power & Light Co.	Electric Services	Utah PSC	16.80%	10.60%	Renamed Pacificorp-Utah
10.	Mountain States Tel. & Tel. Co.	Tele- communications	Utah PSC	13.47%	10.67%	Using Replacement Index[1]
11.	Public Service Co. of Colorado	Gas Distribution	Colorado PSC	15.45%	10.25%	
12.	Mountain States Tel & Tel.	Tele-communications	Colorado PSC	11.90%	11.25%	Renamed CenturyLink
13.	Arizona Public Service Co.	Electric Services	Arizona PSC	15.00%	11.00%	
14.	Southwest Gas Corp.	Gas Distribution	Arizona PSC	16.00%	10.00%	
15.	Public Service Co. of New Mexico	Electric Services	New Mexico PSC	15.50%	10.50%	
16.	Southern Union Gas Co.	Gas Distribution	New Mexico PSC	15.50%	9.53%	Renamed Public Service of New Mexico
17.	Colorado Interstate Corp.	Gas Transmission	FERC	13.47%	10.67%	Using Replacement Index[1]
18.	Northwest Pipeline Corp.	Gas Transmission	FERC	13.47%	10.67%	Using Replacement Index[1]
19.	Kansas-Nebraska Natural Gas Co.	Gas Transmission	FERC	13.47%	10.67%	Using Replacement Index[1]
20.	Transwestern Pipeline Co.	Gas Transmission	FERC	13.47%	10.67%	Using Replacement Index[1]

[1] Replacement index per 5/29/92 Wexpro I Guideline Letter

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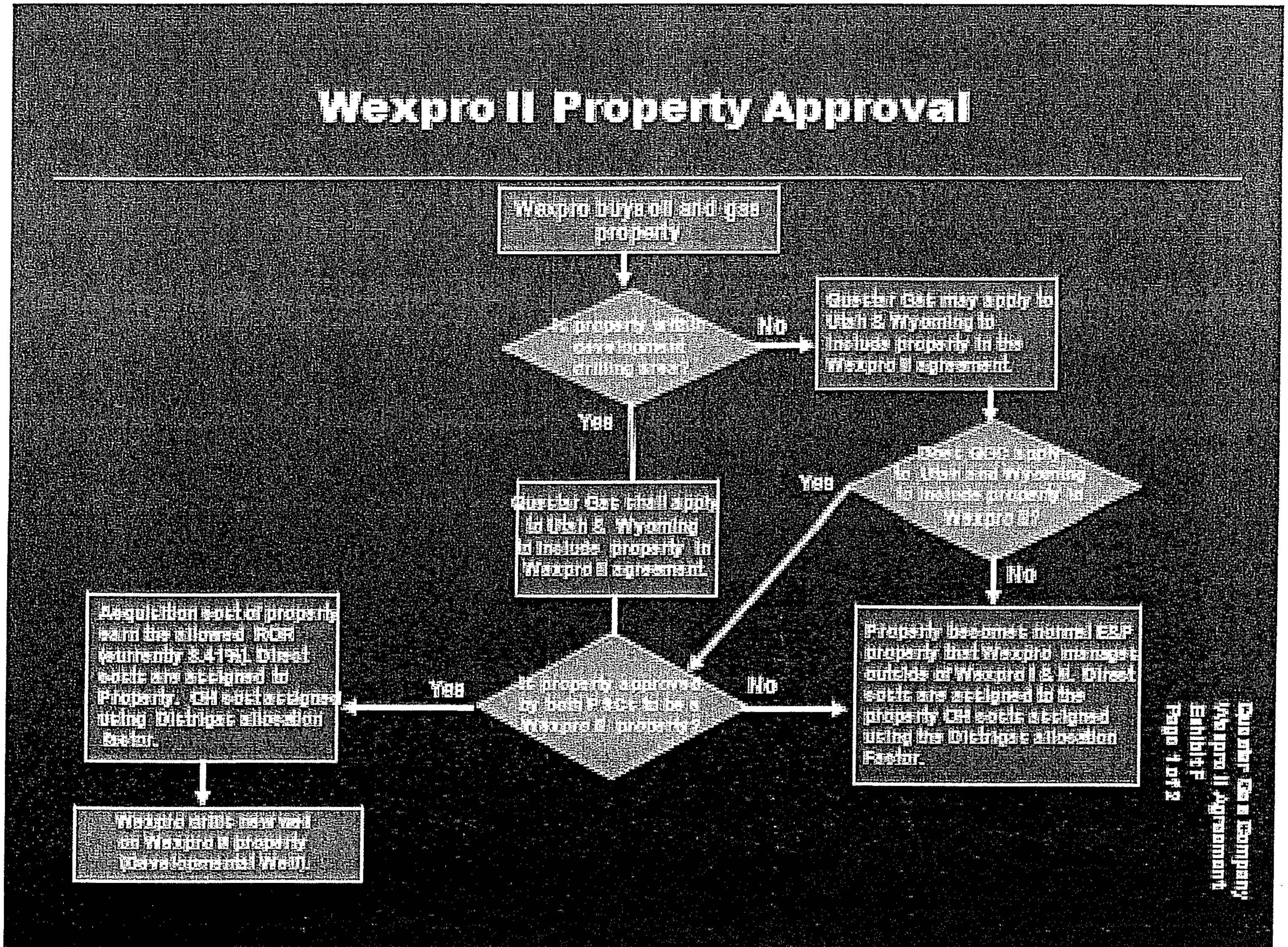
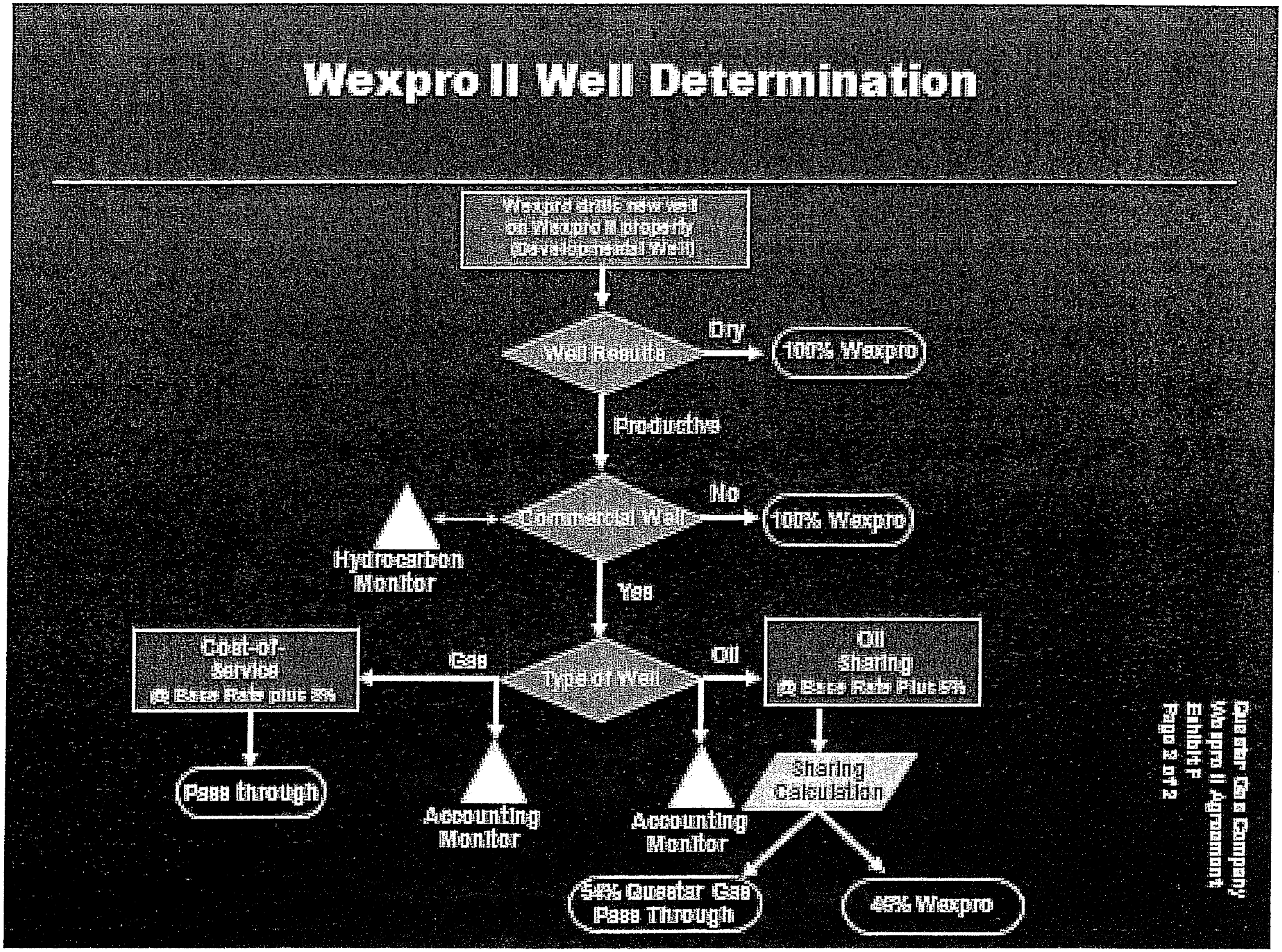


Note: Exhibit F Page 1 reflects changes filed by Questar Gas Company on March 27, 2013.


Wexpro II Well Determination
Wexpro drills new well on Wexpro II property (Developmental Well)
Well Results
Dry
100% Wexpro
Productive
Commercial Well
No
100% Wexpro
Hydrocarbon Monitor
Yes
Type of Well
Gas
Cost-of-Service @ Base Rate plus 5%
Pass through
Accounting Monitor
Oil
Oil sharing @ Base Rate Plus 5%
Accounting Monitor
Sharing Calculation
54% Questar Gas Pass Through
46% Wexpro
Questar Gas Company
Wexpro II Agreement
Exhibit F
Page 2 of 2

Questar Gas Company
Wexpro II Agreement
Exhibit G

Revised April 2, 2012

Index of Wexpro Agreement Guideline Letters

Date	Title
06/14/11	QEP Assignment of F. Wilson #37 Marginal Well Interest to Wexpro
10/24/11	QEP Assignment of the Lance Formation to Wexpro (Jacks Draw #18)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Government #17)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Musser #73)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Musser #72)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Musser #42)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Musser #35)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Musser #34)
03/15/11	QEP Assignment of the Lance Formation to Wexpro (Government #15)
10/07/10	QEP Assignment of Sugarloaf Government #18 Marginal Well Interest to Wexpro
10/07/10	QEP Assignment of Sugarloaf Government #17 Marginal Well Interest to Wexpro
08/31/10	Wexpro Acquisition of Non-Consent Interest in Kinney #4 Recompletion
07/27/10	QEP Assignment of Bruff Unit 50 Marginal Well Interest to Wexpro
07/10/10	QEP Assignment of Bruff Unit 48 Marginal Well Interest to Wexpro
07/01/10	Wexpro Acquisition of Non-Consent Interest in Clifton Federal 34-6 Well
06/22/10	QEP Assignment of Bruff Unit 63 Marginal Well Interest to Wexpro
06/14/10	QEP Assignment of F. Wilson #37 Marginal Well Interest to Wexpro

04/09/10	Wexpro Acquisition of Non-Consent Interest in Church Buttes 184 Well
03/04/10	QEP Assignment of Bruff Unit 55 Marginal Well Interest to Wexpro
02/16/10	Wexpro Acquisition of Non-Consent Interest in Bruff Unit 53 Well
10/09/09	Wexpro Acquisition of Non-Consent Interest in Lansdale 4-7 Well
07/30/09	Wexpro Acquisition of Non-Consent Interest in Lansdale 4-5 Well
07/30/09	Wexpro Acquisition of Non-Consent Interest in Lansdale 4-8 Well
07/09/09	Wexpro Acquisition of Non-Consent Interest in Bruff Unit 54 Well
06/08/09	Wexpro Acquisition of Non-Consent Interest in Church Buttes 166 Well
05/27/09	Wexpro Acquisition of Non-Consent Interest in Bruff Unit 56 Well
05/25/09	Wexpro Acquisition of Non-Consent Interest in Bruff Unit 71 Well
05/20/09	Wexpro Acquisition of Non-Consent Interest in MFS 10-5 Well
04/30/09	Wexpro Acquisition of Non-Consent Interest in Bruff Unit 51 Well
04/14/09	Wexpro Acquisition of Non-Consent Interest in Trail 04D-16W Well
04/08/09	QEP Assignment of Bruff Unit 51 Marginal Well Interest to Wexpro
03/26/09	Wexpro Acquisition of Non-Consent Interest in Church Buttes 183 Well
03/26/09	Wexpro Acquisition of Non-Consent Interest in Church Buttes 179 Well
01/15/09	Wexpro Acquisition of Non-Consent in Pando 32-8 Well
12/08/08	Wexpro Acquisition of Non-Consent Interest in Clifton Federal 34-7 Well
12/08/08	Wexpro Acquisition of Non-Consent Interest in Clifton Federal 34-5 Well
12/08/08	Wexpro Acquisition of Non-Consent Interest in Clifton Federal 28-6 Well
12/08/08	Assignment of Clifton Federal 28-8 Marginal QEP Interest to Wexpro
06/02/08	3D Seismic Program, Dry Piney Unit, Sublette County, Wyoming
03/01/08	Wexpro Acquisition of Non-Consent Interest in Church Buttes 173 Well

01/06/08	Wexpro Acquisition of Non-Consent Interest in Clifton-Federal 34-8 Well
01/03/08	Wexpro Acquisition of Non-Consent Interest in Church Buttes 149 Well
10/02/07	Guideline Letter for Wexpro Monitor Fee Amount
09/11/07	Wheeler Farmout Guideline Letter - Assignment of marginal intervals in West Hiawatha to Wexpro to facilitate Development Gas Drilling under the terms of the Wexpro Agreement
07/05/07	Wexpro Acquisition of Non-Consent Interest in Church Buttes 148 Well
04/23/07	Wexpro Acquisition of Non-Consent Interest in Church Buttes 162 Well
04/17/07	Wexpro Acquisition of Non-Consent Interest in Trail Unit 03C-10J Well
01/12/07	Assignment of Working Interest to Wexpro to Facilitate Developmentn Gas Drilling (Hydrocarbon Monitor approval of assignment of Anadarko's non-consent interest in Church Buttes 89 Well)
03/15/06	Hydrocarbon Monitor approval of assignment of ExxonMobil's non-consent interest in Dry Piney 5 Well
03/15/06	Hydrocarbon Monitor approval of assignment of Exxon Mobil's non-consent interest in Dry Piney 27 Well
03/14/06	Hydrocarbon Monitor approval of assignment of interest in the Upper Mesaverde Formation in West Hiawatha wells Lasher 11 and 12
01/20/06	Hydrocarbon Monitor approval of assignment of interest in the Upper Mesaverde Formation in Hiawatha State Land 7 Well
08/24/05	Hydrocarbon Monitor approval of assignment of interest in the Bear River Formation in Dry Piney #32 & #35 Wells
08/09/04	Guideline Letter regarding assignment of marginal intervals to Wexpro to facilitate Development Gas Drilling under the terms of the Wexpro Agreement
07/26/04	Pre-participation approval by Hydrocarbon Monitor to participate in the 3D Seismic program over Canyon Creek Unit
02/20/04	Guideline Letter Governing the Adoption of Financial Accounting Standards Board Statement #143, Accounting for Asset Retirement Obligations Under the Wexpro Agreement
10/08/02	Election to designate the Mesaverde Formation as a "Productive Gas Reservoir" in the Participating Area A, Island Unit, Uintah County, Utah

09/30/02	The Mesa Unit (Pinedale) Upper Mesaverde Guideline Letter
06/26/02	Guideline Letter for Coal Bed Methane Development Under the Wexpro Agreement
06/26/02	Guideline Letter relating to ownership in the Mesaverde Formation within Jackknife Springs Unit
04/04/01	Guideline Letter Relating to Development and Ownership of the Mesaverde Formation within the Island Unit, Uintah County, Utah
05/31/00	Guideline Letter relating to The Mesa Unit (Pinedale) Lance Formation Ownership
08/18/99	3D Seismic program in Pinedale Anticline
04/27/99	I-47 Product Allocation Ratio
11/13/98	Division Sign Off of Birch Creek #117 as D-24
06/25/98	Guideline Letter Relating to Island Unit — Deepening Wells
01/22/98	Acquisition of 3-D Seismic Data, Brady Field, Wyoming
10/17/94	Guideline Letter Relating to 3-D Seismic Projects
05/16/94	Development Program, Johnson Ridge Field, Wyoming
05/29/92	Refund of Excess Deferred Taxes – Whole-Well Approach for Determining Commerciality in the Church Buttes Unit – Replacement Index Method for Determining Base Rate of Return
12/19/89	1989-90 Base Rate of Return Under the Wexpro Agreement
11/21/89	Joint Account Overhead Fees Guideline Letter
08/25/89	Wexpro Agreement Guideline Letters
07/11/89	Wexpro Agreement — Federal Royalty Assessment of Brady Liquids — Adjustment to Manufacturing Allowance
10/27/88	Wexpro Agreement Guideline for Expanding Participating Areas Inside Federal Units
10/16/87	Nonstatus Well Guidance Letter Dated May 7, 1986
05/07/86	Wexpro Agreement – Accounting of Pre-July 31, 1981, Overriding Royalty Interests – and Nonstatus Wells

03/03/86	The Wexpro Bug Field, San Juan County, Utah
02/27/86	Accounting for Production Taxes
09/07/84	Well Completions in the Hiawatha & Powder Wash Oil and Gas Fields
09/07/84	Tentative Plan to Fracture Stimulate Mesa Unit Well #2, Sublette County, Wyoming
07/16/84	East Hiawatha Enhanced Recovery Project
12/14/83	Delivery Point at the Butcher Knife & Church Buttes Fields, Sweetwater County, Wyoming

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 28th day of March, 2013, a true and correct copy of the foregoing REPORT AND ORDER was delivered upon the following as indicated below:

By Electronic-Mail:

Colleen Larkin Bell (collen.bell@questar.com)
Jenniffer Nelson Clark (jenniffer.clark@questar.com)
Questar Gas Company

Ivan Williams (ivan.williams@wyo.gov)
Wyoming Office of Consumer Advocate

Gary A. Dodge (gdodge@hjdlaw.com)
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Patricia Schmid (pschmid@utah.gov)
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Michele Beck (mbeck@utah.gov)
Office of Consumer Services

By Hand-Delivery:

Division of Public Utilities
160 East 300 South, 4th Floor
Salt Lake City, Utah 84111

Office of Consumer Services
160 East 300 South, 2nd Floor
Salt Lake City, Utah 84111

____
Administrative Assistant

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF QUESTAR GAS COMPANY FOR APPROVAL OF THE WEXPRO II AGREEMENT)))	Docket No. 30010-123-GA-12 (Record No. 13347)

APPEARANCES

For the Applicants Questar Gas Company (Questar):
COLLEEN LARKIN BELL Corporate Counsel, Salt Lake City, Utah

For the Intervenor Office of Consumer Advocate (OCA):
IVAN H. WILLIAMS, Senior Counsel, Cheyenne, Wyoming.

HEARD BEFORE

Chairman ALAN B. MINIER
Deputy Chairman WILLIAM F. RUSSELL
Commissioner KARA BRIGHTON

J. BLAIR BALES, Assistant Secretary,
Presiding pursuant to a *Special Order* of the Commission

Hearing Held April 11, 2013

MEMORANDUM OPINION, FINDINGS AND ORDER APPROVING THE WEXPRO II AGREEMENT
(Issued October 16, 2013)

This matter is before the Wyoming Public Service Commission (Commission) upon the application of Questar for approval of the Wexpro II Agreement and the intervention of OCA.

The Commission, having reviewed the application, attached exhibits, the Wexpro Stipulation and Agreement (Wexpro I), the Wexpro II Agreement, and the evidence adduced at the public hearing, its files regarding Questar, applicable Wyoming utility law, and otherwise being fully advised in the premises, FINDS and CONCLUDES:

Introduction

1. On September 18, 2012, Questar filed its application requesting approval of the Wexpro II Agreement entered into between Questar, Wexpro Company (Wexpro), the Wyoming OCA and the Utah Division of Public Utilities (Wexpro II Parties), pursuant to W.S. § 37-2-101 *et seq.* and the Commission's Rules. (Application, p. 1.) Wexpro I was signed in 1981 by Mountain Fuel Supply Company, Questar's predecessor; Wexpro; Utah Department of Business Regulations, Division of Public Utilities; Utah Committee of Consumer Services; and Staff of the Commission. According to the application, Wexpro I has been a substantial benefit of cost-of-service production to Questar's customers by providing gas at the cost-of-service price, which has historically been lower than the market-based gas price. Further, the application states Wexpro I has provided Questar's customers with a stable source of gas supply and long-term hedge against price volatility. (Application, pp. 1-2.) Under Wexpro I, the cost-of-service gas has saved Questar's Utah and Wyoming customers approximately $1.3 billion, of which Wyoming's allocation is $77 million, since 1981. (Transcript of April 11, 2013, public hearing, hereinafter, Tr., p. 14.)

2. In its application, Questar states on September 12, 2012, the Wexpro II Parties entered into the Wexpro II Agreement to enable Wexpro to develop new properties under similar terms and conditions found in Wexpro I. The application states the Wexpro II Agreement sets forth procedures by which Wexpro will purchase new properties at its own risk and submit those properties to the Utah and Wyoming Public Service Commissions for approval to include the properties as Wexpro II properties. The Wexpro II properties would be managed and developed in the same manner as properties under Wexpro I. (Application, pp. 2-3.)

3. The application seeks an *Order* from the Commission approving the Wexpro II Agreement. (Application, p. 4.) Questar supported the application with the written testimony of Barrie L. McKay, Questar's General Manager of State Regulatory Affairs (Ex. 1), and James R. Livsey, Wexpro's Executive Vice President and Chief Operating Officer (Ex. 2).

4. On October 11, 2012, the Commission issued its *Notice of Application* containing a deadline of November 9, 2012, for requests for intervention. The notice was duly published and broadcast on radio. (Ex. 100.)

5. On November 7, 2012, pursuant to W.S. § 37-2-402(a)(i), the OCA intervened in the case. The OCA is an independent division within the Commission, charged by statute with representing the interests of Wyoming citizens and all classes of utility customers in matters involving public utilities.

6. On February 8, 2013, the Commission issued its *Scheduling Order* setting a procedural schedule and a public hearing commencing on April 11, 2013. (Ex. 100.)

7. On March 11, 2013, the OCA filed the direct testimony of Bryce J. Freeman, Administrator of the OCA, in support of the application (Ex. 201).

8. On March 19, 2013, the Commission issued a *Notice and Order Setting Public Hearing*, which was duly published and broadcast on radio. (Ex. 100.)

9. Pursuant to the orders of the Commission and due notice, the public hearing in this matter was held on April 11, 2013, in Cheyenne. At the end of the hearing, the Commission held public deliberations pursuant to W.S. § 16-4-403, and directed the preparation of an order consistent with its decision.

Summary of Decision

10. The Commission grants Questar's request for approval of the Wexpro II Agreement with conditions agreed upon at hearing.

Contentions of the Parties and Resulting Issues

11. Questar contends the Wexpro II Agreement is beneficial to its customers and is in the public interest.

12. OCA is a signatory to the Wexpro II Agreement and supports its approval.

13. The sole issue is whether the Commission should approve the Wexpro II Agreement as being in the public interest.

Findings of Fact

14. Wexpro I was executed in 1981 to resolve an oil sharing dispute between Mountain Fuel Supply and Wexpro. It established a sharing mechanism where 54% of oil profits are credited to Mountain Fuel Supply customers and 46% are credited to Wexpro. The agreement also established a framework for production of natural gas within defined geographic areas at cost-of-service to Mountain Fuel Supply's (now Questar's) customers. (Ex. 2, pp. 1-2; Ex. 201, p. 5.)

15. Since 1981, Wexpro I provided Questar's customers with a stable source of natural gas and a long-term hedge against price volatility. On average, the cost-of-service gas has been lower priced than market-based sources saving Wyoming customers approximately $77 million over thirty years. Wexpro I provides between one-third and one-half of the natural gas required to supply Questar's customers. (Tr., p. 14; Ex. 1, p. 2.)

16. Because of improvements in exploration and drilling methods, the Wexpro I properties have produced longer and at greater levels than originally anticipated. However, because the geographic area defined in the agreement is limited, it cannot continue to produce at current levels indefinitely. Questar and Wexpro began looking for ways to expand exploration and production beyond the Wexpro I properties so that customers can continue to benefit from cost-of-service gas supplies. The result of those efforts is the Wexpro II Agreement. (Ex. 1, pp. 2-3; Ex. 201, p. 5.)

17. Wexpro II does not replace Wexpro I. Rather, it allows additional properties not eligible for inclusion under Wexpro I to be acquired as cost-of-service gas supplies under the terms of Wexpro II. (Ex. 201, pp. 9-10.) But because Wexpro II is modeled after Wexpro I, Wexpro II properties will be developed and produced under substantially the same terms and conditions set forth in Wexpro I. (Ex. 1, p. 5.)

18. A key provision of Wexpro II is that Wexpro will acquire oil and gas properties at its own risk. Any property acquired within the Wexpro I drilling areas *must* be brought before the Wyoming and Utah Commissions for the opportunity to include the property in the cost-of-service supplies. This right of first refusal alleviates any concern that Wexpro would not offer its best performing properties, and mitigates the risk that ratepayers will be saddled with underperforming properties. If both Commissions approve the property for inclusion as a Wexpro II property, Wexpro will develop the property for the benefit of Questar's customers as provided in the Wexpro II agreement. (Ex. 1, p. 6; Ex. 201, pp. 7-8.)

19. If Wexpro acquires new properties outside the Wexpro I drilling areas, Questar *may* apply to the Wyoming and Utah Commissions for approval to include them as Wexpro II properties. If approved by both Commissions, those properties will be developed as provided in the Wexpro II agreement. (Ex. 1, p. 6.)

20. When Questar files an application for a new Wexpro II property, the Hydrocarbon Monitor will, within seven business days, file an independent review of the assumptions, data, and analysis used by Wexpro in the purchase of the proposed property, but will not provide a recommendation regarding its inclusion as a Wexpro II property. The OCA and Utah Division of Public Utilities will file responses recommending approval or rejection of the proposed property based on their own analysis and the Hydrocarbon Monitor's evaluation. If the proposed property is not approved by both Commissions within 60 days, Questar may withdraw the property from consideration. (Ex. 1, p. 7.)

21. We find OCA is a focal point for many of the functions in the Wexpro II Agreement and

that OCA is committed to communicate with the Commission regarding the processes and substance of the Wexpro II Agreement as may be required. (Tr., p. 157.) We find any OCA reporting requirements will be determined as the interests of the Wexpro II Agreement, the Commission and the OCA may require. (Tr., p. 178.)

22. We find when Questar applies for a property to become a Wexpro II property, all applicable guideline letters shall accompany the application. We find, as agreed to by Questar and OCA, Commission staff shall be involved in the development and approval of the guideline letters as had been done pursuant to Wexpro I. (Tr., pp. 61; 152-153.) We find the guideline letters shall clearly show approval by the entities who are required to approve them, following a format similar to the guideline letters issued under Wexpro I in the 1980s and 1990s. (Tr., pp. 96-97.)

23. We find the public interest would be served by approving the Wexpro II Agreement, with the following agreed upon conditions:

a. Questar shall file the Hydrocarbon and Accounting Monitor Reports as they become available (Tr., p. 48.);

b. Questar shall file the Hydrocarbon Monitor letters documenting certain items which the Hydrocarbon Monitor has the authority to approve (Tr., p. 125.);

c, Questar shall report the results of the Utah technical conference held on May 2, 2013 (Tr., pp. 31-32.);

d. Questar shall clearly separate and identify Wexpro I and II items in its pass-on applications (Tr., p. 45.);

e. Questar shall file annual base rate of return calculations for both Wexpro I and II. The Wexpro II items shall be filed under this docket for tracking purposes; and,

f. OCA will obtain an expert to evaluate potential Wexpro II property purchases, as necessary. (Tr., p. 158.)

24. Any conclusion of law set forth below which includes a finding of fact may also be considered a finding of fact and therefore incorporated herein by reference.

Principles of Law

25. Our basic and overriding standard in this case is the public interest and the desires of the utility are secondary to it. In *PacifiCorp v. Public Service Commission of Wyoming*, 2004 WY 164, 103 P.3d 862 (2004), the Wyoming Supreme Court, 2004 WY 164 at ¶13, quoted with favor *Sinclair Oil Corp. v. Wyoming Public Service Comm'n*, 2003 WY 22, at ¶9, 63 P.3d at 887 (Wyo. 2003):

> Speaking specifically of PSC, we have said that PSC is required to give paramount consideration to the public interest in exercising its statutory powers to regulate and supervise public utilities. The desires of the utility are secondary. [Citation omitted.]

26. The Wyoming Administrative Procedure Act, at W.S. § 16-3-107, establishes general procedures in Commission cases, including the giving of reasonable notice. In accord are W.S. §§ 37-2-201, 37-2-202, and 37-3-106. (*See also*, Commission Rule §§ 106 and 115.)

27. W.S. § 37-2-121 authorizes public utilities to initiate proceedings to employ innovative ratemaking methods:

> . . . Any public utility may apply to the commission for its consent to use innovative, incentive or nontraditional rate making methods. In conducting any investigation and holding any hearing in response thereto, the commission may consider and approve proposals which include any rate, service regulation, rate setting concept, economic development rate, service concept, nondiscriminatory revenue sharing or profit-sharing form of regulation and policy, including policies for the encouragement of the development of public utility infrastructure, services, facilities or plant within the state, which can be shown by substantial evidence to support and be consistent with the public interest.

28. Public utilities are required to file contracts with the Commission as designated under W.S. § 37-3-111. This statute states, in pertinent part,

> Every public utility shall file with the commission copies of contracts, agreements or arrangements to which it may be a party, as the commission may designate. . . .

Commission Rule 218, follows from W.S. § 37-3-111, stating,

> Every utility shall file with the Commission one copy of all special contracts which govern the sale by the utility of public utility service or the purchase by the utility of a utility commodity for resale. If the utility has numerous sale or purchase contracts which are in all essentials similar, the utility may request to file a selected one or a few in lieu of filing all such contracts.

Conclusions of Law

29. Questar is a public utility as defined in W.S. § 37-1-101(a)(vi)(D), subject to the jurisdiction of the Commission under W.S. § 37-2-112. The Commission has the general and exclusive jurisdiction to regulate Questar as a public utility in Wyoming. The Commission has duly authorized Questar to provide retail natural gas public utility service in its respective Wyoming service territories under a certificate of convenience and necessity.

30. The Wexpro II Agreement establishes procedures for Questar to file applications with the Utah and Wyoming Commissions to request approval to include proposed properties under the Wexpro II Agreement. Approved Wexpro II properties will benefit Questar's customers by supplying commodity gas at cost-of-service prices or in the case of an oil property, providing for revenue sharing. The Wexpro II Agreement is the governing document setting out the terms and conditions for the potential future acquisition and development of certain oil and gas properties.

31. Based on our findings and conclusions herein, we further conclude that approval of the Wexpro II Agreement is in the public interest.

32. Proper legal notice of this proceeding was given in accordance with the Wyoming Administrative Procedure Act, W.S. § 37-2-203, and Commission Rule Section 106. The public hearing was held and conducted pursuant to W.S. §§ 16-3-107, 16-3-108, 37-2-203, and applicable sections of the Commission's Rules. The intervenor, OCA, was a party to the case for all purposes.

33. Public deliberations were held in compliance with W.S. § 16-4-403.

IT IS THEREFORE ORDERED:

1. The application of Questar Gas Company for approval of the Wexpro II Agreement is hereby approved subject to the following conditions:

a. All guideline letters applicable to Wexpro I shall also apply to Wexpro II;

b. All applicable guideline letters shall accompany the application for approval of a Wexpro II property;

c. Wexpro I and Wexpro II matters shall be separately identified in Questar's pass-on applications;

d. Questar shall file annual base rate of return calculations for both Wexpro I and Wexpro II. The Wexpro II calculations shall be filed under this docket for tracking purposes;

e. Questar shall file quarterly and annual Hydrocarbon and Accounting Monitor Reports as they become available; and

f. Questar shall file all Hydrocarbon Monitor letters relating to Wexpro I and Wexpro II properties.

2. This *Order* is effective immediately.

MADE and ENTERED at Cheyenne, Wyoming, on October 16, 2013.

PUBLIC SERVICE COMMISSION OF WYOMING

ALAN B. MINIER, Chairman

WILLIAM F. RUSSELL, Deputy Chairman

KARA BRIGHTON, Commissioner

(SEAL)

Attest:

J. BLAIR BALES, Assistant Secretary

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor
_________________________________/

DOCKET NO. 140001-EI

FILED: December 12, 2014

CITIZENS' POST-HEARING STATEMENT OF POSITIONS AND POST-HEARING BRIEF

Pursuant to Order Nos. PSC-14-0084-PCO-EI and PSC-14-0667-PHO-EI, the Citizens of the State of Florida, by and through the Office of Public Counsel, hereby submit their Post-Hearing Statement of Positions and Post-Hearing Brief.

SUMMARY OF ARGUMENT

Florida Power & Light Company's ("FPL's") June 25, 2014 Petition ("Petition") can be summed up as a new way to eliminate shareholder risks and ensure shareholder profits. Under FPL's proposal, FPL will shift all risks of investing in gas reserves to the customers in exchange for promises of potential customer fuel savings and guaranteed trued-up profits (or returns) for shareholders. The Office of Public Counsel ("OPC" or "Citizens") is not opposed to *guaranteed* fuel cost savings to customers; however, FPL simply cannot guarantee those savings to customers over the next 50 years.

The proposed Woodford Project is a speculative investment in an Oklahoma gas reserve. FPL is speculating that the Woodford Project will produce an estimated annual gas quantity at a forecasted per-unit cost level (where forecasted costs are based on numerous FPL assumptions, forecasts, and estimates) that is lower than FPL's estimate of future natural gas market prices. Based on FPL's Revised Exhibit SF-8, which relied upon FPL's July 28, 2014 Fuel Forecast, FPL projects that customers will receive approximately $51.9 million in fuel savings over the projected 50-year life of the Woodford Project. EX 54, BSP 369. This same exhibit estimates the total revenue requirement (including FPL shareholder profits collected from customers) will be approximately $709.4 million over the same time period. In other words, customers will pay FPL and its shareholders approximately $709.4 million to potentially save approximately $51.9 million in fuel over 50 years. **While this estimated, projected, but not guaranteed $51.9 million in fuel savings amounts to less than 2 cents a month for the next 50 years when broken down per customer, FPL's shareholders will receive a fixed 10.5% return or guaranteed profit on the investment.**[1]

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[1] According to Order No. PSC-14-0036-TRF-EI, issued January 14, 2014, in Docket No. 130223-EI, FPL has approximately 4.5 million customers. Thus, taking $51.9 million / 4.5 million customers = $11.53 per customer

OPC maintains that the Florida Public Service Commission ("PSC" or "Commission") lacks subject matter jurisdiction over FPL's Petition and proposal to recover costs associated with gas reserves investments in general and the Woodford Project in particular. Nothing within Chapter 366, F.S., countenances allowing a rate-regulated electric monopoly utility to expand beyond "generation, transmission, and distribution" functions expressly recognized in statute. Because the Commission does not possess the express or implied statutory jurisdiction to approve FPL's Woodford Project, or even the ability to adequately review the reasonableness or prudence of FPL's proposed gas reserves costs for cost recovery, OPC submits such a decision would be a clear abuse of discretion and a radical departure from the essential requirements of law as set forth by the Legislature in Chapters 120, 350, and 366, F.S. Additionally, FPL's request is barred by the express terms of the one-sided settlement approved by Order No. PSC-13-0023-S-EI.

Further, the Commission has stated (and FPL has agreed) that public utilities subject to the Commission's jurisdiction are not allowed to make any profit on fuel costs that flow through the fuel cost recovery clause. This principle derives from, and is consistent with, the statutory definition of utility-related activities and the corresponding limits of the Commission's jurisdiction. Because FPL's shareholders would receive a fixed return or guaranteed profit on every dollar invested in natural gas reserves, FPL's proposal would violate the requirement that regulated utilities are not allowed to profit on fuel acquired for their customers.

In addition, FPL's gas reserves proposal does not comport with the Commission's strict policy that restricts what fossil-fuel related costs may be recovered through the Fuel Adjustment Clause ("Fuel Clause"). While the Commission may be exempt from some aspects of rulemaking pursuant to Section 120.80(13)(a), F.S., PSC Order No. 14546 and its progeny serve as surrogate rules. These orders are polestars, guiding Commission policy as it relates to allowing fossil-fuel related costs normally recovered through base rates to be recovered through the Fuel Clause that **will** result in fuel savings to customers. Simply put, **50 years is a long time to speculate that customers will receive a potential 2 cents a month in savings that may never be realized.** And, in exchange for approximately two cents a month in non-guaranteed fuel savings for the next 50 years, FPL wants its customers to bear all the risks with this investment – regardless of the market price of natural gas and regardless of whether the volume of gas from the Woodford Project can or will be realized. In sum, the customers' potential fuel savings would not be guaranteed, while under the same proposal FPL's profits would be 100% guaranteed over the 50 years period. Therefore, since FPL's Petition (whether approved in part or in whole) cannot satisfy the requirements of Commission policy delineated in Order No. 14546 and its progeny, it must be denied.

Furthermore, FPL's Petition is not a hedge against fuel price volatility to the benefit of customers as contemplated by the Commission's 2002 and 2008 fuel hedging orders and hedging guidelines. The Commission's Hedging Guidelines Order defines "hedging activities" as "natural

over the life of the project. Then, taking \$11.53 / 50 years = \$0.23 per year. Lastly, \$0.23 / 12 months = \$0.01922 per month, or approximately two cents a month savings per customer for the next 50 years.

gas and fuel oil fixed price financial or physical transactions. . . ." Order No. PSC-08-0667-PAA-EI at 15 (emphasis added). A long-term physical hedge typically involves a contractual quantity of gas at a fixed price to be delivered at some agreed future period. The Woodford Project is not a hedge because the Woodford Project does not fix any production costs or volumes of gas. Instead, the production costs and volumes of gas are projected or estimated. Further, instead of apportioning the risks between FPL and PetroQuest, as is done in financial hedging, FPL's proposal would require its customers to assume all of FPL's shareholders' risks regardless of the success or failure of its proposed natural gas reserves investment.

Unlike a true financial or physical hedge, there is nothing fixed within FPL's request for approval of costs associated with gas reserves investments except the 10.5% fixed returns (guaranteed profits) FPL shareholders will receive on the approximately $190 million to be invested in the Woodford Project, and the $709.4 million collected from customers over the next 50 years. Similarly, pursuant to FPL's Guidelines, FPL's request provides fixed returns or guaranteed profits to FPL's shareholders on future investments of up to $750 million per year.

OPC adopts and incorporates by reference herein the remainder of its "Basic Position" as set forth in the Prehearing Order No. PSC-14-0667-PHO-EI, issued November 21, 2014, in this docket.

Thus, for the reasons stated herein, FPL's Petition to recover any costs related to the Woodford Project and any costs related to future investments in gas reserves projects should be denied.

PROCEDURAL MATTERS

OPC has combined its Post-Hearing Statement of Positions and its Post-Hearing Brief into a single document ("Brief"), and will address Issues 1, 2, 3, and 6. The remainder of the issues will be addressed by a separate Brief. Issue 8, on which Citizens take no position, is not reflected in this Brief. OPC also renews the following objections: (1) the Commission's decision to deny OPC's Motion to Dismiss FPL's June 25, 2014, Petition for Lack of Subject Matter Jurisdiction; and (2) the Commission's decision to admit into the hearing record Exhibits 55-58, which reflect the full deposition transcripts of FPL's witnesses, over OPC's objections.[2]

[2] Since the Commission, at the request of staff, placed these deposition transcripts into evidence over the objection of OPC, instead of conducting cross-examination of FPL witnesses on testimony contained in OPC's and the Florida Industrial Power Users Group's ("FIPUG's") portions of the transcripts, OPC relied upon portions of some of the deposition transcripts which OPC sought to exclude from the hearing record. By relying on these portions of the deposition transcripts, OPC does not waive its objection that it was improper to admit entire deposition transcripts into the hearing record, over the objection of a party, which contained "Irrelevant, immaterial, or unduly repetitious evidence" that should have been excluded. Section 120.569(2)(g), F.S. Furthermore, staff moved the depositions into the record contrary to Florida Rule of Civil Procedure 1.310(f)(3), which only allows *parties* to file depositions absent a finding by the court that the deposition was necessary for the decision, and Florida Rule of Civil Procedure 1.330(a)(4), which allows any other *party* to introduce any other parts. (emphasis added). Both of these rules apply to the Commission under Rule 28-106.206, F.A.C. Whereas staff argued in this very docket that it is not a party and the Commission failed to find the depositions necessary in this case, the Commission did not comply with the rules governing the use of depositions.

ISSUES AND POSITIONS

<u>ISSUE 1</u>: Should the Commission approve FPL's request to recover the amounts it would pay to its subsidiary for gas obtained from the PetroQuest joint venture through the fuel cost recovery clause on the basis and in the manner proposed by FPL in the June 25 Petition?

*No. It should be denied. First, the Commission has only the authority or jurisdiction granted it by the Legislature. The Commission lacks subject matter jurisdiction to approve projects and allow recovery of costs that are beyond the "generation, transmission, and distribution" functions expressly recognized in statute for an electric monopoly utility. Prior Commission orders show that the Commission lacks jurisdiction over unregulated subsidiaries and affiliates, such as the one FPL is proposing.

Second, FPL's Petition violates Commission orders and rules. The Woodford Project does not satisfy the criteria for Fuel Clause recovery because its costs are not capital costs normally recovered through base rates as required by Order No. 14546. FPL's proposal is also beyond the policy adopted by the Commission for dealing with fossil fuel-related costs normally recovered through base rates that will result in fuel savings to customers. Further, it does not fit within the regulatory framework established by Commission accounting rules or the Uniform System of Accounts for electric utilities which FPL must follow.

Third, FPL promises fuel savings which it cannot ensure will be delivered over the 50 year life of the Woodford Project. Woodford Project fuel savings are built solely on "projections." FPL cannot fix gas production costs or volumes, and cannot ensure that the cost of Woodford gas will be lower than market prices over the life of the project.

Fourth, FPL's proposal is not hedging. Moreover, assuming arguendo it was hedging, it violates the Commission's hedging guidelines definition of "hedging activities" because none of the costs associated with the gas reserves investment are fixed, except for the fixed cost of shareholder returns and guaranteed profits built into the revenue requirement. Without fixed costs of production or volumes of gas, the customers may pay more than market or worse, pay for gas twice.

Finally, the annual resetting of the fuel factor already effectively mitigates against fuel price volatility experienced by customers without any additional cost or risk. Thus, FPL's proposal to physically hedge gas through gas reserves is unnecessary given all the attendant risks to be borne by the customers. (Ramas, Lawton).*

ARGUMENT:

FPL's Petition Must be Dismissed for Lack of Subject Matter Jurisdiction

In its Motion to Dismiss FPL's June 25, 2014 Petition For Lack Of Subject Matter Jurisdiction ("Motion"), the Citizens demonstrated that the plain language of applicable statutory provisions do not contemplate or authorize an investment in natural gas exploration, drilling, and production that can be included in a public utility's rate base. The Commission denied this Motion on November 25, 2014 before the hearing started. At the outset of the hearing on December 1, OPC renewed its Motion (TR 13) and objection to the Commission's decision and did so again at the conclusion of the hearing on December 2 . TR 1086-87. The Public Counsel's objection to the Commission asserting, maintaining and/or exercising subject matter jurisdiction over FPL's Petition to invest in natural gas reserves is an ongoing one and is not waived by our continued participation in this docket. *Seven Hills, Inc. v. Bentley,* 848 So. 2d 345, 350 (Fla. 1st DCA 2003) ("Subject matter jurisdiction, which arises only as a matter of law, cannot be created by waiver, acquiescence or agreement of the parties, by error or inadvertence of the parties or their counsel, or by the exercise of the power of the court. . . . And we review this issue de novo.") OPC incorporates herein the entirety of its Motion to dismiss and the arguments made therein.

The Legislature has given this Commission the power to regulate the rates and service of "public utilities" only as those powers are defined by Section 366.04, F.S. *See Rinella v. Abifaraj*, 908 So. 2d 1126, 1129 (Fla. 1st DCA 2005) ("An administrative agency has only such power as granted by the Legislature and may not expand its own jurisdiction"); *Diamond Cab Owners Ass'n v. Florida R. & Public Utilities Com.*, 66 So. 2d 593, 596 (Fla. 1953) ("Commission may make rules and regulations within the yardstick prescribed by the Legislature, but it cannot amend, repeal or modify an Act of the Legislature by the adoption of such rules and regulations.").

Further, without express statutory language and absent subsequent Legislative enactment, the Commission lacks authority over FPL's Petition. *Tampa Elec. Co. v. Garcia*, 767 So. 2d 428, 435 (Fla. 2000) ("[W]e find that the Legislature must enact express statutory criteria if it intends such authority for the PSC."); *Panda Energy Int'l v. Jacobs*, 813 So. 2d 46, 54 n.10 (Fla. 2002) (noting that when PSC lacks express statutory criteria for authority, ". . . the solution for the PSC or other interested entities if they desire to expand the PSC's authority is to seek an amendment to the statute.").

Section 366.02(1), F.S., defines "public utility" as "every person, corporation, partnership, association, or other legal entity. . . supplying electricity or gas. . . to or for the public within this state." FPL is an "electric utility" pursuant to Section 366.02(2), F.S., which defines "electric utility" as ". . . any municipal electric utility, investor-owned electric utility, or rural electric cooperative which *owns, maintains, or operates an electric generation, transmission, or distribution system* within the state." (emphasis added). In its statutory framework to regulate public utilities, the Legislature granted monopolies to utilities that operate in the "*electric generation, transmission, or distribution system*" space, but this framework does not authorize any Commission rate-regulated utilities to expand into competitive markets such as the oil and gas exploration, drilling, fracking, and production industry. Section 366.06(1), F.S., further provides that only utility property that is "used and useful[3] in serving the public" is to be reflected in the rates that customers pay.

[3] As demonstrated at hearing, an investment in "gas reserves is largely an investment in the right to drill," and the nature of the asset under Oklahoma law is only the right to explore and drill for natural gas which does not constitute an ownership interest in the gas. *See Sunray Oil Co. v. Cortez Oil Co.,* 188 Okla. 690 (OK 1941). Once gas is "captured," it is no longer an asset of the type that is subject to a "used and useful" determination within the plain

Investing in the exploration, drilling, and fracking of shale to release gas is not part of "own[ing], maintain[ing], or operat[ing] an electric generation, transmission, or distribution system." Consequently, the Commission lacks the jurisdiction to authorize the inclusion of investments in natural gas reserves in regulated rate base and base rates. This issue was conclusively resolved in PSC Order No. 21847 ("EFC Order"), issued in Docket No. 860001-EI-G. There, the Commission ruled that Florida Power Corporation's ("FPC's") Affiliate (not the rate-regulated monopoly electric utility) that owned coal reserves and the "complex supply and delivery network" they created were not subject to the Commission's jurisdiction. In that case, the subject that the Commission addressed was the manner in which FPC (now Duke Energy Florida) created subsidiaries and/or affiliated companies to own and operate coal mines and transport coal to FPC's generation sites. In Order No. 21847, the Commission first described the corporate arrangements in place to provide coal to FPC:

> In March, 1976, Electric Fuels Corporation was established as a wholly-owned subsidiary of Florida Power Corporation and signed a Coal and Supply Delivery Agreement for the purchase and delivery of coal to Crystal River Units 1 and 2. . . . Since 1982, when Florida Progress Corporation, a holding company, was formed, EFC has been an affiliate of FPC.[4]

The Commission then deliberately and unequivocally distinguished between FPC, which was subject to its jurisdiction, and FPC's fuel supply affiliates, over which it possessed no subject matter jurisdiction:

> Chapter 366, Florida Statutes (1987), provides the statutory basis for the exercise of the Commission's jurisdiction over public utilities. Public utilities are defined as "every person, corporation. . . supplying electricity. . . to or for the public within this state." Section 366.02, Florida Statutes. FPC is a public utility as defined in Chapter 366 and is therefore subject to the jurisdiction of the Commission. EFC and the complex supply and delivery network they have created are not subject to the jurisdiction of the Commission under Chapter 366.

Order No. 21847 at 2-3.

By finding that a non-regulated investment is outside its jurisdiction in Order No. 21847, the Commission also effectively identified the coal reserves as an investment that would **not** be eligible for inclusion in rate base. The Commission adjudicated that case because the electric utility did not seek to make **the investment** in the coal reserves part of the electric utility's rate base or to include any portion of the then subsidiary and later affiliate's operations in the regulated operations, or to

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and ordinary meaning of that regulatory concept. Clearly, natural gas reserves fall outside the plain meaning of Florida's "used and useful" statute.

[4] In Order No. 21847, the Commission described a complex arrangement that EFC had entered into for the purchase and delivery of a specific coal to FPC, the details of which have been omitted here because they are not pertinent to this docket. However, it is clear from the order that the Commission was assessing a situation in which EFC, a subsidiary and later an affiliate of FPC, acquired ownership interests in coal reserves that it mined, transported, and sold to FPC.

seek a regulated return or profit on that coal reserves investment. Instead, the issues adjudicated in that case were the affiliate pricing terms between the non-regulated (but affiliated) vendor and the regulated utility. That same type of non-regulated investment – albeit in natural gas as opposed to coal – is present in FPL's proposed gas reserves investments. Therefore, by asking for authority to create the so-called "regulated subsidiary" and to place the assets of that subsidiary into rate base for Fuel Clause purposes and to set rates based on that investment, FPL has crossed an impermissible jurisdictional line.

PW Ventures, Inc. v Nichols, 533 So. 2d 281 (Fla. 1988), reveals the Supreme Court's view of the Legislative mindset when it defined the Commission's jurisdiction. In that case, the Court effectively observed that the Commission's jurisdiction or authority to regulate is co-extensive with the monopoly provision of service. Id. at 282-83. This is significant. The scope of FPL's monopoly is defined by its authority to produce and sell electricity to the public. Id. at 283. *PW Ventures* illustrates that FPL's monopoly authority and the Commission's jurisdictional authority are co-extensive. Exploring, drilling and fracking for and producing natural gas 1,000 miles away in Oklahoma does not fall within FPL's monopoly provision of electric utility service to the public in Florida by any stretch of the imagination. Not surprisingly, FPL's own regulatory expert, witness Terry Deason agreed that the reach of the Commission's jurisdiction coincided with the extent of a utility's monopoly. TR at 943-44. As a result, the *PW Ventures* decision is instructive for this case, and, when read in conjunction with the EFC Order, it is a compelling indicator of the jurisdictional boundary lines that circumscribes the Commission's jurisdiction. The production of natural gas and, of course, the associated investment in that activity fall outside Commission subject matter jurisdiction as a matter of law.

There are two additional Supreme Court cases on point that describe the limits of the Commission's subject matter jurisdiction. *Tampa Elec. Co. v. Garcia*, 767 So. 2d 428 (Fla. 2000) involved a case where the Commission granted a joint determination of need for a power plant with a Florida municipal electric monopoly and an out-of-state wholesale electric generator which was not subject to the rate regulation or jurisdiction of the Commission as a "public utility." In reversing the Commission's decision, the court stated:

> Our decision is founded upon our continuing recognition that the regulation of the generation and sale of power in Florida *resides in the legislative branch* of government. The PSC . . . is an arm of the legislative branch in that the *Commission obtains all of its authority from legislation.*"
>
> . . .
>
> Accordingly, we find that the statutory scheme embodied in the Siting Act and FEECA was not intended to authorize the determination of need for a proposed power plant output that is not fully committed to use by Florida customers who purchase electrical power at retail rates. Rather, *we find that the Legislature must enact express statutory criteria if it intends such authority for the PSC.*

Tampa Elec. Co. v. Garcia, 767 So. 2d 428, 434-435 (Fla. 2000) (emphasis added).

In a subsequent need determination case, *Panda Energy Int'l v. Jacobs*, 813 So. 2d 46 (Fla. 2002), the court further explained its decision in *Tampa Elec. Co. v. Garcia,* noting that when PSC lacks express statutory criteria for authority, "... the solution for the PSC or other interested entities if they desire to expand the PSC's authority is to seek an amendment to the statute." *Panda Energy Int'l v. Jacobs*, 813 So. 2d 46, 54 n.10 (Fla. 2002).

Further, it is axiomatic that an administrative agency, such as the Commission, is vested only with the express or implied statutory authority granted by statute. *Dep't of Revenue ex rel. Smith v. Selles*, 47 So. 3d 916, (Fla. 1st DCA 2010); *City of Cape Coral v. GAC Utilities, Inc.,* 281 So. 2d 493 (Fla. 1973); *Teleco Communs. Co. v. Clark*, 695 So. 2d 304, 308 (Fla. 1997). Any reasonable doubt as to the lawful existence of a particular power of the Commission must be resolved against it. *City of Cape Coral*, at 495. In the case at hand, a review of Chapter 366, F.S., clearly indicates that the Legislature has not expressly or impliedly granted the Commission any statutory jurisdiction to allow rate-regulated monopoly electric utilities to invest in natural gas reserves, to place those fugacious investments in rate base, or to recover any costs associated with natural gas reserves in customer rates (whether in base rates or through the Fuel Clause as FPL is proposing).

FPL's Petition Violates Applicable Commission Orders and Rules

While the FPL petition lacks a jurisdictional basis in Chapter 366, F.S., it also fails when the facts of the proposal are applied to the applicable Commission orders and rules. FPL has proposed that the Commission approve the petition on the basis that this investment is eligible for cost recovery under the Fuel Clause. There is no alternative proposal for recovery before the Commission.5 Moreover, jurisdiction is also lacking on this factual basis for at least three reasons.

First, the lack of the Commission's authority is manifested in the tortured way FPL seeks to make this transaction fit into the Commission's orders and rules that are the product of decades of regulating co-extensively with the monopoly provision of electric service to customers through the owning, maintaining, or operating an electric generation, transmission, or distribution system.

Second, FPL's plan to create a subsidiary to participate in the role now held by USG does not distinguish its situation from that which the Commission addressed in Order No. 21847 and it cannot confer jurisdiction upon the Commission to regulate this subsidiary. FPL's claim that the subsidiary would be "fully consolidated with FPL for regulatory. . . purposes,"6 is a unilateral, self-serving, baseless pronouncement. Evidence taken in the hearing shows that FPL's proposal is vague, contradictory, elusive, and not consistent with the Commission's traditional exercise of jurisdiction. See, for example, FPL witness Kim Ousdahl deposition testimony at 86-87. EX 56. Then, compare with hearing testimony (TR at 428-432) where witness Ousdahl tries to create a blurred division between what the Commission can and cannot oversee. Subject matter jurisdiction arises by virtue of

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[5] In fact, FPL affirmatively stated that the project will effectively go away with respect to FPL if it is not approved for recovery in the Fuel Clause. TR at 390; EX 13 at 1

[6] Petition at 23. In his prefiled testimony that accompanied the petition, FPL witness Sam Forrest refers to the entity as a "fully regulated FPL subsidiary." TR at 86

law only; it is conferred by constitution or statute and cannot be created by waiver or acquiescence. See Board of Trustees of Internal Improvement Trust Fund of State v. Mobil Oil Corp., 455 So. 2d 412 (Fla. 2d DCA 1984), quashed in part on other grounds by Coastal Petroleum Co. v. American Cyanamid Co., 492 So.2d 339 (Fla. 1986).

Third, as discussed in more detail infra, the gas reserves project ("GRP") fails every test the Commission has established for eligibility for cost recovery whether by Fuel Clause or base rates as set out in Orders Nos. 14546; PSC-11-0080-PAA-EI; and PSC-13-0023-S-EI.

FPL's Proposed Gas Reserves Investments Fails the "Three-Prong Test" Established by Order No. 14546

In its Petition, FPL cites Order No. 14546 in support of its request to include such investments in the fuel cost recovery clause. Petition at 7, 21, 22. Order No. 14546 and its progeny set forth the Commission's strict policy concerning what fossil fuel-related costs normally recovered in base rates may be recovered through the Fuel Clause. FPL witnesses Sam Forrest, Kim Ousdahl and Terry Deason also filed testimony in an effort to support this request. However, Order No. 14546 provides no jurisdictional support for FPL's petition. The reason is simple and straightforward. Order No. 14546 identifies, as candidates for the fuel cost recovery clause, items that are ". . . normally recovered through base rates." Order No. 14546 at 4. EX 65. In other words, before an item involving a capital investment can qualify for the alternative ratemaking mechanism of the Fuel Clause, it must first qualify for rate base. Investments in the competitive gas production industry do not qualify for rate base, and so are not "normally recovered through base rates." Accordingly, these investments do not, as a matter of law, Commission precedent, or plain English and common sense, qualify for fuel cost recovery clause under Order No. 14546 or its progeny.

In support of its Petition, FPL offered the testimony of Ms. Ousdahl as its primary witness to "address the appropriate accounting and regulatory treatment" for the proposed investment in Oklahoma gas reserves. TR at 351. Witness Ousdahl suggests that the project qualifies for recovery through the Fuel Clause based on Item 10 of Order No. 14546. TR at 369-370. While expressly referring to this provision of the order as a "test" (TR at 370, line 1), she claims the Woodford Project "clearly and directly meets" that test. She is wrong. The Woodford proposal flunks the test with flying colors.

In applying Order No. 14546, FPL has a major problem. The Woodford Project, which holds the promise of highly coveted, guaranteed profits to FPL's shareholders on the fuel expense that the Company historically has passed through to customers without earning any profits, presents a Catch-22. The only way FPL can meet the test set out in Order No. 14546 (which it expressly recognizes as the Commission's expression of uniform policy)7 is if the Woodford Project meets all three prongs of the test in Item 10, which states:

> 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.

However, if the Woodford Project meets the requirements of the three-prong test, then the project is barred from Fuel Clause recovery by the express provisions of Paragraph 6 of the 2012 Settlement. See Order No. PSC-13-0023-S-EI at 14. Paragraph 6 prohibits Fuel Clause recovery for any costs that meet the first prong of the Item 10 test. FPL literally meets itself coming around the corner in this conundrum; however, the allure of fixed shareholder returns and guaranteed profits on natural gas fuel expenses was perhaps too strong to resist. Thus, FPL appears to be pursuing a simple strategy to evade the problem: just act like the problematic "normally recovered through base rates" provision of Item 10 doesn't exist! This is exactly what witness Ousdahl did. And, if that does not work, hire a former Commissioner to attack the OPC witnesses who point out this obvious oversight(s).

FPL witness Deason testified that this provision of Order No. 14546 sets out a three-prong test and that each prong must be satisfied in order for a project to be "eligible" for Fuel Clause recovery. EX 58 at 25. He opined that the Commission, on a case by case basis, must still make a separate prudence determination on otherwise eligible projects. EX 58 at 30-31. The three prongs test is as follows:

1. Fossil fuel-related costs normally recovered through base rates;
2. But which were not recognized or anticipated in the cost levels used to determine current base rates; and
3. Which, if expended, will result in fuel savings to customers.

The concluding sentence "Recovery of such costs should be made on a case by case basis after Commission approval" is the case by case prudence determination that witness Deason discussed. EX 58 at 30-31. It is clear that prongs 1 and 2 are independent of each other and require different showings. The third prong requires the utility to demonstrate that the fossil fuel-related costs will (not may) result in fuel savings to customers. By the existence of the second prong, it is

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[7] Order No. 14546 states that the order expresses its "intent in the Order to establish comprehensive guidelines for the treatment of fossil-fuel-related costs..." Order No. 14546 at 5. EX 65. Clearly, this order is an expression of industry-wide policy for the electric utilities that are subject to the Commission's jurisdiction. While the Commission is exempt from rulemaking for the Fuel Clause per Section 120.80(13)(a), F.S., the agency is not free to disregard this uniform policy. As discussed *infra*, the agency has recently taken pains to restrict expansionist efforts by FPL to allow the exceptions to swallow the rule. See also Order No. PSC-11-0080-PAA-EI at 9-10. OPC submits that with respect to precedent applicable to circumstances like the Fuel Clause where the Commission has established policy in lieu of rulemaking, disregarding or selectively applying the express provisions of Order No. 14546 would be arbitrary and capricious and an abuse of agency discretion.

clear the Commission recognizes and intends that the project costs are new and not already included in base rates. Witness Deason concurs with this by acknowledging that the intent is that the "fossil fuel-related costs" in prong one must be "***of the type***" that are "normally" or "typically" recovered in base rates. EX 58 at 23-25, 28

In her testimony, witness Ousdahl portrays the Order No. 14546 three-prong test in the following way by describing a blanket rule that depends solely on the utility's intent:

> Item 10 of FPSC Docket No. 850001-EI-B, Order No. 14546 provides that Fuel Clause recovery is appropriate for projects that are intended to lower the delivered price of fuel when those costs were "not recognized or anticipated in the cost levels used to determine current base rates."

TR at 369. Perhaps a better way to portray her convenient re-writing of Item 10 is to look at it as witness Ousdahl has effectively revised it to read:

> ~~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~~ are intended to lower the delivered price of fuel ~~savings~~ to customers. ~~Recovery of such costs should be made on a case by case basis after Commission approval~~.

This opportune revision may be expedient for FPL, but nowhere can witnesses Ousdahl or Deason point to a Commission order or other authority to justify these edits to the Commission's fuel cost recovery policy.

In an astonishing and audacious effort to meet the test, witness Ousdahl deletes the first prong completely. Why? First, because it is highly unlikely that FPL can meet the test since ephemeral investments in the right to explore, drill, and extract natural gas in Oklahoma do not meet the more fundamental test for jurisdictional activities over which the Commission has jurisdiction. Second, assuming, *arguendo,* that FPL can evade the jurisdictional bars that prevent the Commission from even allowing the investment into rate base, it is not of the type that meets the test of being historically, traditionally and typically included in rate base, as pointed out by OPC expert witness Donna Ramas. TR 562

Witness Ramas testified that investments in gas exploration, drilling, and production clearly do not fall under items that would be "normally recovered through base rates" for regulated electric utilities. *Id.* She points to the contorted and tortured accounting path that FPL intends to follow to bootstrap the investment into its regulated books and then presumptively into rate base for subsequent transfer to the Fuel Clause as providing circumstantial evidence that the Woodford Project does not qualify for rate base, and thus base rate treatment and recovery. *Id.* See also testimony of witness Ousdahl at TR 363-366, 373-374; EX 56 at 50-53, 66-85.

FPL offered former Commissioner Deason as their regulatory philosophy expert to rebut the OPC witnesses' testimony that presented the straightforward holdings of the key orders relied upon by FPL. In a display that can only be characterized as gall, he resorted to what amounts to be "name-calling" and accused witness Ramas of contorting, being "misguided and myopic," and of misusing Commission orders in challenging the FPL case. TR at 879, 881, 888, 889. Then, in a desperate attempt to justify the gas reserves investment as being eligible for Fuel Clause, Mr. Deason's own prefiled testimony performed cut-to-fit surgery on the language of Order No. 14546, the fundamental precedent relied upon by his client.

Initially, he sought to create the illusion that the three prongs of the eligibility test in Item 10 of that order are really collapsed into two tests. In response to witness Ramas' testimony that the gas reserves investment is not of the type normally recovered in base rates, he mistakenly mischaracterizes her testimony saying Ms. Ramas testified the deficiency is that the investment is not already in base rates. TR at 885. He acknowledged this error in his deposition. EX 58 at 49-50. He hardly needed to have done that since the error is self-revealing and because the second prong of the test requires FPL to demonstrate that the cost is not included in current base rates. In his deposition, Mr. Deason acknowledged that there are three prongs and that all three prongs must be met in order for the investment to even be eligible for consideration. EX 58 at 25.

Witness Deason testified unequivocally that the first prong required FPL to make the threshold demonstration that the cost proposed for recovery was "of the type" "normally" or "typically" recovered through base rates. EX 58 at 23-25, 28.8

In its Petition, FPL mentions Order No. PSC-93-1331-FOF-EI (gas pipeline lateral); Order No. PSC-95-1089-FOF-EI (rail cars); and PSC-97-0359-FOF-EI (power plant modification) as examples of capital items that were allowed to be recovered through the fuel cost recovery clause. (Petition, at 21-22) None of these orders support FPL's request for recovery of costs associated with speculative gas reserves investments in a competitive industry. In each of them, the Commission approved – not a capital investment in a nonutility, competitive fuel production industry – but an investment that made the fuel or the delivery of fuel produced by and procured from suppliers more economical.[9] Mr. Deason and Ms. Ousdahl cite the same orders in their prefiled testimony with no helpful explication accompanying the citations.

Witness Ousdahl's proffer of further justification for her self-serving interpretation of the Commission's "comprehensive guidelines for the treatment of fossil fuel-related costs" comes in the

[8] In his deposition, Mr. Deason also made the unsupported claim that an electric utility could meet the test by any investment no matter what type. EX 58 at EX 58 at 28-30. However, he acknowledged elsewhere in his deposition that there was no language modifying or amending the language in the first prong and he could point to no order or other authoritative source that so modified the threshold test. *Id.* At 26-27. He also explained that the phrase was really intended to describe the new willingness by the Commission to consider in the Fuel Clause costs previously only base rate recoverable. EX 58 at 28

[9] For instance, by supplying its own rail cars, FPL effectively "bought down" the cost of transporting coal to its plant site, but the rail company continued to provide the (nonutility) transportation service.

form of four later-issued orders. These orders do not change the test that she claims the Woodford project passes, as will be discussed below. Ms. Ousdahl's portrayal of Order No. 14546 and her citation to the other orders is at best incomplete and, at worst, misleading and distorts beyond recognition the very authority FPL purports to rely on.

Principally, she cites to Order No. PSC-11-0080-PAA-EI as somehow supporting her erroneous claim that the heavy editing she has done to Order No. 14546 is the correct Commission policy. Order No. 11-0080 reaches the opposite result, however, and provides no support for her reliance on (the heavily edited) Order No. 14546. In Order No. PSC-11-0080-PAA-EI, the Commission took pains to carefully inventory the circumstances that resulted in capital costs being included in the Fuel Clause. In ***rejecting*** FPL's overreaching attempt to recover a turbine upgrade through the clause, the Commission reaffirmed the provisions of Order No. 14546 and Item 10 in all respects. Notably, with regard to the third prong of the Item 10 test, the Commission stated the following while quoting Item 10 in full:

> As Order No. 14546 states, recovery may be allowed for:
>
> > 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.
>
> We find that the appropriate interpretation of this section of Order No. 14546 is that capital projects eligible for cost recovery through the Fuel Clause <u>should</u> produce fuel savings based on lowering the delivered price of fossil fuel, or <u>otherwise result in burning lower price fuel</u> at the plant.

Order No. PSC-11-0080-PAA-EI at 9. (emphasis added). There are three highly significant aspects of this Order:

First, by quoting Item 10 in its entirety, the Commission reaffirms the test in its entirety and tacitly acknowledges that there are threshold determinations – prongs one and two – that projects must satisfy in order to be eligible for cost recovery under the entire Item 10 provision. This is easily apparent from the context of the order. No regulatory expert is needed to provide context or intent. The only issue in dispute in the turbine upgrade case was whether the upgrade lowered the delivered price of the fuel (coal). Base rate recoverability and exclusion from current base rates were not disputed and, thus, were not at issue. Consequently, the Commission had no reason to interpret or modify those provisions and did not do so. Prongs one and two were left undisturbed.

Second, the Commission used the phrase "should produce fuel savings." It did not use the morph that FPL and witness Ousdahl have proffered – that is, "intended to produce savings." Contrary to FPL's claims, the Commission expressed a strong desire for a high degree of certainty.

The proposal in this docket for which the contrived savings drop over 50% within six months of the filing cannot meet that high threshold. Compare EX 9, SF-8 with EX 54, BSP 369, Revised SF-8.

Third, in the alternative phrasing, the Commission said the project "should… otherwise result in burning lower price fuel . . . ." This bolsters the Commission's policy pronouncements and OPC's position that the savings must be concrete and more certain in nature and not speculative or merely "intended." The very narrow interpretational guidance given by the 2011 order provides no support to include the Woodford investment in the Fuel Clause.

It is especially disappointing that FPL seeks to create an enormous loophole by seeking to rely on an order that is a clear expression of the Commission's desire to reign in and discourage inappropriate and unintended uses of the Fuel Clause as well as FPL's historical efforts to bypass the limited the scope of Order No. 14546. In reaffirming the viability of Order No. 14546 and rejecting FPL's overreaching turbine upgrade clause recovery effort, this very same Commission cited two examples of inconsistencies – both FPL projects – that they clearly indicated were incompatible with the policy established in Order No. 14546 and are isolated to the facts and obviously not to be relied on as exceptions.[10] The Commission concluded, in light of the specific issue presented in the turbine upgrade case and the two inconsistent cases that:

> While it is true that we granted recovery of "non-fossil fuel-related" costs through the Fuel Clause in those two discreet instances, we believe that the appropriate policy *going forward* is to restrict capital project cost recovery through the Fuel Clause to projects that are "fossil fuel-related" *and that lower* the delivered price, or input price, of fossil fuel.

Order No. PSC-11-0080-PAA-EI at 10. (emphasis added).

It cannot be emphasized enough that Order No. PSC-11-0080-PAA-EI did not in any way change the test contained in Item 10 of Order No. 14546, nor did it expand the scope of Order No. 14546 – which was a stipulated order among the investor-owned utilities (IOUs), Commission staff, *and* OPC. The Commission further used the phrase "and that lower" in addressing the savings aspect of prong three. This is further evidence that the required showing to satisfy prong three is more than a forecast, projection, or estimation of customer fuel savings. FPL's misrepresentation of the order is an audacious and impermissible one. When put in the context of the turbine blade issue before this Commission just three years ago, the order can clearly be seen as more in the nature of a rebuke to FPL for misusing the uniform policy of Order No. 14546 and an effort to restrict the Fuel Clause to the intent agreed upon in 1985 by all the signatories and adopted by the Commission. FPL cannot self-anoint itself or its outside consultant to recast the Commission's established expression of policy

[10] One instance was the security costs in the aftermath of September 11, 2001, that were allowed "under unique circumstances" and later transferred to the capacity cost recovery clause. The other instance was an FPL nuclear plant thermal power uprate at Turkey Point Units 3 and 4.

to support FPL's non-jurisdictional ventures in Oklahoma or other states.[11] Therefore, this Commission should reject FPL's new efforts to abuse the Fuel Clause by first selfishly misconstruing and reinterpreting Item 10 and then mischaracterizing Order PSC-11-0080-PAA-EI to support its brazen revision.

FPL's Request Fails the Second Prong of the Item 10 Test in Order No. 14546

In addition, FPL falls short of meeting its burden to demonstrate that the Woodford Project meets the second prong to the Item 10 test – namely that the costs are "...not recognized or anticipated in the cost levels used to determine current base rates..." The sole effort mustered by FPL to meet the second prong of this test is witness Ousdahl's irrelevant claim that "[m]oreover 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." TR at 370. On its face, this 26-word statement cannot be accepted as evidence in this case. There was no test year upon which FPL's current base rates were established as the Commission approved a stipulation in Order No. PSC-13-0023-S-EI that involved a negotiated revenue requirement (or "black box settlement") that was not tied to any cost basis, test year, or minimum filing requirements ("MFRs"). It also included a four-year base rate freeze and injected two new issues not originally included with FPL's rate case, affecting the viability of the four-year stay-out term[12] (including significant amortization discretion totaling $400 million). The relevant point is that the "basis" for establishing current rates is effectively on a four-year, moving basis as FPL is allowed to amortize and/or reverse the amortizations as it sees fit to achieve a desired achieved earnings anywhere between a maximum return on equity of 11.5% and a minimum of 9.5%. Order No. PSC-13-0023-S-EI at 6, 19-21. Even more significant is the testimony of witness Forrest that the Company was "actively" looking at gas reserves projects as early as 2011,[13] which predates the filing of FPL's 2012 rate case. Furthermore, both witnesses Ousdahl and Forrest acknowledged that the asset optimization incentive mechanism approved in the 2012 rate case order

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[11] Witness Deason provided testimony that is nothing more than a strained spin of the two crucial orders (Nos. 14546 and 11-0080). However, his testimony on this point should be heavily discounted, as he acknowledged that his testimony was largely just his opinion and he could not point to orders or authoritative sources to support his recasting and reinterpretation of the orders. EX 58 at 26-27. The orders speak for themselves and OPC has demonstrated that they do not support FPL's position.

[12] Order Nos. PSC-12-0529-PCO-EI and PSC-12-0617-PHO-EI further cast heavy doubt that FPL could ever meet its burden. The four-year term of the agreement contains a base rate freeze that is coupled with FPL's ability to amortize $400 million in depreciation reserves surpluses. This term of the settlement was not included in the original rate case filing and is described by the Commission in the two procedural orders as "specific issues that are part of the proposed settlement agreement, but supplemental to [the issues in the originally filed rate case]." Two of the issues referenced by those orders are relevant to FPL's claim about what was included in establishing base rates. Issues 2 and 4 were new issues that did not relate to the 2013 Test Year and involved authority to amortize up to $400 million of reserve surpluses over the four-year term of the agreement and the creation of the so-called asset optimization incentive mechanism. Order 12-0529 at 11

[13] Mr. Forrest admitted that FPL was actively looking for a gas reserves project as early as 2011. TR at 131; EX 55 at 113-14. FPL's interest was based upon an April 2011 order in Oregon for Northwest Natural. *Id.*; EX 44 (FPL's Response to Staff Int. No. 87)

would or could have a role in the procurement of gas from the proposed gas reserves project(s). TR at 292-294; EX 56 at 46

Witness Ousdahl also admitted that she could not testify whether others in FPL or NextEra were not strategizing or anticipating a gas reserves venture into base rates prior to the filing of the settlement in the 2012 rate case. She could only affirmatively give her opinion that ***the filed MFRs*** did not include a gas reserves estimate. EX 56 at 44-45. However, this is beside the point as the final negotiation of the revenue requirement forming the basis for FPL's current base rates was completed on December 13, 2012; the revised "black box" settlement was not tied to the company's rate case MFRs. Order No. PSC-13-0023-S-EI at 2; TR at 421-26. The only effort to overcome this deficiency in her prefiled direct testimony was Ousdahl's tepid observation at hearing that "I know there were no gas reserve estimates in our filing."[14] TR at 426

There are two problems with FPL's attempt to meet prong two of the test. The MFRs did not, as a matter of law, form the basis for the current base rates. A review of Order No. PSC-13-0023-S-EI indicates that there is nothing in the Order or the settlement that states that the revenue requirement is based on anything other than negotiation. Tellingly, Ousdahl conceded that this was the case (TR at 424) and confirmed under cross-examination: (a) that the negotiated revenue requirement was allocated to customers on the MFR billing determinants for allocating the revenue requirement (TR at 422-423; Order No. 13-0023 at 3,12); (b) that the Canaveral Modernization Project (a generation base rate adjustment or "GBRA") revenue requirement was expressly based on the filed petition and the MFRs (TR at 423-25; Order No. PSC-13-0023-S-EI at 4, 6); and (c) that previously stipulated issues [contained in the first prehearing order dated August 12, 2012] were superseded by the settlement. TR at 424; Order No. PSC-13-0023-S-EI at 8. All of these express terms conclusively demonstrate – by contrast to what is not mentioned in the order with respect to MFRs forming a basis for the negotiated revenue requirement – that there is no "test year" or "MFRs" upon which current base rates were determined. Thus, there is no credible evidence that can

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[14] Order No. PSC-13-0023-S-EI speaks for itself and is completely silent on what went into the settlement revenue requirement. In fact, Order PSC-12-0617-PHO-EI contains the following statement by FPL regarding the nature of the settlement:

> As with all negotiated solutions, the Proposed Settlement Agreement represents a series of interrelated compromises reached by independent parties with varied interests, which differ from their litigation positions. Settlement negotiations also offer an opportunity to innovate. The Proposed Settlement Agreement is not an exception. While none of the terms breaks new substantive ground, the parties resourcefully assembled various elements in a way that strikes a fair balance. And, as with any settlement, the merits of the Proposed Settlement Agreement should be considered as a whole, rather than focusing on any individual provision or subset of provisions in isolation.

FPL's own words at the time the Commission considered and approved the 2012 rate case settlement indicate that there was a negotiated number and no issue was identified as "in or out." The only "term" related to base rates was a single number: $378 million (later re-negotiated downward to $350 million on December 13, 2012). As a stand-alone number and a "term" of the agreement, that number does not break new substantive ground and FPL was careful not to state what went into its formulation other than that it was part of "a series of interrelated compromises."

legally support a finding that FPL made even a rudimentary showing that the second prong of the Item 10 test ("costs. . . which were not recognized or anticipated in the cost levels used to determine current base rates") is met.

The significance of the amortization authorization is that its availability and flexibility mean that FPL has wider latitude during the four-year base rate freeze to effectively include in rates projects not originally included in the 2012 rate case MFRs as opposed to a situation where a static test year and the accompanying MFRs would be used to establish rates. Additionally, in the instant case, FPL has indicated a linkage between the gas reserves project(s) and the asset optimization incentive mechanism which was also a new or incremental issue that was added after the MFR-based filing was made and upon which an additional hearing was required in the 120015 rate case. TR at 292-94; EX 56 at 46. Admittedly, the existence of these facts relating to the new issues that were included in the settlement and the order approving it do not prove conclusively that FPL did recognize or anticipate that the gas reserves project is affirmatively "baked into" current base rates. The new settlement issues completely dissolve the notion that current base rates are based on a single test year (of 2013) or on whatever FPL initially included for cost recovery in that filing. Given witness Forrest's admission that FPL was "actively" pursuing a gas reserve project as early as April 2011 – or nearly one year before the filing of the 2012 rate case on March 17, 2012 – and the insertion of the two post-filing amortization and asset optimization issues, FPL's burden to prove compliance with the second prong is greatly heightened and witness Ousdahl's paltry and erroneous disavowal falls woefully short of meeting that burden.

Ultimately, OPC does not have to prove that a gas reserves project was included in current base rates. Rather, <u>FPL</u> has the burden to prove that it is not "recognized or anticipated in current base rates." As a matter of law, FPL's sole basis for meeting this prong of the test fails because the basis for establishing rates was not the test year from the filed MFRs. What witness Ousdahl claims FPL did or did not include in the test year costs is completely irrelevant to what was recognized or anticipated in current base rates, and the 26-word statement offered in her direct testimony is factually incorrect, constituting the sole effort mustered by FPL to satisfied the second prong of this test. TR at 370.

FPL's Request Fails the Third Prong – "Fossil fuel-related costs . . . which, if expended, will result in fuel savings to customers"

Having failed the first two prongs of the mandatory three-prong eligibility test (which are the three prongs witness Deason acknowledges must be met), the passage or failure of the third prong is a moot point. However, needless to say, FPL flunks that test as well. The third prong requires FPL to demonstrate that "[Such costs] ... if expended, will result in fuel savings to customers." In an attempt to meet this test, witness Ousdahl reinterprets the plain language of Order No. 14546 to fit FPL's speculative savings proposition. She transforms the phrase "will result in fuel savings to customers" into the phrase "are intended to lower the delivered price of fuel." TR 369. When challenged about her blatant mischaracterization of Order No. 14546, witness Ousdahl claimed that the re-characterization was merely her "interpretation" of the order. TR at 419

In applying the third prong of the test in a straightforward manner, OPC witnesses Ramas and Lawton demonstrate that the supposed projected savings in the Woodford Project are too speculative and render it unreliable and insufficient to meet the standard of Item 10 ("will result in fuel savings to customers"). TR at 562, 588, 689-711, 745. Part of Ms. Ousdahl's re-characterization is grounded in her claim that the Commission has allowed companies to meet the test where they merely "project a savings to customers" in fuel costs. TR at 418-419. There is no basis (legal or otherwise) for this claim. At one point, witness Ousdahl describes FPL's purported savings forecasts as "estimated to result in savings to customers" (TR at 370) and she apparently equates "estimated" with "will result."

Witness Deason attempts to bolster this attempt to redefine the third prong and to equate "estimated" with "will result" by pointing to the Scherer rail car decision in Order No. PSC-95-1089-FOF-EI.[15] Mr. Deason seeks in vain to make that order conform the Woodford Project to the third prong by pointing, not to the actual rail car decision but to Order No. PSC-11-0080-PAA-EI, which discussed the rail car decision. TR at 883-884. In that case (as noted elsewhere herein), in a stinging rebuke to FPL for seeking to pass an unqualified turbine project through the Fuel Clause, the Commission inventoried the decisions allowing capital investments to be recovered therein. One of the decisions inventoried was the 1995 Scherer rail car decision. While witness Deason correctly notes that the Commission allowed the rail car assets to be recovered pursuant to the Item 10 test, he uses some grammatical sleight of hand to convert a simple retrospective recounting of what happened – that the buy-versus-lease savings had been estimated – into some sort of substantive prospective ruling by the Commission that fuel savings comparisons would thereafter be "estimated." This simply did not happen.

The cited language was a mere factual recitation and one that actually supports OPC's true reading of the third prong requiring savings to be more certain and less speculative. Mr. Deason also did not mention that review of the underlying order indicates that the issue was stipulated, and he acknowledged under cross-examination that the "estimate" that had occurred was not one that involved estimating fuel prices as is the problem FPL faces in selling the Woodford proposal to the Commission. TR at 916-17.[16]

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[15] While witness Ousdahl cites to the same Scherer rail car decision (TR at 369), she provides no explication as to how it supports the Company's request.

[16] Under re-direct, when asked to provide similarities between the stipulated recovery of the rail cars and the proposed Woodford Project investment, Mr. Deason made an unsubstantiated claim that "the investment in the rail cars, that was a cost, an investment that had not traditionally been included in base rates, so there's that similarity." TR at 991. Yet, Order No. PSC-95-1089-FOF-EI makes no mention that the Commission made a finding about whether the rail cars met the first prong of the eligibility test (i.e., being ***of the type*** normally recovered in base rates) in Item 10 of Order No. 14546. The matter was stipulated as noted in Order No. 95-1089 at the outset of the discussion on the rail cars. Mr. Deason also claimed that "[i]t was an investment made that showed net savings for customers, projected net savings for customers, similar to the project that's in front of the Commission presently."

Further Evidence that FPL's Petition Violates Order No. 14546 and Falls Outside the Commission's Jurisdiction

Since FPL and witness Ousdahl ignored the existence of the first prong of the Item 10 test, OPC witness Ramas addressed both the existence of the first prong and the applicability of it to the facts of the FPL petition. TR at 561-62, 568-75. Ms. Ramas points out that Commission Rule 25-6.014, F.A.C., mandates that all investor-owned electric utilities "shall" maintain its accounts and records in conformity with the Uniform System of Accounts (USOA) [as required by the Federal Energy Regulatory Commission (FERC) for electric utilities]; however, FPL will not record this project in accordance with these rules. TR at 570-71. Ms. Ramas correctly recognizes that this is evidence that even FPL views the Woodford Project as "inconsistent with regulated monopoly operations for which the FERC USOA would apply." TR at 571

She observes that FPL intends to use for the activities in Oklahoma a form of accounting that is entirely unknown to the Commission's regulation of the electric (or gas) industry. Instead of using the form of accounting and chart of accounts mandated by Commission Rule 25-6.014, F.A.C., FPL intends to use Accounting Standard Codification (ASC) 932 – Accounting for Oil and Gas Exploration. Witness Ramas notes that this departure from Commission rules is an indicator that this investment is outside the Commission's jurisdiction and axiomatically does not meet the test established in prong one of Item 10. TR at 562, 572. Witness Ousdahl admits this as well. In her deposition, she stated: "The rules don't contemplate – clearly the rules don't contemplate an electric utility investing in a gas development production. That's clear. . . ." EX 56 at 62

Witness Ramas also demonstrates that the depletion accounting that FPL intends to use is not contemplated by the Commission rules for electric utilities.[17] Ms. Ousdahl also acknowledged as much. EX 56 at 94-95

FPL intends to utilize ASC 932, which includes something called "successful efforts" accounting to record the Woodford transaction on the books of what it calls a "fully regulated subsidiary" using the accounting conventions and chart of accounts common to and standard in the wholly unregulated and competitive oil and gas exploration and production industry (TR at 86, 363) because its non-regulated NextEra cousins that explore for oil and gas have already chosen to use this system of accounts. TR at 572. This further supports a lack of Commission jurisdiction over the activities in Oklahoma.

If this was not enough evidence of an absence of even rudimentary compliance with the first prong of the Item 10 test ("Fossil fuel-related costs normally recovered through base rates. . . "), FPL

TR at 991. Again, the recovery was stipulated (and thus compliance with Item 10 must be presumed); furthermore, the projection of savings was not based on forecasting the price of the fuel commodity. TR at 916-917

[17] The Commission's rules for gas utilities likewise do not contemplate the use of depletion accounting in lieu of depreciation accounting. See Rule 25-7.014(3), F.A.C.

intends to use the FERC USOA for Natural ***Gas*** utilities[18] as a way of "translating" the chart of accounts used in a competitive industry to a system of accounts that is mandated for regulated gas companies and not authorized for electric companies. And then to further extend the boundaries beyond standard accounting procedures, FPL states its intent to use what it calls a "consolidated" USOA for Natural Gas Companies and then to effectuate that "translation" using only the selected instructions that FPL sees fit to use. EX 56 at 69-70, 72-74

After travelling this muddled path of accounting translations to get to the unauthorized USOA for Natural Gas Companies, FPL then proposes to unilaterally inject the gas reserves project <u>into its rate base</u> by recording the investment in the subsidiary in Accounts 123.1 and 145. TR at 451; EX 56 at 51-53. Once this is done, FPL asserts that the investment in the Woodford Project is presumptively in rate base. EX 56 at 53. Finally, having navigated this byzantine maze of Chart of Accounts, FPL indicates they will then take the final step of removing it from rate base and recording it as an investment for Fuel Clause purposes for recovery from customers and receipt of its guaranteed 10.5% ROE. TR at 373. The point here is that the accounting (including depreciation/depletion) treatment proposed by FPL is indirect but compelling evidence that the transactions lie far outside of the Commission's jurisdiction as evidenced by the rules that the agency has developed over decades to monitor, audit, and fully regulate electric utilities and their provision of electric service to the public.

Ironically, aside from demonstrating that the Woodford investment is extra-jurisdictional, FPL's proposed ultimate recording of those investments on the books of FPL in rate base is compelling evidence that FPL ***believes*** that the cost is of the type that is presumptively includable in rate base and, thus, in ***base rates***. While OPC has shown that the overwhelming weight of the evidence demonstrates that the Woodford investment flunks the first prong of the Item 10 test ("costs normally recovered through base rates"), FPL's intent to ultimately record its investment in rate base is significant in demonstrating FPL's belief that it meets the test of Item 10, which simultaneously causes it to fail the test of Paragraph 6 of Order No. PSC-13-0023-S-EI. The analysis supporting why the express language of Order No. PSC-13-0023-S-EI bars FPL's request is discussed *infra* under Issue 6.

Ultimately, however, the Woodford investment fails the tests(s) for cost recovery on several levels: (1) the Commission's lack of subject matter jurisdiction; (2) the investment fails to meet the first prong of the Item 10 test (among other prongs); and (3) it is disqualified from base rate and Fuel Clause recovery under the settlement approved in Order No. PSC-13-0023-S-EI.

For these reasons, FPL's Petition must be denied fundamentally because the Commission does not have jurisdiction over a competitive investment in gas reserves, which are not part of

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[18] Commission Rule 25-7.014, F.A.C., mandates that a natural gas utility subject to its jurisdiction shall maintain its accounts and records in conformity with the USOA as required by FERC for natural gas utilities. Witness Ousdahl testified that FPL is not certificated as a natural gas utility and is not authorized to sell natural gas to the public by this Commission, the FERC, or within the franchised territories in Florida. TR at 391-392; EX 56 at 59

owning, maintaining, or operating an electric generation, transmission, or distribution system. Furthermore, the Petition fails all of the tests established by the Commission for determining eligibility for recovering costs through the Fuel Clause. Finally, FPL is prohibited by the 2012 Settlement it entered into from recovering the Woodford investment through the Fuel Clause, as further demonstrated in Issue 6.

FPL's Fugacious Woodford Project Savings

Risk Analysis

The Woodford Project, seeking to recover gas reserves investment costs through the Fuel Clause, is a first of its kind before this Commission. However, similar type affiliated coal mining operations were acknowledged to be non-jurisdictional by this Commission. See previous section of Brief. The record contains references to only four orders from other jurisdictions allowing gas reserves in rate base; however, three of those orders involve gas local distribution companies ("LDC's") (TR at 131-132) and, in the fourth, the Montana PSC limited the inclusion of gas reserves to natural gas utilities' rate base and limited the use of the natural gas to natural gas customers only. EX 60 at 1, 13; TR at 134-135. FPL alleges the Woodford Project is "effectively de-risked" (TR at 268-269); yet, FPL then acknowledges risks such as variations in production, environmental risks (including contamination and moratoria), geologic risks, drilling risks, and operating cost risks.19 Contrary to FPL's assertion that the Woodford Project is de-risked, many risks actually do exist, and the Woodford Project proposes to place these risks squarely on the shoulders of FPL's ratepayers.

As discussed in more detail below, FPL witness Dr. Tim Taylor, who is employed by NextEra, testified that production levels and operating costs are examined within a range of values. TR at 856, 859-860. Witness Forrest admitted that production costs are not fixed, production levels are not fixed, and customer savings are not fixed. TR at 159-161. In fact, of all the inputs regarding the Woodford Project, the only item that the record supports as being fixed is FPL's ability to earn an authorized return of 10.5% on its investment. TR at 161, 728

Under the Fuel Clause as it currently operates, FPL's customers feel the mitigated effects of market price fluctuation through an annual adjustment (unless a mid-year correction occurs) to the fuel factors. TR at 788. As it stands today, if one of FPL's fuel suppliers does not deliver fuel in accordance with an existing contract, the possible harm to FPL's customers is that FPL may have to secure higher-priced fuel on the market to replace the undelivered fuel, the cost of which would be passed through to ratepayers. TR at 165-166; EX 55 at 33. Under the Woodford Project, FPL's customers will pay to have a well drilled, and if that well does not produce as expected or if the well is dry, then FPL's customers will also have to pay for FPL to procure natural gas at market prices to replace the gas that was anticipated from the well but not obtained. TR at 165-166. Although FPL alleges its customers face risks in the current natural gas market embodied in varying prices (EX 55 at 36), FPL's customers do not currently face the risk of paying twice for gas. EX 55 at 33.

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[19] *See* TR 139-145, 714-719. *See also* EX 55 at 11-15, and EX 57 at 34-36, and 77-80 for discussion regarding types of risk identified by witnesses Forrest and Taylor, respectively.

As discussed during the hearing, the Drilling and Development Agreement ("DDA", which is listed as EX 5) contains many provisions that create undue risk for FPL's customers. Witness Ousdahl contends this Commission will have access to any information FPL has in its possession when reviewing the prudence of Woodford Project costs. TR at 434-438. However, witness Forrest testified that, although there may be a free flow of information between PetroQuest and FPL, the terms contained in section 4.2(a)(viii) of the DDA control the flow of information (EX 5 at 17), and witness Forrest also testified that it is not unusual to have to place "request[s] for information." TR at 147-148. This Commission should not minimize its ability to conduct any prudence review, which places further undue economic risk on FPL's customers, by relying on a regulated entity's request for information from an unregulated third party.

Other provisions, such as sections 4.4(a)(i) and 4.4(d) of the DDA, shift risk to FPL and, correspondingly, to FPL's customers. EX 5 at 18-19; TR at 148-149. Witness Forrest attempted to dismiss provisions such as these by stating "the operating agreement would cover that," referencing default provisions in the operating agreement. TR at 148-149. Yet, witness Forrest acknowledged that the DDA trumps the operating agreement (TR at 154), which causes ratepayer protections to evaporate, much like FPL's projected customer savings. Witness Forrest acknowledged that the incentive to "consent" to the drilling to the initial well for a particular well unit in the DDA will be ignored by FPL (TR 152-153), and such non-consent of the first well-per-well unit could result in potential loss of mineral interest.20

Finally, the record in this proceeding clearly indicates that FPL's customers will move from bearing variability in the market price of natural gas arena to an arena in which FPL's customers bear the variability in the exploration, drilling, and production of natural gas. Currently, FPL's customers pay a market price for natural gas that includes the embedded costs for risks associated with exploration, drilling, production, and delivery. However, under the Woodford Project, FPL's customers will bear the direct variability of production levels, operating costs, and expenses of writing off wells,[21] as well as the risks associated with natural gas exploration and production. TR at 680

Four Key Flawed Assumptions Necessary for Customer Fuel Savings

The Proposed Woodford Project relies on speculation to offer hypothetical customer savings. As of June 2014, FPL projected customer savings of $106.9 million, which were predicated on the following assumptions: (1) all ~~of~~ the proposed wells are drilled successfully; (2) all of the wells produce within a plus or minus 10% range; (3) all other owners non-consent; and (4) FPL's natural

[20] On TR 152-153, witness Forrest discusses a provision of the DDA wherein if FPL chooses to non-consent on the first well of a drilling unit, then FPL loses its interest in all wells of that unit. Although the term encourages FPL to consent to ensure its interest in the remaining wells of the unit, witness Forrest testified that FPL will look at all well consent/non-consent decisions in the same manner, essentially ignoring this term of the DDA and the possible loss of mineral rights it entails.

[21] TR 444-445 regarding the accounting for expensed wells.

gas price forecast is correct. TR at 177. A review of the record shows that FPL's assumptions are not only speculative, but downright flawed.

First, PetroQuest, FPL's second attempt at bringing a fracking partner before this Commission (TR at 383-385), is 60% behind schedule on drilling rig number 1. TR at 187; EX 5 at 60. PetroQuest is also 100% behind schedule on drilling rig number 2, because PetroQuest cannot obtain another rig. TR at 187-188; EX 5 at 61. Witness Taylor further acknowledged that, although he calls PetroQuest an industry leader in the Arkoma Woodford region, he did not analyze the performance of any other companies in the Arkoma Woodford region. TR at 860. A sample size of one does not an industry leader make. PetroQuest's current inability to complete even half of the wells on time severely undermines FPL's assertion that all wells will be successfully drilled.

Second, FPL's projected savings rely on a sensitivity analysis using a plus or minus 10% production level. TR at 116-117. Witness Forrest clearly states FPL is relying on the expertise of Dr. Taylor regarding production levels (TR at 117); however, FPL apparently did not rely on Dr. Taylor's expertise when filing this petition before the Commission. Dr. Taylor's direct testimony filed with FPL's Petition does not allege a plus or minus 10% variance level. Witness Forrest also confirmed that Dr. Taylor did not allege a 10% variance level in his direct testimony. Further, FPL's use of a 10% variance for production levels to calculate savings was information that was uncovered in discovery (EX 55 at 69), which was submitted to staff one month after the submission of the Petition. EX 44, Interrog. No. 90, BSP 88

Although witness Forrest testified he relies on Dr. Taylor's expertise regarding production levels (TR at 1040-1041), the record proves the opposite. Witness Forrest claims that 10% is an industry standard (TR at 117); yet, Dr. Taylor clearly states there is no industry standard for production levels. EX 44, Interrog. No. 90, BSP 88; EX 57 at 17-18. And, not only did Dr. Taylor not allege a 10% production variation in his direct testimony, regarding output and reserve levels, he also stated that he did "not expect any such variances to be significant." TR at 845. Dr. Taylor further testified that, in this context, significant is a variance of "ten to 20 percent in the aggregate." TR at 856. In addition, utilizing a production variance of plus or minus 20%, as testified to by Dr. Taylor, this 20% variance increases the number of nine-box scenarios in which FPL's customers lose money to 1 in 3. EX 64, Att. 3.

FPL attempts to assuage any of the Commission's concerns on this issue by stating that Forrest A. Garb and Associates performed an "independent, confirmatory analysis." TR at 112; EXH 55, at 92-93. However, FPL acknowledges that Forrest A. Garb only reviewed information provided by PetroQuest, USG, FPL, and any publically available information. TR at 163-65. The Forrest A. Garb report clearly delineates the assumptions used in its verification of Dr. Taylor's projections.22 Essentially, Forrest A. Garb checked Dr. Taylor's arithmetic (TR at 769) without

[22] Ex 30 at 3, 26, ¶ 5 lists clauses about the assumptions made in Forrest A. Garb's analysis. Witness Forrest (EX 55 at 94-95) and witness Taylor (EX 57 at 26-27) both verified that the assumptions listed therein applied in the analysis.

independently challenging or verifying any of the underlying assumptions. Perhaps most tellingly, Dr. Taylor acknowledged that this Commission does not have a requirement for a third-party analysis (TR at 518) and, as he testified, one would not hire a third-party to perform an analysis "if you trusted your internal analysis and you didn't have a requirement to go outside for a third party analysis." (EX 57, BSP 933)

Third, FPL's total estimated fuel savings is contingent on all other owners non-consenting to drill wells, which is a variable totally outside of FPL's control. If other owners consent to drill, that changes the economics of the project. In this scenario, FPL's capital expenditures would be reduced to $125 million,23 and customer savings could be reduced by approximately 40%. EX 55 at 74. However, if all other owners non-consent because the economics of producing gas from the Woodford Project are lacking (i.e., the cost of production exceeds market prices), then it calls into question whether it is reasonable or prudent for FPL to consent to additional wells in the Woodford Project.

Fourth, FPL acknowledges that the primary driver for projected customer savings is FPL's forecasts for natural gas prices. EX 55 at 77-78. FPL's Petition alleged "approximately $107 million" in expected customer savings. PET at 7, ¶ 12. FPL based the Petition's fugacious customer savings on a natural gas price forecast from October 2013. TR at 173. However, FPL developed a new natural gas price forecast in July 2014, which showed that projected customer savings dropped to $51.9 million. EX 63. Witness Forrest argues that the Commission should view the $51.9 million as being within the original bands of FPL's base fuel projected savings (TR at 175-177); thus implying that the Commission should still consider FPL's original projection of $107 million in savings to be valid. TR at 1041. Yet, in contradiction to his own testimony, witness Forrest also testified that the Commission should rely on FPL's natural gas price forecasts prepared in support of filings before the Commission, and that the July 2014, natural gas price forecast was prepared to support FPL's 2015 fuel filings before the Commission. TR at 1041. Witness Forrest further acknowledged that it would be appropriate for the Commission to consider the matrix (listed as EX 64, Att. 2) using FPL's July 2014 price forecasts. EX 55 at 80-81. Therefore, according to witness Forrest, when considering FPL's hypotheticals for customer savings, the Commission should consider the most recent forecasts presented by FPL, showing that customers experience losses in 1 out of 3 scenarios and projected savings are only half of what FPL predicted just six short months ago.24

These key assumptions place FPL's customers in a position never before envisioned by this Commission. Although witness Deason suggested the Commission could "vertically integrate the utility one more step on that ladder to go start locking down some gas reserves" (TR at 968-969) by

[23] *See* FPL's Errata Sheet filed November 5, 2014, incorporated in record TR at 77.

[24] *See* EX 64, Att. 2 and 3 using July 2014 Fuel Curve. In both the 10% and 20% production scenarios, customers experiences losses in 1 out of 3 scenarios. As discussed above, FPL relied on Dr. Taylor's expertise in determining production levels, and Dr. Taylor predicts a variation range of 10% to 20% in the aggregate, which supports the use of Att. 3 in the Commission's analysis of the Woodford Project.

somehow expanding the Commission's jurisdiction through public interest determinations, notwithstanding that there is absolutely no statutory authority to authorize electric utility monopolies to vertically integrate into the competitive natural gas exploration, drilling, and production industry, the speculation required to make a determination of prudence or to find the Woodford Project in the public interest is far too great. The testimony indicates FPL is either misunderstanding or not listening to the advice of its NextEra expert. The record, as evidenced by Revised Exhibit SF-8, indicates that half of the projected customer savings can quickly evaporate on a gas reserves project that could last 50 years on the vagaries of a fuel price forecast – which is just one of a multitude of variables that FPL cannot control. Approval of the Woodford Project will subject FPL's customers to the risks, assumptions, and speculation outlined above while fixing FPL's shareholders return or guaranteed profit at 10.5% on every dollar invested in gas reserves projects. Therefore, based solely on the speculative and uncertain nature of FPL's projected cost savings, production costs, and future gas market prices, FPL's request should be denied.

FPL's Gas Reserves Investments Violate the Commission's Hedging Policy and Guidelines

In addition to promising tepid, and speculative, customer fuel savings which FPL cannot guarantee, FPL states its proposal is a hedge against fuel volatility. PET at 6, ¶ 11. In its direct case, FPL stated that PetroQuest's Woodford Project in particular and speculative gas reserves investments in general would be, in effect, a longer-term physical hedge, serving as a "low-cost alternative to financial hedges." TR at 92, 96, 115. FPL argued it would operate as a long-term physical hedge against market-price volatility for multiple decades. PET at 6, ¶ 11, 21, 41. In rebuttal, FPL strongly espoused that its gas reserves proposal was consistent with the Commission's hedging policy as a hedge against volatility in natural gas market prices. TR at 887-88, 891, 901-03, 1001-03. FPL witness Deason testified that shareholders should not bear the risk of gas reserves hedges that exceed volatile market prices. TR 887-888. Mr. Deason claimed that "the gas reserves project is to mitigate risks through hedging for the benefit of customers" and provide "hedging benefits." TR at 894, 903, 909, 926. Witness Deason later testified that there would hopefully be hedging benefits of more stable gas prices associated with FPL's proposal. TR 967, line 20. Mr. Deason also testified that gas prices "are probably less volatile now than they have been in the recent past, but there have been instances of volatility. . . . Right now we may be in a little bit of a lull with that volatility. . . ." TR 977-978

FPL witness Forrest stated "customers will benefit from the Woodford Project because it is a long-term physical hedge against highly volatile gas prices." TR 1003. Mr. Forrest later testified that FPL's proposal was a "form of hedging." TR 1021. He disagreed with Mr. Lawton's "very narrow definition of what constitutes hedging." TR 1036. However, witness Forrest testified that FPL can provide no assurances that the projected production costs for the Woodford Project would be less than the current market price, or that any fuel savings would materialize. TR 1070-71. He further testified that production costs were "not fixed in the sense that a [hedging] swap is fixed" and that nothing under FPL's proposed gas reserves Guidelines fixes the costs for those future investments. EX 55 at 21. FPL is clearly mistaken in its assertions that its proposed gas reserves investments would be a long-term physical hedge, that its proposal is consistent with the Commission's hedging policy and fuel hedging guidelines, and that the proposal will mitigate fuel price volatility for the benefit of the customers. Gas reserves investments are not long-term physical hedges because they cannot fix any costs, they cannot guarantee customer fuel savings, they cannot adequately mitigate fuel price volatility, and they cannot protect against market swings to the benefit of the customers. TR 684-685

FPL's proposal is qualitatively and quantitatively different from the physical and financial fuel hedging program and hedging guidelines approved by the Commission starting with its approval of a hedging settlement between the four large IOUs and Intervenor parties in 2002, and its later clarification and approval of hedging guidelines in 2008. See Order Nos. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI ("2002 Hedging Order"); Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("Hedging Guidelines Order").

In 2002, the Commission approved a settlement between the four generating IOUs, OPC, and the Florida Industrial Power Users Group ("FIPUG") related to IOU fuel procurement and hedging practices. See Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI ("2002 Hedging Order"). However, the 2002 Hedging Order failed to address the issue of "regulatory risk" and how to mitigate that to the IOUs' satisfaction. Regulatory risk is the perceived risk that the regulator may determine some or all of the costs were unreasonable or imprudently incurred and, thus, could disallow some or all of those costs.

Following the 2007 Fuel Clause proceeding, the Commission undertook two comprehensive audits of the IOUs' fuel hedging programs and practices. Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI ("Hedging Guidelines Order"). During the 2008 Fuel Clause cycle, FPL requested approval of fuel hedging guidelines. Hedging Guidelines Order at 3. These guidelines were a "response to the asymmetric reactions of certain stakeholders to gains and losses" associated with FPL's hedging activities, and were FPL's attempt to address perceived regulatory risk. Id. at 3

Black's Law, 7th Edition, defines "hedge" as "to make advance arrangements to safeguard oneself from loss on an investment, speculation, or bet, as when a buyer of commodities insures against unfavorable price changes by buying in advance at a fixed rate for later delivery." OPC witness Lawton defined a physical hedge as "a bilateral contract for gas at a fixed price" but without the protections of a fixed price hedge. TR 685. FPL's fuel hedging guidelines, approved and adopted by the Commission, define "hedging activities" in pertinent part: ". . . natural gas and fuel oil fixed price financial or physical transactions; instruments include fixed price swaps, options, etc. . . ." Id. at 15 (emphasis added). The approved hedging guidelines set forth seven "guiding principles that the Commission recognizes as appropriate and will follow in reviewing [hedging/risk management] Plans and an IOU's hedging actions. . . and the terms of an approved Plan will control for the purposes of reviewing hedging actions. . . ." Id. at 16-17 (emphasis added). FPL's fuel hedging guidelines limited the scope of the Commission's ability to review the prudence of hedging practices and risk management plans to these guiding principles. Id.

The guiding principles included the following statements about hedging: ". . . the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers. . ."; ". . . a well-managed hedging program does not involve speculating. . ."; hedging's ". . . primary purpose is not to reduce an IOU's fuel costs paid over time, but rather to reduce the variability or volatility in fuel costs paid by customers over time. . . ."; ". . . The Commission does not expect an IOU to predict or speculate on whether markets [prices] will ultimately rise or fall. . . ."; ". . . market prices and forecasts of market prices have experienced significant volatility and are expected to be highly volatile and . . . an IOU will [not] try to 'outguess the market' in choosing the specific timing for effecting hedges or the percentage or volume of fuel hedged." Id. at 16 (emphasis added). This partial list of "guiding principles" is illustrative that market prices can be highly volatile, that IOUs were not expected to speculate when hedging, and that they were not expected to accurately predict or forecast the future market prices of fuel. Under the hedging guidelines, IOUs would not try to "outguess the market."

However, FPL's gas reserves investment proposal runs counter to these and the other guiding principles which the Commission and the IOUs are supposed to follow. One of the key guiding principles was to remove prediction and speculation from the IOUs' hedging/risk management plans. In the Woodford Project, FPL is attempting to forecast the market price of gas for the next 50 years, and is attempting to "outguess the market" by speculating that FPL can obtain substantial volumes of natural gas at the wellhead at or below market prices. But, these are activities that the Commission's fuel hedging guidelines expressly prohibit.

Moreover, FPL's Woodford Project is not like a physical hedge because it violates the definition of "hedging activities," which FPL crafted. "Hedging activities" are ". . . fixed price financial or physical transactions; instruments include fixed price swaps, options, etc. . . ." (emphasis added). There is nothing fixed about FPL's Woodford Project. FPL projects possible customer fuel savings; projects the cost of production will be lower than FPL's forecasted market price for natural gas for the next 50 years; and projects/estimates the volumes of gas it projects to obtain from the Woodford Project. Therefore, by FPL's own definition of "hedging activities," FPL's Woodford Project simply cannot be a physical hedge.

With financial hedging, (1) there is a limited number of credit-worthy "hedge" partners; (2) costs and quantities of gas are fixed; (3) remedies are defined if there is a default by a counterparty; and (4) there is no possibility of paying twice for gas. Unlike financial hedging, gas reserves investment activities have multiple variables outside of FPL's control. A few of these variables include, but are not limited to, multitudes of potential gas reserves partners with varying degrees of credit-worthiness; the number of different shale plays with differing physical characteristics; the risk of increasing production costs; the risk of a decreasing market price for gas; the risk of dry wells; etc.

Each variable outside of FPL's control leads to a nearly unlimited number of factors that cannot be fixed or hedged by FPL. As a result, there is a distinct possibility that customers could either (1) pay more than the market price for gas over the life of the project or (2) pay twice for natural gas if gas reserve investments do not produce the volume of gas required.

According to the 2002 and 2008 fuel hedging orders, reducing the volatility of the market price of fuel is the main reason to enter into financial or physical fixed price hedging contracts. FPL cannot guarantee that its gas reserves investments will reduce fuel price volatility in a manner which will meaningfully benefit its customers. FPL's customers bear the risk that the production cost of Woodford Project gas could exceed the market price for gas in each year of the expected 50-year life of the project, thus resulting in higher than market prices being paid by customers. However, overpaying for natural gas for the next 50 years is not a hedge against fuel price volatility or a customer benefit. In addition, over this same 50-year period, FPL's shareholders will receive a guaranteed, trued-up return of 10.5% on this investment regardless of which way the market moves on the price of natural gas.

Fuel Price Volatility Mitigated by the Annual Fuel Clause

While FPL states reducing fuel price volatility is one of the projected outcomes from its proposed gas reserves investments (TR 1010), it is undisputed that the Commission has already meaningfully reduced the market price volatility experienced by utility customers through judicious reforms to the Fuel Clause by shifting from monthly to semi-annual and then to annual hearings to reset the fuel factor. When the Commission shifted to annual fuel adjustment hearings, the Commission found in part that "an annual factor <u>will</u> provide customers with more certain and stable prices. . . industrial and commercial customers prefer more stable electricity prices. . . and residential customers would prefer the simplicity of one fuel factor for an entire year." Order No. PSC-98-0691-FOF-PU, issued May 19, 1998, in Docket No. 980269-PU. (emphasis added). Therefore, unlike FPL's gas reserves investment proposal, the Commission's shift to an annual hearing to reset the fuel factor has effectively mitigated the fuel price volatility experienced by utility customers, and has provided cost-certainty to customers at no additional costs or risks to customers.[25]

Finally, by asking for presumptive recovery of all its Woodford Project costs, FPL is attempting to fully mitigate its "regulatory risk" (in this case, the possible disallowance of imprudently incurred gas reserves investment costs) at the expense of its customers by seeking front-loaded presumptive prudence review of all its projected Woodford Project costs, and limiting the Commission's back-end prudence review to whether or not FPL's request for the recovery of Woodford Project costs simply matches the invoices paid by FPL to its gas exploration, drilling, and production partners. By limiting the Commission's regulatory prudence review, FPL is effectively

[25] For FPL, the residential customer fuel factor for the first 1,000 kWh peaked at 6.413 cents/kWh in the periods January-May 2009 and January-May 2010, and has steadily declined from that peak in 2010 down to 2.947 cents/kWh; thereby, demonstrating that volatility in the cost of fuel <u>as experienced by customers</u> has decreased while the fuel factor has trended downwards, benefiting FPL's customers.

mitigating its regulatory risk, and providing fixed 10.5% returns (guaranteed profits) to FPL's shareholders on all its costs associated with gas reserves investments.

ISSUE 2: If the Commission answers Issue 1 in the negative, what standard should the Commission apply to a request by FPL to recover the price that FPL pays to its subsidiary/affiliate for gas obtained through the joint venture with PetroQuest?

If the Commission denies FPL's Petition and answers Issue 1 in the negative, consistent with the Commission's prior findings related to the acquisition from affiliated entities of fossil fuels for which a competitive market exists, the Commission should make it abundantly clear in this case that if FPL purchases gas from the proposed joint venture between PetroQuest and FPL's yet-unnamed subsidiary (or even if it directly enters into the joint venture with PetroQuest), and from other potential future joint ventures, the amount to be recovered from customers through the fuel cost recovery clause will be limited to, and will not exceed, the market price of gas. The market price of natural gas is readily available to the Commission and its staff. Thus, if the Commission denies FPL's request for approval of the Woodford Project with PetroQuest, and an FPL subsidiary/affiliate sells any gas from the Woodford Project to FPL, the utility should recover the lesser of fully allocated costs or market price. (Ramas, Lawton)

ARGUMENT: Same as Position.

ISSUE 3: What amount, if any, associated with the transactions proposed in FPL's June 25 Petition should be included for recovery through FPL's 2015 fuel cost recovery factor?

No amount should be included for recovery through FPL's 2015 fuel cost recovery factor. Nevertheless, if FPL's subsidiary goes forward with the transaction, then any natural gas obtained by FPL from such subsidiary should be recovered through FPL's 2015 fuel cost recovery factor based on the market price of gas, consistent with how fossil fuel costs obtained from affiliated entities are recovered. However, if the Commission finds that the transaction falls within its regulatory jurisdiction, despite OPC's strong contention that it does not have such authority, then the amount recovered through the 2015 fuel cost recovery factor should be based on the lower of cost or market for the gas obtained from the subsidiary. (Ramas, Lawton)

ARGUMENT:

No costs associated with gas reserves projects should be approved for recovery under FPL's proposal. While OPC appreciates staff's attempt to split the risks and rewards of investing in natural gas reserves, OPC opposes the staff's hypothetical proposal of 50-50 sharing on jurisdictional grounds, believing the Commission lacks any jurisdiction to allow any costs associated with these investments to be recovered risk-free through the Fuel Clause. Similarly, OPC does not support OPC witness Ramas' rational, alternative proposal on jurisdictional grounds.[26]

[26] At the request of some Commissioners, OPC witness Ramas articulated a rational alternative suggestion to the utility's proposal. TR 625-638. OPC witness Ramas stated that the Commission could set the market price of natural gas as a cap for Fuel Clause cost recovery. Her alternative proposal equalizes and appropriately apportions the risks between shareholders and customers. If FPL's forecasts for well and production costs are below the market

<u>ISSUE 6</u>: Is FPL contractually precluded by paragraph 6 of the Stipulation and Settlement Agreement dated December 12, 2012 and approved by the Commission in Order No. PSC-13-0023-S-EI from seeking to increase rates as it proposes?

Order No. PSC-13-0023-S-EI speaks for itself. FPL witnesses testified that its proposed gas reserves investments could be in rate base, thus recoverable through base rates. However, by the express terms of the 2012 Settlement, FPL is barred from recovering any "base rate" costs through the fuel clause until after the expiration of the base rate freeze.

ARGUMENT:

Assuming, *arguendo*, that the Commission finds it has subject matter jurisdiction over the ownership of the rights to drill for natural gas in Oklahoma and elsewhere, and that the investments in such rights to drill meet the provisions of Order No. 14546, FPL's request for recovery through the Fuel Clause must be denied because such recovery is expressly prohibited by Commission Order No. PSC-13-0023-S-EI.

FPL's Request Barred by Paragraph 6 of the 2012 FPL Stipulation and Settlement

The first two sentences of Paragraph 6 of the Stipulation and Settlement attached to Order No. PSC-13-0023-S-EI state:

> Nothing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover though cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically and ordinarily would be recovered through base rates. . . .

Order No. PSC-13-0023-S-EI at 14. FPL's Petition for recovery of gas reserves investments costs must satisfy the first two sentences in Paragraph 6. Part (a) of Paragraph 6 creates a narrow exception to the base rate freeze and removes what would otherwise be a prohibition on FPL merely "requesting" recovery of the investment in the Woodford Joint Venture if the costs "are of a type

price of gas, FPL's shareholders benefit up to the market price of gas. If FPL's forecasted well and production costs exceed the market price of gas, then FPL's shareholders bear that downside risk and cannot recover costs in excess of the market price of gas. The customers are held harmless, but only if FPL is able to secure the volumes of gas it projects to receive from the gas reserves. However, Ms. Ramas' articulated proposal neither addresses the risk to customers if FPL drills a "dry hole" or is not able to secure the volumes of projected gas, nor who is responsible for the cost of "replacement gas." In addition to the jurisdictional reasons, this is why OPC does not support this alternative proposal. This articulated suggestion, while much better than FPL's unilateral, asymmetrical risk proposal, is not shared by OPC.

which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges." In order to satisfy the first prong of Order No. 14546, FPL claims that gas reserves investments are "Fossil fuel-related costs normally recovered through base rates...." Further, FPL takes the position in the Prehearing Order No. PSC-14-0667-PHO-EI that

> It is FPL's position that Issue 6 is subsumed by Issue 1. Moreover, the premise of this issue is that the PetroQuest joint venture would increase rates, whereas FPL's testimony demonstrates that there is a high probability that it would reduce rates because of the fuel savings that it would make possible. The first sentence of paragraph 6 in the Stipulation and Settlement Agreement provides expressly that "[n]othing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges. . . ." FPL's request to recover costs associated with the PetroQuest joint venture through the Fuel Clause is fully consistent with the Commission's traditional and historical practices under Order No. 14546 (fuel-saving measures) and Order Nos. PSC-02-1484-FOF-EI and PSC-08-0667-PAA-EI (hedging), because it is projected to provide net savings for customers and would serve as a valuable longer term physical hedge.

What is notable about FPL's position is that cited Order No. 14546 as authority to request recovery through the Fuel Clause. If, *arguendo*, the investment in gas reserves is eligible for Fuel Clause recovery through Order No. 14546, then it must by definition satisfy the first "normally recovered through base rates" prong of Order No. 14546.

Further, FPL's position statement quoted only part (a) of the first sentence, but it failed to include the second sentence: "It is the <u>intent of the Parties</u> in this Paragraph 6 <u>that FPL not be allowed to recover though cost recovery clauses</u> increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and <u>traditionally, historically and ordinarily</u> would be recovered through base rates." (emphasis added). The second sentence is controlling over the first, and restricts what, if any, costs can be recovered.

In order to satisfy the "base rates" requirement prong of Order No. 14546, witness Deason provided testimony, alleging that the gas reserves investment costs are normally, typically, and historically base rate recoverable or recovered. EX 58 at 23-28.[27] If, *arguendo*, this is true, then it

[27] FPL's Comptroller Ousdahl testified in her deposition when asked about her prefiled direct testimony at TR 373 about removing the proposed investment from rate base and transferring it to clause recovery:

> Q: So are you presuming that GRCO would be a regulated above-the-line operations [sic] for purposes of including it where you do; you're just transferring it from base rates to clause?
>
> A: That's correct.

EX 56 at 53.

would seemingly satisfy part (a) of the first sentence of Paragraph 6 and, if such is the case, then the proposed investment is *de facto* ineligible under the second sentence of Paragraph 6.

FPL has chosen to put all its eggs in the basket created by Order No. 14546 and, therefore, obligates itself to meet the burden of demonstrating compliance with all three prongs of Item 10. In so doing, however, FPL's Petition automatically fails on the basis that the second sentence – "the intent of the Parties" – outlaws increases in any clause if the investment would be "traditionally, historically and ordinarily" recovered in base rates. While the first sentence may permit FPL to ***request*** recovery of costs that would ordinarily be clause recoverable, but pursuant to the "intent of the Parties" in the second sentence, such costs ***cannot*** be recovered in the Fuel Clause. It is self-evident then, that if the Woodford investment passes the Item 10 test in Order No. 14546, then it simultaneously fails the second "intent of the Parties" sentence of Paragraph 6. FPL created its own Catch-22 situation by entering into the 2012 Settlement. It was a management decision at the time and now the Company must live with the deal it struck and which it induced the Commission to approve. FPL cannot have its cake and eat it, too.

Part (b) of the first sentence relates to "incremental costs not currently recovered in base rates" that could become clause recoverable subsequent to the settlement. However, there is nothing "incremental" about FPL's proposed recovery of its proposed gas reserves costs. To the extent the Commission would be inclined to consider the gas reserves investment under part (b) of Paragraph 6, OPC contends that FPL cannot demonstrate that the costs are "incremental costs" and not already included in current base rates as a result of the 2012 Settlement (see discussion *supra*).

With respect to the notion that the gas reserves investment are "hedges" and being a hedge provides an independent basis for Fuel Clause eligibility separate and apart from Order No. 14546, OPC maintains its position reflected in testimony and elsewhere in this Brief that the Woodford Project's projected costs are not a hedge. Assuming, *arguendo,* that the gas reserves investment does constitute a hedge, it is nevertheless not lawfully recoverable pursuant to the second sentence of Paragraph 6 inasmuch as (and only to the extent that they would be jurisdictional costs) they would be recorded in rate base and presumptively recovered in base rates[28] absent FPL seeking to recover them pursuant to Order No. 14546.

ISSUE 8: What effect, if any, does Commission's decision on Issue 3 have on the fuel cost recovery factor and GPIF targets/ranges for the period January 2015 through December 2015??

No position.

[28] See EX 56 at 53.

CONCLUSION

For the reasons stated herein, the Commission should deny FPL's Petition for approval of recovering costs associated with the Woodford Project and instruct FPL that it will not entertain any further consideration of FPL's desire to enter into the competitive natural gas exploration, drilling, fracking, and production industry.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing **CITIZENS' POST-HEARING STATEMENT OF POSITIONS AND POST-HEARING BRIEF** has been furnished by electronic mail and/or U.S. Mail on this 12th. day of December, 2014, to the following:

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power
cost recovery clause and generating
performance incentive factor.
_______________________________/

Docket No. 140001-EI
Filed: December 12, 2014

THE FLORIDA INDUSTRIAL POWER USERS GROUP'S
POST-HEARING STATEMENT OF ISSUES
AND POSITIONS AND POST-HEARING BRIEF

The Florida Industrial Power Users Group (FIPUG), by and through its undersigned counsel, files this Post-Hearing Statement of Issues and Positions and Post-Hearing Brief as it relates to Issues 1, 2, 3, 6 and 8 affecting Florida Power and Light Company (FPL) in the above-referenced matter. This bifurcated briefing is done consistent with the Chairman's briefing schedule order announced at the conclusion of the evidentiary hearing. (Tr. 1094-1095).

BASIC POSITION AND SUMMARY

FIPUG opposes FPL's efforts to have ratepayers fund oil and gas exploration and production ventures in Oklahoma. FPL's proposal places the risk of future natural gas market prices squarely on the backs of ratepayers. Ironically, FPL has avoided this very same risk for years, as fuel costs are passed through annually to ratepayers in this proceeding. FPL's ratepayers do not want to accept this natural gas fuel cost risk, and it should not be forced upon them. No thank you! FPL's request to increase its rate base adding hundreds of millions of dollars in natural gas production costs, and to earn a return on those monies, will help FPL annually bolster its rate base. FPL's Petition unquestionably benefits FPL's shareholders; potential benefits to FPL's ratepayers are uncertain and speculative.

The question FPL presents, namely, whether FPL should be able to enter into the natural gas exploration and production business and the Woodford Project using ratepayer monies, has significant public policy ramifications. When confronted with significant public policy questions such like this one, the Commission should defer to the Legislature for guidance. Put simply, as a branch of the Legislature, the PSC should leave the question of whether a regulated Florida utility is empowered to venture into the risky oil and gas exploration and production business to the Legislature. As the Office of Public Counsel pointed out in its Motion to Dismiss for Lack of Subject Matter Jurisdiction, a motion joined by FIPUG, there is no indication that the Florida Legislature contemplated ratepayer dollars being used to fund natural gas exploration and production in Oklahoma. The Commission should not venture into the Legislature's public policy arena unless and until the Legislature expressly authorizes Florida utilities to engage in the exploration and production of natural gas outside of Florida.

Finally, FIPUG entered into a Stipulation and Settlement Agreement ("Agreement") with FPL which called for a base rate freeze through December of 2016. The Agreement stated in pertinent part that: "It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically and ordinarily would be recovered in base rates." The type of costs FPL seeks to recover, capital and operational expense associated with natural gas operations and production, are the type of costs which are more appropriately characterized as base rate costs, if recoverable, and thus precluded by the terms of the parties' Agreement.

For the reasons set forth above, the Commission should deny FPL's Petition.

Florida Power & Light Company (FPL)

ISSUE 1: Should the Commission approve FPL's request to recover the amounts it would pay to its subsidiary for gas obtained from the PetroQuest, Inc. joint venture through the fuel cost recovery clause on the basis and in the manner proposed by FPL in the June 25 Petition?

(In conjunction with this compromise on the wording, FPL and OPC to stipulate to allowances of 200 words for their respective position statements on Issue 1 in the post-hearing briefs)

FIPUG: No. The costs FPL seeks to recover should not be recoverable through the fuel clause as a matter of law or Commission policy. Key undisputed facts as detailed in the Argument section of this brief – including, but not limited to a financially suspect and below investment grade operator, PetroQuest, Inc., mountains of hearsay testimony about PetroQuest, but no witness from PetroQuest bothering to show up to address the Commission, no signed operating agreement with PetroQuest presented to the Commission for its consideration -- lead to the inescapable conclusion that FPL's Petition should be denied.

ISSUE 2: If the Commission answers Issue 1 in the negative, what standard should the Commission apply to a request by FPL to recover the price that FPL pays to its subsidiary/affiliate for gas obtained through the joint venture with PetroQuest?

FIPUG: The Commission should apply its policy regarding affiliate transactions to ensure that ratepayers are not charged more than market prices for gas obtained through the proposed joint venture with PetroQuest.

ISSUE 3: What amount, if any, associated with the transactions proposed in FPL's June 25 Petition should be included for recovery through FPL's 2015 fuel cost recovery factor?

FIPUG: No amount should be recovered for the FPL-PetroQuest Oklahoma oil and gas exploration and production project. FPL acknowledges that its affiliated corporate interests find the PetroQuest deal quite attractive and acceptable. Conversely, consumer interests (Office of Public Counsel, FIPUG, Florida Retail Federation and PCS Phosphate) do not find the PetroQuest oil and gas deal attractive and acceptable. Thus, rather than forcing a deal upon ratepayers that ratepayers find unwanted and speculative, the Commission should permit FPL's non-regulated corporate interests to profit, possibly, from the announced PetroQuest deal.

ISSUE 6: Is FPL contractually precluded by paragraph 6 of the Stipulation and Settlement Agreement dated December 12, 2012 and approved by the Commission in Order No. PSC-13-0023-S-EI from seeking to increase rates as it proposes?

FIPUG: Yes. The parties to the December 12, 2013 Stipulation and Settlement Agreement negotiated a resolution to a litigated rate case that provided rate stability and predictability for the duration of the Settlement. Language was included in the Agreement to prevent "end runs" around the Agreement, and the associated rate stability and predictability. FPL's petition seeks to recover rates through the fuel clause for natural gas operation and production costs. These type costs, if they were to be recovered, are more analogous to base rate type expenditures that would be "ordinarily" recovered in base rates. Accordingly, the following provision contained within the Agreement prevents the recovery of these costs through the fuel clause, at least until the term of the Settlement Agreement expires: "It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically and ordinarily would be recovered in base rates."

ISSUE 8: What effect, if any, does Commission's decision on Issue 3 have on the fuel cost recovery factor and GPIF targets/ranges for the period January 2015 through December 2015?

FIPUG: As the Commission should not permit recovery of oil and gas exploration and production costs to be recovered through the fuel clause, the Commission's decision to disallow such recovery should have no effect on the fuel cost recovery factor.

Discussion of Issue 1

FIPUG respectfully requests that the Commission deny FPL's Petition based a host of proven, and in many cases, uncontroverted facts adduced during the two day evidentiary hearing held on December 1 and December 2, 2014. The key facts that FIPUG argues compels denial of FPL's Petition are succinctly stated as follows:

1. **PetroQuest, Inc. is rated below investment grade and a speculative credit risk according to Standard and Poor's and Moody's credit rating agencies.**

PetroQuest, Inc., the entity that FPL, the Commission and ratepayers will be dependent upon to drill wells, find natural gas and operate natural gas wells, is rated below investment grade and is financially suspect. Tr. 1045. Specifically, PetroQuest is rated as B3/Stable by

Moody's and B/Stable by Standard and Poor's credit rating agencies. Tr. At 1051. According to Moody's, a B rating means PetroQuest's "obligations are considered **speculative** and subject to high credit risk." (emphasis added). Ex. 68. Standard and Poor's describes the financial obligations (short term bonds) of PetroQuest as "vulnerable and has significant **speculative** characteristics ..... faces major ongoing uncertainties which could lead to [PetroQuest's] inadequate capacity to meet its financial commitments." (emphasis added). Ex. 69. The Commission should pay heed to this clear warning issued by the rating agencies.

2. **No executed operating agreement between PetroQuest, Inc. and FPL's corporate benefactor, USG Properties Woodford I, LLC, was presented to the Commission.**

FPL did not present the Commission with an executed Operating Agreement between PetroQuest, Inc. and USG Properties Woodford I, LLC ("USG"), FPL's corporate benefactor who is holding this deal open for FPL. The binding, executed operating agreement, a key document which details the respective rights and responsibilities of the parties, was never made available to the Commission. Tr. 231, 235. The Commission should not approve a proposal that will cost more than $100 million dollars without having the executed operating agreement before it for review and consideration.

3. **The proposed Woodford project may save ratepayers money, but maybe not, particularly when one considers the historical production costs of extracting natural gas in the area compared to natural gas market prices;**

The Woodford Project could save customers money. Maybe. Possibly. Depends on natural gas markets, which nobody can accurately predict.

However, the Woodford Project may very well not save the ratepayers money. FPL witnesses hedged repeatedly when asked whether the Woodford project would save ratepayers money. It could, but it might not. Nothing is guaranteed. Nobody knows where and which direction natural gas markets will head in the coming years. The Woodford Project is a bet. Put simply, this Commission should not use ratepayers' dollars to speculatively wager on the future market price of natural gas.

Tellingly, the average cost of production in the Woodford area has been greater than average natural gas market price for the past four years. Stated differently, using average production costs in the Woodford area compared to natural gas market prices (data provided to FPL by Wood Mackenzie, a reputable company, ratepayers), FPL ratepayers would have lost money every year for the past 4 years. The following chart, in evidence as FPL's response to staff's interrogatory number 75, shows this clearly:

	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

4. **The Commission has no jurisdiction to oversee natural gas drilling and production activities or companies in Oklahoma, Texas and other states.**

Put simply, the ratepayers will be funding operations of companies in other states over whom the Commission has no ability to regulate. Tr. 229. The Commission has no jurisdiction over PetroQuest, Inc. The Commission has no jurisdiction over USG. The Commission has no jurisdiction over natural gas production operations in Oklahoma, or any other state. If and when something goes awry, which will undoubtedly happen, the Commission will not have the ability to investigate the facts and circumstances by asking those directly involved questions or for information.

5. **The risks associated with natural gas extraction, operations and production (explosions, blow outs, causation of seismic activity, etc.) are exceedingly high, and ratepayers will ultimately bear responsibility for those risks.**

As was pointed out many times during the evidentiary hearing, FPL's proposed venture into the natural gas business in Oklahoma is an unprecedented, unfamiliar and uncertain venture into uncharted territory for the Commission and FPL ratepayers. To better understand the risks involved, a review of the 2013 PetroQuest annual report is helpful. The annual report, an exhibit to the deposition FPL witness Taylor and in evidence, has 11 pages of detailed risks facing the company. Below are the highlighted risk summaries.[1]

- 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 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.
- 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.
- Declining general economic, business or industry conditions may have a material adverse effect on 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.
- 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.

[1] Each risk warning has additional detail describing the risk; the operating hazard risk provides partial detailed information describing the risks associated with operating natural gas wells.

- Our future success depends upon our ability to find, develop, produce and acquire additional oil and natural gas reserves that are economically recoverable.
- 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.
- Losses and liabilities from uninsured or underinsured drilling and operating activities could have a material adverse effect on our financial conditions and operations.
- Lower oil and natural gas prices may cause us to record ceiling test write-downs, which could negatively impact our results of operations.
- Factors beyond our control affect our ability to market oil and natural gas.
- 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.
- 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 the future.
- 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.

- 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.
- Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operation and cash flows.
- We face strong competition from larger oil and natural gas companies that may negatively affect our ability to carry on operations.
- SEC rules could limit our ability to book additional proved undeveloped reserves in the future.
- 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.
- We may be unable to successfully identify, execute or effectively integrate future acquisitions, which may negatively affect our results of operations.
- Hedging production may limit potential gains from increases in commodity prices or result in losses.
- The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or personnel may restrict our operations.
- The loss of key management or technical personnel could adversely affect our ability to operate.
- 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.
- Environmental compliance costs and environmental liabilities could have a material adverse effect on our financial condition and operations.
- 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.
- 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.

Additionally, seismic activity in Oklahoma has increased, and many suggest that increased seismic activity is linked to the advanced techniques being used to extract natural gas. This is just another risk to be added to the list above.

This risks are significant are material. The risks are disclosed to the public in accordance with Securities and Exchange reporting requirements. The risks should not be minimized or pushed aside, particularly when one considers that FPL has not written due diligence report on PetroQuest, Inc. or the Woodford Project.

6. **No written due diligence report was prepared evaluating the risks and benefits of the Woodford Project.**

It is common practice when evaluating business opportunities to perform due diligence resulting in a due diligence report which focuses on the opportunity and partners/key players who will be involved in the business venture. This due diligence process and resulting report assists the utility and others analyze the proposed deal and the associated risks. Surprisingly, FPL did not have or use a due diligence report when evaluating the Woodford Project or PetroQuest, Inc. (Tr. 200-201).

7. **FPL suggests that the Woodford reserves are nearly a certainty based on the review of data by third parties. Reserve engineering is a subjective process of estimating underground accumulations of natural gas that are difficult to measure.**

FPL suggests that, based on analysis of data, including production information from other natural gas wells, it is anticipated that the drilled Woodford wells will be productive. FPL failed to tell the Commission that reserve engineering, a process used in estimating future production of an area, is a **subjective** undertaking. See 2013 PetroQuest Annual Report.

8. **FPL assumes virtually no risk with the Woodford project; ratepayers assume inordinate amounts of risk.**

FPL assumes virtually no risk with the Woodford project, including market risk. Tr. 215. FPL finances, with ratepayer money, natural gas operations in Oklahoma. FPL assembles the invoices for the natural gas operations, submits them to the Commission as part of a fuel clause filing, and represents that the expenses incurred by third parties were prudent. FPL then earns a 10.5% return (its return on equity midpoint) on its qualifying capital expenditures: no risk, handsome return. Ratepayers bear risk associated with the natural gas venture while FPL has effectively insulated itself and its shareholders from significant risk.

9. **The Commission should clarify FPL's duties and obligations if the Petition is granted, including clarifying that FPL owes a fiduciary duty to its ratepayers.**

It is clear that the proposed Woodford project will benefit FPL shareholders. It is uncertain whether FPL's ratepayers will indeed benefit. To ensure that FPL makes decisions that are in the ratepayer's best interest, which FPL says is its intention, the Commission should recognize the special, fiduciary relationship that a utility has with its captive ratepayers in a monopoly relationship. Giving express recognition to the fiduciary relationship, which is supported by the facts of the case, and a concession by FPL witness Ousdahl that a fiduciary relationship exists between FPL and its customers, the Commission should recognize the fiduciary relationship and fiduciary duty that FPL owes its ratepayers. Tr. 837.

10. Where is PetroQuest, Inc.?

No witness from PetroQuest, Inc. appeared before the Commission. In the Woodford Project, PetroQuest, Inc., is the key player; it is the operator of the natural gas venture; it proposes where to sink wells; it must managed loads of financial and operational risk. Before saddling FPL's ratepayers to a company upon whom they will be dependent to extract natural gas, it seems that the Commission and consumer interests would have been well-served to have someone from PetroQuest, Inc. appear before the Commission during the hearing. This did not happened.

FIPUG incorporates and adopts the legal and factual arguments set forth by the Office of Public Counsel regarding whether the Woodford project costs may be recovered through the fuel clause. Such costs should not be recovered through the fuel clause for the reasons set forth by the Office of Public Counsel.

Discussion on Issue 6

The parties to the December 12, 2013 Stipulation and Settlement Agreement (including FPL and FIPUG) negotiated a resolution to a litigated rate case that provided rate stability and predictability for the duration of the Settlement. Language was included in the Agreement to prevent "end runs" around the Agreement, and the associated rate stability and predictability.

FPL's petition seeks to recover rates through the fuel clause, up to $190 million dollars, for natural gas exploration and production costs in Oklahoma related to the Woodford project. These type costs, if they were to be recovered, are more analogous to base rate type expenditures that would be "ordinarily" recovered in base rates. Accordingly, the following provision contained within the Agreement prevents the recovery of these costs through the fuel clause, at least until the term of the Settlement Agreement expires:

> It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically and ordinarily would be recovered in base rates.

Large capital expenditures for items such as power plants and transmission assets have historically and ordinarily been recovered in base rates. The fuel clause has been historically used to flow through the direct costs of fuel, and closely related attendant costs. The fuel clause has not been used to allow for the recovery of costs that would ordinarily be recovered in base rates. Large capital expenditures expended on things like drilling wells and related equipment would be the type of expenditures that would ordinarily be recovered in base rates.

As FPL witness Taylor testified, the anticipated production costs of the Woodford project are predictable and not expected to vary. Accordingly, since these costs lack the variability that the fuel clause is supposed to protect against, these predictable, stable production costs would ordinarily be recovered in base rates. As such, the settlement agreement contractual language precludes the recovery of such costs through the fuel clause, at least until the term of the current settlement agreement expires.

CONCLUSION "NO THANK YOU"

Based on the reasons set forth above, the Commission should deny FPL's Petition to put FPL ratepayers squarely in the natural gas business in Oklahoma. The consumer interests politely yet forcefully have said, "No thank you" to FPL's self-serving proposal. The Commission should deny FPL's Petition.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	Docket No: 140001-EI Filed: December 12, 2014

FLORIDA POWER & LIGHT COMPANY'S POST-HEARING BRIEF (ISSUES 1, 2, 3, 6 AND 8)

Florida Power & Light Company ("FPL" or the "Company"), pursuant to Order No. PSC-14-0667-PHO-EI (the "Prehearing Order") and direction given at the December 1-2, 2014 hearing on this matter, hereby files with the Florida Public Service Commission ("FPSC" or "Commission") its post-hearing statement of issues, positions, and brief ("Post-Hearing Brief") on Issues 1, 2, 3, 6 and 8 in the Prehearing Order, and states:

I. OVERVIEW AND SUMMARY OF ARGUMENT

"Innovation is the ability to see change as an opportunity, not a threat."

In recent years, FPL has made significant investments in clean, fuel-efficient natural gas generation and transportation. FPL currently supplies 62% of the electricity consumed in Florida, with approximately 65% of this coming from natural gas fired generation. FPL's investments in natural gas have saved customers more than $7 billion in fuel costs since 2001, and these investments will continue to provide customer savings for decades.[1] With such a large demand for natural gas, establishing a predictable, reliable, and low cost fuel supply is imperative for FPL and its customers. FPL now looks to continue its efforts to ensure a reliable and stable source of delivery of clean electricity for its customers, by making targeted investments in natural gas production.

[1] When FPL filed its Petition and testimony in this matter, FPL's investments had saved customers more than $6.5 billion in fuel costs since 2001. That number is expected to grow to about $7.5 billion by the end of 2014.

As a means to achieve this goal, FPL is seeking a Commission determination that the Woodford Gas Reserves Project (the "Woodford Project"), a joint venture with PetroQuest Energy, Inc. ("PetroQuest") to invest in gas production in the Woodford Shale region, is prudent and that the revenue requirements associated with this investment may be recovered through the Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause"). In effect, FPL is asking to replace one type of cost (commodity purchase costs) with another (production costs), with respect to a portion of the gas it burns in its power plants. The Woodford Project will provide significant benefits to customers in two important ways.

First, it will provide a hedge against volatile natural gas prices. As the single largest electric utility purchaser of natural gas in the United States, FPL currently uses short-term financial hedges to mitigate price volatility for customers in what is an inherently volatile market.[2] While that program has been successful, the price stability it provides is temporally limited. The gas reserves proposal at issue in this proceeding would replace a portion of this existing short-term *financial* hedging program with a longer-term *physical* hedge that will provide price stability over a much longer time horizon.

Second, the Woodford Project is projected to deliver very substantial fuel savings for customers. Under the same gas price forecast that FPL used for its recent DSM goals and Ten Year Site Plan filings, the project is estimated to deliver $107 million of fuel savings on a net present value ("NPV") basis. And, these savings are estimated to start in year one and continue for each and every year of the project.

[2] Natural gas prices have demonstrated varying degrees of volatility over the years, and in fact prices have experienced a price variation of 92% in 2014 to date. Tr. 213 (Forrest). Even the EIA, whose escalation rates Mr. Lawton endorses, forecasts substantial upward volatility in gas prices over the next few years: an increase of $1.34 (34%) from 2015 through 2018. *See* Ex. 11, Column J. This volatility in the recent past and near future utterly discredits Mr. Lawton's assertion that he sees little – certainly no more than 10% -- volatility in gas markets today. *See* Tr. 748, 790 (Lawton).

The Office of Public Counsel ("OPC") and Florida Industrial Power Users Group ("FIPUG") filed testimony opposing FPL's requests. FPL is disappointed[3] that the intervenors are opposing a project that FPL projects will provide real value for customers. Their opposition is strident, but not well-founded. They erroneously argue that the Woodford Project shifts risks from investors to customers, that the risks to customers are significant with little benefit to customers, and that the project provides a windfall for FPL's shareholders. Each of these arguments lacks merit and has been thoroughly rebutted.

II. BENEFITS OF FPL'S PROPOSAL

A. <u>The Commission Should Not be Distracted By the Intervenors' Mischaracterization of FPL's Proposal</u>

In this proceeding, FPL is requesting a determination that it is prudent for FPL to acquire an interest in a natural gas reserves project that will provide price stability and projected fuel savings for customers. FPL also requests that the revenue requirements associated with investing in and operating the gas reserves are eligible for recovery through the Fuel and Clause. As is shown by the facts presented by FPL in this case, FPL's investment in the Woodford Reserve *is* prudent. The Woodford Project offers customers two very substantial benefits:

- The proposed investment will provide long-term price stability for a portion of FPL's natural gas needs. By disassociating a portion of FPL's natural gas purchases from volatile market prices, and instead obtaining a portion of its natural gas requirements at a stable, lower cost of production, this investment will allow the Company to replace a

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[3] While disappointed, FPL is not surprised by these intervenors' reflexive opposition, even to a proposal that is expected to reduce and stabilize fuel costs for their clients and members. For example, OPC witness Ramas acknowledged that in formulating her position she had not even thought to inquire as to FPL's track record on a range of projects that have dramatically reduced the cost and environmental impact of electric generation. Tr. 601-02.

portion of its short-term financial hedging program for fuel purchases with, in effect, a longer-term physical hedge. Tr. 115 (Forrest).

- The revenue requirements associated with the project, on an NPV basis, are projected to be approximately $107 million lower than the cost of the natural gas FPL would otherwise be required to purchase over the expected economic life of the project. Tr. 115 (Forrest). This results in direct savings for customers that will begin immediately upon FPL's initiation of the Woodford Project and continue over the project's life. TR. 114 (Forrest); Ex. 9.

Sadly, the intervenors have resorted to scare tactics in a misguided attempt to distract attention from the robust value this opportunity brings for customers. But those arguments cannot obscure the following three, fundamental points about the Woodford Project.

1. <u>This is *not* a proposal that shifts risks from investors to customers</u>

First and foremost, the intervenors suggest that the Woodford Project would shift risks onto customers. This is 180 degrees from the truth. At present, FPL buys the natural gas needed for its power plants at market prices. Tr. 95-96 (Forrest). Unless FPL acts imprudently in making those purchases, its costs are recovered in full from customers through the Fuel Clause. Thus, customers bear essentially all of the risk of price fluctuations in the volatile natural gas market. Tr. 96 (Forrest); Tr. 894 (Deason). If the Woodford Project is approved, customers will pay the actual and much more stable cost of gas produced from the project, which is being developed in a well-known and proven gas producing area, again subject to prudence review of FPL's actions with respect to the project. Tr. 114-16, 122, 124, 126, 130, 162, 275-76, 286 (Forrest). There is no shift of risk, but rather a *reduction* of customer risk through a substitution of the controlled, low risk associated with gas production from the Woodford Project, for the very substantial risk of purchasing 100% of FPL's gas requirements in the volatile gas markets. Tr. 894-95 (Deason).

2. <u>This proposal *reduces* risks that customers (not shareholders) currently bear and at the same time creates significant opportunities for customer savings</u>

Regardless of where gas prices actually end up, customers will benefit from the Woodford Project because it is a long-term physical hedge against highly volatile gas prices. Tr. 91-93, 1003, 1006-08 (Forrest). It is curious, if not completely inconsistent, that the intervenor witnesses seek to downplay this valuable role of the Woodford Project as a long-term hedge, because if they are right that there is a high degree of uncertainty about future gas prices, then that environment is exactly where a long-term hedge would be most valuable. *Id.* Moreover, customers stand to save millions of dollars under almost all sensitivity analyses performed by FPL (and under all the alternative forecasting approaches proposed by the intervenors), with the most likely scenario resulting in a net present value savings of $107 million. Ex. 9. There is an extremely high probability -- 85% -- that customers will see savings from the Woodford Project. Tr. 333-34, 1012, 1043 (Forrest). Even in the one sensitivity scenario under which customers would see an additional cost from the project, it is small and would occur only in the event that market prices are extremely low for a sustained period and simultaneously the production level is 10% below forecast (actual production levels for the aggregate output from existing wells have been within 1% of estimates). Tr. 117-18 (Forrest); Ex. 9; Tr. 870 (Taylor). That would still be a very good day for customers, as overall fuel costs would be dramatically lower than under FPL's current projections. Tr. 96, 117-18, 1002-03 (Forrest). Intervenors conveniently ignore this fact.

3. <u>The investment necessary to reduce risk and create savings for customers under the Woodford Project is compensated at a rate no different than any other investment FPL's shareholders make in power plants, poles or wires (i.e., it is not a</u>

guaranteed return, but simply a return at the authorized cost of capital for property that is considered used and useful)

FPL is only proposing to earn the mid-point of its Commission-authorized return on equity ("ROE") for the Woodford Project, which is what the Commission has determined is necessary to attract equity capital to FPL on investment that is both used and useful in providing electric service to customers.[4] Despite OPC's attempt to categorize this as a "windfall" for FPL, earning that ROE on the Woodford Project is not only appropriate, but necessary in order to finance the project. Tr. 311-12 (Forrest). It is simply a project cost like any of the other expenses that FPL must incur in order to secure gas at the cost of production. Tr. 896-99 (Deason). As such, recovery of the Commission-approved ROE on the Woodford project is not an impermissible "profit." Rather, it is exactly what the Commission routinely permits utilities to recover on investments through the Fuel Clause, calculated in the manner to which OPC and FIPUG have previously stipulated. *Id.*; Tr. 373 (Ousdahl); Order No. PSC-12-0425-PAA-EU.

Simply put, on each of these major themes, the intervenors are dead wrong. Given the clear and substantial benefits for customers as supported by the competent, substantial evidence, FPL's Woodford Project is a prudent investment. Intervenors' instinctive opposition is perplexing.

B. The Woodford Project is a prudent investment for FPL and its customers

1. Objective – protect customers by mitigating some of FPL's long-term exposure to the volatile natural gas market

FPL currently purchases -- and projects well into the future that it will purchase -- up to 600 billion cubic feet ("Bcf") of gas annually. Tr. 89-90, 746-47 (Forrest). This gas fuels the generation facilities that have saved customers over $6.5 billion since 2001 and which will be used to save additional costs into the future. Tr. 90 (Forrest). With such a large demand for

[4] OPC witness Ramas agrees that the gas produced by the Woodford Project would be used and useful. Tr. 606.

natural gas, establishing a predictable, reliable, and low cost fuel supply is imperative for FPL and its customers. Tr. 85 (Forrest). FPL currently secures physical gas, months or several years in advance, with pricing formulas based on publicly available index postings. These pricing formulas can result in a large degree of price volatility due to movements in the underlying natural gas and/or index postings. Tr. 91 (Forrest).

FPL mitigates this natural gas price volatility through its Commission-approved short-term hedging program by financially hedging a portion of its projected gas consumption for the following year. Tr. 91-92 (Forrest). However, FPL's hedging program is limited in that the market does not have the liquidity to provide fixed-price hedges over the many years that gas can be produced from a portfolio of gas reserves projects. Short-term financial hedges necessarily will reflect the rise of market costs over extended periods of time, which long-term cost of service-based physical hedges can keep low. Tr. 92 (Forrest). Finally, long-term fixed-price physical supply contracts are not readily available, as gas suppliers typically only hedge on a shorter-term basis, and there is significant credit exposure to counterparties. Tr. 93 (Forrest).

Roughly 70% of FPL's natural gas supply portfolio is made up of shale gas. Tr. 97 (Forrest). FPL recognized the projected growth in the shale gas market, combined with the importance of shale gas as a part of FPL's fuel supply portfolio, and initiated a review of opportunities to acquire an interest in the production of gas from these same sources, in order to provide customer savings and price stability. *Id.*

Acquiring an interest in natural gas reserves would provide a longer-term physical hedge that compliments and diversifies FPL's current short-term financial hedges, while also providing a level of expected savings in the form of lower gas costs. Tr. 85-86, 96, 115, 126-27 (Forrest). Investments in natural gas reserves would not add to but rather would replace a commensurate portion of the financial hedging program, which only provides short-term protection against price volatility with no expected savings. Tr. 96 (Forrest).

2. Solution – meet a portion of FPL's gas requirements at a lower, stable cost of production from the Woodford Project

FPL began reviewing opportunities for acquiring an interest in the production of shale gas by exploring options with its existing suppliers and producers who would be able to meet FPL's conditions. FPL was ultimately able to make arrangements with PetroQuest to enter into a joint venture for investment in gas reserves and production in the Woodford Shale. Tr. 97-99 (Forrest). The region of the Woodford Shale in the Arkoma Basin of southeastern Oklahoma, where the Area of Mutual Interest ("AMI") acreage with PetroQuest is located, produces dry natural gas and is viewed by PetroQuest as the "crown jewel" of its gas production portfolio. Ex. 57, Deposition Exhibit 2, at p. 5. With the advent of technological advances in horizontal drilling and completion methods, many exploration and production companies are actively drilling the Woodford Shale. Tr. 289 (Forrest); Tr. 848-50 (Taylor).

PetroQuest is a well-known, highly regarded and publicly traded independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties in the United States. Tr. 99 (Forrest). PetroQuest has drilled over 120 wells in the Woodford Shale and has established itself as an efficient, low-cost developer of natural gas reserves. Tr. 506 (Taylor).

FPL's search for opportunities to invest in gas reserves was hindered by the need to allow time for Commission review before making a binding commitment to invest. Tr. 97-98 (Forrest).[5] In order to overcome this obstacle for the Woodford Project, USG Properties

[5] In its brief currently scheduled to be filed on January 5 regarding FPL's proposed Gas Reserves Guidelines, FPL will explain the need for guidelines to address concerns regarding the timing of entering into gas reserves contracts. It would not have been practical to establish guidelines for the Woodford Project. As explained by FPL witness

Woodford I, LLC ("USG"), an affiliate of FPL, entered into a series of agreements on June 18, 2014 with PetroQuest (collectively referred to as the "PetroQuest Agreement"), under which USG will pay a share of the costs for developing and operating natural gas production wells and will receive a portion of PetroQuest's working interest in those wells in the Woodford Shale Gas region.[6] Tr. 101-02 (Forrest); *see also* Ex. 7. Both USG and FPL were involved in negotiating the terms of the PetroQuest Agreement. Tr. 100 (Forrest). FPL is entitled to acquire USG's interest in the Woodford Project via assignment upon a finding by the Commission that the Woodford Project is prudent and that FPL may recover the costs of the project through the Fuel Clause. Upon such a finding, all of USG's interests in the Woodford Project will be transferred to FPL at USG's net book value. Tr. 108 (Forrest); Tr. 352 (Ousdahl). If the Commission does not approve the Woodford Project, then USG will retain its interest and all benefits in the project. Tr. 100 (Forrest). The net book value at the time of purchase between USG and FPL is estimated to be approximately $68.4 million, assuming regulatory approval and transfer by January 1, 2015, and based on current assumptions as to the timing of the drilling program and resulting gas production. Tr. 358-60 (Ousdahl); *see also* Ex. 15. FPL estimates a total capital expenditure of approximately $191 million under the PetroQuest Agreement.[7] Tr. 107 (Forrest).

3. <u>FPL's proposed accounting for the Woodford Project is transparent and effective</u>

Deason, this is because the Woodford Project has a short "shelf life," the total size of the Woodford Project is small, and lessons learned in evaluating a specific project first can be valuable in trying to develop general guidelines. Tr. 963-64.

[6] The PetroQuest Agreement comprises several documents including a Drilling and Development Agreement (DDA"), a Joint Operating Agreement ("JOA"), and a Tax Partnership Agreement. *See* Exs. 5 and 6. There is a signed Joint Operating Agreement for each well, but of necessity those agreements are not signed at the time that the DDA was executed. Rather, an agreed form of the JOA is attached as an exhibit to the DDA, which is then used as the template for each well's JOA. Tr. 235-36 (Forrest).

[7] $191 million represents the high end of FPL's investment in the Woodford Project, because it assumes that FPL consents to all 38 wells under the PetroQuest Agreement and that all of the other participants in the Woodford project non-consent to participation in those wells. Tr. 111-12 (Forrest).

FPL will establish a separate, wholly-owned direct subsidiary to hold FPL's interest in the Woodford Project, conduct its gas production activities and to transact the sale of the commodity to FPL for its customers at production costs. Tr. 352-53, 356-58 (Ousdahl). FPL intends that the transfer from USG would be to the subsidiary rather than directly to FPL. *Id.* The subsidiary will be fully consolidated with FPL for this Commission's regulatory and financial reporting purposes. *Id.*; *see also* Ex. 13. This structure will allow maximum flexibility to minimize state income tax obligations, allow for the separation of Federal Energy Regulatory Commission ("FERC") electric chart of accounts for regulatory reporting purposes, and provide clearer definition and transparency for the investment and activities associated with gas reserves projects. Moreover, because costs associated with gas production will be recovered through the Fuel Clause, the separate legal entity facilitates segregation for ratemaking and earnings surveillance related to base rates. Tr. 356-57 (Ousdahl).

Upon transfer, FPL will be subject to ASC 932 Accounting for Oil and Gas Exploration and ASC 980 (formerly known as FAS 71) -- Accounting for the Effects of Certain Types of Regulation. Accounting for oil and gas production is a highly specialized and unique form of energy accounting. Tr. 363 (Ousdahl). 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. *Id.* In order to ensure consistency with Commission, FERC, and the U.S. Securities and Exchange Commission ("SEC") requirements, FPL intends to use the industry standard chart of accounts to record all costs associated with the investment at the subsidiary level. Tr. 374 (Ousdahl). FPL is proposing to use the FERC Uniform System of Accounts ("USOA") natural gas chart of accounts in FPL's consolidated financial statements. Tr. 374, 804 (Ousdahl); *see also* Ex. 19.

Consistent with the SEC's guidance, FPL will use the successful efforts method of accounting. Tr. 363 (Ousdahl). Under the successful efforts method of accounting, 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. In addition, estimates of reserves must be updated on an annual basis for financial reporting purposes. Tr. 365-66 (Ousdahl).

FPL will calculate the revenue requirements for the Woodford Project (e.g., depletion, O&M, return on the investment) to be recovered through the Fuel Clause, using a projection for each year of the expected quantities and related costs. Tr. 372 (Ousdahl). The first year in which costs associated with the Woodford Project will be projected for recovery in the Fuel Clause is 2015. FPL will calculate the associated return on its capital invested in the Project in the same manner as it does with other clause related capital investments. Tr. 73 (Ousdahl); *see also* Ex. 18.

4. The Woodford Project will deliver tremendous benefits for customers

As noted above, the Woodford Project will benefit customers by providing price stability over a longer-term than is possible with the current short-term hedging program. Tr. 91-92, 115-16 (Forrest). By disassociating a portion of FPL's natural gas purchases from volatile market prices, and instead obtaining a portion of its natural gas requirements at a stable, lower cost of production, this investment will allow the Company to replace a portion of its short-term financial hedging program for fuel purchases with, in effect, a long-term physical hedge. Tr. 96, 115, 1003, 1006-10, 1022 (Forrest). At the same time, by procuring only a portion of FPL's gas requirements through investments in gas reserves, FPL maintains the flexibility to purchase lower-priced gas in the market, if available, for the remainder of FPL's needs. Tr. 96 (Forrest). This means that FPL customers can benefit should gas prices unexpectedly or temporarily fall.

Tr. 96, 117-18, 1013 (Forrest); Tr. 971 (Deason). Moreover, if the market evolves in a way that places downward pressure on the forward market price for gas, 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. Tr. 125 (Forrest). This represents a substantial mitigant to any price risk for the portion of gas procured through this physical form of hedging, at the same time that the substantial net benefit to customers from falling prices would still be realized through lower gas prices for the much larger volumes of gas that FPL will be purchasing at market prices.

Beyond its hedging benefits, the Woodford Project is expected to result in substantial fuel savings for customers. Tr. 87, 115, 118-19, 124-25, 126, 130, 1022-23 (Forrest). To perform an economic evaluation of this investment, FPL utilized its natural gas price forecast along with estimated natural gas production and projected costs for the Woodford Project that were developed by FPL witness Taylor. Tr. 110 (Forrest). Dr. Taylor performed an internal analysis using industry accepted methods for forecasting. Tr. 508-09 (Taylor). FPL also retained Forrest A. Garb & Associates ("FGA"), a well-recognized external consultant, to provide an independent confirmatory analysis, which concluded that Dr. Taylor's analysis is a reasonable estimate of the volumes of gas to be expected from the drilling program.[8] Tr. 112 (Forrest), Tr. 510 (Taylor); Ex.30. The analysis shows that the Woodford Project is economically viable and commercially attractive, with robust reserves available with a high expectation of natural gas recovery,

[8] During cross-examination, Mr. Lawton disparaged FGA's work as merely "checking [Dr. Taylor's] arithmetic." This is grossly inaccurate, as Mr. Lawton could have readily ascertained by simply reading the FGA report that is Ex. 30 (confidential). The report details on pages 2 through 5 of 30 the steps that FGA undertook to prepare its own, independent reserves estimate, the results of which corroborated the results that Dr. Taylor obtained using *his* own, distinct estimation methodology. The only thing that the FGA and Taylor reserves estimates shared was a common set of input data, which was provided to FGA (see General Comment 5 on page 26 of 30). Sharing a common set of inputs is not only appropriate but essential if the reserves estimates are to be compared for confirmation, as the use of different inputs would confound the comparison.

operated by an industry leader in this region. Ex. 29, 30, 31, 32; Tr. 110-12 (Forrest); Tr. 494, 511 (Taylor).

FPL then determined the revenue requirements for the Project over its 30-plus year economic life. Tr. 113-14 (Forrest); Ex. 8, 9. FPL's revenue requirements were converted to an estimated cost per MMBtu of natural gas, using the total expected gas production volumes. *Id.* FPL also conducted sensitivity analyses to evaluate the impact of a lower natural gas price forecast and/or less natural gas production from the Woodford Project than is expected. Tr. 116-18 (Forrest). The economic benefit of the Woodford Project for FPL's customers is clear – FPL will be able to procure natural gas at a lower and more stable cost per MMBtu than would otherwise be incurred if the same amount of natural gas were to be purchased at market prices. This holds true even in the event that natural gas market prices decline further from current forecasted prices or production from the Woodford Project is lower than expected. *Id.* The benefits will start immediately upon FPL taking assignment of the PetroQuest Agreement and then continue over the productive life of the Woodford Project wells. Tr. 114 (Forrest). The revenue requirements associated with the project, on an NPV basis, are projected to be approximately $107 million lower than the forecasted cost of the natural gas FPL would otherwise be required to purchase over the expected economic life of the project. Tr. 115 (Forrest). FPL's revenue requirements are projected to be lower than the forecasted market price of natural gas on a dollars per MMBtu basis during the entire life of the project, with customers experiencing a majority of their savings early in the life of the Project.[9] *Id*; *see also* Ex. 8.

[9] As discussed by FPL witness Forrest, these economics assume 100% of the gas would be delivered to Florida. However, once the gas is delivered to FPL by PetroQuest, it will be treated as a part of the entire procurement portfolio. If transportation costs could be reduced or other economic advantage derived for customers from selling the Woodford Project gas and then simultaneously buying the same quantity of gas at a different location, FPL will do so. The resulting savings would be passed on to FPL's customers through the Fuel Clause and would be treated as a gain under the Commission-approved Incentive Mechanism. Tr. 292-93 (Forrest).

5. The Intervenors' "riskiness" arguments against the Woodford Project fall well short of the mark

In addition to the three arguments addressed at the outset, the intervenors have raised a number of secondary arguments, all asserting that the Woodford Project is too risky in one way or another. Specifically, they question the adequacy of the accounting controls, and they fret over production-related and price-related risks. As shown below, none of these areas of purported "riskiness" should give the Commission any pause in approving the Woodford Project.

a. FPL's proposed accounting for the Woodford Project will provide appropriate oversight and control

OPC witness Ramas asserts that FPL's investment in the Woodford Project is not compatible with the FERC USOA and that FPL is not proposing to record the investments in the Woodford Project in the Plant in Service Accounts that fall under the FERC USOA. Tr, 559-60, 563-64, 571 (Ramas). Ms. Ramas is wrong, and is evidently unfamiliar with the use of account mapping. Tr. 804 (Ousdahl). As FPL witness Ousdahl testified, FPL will use the standard SEC financial accounting classifications for this industry at the subsidiary level, and will then map the information to the FERC USOA natural gas chart of accounts for FPL consolidation and financial reporting and ratemaking. Tr. 363, 374, 441 (Ousdahl); Ex. 17, 19. Ms. Ramas' confusion continues with the incorrect assertion that GAAP and the FERC USOA are mutually exclusive. Ms. Ousdahl makes clear that GAAP contemplates the effects of regulation, as codified in Accounting Standards Codification ("ASC") 980 Regulated Operations. Tr. 806-07 (Ousdahl).

Similarly, Ms. Ramas' suggestion that the annual revision to depletion rates is not consistent with the Commission's depreciation requirements under the Commission's rules underscores her misunderstanding of the accounting requirements for natural gas production. Tr.

807-08 (Ousdahl). As discussed by Ms. Ousdahl, depletion accounting is integrally woven into the FERC USOA, as is evident by its reference in several provisions including Subchapter F of the USOA Natural Gas, Part 201, 12A, and FERC Account 404.1 – Amortization and Depletion of Producing Natural Gas Land and Land Rights. *Id.*

Both OPC and FIPUG raise concerns about the Commission's ability to audit PetroQuest, suggesting that the Commission would have no ability to directly and independently confirm the accuracy and reasonableness of the Woodford Project gas production and drilling costs. These criticisms are misplaced. Tr. 808-12 (Ousdahl); Tr. 907-09 (Deason). The FPSC performs audits by examining the books and records of the utility to validate that the costs which make up the revenue requirement are properly recorded in compliance with the USOA such that the resulting revenue requirement is reasonable. Tr. 808 (Ousdahl). This examination ensures that the costs reflected in the clause are recoverable from customers under the applicable orders, rules and statutes. *Id.* This is currently done for FPL's joint venture agreement with JEA for FPL's interest in the St. Johns River Power Park, and FPL's joint venture with Georgia Power Company for FPL's interest in the Plant Scherer Unit 4. Tr. 809 (Ousdahl). The Commission does not audit the books and records of any of FPL's vendors or joint venture partners. Tr. 810 (Ousdahl).

FPL's joint venture agreements all provide FPL access to the owner/operator's books and records for periodic on-site audit of its billings to FPL to ensure all charges are appropriately incurred by FPL's customers. Tr. 810 (Ousdahl); Ex. 5, 6, 7, 13. The Commission will have access to all of FPL's records. Tr. 373, 378-379, 810-11, 838-39 (Ousdahl). Furthermore, FPL will design and implement new controls and revisions to its existing controls in order to provide appropriate assurance of financial reporting for its investment in the Woodford Project, including the development and implementation of Sarbanes Oxley processes designed to ensure gas reserves transactions are in compliance with GAAP and any unique regulatory requirements, if any, and examination by an independent auditor. Tr. 811-12 (Ousdahl). In sum, the Commission and its Staff have all the access necessary to assure the accuracy and reasonableness of the Woodford Project gas production and drilling costs.

b. The Woodford Project's production risks are well understood and low

OPC witness Lawton asserts that there may be substantial variability in the forecast of production from the Woodford Project. This assertion is unfounded. Tr. 845-46 (Taylor). In order to forecast production, FPL utilized the services of FPL witness Dr. Taylor, who, unlike witness Lawton, has extensive academic training, as well as over 35 years of experience in estimating gas reserves. Tr. 112 (Forrest); Tr. 490-91 (Taylor); Ex. 21, 35. While it is possible that the output and reserves levels will vary to some degree, Dr. Taylor does not expect any such variances to be significant. Tr. 845 (Taylor). Based on his analysis, Dr. Taylor does not expect production levels from the Woodford Project to vary beyond 10 percent in either direction. Tr. 869-70 (Taylor). In fact, actual, observed variability for the first four years of aggregate production from the wells studied in the type curves has been within *1 percent* of the type curves.[10] Tr. 870 (Taylor); Ex. 11, 12. It is important to note that the Woodford Project is not "gas exploration"; rather, it is "gas development" in an area that has been thoroughly defined by the existing wells, and as such has been substantially "de-risked" for production. Tr. 846-47, 853 (Taylor). As explained by Dr. Taylor, a review of Exhibit TT-8 (Ex. 28) makes clear just how close the Woodford Project wells will be to existing, producing wells. Dr. Taylor's results were subsequently confirmed by FGA as an independent third party. Ex. 30.

[10] In contrast, the market price of gas that FPL otherwise would be paying swings dramatically: 92% in 2015 to date. Tr. 213 (Forrest)

OPC argues that, because Dr. Taylor has only 4 years of actual data to compare to the type curves, not enough is yet known to assess their accuracy. Quite to the contrary, the large majority of production from the wells used for the type curves occurs in the early years, providing a solid basis of information on the remaining years of production. Tr. 845-46 (Taylor); Ex 31, 32. Exhibits TT-11 and TT-12 (Ex. 31, 32) show that actual production from the wells for those first four years tracks the type curves very closely. *Id*; Tr. 868-69 (Taylor).

OPC witness Lawton shows his unfamiliarity with the oil and gas industry by suggesting that drilling in the Woodford Shale has come to a "basic standstill" as a result of competitive prices in the oil and gas markets. Tr. 719-20 (Lawton); Tr. 849-51 (Taylor). This is demonstrably untrue. Tr. 849-50 (Taylor). While drilling activity is lower than four years ago, it remains active, and in fact has increased between 2013 and 2014. *Id.*

OPC witness Lawton and FIPUG witness Pollock both assert that there are uncertainties around operation, production and transportation costs that are not factored into FPL's projections. Again, their assertions miss the mark. Tr. 847-49 (Taylor); Tr. 1008-09 (Forrest). Natural gas production is well understood, and the operating costs associated with gas production are highly predictable. Tr. 847 (Taylor). Furthermore, PetroQuest has a long history of production in the Arkoma-Woodford region, and it is very familiar with operations in the region. Tr. 851 (Taylor). For the Woodford Project, Dr. Taylor used the average of the actual operating cost for each of 12 prior months from PetroQuest's records for the AMI, clearly the best source of information as to what future operating costs will be for the Woodford Project. Tr. 848 (Taylor). He did not escalate those operating costs over the project life because of continuing evolution of the production technologies, along with producing multiple wells from a common surface facility, is likely to cause those costs to decline, not increase, over time. Tr. 847-48

(Taylor); Tr. 1027 (Forrest). OPC witness Ramas agreed that the operating costs are likely to decline. Tr. 617-18 (Ramas). And this downward trend is borne out by Ex. 53 (Int. 75) and the testimony of FPL witness Forrest, which indicate Woodford area production costs declined from \$4.75 in 2010 to \$3.79 in the first half of 2014. Tr. 1019, 1067-68 (Forrest).

FIPUG witness Pollock asserts that it is unreasonable to assume that the gas pipeline transportation rate included in FPL's estimated costs for the Woodford Project will remain unchanged during the life of the Woodford Project, and arbitrarily recommends a 2% increase per year. However, as FPL witness Forrest notes, FPL assumed the most direct and obvious transportation alternative for its financial analysis of the Woodford Project, rather than the cheapest. Tr. 1026 (Forrest). The likelihood is that transportation costs will be substantially *lower* than that assumption, not higher. *Id.*

FIPUG witness Pollock and OPC witness Lawton pointed to risk disclosure statements that PetroQuest makes as a publicly traded company to imply that participating with PetroQuest in the Woodford Project will entail a high degree of risk, and that PetroQuest's relatively small size and scale make it risker than its peers. Both of these assertions are wrong. These sorts of risk disclosure statements are commonplace for publicly traded companies, regardless of the industry. Tr. 531-32 (Taylor); Tr. 1021-22 (Forrest). It is common for many public companies that produce, transport, or consume natural gas as part of their business to include an exhaustive list of these very same risks in their filings with the Securities and Exchange Commission. *Id*; *see also* Ex. 57 at 76-79. Furthermore, PetroQuest's size has nothing to do with its ability to drill and produce wells in an efficient and profitable manner. Tr. 851 (Taylor). There are many more small independent companies in this industry than there are major companies. PetroQuest concentrates in only a few geographic areas, and it has developed expertise in drilling, completing and operating wells in those areas. PetroQuest has a long history of very successful operations in the oil and gas industry generally and the Arkoma- Woodford region in particular, which has made it highly respected within the industry. *Id.*

FIPUG also criticizes PetroQuest as being credit-rated below investment grade. However, this is an unfounded criticism in the context of this type of transaction. First, it is not uncommon for smaller "niche" or specialty gas companies of this size to be below investment grade. Tr. 201-02 (Forrest). Second, drilling operations are funded on a pay-as-you-go basis, thus mitigating any long-term financial risk. Tr. 443-45 (Ousdahl). Third, as discussed above, PetroQuest is a well-known, highly regarded and publicly traded independent oil and natural gas company engaged in the acquisition, exploration, development, and production of oil and natural gas properties in the United States. Tr. 99 (Forrest). PetroQuest has drilled over 120 wells in the Woodford Shale and has established itself as an efficient, low cost developer of natural gas reserves. Tr. 506 (Taylor). Additionally, if there ever were a need, FPL is protected by step-in rights in the PetroQuest Agreement. Tr. 203 (Forrest).

Finally, OPC and FIPUG point to a modest drilling delay for the Woodford Project and suggest that it portends significant changes to the project economics. This is a complete red herring. While there has been a delay with *one* drilling rig, the delay is the result of PetroQuest's search for a drilling rig that meets their needs in terms of efficiency and cost. Tr. 527-28 (Taylor); Tr. 327-28 (Forrest). The delay is expected to be minimal, will have little impact on value for FPL customers, and allows for the potential to catch up once the rig is in place. Tr. 327-28 (Forrest). It is clearly better for FPL and all concerned for PetroQuest to secure the proper rig for the job (and therefore minimize drilling costs) rather than rush ahead with inappropriate equipment. As Mr. Forrest testified, the gas isn't going anywhere in the meantime, and FPL only pays for drilling costs as they are incurred. *Id.* In short, there is little or no adverse impact from a modest schedule extension, and certainly no impacts that would warrant PetroQuest (and ultimately FPL and its customers) incurring higher costs just to stay on schedule. This is simply another example of intervenors fabricating concerns where none actually exist.

c. The Woodford Project is a good deal for customers under a wide range of price forecasts, including all of the intervenor methodologies

OPC and FIPUG both challenge FPL's projection of gas prices and propose their own, lower price forecasts; yet, interestingly, even the intervenor forecasts show that the Woodford project would produce savings for customers. Ex. 11. FPL's gas price forecast is reasonable and was developed using the same methodology that FPL has used – and this Commission has accepted. Tr. 1011-1012 (Forrest). The specific forecast FPL presented was also used in FPL's 2014 Ten Year Site Plan and DSM Goals proceeding, both of which were contemporaneous with FPL's filing of the gas reserves petition. *Id.* As it does routinely when presenting project proposals that depend in part on fuel price forecasts, FPL presented a sensitivity analysis as part of its direct case. Tr. 116-18, 1012-13 (Forrest). FPL ran "Low Fuel" price and "High Fuel" price sensitivities that were part of the 9-box customer savings estimates. These sensitivity cases represented a full standard deviation above and below the Base Case fuel forecast. The sensitivity analysis demonstrated the robustness of FPL's conclusion that the Woodford Project will produce fuel savings. Eight out of nine sensitivity cases show customer savings, ranging from $10.3 million NPV to $246.7 million NPV, with an overall 85% probability of customer savings. *Id.* In only one unlikely scenario where fuel prices and production were simultaneously low and remained low for decades, was there a net cost increase to customers, and then it was only about $14 million NPV. Tr. 117, 1012 (Forrest). And, if that scenario did come to pass, it would be a very good day for customers: Mr. Forrest calculates that the typical 1,000-kWh bill would be lower by $4.86 on a net basis compared to the base case forecast, after taking the small ($0.07) cost impact of the Woodford Project gas into account. Tr. 118 (Forrest).

A review of the intervenors' alternative gas price forecasts reveals three points, none of which supports their contentions: (i) the intervenor witnesses are unsophisticated in fuel forecasting, as evidenced by their numerous methodological errors in applying their preferred forecasting approaches. Tr. 1020-1021 (Forrest); (ii) the Woodford Project would result in fuel savings under all three of their forecasting approaches (Ex. 11); and (iii) if they are correct that there is a lot of uncertainty as to how gas prices ultimately will turn out, then that simply emphasizes the value of the Woodford Project as a long-term hedge. Tr. 1006-10 (Forrest). In addition to the intervenor witnesses' gas price forecasts, FPL was asked to evaluate the Woodford Project using the July 2014 forecast that was the basis for the 2015 Fuel Clause projections that were filed subsequent to the gas reserves petition. Using this forecast would still result in $52 million NPV in customer savings, further buttressing the conclusion that the Woodford Project would save customers money over a wide range of gas price forecasts. Ex 64.

6. <u>Conclusion</u>

In short, the intervenors' misguided attempts to derail the Woodford Project all miss the mark. Flawed assumptions, contradictions, and even invented facts pervade their arguments. Given the clear and substantial benefits for customers as supported by the competent substantial evidence, FPL's Woodford Project is a prudent investment.

III. THE COSTS OF THE WOODFORD PROJECT ARE ELIGIBLE FOR FUEL CLAUSE RECOVERY

There are at least[11] three clear bases for recovery of the Woodford Project costs through the Fuel Clause.[12]

First, the Commission has a long-standing practice dating back to 1985 in Order No. 14546 of including capital projects in the Fuel Clause when they are undertaken in order to reduce the delivered cost of fossil fuels that customers must pay. As noted in Order No. PSC-11-0080-PAA-EI ("Order 11-0080"), Fuel Clause recovery for this sort of capital project has been permitted in numerous Commission decisions subsequent to Order 14546. In Order 11-0080 the Commission stated its going forward policy on the recovery of capital projects in the Fuel Clause: "...we believe that the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are 'fossil fuel-related' and that lower the delivered, price or input price, of fossil fuel." That is what the evidence in this case shows will result from the Woodford Project. Tr. 369-71 (Ousdahl), 88-89, 110-18 (Forrest), 880-86 (Deason). Even OPC witness Lawton acknowledged that the Woodford Project is fossil-fuel

[11] FPL notes there are "at least" three bases for recovery through the Fuel Clause because there is a fourth ground for recovery, if the three grounds discussed above were not available. In Order 14546, after setting forth ten specific items appropriate for recovery through the Fuel Clause, the Commission provided yet another opportunity for recovery of costs through the fuel Clause. It stated:

> "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 the order and the utility seeks to recover such costs through its fuel adjustment clause, the utility would present testimony justifying such recovery in an appropriate fuel adjustment hearing."

So, if the Commission were to find that the Woodford Project costs are neither appropriately capital costs recoverable under Item 10 in Order 14546 nor hedging costs, it could still find the Woodford Project costs to be "unanticipated costs" under Order No. 14546 and allow their recovery since FPL has presented evidence justifying such costs in a fuel hearing.

[12] Because there are well-established, clear bases under the Commission's existing policy on how the Fuel Clause is to function, there is no need for legislative guidance as to whether Woodford Project costs are properly recoverable through the Fuel Clause. Mr. Deason testified that "I think the Commission has adequate jurisdiction and adequate discretion to consider this proposal on its merits without any further guidance from the Legislature." Tr. 957. There is no contrary evidence in the record.

related. Tr. 751(Lawton) and will save FPL customers $43.76 million NPV. Tr.774 (Lawton); Ex 38).

Second, the Commission also has authorized the recovery of natural gas hedging costs through the Fuel Clause. Order No. PSC-02-1484-FOF-EI; Order No. PSC-08-0667-PAA-EI. The Woodford Project provides a long-term physical hedge of natural gas that would be an effective complement to FPL's existing program of short-term hedges in mitigating the volatility of natural gas prices. Tr. 91-93, 1003, 1006-08 (Forrest); 891, 901-03 (Deason). Therefore, the Woodford Project is recoverable under the Fuel Clause as a hedging cost. Tr.902-03 (Deason).

Third, regardless of the form of expenditure, it is a cost of gas that is burned in power plants for the benefit of customers. One form of cost for natural gas (gas reserves) would be simply replacing another (purchased commodity cost) for recovery in the Fuel Clause -- just a different way of procuring the fuel that is burned to generate electricity. Tr. 967 (Deason).

The evidence demonstrates that Fuel Clause recovery is a better means of recovery of gas reserves costs than base rate recovery. Commissioner Brown's questioning of Mr. Forrest reveals several advantages of Fuel Clause recovery: (a) quicker review and implementation, allowing FPL to preserve customer benefits, (b) greater transparency with an annual review, and (c) a better match of recovery to actual revenue requirements given the quick depletion of gas reserves. Tr. 302-03. As Mr. Forrest concluded, "[f]or customers, I think this is just an absolute home run. You know, it ultimately gets down to whether the Commission believes that there is a better way of mitigating long-term risks than just ignoring it." Tr. 303.

A. **Fuel Clause recovery of Woodford Project is appropriate under Item 10 in Order No. 14546 and subsequent Commission decisions implementing Order 14546**

In 1985 the Commission created a docket to consider the proper means of recovery of fossil fuel-related costs. A workshop among interested parties was held, and a stipulation of the participating parties, which included both FPL and OPC, was reached, submitted to the Commission and approved.[13] The Commission's action was committed to an order, Order No. 14546. In this proceeding FPL has requested recovery of the Woodford Project costs through the Fuel Clause based, in part, on Item 10 in Order 14546:

> As a result of our determination on this proceeding, prospectively, the following charges are properly considered in the computation of the average inventory price of fuel used in the development of the fuel expense in the utilities' fuel cost recovery clauses:
>
> ...
>
> 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.

Order 14546 at 4, 5. FPL's witnesses Ousdahl (Tr. 369-71), Forrest (Tr. 88-9, 110-18) and Deason (Tr. 880-86) have all addressed why recovery of the Woodford Project pursuant to this provision in Order 14546 is appropriate.

Over the course of the intervening decades, there have been a number of occasions where the Commission has applied and interpreted Item 10 in Order 14546. In Order 11-0080 the Commission (a) provided a comprehensive summary of how Item 10 in Order 14546 had been applied to date, (b) offered further interpretation as to just how this provision in Order 14546 should be applied, and (c) provided a "going forward" statement of how the provision should be applied. Each of these is instructive regarding the eligibility of the Woodford Project and future gas reserves projects for Fuel Clause recovery.

The comprehensive summary of the Commission's prior application of Item 10 found in Attachment A to Order 11-0080 provides a great deal of insight as to the proper application of

[13] FIPUG was informed of the stipulation and took no position on it, which today would be referred to as a Type 2 stipulation. Order 14546 at p. 1.

the standard in this case. Two points in particular are applicable in this case. First, it is clear from summaries of various orders that the savings in fuel costs that justified recovery of the projects in question were not guaranteed or actual; rather, they were based on projections or estimates of future savings.[14] Of course, the $107 million NPV savings associated with the Woodford projection is an estimate based upon the best information available at the time of the forecast. Tr. 114-18 (Forrest). Second, in Attachment A the Commission repeatedly summarized Item 10 in Order 14546 with the following sentence: "Order No. 14546 allows a utility to recover fossil-fuel related costs which result in fuel savings when those costs are not previously addressed in determining base rates."[15] Tr. 884 (Deason). No Woodford Project costs were included in the projected test year reviewed by the Commission when it established FPL's current base rates.[16] Tr. 370 (Ousdahl). So, the Woodford Project's costs meet this oft-repeated eligibility criterion of Order 14546 as well. Tr. 883-86 (Deason).

[14] Order PSC-95-1089-FOF-EI, FPL's recovery of rail cars, "FPL *projects* that the $24,024,000 cost *will save* ratepayers more than $24 million above the cost of *cars over a 15 year period*."; Order PSC-95-1089-FOF-EI, FPC's recovery of Intercession City CTs, "The conversions were *to produce an estimated savings* of $2.5 million ...."; Order No. PSC-95-0450-FOF-EI, FPL modifications to power plants, "FPL stated ... *estimated savings* of $80 million."; Order No. PSC- 96-1172-FOF-EI, FPL uprate of TP 3 and 4, "The thermal power uprate was *estimated to produce $198 million in savings* ...."; Order No. PSC-96-0353-FOF-EI, FPC's Debary unit 9 conversion, "The conversion *was to produce* an *estimated savings* of $2.1 million ...."; Order No. PSC- 97-0359-FOF-EI, FPC unit conversions, "The conversions *were to produce an estimated savings* of $22 million ...."; Order No. PSC-97-0359-FOF-EI, FPL generating plant modifications, "The modification were *to produce an estimated savings* of $19 million...."; Order No. PSC-98-0412-FOF-EI, FPC conversions of Suwannee 3, "The conversion was *to produce an estimated savings* of $3.25 million...."; Order No. PSC-98-1715-FOF-EI, FPC conversion of Debary 8, "The conversion was *to produce an estimated savings* of $3.25 million ...."; Order No. PSC-01-2516-FOF-EI, "Parties restated that regulatory treatment of capital costs that are *expected to reduce long-term fuel costs* is the treatment prescribed in Order 14546...." (*Emphases added.*)

[15] This repeated statement in Attachment A is very similar to an interpretation of Order 14546 set forth in the body of Order 11-0080: "[w]e find that the appropriate interpretation of this section of Order No. 14546 is that capital projects eligible for cost recovery through the Fuel Clause should produce fuel savings based on lowering the delivered price of fossil fuel, or otherwise result in the burning lower price fuel at the plant." That is precisely what will happen with the fuel savings from the Woodford Project. Tr. 114-18 (Forrest); Ex. 64.

[16] OPC suggested in its cross-examination at hearing that one should not look to the MFRs in the most recent rate case to determine whether a project's costs are reflected in base rates, when the result of the rate case was a settlement. This is directly at odds with the Commission's decision in Order No. PSC-05-1252-FOF-EI, issued on December 23, 2005 in Docket No. 050001-EI, where the Commission disallowed recovery of St. Lucie Unit 2 sleeving project costs under Order 14546 because FPL knew of that project at the time that it filed the MFRs in a rate case that settled. The implication by OPC that a "black box" settlement would comprehend costs that were not

Order 11-0080 also set forth the Commission's going forward policy regarding Item 10 in Order 14546. It stated: "we believe that the appropriate policy going forward is to restrict capital project cost recovery through the Fuel Clause to projects that are 'fossil fuel-related' and that lower the delivered price or input price of fossil fuel." Multiple FPL witnesses have shown that the Woodford Project meets this going forward policy. Tr. 369-71 (Ousdahl); Tr. 88-89, 110-18 (Forrest), Tr. 880-86 (Deason); Ex. 9, 11, 63, 64. As noted above, even OPC's witness Lawton agreed that the Woodford Project is fossil fuel related and should save customers $43.8 million NPV, a clear and definitive "lower[ing] of the delivered price or input price of fossil fuel." *See* Tr. 751, 774 (Lawton); Ex. 38

In short, it is abundantly clear that the Woodford Project meets the requirements of Item 10 in Order 14546 and the subsequent Commission decisions implementing Order 14546, Item 10. It has been shown not only by FPL's evidence, but also by OPC's and FIPUG's witnesses.[17]

B. <u>The Woodford Project as a hedge properly recovered through the Fuel Clause</u>

In Order No. PSC-02-1484-FOF-EI, after a spin-off of issues from the 2001 fuel adjustment proceeding, the Commission approved a settlement, signed by both OPC and FIPUG, which addressed utility risk management plans related to fuel procurement. Part of the Commission's rationale for approving the settlement was that it "appears to remove disincentives that may currently exist for IOUs to engage in hedging transactions that may create customer benefits by providing a cost recovery mechanism for prudently incurred hedging transaction costs, gains and losses, incremental operating and maintenance expenses associated with new and expanded hedging programs." Order No. PSC-02-1484-FOF-EI at 2. In this proceeding,

addressed in MFRs, not known at the time MFRs were filed, and to be incurred well beyond the test period far exceeds the realm of logic.

[17] Even under Mr. Pollock's infirm fuel forecast, FPL's customers are projected to enjoy $26.8 million in NPV savings due to the Woodford project. Tr. 1016-18 (Forrest); Ex. 42.

witness Deason correctly characterized the settlement as endorsing "the use of hedging, both financial and physical hedges, as a risk management tool to mitigate price volatility for the benefit of customers." Tr. 901 (Deason). So, since 2002 the Commission has had a policy in place that is meant to encourage investor-owned utilities to hedge their fuel purchases.

The evidence in this case shows that FPL's proposed Woodford Project is a form of long-term hedge and its costs are properly recoverable through the Fuel Clause. Tr. 91-93, 116, 1003, 1006-08 (Forrest). Former Commissioner Deason testified to the consistency of the Woodford Project with the Commission's hedging policy:

> Q Is FPL's proposed gas reserve project consistent with this policy?
>
> A Yes, it is. In particular, the policy recognizes that the Fuel Clause is an appropriate mechanism to effectuate cost recovery for hedging activities, that there should be flexibility in structuring hedging proposals, that there should be a determination of prudence, that the customers benefits should be the emphasis of a hedging initiative, that potential disincentives to hedging should be removed that otherwise could prevent achieving customer benefits, and that both gains and losses can result from prudent hedging initiatives. Consistent with this policy, FPL is seeking a determination of prudence for its gas reserves project that is anticipated to provide cost benefits along with its hedging benefits.

Tr. 902-03 (Deason).

Mr. Forrest addressed the hedging benefits associated with the Woodford Project. In his direct testimony he stated that, "[t]he PetroQuest transaction provides FPL's customers with a source of physical gas supply that provides for stable pricing over the production term of the project, thus mitigating volatility inherent in FPL's natural gas procurement." Tr. 85-86 (Forrest). Even Mr. Lawton agreed that "it is always prudent to mitigate volatility." Tr. 780 (Lawton). Mr. Forrest went on to explain how FPL currently hedges some of its natural gas purchases with a short-term hedging program, but he pointed out at least three significant limitations of the existing program.[18] Tr. 91-92 (Forrest). He also testified that long-term fixed price contracts were not available to provide a long-term hedge for FPL's customers. Tr. 93 (Forrest). Mr. Forrest then addressed the hedging value of FPL acquiring natural gas reserves:

> Because the market price of natural gas is volatile and is a large component of the price of electricity, it can cause significant short- and long-term swings in customers' electric bills. Acquiring an interest in natural gas reserves and drilling operations would provide a longer-term physical hedge against future increases in natural gas costs for FPL's customers. Because the gas reserves are effectively delivering both physical supply and prices at or below FPL's current projections, they would partially supplant the need for financial hedges and allow FPL to reduce the amount of short-term financial hedges that it places.

Tr. 96 (Forrest).

Mr. Forrest explained that the production of gas from proven reserves decouples the price of natural gas from volatile market prices and ties the cost of gas to production costs, which are much more stable. Tr. 216-18 (Forrest). The costs of production in the AMI in which the Woodford Project will be located have declined over time and are projected to remain stable or even decline further. Tr. 869-70 (Taylor). In contrast, every fuel forecast before the Commission in this proceeding shows increasing market prices of natural gas over the life of the Woodford Project. The evidence is abundant that the market prices remain extremely volatile. The volatility of natural gas during 2014 so far has been 92%, and the NYMEX pricing for natural gas in 2025 recently swung from $5.60 down to $4.60 and then back to $5.60 in a period of just four months. Tr. 176, 213 (Forrest). So not only is procuring fuel at the cost of production projected to generate fuel savings for customers from day one (Ex. 9), but also it

[18] Those three limitations are (1) the financial markets do not have the liquidity to provide fixed-price hedges over 30 years or longer; (2) during periods of rising market prices, financial hedges also reflect rising costs, where an ownership interest in gas reserves is better able to keep gas costs low; and (3) even FPL's strong balance sheet would limit its ability to secure required credit support. Tr. 92 (Forrest).

should provide much greater price stability. In short, the Woodford Project will mitigate price volatility, something that even OPC witness Ramas acknowledged. Tr. 627 (Ramas).[19]

The Woodford Project is a highly beneficial hedge, providing price stability to customers. It enjoys significant advantages over existing short-term hedges, which are limited both in duration (no more than two years versus 30-50 years for this long-term physical hedge) and by credit requirements (while financial hedges require collateral, the Woodford Project does not). The Woodford Project is consistent with the Commission policy on hedging and would improve FPL's current hedging program. Therefore, even if it were not projected to save customers $107 million NPV, it would be properly recovered through the Fuel Clause.

C. The intervenor witnesses' arguments against Fuel Clause recovery are all flawed

1. OPC witness Ramas egregiously misinterprets Order 14546, Item 10

Without regard for subsequent applications and interpretations, OPC witness Ramas picked two phrases out of Item 10 in Order 14546 and erroneously concluded that the Woodford Project does not qualify for Fuel Cost recovery. Witness Deason characterized her interpretations as "overly restrictive." He was being polite. They are just plain wrong.

Witness Ramas begins by quoting the passage in Order 14546 upon which FPL relies in seeking Fuel Cost recovery for the Woodford Project.

> Fossil fuel-Related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine base rates and which, if expended, will result in fuel savings to customers.

Focusing on two phrases taken in isolation, she makes two erroneous arguments. First, she argues the phrase "normally recovered through base rates" precludes recovery on gas reserves

[19] While natural gas prices are less volatile now than they have been in recent past, traditionally natural gas has been volatile, and it remains volatile. Mr. Forrest documented a 92% volatility of natural gas prices in the current year. Tr. 213. Furthermore, there are a number of unknowns on the horizon that could affect volatility. Tr. 377-79 (Forrest).

because gas reserves have not historically recovered through base rates. Second, she argues the savings have to be actual or guaranteed; they cannot be estimated or projected. Her erroneous interpretations will be addressed in turn. Witness Deason very effectively rebutted both of witness Ramas' arguments. Tr. 881-83 (Deason).

The phrase "normally recovered through base rates" is not a reference to what has historically recovered through base rates. Under Ms. Ramas' overly restrictive interpretation literally nothing could ever be recovered through the Fuel Clause if it had not been recovered through base rates previously. Understandably, witness Ramas offers no policy rationale for such an interpretation, because there is none. Instead, the phrase is a reference to whether items could properly be included in rate base, and therefore, recovered through base rates. That is determined by looking to Section 366.06, Florida Statutes, the statute that addresses investments that can properly be included in rate base. Simply put, that statute authorizes the inclusion in rate base of assets that are prudently invested and used and useful in providing utility service. The Woodford Project investment will be prudently invested; it will be used and useful; and it will be used to provide service (and savings) to customers. Tr. 87-118 (Forrest), Tr. 893, 905 (Deason). So, it would be properly recovered in base rates, but it was not so recovered when FPL's current base rates were set. Tr. 370 (Ousdahl). Consequently, under Order 14546, Item 10, it is properly recovered through the Fuel Clause.

This interpretation of Order 14546, Item 10 is not only consistent with the statutory scheme and common sense, but also with the Commission's prior implementation of this passage. At the time the Commission allowed rail cars for coal transportation to be recovered through the Fuel Clause, such costs had not historically been included in rate base and recovered through base rates. However, their recovery was allowed through the Fuel Clause. The

Commission did not adopt witness Ramas' overly restrictive reading of that provision in those cases, and it should not now.

Witness Ramas' insistence that the phrase "will result in fuel savings to customers" requires actual or guaranteed fuel savings is also easily refuted by the Commission's prior orders applying Order 14546, Item 10. Most of those orders are summarized in Attachment A to Order 11-0080 and in footnote 14 above. They show unequivocally that the savings involved were projected or estimated. This makes sense because the Fuel Clause is initially based upon projections, and it is in projection filings where recovery for capital projects is sought.

Finally, it should be noted that if witness Ramas' flawed interpretations of Order 14546, Item 10 were adopted, they would frustrate the future operation of this provision and stifle utility innovation designed to reduce customer fuel costs. This would cause utility customers potentially to forego hundreds of millions of dollars in fuel savings with respect to gas reserves projects alone, hardly a customer-favoring "public interest" outcome.

2. <u>Witness Ramas also misinterprets Order 20604</u>

Witness Ramas argues that Order 20604 ties the Commission hands and as a matter of policy precludes it from approving any fuel arrangement that is at other than market price. Once again former Commissioner Deason fully exposed witness Ramas' misuse and misreading of Order 20604. Tr. 888-92 (Deason). His summary of that testimony bears repeating:

> Witness Ramas' heavy reliance upon Order 20604 shows that she has a blind faith in the natural gas market and the prices that it charges. But the FPL gas reserves project challenges that blind faith with a fundamental and important question: "Is there a better way to protect customers then simply assuming that 100% reliance on natural gas market prices is best?" As shown in the direct and rebuttal testimony of FPL's witnesses, the answer is a clear "yes." Neither Order No. 14546 nor Order 20604 should be interpreted in a way that interferes with the Commission's and FPL's ability to use this better way for the benefit of customers.

Tr. 892. (Deason). The evidence shows that FPL has found a "better way."

3. OPC witness Ramas' asymmetrical recovery standard is unfair.

Witness Ramas originally recommended in pre-filed testimony that FPL should be limited to Fuel Clause recovery of the market price of gas. In cross-examination, even witness Ramas stopped short of suggesting that FPL just charge market prices. Ultimately, she argued that FPL should recover no more than the market price of gas, but if production costs turned out to be lower than market prices, then FPL's recovery should be limited to production costs. This approach is asymmetrical and inappropriate. Former Commissioner Deason correctly characterized witness Ramas' asymmetrical approach as a "heads I win, tails you lose" philosophy that turns established regulatory principles "on their heads." Tr. 899-900 (Deason).

4. OPC witness Lawton's selective quoting of Order 11-0080 is misleading

As noted in Section II. A. above, Order 11-0080 is very instructive in its interpretation and application of Order 14546 and the recovery of capital projects through the Fuel Clause. Mr. Lawton selectively quotes one paragraph of this instructive order. In his cross-examination (Tr. 751-63 (Lawton), it became readily apparent that Mr. Lawton's coverage of Order 11-0080 was so selective as to be misleading. He left out passages of Order 11-0080 that effectively rebut (a) both of OPC witness Ramas' misinterpretations of Order 14546 Item 10 and (b) his own assertion that the Commission prohibits profits on fuel costs contained in the Fuel Clause.

5. OPC witness Lawton incorrectly asserts Commission policy on recovery of profits through the Fuel Clause precludes recovery of a return on fuel-saving capital projects

Witness Deason effectively rebuts this faulty concept set forth by Mr. Lawton. Tr. 897-99 (Deason). Moreover, the error of his assertion is readily apparent from a thorough reading of either or both Order Nos. 14546 and PSC 11-0080. They authorize a return on investment on capital projects included in the Fuel Clause. If an investment is financed in part with equity, then such a return necessarily includes a return on equity. If he had not been in such a rush to throw mud on the wall with his arguments, Mr. Lawton would have understood his argument was inconsistent with the very orders upon which he ostensibly relied.

6. <u>Fuel Clause recovery of the Woodford Project is not precluded by FPL's 2012 rate case settlement</u>

FPL's legal analysis is set forth in Issue 6 below. It shows that the 2012 rate case settlement does not restrict Fuel Clause recovery pursuant to the Commission's traditional and historical practices, and FPL is requesting recovery of the Woodford Project pursuant established Commission practices on fuel-saving measures and hedging. Moreover, the evidence supports FPL's legal conclusion. Mr. Deason addressed this issue in response to a question by Commissioner Edgar:

> COMMISSIONER EDGAR: Can you speak to the to issue six, which is basically does that stipulation and settlement that was approved by this Commission preclude FPL from seeking these sorts of costs through the Fuel Clause?
>
> . . .
>
> THE WITNESS: … The settlement dealt with base rates. We're in a proceeding that's in the fuel docket. This proposal is consistent with the Commission's policy concerning the handling of investments which save fuel costs. It's appropriately before the Commission within the fuel docket. I do not see a conflict between considering this investment in terms of the fuel docket in that it being somehow prohibited or being somehow in conflict with the settlement.

Tr. 987-88 (Deason).

D. <u>Staff's 50/50 sharing approach is inconsistent with established Commission Fuel Clause policy and fundamental precepts of ratemaking</u>

In depositions and again at hearing, the Commission Staff seemed to suggest some form of a "50/50 sharing" approach. It is not clear whether Staff had a firm proposal in mind (or, indeed, what the particulars of such a proposal would be), or whether Staff was simply raising it as a potential discussion point. To the extent that it was intended as more than a possible discussion point, FPL respectfully submits that such an approach is inappropriate.

1. **<u>A sharing approach is outside the scope of this proceeding</u>**

FPL's petition and testimony do not propose any form of shared approach. Rather, FPL's proposal is to make an investment that will be used and useful in providing a form of risk reduction and savings for customers, effectively no different than many other investments the Company makes. In doing so, FPL has based its request upon established Commission precedent. The Commission's decision should be based upon the petition before it.

2. **<u>There is an insufficient evidentiary basis for the 50/50 concept raised</u>**

Staff presented no witness setting forth just what the 50/50 sharing concept is, how it would operate in practice, or how it would be consistent with any prior Commission precedent. Neither is the concept addressed in the filed testimony of any party, having been raised for the first time in depositions after testimony was filed. Therefore, precisely what was being raised for discussion would have to be deduced from Staff's cross-examination questions. There is insufficient evidence and clarity as to the particulars of the concept that formed the basis for Staff's questions during depositions and at the hearing.[20] The entire focus of this proceeding has been on whether existing established policy applies to the Woodford Project, not whether that policy should be changed.

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[20] FPL is truly uncertain regarding just what Staff's approach would entail. On possible interpretation is that FPL would share with its customers half the actual fuel savings resulting from the Woodford Project; so customers would receive only half of the savings that FPL proposes. In exchange, customers would share with FPL half of something that FPL would receive under FPL's proposal. It is unclear whether what FPL would be required to split is one half of the entire revenue requirements associated with the Woodford Project or just half of the return on equity associated with the Woodford project, two very different values, as most of the Project's revenue requirements do not flow to equity investors, but are just used to pay costs other than an equity return. In addition, if the savings were to be calculated on a year-by-year basis, the result in terms of the sharing could be quite different than if the investment was compared to market prices over the life of that investment which is the way in which this investment is properly assessed. It is also unclear how and to what extent Staff's proposal might affect FPL's achieved rate of return for earnings surveillance purposes. These are just a few of the questions or clarifications that are not addressed in the record.

3. A 50/50 sharing approach would be an abrupt change from long-established, proven Fuel Clause policy as set forth in Order 14546 and its progeny

The policies adopted in Order 14546 were based upon a stipulation involving multiple stakeholders after negotiations. They were developed from consensus building. These policies for promoting the recovery of fuel-saving projects through the Fuel Clause have worked to serve customer interests. Tr. 878-910 (Deason). There has been no showing that those policies will not continue to work, and more importantly, there has been no compelling reason offered, much less proven, as to why the Commission should deviate from the policies.

4. A sharing approach is unnecessary

There is no need for a sharing mechanism, however designed, to protect customers. FPL has a proven record of proposing capital investments designed to generate fuel savings for customers. Tr. 90 (Forrest). It has made such proposals repeatedly in the Fuel Clause. *See* Order 11-0080, Attachment A. It has also made significant investments in fuel-efficient natural gas generation facilities designed to save customers fuel costs. Tr. 90 (Forrest). FPL has been highly successful in those efforts, saving customers more than $6.5 billion in fuel costs since 2001. *Id.* FPL clearly understands it has a duty to act in its customers' interests, and it has repeatedly acted in that fashion, serving customers reliably while keeping bills low. *Id.* There is no basis for the Commission to conclude that reducing the hedging and estimated fuel savings benefits for customers through some sort of sharing mechanism is a better deal for customers than the Woodford Project, as proposed.

Similarly, a sharing approach is unnecessary to motivate utilities to make solid investments that are effective in reducing fuel costs for customers. There is nothing in the record to suggest that the fuel-savings projects previously approved by the Commission and summarize in Order 11-0080, Attachment A were ill-chosen or ineffectively implemented. And, if that ever turned out to be the case, then the Commission would have full authority to evaluate the prudence of the utility's actions.

5. **Sharing proposals misapprehend customer risk**

The premise behind sharing proposals appears to be the idea that the Woodford Project places the risk of market price fluctuations onto customers; therefore, sharing is necessary to mitigate customer risk. In fact, the opposite is true. Under current fuel procurement practices, FPL's customers pay the market price of gas. Tr. 210 (Forrest). That means they are 100% exposed to market price volatility. Tr. 215-17 (Forrest). By tying the cost of gas to stable gas production costs instead of the market price of gas that varies far more than production costs, the Woodford Project protects customers from the risk of natural gas market price volatility. Tr. 217 (Forrest). Simply stated, the Woodford Project does not increase customer risk -- it mitigates price volatility. Tr. 618-19, 627 (Ramas).

6. **A sharing approach would not be in the public interest**

The Commission is mandated by the Legislature to act in the public interest in its regulation of FPL. Section 366.01, Florida Statutes; Tr. 903-04 (Deason). FPL is proposing to invest in the Woodford Project to provide benefits to its customers. Tr. 1002 (Forrest). A sharing proposal would shift 50% of the fuel savings benefits that customers would enjoy to FPL, cutting customers' benefits in half. It is not in the public interest to shift to FPL half the savings designed for customers. Conversely, half of FPL's revenue requirements, or at least half of FPL's authorized return on equity in the Woodford Project, would no longer be paid by customers. This could lead to a confiscatory return to FPL if fuel savings were lower than projected, which is not in the public interest. On the other hand, if fuel savings were greater than expected, it could result in FPL's earnings on the Woodford Project exceeding the authorized return on equity range, which typically would be seen by intervenors as not in the public interest.

The Commission's current policy regarding recovery of capital projects through the Fuel Clause has worked for almost thirty years and has proven to be in the public interest. There is no apparent reason to abandon it in favor of an unclear proposal that stands a good chance of not serving the public interest.

7. **A sharing proposal is at odds with the regulatory policy set forth in statute**

The applicable statutory standard was addressed by former Commissioner Deason:

> Q What does the statute say about the recovery of utility investments?
>
> A. Section 366.06 requires the Commission "to investigate and determine the actual legitimate costs of property of each utility company, actually used and useful in the public service" and that the net investment "shall be used for ratemaking purposes and shall be the money honestly and prudently invested by the public utility company in such property...." So, succinctly, the standard is one of prudently incurred costs in property that serves the public.
>
> Q Does FPL's proposed gas reserves project fall within this statutory provision?
>
> A Yes. FPL is seeking the Commission's determination that its investment in the gas reserves project is prudent and is used and useful in serving the public, such that it is in the public interest and eligible for cost recovery. What is being sought is squarely within the statutory framework and is eligible for cost recovery through the Fuel Clause.

Tr. 905 (Deason).

Under that approach, the investment in the Woodford Project would be prudently invested and used and useful in serving the public. However, the return that would be earned on this significant investment being made to serve customers could vary significantly, for factors outside FPL's control and unrelated to the prudence of FPL's actions. If savings are lower than forecasted, the effective return to FPL could be confiscatory. Conversely, if savings are at the high end of the forecast, FPL could earn far above its authorized return on equity range. This would be a significant departure from the required statutory scheme and the Commission's current implementation of it. There is no compelling reason to deviate from that scheme. As an investment prudently made and used and useful in providing service, FPL is entitled to earn its authorized rate of return on the investment – nothing more and nothing less.

E. <u>Conclusion -- The Woodford Project is properly recovered through the Fuel Clause, without dilution or distortion by a 50/50 approach</u>

It is clear from the evidence and argument offered in this case that the Woodford Project is properly recovered through the Fuel Clause, because it is consistent with Order 14546 and its progeny as well as the Commission policy set forth in Order No. PSC-02-1484-FOF-EI for recovery of hedging costs. The Intervenor witnesses' misinterpretations of Commission policy to the contrary have been definitively rebutted. Finally, there is no valid or supportable justification to dilute or distort the Fuel Clause recovery with either Staff's 50/50 sharing approach or OPC's proposal to limit FPL's recovery asymmetrically to the lesser of each year's production cost of gas or market prices.

IV. ISSUES AND POSITIONS

<u>ISSUE 1:</u> **Should the Commission approve FPL's request to recover the amounts it would pay to its subsidiary for gas obtained from the PetroQuest joint venture through the fuel cost recovery clause on the basis and in the manner proposed by FPL in the June 25 Petition?**

<u>FPL:</u> Yes. FPL's investment in the PetroQuest joint venture is prudent. FPL's investment in the PetroQuest joint venture is projected to provide for $107 million in customer fuel savings over the life of the project. In addition, the PetroQuest joint venture will provide for fuel price stability, effectively acting as a long-term hedge. Because it is designed to reduce the delivered price of fossil fuel (natural gas) and the costs for the PetroQuest joint venture were not recognized or anticipated in the cost levels used to determine FPL's current base rates, the costs associated with the PetroQuest joint venture are appropriate for recovery through the Fuel Clause. The PetroQuest joint venture also provides a longer-term physical hedge to complement FPL's existing program of short-term financial hedges, and it is properly recoverable through the Fuel Clause as a hedging cost. Finally, Fuel Clause recovery of costs for the PetroQuest joint venture appropriately substitutes for Fuel Clause recovery of the volume of purchased gas that it replaces.

<u>ISSUE 2:</u> **If the Commission answers Issue 1 in the negative, what standard should the Commission apply to a request by FPL to recover the price that FPL pays to its subsidiary/affiliate for gas obtained through the joint venture with PetroQuest?**

<u>FPL:</u> Although FPL has agreed to the inclusion of this issue in the Prehearing Statement, it is effectively moot. If the Commission rejects FPL's Petition, FPL will not pursue the PetroQuest joint venture. Instead, FPL's unregulated affiliate, USG Properties Woodford I, LLC will retain all of the rights, benefits and responsibilities of the PetroQuest joint venture. Therefore, the question of what Commission standards would apply to recovery for the PetroQuest joint venture in the event of Commission rejection is purely hypothetical and need not be addressed.

<u>ISSUE 3:</u> **What amount, if any, associated with the transactions proposed in FPL's June 25 Petition should be included for recovery through FPL's 2015 fuel cost recovery factor?**

<u>FPL:</u> For 2015, the amount to be recovered is projected to be $45,473,295, which is based on FPL's share of the costs to be incurred in 2015 for the PetroQuest joint venture. The recovery amount will be adjusted through the normal Fuel Clause true-up mechanism as actual 2015 costs are known.

<u>ISSUE 6:</u> **Is FPL contractually precluded by paragraph 6 of the Stipulation and Settlement Agreement dated December 12, 2012 and approved by the Commission in Order No. PSC-13-0023-S-EI from seeking to increase rates as it proposes?**

<u>FPL:</u> It is FPL's position that Issue 6 is subsumed by Issue 1. Moreover, the premise of this issue is that the PetroQuest joint venture would increase rates, whereas FPL's testimony demonstrates that there is a high probability (85%) that it would reduce rates because of the fuel savings that it would make possible. Regardless of where Issue 6 is addressed, FPL's position on this issue is "no." The first sentence of paragraph 6 in the Stipulation and Settlement Agreement provides expressly that "[n]othing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges …." FPL's request to recover costs associated with the PetroQuest joint venture through the Fuel Clause is fully consistent with the Commission's traditional and historical practices under Order No. 14546 (fuel-saving measures) and Order Nos. PSC-02-1484-FOF-EI and

PSC-08-0667-PAA-EI (hedging), because it is projected to provide net savings for customers and would serve as a valuable longer term physical hedge.

ISSUE 8: **What effect, if any, does Commission's decision on Issue 3 have on the fuel cost recovery factor and GPIF targets/ranges for the period January 2015 through December 2015?**

FPL: If the Commission approves recovery of costs associated with the PetroQuest joint venture through the Fuel Clause, FPL does not propose to revise the fuel cost recovery factors for the period January 2015 through December 2015. Rather, FPL would reflect both the costs and fuel savings associated with the PetroQuest joint venture in the actual/estimated and final true-ups for 2015. The GPIF targets/ranges table that was approved by stipulation at the October 22, 2014 hearing in this docket would change slightly as a consequence of approving cost recovery for the PetroQuest joint venture. As revised, the proper values for FPL in the table would be as shown in Appendix A to this brief.

V. CONCLUSION

FPL respectfully requests that the Commission find that FPL's participation in the Woodford Project is prudent and that the Woodford Project costs are eligible for recovery through the Fuel Clause.

Respectfully submitted this 12th day of December, 2014.

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APPENDIX A

GPIF TARGET AND RANGE SUMMARY
JANUARY THROUGH DECEMBER, 2015

Company (Exhibit)	Plant/Unit	EAF Target EAF (%)	EAF Maximum EAF (%)	EAF Maximum Savings ($000's)	ANOHR Target ANOHR BTU/KWH	ANOHR Maximum ANOHR BTU/KWH	ANOHR Maximum Savings ($000's)	Total Projected Max Fuel Savings ($000's)
FPL (JCB-2)	Ft. Myers 2	84.1	86.6	4,621	7,197	7,064	3,193	7,814
	Martin 8	84.7	87.2	5,003	6,922	6,789	3,875	8,878
	Manatee 3	90.3	92.8	4,322	6,921	6,804	2,802	7,124
	St. Lucie 1	83.5	86.5	10,302	10,405	10,277	4,324	14,626
	St. Lucie 2	84.8	87.8	8,486	10,288	10,142	4,019	12,505
	Turkey Point 3	83.2	86.2	8,459	11,143	10,972	4,506	12,965
	Turkey Point 4	93.6	96.6	9,317	11,002	10,821	5,305	14,622
	Turkey Point 5	91.1	93.6	5,530	7,011	6,861	2,862	8,392
	West County 1	89.8	92.3	5,343	6,794	6,648	5,234	10,577
	West County 2	78.8	81.8	5,692	6,866	6,726	4,367	10,059
	West County 3	90.0	92.0	3,955	6,703	6,568	4,388	8,343
	Total			71,030			44,875	115,905

CERTIFICATE OF SERVICE
DOCKET NO. 140001-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service on this 12th day of December, 2014 to the following:

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