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June 19, 2009

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Ms. Ann Cole, Director
Office of Commission Clerk
Room 110, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Docket No. 090172-EI

Dear Ms. Cole:

Enclosed for filing on behalf of Florida Gas Transmission Company, LLC is an original and 15 copies of the following documents:

1. The redacted version of the Direct Testimony of Benjamin Schlesinger and Exhibit BSA-2 on behalf of Florida Gas Transmission Company, LLC; and

2. The Direct Testimony of Michael T. Langston on behalf of Florida Gas Transmission Company, LLC.

Please indicate receipt of this document by stamping the enclosed extra copy of this letter.

Thank you for your assistance in this matter.

Sincerely,

Floyd R. Self

FRS:amb
Enclosures
cc: Parties of Record

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that true and correct copies of the foregoing have been served by Electronic Mail and/or U.S. Mail this 19th day of June, 2009 upon the following:

Martha Brown, Esq.*
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Floyd R. Self

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090172-EI

FLORIDA GAS TRANSMISSION COMPANY, LLC

DIRECT TESTIMONY OF MICHAEL T LANGSTON

Q. Please state your name and business address.

A. My name is Michael T. Langston. My business address is 5444 Westheimer Road, Houston, Texas 77056.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Florida Gas Transmission Company, LLC ("FGT"). FGT is a limited liability company formed under the laws of the state of Delaware (formerly a corporation incorporated under the laws of the state of Delaware and converted to a limited liability company on September 1, 2006). FGT is a wholly-owned subsidiary of Citrus Corp., the stock of which is owned 50 percent by CrossCountry Citrus, LLC and 50 percent by El Paso Citrus Holdings, Inc. El Paso Citrus Holdings, Inc. is a wholly-owned subsidiary of El Paso Corporation. CrossCountry Citrus, LLC is owned by CrossCountry Energy, LLC, which is an indirect wholly-owned subsidiary of Southern Union Company ("Southern Union").

Q. What are your responsibilities with FGT?

A. I am Senior Vice President, Government and Regulatory Affairs with primary responsibility for rate and regulatory matters for FGT. I hold the same positions with Panhandle Eastern Pipe Line Company, LP; Southwest Gas Storage Company; Trunkline Gas Company, LLC; Trunkline LNG Company, LLC; and Sea Robin Pipeline Company, LLC.

Q. Please describe briefly your educational and professional background.

A. I received a Bachelor of Science Degree in Electrical Engineering with honors from the University of Texas at Austin in 1975. I received a Master of Business Administration from Southern Methodist University in Dallas, Texas in 1978. I was employed by Mobil Pipe Line Company from 1975 to 1979 in various positions in their engineering and project development departments. From 1979 to 1986, I was employed by Texas Oil & Gas Corp. and its affiliate, Delhi Gas Pipe Line Corporation, holding various positions in corporate planning, special projects, and project development. I joined Southern Union in September 1986 and have been employed by Southern Union and its affiliates since that time, holding various positions involving gas supply, gas marketing, gas control, contract administration, business development, and state and federal regulatory areas. For the period from September, 1986 to September, 2002, I had primary responsibility for supply and transportation contracting for Southern Union operations in Texas, Missouri, and Florida. I am also a Registered Professional Engineer in the states of Texas, Oklahoma, and Louisiana.

Q. Have you previously testified or presented testimony before the Florida Public Service Commission ("FPSC")?

A. I have not previously testified before the Florida Public Service Commission, but have submitted testimony in state proceedings in Texas, New Mexico, Arizona, and Missouri. I have also provided testimony at the federal level at the Federal Energy Regulatory Commission ("FERC").

Q. What is the purpose of your testimony?

A. The Florida Power and Light Company ("FPL") proposed $1.6 billion intrastate Florida EnergySecure pipeline ("FES") is not in the best interests of the ratepayers and should be denied. My testimony will address why FPL has failed to demonstrate the need for its proposed intrastate pipeline and, alternatively, if the FPSC approves the project, why the FES pipeline should not be included in rate base but rather in a separate subsidiary. Specifically, my testimony will: (1) demonstrate that the natural gas demand identified by FPL in its petition and direct testimony does not warrant the proposed $1.6 billion pipeline; (2) discuss the lack of a complete analysis of the supply and transportation costs upstream of Transcontinental Gas Pipe Line Company, LLC ("Transco") Station 85 and the alternatives not considered by FPL; (3) discuss upstream supply and transportation costs not included in the FPL analysis and how the failure to address these costs undermines FPL's FES pipeline; (4) evaluate the investment alternatives FPL considered and the adverse impacts on FPL's customers because of the cost recovery methods FPL proposed; (5) review the alternate cost recovery methods that should be considered for these facilities and why they do not support approval for the

FES system; and (6) discuss other policy matters this Commission should evaluate and the adverse consequences on ratepayers if FPL's proposal is adopted.

Q. Please briefly describe the prepared testimony of FGT's other witnesses in this proceeding.

A. Dr. Benjamin Schlesinger of Benjamin Schlesinger & Associates will provide testimony reviewing the economic and cost issues inherent in FPL's filing, including gas price projections, basis forecasts, and rate inconsistencies that undermine claims of the need for the FES system.

Q. What exhibits are you presenting in this proceeding?

A. I am responsible for the following exhibits:

Exhibit No.	Description
MTL-1	Map of FGT pipeline system
MTL-2	Map of FGT system w/Phase VIII expansion
MTL-3	FGT Expansions into Florida
MTL-4	FPL Ten Year Site Plan Filings
MTL-5	FPL Response to FGT Interrogatory No. 53

MTL-6	FPL Response to Staff Interrogatory No. 23-1.
MTL-7	May 7, 2009 FERC Order on Transco Mobile Bay South Expansion Project
MTL-8	July 25, 2008 FERC Order on MidContinent Express Expansion
MTL-9	September 28, 2007 FERC Order on Gulf South Southeast Expansion Project
MTL-10	December 3, 2008 Tariff Filing for Gulf South Southeast Expansion transportation rates
MTL-11	Map of Expansion capacity in the Perryville area
MTL-12	EIA Report, Natural Gas Market Centers: A 2008 Update, April, 2009
MTL-13	March 18, 2009 FGT Proposal

MTL-14 Basis Prices Chart June 11, 2009

Background [Issues 2, 5, and 10]

Q. Please describe the FGT system and the services it offers within the state of Florida.

A. FGT operates an approximate 5,000-mile pipeline system with extensive access to diverse natural gas supply sources with interconnected supply receipt point capacity of over13 Bcf/day(billion cubic feet per day) of supply capability. FGT can transport and deliver up to 2.3 Bcf/day of natural gas to the Florida peninsula. The Florida customer base includes electric utilities, independent power producers, industrials, and local distribution companies. FGT provides firm and interruptible transportation services and is interconnected to many storage providers capable of providing up to 187 Bcf of storage capacity with approximately 4 Bcf/day of delivery capability into FGT. A map of the FGT system is attached as Exhibit MTL-1.

Consistent with the presentation by FPL, in my testimony I utilize one (1) million cubic feet per day (MMcf/day) as equal to 1,000 million British thermal units (Btu) per day (MMBtu/day). This assumed a constant heat content of 1,000 Btu per cubic foot of natural gas. I will refer to capacity in Mcf/day (thousand cubic feet per day), MMcf/day (million cubic feet per day), or in Bcf/day (billion cubic feet per day) and refer to transportation costs in dollars per MMBtu/day.

Q. Please describe any expansions currently underway or planned by FGT.

A. FGT held an open season from January 14, 2008 through February 15, 2008 to solicit interest in an expansion of the FGT system. As a result of the open season, FGT filed a certificate application with the FERC on October 31, 2008 to construct an expansion to increase its natural gas capacity into Florida by approximately 820 MMcf/day. The proposed Phase VIII Expansion includes construction of approximately 500 miles of large diameter pipeline and the installation of approximately 200,000 horsepower of compression. Pending FERC approval, which is expected in the latter half of 2009, FGT anticipates an in-service date by April 1, 2011. The current estimated cost of the Phase VIII expansion is approximately $2.4 billion, including capitalized equity and debt costs. To date, FGT has entered into precedent agreements or amended precedent agreements with shippers for transportation services for 25-year terms accounting for approximately 74% of the available expansion capacity which, depending on elections of certain shippers, may increase to 83% of the capacity being added. A map of the Phase VIII expansion facilities is included as Exhibit MTL-2.

Q. Did FPL contract for any of the FGT Phase VIII Expansion capacity?

A. Yes. Prior to the conclusion of the open season, which ended on February 15, 2008, FGT issued an announcement that FPL had agreed to become the anchor shipper of the proposed expansion with a 25-year service agreement of 400,000 Mcf/day. This is also outlined in the testimony of FPL witnesses Sharra and Sexton.

Q. During this process, did FGT indicate a willingness to expand to provide even more capacity to FPL?

A. Yes. However, FPL elected to only contract for the 400,000 Mcf/day of additional capacity.

Q. Would FGT have been willing to provide additional capacity to FPL if requested?

A. Yes.

Q. And what would have been the consequences of such a request?

A, We certainly would have factored such requests into our expansion proposal just as we did for the other shippers. To the extent FPL was willing to contract for such additional capacity, we would have increased the proposed capacity addition in our expansion filing. I find it interesting that in the three months following the close of our open season FPL filed its determination of need cases for the two power plant conversions that FPL claims are now driving the demand for its new pipeline. These power plant conversion projects are not developed overnight. Thus, even if FPL had not fully developed the specific gas needs for these plants by the conclusion of the open season, they certainly could have advised us of their potential need and we could have factored that in to our Phase VIII expansion.

Q. Has FGT expanded its system in the past when needed to serve increasing loads in Florida?

A. Yes. Exhibit MTL-3 is a graph that shows the capacity capabilities of FGT in the Florida market for the expansions from its Phase I expansion to the current Phase VIII expansion. As shown, following the Phase VIII expansion, FGT will have a system capacity of 3.0 Bcf/day, an increase of 275% from the capacity following the Phase I expansion in 1987.

Q. Once the Phase VIII expansion is completed, will FGT have excess capacity in its system?

A. Yes. Depending on the election of one shipper FGT will have excess capacity of between 139,000 Mcf/day to 214,000 Mcf/day.

Q. Could this capacity now be utilized to serve the FPL loads at Cape Canaveral and/or Riviera even though these plants were not part of the original Phase VIII expansion?

A. Yes. The excess Phase VIII capacity could be utilized to serve these needs with some additional facility expansions to add capacity to those delivery points. For example, with the addition of one compressor station at an estimated cost of less than $50 million, FGT could provide an additional 200,000 Mcf/day of excess Phase VIII capacity to the existing FPL oil/gas line, which is then capable of delivering this capacity to the Riviera plant.

Q. Would FGT be able to deliver this excess capacity to Riviera on the time schedule FPL has proposed?

A. Yes. Such facilities could be designed, approved, constructed, and in service by the January 1, 2014 date outlined by FPL in testimony.

Q. Could any of this excess Phase VIII capacity be delivered to Cape Canaveral?

A. Yes, but it would require the construction of a new lateral and other facilities to deliver the gas. While this would not be as simple as for Riviera, it could still be done in a timely and cost effective manner.

Q. How would FPL's ratepayers pay the costs associated with delivering this capacity to Cape Canaveral or Riviera?

A. The cost to the rate payers would be just like any other transportation cost. It would be passed through the fuel charge. In addition, FPL would be able to contract for only the capacity it needed, and not burden its ratepayers with the cost of additional unused capacity, such as is being proposed by FPL in this proceeding.

The Solicitation Process [Issues 1 and 2]

Q. Before FPL initiated this determination of need proceeding, FPL solicited proposals for transmission capacity. Was FGT one of those parties that responded to FPL's invitation for proposals?

A. Yes we did. In fact, FGT made two formal written proposals, one on September 2, 2008, and an updated response dated March 17, 2009 and received by FPL on March 18, 2009 (referred to as the March 18, 2009 Proposal). In addition, between these two formal proposals, FGT and FPL undertook a series of exchanges that led FGT to submit to FPL two emailed proposals between the formal written responses, one being sent on October 9, 2008, with the other sent on January 12, 2009.

Q. Why did FGT submit the two emailed proposals and the final formal written proposal on March 18th?

A. The discussions between FGT and FPL were an ongoing process through which FPL continued to clarify some of its operational parameters, including the specific gas volumes being considered, which required FGT to revise its proposal over time to meet the changing circumstances. In addition, the market for steel prices was on an upward spiral in the fall of 2008, but by March 2009 steel prices were declining, and so the FGT proposals reflect these market dynamics as well.

Q. Based upon what FPL has said about the proposals it received, has the FGT proposal been identified by FPL in its direct testimony.

A. Yes. FGT's January 12, 2009 proposal has been identified by FPL as the "Company B" proposal, and included in its economic analysis. The March 18, 2009 proposal is simply referred to as an unsolicited update, and the improved cost information was not specifically analyzed by FPL.

Q. Can you briefly describe the terms of this proposal to FPL?

A. As FPL has described, the FGT proposal provided interstate pipeline transportation capacity that originated at various pipeline interconnects at Citronelle, Alabama, and delivered natural gas capacity to both the Cape Canaveral and Rivera energy centers. The proposal essentially involved various additional looping to the existing FGT pipeline system as well as additional compression facilities. The cost of these facilities would be approximately $1 billion. I have attached a copy of our March 18, 2009 Proposal as MTL-13.

Q. Does this proposal represent FGT's final and best offer to FPL to serve Cape Canaveral and Riviera?

A. No. As I said in connection with the evolution of our proposals from the original formal written proposal in September to the March proposal, the discussions over time with FPL led to FGT obtaining additional information about the real parameters of what FPL was seeking. FPL has continued to change these requirements even with the filing of the Petition in this docket. For example, FPL never identified to FGT the availability of converting the 36 mile oil/gas pipeline from the Martin plant to the 45th Street Terminal near the Riviera Plant. FGT's cost includes approximately $132 million of capital to provide additional directly connected capacity to the Riviera Plant. If we had known of the availability of this FPL-owned pipe, we would have incorporated those savings into our proposal as well.

Q. Overall, did the FGT March 18, 2009 Proposal meet the operational and other objectives set forth by FPL in its solicitation?

A. Yes. The March 18, 2009 Proposal met the FPL stated objectives at the time, assuming the need for the additional natural gas transmission capacity identified by FPL. FGT's proposal is superior to FPL's proposed FES pipeline.

Q. Can you explain why this is true?

A. The Commission cannot consider the intrastate pipeline in a vacuum. While the upstream or interstate pipeline that will deliver gas to the intrastate pipeline is not before this Commission, the cost and consequences of the interstate pipeline are going to have a direct impact on the FES pipeline and certainly the Florida ratepayers. Thus, when considered on an end to end basis, comparing the combined Company E interstate pipeline and the FPL intrastate pipeline to the interstate pipeline proposed by FGT, FGT's proposal involves less total cost, less cost impact on ratepayers, and greater access to more diverse gas supplies than the Company E/FES pipeline proposal put forth by FPL.

Q. Can you elaborate on these points?

A. Yes, in connection with each of the identified issues in this case, I will address why the Commission should not certify the need identified by FPL and certainly not its proposed $1.6 billion intrastate FES pipeline. In order to better understand the problems inherent in the FPL pipeline proposal, it is necessary to first review the basic demand projections provided by FPL that underlie FPL's claimed need for additional transmission pipeline.

Demand Projections [Issues 1, 3, and 5]

Q. Are FPL's capacity requirements based on sound assumptions?

A. No. There are significant differences between FPL's forecasts and other published documents. A review of the publicly filed documents and associated projections does not justify the needs claimed by FPL. I will discuss the differences in the overall population growth projections as well as the capacity and peak day requirements outlined in FPL's filings.

Q. Has FGT reviewed the population projections that form the basis of the long term demand requirements?

A. I have reviewed the testimony of FPL witness Morley. As outlined in Dr. Morley's testimony, the population projections utilized were based on work performed by the University of Florida, with the most recent data dated from October, 2008.

Q. Did FPL make any adjustments to the data?

A. Yes. Dr. Morley adjusted the forecast data between 2012 and 2022 to provide an increase of over 30% higher population growth per year as compared to the University of Florida projections.

Q. Do the more recent University of Florida projections support this FPL adjustment?

A. No. Dr. Morley has outlined that the University of Florida projected population growth of 127,000 in 2008 and 75,000 in 2009, or a total of 202,000 for the most recent two year period. Bulletin # 153 published by the Bureau of Economic and Business Research of the University of Florida ("EBR Bureau"), and dated March, 2009, indicates that population growth in 2009 and 2010 will average only 37,000 people per year, or a total of only 74,000 over the two year period. Following that, the long term growth will continue to average less than 255,000 per year as outlined in the previous projections.

Q. Does this call into question the basis of the adjustments made by FPL?

A. Yes, FPL's adjustments are unreasonable. After FPL increased the October 2008 data, the EBR Bureau's March 2009 projections show an expected population growth in 2010 of approximately 37,000 versus a forecasted level of 75,000 only five months previous. This seems to indicate that the impact of the current economic recession may, in fact, have the longer lasting effect of decreased population growth expected by the University of Florida.

Q. Are there other inconsistencies in the FPL data?

A. Yes. Attached as Exhibit MTL-4 is a comparison of FPL's 2008 Ten Year Site Plan natural gas requirements forecast to the 2009 Ten Year Site Plan natural gas requirements forecast. In addition, I have compared the annual daily average gas demand to the existing combined daily transport capacity of the FGT and Gulfstream Natural Gas System, LLC ("Gulfstream") pipelines that is held by FPL. As shown on MTL-4, on an average daily basis, FPL does not have a need for additional firm capacity for the term of the 2009 Ten Year forecast. Notably, for the period from 2014 through the end of the forecast period, there is a minimum excess capacity of between 271,041 Mcf/day and 520,641 Mcf/day. Certainly this does not support the construction of an additional 600,000 Mcf/day of capacity.

Q. Doesn't FPL have to consider its peak day supply demand in its planning?

A. Yes. Attached as Exhibit MTL-5 is FPL's response to FGT's Interrogatory No. 53, which shows that over the last three years, the peak capacity requirements for FPL have not exceeded 1,716,604 MMBtu/d(Mcf/day equivalent). With the addition of the maximum projected load of 400,000 Mcf/day at the Cape Canaveral and Riviera plants, the total peak could be estimated at 2,116,604 Mcf/day. Given this peak load estimate, and FPL's existing contracts for 1,911,852 Mcf/day of capacity following the FGT Phase VIII expansion, this indicates a need for a capacity addition, in 2014 of approximately 200,000 Mcf/day, not the 600,000 Mcf/day planned under the FES proposal.

Q. Is this different than the natural gas requirements FPL expects in this proceeding?

A. Yes. Based upon the FPL response to Staff Interrogatory No. 23-1, the forecasted natural gas requirements that form the base case in this docket are higher than the forecast in the 2009 Ten Year Site Plan requirements. For example, in 2014, FPL indicates a requirement of 2.312 Bcf/day, while in the ten year site plan, filed only one week prior to the filing of this docket, the natural gas requirements would average 1.391 Bcf/day. I first assumed that FPL's answer to Staff's Interrogatory No. 23-1 reflected a peak day demand scenario, but in comparing this to the data in Exhibit MTL-5, the numbers shown for 2009 and 2010 do not approach the peak day requirements FPL outlined for 2006-2008. Attached as Exhibit MTL-6 is a copy of the FPL response to Staff Interrogatory No. 23-1.

Q. Are the expected loads at Cape Canaveral and Riviera the difference in the forecast?

A. No. The expected loads at Cape Canaveral and Riviera were included in the Ten Year Site Plan filed by FPL on April 1, 2009. However, in the forecast provided in Exhibit MTL-5, FPL is indicating a capacity need in 2011of 1.920 Bcf/day, a number that is almost exactly equal to the transport capacity FPL will have under contract. However, there is no reconciliation as to the peak day usage and the total capacity numbers. From the data in Exhibit MTL-6, the peak day demand would have to grow by almost 12% in a period when the population growth projections are almost flat.

Q. Does this create a question as to the need for additional pipeline capacity?

A. Yes. There appears to be an incomplete analysis of demand. At this time, while there may be a need for 200,000 Mcf/day of additional capacity, there does not appear to be a need for the 600,000 Mcf/day planned to be constructed in this filing.

Q. So is there a demand basis for FPL's proposed expansion?

A. No. It seems clear that additional facilities would be needed to deliver an incremental 200,000 Mcf per day of supplies to the Cape Canaveral plant after conversion. However, the 200,000 Mcf per day of capacity needed at the Riviera plant after conversion could possibly be met by excess FGT Phase VIII capacity. FGT's filed recourse rates are substantially below that proposed by the Company E/FES proposal. As indicated to FPL, FGT is willing to contract to provide this incremental Phase VIII capacity.

Q. Based on the demand information available at this time, and provided by FPL, has FPL substantiated a Commission finding in this docket for the certification of the requested need?

A. No, the various forecasts provided by FPL are unreconciled, and do not support the requested need.

Q. If you assume that over time FPL might eventually grow into its proposed $1.6 billion pipeline, would the construction of the pipeline now create competitive benefits that would outweigh the lack of demand over the next ten or more years?

A. No. The systems currently serving the state of Florida are regulated and based on cost of service ratemaking. Given these constraints, there is not the ability of the existing pipeline systems to exercise market power and arbitrarily increase prices. Pipeline capacity can be provided under regulations designed to protect both existing customers and expansion services as needed by the market. An assumption that creation of additional, excessive capacity will create greater competitive pressures in a regulated market reflects a serious misunderstanding of how this market works. Similarly, justification for a "third" pipeline through a calculation of market concentration in such a regulated environment also does not justify an additional $1.6 billion pipeline on competitive grounds. The Commission should deny FPL's request due to insufficient demand to justify a 600 MMcf/day new pipeline.

Supply and Transportation Alternatives

Upstream of Transco Station 85 (Issues 3, 5, 6, and 10)

Q. FPL has indicated that access to Transco Station 85 is needed in order to provide expanded access to natural gas supplies not now available to FPL. Do you agree?

A. No. In fact, the majority of supplies FPL plans to access at Transco Station 85 can also presently be accessed via FPL's existing capacity on the Southeast Supply Header ("SESH") system through purchases at the Perryville, Louisiana area.

Q. In FGT's proposal, did FGT seek to provide FPL with access to supplies from Transco Station 85?

A. No. To better meet the diversified supply objectives, FGT proposed to interconnect at Citronelle, Alabama, where the existing Transco Mobile Bay lateral interconnects with the FGT system. In addition, FGT offered to transport supplies from other interconnects offering greater supply diversity than available at Transco 85. FGT's proposal provided FPL with greater options for supply contracting.

Currently, interconnects already exist between the Transco Mobile Bay lateral and the FGT and Gulfstream systems to supply gas to FPL from the Transco system. Transco has announced plans to increase its ability to move supplies from interconnects at or near Transco Station 85 to both FGT and Gulfstream, with such expansion plan recently approved by the FERC. The proceeding is FERC Docket No. CP08-476-000, which was approved by FERC order dated May 7, 2009, whereby Transco is adding the ability to move an additional 253,000 Mcf/day of capacity between Transco Station 85 and the FGT and Gulfstream systems. This expansion should be in service by May, 2010. A copy of the May 7, 2009 FERC order is attached as Exhibit MTL-7.

Q. Did FPL participate in this expansion to expand the access to Transco Station 85 supplies?

A. No. Transco held an open season for this expansion from October 17, 2007 through November 16, 2007 soliciting interest in expanded capacity from Transco Station 85 to interconnects with FGT and Gulfstream. FPL did not contract for capacity, but Progress Energy Florida, Inc. ("PEF") did participate in this expansion.

Q. Would Transco be able to expand and provide even greater amounts of capacity to move gas from Station 85 to the FGT and Gulfstream systems?

A. Yes. Transco has recently held an open season for a further expansion of its capacity to move gas from Station 85 to FGT and Gulfstream. The open season for up to 550,000 MMBtu/day of year-round firm transportation service was conducted from January 22, 2009 to February 26, 2009, while FPL was in the process of evaluating how to deliver gas to the Cape Canaveral and Riviera plants. Transco indicated in the open season announcement that the maximum rates applicable to the expansion would be the maximum daily firm reservation rate and commodity rate under Transco Rate Schedule FT for Zone 4a, which is approximately 9 cents per MMBtu. The proposed in service date would be as early as May, 2011.

Q. What is driving these expansions?

A. As pointed out in FPL witness Sexton's and Sharra's testimony, several other upstream system expansions are underway to bring additional amounts of supply from production areas in Texas, Oklahoma, Arkansas, and Louisiana to many pipeline interconnects, including in the Perryville, Louisiana area, and also farther east to interconnect with Transco at or near Station 85. Historically, the demand for natural gas in the markets served by Transco is the highest during the winter season, when gas is needed for heating loads as well as electric generation demands.

Alternatively, the natural gas demand in Florida is highest in the summer, primarily for the generation of electricity to serve air conditioning loads. Therefore, supply deliveries to Transco Station 85 can access both winter and summer markets for natural gas.

Q. Are there other markets that this production could serve?

A. Yes. All of the expansions upstream of Transco Station 85 mentioned by FPL witnesses also interconnect with other interstate and intrastate pipelines in the Perryville, Louisiana area. As such, those systems are capable of serving the Midwest United States markets, as well as some other systems serving the Northeast United States markets as well. These supplies will also interconnect with the existing Destin Pipeline Company, LLC ("Destin") system which delivers gas into the FGT system.

Q. With so many market alternatives, where do you expect this gas to move once these systems are in service?

A. It appears that FPL has not performed this analysis. FGT knows from experience as a transportation provider that the gas will move to the market providing the highest net-back price to the producer. As such, the transportation cost between these points, as compared to the ultimate market price available for gas at these points, will determine where the gas is delivered.

Q. Are the transportation alternatives and costs between Perryville and Transco Station 85 available today?

A. For the Boardwalk Pipeline Partners, LP ("Boardwalk") and Mid-Continent Express Pipeline, LLC ("Midcontinent Express") expansions that FPL references, the filings made with the FERC show the applicable transportation costs. For Mid-Continent Express, the certificate order dated July 25, 2008 in FERC Docket No. CP08-6-000 and CP08-9-000, indicate that once fully expanded, the tariff recourse transport rates from an Enogex interconnect at Bennington, Oklahoma to an interconnect with Columbia Gulf Transmission near Delhi, Louisiana (in the Perryville area) will be at $0.2892 per MMBtu on a 100% load factor basis. The transport rate from the Columbia Gulf interconnect to Transco Station 85 will be $0.2506 per MMBtu on a 100% load factor basis. A copy of this July 25, 2008 FERC certificate order is provided as Exhibit MTL-8.

The Boardwalk expansion referred to by FPL is an expansion of the Gulf South Pipeline Company, LP ("Gulf South") interstate pipeline owned by Boardwalk. This expansion picks up gas from the terminus of the previous Gulf South expansion that provided capacity of 1.7 Bcf/day from East Texas to the Perryville area and terminating near Harrisville, Mississippi. This previous expansion is interconnected to many pipelines in the Perryville, Louisiana area. For the Gulf South Southeast pipeline system expansion, filed in FERC Docket No. CP07-32-000, this pipeline is further expanded to extend to an interconnect with Transco at Station 85 in Alabama. The incremental transportation rate over this portion of the system is approximately $0.1659 per MMBtu. Gulf South also leased capacity from Destin, at an additional cost of $0.065 per MMBtu, to allow deliveries to be made directly to FGT or Gulfstream if this leased capacity on the Destin pipeline is used. The total expansion capacity on the Boardwalk/Gulf South system is 660,000 Mcf/day, with the capability to deliver 260,000 Mcf/day to FGT and/or Gulfstream utilizing leased capacity on the Destin system. A copy of the FERC certificate order dated September 28, 2007 for the Boardwalk/Gulf South project is provided as Exhibit MTL-9, and the associated tariff filing dated December 3, 2008 is provided as Exhibit MTL-10.

Q. As a result of the growth of supply volumes in the shale gas areas, are there other expansions being contemplated or proposed?

A. Yes. Recently, Energy Transfer Partners, L. P. proposed its Tiger pipeline to transport additional shale gas production volumes to the Perryville, Louisiana area. This indicates a growing amount of such unconventional gas supply showing up at the Perryville area. As such, this point has the potential to become a very liquid supply trading point. Attached as Exhibit MTL-11 is a simplified map that shows various pipeline systems from the Oklahoma/Texas/Arkansas area into Perryville, and systems out of Perryville to points farther east, such as Transco Station 85.

Q. Do you have any support for your position that the Perryville area is a more liquid supply point as compared to Transco Zone 4 (Station 85)?

A. Attached as Exhibit MTL-12 is a report prepared by the Energy Information Administration dated April 2009, which reviews Natural Gas Market Centers in the United States. As shown in the report, the Perryville area market center had the largest increase in total interconnect capacity between 2003 and 2008 as compared to any other natural gas market center in the United States.

There is not currently a market center identified in Transco Zone 4 or at Transco Station 85. While supply access may also be increasing at Transco Station 85, there will not be the liquidity that is available at the Perryville area. Greater liquidity translates into more competitive gas prices.

Q. Are the current market prices for gas at the Perryville and Transco Station 85 points available today?

A. Yes. Market prices for gas delivered to pipelines in the Perryville area and to Transco Zone 4, which is the zone in which Transco Station 85 is located, are both available on a daily basis. For gas delivered in the Perryville area, the index prices for ANR SE and Columbia Gulf mainline are indicative of Perryville area prices. Attached as Exhibit MTL-14 is a chart that shows the NYMEX natural gas price at the Henry Hub by month from July, 2009 through December, 2012. In addition, the basis swap prices, or price above or below the Henry Hub price, is shown for prices at ANR SE and Columbia Gulf mainline (Perryville area), Transco Zone 4 (Transco Station 85), and FGT zone 3 pricing. FGT Zone 3 would include supply receipts from interconnects with SESH, Destin, and Transco.

Q. What does the comparison of these prices point out?

A. The average pricing over the 42 month period is (1) approximately \$0.09 to \$0.14 below the Henry Hub price for the Perryville area, (2) approximately \$0.0333 below the Henry Hub price for the Transco Station 85 area, and (3) approximately \$0.0389 above the Henry Hub price into FGT in Zone 3.

Q. When comparing the market prices and transportation costs, what conclusions can be drawn?

A. At this time, given the transportation cost from the Perryville area to Transco Station 85, it appears that the market prices for gas at the Perryville Hub would provide better netbacks to producers as compared to the expected pricing at Transco Station 85. However, once all gas demand at that location is met, then gas would move to other markets, such as to planned interconnects at Transco Station 85. For gas supplies that do move from the Perryville area to southeast markets, based on filed tariffs, the Gulf South expansion in conjunction with the Destin lease capacity, excluding fuel, would be approximately $0.23 per MMBtu. When compared to a transport rate from Perryville to Transco Station 85, then to FGT, this is a much lower cost alternative, and would seem to offer better overall economics for producers and/or customers.

Q. Did FPL include any analysis of this in their filing?

A. It does not appear so.

Q. Would there appear to be other alternative supply points that FPL should consider?

A. FPL has contracted for 500,000 Mcf/day of capacity from the Southeast Supply Header LLC ("SESH") which allows them access to Perryville supplies. These volumes can then be moved into their existing capacity on the FGT and Gulfstream systems. It appears that Perryville will be a much more liquid supply trading area as compared to Transco Zone 4 (Station 85 area).

Q. Have all of the transportation alternatives upstream of Transco Station 85 been analyzed by FPL?

A. No. Supplies from Boardwalk and Midcontinent Express are also capable of interconnecting to the Destin system. This system is also currently interconnected to the FGT and Gulfstream systems, and also accesses storage capacity. As noted, Boardwalk (Gulf South) holds a lease on the Destin system, and for an incremental charge of $0.065 per MMBtu it can deliver gas directly to FGT and/or Gulfstream.

Q. Were the supply interconnect alternatives you discuss offered to FPL in the proposal made by FGT?

A. Yes. FGT offered to provide transportation capacity from interconnects with SESH, Destin, Transco, and other supply connects. This would seem to provide more supply options to FPL, particularly for various transport paths back to the Perryville area, which will clearly be the most liquid supply point.

Q. Based upon this analysis, is the proposed originating point of the FPL intrastate pipeline appropriate?

A. No. The originating point of the FPL intrastate pipeline is based upon where Company E will interconnect its new interstate pipeline, and Company E's pipeline will originate and interconnect at Transco 85. The entire design of both pipelines, and certainly for purposes of this Commission's review of FPL's intrastate pipeline for the originating point of FPL's pipeline, is to obtain new and more diversified supply options. As I have discussed, while you certainly get what is available at Transco 85, FPL's stated objective is not sufficiently met by originating at Transco 85. In this case, FGT's proposal is superior but also the only proposal that reliably and consistently meets the stated objectives.

Supply Pricing [Issues 5, 9, and 10]

Q. Did FPL's witness Sexton provide supply pricing information?

A. FPL witness Sexton indicated that he projects supply pricing at Transco Station 85 to be $0.0375 lower than the Henry Hub price. He did not review or comment on supply pricing at the Perryville area, or the expected transport cost to move supplies between these points.

Q. In your opinion, does the supply analysis presented by FPL appear to be complete?

A. No. The FPL analysis is designed to focus solely on supply access at Transco Station 85, which in turn supports the proposed Company E/FES option for transport capacity. While claiming to promote new, diverse supplies it unnecessarily limits options.

Q. What is the consequence of this lack of supply analysis by FPL?

A. The analysis prepared by FPL, even if assumed to be correct, would likely leave FPL's customers paying a higher overall cost for gas as compared to supply pricing that could be accessed at the Perryville area. In addition, the transportation costs between Perryville, Transco Station 85, and FGT have clearly not been adequately analyzed by FPL.

Transportation Alternatives Downstream of Transco Station 85 [Issues 1, 2, 5, 11, and 13]

Q. What is FPL proposing in this docket?

A. Based on its analysis, FPL is requesting the FPSC to approve a contract with Company E for 600,000 Mcf/day of capacity under a 20 year arrangement. This would provide capacity from Transco Station 85 to an interconnect with the proposed FES pipeline near FGT Compressor Station No. 16 in Bradford County, Florida. These arrangements would begin providing transportation capacity to the planned new natural gas generation units to be located at the FPL Cape Canaveral and Riviera Beach plants by January 1, 2014. The proposal will also provide delivery capacity to the natural gas generating units at the FPL Martin plant in Martin County, Florida.

Q. Does FPL have a need for 600,000 Mcf/day of additional capacity beginning January 1, 2014?

A. No. FPL acknowledges that, even based on its own forecast, it would only have a need for 400,000 Mcf/day of additional capacity for at least the next 8-10 years. In reality, as noted previously in my testimony, even on a peak day basis, it does not appear that FPL needs more than approximately 200,000 Mcf of additional capacity.

Q. Who will bear the cost of the excess capacity?

A. FPL is proposing to include its investment in the FES pipeline in its rate base. Presumably any increased operation, maintenance, third party operation cost, general and administrative expenses, taxes, and other costs would also be recovered as part of FPL's overall total cost of service and rate design. As such, any cost attributable to excess capacity will be fully borne by FPL customers through their electric rates. That is a $1.6 billion investment which under FPL's best scenario is only two-thirds necessary but which realistically may only be, at best, one-third necessary.

Q. How has FPL dealt with this in their rate analysis?

. FPL has provided annual cost of service type calculations and assumed a 100% load factor (i.e. that all 600,000 Mcf of capacity is utilized every day) and arrived at an equivalent transportation rate to include in its economic analysis. For example, the first year rate is approximately $1.32 per MMBtu.

Q. Do you view this rate calculation as correct?

A. No. FPL has put forward a rate in its analysis assuming the full system utilization of 600,000 Mcf/day, when clearly FPL needs, according to its testimony, only 400,000 Mcf/day of capacity, and more likely less than that. As such, the equivalent first year transport rate FPL calculates is substantially understated. The rate could be substantially higher, depending on actual usage. While FPL has proposed to credit any third party revenues from other transport services, no estimate of such credits is available, nor would such credits reasonably offset the true cost of excess capacity of 200,000 Mcf/day. Besides, FPL has said that such transport services, and hence any revenues derived from transportation, is not a part of the proposal before the Commission, and so such speculation should not be included in this case.

Q. Does FPL propose to recover the Company E expenses in the same manner as the recovery of the FES pipeline costs?

A. No. For the upstream Company E transportation costs, FPL proposes to recover these costs via the fuel cost recovery mechanism currently in place.

Q. Does this mean that the overall cost for the Company E/FES proposal is recovered by different means?

A. Yes. The Company E transport cost will be recovered by inclusion in the fuel cost recovery mechanism, while the cost of the FES pipeline will be rolled into the FPL electric rates, and recovered from ratepayers through base electric rates.

Q. Are the costs of the FGT proposal recovered in a similar manner?

A. No. The FGT cost would all be recovered via the fuel cost recovery mechanism.

Q. Does this different rate recovery mechanism affect the economic outcome of the alternative analysis?

A. Yes. FPL has compared the alternatives to its FES proposal assuming a calculation of rates on a similar basis. However, this is not how FPL is proposing to actually recover the costs associated with its proposal. While FPL has the option of only contracting for the 400,000 Mcf per day of capacity it states it actually needs, by proposing to construct excess capacity, and include the excess cost of such capacity in electric rates, this leads to greater cost to its customers.

Q. What is the level of excess cost that the customers may be paying?

A. The actual level of excess cost will be determined by the actual system usage. However, for comparison purposes, based on FPL's analysis of FGT's proposal, including its assumption of cost from Transco Station 85 to Citronelle, Alabama, the total cost under the March 18, 2009 proposal would be approximately $1.88 per MMBtu. This was for capacity of 400,000 Mcf/day, the amount FPL admits it needs, and the $1.88 per MMBtu for this 400,000 Mcf/day of capacity would have an annual cost of $274.48 million. If you assume the exact same cost of $1.88 per MMBtu, but for a contract for 600,000 Mcf/day, the annual cost would be $411.72 million. This is an annual incremental additional cost of $137.24 million, or 50% higher than the annual cost of the FGT proposal. Since under the most favorable of circumstances the additional 200,000 Mcf/day of capacity will not be needed until at least 8 years after the system begins operation, this would leave the customers paying an additional incremental $1.1 billion in only 8 years.

Q. Is the Company E/FES proposal at the same rate as that proposed by FGT?

A. No. As outlined in my testimony, due to the different rate recovery proposals, it is difficult to make a direct comparison. However, if you look at only the initial 20 year term, where the pipeline rate proposals are fixed, and you take the average of the FPL declining rate calculations, the per unit rate would be slightly higher than that proposed by FGT. However, as shown above, the net cost result is at least a 50% higher annual cost for capacity actually needed, even under FPL's assumptions. A full analysis of the economic approach used by FPL is included in the testimony of Dr. Schlesinger.

Q. FPL believes that this additional capacity and the FES system need to be built to generate competition within Florida. Do you agree?

A. No. The "competition" argument put forth by FPL's witness Sexton is based upon an analysis of the California and Texas markets. He correctly points out that in Texas, the substantial in-state production makes a comparison to the Florida market unrealistic. However, he argues that the California and Florida markets are somewhat similar and supportive of a decision to build the FPL pipeline.

Q. What are the market dynamics in California?

A. In California, there are two major utilities, Pacific Gas & Electric Company ("PG&E"), and Southern California Gas Company ("SoCal"). These two companies own the in-state natural gas transmission lines as well as the gas distribution lines serving customers in California. But the ownership of the pipelines by the utilities is not handled in the same way as FPL is now asking in this proceeding.

Significantly different than what FPL wants from this Commission, the California Public Utility Commission has segregated the natural gas transmission facilities, and has dictated terms and conditions whereby industrial and commercial customers can access these systems, not unlike rate and service regulation established by the FERC at the federal level. Thus, the cost of the California gas pipelines are not in the electric utilities' rate base.

Moreover, due to franchised service areas, only the natural gas transmission facilities of SoCal provide service across southern California, and the natural gas transmission facilities of PG&E do not compete for customers in this area. While there are other more limited pipelines into California, such as the Mojave Pipeline system, there is little direct transmission competition within California.

Q. Is this similar to the Florida market?

A. Not at all. Currently, as pointed out in the FPL testimony, FGT and Gulfstream provide broad service within Florida, not unlike the PG&E and SoCal systems, but they also compete directly with multiple locations where both pipelines serve the same location. In addition, by having FERC oversight, and non-affiliated transactions, this would seem to offer a more competitive, and better regulatory structure than that offered within California.

Q. Would the FES pipeline compete on a similar basis?

A. No. FPL wants to roll in the $1.6 billion cost of its intrastate pipeline into its rate base and have customers pay for it, regardless of usage. Where there is competition, as there is at most FPL plants, companies such as FGT must provide cost competitive rates. With FPL's proposal, once approved by the Commission, there will be no financial risk to FPL's recovery of its investment with a Commission-allowed return, even if the system never moved any gas.

Thus, the competitive circumstances in California are not as represented by FPL and, most significantly, the gas transmission pipelines are not in the electric rate base. If anything is to be learned from California, keep the pipelines out of the electric rate base and in a separate highly structured and regulated subsidiary.

EnergySecure Pipeline Cost Recovery [Issues 4, 5, 7, 8, 11, 12, and 15]

Q. Does the recovery of this pipeline investment and operating costs by FPL through its proposed rate base treatment provide any unfair advantages to FPL?

A. Yes. In this manner, the costs are fully recovered, and FPL earns a return on its equity portion of the investment in these facilities. In addition, such a mechanism shields FPL from any utilization risk. By this I mean that in normal pipeline investment, a pipeline company designs a transportation rate based on the total capacity of the pipeline. If the total capacity is not "sold" or "subscribed" by contract, then the pipeline company is at risk for the recovery of those dollars and that part of its investment. The result is that for a pipeline like FGT, its shareholders are at risk for any unsubscribed capacity, not its customers. With FPL's FES pipeline proposal, the customers are at risk, not the FPL shareholders.

Q. Doesn't a pipeline rate include an equity return on investment similar to that which you outline for FPL?

A. Yes. However, the difference is that FPL will not suffer any risk of under recovery of costs or any failure to earn a full equity return on its pipeline investment, regardless of whether the system ever transports any gas. This is not the case with normal pipeline investments. FERC regulated pipelines set rates based on their cost of service, including an equity return, based on an assumed 100% load factor on the system. If these systems do not contract for the full capacity, they will not recover the equity return that would be allowed. This is particularly true when pipelines contract on a negotiated rate basis. In FPL's proposal, there is no incentive to achieve a highly utilized system.

Q. What is the impact of this type of incentive?

A. When the economic incentive does not drive full utilization of the pipeline capacity, the effective cost to customers of the capacity that is used is increased.

Q. Is there a different way in which this could be recovered?

A. Yes. FPL has included in its economic analysis an assumed "rate" that is based on a 100% load factor. This was calculated in order to allow a comparison to the other pipeline proposals. However, the actual recovery of the costs will not be based on this "rate." For example, the pipeline assumes a rate of $1.32 per MMBtu in the first year. This is based on recovery of the costs over the full 600,000 Mcf/day of capacity. If this capacity is not fully utilized, and the pipeline investment and operating cost are recovered in electric rates, then the effective transportation rate on the pipeline will be much higher than the assumed $1.32 per MMBtu.

Q. Is there a better way for FPL to price this investment?

A. Yes. If the need for this pipeline is established, this Commission should require FPL to separate the pipeline investment into a separate cost of service company, and require that a cost of service rate be developed based on a 100% load factor basis. Once this has occurred, the capacity actually utilized by FPL, priced at this rate, should be recovered via the fuel cost recovery mechanism, exactly as the other natural gas transportation costs paid by FPL are recovered.

Q. What are the advantages of this methodology?

A. FPL customers will only pay for capacity actually needed for the operation of the system. FPL shareholders would be at risk for underutilization should the forecasted loads not materialize according to its own 40 year forecast.

Q. Is this how pipeline capacity rates are developed at the federal level?

A. Yes. Pipelines will propose expansions, and if there is adequate demand, the systems are expanded. In general, the FERC will not allow expansions where the pipeline intends to "rate base" or roll-in the investment with its existing system investment if such an expansion would serve to increase the rate to existing customers.

When this occurs, the pipeline must file for an incremental rate, based only on the investment for the expansion capacity. In this manner, such incremental investment does not affect existing customers, and the pipeline remains at risk for the system utilization and cost recovery.

Q. Is this the rate methodology used by FGT in its Phase VIII expansion?

A. Yes. FGT has proposed a new incremental recourse rate for the Phase VIII investment, and in addition, has committed to contract for the capacity at negotiated rates below this level. As such, FGT is fully at risk for any under recovery of its investment and operating cost for the Phase VIII facilities.

Q. Is this one reason pipeline companies do not maintain substantial excess capacity on their systems?

A. Yes. An interstate pipeline cannot burden its existing customers with paying for excess capacity. Customers generally do not want to pay for such excess capacity that is not providing direct benefit, and expansions are not allowed to impact existing system rates. As such, it does not make economic sense for pipelines to construct substantial excess capacity. As a result, the arguments put forward by FPL witnesses that there is currently no excess capacity in existing transmission lines is a hollow argument, since pipelines will expand their systems if there is economic demand for such expansions. As shown in Exhibit MTL-3, FGT has substantially expanded its system to meet Florida's market requirements.

Q. Is the FGT expansion pipeline capacity priced on this 100% load factor basis?

A. Yes. In the FGT Phase VIII filing, the rate applicable to the system is calculated on a 100% load factor basis. As such, if FGT charges rates below the cost of service level, or does not fully subscribe the capacity, it will not earn the allowed equity return on the investment.

Q. Is pipeline capacity always priced at the calculated cost of service rate?

A. The pipeline will always have a "recourse" rate, or cost of service based rate approved by the FERC, which is the rate at which service would be available on an open access basis. However, in the FGT Phase VIII expansion, FGT has contracted with its customers at a fixed rate that is negotiated, and is lower than the proposed FERC cost of service rate.

Q. For the FGT Phase VIII expansion, why are these negotiated rates below the FERC cost of service rate?

A. The reason is that FGT is taking a greater risk of earning a return on its investment in the early years of the expansion operation. Since the FGT customers have signed long term agreements, the rate also reflects the reduction in overall cost of service over time for the capacity. This effectively leaves FGT at risk for the long term utilization of the system while providing the customers with a fixed, known rate.

Q. Could such an approach be taken with FPL's proposed pipeline?

A. Yes. FPL could fix a rate, calculated over the initial 20 year period, for the initial 600,000 Mcf/day of capacity it claims is needed. The portion of this capacity that is actually needed, i.e. 400,000 Mcf/day at most, could be priced at the "negotiated" rate and recovered via the FPL fuel cost recovery mechanism. Any risk of utilization of the additional capacity would remain with FPL, and any future capacity needs would require a similar filing with the Commission to determine if there is adequate system need to allow recovery of any additional cost, or if there are other more competitive transport alternatives available at the time.

Q. How would such a rate be negotiated?

A. It can't. Since FPL's regulated operations would own both the electric generation facilities and the pipeline, such a rate cannot be negotiated by FPL. For third party providers, this is not an issue, and the competitive market determines the best alternative. This is why, if the Commission ultimately finds a need for this pipeline, the complete cost of the pipeline needs to be placed in a separate operating affiliate of FPL's and not within its electric regulated rate base. In this manner actual utilized transportation capacity costs would be passed through to electric ratepayers through the fuel charge.

Q. If the Commission does not place the FPL pipeline in a separate subsidiary, would its ownership and operation of the pipeline provide access that is unreasonably preferential, prejudicial, or unduly discriminatory?

A. From an operational standpoint, yes. Ratepayers would be forced to cover excessive and unnecessary expenses for capacity that is not needed or utilized, which is certainly prejudicial. Moreover, to the extent that FPL were to sell transmission capacity to others, the Commission would need to take strong steps to insure there is full open and transparent information as to how such services were provided, and to allow third parties priorities equal to FPL's electric operations in utilization of the system. Having all of the investment in its electric rate base would certainly create the possibility of an unduly discriminatory situation for customers and vis a vis other pipeline companies. If this system is allowed, clearly the best policy alternative would be to require a separate gas transmission subsidiary, subject to strong open access and transparent operating rules should be mandated by the Commission.

Q. If the Commission required FPL to monitor and report the final cost of the FES system following completion, would that provide any protection to customers?

A. No. If the Commission allows FPL to include such large costs in rate base, then any cost variance would not affect the ability of FPL to recover a full return on this investment regardless of usage. The customers would pay for this through electric rates.

Pipeline Operations [Issues 2 and 4]

Q. Does FPL intend to operate the EnergySecure pipeline system?

A. This is unclear. FPL discusses the possibility of contracting with a third party operator for this system, or operating it with FPL personnel.

Q. Does FPL have the necessary operating experience?

A. FPL points to its operation of small existing pipelines. To my knowledge, FPL has not operated a large diameter, high pressure, pipeline system that is 279 miles long.

Q. Are there third party operators that could provide this service?

A. Yes. However, in order for the Commission to assess the capability of either FPL or a third party to operate this system safely and reliably, FPL should provide more specific information as to its specific intention is in this regard.

Issues for the FPSC [11, 13, 14, and 16]

Q. Based on the different cost recovery mechanism proposed, what policy issue does this create for the Commission?

A. If the Commission allows the rate base treatment of pipeline assets in setting electric rates, this would allow a "guaranteed" return on this level of investment regardless of use. The Commission should consider whether allowing such rate base treatment of non-electric property in base electric rates is a direction it feels is prudent. This clearly leaves the consumers more at risk for any pipeline capacity decisions as compared to the current arrangement where such costs are recovered via a fuel cost recovery mechanism.

Q. Have other jurisdictions dealt with this issue?

A. In California, the California Commission specifically required the gas operations to be separate from the electric operations. In addition, it has required the pipeline operations to be conducted in an open access manner, similar to the requirements at the federal level for interstate pipelines under FERC regulations.

There may be small pipeline systems that are more integral to electric operations that have been included in electric rate base. Nevertheless, the Commission should consider the policy implications of allowing FPL to operate a large diameter, high pressure pipeline to transport gas across the state where such a large pipeline investment has never been included in the electric rate base.

Q. Are there other concerns?

A. Yes. If such rate based treatment is allowed, there will be an incentive for FPL to expand such a system, as there would be little risk to its shareholders that such investment would not generate an adequate return. This would allow FPL to hold an unfair competitive advantage over existing pipeline capacity providers in future expansions. With FPL's size as the largest electric provider in the state, and if future FPL pipeline capacity expansions are not limited within the state, this also raises the question as to whether the Commission would require that FPL expand and operate its system to serve local distribution system loads, industrial loads, alternative generation facilities, etc.

Additionally, the Commission should determine if there are other investments that FPL is more uniquely qualified to make, such as alternate solar powered facilities, where an investment of $1.6 billion would be more appropriate from a public policy standpoint.

Q. Can you outline any other concerns you see in the FES filing?

A. Yes. FPL has failed to show (1) there is a real need based on the population growth expected, the Ten Year Site Plans filed, and expected peak day gas demand as compared to the existing pipeline capacity held, (2) that the proposed pipeline project would result in lower costs to the FPL consumers as compared to the other proposals received, (3) that all supply and pricing alternatives upstream of Transco Station 85 have been adequately investigated, (4) that transportation alternatives from Transco Station 85 to FGT Compressor Station 16 and to the Cape Canaveral and Riviera Plants have been adequately reviewed, and (5) that the Commission should allow FPL's investment in pipeline facilities under the rate proposals offered by FPL.

In addition, it is clear that FPL could have proposed a structure that would balance the risk for any underutilization of the proposed system between its electric customers and its shareholders. Instead, it is seeking a guaranteed return of this investment from its electric customers.

Summary

Q. Please summarize the key points of your testimony?

A. FPL has failed to provide adequately supported data to justify the requested determination of need. The long term forecast of natural gas requirements offered by FPL are not supported, FPL's analysis and conclusions regarding upstream supply and transportation alternatives are incomplete and do not meet the objectives set forth by FPL, and there are substantial errors in the overall economic analysis of alternatives. This is an unnecessary $1.6 billion pipeline that will result in higher long term cost to FPL electric customers.

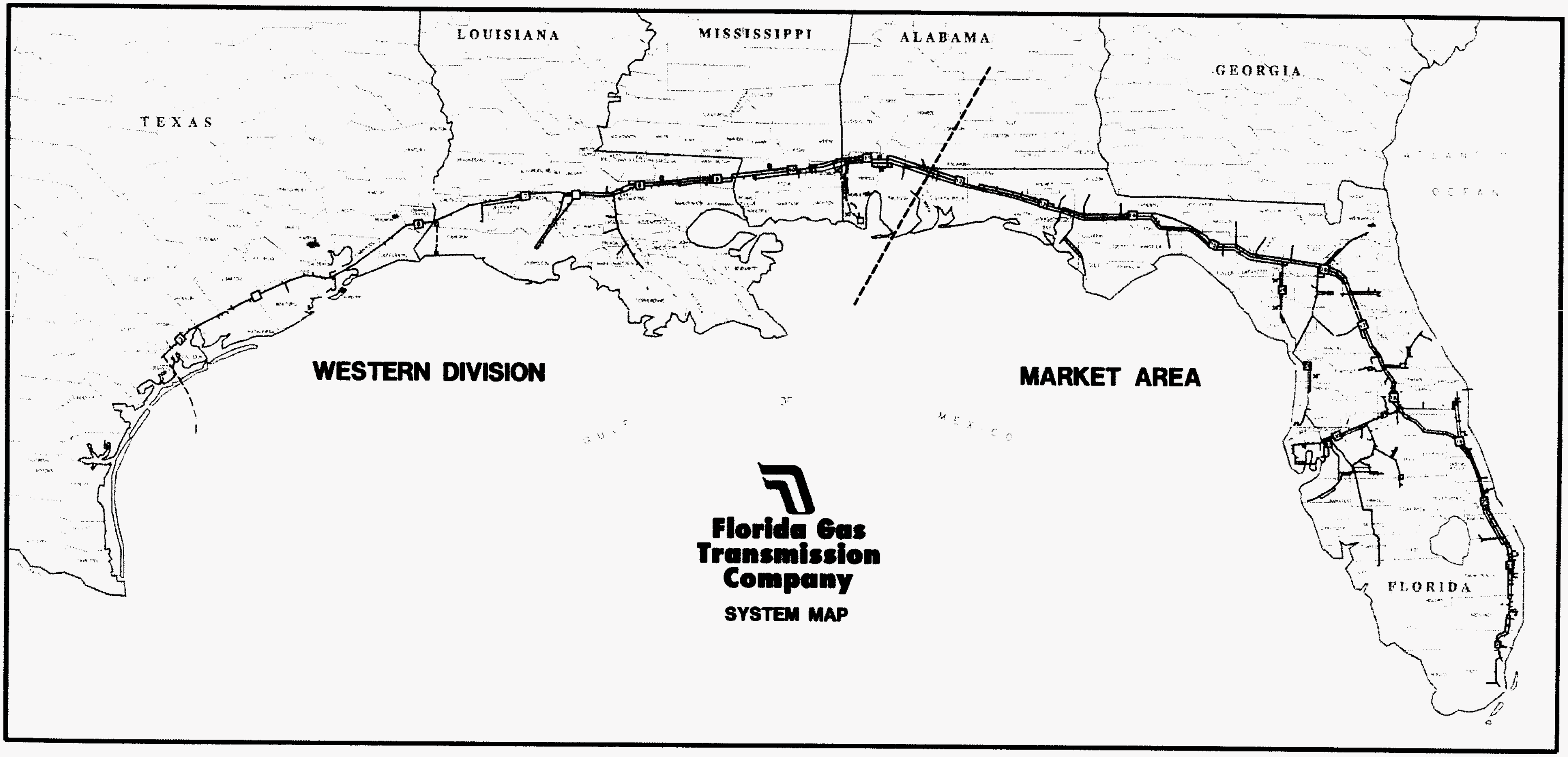
Q. Based on the information provided by FPL in its petition for determination of need should its natural gas transmission pipeline be approved?

A. No. FPL's proposal fails to meet the standards for a determination of need and it is not in the best interest of the electric ratepayers. The Commission should deny FPL's requested certification of need.

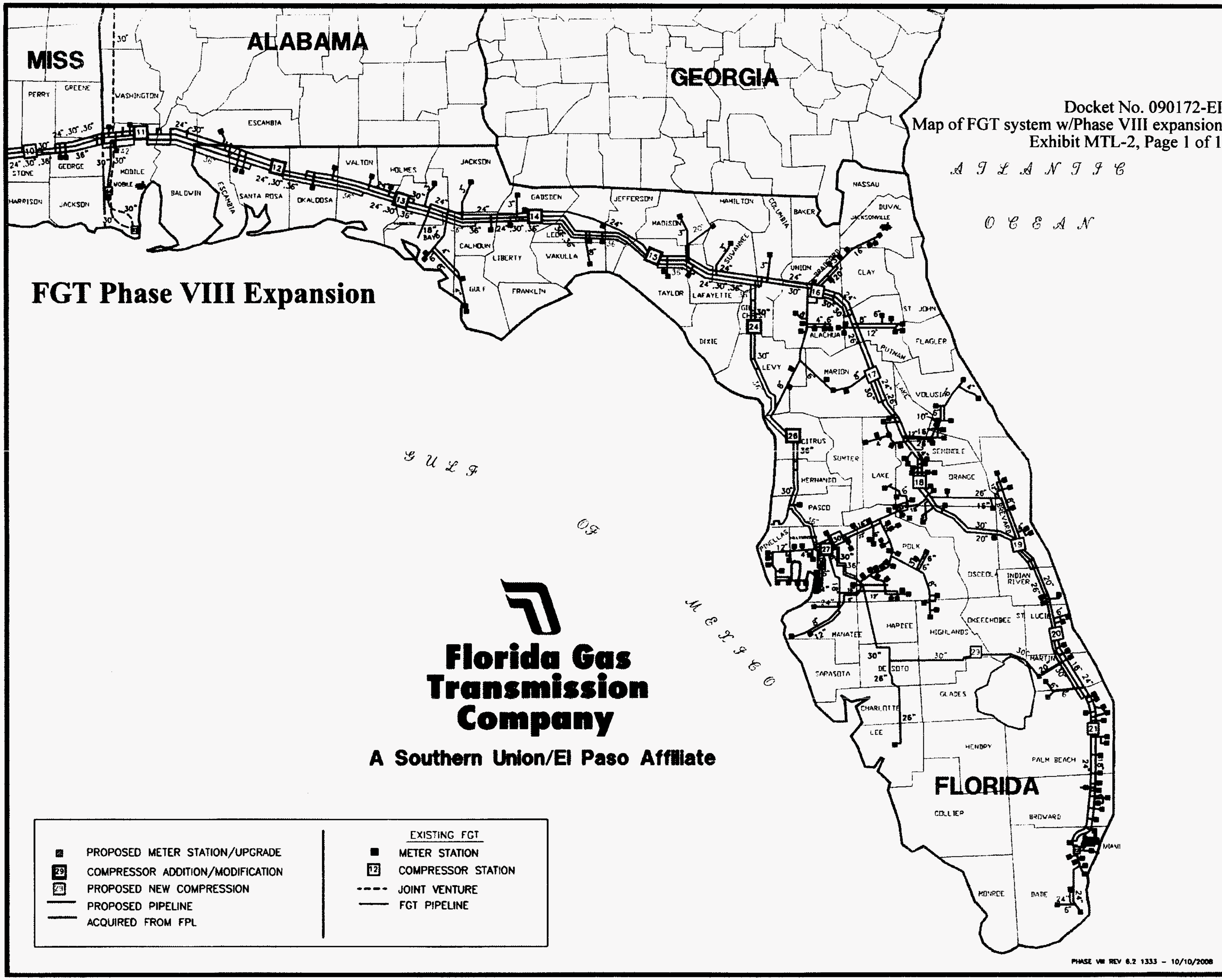
Q. Does this conclude your pre-filed direct testimony?

A. Yes.

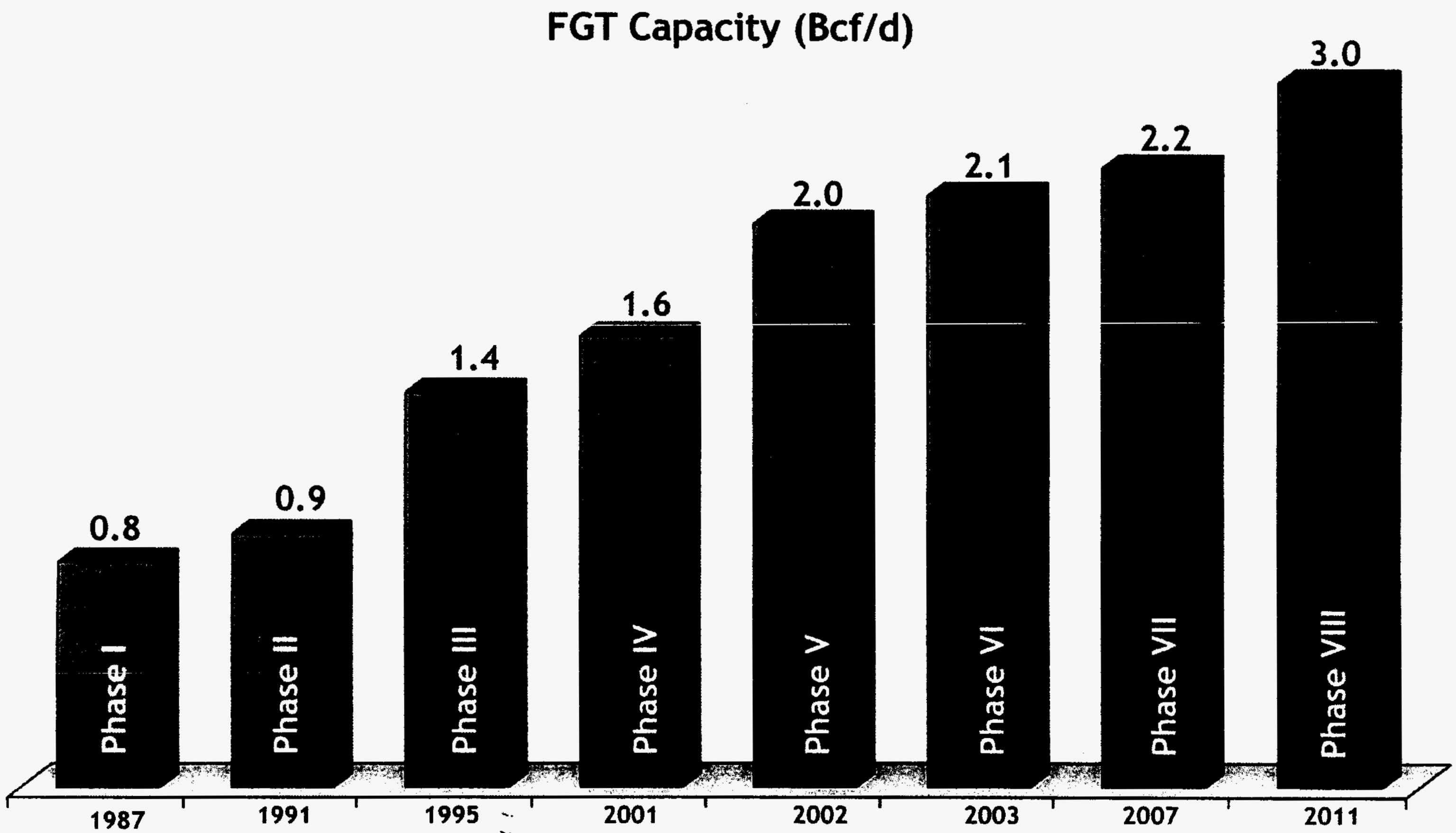
Docket No. 090172-EI
Map of FGT pipeline system
Exhibit MTL-1, Page 1 of 1



Docket No. 090172-EI
Map of FGT system w/Phase VIII expansion
Exhibit MTL-2, Page 1 of 1



History of Market Area Expansions



FGT Has Consistently Increased Capacity to Meet Market Demand

Source: Company

Florida Power & Light Company - Ten Year Site Plan

Natural Gas Requirements

[Source: FPL Site Plan filed with FL PSC - April 2009]

Natural Gas Requirements - MMcf - Year (1)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual											
2009 Plan	447,354	449,819 (a)	375,691	470,309	494,198	504,620	481,038	507,792	524,072	580,258	598,896	585,348
2008 Plan	447,353	474,527	496,322	549,764	613,218	626,260	638,207	685,761	705,665	777,390	799,950	

Comparison of 2009 vs 2008 Ten Year Site Plans - Projected Gas Requirements Avg Day Mcf

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual											
2009 Plan	1,225,627	1,232,381	1,029,290	1,288,518	1,353,967	1,382,521	1,317,912	1,391,211	1,435,814	1,589,748	1,640,811	1,603,693
2008 Plan	1,225,627	1,300,074	1,359,786	1,506,203	1,680,049	1,715,781	1,748,512	1,878,797	1,933,329	2,129,836	2,191,644	—
Difference	0	-67,693	-330,496	-217,685	-326,082	-333,260	-430,600	-487,586	-497,515	-540,088	-550,833	—

Comparison of FPL 2009 Ten Year Site Plan Projected Gas Requirements vs Total FGT & Gulfstream FT

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual										
Projected Requirements	1,232,381	1,029,290	1,288,518	1,353,967	1,382,521	1,317,912	1,391,211	1,435,814	1,589,748	1,640,811	1,603,693
Annual Daily Avg FT (2)	1,351,852	1,511,852	1,511,852	1,911,852	1,911,852	1,911,852	1,911,852	1,911,852	1,911,852	1,911,852	1,911,852
Difference	-119,471	-482,562	-223,334	-557,885	-529,331	-593,940	-520,641	-476,038	-322,104	-271,041	-308,159

Notes:

"Annual Daily Avg FT" is the total annual daily average FT contract volume on Gulfstream and FGT including Phase VIII contract volumes

(a) Actual

(1) Data from Ten Year Site plans filed by FPL on April 1, 2008 and April 1, 2009, Schedule 5

(2) After Phase VIII - Total FGT 1,216,852. Total Gulfstream 695,000. Total summer season is 1,969,000.

Florida Power & Light Company
Docket No. 090172-EI
FGT Second Set of Interrogatories
Interrogatory No. 53
Page 1 of 1

Q.
Provide the maximum coincident daily gas usage for the FPL system each year for the last 3 years.

A.
2006: 1,687,685 MMBtu/d
2007: 1,716,604 MMBtu/d
2008: 1,699,346 MMBtu/d

Q.

1. Please complete the table below describing projected NG requirements necessary to serve load.

	Natural Gas Requirements (Bcf/day)
	FPLFlorida
2009	
2010	
2011	
2012	
2013	
2014	
2015	
2016	
2017	
2018	
2019	
2020	
2021	
2022	
2023	
2024	
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	

A.

FPL's response to Staff's First Set of Interrogatories No. 23 is included in the attached spreadsheet.

STAFF'S FIRST SET OF INTERROGATORIES NO. 23 - I

	Natural Gas Requirements To Serve Load(Bcf/day)	
Year	FPL	Florida
2009	1.445	2.290
2010	1.518	2.498
2011	1.920	2.728
2012	1.912	2.789
2013	2.112	2.950
2014	2.312	3.129
2015	2.312	3.256
2016	2.312	3.416
2017	2.312	3.455
2018	2.312	
2019	2.312	
2020	2.312	
2021	2.399	
2022	2.487	
2023	2.662	
2024	2.749	
2025	2.924	
2026	3.099	
2027	3.187	
2028	3.274	
2029	3.449	
2030	3.537	
2031	3.624	
2032	3.887	
2033	4.062	
2034	4.062	
2035	4.062	
2036	4.237	
2037	4.324	
2038	4.412	
2039	4.499	
2040	4.674	

Notes:

1. FPL's requirements are based on the base case scenario with the EnergySecure Pipeline filed in Docket No. 090172-EI

2. Florida requirements are based on the Florida Reliability Coordinating Council, Inc. 2008 Regional Load & Resource Plan issued in July of 2008 (Page S - 17). Data is only available through 2017.

127 FERC ¶ 61,122
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Transcontinental Gas Pipe Line Corporation Docket No. CP08-476-000

ORDER ISSUING CERTIFICATE

(Issued May 7, 2009)

1. On September 18, 2008, Transcontinental Gas Pipe Line Corporation (Transco) filed in Docket No. CP08-476-000 an application under section 7(c) of the Natural Gas Act (NGA) [1] for a certificate of public convenience and necessity authorizing Transco's Mobile Bay South Expansion Project (project), an expansion of the capacity of Transco's existing Mobile Bay Lateral, which will enable Transco to provide 253,500 dekatherms per day of incremental southbound firm transportation service. We will authorize the Mobile Bay South Expansion Project, with appropriate conditions, as discussed below.

I. Background

2. Transco is a natural gas pipeline company engaged in the transportation of natural gas in interstate commerce. Transco's transmission system extends from its principal sources of supply in Texas, Louisiana, Mississippi and Alabama and the offshore Gulf of Mexico area, through Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania and New Jersey, to its termini in the New York City metropolitan area.

3. Transco originally constructed the 123.4 mile, 30-inch diameter Mobile Bay Lateral[2] in 1987 pursuant to section 311 of the Natural Gas Policy Act (NGPA)[3] to access gas produced in Mobile Bay and in the offshore Alabama area generally. The Mobile Bay lateral extends generally northward from the tailgate of the Mobil Oil Exploration and Production Southeast, Inc. gas treatment plant near Coden, Mobile County, Alabama

[1] 15 U.S.C. § 717, *et seq.* (2006).

[2] The lateral was originally named the Mobile Bay Pipeline.

[3] 15 U.S.C. § 3301, *et seq.* (2006).

to an interconnection with Transco's mainline near Butler, Choctaw County, Alabama. The line was placed in service on April 8, 1988, with a maximum capacity of 461,962 Mcf per day. On October 20, 1992, the Commission granted Transco a certificate of public convenience and necessity under section 7 of the NGA to operate the pipeline as a jurisdictional facility and provide transportation service under Subpart G of Part 284 of the Commission's regulations.[4]

4. By orders issued on January 15, 1993,[5] and September 15, 1993,[6] the Commission authorized Transco and Florida Gas Transmission Company (Florida Gas) to expand the Mobile Bay Lateral's capacity to approximately 829,000 Mcf per day by adding 21,532 horsepower (hp) of compression at the existing Compressor Station 82 in Mobile County, Alabama.[7]

5. By orders issued on October 29, 1997, and January 30, 1998, the Commission[8] authorized Transco to further expand its capacity on the Mobile Bay Lateral. This expansion project included the construction of Compressor Station 83 in Mobile County, Alabama, additional compression at Compressor Station 82, and construction of an approximately 72-mile offshore extension of the lateral and other minor facilities. In addition, Transco's capacity on the onshore portion of the Mobile Bay Lateral was increased to 784,426 Mcf per day as a result of the expansion project.

6. The maximum daily capacity of the onshore portion of the Mobile Bay Lateral currently stands at 1,093,042 Mcf, with 784,426 Mcf per day owned by Transco and 308,616 Mcf per day owned by Florida Gas. The offshore portion is fully owned by Transco and has a maximum capacity of 350,000 Mcf per day.

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[4] *Transcontinental Gas Pipeline Corp.*, 61 FERC ¶ 61,073 (1992); *reh'g denied*, 63 FERC ¶ 61,024 (1993).

[5] *Transcontinental Gas Pipe Line Corp.*, 62 FERC ¶ 61,024 (1993).

[6] *Transcontinental Gas Pipe Line Corp.*, 64 FERC ¶ 61,288 (1993).

[7] The 829,000 Mcf per day of capacity made available by the expansion included 86,152 Mcf per day of capacity turnback by existing firm customers on the lateral.

[8] *Transcontinental Pipe Line Corp.*, 81 FERC ¶ 61,104 (1997) and *Transcontinental Pipe Line Corp.*, 82 FERC ¶ 61,084 (1998). Florida Gas did not participate in this expansion project.

II. Proposal

A. Facilities

7. Transco proposes to construct and operate Compressor Station 85, a new 9,470 hp compressor station to be located at the interconnection of the Mobile Bay Lateral and Transco's main line in Choctaw County, Alabama. As proposed, the project will include the installation of two 4,735 hp gas-fired compressor units, along with supporting compressor station facilities, and approximately 2,400 feet of 30-inch diameter pipeline connecting the outlet of the station to the Mobile Bay Lateral.[9] Transco states that construction of the project facilities will enable it to provide firm transportation service from Station 85 and interconnects with third-party pipelines at Station 85 southward to delivery points located on the Mobile Bay Lateral, including a delivery point to Gulfstream Natural Gas System, L.L.C., while preserving Transco's capability to provide its certificated level of northbound firm transportation service on the Mobile Bay Lateral.[10]

B. Rates

8. Transco states that it executed binding precedent agreements for 100 percent of the incremental firm transportation capacity to be made available by the project -- one with Florida Power Corporation, d/b/a Progress Energy Florida, Inc., and one with Southern Company Services, Inc., as agent for its affiliates Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Transco states that the precedent agreements provide for the shippers to pay the total maximum reservation rate and total maximum commodity rate under Transco's Rate Schedule FT for the Mobile Bay Lateral and all applicable charges, surcharges, and compressor fuel and line-loss make-up retention. Transco requests a predetermination that it may roll the costs of the project into its system-wide cost of service in its next general NGA section 4 rate proceeding.

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[9] Transco states that using the guidelines presented in a research study conducted by the Interstate Natural Gas Association of America, it has determined that currently-available waste heat recovery to power systems are not economically viable for this facility.

[10] Transco's application does not propose any changes to the offshore portion of the Mobile Bay Lateral.

III. Interventions

9. Notice of Transco's application was published in the *Federal Register* on October 3, 2008 (73 Fed. Reg. 57,616). The parties listed in Appendix A filed timely, unopposed motions to intervene. The timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.[11] Numerous federal and state representatives, local producers, and other energy related companies filed comments in support of Transco's application.

10. National Fuel Gas Distribution Corporation, UGI Distribution Companies; BP Energy Company; Pivotal Utilities Holding, Inc., d/b/a Elkton Gas (in Maryland) and Elizabethtown Gas (in New Jersey); Atlanta Gas Light Company; Virginia Natural Gas Company; the Municipal Gas Authority of Georgia; and the Transco Municipal Group filed untimely motions to intervene. These parties have demonstrated an interest in this proceeding and granting their late interventions will not unduly delay or disrupt this proceeding or otherwise prejudice other parties. Therefore, for good cause shown, we are granting these late motions to intervene pursuant to Rule 214(d).[12]

11. The motion to intervene of Consolidated Edison Company of New York, Inc. and Philadelphia Gas Works (Con Edison and PWG) included a limited protest and request for conditions and clarification. The motion to intervene of Brooklyn Union Gas Company d/b/a National Grid (collectively the National Grid Gas Delivery Companies or National Grid) included comments and a request for clarification. The motion to intervene of Alabama Department of Conservation and Natural Resources included comments.

12. Transco filed an answer to the limited protest and request for conditions and clarification filed jointly by Con Edison and PGW, and to the comments and request for clarification filed by National Grid. Answers to protests are not allowed under Rule 213(a)(2) of the Commission's Rules of Practice and Procedure.[13] However, we will waive this rule to admit Transco's answer because this pleading has provided information that assisted us in our decision-making.

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[11] 18 C.F.R. § 385.214 (2008).

[12] 18 C.F.R. § 385.214(d) (2008).

[13] 18 C.F.R. § 385.213(a)(2) (2008).

IV. Discussion

13. Since the proposed facilities will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.

Certificate Policy Statement

14. The Certificate Policy Statement provides guidance as to how we will evaluate proposals for certificating new construction.[14] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new pipeline facilities, the Commission balances the public benefits against the potential adverse consequences. Our goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

15. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, we will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will we proceed to complete the environmental analysis where other interests are considered.

16. As noted above, the threshold requirement is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. Transco will provide its proposed expansion service under its existing Part 284 rates. Since none of the project costs are included in Transco's currently-effective

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[14] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

rates, accepting Transco's proposal to charge these rates as initial rates for the project will not result in subsidization by existing customers. Further, as discussed below, we find that project revenues will exceed the projected cost of service and a presumption of rolled-in rate treatment is appropriate. Thus, Transco's existing shippers will not subsidize the Project.

17. Transco's proposal will have no adverse impact on its existing customers since the proposal will not result in any degradation of service to them. Further, we find no adverse impacts on existing pipelines in the market or their captive customers because the proposal is for new incremental service and is not intended to replace existing service on any other existing pipeline. Additionally, no pipeline company has protested Transco's application.

18. Transco proposes to construct the project and associated facilities on 40 acres of a 126.8-acre site near milepost 784.3 on the Transco mainline in Choctaw County, Alabama. Transco contends that the compressor station property was selected to minimize impacts to land use, nearby landowners, and the environment. Transco states that all clearing, grading, and land disturbance for the project will be limited to areas within Transco's Compressor Station 85 property line. Therefore, we find that there should be minimal adverse environmental effects.

19. We conclude that any potential adverse effects of the project are outweighed by the substantial benefits of the project. The project will expand the Mobile Bay Lateral's flexibility and utilization by creating bidirectional flow capability. The project customers will use this capacity to access additional gas supply and third-party storage services along the Mobile Bay Lateral, as well as expanding markets in southern Alabama and Florida, in order to serve their growing requirements for natural gas without impacting existing customers' services. We also conclude that there is substantial market demand for the project as demonstrated by the fact that Transco executed precedent agreements that provide for the long-term subscription of all of the incremental capacity to be made available by the project. Transco's existing customers will not subsidize the project and there will be no degradation of service to Transco's existing customers or any adverse effects on existing pipelines or their customers. Finally, adverse impacts on landowners and neighboring communities will be minimal. For these reasons, we find, consistent with the Certificate Policy Statement and section 7(c) of the NGA, that the public convenience and necessity requires approval of Transco's proposals.

Rates

Cost of Service and Rates

20. Transco contends that the project qualifies for rolled-in rate treatment. Using the existing system-wide rates, Transco's Exhibit P reflects an estimated cost of service of $8,039,295 and associated estimated revenues of $8,414,451, thus projecting a revenue

benefit of $375,156. Transco states that the estimated incremental rate for the proposed project is lower than Transco's currently effective maximum rate under Rate Schedule FT for Zone 4A transportation. Thus, it proposes rolled-in rate treatment for the project so that the existing customers will receive a net financial benefit from the relatively inexpensive expansion proposed herein.[15]

Request for Clarification

21. In their clarification requests, Con Edison and PGW and National Grid contend that Transco projects that revenues will exceed the incremental cost of service by $375,156, a difference of only 4.7 percent. Con Edison and PGW and National Grid state that even a modest increase in Transco's estimated cost of service would void the premise supporting Transco's rolled-in rate request, making it premature for the Commission to grant Transco's request for permission to roll in the costs of the project in its next general NGA section 4 rate case. Consistent with Commission precedent,[16] Con Edison and PGW request that the Commission clarify that such a pre-determination will only be applicable when Transco files its next general rate case and shows that rolled-in rates do not result in subsidization of the project by other shippers. National Grid requests that the Commission clarify that Transco will have the burden of proof under NGA section 4 to justify and fully support its request to roll in the costs of the project in any future general rate proceeding.

22. Transco contends that when the Commission makes a pre-determination in a certificate proceeding regarding whether rolled-in rate treatment is appropriate, it bases its decision on the facts, estimates, and assumptions at the time the certificate is issued.[17] Transco maintains that the Commission cannot foresee whether circumstances will change to such an extent that a project is no longer eligible for rolled-in rate treatment by the time the pipeline files its next rate case.[18] Transco asserts that speculation as to

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[15] Transco calculates the incremental rate for the project to be $0.08689 per Dth, as compared to the currently effective Zone 4A rate of $0.09094 per Dth. The cost of service is based on an estimated facilities cost of $36,903,935, plus estimates for overhead and maintenance expenses, a pre-tax return of 15.34 per-cent (the pre-tax return underlying the design of Transco's approved settlement rates in Docket No. RP01-245-000, *et. al.*) and a depreciation rate included in Transco's approved settlement in Docket No. RP06-569, *et. al.*

[16] *See, e.g., Iroquois Gas Transmission System, L.P. (Iroquois)*, 122 FERC ¶ 61,242, at P 14 (2008).

[17] *El Paso Natural Gas Co.*, 113 FERC ¶ 61,183, at 61,730 (2005).

[18] *Id.*

whether it may overrun the estimated cost of the project does not constitute a valid basis for the Commission to withhold application of its policy to the project. Specifically, Transco avers that Exhibit P demonstrates that the firm transportation revenues will exceed expenses for the first year. Transco asserts this constitutes the requisite demonstration that existing firm transportation customers will not subsidize the project. Further, Transco states that consistent with Commission policy, the Commission should determine that Transco be permitted to roll-in the costs of the project in Transco's first general rate case following the in-service date of the project. Transco contends that this would be the proper forum for any party to evaluate the final cost of the project and identify any change in material circumstances that may warrant a reexamination of rolled-in rate treatment.

Commission Determination

23. Based on the facts, estimates, and assumptions before the Commission at this time, it appears that the revenues which would be generated by providing service at the proposed recourse rates would exceed the project's associated cost of service. Absent a change in circumstances, rolled-in rate treatment for these costs would benefit existing customers by reducing their rates.[19] Therefore, we will grant Transco's request for a pre-determination supporting rolled-in rate treatment for the costs of the Project in its next general NGA section 4 rate proceeding, absent a significant change in circumstances. Our holding here is consistent with Commission precedent.

24. If cost overruns occur, as Con Edison and PGW are concerned might happen due to the narrow difference between project revenues and the estimated incremental cost of service, such an event may constitute a significant change in circumstances warranting a reconsideration of the roll-in pre-determination.[20] To ensure that all parties have full knowledge of the costs and revenues attributable to the project, we will require Transco to account for the construction and operating costs and revenues separately in accordance with section 154.309 of the Commission's regulations.[21] With such information, the parties and the Commission can evaluate the costs of the project and will be able to identify any change in material circumstances that may warrant a re-examination of rolled-in rate treatment in its next section 4 rate proceeding.

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[19] Id.

[20] *Iroquois*, 122 FERC ¶ 61,183, at P 15 (2008). *See also, Northern Border Pipeline Co.*, 90 FERC ¶ 61,263, at 61,877 (2000).

[21] 18 C.F.R. § 154.309 (2008).

Fuel Costs

25. Con Edison and PGW contend that the proposed north to south movement of gas in Transco's Zone 4A at rolled-in rates would cause Transco's system customers to subsidize fuel requirements properly attributable to the project's customers. Con Edison and PGW contend that Transco's rate design for the allocation of fuel costs assumes that a movement commencing and terminating in Zone 4A is accomplished via backhaul or displacement. Con Edison and PGW state that this will not be the case once the project facilities are constructed. Con Edison and PGW request that the Commission condition any approval of Transco's application to require Transco to allocate fuel to the project transportation in the same manner that it allocates fuel to other forward-haul transmission services.

26. Transco asserts that Con Edison and PGW misunderstand Transco's proposal with regard to charging fuel for the firm transportation service rendered under the project. Transco proposes that the initial rates applicable to the firm transportation service will be the prevailing rates under Transco's Rate Schedule FT for transportation within Zone 4A in effect at the time service commences, which will include the applicable fuel-retention percentage. Transco states that since the firm transportation service under the project will be provided on a forward-haul basis entirely within Transco's Zone 4A, the applicable fuel factor will be the Zone 4A to Zone 4A fuel percentage set forth on Sheet No. 44 of Transco's Tariff, as that fuel-retention percentage may be revised from time to time.[22] Transco clarifies that it will include such firm transportation service in future calculations of Transco's fuel retention percentages like any other forward-haul, firm transportation service rendered by Transco.

Commission Determination

27. Transco's project involves the installation of 9,470 hp of additional gas-fired compression. Such an increase in compression may increase fuel costs for existing shippers who transport within Zone 4A.[23] Transco's application does not provide any information as to the possible impact the new compression will have on fuel costs or fuel retention levels to existing shippers. Therefore, we will require Transco to separately maintain its accounts for the fuel used by the project and report the results in its first

[22] The current fuel retention percentage for forward-haul transportation within Zone 4A is 0.42 percent. Transco states that with the in-service date of the Project and the ensuing north to south forward-haul of gas in Zone 4A, all transportation in Zone 4A will be assessed the Zone 4A fuel retention factor and Sheet No. 44 will be revised accordingly.

[23] The Zone 4A fuel retention factor is currently 0.42 percent.

section 4 fuel tracker rate filing after the expansion is in service demonstrating that existing shippers will not be adversely affected by the inclusion of the project's compression costs in its Zone 4A Fuel rate.[24]

Environmental Analysis

28. October 21, 2008, we issued a Notice Of Intent To Prepare an Environmental Assessment (NOI). The NOI was mailed to interested parties including federal, state, and local officials; agency representatives; environmental and public interest groups; Native American tribes; local libraries and newspapers; and affected property owners. The NOI comment period ended on November 20, 2008.

29. We received comments on the NOI from the State of Alabama, Department of Conservation and Natural Resources, Wildlife and Freshwater Fisheries Division (ADCNR); the Alabama Department of Environmental Management, Water Division (ADEM); and Mr. Johnny Morgan.

30. To satisfy the requirements of the National Environmental Policy Act, our staff prepared an environment assessment (EA) which was placed in the public record on March 16, 2009. The analysis in the EA included the Project's purpose and need, geology, soils, water resources, wetlands, vegetation, fish and wildlife, threatened and endangered species, land use, recreation, cultural resources, air quality and noise, and alternatives. The EA also addressed all substantive issues raised in the scoping letters.

31. In its comment letter on the NOI, the ADEM advised that the Alabama Best Management Practices as provided in the *Alabama Handbook For Erosion Control, Sediment Control, And Stormwater Management On Construction Sites And Urban Areas* (AL Handbook) should be implemented prior to, during, and after construction of the Project. To reduce the potential for erosion, Transco would use its Construction Best Management Practices Plan (CBMP Plan) which incorporates our staff's Upland Erosion Control, Revegetation, and Maintenance Plan (Plan) and Wetland and Water body Construction and Mitigation Procedures during construction and restoration of the Project. Transco's CBMP Plan also includes measures to comply with the ADEM's regulations and the AL Handbook. We concur with the finding in the EA that Transco's use of its CBMP Plan would be acceptable for the project.

[24] Con Edison and PGW also contend that Transco's application does not contain an estimate of the electric power costs for the Project. Since Transco is not proposing to install any electric-powered compression, there are no incremental electric power cost issues in connection with Transco's proposal.

32. The ADEM and the ADCNR contend that Transco should comply with the regulations under the section 404 of the Clean Water Act and other applicable permits issued by the U.S. Army Corps of Engineers or the ADEM. The ADEM also recommended contacting the U.S. Fish and Wildlife Service (FWS) and the ADCNR to address potential impacts to endangered and threatened species. Transco received a Nationwide Permit 12[25] authorization for the project on October 14, 2008.

33. The EA indicates that the threatened gopher tortoise, gulf sturgeon, inflated heel splitter mussel and the endangered wood stork are known to occur or could occur within the region surrounding the proposed project facilities. However, the EA also states that the gulf sturgeon and the heel splitter mussel require significant aquatic habitat found in perennial water bodies, which are not impacted by the proposed project facilities. Thus, construction and operation of the proposed project would not affect these two species. Additionally, since the wood stork generally forages in areas containing standing water, and the proposed project facilities would not impact any such areas, the EA concludes that construction and operation of the proposed project would not affect this species.

34. Transco surveyors observed potentially suitable gopher tortoise habitat. However, no gopher tortoises or their burrows were located during surveys. The EA discusses Transco's proposed measures to confirm that gopher tortoises are not in the project area during construction and to train its workers in how to avoid impact on this species. The EA concludes that construction and operation of the proposed project is not likely to adversely affect this species. On March 24, 2009, the FWS concurred with the EA's determination.

35. The ADCNR suggested that directional drilling should be utilized at stream crossings where habitat known to support sensitive species exists. The EA discusses the proposed stream crossings and concludes that none of the water bodies crossed by the proposed pipeline are classified as sensitive, contain habit for sensitive species, or are known to contain any contaminants. Transco would cross three water bodies using open-cut construction techniques. Based on Transco's proposed water body crossing techniques, the relatively small size of the water bodies and the implementation of minimization and mitigation measures as described in Transco's CBMP Plan and Spill Prevention and Control (SPCC) Plan, the EA concludes that construction and operation of the proposed project would not significantly impact surface waters. We agree.

36. The ADCNR's comment letter also suggested that topsoil from both wetland and upland areas be segregated and replaced following construction. Transco's data response

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[25] A Nationwide Permit 12, issued by the U.S. Army Corps of Engineers, details the activities required for the construction, maintenance, and repair of utility lines (including gas pipelines) and associated facilities in waters of the United States.

filed on February 3, 2009, indicates that topsoil segregation would be performed in wetlands. Transco's CBMP Plan and our staff's Plan state that topsoil segregation would only occur in non-agricultural uplands when requested by the landowner or land managing agency. Since the approximately 130-acre parcel on which the project would occur is owned in fee by Transco, Transco does not propose to segregate topsoil in uplands. As stated in the EA, the measures proposed in Transco's CBMP Plan, including those measures addressing topsoil segregation, are acceptable.

37. To reestablish vegetation and to control erosion along the right-of-way following construction, the ADCNR recommended seeding with either brown top millet in summer or winter wheat during the fall and winter. The EA describes Transco's proposal for revegetating disturbed areas. Transco has committed to consult with the Natural Resource Conservation Service (NRCS) to obtain its recommendations for seed mixtures. The NRCS's seeding recommendations are consistent with those from the local soil conservation authority or land management agency. The ADCNR also states the use of herbicides to control vegetation along the right-of-way is preferable to mowing. However, if mowing is conducted, the ADCNR recommends the impacts to nesting birds be minimized by not mowing during the period from March 15 to August 1. In a February 3, 2009 data response, Transco agreed to this timing restriction for mowing.

38. Mr. Morgan submitted a comment about his lake camp which is located more than one-quarter mile southwest of the project. Mr. Morgan is concerned that the project would impact air quality, noise, water resources, fisheries, and wetlands. As stated in the EA, the lake camp is located approximately 3,000 feet west-southwest of the proposed location of the compressor building and approximately 1,650 feet west of Transco's western property boundary. For purposes of the analysis in the EA, the camp was treated as a residence and a potential Noise Sensitive Area (NSA). The acoustic analysis report for the lake camp concluded that the noise attributable to Transco's proposed Compressor Station 85 at the lake camp is expected to be significantly lower than 55 decibels on the A-weighted scale at the day-night sound level (55 dBA (L_{dn})), as required by environmental condition 10.

39. To ensure noise levels during operation are at acceptable levels, environmental condition 10 also requires Transco to conduct a noise survey of the new Compressor Station 85 at full load. If the noise exceeds an L_{dn} of 55 dBA at Mr. Morgan's camp or any other nearby NSA, Transco must file a report on what additional noise controls it will install to meet that level within one year of the in-service date.

40. The EA describes the results of our air quality screening analysis and concludes that construction and operation of Transco's project would not have a significant impact on the air quality in the project area. The EA also addresses the other concerns raised by Mr. Morgan and concludes that with the implementation of the mitigation measures described in Transco's CBMP and SPCC Plans, the project would have no impact or minimal impact on these resources.

41. Based on the discussion in the EA, we conclude that if constructed or operated in accordance with Transco's application and supplements, approval of this proposal would not constitute a major federal action significantly affecting the quality of the human environment.

42. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this certificate. We encourage cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[26]

43. The Commission on its own motion, received and made a part of the record all evidence, including the application, as supplemented, and exhibits thereto, submitted in this proceeding and upon consideration of the record,

<u>The Commission orders</u>:

(A) A certificate of public convenience and necessity is issued authorizing Transco to construct and operate the Mobile Bay South Expansion Project, as described more fully in the order and in the application.

(B) The certificate issued herein is conditioned on Transco's compliance with all of the applicable regulations under the NGA, particularly the general terms and conditions set forth in Parts 154, 157, and 284, and paragraphs (a), (c), (e), and (f) of section 157.20.

(C) Prior to commencing construction, Transco must execute service agreements for the levels and terms of service reflected in the precedent agreements submitted in support of its proposal.

(D) Transco's facilities shall be constructed and made available for service within one year of the date of the order in this proceeding, in accordance with section 157.20(b) of the Commission's regulations.

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[26] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply v. Public Service Commission*, 894 F.2d 571 (2d Cir. 1990); and *Iroquois Gas Transmission System, L.P.*, 52 FERC ¶ 61,091 (1990) and 59 FERC ¶ 61,094 (1992).

(E) Transco's request for a predetermination favoring rolled in rate treatment for the costs of the project in its next general section 4 proceeding is granted, absent a significant change in circumstances.

(F) Transco is required to separately maintain its accounts for the project costs, including fuel, and revenues consistent with section 154.309 of the Commission's regulations.

(G) The certificate issued herein is conditioned on Transco's compliance with the environmental conditions set forth in Appendix B to this order.

(H) Transco shall notify the Commission's environmental staff by telephone, e-mail, and/or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Transco. Transco shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(I) The late filed motions to intervene are granted.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A

Motions to Intervene in Docket No. CP08-476-000

- Florida Gas Transmission Company, LLC
- Southern Company Services, Inc., as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Southern Power Company (collectively, "SCS")
- North Carolina Utilities Commission
- Piedmont Natural Gas Company, Inc.
- Atmos Energy Corporation
- Chevron USA Inc.
- Exxon Mobile Corporation
- Hess Corporation
- Washington Gas Light Company
- PSEG Energy Resources & Trade LLC
- Public Service Company of North Carolina, Inc.
- South Carolina Electric & Gas Company
- PECO Energy Company
- Consolidated Edison Company of New York, Inc. and Philadelphia Gas Works
- NJR Energy Services Company
- New Jersey Natural Gas Company
- The Brooklyn Union Gas Company d/b/a National Grid NY; KeySpan Gas East Corporation d/b/a National Grid; Boston Gas Company, Colonial Gas Company, and Essex Gas Company, collectively d/b/a National Grid; EnergyNorth Natural Gas Inc., d/b/a National Grid NH; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid, all subsidiaries of National Grid USA, (collectively "the National Grid Gas Delivery Companies" or "National Grid")
- Florida Power Corporation d/b/a Progress Energy Florida, Inc.
- State of Alabama Department of Conservation and Natural Resources
- Wildlife and Water Fisheries Division
- Municipal Gas Authority of Georgia
- Alabama Department of Environmental Management

Untimely Motions to Intervene in Docket No. CP08-476-000

- National Fuel Gas Distribution Corporation
- UG Distribution Companies
- BP Energy Company and BP
- Elizabethtown Gas

- Atlanta Gas Light Company
- Virginia Natural Gas Company
- Elkton Gas
- The Municipal Gas Authority of Georgia
- The Transco Municipal Group

Appendix B

Environmental Conditions for the Mobile Bay South Expansion Project

As recommended in the EA, this authorization includes the following condition(s):

1. Transco shall follow the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests) and as identified in the EA unless modified by the order. Transco must:

   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);
   b. justify each modification relative to site-specific conditions;
   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
   d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification.**

2. The Director of OEP has delegation authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project. This authority shall allow:

   a. the modification of conditions of the order; and
   b. the design and implementation of any additional measures deemed necessary (including stop-work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction and operation.

3. **Prior to any construction**, Transco shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, environmental inspectors, and contractor personnel would be informed of the environmental inspector's authority and have been or would be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

4. Transco shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, and documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any

other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **before construction in or near that area.**

This requirement does not apply to route variations required herein or extra workspace allowed by Transco's Construction Best Management Practices Plan, minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;
b. implementation of endangered, threatened, or special concern species mitigation measures;
c. recommendations by state regulatory authorities; and
d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

5. **Within 60 days of the acceptance of this certificate and before construction begins,** Transco shall file an initial Implementation Plan with the Secretary for review and written approval by the Director of OEP. Transco must file revisions to the plan as schedules change. The plan shall identify:

a. how Transco will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EA, and required by the order;
b. the training and instructions Transco will give to all personnel involved with construction; and
c. provide a Gantt or PERT chart (or similar project scheduling diagram) and dates for the start and completion of the project.

6. Transco shall employ at least one environmental inspector for the project. The environmental inspector(s) shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the order and other grants, permits, certificates, or other authorizing documents;
b. empowered to order correction of acts that violate the environmental conditions of the order, and any other authorizing document;
c. responsible for documenting compliance with the environmental conditions of the order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

d. responsible for maintaining status reports.

7. **Beginning with the filing of its initial Implementation Plan**, Transco shall file updated status reports with the Secretary on a **monthly basis** until all construction and restoration activities are complete. On request, these status reports should also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on Transco's efforts to obtain the necessary federal authorizations;
b. the construction status of the project work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;
c. a listing of all problems encountered and each instance of noncompliance observed by the environmental inspector(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);
d. corrective actions implemented in response to all instances of noncompliance, and their cost;
e. the effectiveness of all corrective actions implemented;
f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the order, and the measures taken to satisfy their concerns; and
g. copies of any correspondence received by Transco from other federal, state or local permitting agencies concerning instances of noncompliance, and Transco's response.

8. Transco must receive written authorization from the Director of the OEP **before commencing service from the project.** Such authorization would only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the project are proceeding satisfactorily.

9. **Within 30 days of placing the certificated facilities in service,** Transco shall file an affirmative statement with the Secretary, certified by a senior company official:

a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities would be consistent with all applicable conditions; and
b. identifying which of the certificate conditions Transco has complied with or would comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if

not previously identified in filed status reports, and the reason for noncompliance.

10. Transco shall file noise surveys with the Secretary **no later than 60 days** after placing the Compressor Station 85 in service. If the noise attributable to the operation of the new Compressor Station 85 at full load exceeds an L_{dn} of 55 dBA at any nearby (NSAs or noise-sensitve areas), Transco shall file a report on what changes are needed and shall install additional noise controls to meet that level **within one year** of the in-service date. Transco shall confirm compliance with this requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls.

124 FERC ¶ 61,089
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Midcontinent Express Pipeline LLC	Docket No. CP08-6-000
Enogex Inc.	Docket No. CP08-9-000

ORDER ISSUING CERTIFICATES

(Issued July 25, 2008)

1. On October 9, 2007, Midcontinent Express Pipeline LLC (Midcontinent) filed in Docket No. CP08-6-000 an application under section 7(c) of the Natural Gas Act (NGA) for authorization to construct and operate a new 506-mile pipeline extending from southeastern Oklahoma to western Alabama with a capacity of up to 1,532,500 dekatherms per day (Dth/d). Midcontinent also requests a blanket construction certificate under Part 157, Subpart F of the Commission's regulations, and a blanket transportation certificate under Part 284, Subpart G of the regulations. As part of the project, Midcontinent further requests authorization to lease up to 272,000 Dth/d of capacity on the Oklahoma intrastate pipeline system of Enogex Inc. (Enogex). On October 9, 2007, Enogex filed in Docket No. CP08-9-000 an application under section 7(c) of the NGA requesting issuance of a limited jurisdiction certificate authorizing its lease of capacity to Midcontinent. For the reasons set forth below, we are granting the requested authorizations, subject to conditions.

I. Background and Proposal

2. Midcontinent is a Delaware limited liability company and is owned 50 percent by Kinder Morgan Energy Partners, L.P. and 50 percent by ETC Midcontinent Express Pipeline, L.L.C. (ETC), a subsidiary of Energy Transfer Partners, L.P. Midcontinent is a new entity which will become a natural gas company subject to the jurisdiction of the Commission under the NGA upon acceptance of authorizations issued by the Commission in this proceeding.

3. Enogex is an intrastate pipeline operating natural gas transportation facilities entirely within the State of Oklahoma. The Enogex system consists of approximately 2,283 miles of transmission pipeline arranged in a web-like configuration. Enogex receives natural gas into its system from numerous wells and gathering facilities and from other intrastate and interstate pipelines. Enogex offers firm and interruptible intrastate transportation services, and it offers interruptible transportation service in interstate commerce under section 311(a)(2) of the Natural Gas Policy Act of 1978 (NGPA).

4. Midcontinent states that its project addresses the need for new pipeline infrastructure to link natural gas production from the Barnett Shale and Bossier Sands in Texas, the Woodford/Caney Shale and Granite Wash in Oklahoma, and the Fayetteville Shale in Arkansas[1] with markets further east. Midcontinent provides estimates indicating that growth in production from these areas will provide approximately 7.0 Bcfd in incremental volumes by the year 2015.[2]

Midcontinent Facilities

5. Midcontinent proposes to construct its project in two phases at a total estimated cost of approximately $1.34 billion - $1.28 billion for the initial phase and $0.06 billion for the expansion phase. The proposed system will have two capacity zones in addition to the Enogex leased capacity. Zone 1 will extend approximately 308 miles from the Enogex interconnection at Bennington, Oklahoma to an interconnection with Columbia Gulf Transmission (Columbia Gulf) near Delhi, Madison Parish, Louisiana and will have an initial capacity of 1,432,500 Dth/d.[3] Zone 2 will extend approximately 198 miles further to the terminus at an interconnection with Transcontinental Gas Pipe Line Corporation (Transco) at its Station 85 near Butler in Choctaw County, Alabama, and will have an initial capacity of 1,000,000 Dth/d. The final expanded system's capacities will be 1,532,500 Dth/d in Zone 1 and 1,200,000 Dth/d in Zone 2.

6. The proposed initial phase facilities will consist of 30-inch diameter pipeline extending approximately 40 miles from the interconnection with Enogex at Bennington in Bryon County, Oklahoma, increasing to 42-inch line for the next 268 miles, and

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[1] No part of the project will be located in Arkansas; however, a proposed interconnection with Natural Gas Pipeline Company of America (NGPL) can potentially provide Arkansas gas access to the project.

[2] *See*, Exhibit H, page 2 of 6, of Midcontinent's application.

[3] On May 16, 2008, Midcontinent filed a revised Exhibit G showing an increase in Zone 1 capacity of 32,500 Dth/d for both the initial and expansion phases. The capacity in Zone 2 is unchanged.

decreasing in size to 36-inch line for the last 198 miles.[4] Fourteen interconnections providing receipt and/or delivery with existing intrastate and interstate pipelines are planned, along with ancillary facilities such as numerous mainline valves and pig launcher/receivers.[5] Also as part of the initial phase, Midcontinent proposes to construct two mainline compressor stations – the Lamar Compressor Station with 38,855 horsepower (hp) of reciprocating engine-driven compression in Lamar County, Texas, and the Perryville Compressor Station with 32,720 hp of reciprocating engine-driven compression in Union Parish, Louisiana. In order to receive supplies from CenterPoint, Midcontinent proposes to construct the Delhi Booster Station, with 9,470 hp of reciprocating engine-driven compression, at the interconnect with CenterPoint and a 4.2-mile, 16-inch lateral line extending from the booster station to Midcontinent's mainline, all to be located in Richland and Madison Parishes, Louisiana. Midcontinent anticipates an in-service date of October 31, 2008, for the first 40 miles of pipeline from Enogex at Bennington to an interconnection near Paris in Lamar County, Texas with NGPL and Houston Pipe Line, an affiliate of ETC.[6] The remainder of the initial phase facilities are anticipated to be in service on or about February 28, 2009.

7. The proposed expansion phase facilities will consist of two additional mainline compressor stations – the Atlanta Compressor Station with 12,270 hp of reciprocating engine-driven compression in Cass County, Texas, and the Vicksburg Compressor Station with 18,405 hp of reciprocating engine-driven compression in Warren County, Mississippi. Midcontinent requests authorization to construct these expansion facilities any time during the first five years after its initial phase facilities are in operation.

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[4] The pipeline facilities will cross Bryan County, Oklahoma; Fannin, Lamar, Red River, Franklin, Titus, Morris, and Cass Counties, Texas; Caddo, Bossier, Webster, Claiborne, Lincoln, Union, Ouachita, Morehouse, Richland, and Madison Parishes, Louisiana; Warren, Hinds, Rankin, Simpson, Smith, Jasper, and Clarke Counties, Mississippi; and Choctaw County, Alabama.

[5] The proposed interconnections are with Enogex, NGPL (twice); Houston Pipe Line Company, L.P (Houston Pipe Line); Texas Gas Transmission, LLC; ANR Pipeline Company; Columbia Gulf (twice); Texas Eastern Transmission, L.P.; Southern Natural Gas Company; Tennessee Gas Pipeline Company; Destin Pipeline Company, LLC; Transco; and CenterPoint Energy Gas Transmission (CenterPoint).

[6] The revised Exhibit G filed by Midcontinent on May 16, 2008, indicates that the capacity on the first 40 miles of its system will be 875,000 Dth/d.

Enogex Capacity Lease

8. Enogex requests a limited jurisdiction certificate to enable it to lease its capacity to Midcontinent without its facilities and otherwise non-jurisdictional activities becoming jurisdictional, and Midcontinent requests certificate authorization to lease such capacity.

9. Midcontinent and Enogex have entered into a renewable operating lease agreement which provides that Midcontinent will lease 272,000 Dth/d of capacity (exclusive of fuel) on Enogex's intrastate system for a primary term of 10 years.[7] Enogex will support firm deliveries from the receipt points specified in the lease (Waynoka, West Pool, and East Pool) to the Bennington lease delivery point through a combination of existing capacity and capacity Enogex will create through the addition of compression and certain other pipeline facilities.[8]

10. Enogex states that the lease will enable Midcontinent to transport gas on a firm basis from various points in Oklahoma to the interconnection of the Enogex system with Midcontinent at Bennington. Midcontinent will use the capacity to provide open-access transportation service to its customers pursuant to its FERC Gas Tariff. Midcontinent will pay Enogex a monthly lease charge, plus fuel and gas lost and unaccounted-for.

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[7] On April 23, 2008, Midcontinent filed supplemental information revising the capacity to be leased from 275,334 Dth/d to 272,000 Dth/d, and modifying the receipt point quantities shown in Exhibit A of the lease agreement. As discussed in separate filings also dated April 23, 2008, Midcontinent and Enogex have withdrawn their original requests that the Commission grant authorization to increase the lease capacity, at any time during the first five years of the project operation, up to a total of 800,000 Dth/d.

[8] Enogex intends to construct 43 miles of 24-inch lateral pipeline in Woods and Major Counties, Oklahoma to provide an interconnection with the Waynoka Plant and a new 24,000 hp compressor station at the Bennington delivery point. These facilities will be integrated with Enogex's existing intrastate system; thus, Enogex must obtain the requisite state authorizations for these facilities. Enogex states that the 43-mile long pipeline will be constructed regardless of whether the Commission approves the subject lease arrangement with Midcontinent. Therefore, the environmental review in this proceeding did not include Enogex's planned pipeline. The compressor station will boost pressure at Bennington where Enogex's system interconnects with several other pipelines. Thus, while the compressor station is needed to deliver gas transported using upstream capacity leased to Gulf Crossing Pipeline Company LLC (Gulf Crossing) and Midcontinent, the compressor station is also needed to deliver gas transported by Enogex under section 311 of the NGPA using its remaining capacity. The compressor station was included in the environmental review in the Gulf Crossing proceeding.

Open Season and Precedent Agreements

11. Midcontinent conducted an open season for the project between December 13, 2006 and January 16, 2007.[9] The open season provided for three categories of shippers with distinct rights based on level of commitment. "Foundation" shippers commit to 500,000 Dth/d or more in Zone 1 and 300,000 Dth/d or more in Zone 2 for a term of at least 10 years. "Anchor" shippers commit to more than 150,000 Dth/d in Zone 1 and Zone 2 for a term of at least ten years, but less than the commitment required of foundation shippers. "Standard" shippers are all other shippers. Prior to commencement of the open season, Midcontinent had executed agreements with one foundation shipper, one anchor shipper, and one standard shipper. Midcontinent states that all these initial shippers elected to pay negotiated rates. Midcontinent has filed executed precedent agreements for almost the entire Zone 1 and Zone 2 initial phase capacities of its proposed system.[10]

12. Midcontinent states that it does not believe that any aspects of the precedent agreements reflect material deviations from the pro forma service agreements in its tariff. However, Midcontinent provides a description of the most important non-conforming provisions and seeks a determination that even if some contractual provisions can be construed to constitute material deviations, no provision of any precedent agreement is unduly discriminatory. These provisions are discussed in detail below.

Midcontinent's Proposed Rates

13. Midcontinent, as a new pipeline, is proposing to offer firm (Rate Schedule FTS) and interruptible (Rate Schedules ITS, PALS, and IBS) open-access transportation services at cost-based recourse rates under Part 284 of the Commission's regulations, and has filed a pro forma tariff for review. Midcontinent has proposed three separate sets of rates: (1) interim period rates, for Rate Schedules FTS and ITS only, to be applicable if and when parts of the system go into service but before the entire initial phase facilities are in service; (2) base rates to be applicable when the entire initial phase facilities are in

[9] On May 9, 2008, Midcontinent filed a data response indicating that the open-season deadline was extended to January 16, 2007, from the January 15, 2007 date stated in its October 9, 2007 application.

[10] Midcontinent has requested privileged and confidential treatment for all of the precedent agreements on the grounds that the agreements are the product of extended negotiations with shippers in a highly competitive environment. On June 17, 2008, Midcontinent filed an amendment to the agreement with the foundation shipper agreeing to provide an additional 100,000 Dth/d of Zone 1 capacity through construction of expansion facilities.

service; and (3) expansion rates to be applicable once the expansion phase facilities are in service. Midcontinent will charge shippers who use the Enogex leased capacity a separate charge that will recover all of the lease costs.

14. Midcontinent states that the pipeline will be laid in four potential segments, with compression added later. Interim rates are proposed for each of the four segments to be applicable when the segments, if any, can go into service ahead of the date the entire initial phase facilities are placed in service. The proposed interim rates are additive.

15. Midcontinent is seeking a determination that rolled-in rate treatment will be appropriate for its expansion phase facilities, consisting of two new compressor stations, one in each of its two zones. Midcontinent has provided information indicating that initial phase shippers will save about $6.7 million per year if the expansion phase facilities are rolled into the system's cost of service.[11]

II. <u>Notice, Interventions, Protests, and Motions</u>

16. Notice of Enogex's application in Docket No. CP08-9-000 was published in the *Federal Register* on October 24, 2007 (72 Fed. Reg. 60,332). Notice of Midcontinent's application in Docket No. CP08-6-000 was published in the *Federal Register* on October 26, 2007 (72 Fed. Reg. 60,932).

17. ConocoPhillips Company (ConocoPhillips), Midcontinent, Apache Corporation (Apache), ScissorTail Energy LLC (ScissorTail), BP America Production Company and BP Energy Company (Collectively, BP), Chesapeake Energy Corporation (Chesapeake), Chevron, U.S.A. Inc. (Chevron), Marathon Oil Company (Marathon Oil), and Unimark LLC (Unimark) filed timely, unopposed motions to intervene in the Enogex proceeding. ConocoPhillips, Southern Natural Gas Company (Southern), Calpine Energy Services, L.P., Apache, Chevron, BP, Chesapeake, Marathon, and Enogex Inc., filed timely unopposed motions to intervene in the Midcontinent proceeding. Timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.[12] CenterPoint, Oklahoma Independent Petroleum Association (OIPA), and American Electric Power Service Corporation filed unopposed motions to intervene out-of-time in the Enogex proceeding. Alan Herbert, Leigh Alexander McClendon, III, Shannon McClendon, MarkWest Energy Partners, L.P and MarkWest Pioneer, L.L.C. (MarkWest); and XTO Energy Inc. (XTO) filed unopposed motions to intervene out-of-time in the Midcontinent proceeding. All have shown an interest in this proceeding, and their intervention at this stage of the proceeding will not cause undue

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[11] *See*, Part III, page 1 of 1, of Exhibit P of Midcontinent's application.

[12] 18 C.F.R. § 385.214(c)(1) (2008).

delay or unfairly prejudice the rights of any other party. Accordingly, for good cause shown, we will permit their late intervention.[13]

18. Chesapeake and XTO, as well as Enogex and Midcontinent, filed comments in support of the applicants' proposals. Chesapeake asserts that the lease of facilities to Midcontinent will enable Midcontinent to provide seamless, integrated service to its shippers, thereby facilitating the delivery of important new sources of natural gas to markets. Chesapeake stresses that the lease of facilities to Midcontinent permits the expansion of service in an efficient and environmentally-friendly way. XTO states that the project will tap into under-utilized basins and encourage investments to develop these resources for the ultimate benefit of consumers. Various governmental authorities, and individuals, also filed comments in support of the project, primarily arguing that the project will bring economic benefits.

19. Apache, ConocoPhillips, Indicated Shippers (Chevron and Marathon Oil), and Unimark filed timely protests in the Enogex proceeding. ConocoPhillips, Apache, and BP filed timely protests in the Midcontinent proceeding. Environmental protests and comments are addressed in the environmental discussion below and in the Environmental Impact Statement.

20. ConocoPhillips, Apache, the Indicated Shippers and Unimark argue in their protests that the lease of capacity from Enogex to Midcontinent, in concert with Enogex's lease of capacity to Gulf Crossing,[14] will impair their rights as section 311 interruptible shippers on Enogex's system. They assert that, because Enogex does not offer firm section 311 service, the lease is unduly discriminatory. Unimark requests that the lease proposal be rejected or, alternatively, set for hearing. On November 13, 2007, Apache filed a motion to consolidate Midcontinent's and Enogex's certificate proceedings in these dockets and Enogex's section 311 rate proceeding in Docket No. PR08-1-000,[15] contending that all three proceedings share issues of undue discrimination related to the lease. Apache further raises the issue that Enogex offers its existing section 311 service

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[13] 18 C.F.R. § 385.214(g) (2008).

[14] *Gulf Crossing*, *et al.*, 123 FERC ¶ 61,100 (2008) (*Gulf Crossing*). The Commission certificated Gulf Crossing's lease of 90,000 Dth/d of capacity on Enogex's system and the construction of new pipeline facilities from an interconnection with Enogex at Bennington to an interconnection with Gulf South Pipeline Company, LP, from whom Gulf Crossing is also approved to lease capacity, to deliver gas to Gulf Crossing's terminus at an interconnection with Transco at its Station 85 in Alabama.

[15] On October 1, 2007, Enogex filed a petition in Docket No. PR08-1-000 for approval to increase its section 311 transportation rates.

only on an interruptible basis and has proposed a rate increase for its section 311 interruptible service, while offering in this certificate proceeding to offer firm transportation service under an NGA certificate only to Midcontinent, by way of the lease, at a rate equal to or less than its existing section 311 rate. Apache states that the rate proceeding is the proper forum for analyzing the rate implications of the proposed lease and the need for Enogex to offer firm section 311 service on its system.

21. On November 28, 2007, Chesapeake, Enogex, and Midcontinent filed motions for leave to file answers and answers to protests, arguing that the Commission views lease arrangements differently than transportation services and that Enogex need not offer firm transportation to its existing section 311 shippers in order to meet the requirement of not being unduly discriminatory. In those filings, Enogex and Midcontinent also oppose Apache's request for consolidation of Enogex's section 311 rate proceeding with Midcontinent's and Enogex's certificate proceedings in these dockets, arguing that the proceedings involve different parties and present distinctly different issues under different federal statutory provisions. Enogex further emphasizes that the issue of potential firm section 311 service on Enogex's system has been raised in its section 311 rate proceeding. On December 13, 2007, Apache filed an answer responding to Chesapeake's, Midcontinent's and Enogex's answers to the protests.[16]

22. On April 8, 2008, as amended on April 11, 2008, Apache filed a motion requesting a consolidated hearing, or alternatively, a staff panel in the rate proceeding and a technical conference in the certificate proceedings.[17] Apache argues that contested issues of material fact include: (1) whether Enogex has sufficient capacity to lease firm capacity to Midcontinent without negatively impacting existing interruptible section 311 service; (2) whether Enogex's offering of firm transportation to Midcontinent is unduly discriminatory; and (3) whether Enogex's offering of firm transportation to intrastate shippers but not 311 shippers is unduly discriminatory. At bottom, Apache contends that open-access principles require that firm service be offered on a non-discriminatory basis to all interested parties, including interruptible section 311 shippers, and that existing interruptible section 311 service should not be negatively impacted.

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[16] Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits answers to protest and answers to answers. We will waive this rule to admit all answers described herein because they have assisted us in our decision-making.

[17] Oklahoma Independent Petroleum Association and Unimark filed pleadings on April 15 and April 11, 2008, respectively, supporting Apache's motion.

23. On April 23, 2008, Enogex and Midcontinent filed answers to Apache's motion for hearing. Midcontinent states that it modified its lease agreement with Enogex to reduce the leased capacity from 800,000 Dth/d to 272,000 Dth/d, thereby greatly reducing any adverse impact to Apache. Moreover, Midcontinent restates its position that, because under Commission policy capacity leases are property interests which are fundamentally different from contracts for transportation services, Apache is not a similarly situated shipper. Therefore, the issues in dispute are not of material fact, but rather of Commission policy.

24. Enogex, too, contends that, because lease arrangements are fundamentally different from transportation service agreements, there can be no undue discrimination as claimed by Apache. According to Enogex, Apache is not entitled to the same rates and services as Midcontinent because they are not in a similarly situated position. Moreover, Enogex maintains that the Commission has no legal basis to require that Enogex offer firm section 311 service. Also, states Enogex, under Commission policy and precedent, it is not unduly discriminatory to offer intrastate firm service while only offering interruptible section 311 service.[18] Regarding Apache's claim of adverse impact, Enogex contends that as an interruptible shipper, Apache has no standing to complain that their capacity may be reduced or interrupted from time to time. In any event, states Enogex, there is record evidence demonstrating that the Midcontinent and Gulf Crossing leases will not adversely affect the design flowing capacity of the Enogex system and/or the availability of interruptible service, particularly in view of the fact that the capacity to be leased has been reduced to 272,000 Dth/d.

25. On May 13, 2008, Apache filed an answer to Enogex's and Midcontinent's answers of April 23, 2008, supported by a PowerPoint presentation and affidavit. In this filing, Apache raises the claim that Commission policy requires identification of receipt points (not identified here, as pooling points encompass all points) and delivery points. Also, states Apache, Lease Article I, 1.1(a) provides that the parties may change the receipt points under the lease at any time, thus conveying a floating capacity right to move anywhere on the system at any time, preempting existing gas flows and potentially shutting in production, rather than a defined property interest as other approved leases. In these circumstances, it is not clear, according to Apache, what capacity has been reserved, nor what capacity will remain. Apache now contends that in addition to requiring that Enogex offer firm section 311 transportation service, the Commission should require that Enogex define a clear capacity path, demonstrate that existing shippers will not be harmed, and file an application to amend the lease for any future increases in leased capacity.

[18] *See Cranberry Pipeline Corp.*, 97 FERC ¶ 61,280 (2001).

26. Enogex and Midcontinent filed responsive pleadings on May 28, 2008. In addition to restating the applicability of various Commission policies on which it relies, as well as its position that the record shows that there is sufficient capacity on Enogex to support both the lease and historical section 311 service, Enogex points out that the Commission has approved interstate transportation services that have pools as receipt points.[19] Enogex emphasizes that it has other Commission-approved leases[20] (with Gulf Crossing and Ozark Gas Transmission L.L.C.) and argues there is no basis to reject the proposed lease of capacity to Midcontinent on the grounds argued by Apache, i.e., because it does not specify a capacity path. Midcontinent distinguishes the cases on which Apache relies for the premise that specific receipt points must be designated in a capacity lease, asserting that none of those cases ruled on the appropriateness of a capacity lease or address policy on leases in any manner. Further, Midcontinent claims that the approved lease of Enogex capacity to Gulf Crossing has many of the same provisions as Enogex's proposed lease of capacity to Midcontinent. Midcontinent points out that the Commission-approved lease in *Transok* [21] contained ten primary receipt points, later reduced to eight, with the option to change points upon mutual agreement, and that the lease approved in *Texas Gas Transmission, LLC (Texas Gas)*[22] contained four primary and four secondary points. On June 4, 2008, Apache answered, and on June 19, 2008, Enogex answered Apache.[23]

27. We will deny Apache's request to consolidate Enogex's section 311 rate proceeding in Docket No. PR08-1-000 and the two NGA section 7(c) certificate proceedings in Docket Nos. CP08-6-000 and CP08-9-000. The Commission consolidates matters only if a hearing is required to resolve common issues of law and fact and consolidation will ultimately result in greater administrative efficiency. We do not believe administrative efficiency will be served by consolidating the section 311 rate

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[19] *See CNG Transmission Corp.*, 79 FERC ¶ 61,219, at 61,995 (1997).

[20] *Transok, Inc., et al.*, 81 FERC ¶ 61,005 (1997) (Enogex's predecessor, Transok, leased capacity to Kansas Pipeline Company, now Enbridge Pipelines); *Transok, et al.*, 97 FERC ¶ 61,362 (2001) (*Transok*) (Transok leased capacity to Ozark Gas Transmission L.L.C.); *Gulf Crossing*, *supra*, (Enogex leased capacity to Gulf Crossing).

[21] 97 FERC ¶ 61,362 (2001).

[22] 119 FERC ¶ 61,281 (2007).

[23] Other filings, not specifically noted here, were made which merely reiterate arguments previously raised. Various persons filed either in support of Apache's request for a hearing or stating that Apache's request is baseless. All of the comments filed have been considered herein and are accepted as part of the record.

proceeding with certificate proceedings which involve different questions of law and fact[24] and different parties, as well as different statutory provisions and standards. Moreover, we see no purpose in consolidating the two certificate proceedings in view of the fact that all issues in each proceeding are addressed in this order without need for an evidentiary hearing.

28. In addition, we will deny Apache's motion for evidentiary hearing or alternatively, a staff panel in the rate proceeding and a technical conference in the certificate proceedings. We find that there is ample record, based on the parties' various filings, to resolve all material issues of fact. We will address the legal and factual issues raised in the comments and protests below, as appropriate.

III. Discussion

29. Because the facilities proposed by Midcontinent will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, their construction and operation are subject to the requirements of sections 7(c) and (e) of the NGA. Likewise, Enogex's operation of capacity that it will lease to Midcontinent, as well as Midcontinent's acquisition of such capacity by lease, are subject to the requirements of section 7(c).

Enogex Capacity Lease

30. Historically, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[25] To enter into a lease agreement, the lessee generally needs to be a natural gas company under the NGA and needs section 7(c) certificate authorization to acquire the capacity. Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. The leased capacity is allocated for use by the lessee's customers. The lessor, while it may remain the operator of the pipeline system, no longer has any rights to use the leased capacity.[26]

31. The Commission's practice has been to approve a lease if it finds that: (1) there

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[24] We note that Apache's assertion that there is a common issue fact, i.e., undue discrimination, hinges on its claim that Enogex should be required to offer firm section 311 service which, as discussed below, the Commission will not do.

[25] *Texas Eastern Transmission Corp.*, 94 FERC ¶ 61,139, at p. 61,530 (2001).

[26] *Texas Gas Transmission, LLC,* 113 FERC ¶ 61185, at P 10 (2005).

are benefits from using a lease arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the terms of the lease; and (3) the lease arrangement does not adversely affect existing customers.[27] The lease agreement between Midcontinent and Enogex satisfies these requirements.

32. As more fully discussed below, we find that the payments are satisfactory, there are significant benefits, and those benefits outweigh any potential harm to Enogex's customers. Therefore, we find that the proposed lease is required by the public convenience and necessity, subject to the conditions described herein.

33. It is appropriate to ensure that Midcontinent's capacity lease arrangement does not result in subsidization in the future. Therefore, consistent with current policy[28] and Midcontinent's proposal to charge its customers separate incremental rates for the leased capacity on Enogex's system, the Commission will condition its approval of the lease on Midcontinent's not being permitted in the future to shift any of its costs associated with the leased capacity to customers that do not use the leased capacity. The Commission will likewise condition its approval of the lease on Enogex's not shifting any costs associated with the leased capacity to their other interstate customers.[29] Midcontinent shall maintain separate accounting records to ensure that costs and revenues associated with the leased capacity from Enogex can be identified in any future proceeding and that Midcontinent's other customers are not subsidizing shippers who use capacity leased from Enogex.

34. To enable Enogex to carry out its responsibilities under the lease agreement, we will issue Enogex a limited jurisdiction certificate. The Commission looks closely at proposals that would create dual jurisdiction facilities, i.e., facilities that would be subject to state and federal jurisdiction, in order to avoid duplicative and/or potentially inconsistent regulatory schemes over the same facilities. However, here, although federal regulation of Enogex will be "limited," Enogex and Midcontinent will both be subject to exclusive federal regulation regarding the lease and 272,000 Dth/d of capacity on the Enogex system and any issues that may arise thereunder. The limited jurisdiction certificate will enable Enogex to operate the leased capacity being used for NGA jurisdictional services subject to the terms of the lease and subject to Midcontinent's open-access tariff. The limited jurisdiction certificate will require Enogex to operate the

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[27] *Id.*; *Islander East Pipeline Company, L.L.C.,* 100 FERC ¶ 61,276, at P 69 (2002).

[28] *Gulf South Pipeline Company, L.P., and Texas Gas Transmission, LLC,* 119 FERC ¶ 61,281 (2007).

[29] *Gulf Crossing, supra.*

leased capacity in a manner that ensures Midcontinent's ability to provide services, including interruptible transportation, using the leased capacity on an open-access, non-discriminatory basis. We have approved a similar lease in the past involving Enogex.[30] Our finding that Enogex is NGA-jurisdictional is limited to its role as lessor-operator of capacity used by Midcontinent to provide Midcontinent's interstate services. Enogex will remain non-jurisdictional as to its intrastate activities and may continue to provide NGPA section 311 transportation services on its system.

Lease Benefits

35. The Commission has found that capacity leases in general have several potential public benefits. Leases can promote efficient use of existing facilities, avoid construction of duplicative facilities, reduce the risk of overbuilding, reduce costs, minimize environmental impacts, and result in administrative efficiencies for shippers.[31] Here, the lease arrangement will provide for a significant portion of Midcontinent's proposed system without construction of duplicative facilities which would essentially parallel the Enogex system. The leased capacity allows for the efficient use of the available capacity on Enogex, avoids the environmental impact and impacts on landowners associated with constructing duplicative facilities, substantially reduces the costs of constructing Midcontinent's system, and allows Midcontinent's system to be placed in service earlier than if redundant facilities were constructed. The lease will provide Midcontinent's shippers with seamless access, under a single firm transportation contract, from the production area in Oklahoma to multiple pipelines serving the southern and eastern United States.

Lease Payments

36. Midcontinent states that the payment it proposes to make to Enogex under the lease is less than Enogex's maximum applicable transportation rates for comparable service. However, a comparison of the proposed lease payment with an Enogex firm interstate rate is not possible, because although Enogex provides interruptible interstate service under section 311 of the NGPA, it does not currently offer firm section 311 transportation service. While Enogex acknowledges that its firm intrastate transportation rates are also not directly comparable to the Midcontinent lease payment, Midcontinent notes that Enogex's December 28, 2007 response to a Commission data request in CP07-403-000 provides figures for what Enogex avers are its most comparable firm intrastate transportation service agreements. According to this data, the average demand charge

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[30] *See, Gulf Crossing, supra.*

[31] *See, e.g., Dominion Transmission, Inc.*, 104 FERC ¶ 61,267, at P 21 (2003); *Islander East Pipeline Company,* 100 FERC ¶ 61,276, at P 70 (2002).

with an MDQ of equal to or greater than 90,000 Dth per day is $0.193 per Dth. Under the lease, Midcontinent will make a payment equal to $0.09 per Dth for receipts at the East Pool, $0.17 per Dth for receipts at Waynoka and $0.15 per Dth for receipts at the West Pool, all of which are lower than $0.193 per Dth. In addition, Midcontinent states that the negotiated lease payments to Enogex are substantially less than what Midcontinent's recourse rates for comparable service would be, given the capital costs for construction, if Midcontinent were to duplicate the facilities Enogex will use to provide the lease capacity.

37. We find that Midcontinent's shippers that intend to use the Enogex lease would pay a higher rate if Midcontinent were required to construct redundant facilities in Oklahoma in order to provide the service. In conclusion, the Commission agrees that under the circumstances here, where there is no directly comparable rate, the comparison above is a reasonable comparison method and, for the purposes of approving the lease, we find that the demand charges that Midcontinent will pay under the lease will be less than comparable firm demand charges on the Enogex System.[32]

Effect on Existing Customers

38. Apache, BP, Conoco Phillips, Indicated Shippers and Unimark filed protests and comments expressing significant concerns with regards to Midcontinent's lease with Enogex and the lease's impact on Enogex's existing customers. The protesters' concerns are addressed below.[33]

<u>Impact on Availability of Capacity for Existing Enogex Services</u>

39. The protesters believe there is a likelihood Enogex's existing interruptible section 311 transportation service will be curtailed due to the size of the lease and state that existing interruptible section 311 shippers have no way of protecting their service since Enogex does not currently offer firm section 311 transportation service. Apache states that Enogex has not provided such assurances that existing interruptible section 311 shippers will continue to receive current levels of service. In fact, Apache and Indicated Shippers note that Enogex has stated just the opposite – that customers who take

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[32] *Gulf Crossing, supra.*

[33] BP and Apache protested Midcontinent's right to increase the lease capacity to 800,000 Dth/d. The issue is moot, as Midcontinent and Enogex have withdrawn their requests for approval to lease up to 800,000Dth/d and now request authority for a lease capacity of up to only 272,000 Dth/d. Any increase in the lease capacity would require that Midcontinent and Enogex file for certificate authority to amend the lease.

interruptible service on the Enogex system have no claim on Enogex capacity but will continue to receive service to the extent service is available.

40. ConocoPhillips is concerned that the lease will severely impair its current contractual rights on Enogex. ConocoPhillips is a storage customer and uses Enogex's interruptible section 311 transportation service to inject and withdraw its storage gas. It states that Enogex has not offered firm section 311 service to any of its shippers, yet the capacity leased to Midcontinent will be used by Midcontinent to provide firm interstate service, clearly impairing the value and availability of the storage and transportation services provided to ConocoPhillips by Enogex. In addition, ConocoPhillips and Unimark state that it appears the interruptible interstate service offered by Midcontinent pursuant to the lease would have priority over existing section 311 shippers on Enogex.

41. Enogex states in its November 28, 2007 answer that the lease will not adversely affect existing customers entitled to service on the Enogex system. Enogex states interruptible customers are not *per se* entitled to a particular quantum of service on Enogex and these customers cannot legitimately claim a right to continue to receive a specific amount of interruptible service or assert a corollary right to veto an arrangement that would reduce the quantity of service to which they feel entitled. Enogex also states in its April 23, 2008 answer that the flow diagram information provided in its December 31, 2007 Supplemental Data Response demonstrates that the Enogex system, as it will be configured by the in-service dates of the Midcontinent lease and the Gulf Crossing lease, will readily accommodate the initial capacity commitments Enogex has made under those leases and that the proposed interconnects with Midcontinent and Gulf Crossing will not adversely affect the design flowing capacity of the Enogex system.

42. In its June 4, 2008 answer to Midcontinent, Apache states that Enogex's system is becoming more constrained and that the lease will make things worse. Specifically, Apache states that for May 30-31, 2008, capacity was not available at three of Enogex's delivery points, and that several new Apache wells have been refused connection. On June 19, 2008, Enogex answered Apache, stating that the three constrained delivery points were constrained by take-away capacity on the interconnecting pipelines, as well as the capacity of Enogex's laterals feeding them. Enogex also states that the decision of its gathering affiliate was based on specific connection criteria in the agreement with Apache and had nothing to do with availability of capacity on the mainline portions of Enogex. Enogex concludes that the addition of new firm take-away capacity on Midcontinent will help relieve such interconnection-specific capacity constraints.

43. The Commission finds that the lease arrangement will not have an unduly adverse impact on Enogex's existing services. Engineering information provided by Enogex demonstrates that the Enogex system, as it will be configured by the in-service dates of the Midcontinent lease and the Gulf Crossing lease, will readily accommodate the capacity commitments Enogex has made under the Midcontinent and Gulf Crossing leases. Further, while certain individual receipt points may decrease in capacity, there

will be an overall increase in capacity on Enogex's system as discussed below in the engineering section. Thus, rather than the lease arrangement resulting in reduced gas supplies available to the market due to wells being forced to shut-in, the capacity of the Enogex system will increase as a result of the facility additions Enogex plans and the availability of firm transportation on Midcontinent for supplies produced in Oklahoma should promote the development of new prolific sources of supply there. In addition, Enogex states in its answer that the lease will not adversely affect existing customers entitled to service on the Enogex system. Enogex will continue to provide interruptible section 311 transportation service, with the same rights as that service holds today, after implementation of the lease. While the amount of capacity Enogex can provide as interruptible section 311 transportation service could change at some point in the future, those transactions are, by definition, interruptible, and therefore subject to change.[34] In these circumstances, the Commission finds that the benefits from the Enogex lease outweigh any possible changes that may result to shippers receiving interruptible section 311 service.

44. The Commission does not believe that the lease will provide priority to interstate interruptible service offered by Midcontinent over existing interruptible section 311 service on Enogex. The Commission views a lease of pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[35] Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. Midcontinent and Enogex will schedule their pipelines separately and according to the provisions of their individual tariff or Statement of Operating Conditions. Enogex must ensure that its use of capacity dos not prevent it being able to satisfy its obligation to ensure that Midcontinent is able to use the 272,000 Dth/d, including for interruptible interstate transportation. That said, once satisfaction of that obligation has been assured, Enogex can then use any available capacity for its own intrastate services and section 311 services. Shippers will have the option of contracting for interruptible capacity on either pipeline.

<u>Lease is Unduly Discriminatory</u>

45. Apache, ConocoPhillips, Unimark and Indicated Shippers allege that because Enogex is offering firm capacity to Midcontinent through the lease but has not sought to offer firm section 311 transportation service to its existing shippers, the proposed lease is unduly discriminatory. They believe this discriminatory treatment is further exacerbated by the fact that the proposed rate Midcontinent will pay for the lease capacity may be lower than Enogex's section 311 interruptible rate. In addition, they note that Enogex did

[34] *Gulf Crossing, supra* at P 121.

[35] *Texas Eastern Transmission Corp.*, 94 FERC ¶ 61,139, at p. 61,530 (2001).

not post the availability of firm service to interstate delivery points or hold an open season for firm interstate service. Apache states that the discrimination is especially egregious since Apache has dedicated production to the Enogex system and is, in essence, hostage to its system.

46. Apache and Indicated Shippers state that while the Commission has found that a pipeline offering to provide section 311 transportation service may limit the overall capacity that it makes available for firm section 311 contracts, in the event it does offer firm interstate transportation (via section 311) that transportation must be offered on a nondiscriminatory basis.[36] Indicated Shippers state that it appears Enogex may be trying to circumvent this non-discriminatory requirement by granting firm interstate capacity but only in the form of the capacity leased to other pipelines. Indicated Shippers state it is unduly discriminatory that Enogex has entered into leases with Midcontinent and Gulf Crossing for firm service despite the fact that many existing shippers using interruptible section 311 service want firm service on Enogex and are willing to convert their existing interruptible service to firm service. Apache and Indicated Shippers request that the Commission address the undue preference for the leased capacity by requiring Enogex to provide firm section 311 service to existing shippers who want it, if the Commission does not reject the lease outright.

47. Chesapeake states the Commission cannot require Enogex to offer firm section 311 service, therefore, the lease offers shippers an opportunity to obtain firm capacity to which they otherwise would not have access. Chesapeake avers that the lease allows Midcontinent to provide a seamless, integrated service to its shippers, facilitating the delivery of important new supply sources to pipelines serving growing markets in the Northeast and Florida. Chesapeake states Apache and other producers were free to participate in the Midcontinent open seasons and obtain such capacity, and their business decisions not to participate should not prevent Chesapeake and other Midcontinent shippers from obtaining firm transportation rights that would otherwise be unavailable to them.

48. Enogex states in its answer that the Commission views lease arrangements differently than transportation services under rate contracts and that to meet the requirement that a capacity lease be non-discriminatory, a lessor need only offer the same type of service to other similarly situated shippers, which, the Commission has held does not necessarily require that the lessor make such service available to 'shippers.'[37] Enogex states this principle is based upon the premise that a capacity lease is a property

[36] *Peoples Gas Light and Coke Co.,* 118 FERC ¶ 61,203 (2007); *Transok, Inc.,* 54 FERC ¶ 61,229 (1991).

[37] *Islander East Pipeline Company,* 100 FERC ¶ 61,276 (2002).

interest that requires NGA section 7 certificate authorization, which is only available to a natural gas company under the NGA. Enogex states that under Commission precedent the lease affords Midcontinent property rights to capacity in the Enogex system that are not equivalent to firm section 311 transportation service. Enogex states that none of the parties that contend the lease is discriminatory can properly lay a claim to the same type of "service" as in the lease since none are natural gas companies under the NGA and none are in a position, or are actually seeking, to enter into an NGA lease-type arrangement with Enogex.

49. Enogex also states there is no basis on which the Commission can lawfully compel Enogex to offer firm transportation service to its section 311 shippers. Enogex states the Commission has held that pipelines offering transportation service under NGPA section 311 have the sole discretion to decide whether or not to offer service on a firm basis and the Commission has specifically stated it cannot require section 311 pipelines to offer firm services.[38]

50. Apache states in its answer that Enogex's proposition that a lease is different from transportation service and that property rights transferred in a lease are not equivalent to firm transportation service is flawed since they ignore that the discrimination occurs by virtue of the fact that shippers on the leased Enogex capacity are offered firm transportation, whereas shippers on the unleased Enogex capacity are not. Therefore, Apache believes Enogex is not treating similarly situated shippers the same and is not in compliance with the Commission's regulations for section 311 pipelines. Apache also states that while it is true that the Commission has not required a section 311 pipeline to offer firm service, if a section 311 pipeline does elect to offer service on a firm or interruptible basis, under the Commission's regulations it must do so without undue discrimination.[39]

51. As stated above, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline that requires NGA section 7 certificate authorization. As such, this type of arrangement is only available to a natural gas company under the NGA. Lessees are not treated as shippers and the Commission does not consider them to be similarly situated to interstate shippers on the lessor's pipeline.[40] Enogex will not be

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[38] *See, e.g., Peoples Gas Light & Coke Co.,* 118 FERC ¶ 61,203 (2007); *Tejas Gas Pipeline Co.,* 81 FERC ¶ 61,053 (1997).

[39] *Id.*

[40] *See, Islander East Pipeline Company, L.L.C.,* 100 FERC ¶ 61,276 at P 87-89 (2002).

providing firm transportation service over the leased capacity – Midcontinent will. Therefore, the Commission does not believe that Enogex is acting in an unduly discriminatory manner in leasing capacity to Midcontinent while not electing to provide firm section 311 transportation service.

52. Enogex is an intrastate pipeline and section 284.7(a)(2) of the Commission's regulations[41] states that intrastate pipelines that provide transportation service under Subpart C (section 311) *may* offer such transportation on a firm basis.[42] Part 284 of the Commission's regulations require that intrastate pipelines that offer section 311 transportation service on a firm or interruptible basis must provide such service without undue discrimination, or preference. The Commission's regulations do not require intrastate pipelines to provide NGPA section 311 interstate service on a firm basis. However, to the extent an intrastate pipeline does provide interstate firm service, it must do so consistent with the Commission's regulations.[43] Therefore, the Commission will not require Enogex to provide firm section 311 service to existing shippers; however, if Enogex does elect to provide that service, it must do so on a non-discriminatory basis.

Rate Stacking

53. Apache, ConocoPhillips, Unimark and Indicated Shippers state that for a shipper that only desires service to Enogex's existing interstate delivery points, having to purchase firm service on Midcontinent adds incremental costs for undesired incremental services and provides Midcontinent an unfair competitive advantage compared to other pipelines that can take delivery of gas off Enogex. The anti-competitive impact of this tying of capacity is exacerbated by the substantial payments shippers would have to make for Midcontinent capacity in order to access firm capacity on Enogex. For example, ConocoPhillips states that currently a shipper moving from Enogex's West zone to Bennington would pay a maximum rate of $0.17 per Dth plus fuel charges of 0.82 percent. To receive the identical service under Midcontinent's ITS, ConocoPhillips states that a shipper would have to pay the Zone 1 rate of $0.3015, plus the lease charge of $0.15, for a total of $0.4515 per Dth and a fuel charge of 1.51 percent.

54. Apache notes in its answer that if it were to purchase firm capacity on the Midcontinent leased portion of Enogex, it would be paying twice for the same capacity – once to Enogex and once to Midcontinent. Apache states it has dedicated production to Enogex and, therefore, is not "free" to purchase capacity on Midcontinent on a firm basis

[41] 18 C.F.R. § 284.7(a)(2)

[42] *See, e.g., Cranberry Pipeline Corporation,* 97 FERC ¶ 61,280 (2001).

[43] *Peoples Gas Light and Coke Company,* 118 FERC ¶ 61,203 (2007).

because it must deliver its dedicated gas into Enogex's gathering and transportation system.[44] Thus, even if Apache purchased firm capacity on Midcontinent, it would not be guaranteed delivery through the gathering system to the leased Midcontinent portion of the Enogex mainline, and even if it could, it would suffer the unduly discriminatory consequences of rate stacking.

55. In its February 26, 2008 data response, Midcontinent states that customers on Enogex will pay Enogex's interruptible section 311 rate to make their gas available at the West Pool and East Pool lease receipt points, while gas taken at the Waynoka receipt point does not incur any Enogex fees as there are no upstream Enogex facilities. Midcontinent also states that the lease is specific in providing that the delivery point under the lease is a point of interconnection with Midcontinent.[45] Midcontinent continues that the lease as negotiated was a critical factor in the foundation shipper's and other shippers' decisions to sign agreements for firm service on Midcontinent, and, if the lease is modified, the foundation shipper has certain reduction rights. However, Midcontinent states, shippers on the Enogex system making use of capacity not subject to the Midcontinent lease should continue to be able to use Enogex's interruptible section 311 services to bring gas to Midcontinent at Bennington and Midcontinent would allow its shippers (those holding capacity downstream of Bennington) to nominate such volumes into Midcontinent at Bennington. No lease charges from Midcontinent would be associated with receipts of gas which Enogex transported under section 311.

56. An Enogex shipper who chooses to purchase capacity on Midcontinent and utilize the lease capacity to receive its own gas at either the West Pool or the East Pool will pay the Enogex interruptible section 311 rate in addition to Midcontinent's rates just as the Enogex shipper would for delivery from Enogex system into any interstate pipeline with whom it had acquired capacity. That is not rate stacking. Enogex's shippers do not have to contract for firm capacity on Midcontinent in order to sell their gas into Midcontinent's system, even via the leased capacity. In fact, the shippers are free to deliver their volumes elsewhere, as they do now. However, there are multiple Enogex shippers who have made a business decision to contract for capacity on Midcontinent, including the

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[44] In its June 19, 2008 filing, Enogex counters that Apache could have participated because it delivers much of its gas to the West Pool and its contracts with Enogex do not prevent its contracting with Midcontinent.

[45] Midcontinent's February 26, 2008 data response states that shippers that committed to firm capacity on the Midcontinent project sought a seamless means by which to move gas received into the Enogex system in Oklahoma to Midcontinent's various points of delivery and did not request the option to have gas delivered to a pipeline other than Midcontinent at Bennington.

lease capacity. We find that the claims that Enogex shippers will be forced to pay stacked rates are baseless.

Lease Rates are Unduly Discriminatory

57. ConocoPhillips, Indicated Shippers and Unimark are concerned that the lease payments are unduly discriminatory. They state that the lease payments are substantially less than Enogex's interruptible rates[46] and since firm capacity is inherently more valuable than interruptible capacity, it seems obvious that the lease payment is unduly discriminatory against similarly situated shippers forced to pay the higher interruptible rate. Indicated Shippers state that the Commission recognizes that rates should reflect the differences in quality between firm and interruptible service and application of this principle makes it clear that the proposed lease payment is unjustified. It avers that section 311 interruptible service on Enogex is inferior to firm capacity service and is likely to become significantly less reliable if Enogex enters into leases with Gulf Crossing and Midcontinent. In view of the lower quality of interruptible service, Indicated Shippers state that Enogex needs to justify why the lease payments may be even less than rates for interruptible service.[47]

58. Enogex states in its answer that the Commission's lease policy, as stated in *Texas Eastern Transmission Corp.*,[48] recognizes that capacity lease arrangements differ from firm section 311 transportation service and the Commission has declined to engage in direct comparisons between a lessor's existing rates and payments to be charged under a lease agreement. Instead, according to Enogex, where parties challenging a lease arrangement have urged the Commission to compare lease payments with existing system rates, the Commission has approved a lease where the rates existing customers will pay will not increase as a consequence of the lease arrangement.[49]

59. As noted above, a lease of capacity is not the same as the provision of firm transportation service. Under Commission policy, a lease proposal will not be approved unless the lease payments are less than, or equal to, the lessor's firm transportation rates

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[46] ConocoPhillips states that Enogex has filed for substantial increases to its interruptible section 311 rates in Docket No. PR08-1-000.

[47] Indicated Shippers note that Enogex is currently seeking Commission authorization to increase its interruptible section 311 rates by up to 215 percent in PR08-1-000.

[48] 74 FERC ¶ 61,074 (1996).

[49] *Islander East Pipeline Company,* 100 FERC ¶ 61,276, at P 69 (2002).

for comparable service over the terms of the lease. That the payments may also be less than the lessor's interruptible rates is not a disqualifying factor. Shippers on Enogex are not similarly situated to interruptible shippers on Midcontinent. Therefore, the Commission does not believe the lease payment is indicative of undue discrimination.[50]

Lease Points

60. Apache's May 13, 2008 answer states that Article I, 1.1(a) of the lease provides that the parties may change the receipt points under the lease at any time and, therefore, the lease does not identify the physical location of pipeline facilities that will be reserved for service under the lease. Apache states that the lease is an attempt to lease an entire pipeline system without specifying a path and this distinguishes the lease from other leases the Commission has approved, which convey a defined property interest. Apache states that it is unjust and unreasonable for the Commission to approve a lease that has no defined facilities reserved for its use and that the Commission may not approve the Midcontinent lease unless it can be demonstrated that the path avoids congestion on its system.

61. Enogex states in its January 11, 2008 data response that because its system is not a long haul pipeline, the multidirectional and frequently changing flows driven by changes in market demands mean there is no dominant flow pattern on the Enogex system. Enogex states it will use its entire system as necessary to receive and deliver gas under the lease arrangements from and to the specified receipt and delivery points, rather than specific paths.

62. The operational attributes of a pipeline system will dictate the specific point and path rights shippers have in their transportation contract. For those pipelines such as Enogex that have multidirectional and frequently changing flows, it may be operationally infeasible to implement physical pathing. On these systems gas may flow over multiple routes depending upon a variety of factors, including the location of other pipeline interconnections, the location and volume of storage, and local production requirements, as well as the demands placed on the pipeline on a particular day. Reflecting the operations of their systems, some pipelines contract firm capacity to customers at specific receipt points and at specific delivery points and do not identify any specific gas flow path.[51]

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[50] *Id.* P 89.

[51] *See, e.g., Gulf South Pipeline Company, LP,* 98 FERC ¶ 61,278 (2002); *Dominion Transmission, Inc.,* 95 FERC ¶ 61,316 (2001).

63. Midcontinent's lease with Enogex clearly identifies in Exhibit A, as modified in Amendment No. 4 filed with the Commission on April 23, 2008, the specific receipt and delivery points in the lease. Although two of the receipt points are located at Enogex's East and West Pool and not at a physical receipt meter,[52] establishing the receipt points at the pools is not inappropriate. The specific points and capacities in the lease were negotiated by the parties and the payment under the lease reflects their economic value to the parties. The lease agreement does not provide Midcontinent with a defined capacity path. However, it is not necessary to have a defined path in order to assess the effects of the lease on Enogex's system and its existing shippers, as discussed in the engineering section below. Apache's request to deny the lease due to it not establishing a defined transportation path is denied.

Conclusion

64. Based on the benefits the proposed lease will provide to the market and the lack of adverse effect on existing customers, we find that the public convenience and necessity requires approval of the proposed lease arrangement. Midcontinent has designed incremental firm and interruptible rates based on the lease charges it will pay to Enogex under the lease to recover the costs of the leased capacity from only those shippers that will use the leased capacity.[53] We approve Midcontinent's proposed incremental recourse rates for the leased capacity.

Certificate Policy Statement

65. On September 15, 1999, the Commission issued its Certificate Policy Statement to provide guidance as to how it will evaluate proposals for certificating new construction.[54] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new pipeline facilities, the Commission balances the public benefits against the potential adverse consequences. Our goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's

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[52] Midcontinent's February 26, 2008 data response states that these pooling points are paper points at which gas is made available for purchase on an aggregated basis.

[53] Midcontinent will also track and charge fuel for the Enogex leased capacity.

[54] *Certification of New Interstate Natural Gas Pipeline Facilities* (Certificate Policy Statement), 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128 (2000), *order on clarification,* 92 FERC ¶ 61,094 (2000).

responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

66. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers.

67. The Commission also considers potential impacts of the proposed project on other pipelines in the market and those existing pipelines' captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered.

68. Midcontinent is a new entrant with no existing customers. Thus, there is no potential for subsidization on Midcontinent's system through the construction of the initial phase facilities, and, as discussed below, we are approving recourse rates associated with the construction of the expansion phase facilities which will result in lower rates for the initial phase shippers. However, as discussed above, we are conditioning our approval of Midcontinent's incremental rates for leased capacity on Midcontinent's not being permitted in the future to shift any of its costs associated with the leased capacity to customers that do not use the leased capacity. As conditioned, the Commission finds that Midcontinent's proposal will meet the threshold test that existing customers not subsidize the project.

69. Furthermore, the project will not degrade any present services to existing customers, as Midcontinent has no existing customers. The project will likewise have no adverse impact on existing pipelines or their captive customers as the proposed facilities will be transporting new domestic sources of gas so that the project will not replace service currently provided on existing pipelines. Further, no pipelines have objected to the project.

70. We are also satisfied that Midcontinent has taken appropriate steps to minimize adverse impacts on landowners. Over 51 percent of the proposed pipeline facilities will be collocated with existing utility rights-of-way. Midcontinent's project will require approximately 3,158 acres for operation. Midcontinent states that it expects to acquire 93

percent of the total necessary easements by July 15, 2008, with the rest acquired through the use of eminent domain.[55]

71. The proposed project will benefit the public because it will provide an important transportation link for new and diverse sources of natural gas supplies to numerous other pipeline systems and new natural gas markets across the eastern United States. The increased take away capacity from areas of rapidly expanding production will promote the development of significant new supplies. Midcontinent has entered into precedent agreements with shippers for almost all of the capacity of the initial phase facilities and all of the Zone 1 expansion capacity. Therefore, consistent with the criteria discussed in the Certificate Policy Statement and section 7(c) of the NGA, we find that the benefits of Midcontinent's proposed project will outweigh any potential adverse effects, and that the proposed project is required by the public convenience and necessity.[56]

72. Consistent with our standard practice, we will condition our certificate authorization so that construction cannot commence until after Midcontinent executes contracts that reflect the levels and terms of service represented in its precedent agreements.[57]

Precedent Agreements

73. The precedent agreements filed by Midcontinent contain the particular agreements between Midcontinent and the various shippers supporting the project. According to Midcontinent, these agreements define the negotiated rates shippers will pay, spell out certain rights parties have prior to the Midcontinent system going into service and provide rights as to future actions. Shipper rights may vary depending on whether the shipper qualifies as a foundation shipper, an anchor shipper or a standard shipper.

74. Midcontinent states that the precedent agreements it filed represent the financial support for the project and that absent these commitments the project could not go forward. Therefore, other shippers or potential shippers cannot be viewed as similarly situated to these initial shippers. In addition, according to Midcontinent none of the

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[55] *See*, Midcontinent's February 28, 2008 Data Response No. 9.

[56] We will not grant Midcontinent's request for a five year time period in which to construct the expansion phase facilities. We will instead condition Midcontinent's certificate on construction of all of its proposed facilities, including the expansion phase facilities, within three years of the date of this order.

[57] *See, e.g., Tennessee Gas Pipeline Company*, 101 FERC ¶ 61,360, at P 21 (2002).

provisions in the precedent agreements affects the actual terms of any service and, therefore, none of these contract provisions creates the risk of undue discrimination. For these reasons, Midcontinent does not believe that any aspect of the precedent agreements results in a material deviation from the pro forma service agreements contained in the tariff. However, Midcontinent believes that if the Commission determines that a deviation exists, that deviation should be acceptable and not material. Therefore, Midcontinent seeks a predetermination that even if some contractual provisions could be construed to constitute a material deviation from the form of service agreement, none of the provisions are unduly discriminatory. The non-conforming provisions are discussed below.

Expansion Phase Rights

75. Foundation shippers have a one-time right during the first five years of their contracts to require that Midcontinent construct the expansion phase capacity in Zone 1. According to Midcontinent, foundation shippers provide the most critical contract support for the construction of the project and this provision is an integral part of the arrangements under which foundation shippers agreed to provide contractual support for construction of the Midcontinent system.[58]

Additional Capacity Expansion Rights

76. Under certain precedent agreements, the shipper will have defined rights to require that Midcontinent file an application with the Commission to increase the capacity of specific portions of the pipeline. Midcontinent states that this right does not determine any allocation of capacity, but will entail a new open season for the expansion capacity for all interested shippers. Midcontinent states this provision addresses potential future capacity needs of the shippers and is an integral part of the arrangements under which they agreed to provide contractual support for construction of the Midcontinent system. However, Midcontinent notes that this provision does not require any current Commission action and does not affect either the initial firm transportation contracts or the firm transportation service provided by the facilities Midcontinent is constructing.[59]

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[58] In its June 17, 2008 filing, Midcontinent states that the foundation shipper has now exercised its right to acquire 100,000 Dth/d of capacity in Zone 1 through the construction of expansion facilities.

[59] BP has protested the provisions of Rate Schedule FTS that provide foundation shippers with the right to acquire future expansion capacity and that issue will be discussed in further detail below.

Most Favored Nation Provision for Rates

77. Certain precedent agreements contain a most favored nation provision such that, if Midcontinent offers a negotiated, discount, or recourse rate to another shipper more favorable than the precedent agreement shippers' negotiated rates, Midcontinent must provide the favorable rate to the precedent agreement shipper. Midcontinent states that this provision reflects the expectation of the expansion shippers that Midcontinent will not place them in the position of subsidizing other competing shippers for the purchase and sale of gas. Midcontinent states that the Commission has previously accepted this type of rate provision.[60]

Liquidated Damages Provision

78. Certain precedent agreements allow for liquidated damages in the event Midcontinent fails to meet a specified in-service date or other such conditions. Since this arrangement pre-dates the actual construction of the Midcontinent system, Midcontinent states it is reasonable that Midcontinent and shippers share the construction and start-up risk through a liquidated damages provision. Midcontinent notes that liquidated damages in no way affect the terms of service once the Midcontinent system goes into operation.

Termination Rights

79. Shippers entering into precedent agreements are permitted to terminate their contracts under certain circumstances prior to the in-service date. Midcontinent states these rights have no effect on the nature of service once the Midcontinent system becomes operational and the termination provisions are a reasonable means to address the risks being taken by these shippers during the certification and construction phase in contracting for capacity on the new pipeline.

Interruptible Revenue Crediting

80. In certain precedent agreements, Midcontinent has agreed to provide an additional credit for interruptible revenues. Midcontinent notes that all shippers benefit in the form of lower rates from the costs Midcontinent has allocated to interruptible services in the design of its recourse rates and that it is reasonable as part of a negotiated rate agreement that shippers can negotiate in the precedent agreement to obtain some additional benefit if interruptible shippers utilize the capacity which the contractual commitments of the firm shippers make possible.

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[60] *Gulfstream Natural Gas System,* 100 FERC ¶ 61,036 (2002), *order on reh'g,* 101 FERC ¶ 61,368 (2002).

Fuel Caps

81. Certain precedent agreements set out a cap on the fuel gas and lost and unaccounted-for gas which may be assessed. Midcontinent states this represents a negotiated fuel arrangement, which is permissible under Commission policy, and that the Commission has accepted negotiated rate tariff provisions which encompass the negotiation of fuel rates.[61] Consistent with Commission policy, Midcontinent states it will calculate fuel and lost and unaccounted-for percentages on the assumption that full volumes will be achieved from all shippers and, therefore, no other shipper will be subsidizing these negotiated rate arrangements.

82. The Commission finds that the above non-conforming provisions as described by Midcontinent would constitute material deviations from Midcontinent's pro forma service agreements. However, the Commission in other proceedings has found such non-conforming provisions necessary to reflect the unique circumstances involved with the construction of new infrastructure and to provide the needed security to ensure the viability of the project.[62] Here, Midcontinent has adequately supported the need for each provision to secure the necessary financial commitments for construction of the project or clearly stated how the provision will not affect the terms of service once the pipeline goes into service. In addition, several of these rights have no effect once the system becomes operational. For these reasons, the Commission finds the proposed non-conforming provisions permissible, in that they do not present a risk of undue discrimination, and will not affect the operational conditions of providing service, nor result in any customer receiving a different quality of service from that available to Midcontinent's other customers.[63]

83. When a contract deviates materially from the form of service agreement, the contract must be filed and made public.[64] We require disclosure of contracts with material deviations because the public disclosure of these agreements prevents undue discrimination through secret rates or terms. Accordingly, Midcontinent must file at least 30 days before the in-service date of the proposed facilities an executed copy of each non-conforming agreement reflecting the non-conforming language and a tariff sheet

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[61] *See, e.g., Florida Gas Transmission Company,* 93 FERC ¶ 61,203 (2000), citing *Noram Gas Transmission*, 77 FERC ¶ 61,011, at 61,035 (1996).

[62] *See, e.g., Rockies Express Pipeline LLC*, 116 FERC ¶ 61,272, at P 78 (2006).

[63] *See, e.g., Gulf South Pipeline Co., L.P.*, 115 FERC ¶ 61,123 (2006); and *Gulf South Pipeline Co.*, 98 FERC ¶ 61,318, at p. 62,345 (2002).

[64] 18 C.F.R. § 154.1(d) (2008).

identifying these agreements as non-conforming agreements consistent with section 154.112 of the Commission's regulations. In addition, the Commission emphasizes that the above determination relates only to those items as described by Midcontinent in its application and not to the entirety of the precedent agreements or the language contained in the precedent agreements.

Midcontinent's Initial Rates

84. Midcontinent proposes to offer cost-based firm (Rate Schedule FTS) and interruptible (Rate Schedules ITS, PALS and IBS) open-access transportation services on a non-discriminatory basis under Part 284 of the Commission's regulations.[65] Midcontinent states that the proposed rates reflect a straight fixed-variable rate design. Midcontinent states that it may offer negotiated rates as an option pursuant to section 30 of the General Terms and Conditions (GT&C) of its pro forma tariff. The pro forma tariff has been developed in consultation with the shippers that have entered into precedent agreements supporting the construction of the project.

85. Midcontinent will be divided into two capacity zones in addition to the Enogex lease capacity. Midcontinent has filed three separate sets of rates, including: (1) interim period rates which would be applicable if and when parts of the Midcontinent system go into service but before the entire initial phase system goes into service; (2) base rates for the period once the entire initial phase of the Midcontinent system goes into service; and (3) expansion rates reflecting the addition of expansion compression facilities needed to increase capacity in Zone 1 by 100,000 Dth/d and in Zone 2 by 200,000 Dth/d (referred to as expansion phase capacity).

86. The initial phase proposed base FTS rates are derived using a $253,710,901 first year cost of service[66] (with $154,067,961 of the cost of service allocated to Zone 1 and $99,642,940 allocated to Zone 2) and annual FTS reservation billing determinants of

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[65] *See* Midcontinent's FERC Gas Tariff, Pro Forma Original Volume No. 1.

[66] Midcontinent's proposed cost of service consists of $7,921,087 of operation and maintenance expenses, $38,333,186 of depreciation expenses, $129,333,959 of return allowance (at 13.0 percent rate of return on equity based on a capital structure of 55 percent equity and 45 percent debt, and 7.0 percent cost of debt), $55,509,871 of income taxes, $25,612,798 of taxes other than income taxes and a $3,000,000 credit for interruptible services for a total cost of service of $253,710,901. For year 1, Midcontinent reflects a proposed rate base comprised of gross plant investment of $1,279,042,285, less accumulated depreciation of $19,166,593, plus materials and supplies inventory of $675,200, less accumulated deferred income taxes of $4,881,391 for a total rate base of $1,255,669,501.

16,800,000 Dth for Zone 1 and 12,000,000 Dth for Zone 2 based on Midcontinent's maximum daily design capacity.[67] The proposed maximum cost-based FTS reservation rate for Zone 1 is $9.13 per Dth (a $0.3015 per Dth daily rate) and for Zone 2 is $8.28 per Dth (a $0.2730 per Dth daily rate). Midcontinent estimates $676,793 of variable costs for Zone 1 and $284,070 of variable costs for Zone 2 resulting in a proposed FTS commodity rate of $0.0013 per Dth for Zone 1 and $0.0008 per Dth for Zone 2.

87. Customers using the Enogex lease capacity will pay Midcontinent a separate charge for service on the leased capacity, in addition to the applicable charges for Midcontinent's Zone 1 and Zone 2. Customers will pay a daily demand rate of $0.17 per Dth for transportation from the Wayanoka receipt points, a daily demand rate of $0.15 per Dth for transportation from receipt points in Enogex's Western Pool and a daily demand rate of $0.09 per Dth for transportation from receipt points in Enogex's East Pool. Since all costs incurred (transportation fees, fuel, and lost and unaccounted-for) by shippers will be passed through without profit or loss, no costs relating to the Enogex lease are included in the calculation of Zone 1 or Zone 2 recourse rates.

88. The proposed maximum ITS rate for Zone 1 is $0.3015 per Dth and for Zone 2 is $0.2730 per Dth. Midcontinent is proposing to recover its fuel gas, including lost and unaccounted-for gas, through a tracker mechanism defined in section 36 of the pro forma tariff. Fuel gas will be tracked and charged separately for Zone 1 and Zone 2. Customers using the Enogex lease capacity will pay Enogex's fuel and lost and unaccounted-for charges consistent with Enogex's Statement of Operating Conditions in addition to the Midcontinent fuel rate.

Interim Rates

89. In response to shipper requests, Midcontinent is proposing interim rates for service should service be available on one segment of the pipeline before the in-service date for the entire initial phase system. Midcontinent intends to construct the pipeline using a number of different construction spreads and states that based on when construction ends, interim service may be provided in one or as many as four distinct, separate pipeline segments. The interim rates are derived in the same manner as the recourse rates, however, it is anticipated that compression will not be installed during the interim period.[68] Midcontinent has developed separate rates based on the minimum facilities required to be in service for each segment and the anticipated capacity available on each

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[67] Midcontinent is required to recalculate its rates using billing determinants based on its revised Exhibit G filed on May 16, 2008.

[68] Midcontinent proposes to charge only an Unaccounted For Gas charge of 0.15 percent, which will be assessed only once on each Dth transported.

segment. In addition, Midcontinent has elected to charge a rate for Segment 4[69] no greater than the Zone 2 fully-operational recourse rate since the calculated interim rate is extremely high ($1.3463/Dth) given the limited flow capability without compression.

Expansion Phase Rates

90. Midcontinent is seeking authorization to allow it to add, at any time during the first five years of the project, the compression facilities needed to increase Zone 1 capacity by 100,000 Dth/d and Zone 2 capacity by 200,000 Dth/d. The proposed maximum cost-based FTS reservation rate for Zone 1 for the expansion phase capacity is $8.75 per Dth (a $0.2877 per Dth daily rate) and for Zone 2 is $7.58 per Dth (a $0.2492 per Dth daily rate). The proposed FTS commodity rate for Zone 1 is $0.0015 per Dth and $0.0014 per Dth for Zone 2. Midcontinent is seeking a Commission determination that rolled-in rate treatment is appropriate for these facilities. The rolled-in rate analysis submitted by Midcontinent shows that the resulting recourse rates and fuel retention percentages that would result from rolling in the expansion facilities would reduce the total transportation costs to recourse rate shippers.

91. The Commission has reviewed the proposed cost of service and proposed initial phase rates, interim rates and expansion phase rates and generally finds them reasonable for a new pipeline entity, such as Midcontinent, subject to the modifications and conditions discussed below. In addition, the Commission has reviewed the rolled-in rate analysis submitted by Midcontinent and is in agreement that the recourse rates and fuel retention percentages resulting from the expansion phase capacity, based on the cost estimates provided by Midcontinent, will result in reduced transportation costs for recourse rate shippers, barring any significant change in the circumstances. If future rate review shows that the benefits of the project are significantly offset by increased construction or fuel costs associated with the project, the Commission would consider such offset a significant change in circumstances.

Return on Equity and Capital Structure

92. Midcontinent proposes a capital structure of 55 percent equity and 45 percent debt. The overall rate of return of 10.3 percent incorporates a return on equity of 13.0 percent based upon the project's business and financial risk. Midcontinent states that the proposed rate of return is consistent with that granted to other new pipeline projects.[70]

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[69] Segment 4 extends 198 miles from the interconnection with Columbia Gulf to the system terminus at Transco's Station 85 near Butler, Alabama.

[70] *See, e.g., Rockies Express Pipeline LLC,* 116 FERC ¶ 61,272 (2006); *Cheniere Corpus Christi Pipeline Co.,* 111 FERC ¶ 61,081 (2005) (order approving initial rates reflecting 14 percent rate of return on equity); *Midwestern Gas Transmission Co.,*

(continued...)

We find that Midcontinent's proposal to finance the instant project is consistent with other recent projects approved by the Commission for new pipeline companies. In these projects, the Commission approved a capital structure of 45 percent debt and 55 percent equity, as well as a return on equity of 13.0 percent.[71] Accordingly, we will approve Midcontinent's proposed capital structure and rate of return on equity.

Interruptible Services Revenue Crediting

93. Midcontinent has proposed a $3,000,000 credit to the cost of service for interruptible services. The Commission's policy regarding new interruptible services requires the pipeline to either credit 100 percent of the interruptible revenues, net of variable costs, to firm and interruptible customers or to allocate costs and volumes to these services.[72] Midcontinent's crediting of $3,000,000 to the cost of service in the design of initial rates has the same effect as allocating costs to interruptible services, therefore, Midcontinent's crediting is in compliance with the Commission's policy.

PALS Rate

94. The rate for Midcontinent's Rate Schedule PALS service is a single rate for each rate zone that reflects the sum of the ITS rates of both rate zones. Midcontinent states that since usage of the service may impact the entire system, Midcontinent has derived the rate by combining the ITS rates for both zones. However, Midcontinent's PALS Rate Schedule provides that parked or loaned gas is to be delivered or received at specific points on its system. In addition, parked quantities are to be redelivered to a shipper at the same point that the shipper tendered the gas to Midcontinent and loaned quantities are to be returned to Midcontinent at the same point where the shipper borrowed the gas. The Commission finds that the PALS rate proposed by Midcontinent is inappropriate, because it exaggerates the rate for the service provided.[73] Midcontinent's proposal charges PALS customers as if they are using Midcontinent's entire system. However, Midcontinent's tariff specifically limits PALS customers to delivering and receiving gas at the same point. Thus, Midcontinent's PALS customers may use only one zone.

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114 FERC ¶ 61,257 (2006) (order approving initial rates reflecting 13 percent rate of return on equity).

[71] *See, e.g., Rockies Express Pipeline LLC,* 116 FERC ¶ 61,272 (2006).

[72] *See, e.g., Creole Trail LNG, L.P. and Cheniere Creole Trail Pipeline, L.P.*, 115 FERC ¶ 61,331, at P 27 (2006); *Entrega Gas Pipeline Inc.*, 112 FERC ¶ 61,177, at P 51 (2005).

[73] *See, e.g., Williams Central Gas Pipelines, Inc.,* 85 FERC ¶ 61,187 (1998).

Although Midcontinent returns a thermally equivalent quantity of parked gas, the fact that gas is delivered and received at the same specified point in either Zone 1 or Zone 2 affects the PALS shipper as if the gas were physically parked at one specified area on the system. Accordingly, the Commission directs Midcontinent to charge a PALS rate for each zone solely reflecting the interruptible rate for that zone.

Rate Changes and Three-Year Filing Requirements

95. If Midcontinent desires to make any other rate changes not specifically authorized by this order prior to placing its facilities into service, it must file an amendment to its application under NGA section 7(c). In that filing, Midcontinent will need to provide cost data and the required exhibits supporting any revised rates. After the facilities are constructed and placed in service, Midcontinent must make a NGA section 4 filing to change its rates to reflect any revised construction and operating costs.

96. Consistent with Commission precedent, the Commission will require Midcontinent to file a cost and revenue study at the end of its first three years of actual operation to justify its existing cost-based firm and interruptible recourse rates.[74] In its filing, the projected units of service should be no lower than those upon which Midcontinent's approved initial rates are based. The filing must include a cost and revenue study in the form specified in section 154.313 of the regulations to update cost of service data.[75] After reviewing the data, the Commission will determine whether to exercise our authority under NGA section 5 to establish just and reasonable rates. In the alternative, in lieu of this filing, Midcontinent may make an NGA section 4 filing to propose alternative rates to be effective no later than 3 years after the in-service date for its proposed facilities.

Pro Forma Tariff Issues

Currently Effective Rates

97. The Rate Schedule ITS Overrun rate on Original Sheet No. 6 is incorrectly stated as $0.0315. The correct rate is $0.3015. Midcontinent is directed to correct the rate.

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[74] *See, e.g., Empire State Pipeline and Empire Pipeline, Inc.*, 116 FERC ¶ 61,074, at P 133 (2006); *Entrega Gas Pipeline Inc.*, 112 FERC ¶ 61,177, at P 52 (2005)

[75] 18 C.F.R. § 154.313 (2008).

Rate Schedule FTS and PALS

98. BP protests section 2.7 of Rate Schedule FTS, which it believes provides foundation shippers with a preferential right to acquire future expansion capacity. BP believes this is unduly discriminatory and should be rejected. According to BP, the Commission allows a pipeline to offer rate incentives to attract anchor shippers and a pipeline can also agree to initiate an open season for a future expansion for an anchor shipper. However, the Commission does not allow a pipeline to offer anchor shippers preferential service conditions or a preferential right to future expansion capacity.

99. Chesapeake urges the Commission to approve the rights of foundation shippers to obtain additional capacity as provided in section 2.7 of Rate Schedule FTS. Chesapeake states the granting of rights to expansion phase capacity are clearly presented to the Commission as part of Midcontinent's application and reflect a business resolution of complicated and important financial issues – Midcontinent wanted long-term firm commitments for the greatest amount of capacity while Chesapeake wants to limit the risk that it will be required to pay for capacity that it cannot use. Chesapeake also states the protesters misread the right of foundation shippers to contract for unsubscribed firm capacity in that it only establishes the right under which a foundation shipper can contract for capacity which is not otherwise subscribed by other shippers. Chesapeake states that the capacity remains available for firm contract under Midcontinent's usual tariff provisions.

100. Midcontinent states in its answer that the Commission has recognized that foundation and anchor shippers can receive certain rights beyond those provided to other shippers given their status as the stepping stone for the project going forward. According to Midcontinent, the modest 100,000 Dth per day of expansion rights provided to foundation shippers for the expansion phase capacity was a necessary precondition to the foundation shipper signing their precedent agreement. Midcontinent states that any other expansion rights contained in the precedent agreement would be the subject of a new competitive open season.

101. Section 2.7 of Rate Schedule FTS provides foundation shippers with the rights to obtain capacity through two separate processes. The first option provides a foundation shipper with a right to cause Midcontinent to construct expansion phase capacity and to acquire such capacity at a mutually agreed rate and term. Order No. 686 recognized a pipeline's right to provide rate incentives in order to get project sponsors to commit to a project.[76] However, the Commission also affirmed that there must be no discrimination in announcing an open season for new capacity, and in accepting bids, all potential

[76] *Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates,* Order No. 686, FERC Stats. & Regs. ¶ 31,231, (2006).

customers must have an equal opportunity to obtain firm capacity. Midcontinent states in its May 9, 2008 data response that the one-time right to require that Midcontinent construct expansion phase capacity was stated in the terms and conditions of the form of Precedent Agreement for foundation shippers which was made available to all parties who were interested in contracting for capacity. Therefore, the Commission believes Midcontinent's procedures assured that all potential customers interested in contracting for capacity had an equal opportunity to obtain this capacity right.

102. Section 2.7 also provides foundation shippers with the right, within a period of up to five years after the project's commencement date, to acquire unsubscribed firm capacity at an agreed rate for an agreed term. However, this right does not provide foundation shippers with a preferential right to capacity over other shippers. Midcontinent states in its May 9, 2008 data response that it is Midcontinent's intent to make any unsubscribed firm capacity (other than expansion phase capacity) available to all shippers and that once in service, Midcontinent will clearly post on its interactive website the level of unsubscribed capacity that may exist from time to time. Therefore, any available capacity a foundation shipper wishes to acquire as a result of this right will have previously been made available to all shippers[77] and that capacity will need to be acquired through the procedures outlined in section 2 of Midcontinent's GT&C. In addition, the Commission clarifies that once the expansion phase capacity has been constructed any capacity that is unsubscribed as a result of that expansion must also be made available to all shippers.

103. BP objects to the penalty provisions of Rate Schedule PALS associated with undelivered loaned gas or unparked gas at the end of the customer's contract. BP states that if a shipper cannot extend the terms of a PALS contract, Midcontinent's 50 percent cashout penalty is too harsh and a 20 percent cashout penalty on end-of-contract balances would suffice to encourage customers to ensure against end-of-contract balances.

104. Midcontinent states that if there is still undelivered loaned gas or unparked gas at the end of a customer's PALS contract, Midcontinent will first attempt to agree to an extension of the agreement in order to allow for any remaining imbalance to be reduced to zero. Midcontinent states it is only if an agreement cannot be reached that Midcontinent will provide the shipper with a time frame within which the remaining gas must be reduced to zero and that it is only after this time period that a penalty is imposed. Midcontinent states that given that these situations can impact Midcontinent's ability to provide service to other shippers, the penalty needs to be severe enough to prevent this type of activity. Therefore, Midcontinent believes its penalties are appropriate.

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[77] GT&C section 2.1(b)(1) states that Midcontinent shall conduct an initial open season for all firm forward-haul capacity.

105. On June 9, 2008, BP stated in its status report it would withdraw its protest based on BP's understanding that Midcontinent will file revised tariff language that restricts the penalty during a Non-Critical Period to 35 percent of the Daily Index Price. BP also states that if, due to an interruption on Midcontinent's system during a Non-Critical Period a shipper is unable to nominate PALS volume to clear its PALS account, the revised tariff language will state the PALS penalty will be waived for a term equal to the greater of five business days or the length of the interruption.

106. In previous orders addressing PAL service the Commission has approved the concept of the 50 percent adder.[78] However, the Commission has found that the use of the daily index price in determining the penalty rate for failing to redeliver loaned gas or remove parked gas can be unnecessarily punitive since the daily highest or lowest price can greatly vary from the actual cost of the gas when the imbalance occurred and may unduly increase the penalties for imbalances, which is contrary to Order No. 637. Accordingly, the Commission has required PALS penalties to be based on 150 percent of the average weekly price for the appropriate geographic area.[79] Therefore, Midcontinent is directed to base the penalty for failing to redeliver loaned gas or remove parked gas on 150 percent of the average *weekly* price for the appropriate geographic area and to revise its tariff to address BP's concerns with regards to penalties being assessed when a shipper is unable to nominate to clear its PALS account during a Non-Critical Period.

Operational Balancing Agreement

107. Section 6(b) of Rate Schedule FTS, section 6(b) of Rate Schedule ITS and GT&C section 1.31 state that Midcontinent will enter into Operational Balancing Agreements (OBAs) at delivery points whenever feasible to deal with imbalances. Section 1.31 also states that Midcontinent shall not be obligated to enter into an OBA with any form of cashout. In Order No. 587-G,[80] the Commission adopted a regulation (section 284.10(c)(2)(i))[81] requiring each interstate pipeline to enter into operational balancing agreements at all points of interconnection between its system and the system of another

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[78] *See, e.g., Algonquin Gas Transmission Co.*, 98 FERC ¶ 61,211 (2002); *order on rehearing and compliance filings,* 104 FERC ¶ 61,118 (2003).

[79] *Texas Eastern Transmission, LP,* 102 FERC ¶ 61,198 (2003).

[80] *Standards For Business Practices Of Interstate Natural Gas Pipelines*, Order No. 587-G , FERC Statutes and Regulations, ¶ 31,062 (Apr. 16, 1998), *on reh'g*, Order No. 587-I, FERC Statutes and Regulations ¶ 31, 067 (Sep. 29, 1998).

[81] 18 C.F.R. §284.10 (c)(2)(i) (2008).

interstate or intrastate pipeline. Midcontinent will be required to comply fully with this regulation once in service.

Section 2 – Priority of Service

108. BP states that Midcontinent's Net Present Value (NPV) discount factor (GT&C section 2.1(c)(3)) should reflect the interest rate the Commission establishes for refunds. BP states the purpose of the discount factor is to reflect the time value of money associated with payments for capacity and the Commission's refund interest rate, which relies on the Federal Reserve's Quarterly Prime Rate, is the appropriate NPV discount factor. In its answer, Midcontinent agrees with BP that the NPV discount factor should reflect the interest rate that the Commission establishes for refunds. Midcontinent is directed to revise its tariff accordingly.

109. BP also states that since the value of capacity on Midcontinent will vary daily based on market conditions, an interruptible shipper with a discount rate should be able to indicate in its nomination that the shipper would be willing to increase the rate it is paying for service on a specific Gas Day as part of the scheduling process. Midcontinent opposes this in its answer, stating a shipper will have no incentive to sign a contract that reflects the full market cost of the transport if the shipper knows it may simply bid a higher rate during the nomination process if the system became constrained. On June 9, 2008, BP stated in its status report that it would withdraw its protest based on BP's understanding that Midcontinent will revise its tariff to allow interruptible shippers to increase their rate during the timely nomination cycle.[82] Midcontinent is directed to revise its tariff accordingly.

110. BP states that Midcontinent proposes to give a higher scheduling priority to authorized overrun service as compared to interruptible services (section 2.5(a)) as well as give authorized overrun service scheduling priority over interruptible services at delivery points (section 8.2).[83] According to BP, this is in conflict with the Commission's policy that authorized overrun service be accorded the same priority as interruptible service. Both Midcontinent and Chesapeake state in their answers that they recognize the Commission's general preference to schedule all interruptible services based on price, however, they believe it is reasonable, as part of the overall allocation of risk between Midcontinent and firm shippers, to provide firm shippers with this limited priority in exchange for the financial commitments they have made and the corresponding risks they will bear.

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[82] BP states this would also apply to the scheduling of authorized overrun volumes that are billed at the ITS rate.

[83] The Commission notes this also occurs in section 2.3(a)(4).

111. The Commission considers authorized overrun and interruptible service to be identical, and has held that pipelines must revise their tariffs so that interruptible and overrun services are accorded the same scheduling priority.[84] Although authorized FTS overrun service is associated with a firm service contract, it remains an interruptible service. Firm shippers do not pay a reservation charge for authorized overrun service. Authorized overrun service is to be provided only for nominations in excess of the firm shipper's contract demand. Further, the authorized overrun service rate is a charge equal to the rate paid by Midcontinent's interruptible transportation customers. Although the Commission clarified in Order No. 686 that pipelines may provide rate incentives in order to get project sponsors to commit to a project, the order did not apply to non-rate issues such as capacity allocation.[85] The Commission considers the proposal by Midcontinent to provide authorized overrun service a higher scheduling priority than interruptible service to be contrary to Commission policy. Therefore, Midcontinent is directed to revise these provisions of its tariff, as well as section 2.3, to provide the same priority to authorized overrun service and interruptible service.

Section 6 – Title Transfer Nominations

112. Section 6.9 requires an entity to submit a transfer nomination to Midcontinent whenever gas is purchased at a receipt point on Midcontinent's system by an entity that is not going to nominate that gas for receipt by Midcontinent. Midcontinent states transfer nominations are needed in order to be able to confirm the nominated receipts at that point. Midcontinent is proposing to assess a Title Transfer Charge of $25 per transaction for transactions where gas is purchased and sold at a receipt point, including a pooling point. The charge is to cover the administrative costs of tracking title to the gas as it changes at these points, which Midcontinent states involves the use of pipeline computer services and personnel. Each day the title transfer nomination is in effect shall be considered to be a separate transaction. Midcontinent's tariff states that a third party may provide title tracking services on Midcontinent's system.

113. Midcontinent states that it has reduced its allocable cost of service by an allocation of costs to this title transfer service. Midcontinent's February 26, 2008 data response states that it expects to incur $257,000 in annual costs which it describes as "Transportation/Services – Scheduling" in order to provide the title transfer service. Midcontinent also states that it estimates a total of 10,220 title transfer tracking transactions per year. However, Midcontinent does not provide any description of the additional computer systems it will have to purchase or additional staff it will have to hire in order to provide title transfer service that are in addition to the systems and staff

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[84] *See, e.g., Cheniere Creole Trail Pipeline*, 121 FERC ¶ 61,171 (2007).

[85] FERC Statutes and Regulations ¶ 31,231(2006).

already required to provide transportation service. The Commission does not believe that Midcontinent has made a clear showing that the costs it states it will incur in order to provide title transfer tracking service are charges it will incur separate and apart from the costs it will already incur to schedule the pipeline and provide other transportation services and that shippers are already paying for as part of Midcontinent's cost of service. In addition, Midcontinent has no rate schedule on file for title transfer service and the Commission has not permitted pipelines to collect surcharges on these types of administrative functions without a rate schedule on file.[86] Finally, the Commission has concerns over the impact of Midcontinent's title transfer charge on the development of market centers on Midcontinent's system since that charge appears to be mandatory and apply to all transactions. Therefore, Midcontinent's proposal to assess a Title Transfer Charge of $25 on all transfer nominations is rejected, subject to Midcontinent providing a rate schedule to provide the service, additional data to support the fee, and Midcontinent addressing the Commission's concerns with regard to market centers.

Section 6.12 –Pooling

114. Section 6.12 of Midcontinent's GT&C states that Midcontinent has established one pooling point in Zone 1 and one pooling point in Zone 2, and that gas may be scheduled for delivery to, or receipt from, either pooling point. These pooling points are not physical points, but are paper points used for aggregation and nominations. Midcontinent's application states that a shipper nominating for delivery into a pool in either zone will pay all applicable reservation, commodity, fuel and gas lost and unaccounted-for charges.[87] In addition, Midcontinent's application states that shippers will pay a commodity charge of 2 cents per Dth for transportation under an ITS Agreement from a Pooling Point to a delivery point in the same zone as the receipt pooling point. Midcontinent's application also states that a shipper may nominate the pooling point as a receipt point for delivery within that zone if, in the case of Zone 1, the delivery is to be west of the Perryville compressor station and, in the case of Zone 2, if the delivery is to be west of mile post 352 in Warren County, Mississippi and the shipper will pay all applicable reservation, commodity, fuel and lost and unaccounted-for charges for that zone.

115. Order No. 587-F states that when a pool exists in a rate zone, the charge for shipment in that zone must be incurred either for shipment to the pool or shipment out of

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[86] *Natural Gas Pipeline Company of America,* 80 FERC ¶ 61,372 (1997); *order on reh'g,* 81 FERC ¶ 61,296 (1997).

[87] *See* Application at p. 7.

the pool.[88] In several instances Midcontinent's proposed pooling structure appears to recover commodity and fuel charges from transportation into and out of Midcontinent's pools that are within the same rate zone as the delivery. Midcontinent is directed to revise its pooling procedures so that the charge for shipment within the rate zone is only incurred once either for shipment to the pool or from the pool.

Section 6.13 - Segmentation

116. BP states that GT&C section 6.13(d) requires a shipper to obtain Midcontinent's consent to reverse the flow direction as part of its segmentation of capacity and avers that this is against Commission policy which requires pipelines to give shippers comprehensive rights to segment capacity.[89] Midcontinent states in its answer that its system, as designed, does not have reverse flow capabilities so that any backhaul may only be by displacement and Midcontinent's consent requirement is reasonable because a backhaul can only be accommodated depending on the operational condition of the system at a given point in time. BP states in its January 24, 2008 reply that it is withdrawing its protest based on BP's understanding that Midcontinent will not bar a segmentation of capacity that involves a reversal in the gas flow as long as the transaction can be scheduled as part of Midcontinent's scheduling priorities. Midcontinent is directed to modify its tariff accordingly.

Section 10 – Imbalances and Scheduling Charges

117. BP states that the Commission requires a pipeline to submit a filing to recover operational gas costs, not to invoice it as an additional charge or credit as Midcontinent proposes in section 10.6. This ensures there will be a Commission proceeding to determine that operational purchases are prudent. BP also believes the Commission should require Midcontinent to rely on competitive bidding to buy or sell operational gas. BP believes that competitive bidding ensures fair competition among gas suppliers and buyers, minimizes the costs incurred by the pipeline in buying operational gas and maximizes the revenue received by the pipeline from the sale of operational gas.

118. Midcontinent states in its answer that the notion of competitive bidding assumes that Midcontinent has sufficient time to go through a posting and bidding process. Midcontinent does not believe this may always be the case. Midcontinent states that as long as Midcontinent does not discriminate in the buying and selling of gas, Midcontinent's tariff provision is proper. Midcontinent also states the process of how

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[88] Order No. 587-F, FERC Statues and Regulations, Proposed Regulations 1988-1998, ¶ 32,527, at p. 33,351 (1997).

[89] Order No. 637-B, 92 FERC ¶ 61,062, at 61,165.

Midcontinent will pass back or collect the costs and revenues associated with the buying and selling of gas was negotiated with the shippers that signed precedent agreements and if an individual shipper feels the revenues passed back or surcharged are not supported, they may bring the issue to the Commission's attention at that time. Midcontinent states there is no need to require a formal filing.

119. On June 9, 2008, BP stated in its status report it would withdraw its protest based on BP's understanding that Midcontinent will file revised tariff language that states that

Midcontinent will rely on competitive bidding for the purchase and sale of operational gas, except in an emergency situation.

120. Midcontinent is directed to revise its tariff so that it will rely on competitive bidding for the purchase and sale of operational gas, except in emergency situations. In addition, the Commission believes that it is appropriate for Midcontinent to be required to file a report for review of its operational purchases and sales.[90] In *Dominion Transmission, Inc.*,[91] the Commission required an annual report to help ensure that the pipeline was not charging its customers for the under-recovery of gas on the one hand while realizing revenue generated from the sale of gas for over-recovery on the other.[92] The Commission also found that the annual filing will provide interested parties with the opportunity to examine the pipeline's sales of excess gas and question the revenues realized from such sales. Accordingly, Midcontinent is required to file to revise its tariff to provide for the filing of an annual report on operational purchases and sales. The report should indicate the source of the gas, date of the purchase/sale, volumes, purchase/sale price, costs and revenues from the purchase/sale, and the disposition of the costs and revenues.

Section 12 – Creditworthiness

121. Sections 12.1(b)(1)(i) through (iv) provide that a shipper that fails to satisfy Midcontinent's credit criteria may continue to receive service if it provides security for 12 months of reservation fees through a variety of forms of collateral. Midcontinent states that the Commission has recognized that, in conjunction with the construction of new facilities, interstate pipelines can require more than the standard three months of

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[90] *See, e.g., WIC,* 107 FERC ¶ 61,315 (2004), *order on reh'g,* 111 FERC ¶ 61,215 (2005); *Colorado Interstate Gas Co.,* 107 FERC ¶ 61,312 (2004), *order on reh'g,* 111 FERC ¶ 61,216 (2005).

[91] 106 FERC ¶ 61,029 (2004).

[92] *Id.* at 61,101.

collateral if the shipper is not creditworthy. Midcontinent has determined that 12 months worth of reservation fees backed by a creditworthy source is the minimum required to justify taking the risk in the project. Midcontinent states this reflects a reasonable balance between Midcontinent and the shippers that have contracted for capacity to support construction of the project. Midcontinent also states that 12 months of collateral protects it from shippers that are not as creditworthy stepping directly into the shoes of the initial shippers (that met the requisite credit assurances) through a permanent release and receiving service on credit terms and conditions that do not appropriately reflect the overall risk of the project.

122. The Commission's longstanding policy has been to require no more than the equivalent of three months' worth of reservation charges as security for a shipper that has been found to be non-creditworthy. The Commission believes this amount reasonably balances the shippers' right to continued service with the pipelines' risk in remarketing the capacity.[93] When undertaking a major system expansion or constructing a greenfield pipeline, such as Midcontinent, a transporter and its lenders bear a substantially greater risk of cost recovery. Therefore, the Commission's creditworthiness policy permits larger collateral requirements for pipeline construction projects to be executed between the pipeline and the initial shippers. However, once the pipeline is in service, new shippers on the system should not be subject to that same standard.

123. In addition, the Commission permits a pipeline to refuse to allow a permanent release of capacity if it has a reasonable basis to conclude that it will not be financially indifferent to the release.[94] Therefore, the concerns raised by Midcontinent about noncreditworthy shippers directly stepping into the shoes of the initial shippers should be minimized. For the reasons stated above the Commission finds that Midcontinent's proposal to require security equal to twelve months of service charges for shippers found to be non-creditworthy is excessive for shippers subscribing to service after the pipeline is in operation. Midcontinent is directed to change its tariff to require security for up to three months of service charges.

Section 14 – Capacity Release by Firm Shippers

124. BP states that GT&C section 14.18(a) of Midcontinent's tariff states that if a shipper releases capacity for the remaining duration of its contract at the higher of the maximum tariff rate or the negotiated rate the shipper is paying, the releasing shipper can

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[93] *Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding,* FERC Stats. & Regs. ¶ 31,191 (2005).

[94] *See, e.g., Texas Eastern Transmission Corp.,* 83 FERC ¶ 61,092, at p. 61,446 (1998).

ask Midcontinent to relieve it of any liability in connection with the contract (a Permanent Release). BP states a Permanent Release requires a release for the remaining duration of the contract, where the pipeline is not adversely affected in terms of the reservation charge payments the pipeline will receive. Therefore, according to BP, as long as the Replacement Shipper will pay a rate that is no lower than the Releasing Shipper's rate the pipeline will be financially-neutral and the release qualifies as a Permanent Release. Therefore, BP believes Midcontinent must allow Permanent Releases at the rate that the Releasing Shipper is paying.

125. Midcontinent states in its answer that BP misreads section 14.18 of the GT&C and section 14.18(b) sets forth the criteria under which MEP will allow a Permanent Release of capacity with the Releasing Shipper no longer being liable to Midcontinent. The three criteria are: (1) the release shall be for the remaining term of the agreement; (2) the replacement shipper shall agree to pay a rate equal to or greater than the reservation rate which the Releasing Shipper paid (or another rate as Midcontinent shall agree to accept); and (3) the Replacement Shipper shall have met the creditworthy standards of Midcontinent's tariff. Midcontinent states that each of these conditions is consistent with Commission policy.

126. BP states in its January 24, 2008 reply it is withdrawing its challenge of the proposed tariff language on Permanent Releases based on the understanding that Midcontinent will propose revised tariff language that addresses BP's concerns. Midcontinent is directed to revise its tariff to address BP's concerns.

127. BP states that Midcontinent's proposed section 14.20(b), which states that if Midcontinent terminates a Releasing Shipper's contract due to the Releasing Shipper's lack of creditworthiness or failure to pay, the Replacement Shipper can retain the capacity by paying a rate that equals the greater of the applicable maximum rate or the same rate as the Releasing Shipper paid, violates the Commission's policy that the Replacement Shipper can retain the capacity if it agrees to pay the lesser of the Releasing Shipper's contract rate, the maximum rate or some other rate acceptable to the pipeline.[95] BP believes Midcontinent should revise its tariff to comply with Commission policy. Midcontinent states in its answer that it accepts BP's proposed revision. Midcontinent is directed to revise its tariff accordingly.

Section 16 – Pre-Granted Abandonment, Contract Rollovers and Right of First Refusal

128. BP protests Midcontinent's proposal to require a shipper that wants to retain its capacity via the Right of First Refusal (ROFR) process to agree to both a price (up to the

[95] *Columbia Gulf Transmission Co.*, 117 FERC ¶ 61,073, at P14 (2006).

maximum rate) and a term which at least equals the bid on all or any portion of the service the existing shipper wishes to retain (GT&C section 16.2(d)(3)). BP states that an existing shipper should be able to retain its capacity by submitting a bid that has a net present value (NPV) that is equal to or greater than the NPV of the best bid. BP avers that Midcontinent relies on the NPV method to determine which shipper has submitted the best bid and BP states that the Commission has recognized that it would be unduly discriminatory to utilize the NPV method to determine the best bid but to impose a bid component match requirement on the existing shipper. Therefore, BP urges the Commission to find that the existing shipper should only have to match the NPV of the best bid.

129. Midcontinent states in its answer it is not required to deem any bid as acceptable to the extent that it is below the maximum recourse rate. If Midcontinent accepts a bid at or below the maximum recourse rate it is in effect establishing the form of discount that it will accept. Midcontinent states it should not be forced to accept another form of bid for a shorter term as this would require Midcontinent to accept a discount that it does not find acceptable. If the acceptable bid in the ROFR process is a maximum recourse rate bid, then in order to have an equal NPV the existing shipper would have to match the term of the acceptable bid.

130. On June 9, 2008, BP stated in its status report it would withdraw its protest based on BP's understanding that Midcontinent will file revised tariff language to state that an existing shipper can retain its capacity via ROFR by matching the NPV of the best bid; however, if the best bid is for more than five years, the existing shipper need only match the NPV associated with the first five years covered by the bid. Midcontinent is directed to revise its tariff accordingly.

Section 20 and Section 2.2(d) – Force Majeure

131. Section 20 of Midcontinent's GT&C provides a definition of Force Majeure, describes the responsibilities of Midcontinent and its shippers when Force Majeure is declared and states that Midcontinent will post on the Informational Posting section of its Interactive Website any information related to a declaration of Force Majeure. Section 2.2(d) lists those situations under which Midcontinent will provide a reservation charge credit for service not provided. According to section 2.2(d)(2)(ii), no credit is provided during the first 10 days of a Force Majeure event or prior to the date Midcontinent should have overcome the Force Majeure, whichever occurs first. Section 2.2(d)(2) also requires Midcontinent to provide a full reservation charge credit in a Force Majeure situation if Midcontinent is not able to schedule 95 percent of the firm daily volume. In Opinion No. 406,[96] the Commission denied the pipeline's proposal to reduce its reservation charge

[96] *Tennessee Gas Pipeline Co.,* 76 FERC ¶ 61,022 (1996); *order on reh'g,* 80 FERC ¶ 61,070 (1997).

credit threshold from 98 percent to 95 percent and required the pipeline to provide full reservation charge credits when it failed to provide 98 percent of scheduled volumes. We see no reason to permit the lower percentage amount here and direct Midcontinent to revise its tariff to provide a full reservation charge credit if Midcontinent is not able to deliver 98 percent of firm scheduled volumes.

Section 29 – NAESB Standards

132. The Commission believes that Midcontinent has complied with the bulk of the NAESB standards, however, several standards have not been included in its pro forma tariff. Midcontinent has not complied with the following NAESB standards: 1.3.6, 4.3.89, 4.3.90, 4.3.91 and 4.3.92. In its compliance filing, Midcontinent is directed to either incorporate these standards verbatim or by reference.

Accounting

133. An allowance for funds used during construction (AFUDC) is a component part of the cost of constructing the project. Gas Plant Instruction 3(17) prescribes a formula for determining the maximum amount of AFUDC that may be capitalized as a component of construction cost.[97] That formula, however, uses prior year book balances and cost rates of borrowed and other capital. In cases of newly created entities, such as Midcontinent, prior year book balances do not exist; therefore, using the formula contained in Gas Plant Instruction 3(17) could produce inappropriate results for initial construction projects. Therefore, to ensure that the amounts of AFUDC are properly capitalized in this project, we will require Midcontinent to capitalize the actual costs of borrowed and other funds for construction purposes not to exceed the amount of debt and equity AFUDC that would be capitalized based on the overall rate of return approved.[98]

134. In cases similar to Midcontinent's, the Commission has required the applicant to limit its AFUDC rate to a rate no higher than it could earn on operating assets. The Commission limited the maximum amount of AFUDC that the pipeline could capitalize by limiting the AFUDC rate to a rate no higher than the overall rate of return underlying its recourse rates.[99] We will therefore require Midcontinent to ensure that its maximum

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[97] 18 C.F.R. Part 201 (2008).

[98] *See*, e.g., *Cheniere Creole Trail Pipeline, L.P.*, 115 FERC ¶ 61,331 (2006), *Port Arthur Pipeline, L.P.*, 115 FERC ¶ 61,344 (2006), and *Golden Pass Pipeline, L.P.*, 112 FERC ¶ 61,041 (2005).

[99] *See, Gulfstream Natural Gas System, L.L.C.*, 91 FERC ¶ 61,119 (2000) and *Buccaneer Gas Pipeline Company L.L.C.*, 91 FERC ¶ 61,117 (2000).

AFUDC rate for the entire construction period is no higher than the overall rate of return underlying its recourse rates. Further, Midcontinent must use its actual cost of debt (short-term and long-term) in the determination of its AFUDC rate, if it results in an AFUDC rate lower than the overall rate of return underlying its recourse rates.[100]

135. As detailed above, Midcontinent will lease up to an additional 272,000 Dth/d of firm capacity on Enogex's intrastate pipeline system. We will accept Midcontinent's proposal to treat the capacity lease with Enogex as an operating lease and to record the monthly lease payments in Account 858, Transmission and Compression of Gas by Others.[101] This accounting treatment is consistent with similar capacity lease agreements approved by the Commission.[102]

Engineering

136. Our analysis of the engineering information submitted by Midcontinent in its Exhibits G, G-I, and G-II, as amended, concludes that Midcontinent's facilities are appropriately designed to provide up to 1,532,500 Dth/d of firm capacity in Zone 1 and 1,200,000 Dth/d in Zone 2.

137. Our analysis of the engineering information supplied by Enogex, as well as our review of Apache's May 13, 2008 filing of information in rebuttal, as supplemented on July 1, 2008, concludes that, while certain individual receipt points may decrease in capacity, the overall amount of capacity on Enogex's system will increase as a result of the facility addition Enogex plans. The Enogex system is web-like in configuration, with gas flows changing direction regularly depending on market demands. Thus, there is no dominant flow pattern. In such cases, historical operating conditions can be used in conjunction with estimates of future operating conditions to determine changes in receipt and delivery point capacities. The Midcontinent lease provides for a single delivery point at Bennington and receipts of up to 100,000 Dth/d at Waynoka, in Enogex's West Zone, up to 165,000 Dth/d at West Pool, and 7,000 Dth/d at East Pool, with the flexibility to also receive Waynoka volumes at West Pool, at the Waynoka rate, and West Pool volumes at either West Pool or East Pool, at the West Pool rate. Receipts at the pooling

[100] *See, Mill River Pipeline, L.L.C.*, 112 FERC ¶ 61,070 (2005).

[101] *See* Midcontinent's data request response dated February 26, 2008.

[102] *See, e.g., Gulf Crossing, supra*; *Gulf South Pipeline Company,* 119 FERC ¶ 61,281 (2007); *Rockies Express Pipeline LLC,* 119 FERC ¶ 61,069 (2007); *Natural Gas Pipeline Company*, 118 FERC ¶ 61,211 (2007); *Discovery Producer Services LLC*, 117 FERC ¶ 61,243 (2006); and *Midwest Gas Transmission Company* and *Trunkline Gas Company*, 73 FERC ¶ 61,320 (1995).

points may originate from any receipt point within the applicable zone. While no specific path for deliveries under the lease can be determined, the effect of the lease on the operational capacities at receipt and delivery points on Enogex's system can be reasonably determined from the information provided by Enogex in its December 31, 2007 filing.

Environment

138. The potential environmental impacts of Midcontinent's project were evaluated in the draft and final environmental impact statements (EIS) to satisfy the requirements of the National Environmental Policy Act (NEPA).[103] The final EIS has been prepared in cooperation with the U.S. Fish and Wildlife Service (FWS), the U.S. Environmental Protection Agency (EPA), the National Park Service (NPS), the Natural Resources Conservation Service (NRCS), the U.S. Army Corps of Engineers (COE), the Louisiana Department of Environmental Quality (LDEQ), the Texas Parks and Wildlife Department (TPWD), the Louisiana Department of Wildlife and Fisheries (LDWF), the Mississippi Department of Wildlife, Fisheries, and Parks (MDWFP), and the Alabama Department of Conservation and Natural Resources (ADCNR).

139. The Commission approved Midcontinent's request to use the Pre-Filing Review Process for the proposed Project on February 22, 2007, in Docket No. PF07-4. As part of our Pre-Filing review, Staff issued a *Notice of Intent to Prepare an Environmental Impact Statement, Request for Comments on Environmental Issues and Notice of Public Scoping Meetings* (NOI) on April 2, 2007. Subsequently, on August 14, 2007, the FERC issued a *Supplemental Notice of Intent to Prepare an Environmental Impact Statement for the Proposed Midcontinent Express Pipeline Project, Request for Comments on Environmental Issues, and Notice of Public Site Visit* (Supplemental NOI). These notices were published in the *Federal Register*[104] and sent to affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; Native American tribes; local libraries; newspapers; and, other interested parties.

140. Subsequent to the issuance of our NOIs, six public scoping meetings were held in communities along the proposed route, Staff participated in three public site visits, and Staff received numerous written and verbal comments from landowners, concerned citizens, public officials, and government agencies concerning project impacts on land uses, soils, wetlands and waterbodies; water quality; vegetation and wildlife; threatened and endangered species; air quality, noise impacts; visual impacts, future development; property values; tribal lands and cultural resources; use of eminent domain; timber

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[103] 42 U.S.C. §§ 4321-4347 (2005).

[104] 72 Fed. Reg. 17,153 (April 6, 2007), and 72 Fed Reg. 39,617 (July 19, 2007).

production; the project purpose and need; environmental justice; safety; state- and federally-managed lands; and potential alternatives to the proposed route and planned facilities.

141. The Commission issued a draft EIS on February 8, 2008. Public notice of the availability of the draft EIS was published in the *Federal Register*.[105] The draft EIS was mailed to federal, state, and local government agencies; elected officials; Native American tribes; local libraries and newspapers; intervenors; and other interested parties (i.e., affected landowners, miscellaneous individuals, and environmental groups who provided scoping comments or asked to remain on the mailing list). In addition, affected landowners who were added to the mailing list after the NOI was issued, and landowners potentially affected by some of the alternatives under consideration, were sent the draft EIS. The public was given 45 days from the date of publication in the *Federal Register* to review and comment on the draft EIS. Six public draft EIS comment meetings were held in the project area to solicit comments, and in addition, written and electronic comments were submitted directly to the Commission.

142. During this period and at the public comment meetings Staff received numerous comments regarding the location of the proposed pipeline, the affects to land use, safety and reliability, cumulative impacts, alternatives, and other factors. Specifically, Staff received comment letters from three federal agencies: the U.S. Department of Interior (DOI), the NRCS, and the EPA; seven state agencies: the Oklahoma Historical Society, the TPWD, the Texas Historical Commission, the LDWF, the Louisiana Department of Natural Resources, the Louisiana Economic Development Department, and the Alabama Historical Commission; and three local government agencies: the Bossier Parish (Louisiana) Tax Assessor, the Paris (Texas) Economic Development Corporation, and the Hinds County (Mississippi) Economic Development District; as well as 23 landowners or interested individuals. Staff also received a comment from one Louisiana State Senator.

143. The Commission issued the final EIS on May 30, 2008. Public notice of the availability of the final EIS was published in the *Federal Register*.[106] The final EIS was mailed to the same parties as the draft EIS, as well as to parties that commented on the draft EIS and landowners newly identified as affected by proposed route variations. The distribution list is provided as Appendix A of the final EIS.

144. The final EIS considers and responds to the comments received on the draft EIS. The final EIS concludes that construction and operation of Midcontinent's proposed

[105] 72 Fed. Reg. 63,566 (Nov. 9, 2007).

[106] 73 Fed. Reg. 16,663 (March 28, 2008).

project would result in limited adverse environmental impacts. The limited impacts would be most significant during the period of construction. The final EIS finds that if constructed and operated in accordance with applicable laws and regulations, Midcontinent's proposed mitigation plans, and the recommended mitigation measures set forth in the final EIS, the proposed project would be an environmentally acceptable action.

Landowner Comments on the Final EIS

145. Staff received a comment from a family in Louisiana, the Price Family Co-heirs, who were concerned about potential project-related impacts to their property. Specifically, the family was concerned that the location of the proposed project on their property (i.e., routing through the central portion of the property and along frontage to the single access road) near Milepost (MP) LA 185.6 would limit future development potential for family members. Additionally, the family was concerned about the proximity of the proposed project to an existing residence on their property, the resulting safety risk, and a possible loss of property value.

146. Staff evaluated multiple route variations during the scoping and draft EIS comment periods. These route variation evaluations included review of landowner-identified issues and suggested pipeline routes. The proposed route identified in the final EIS was based on our consideration of this input received during that time. Slight adjustments to the location of the proposed route or additional temporary workspaces are possible even if the certificate is approved and construction begins. This process is typically related to site-specific conditions and landowners may continue to work with the pipeline company regarding possible adjustments.

147. Aboveground structures (such as new homes), not associated with the project, would be precluded from the 50-foot-wide permanent pipeline right-of-way (ROW). Structures may be built outside of the permanent ROW, but their location in relation to the proposed route would depend on many factors, including personal preference in regard to proximity to a pipeline.

148. The Commission encourages pipeline companies to avoid residences and residential areas to the maximum extent possible. Midcontinent has routed the proposed project in a manner to avoid residences to the extent possible and has considered and adopted numerous route variations designed to avoid or minimize impacts to residences. Midcontinent has further provided site-specific residential crossing plans for all residences within 25 feet of the proposed project. The Commission has also evaluated several route variations that would minimize impacts to residential areas and has reviewed the site-specific residential construction plans submitted by Midcontinent and has found them to be acceptable. It appears that the proposed pipeline would be located at least 150 feet away from the existing Price family residence.

149. The Commission does acknowledge in section 3.9.5 of the final EIS that a variety of factors could affect the resale value of land. Potential property value loss would be addressed during easement negotiations. However, the Commission does not get involved in landowner negotiations with the pipeline company.

150. Staff received a comment on the final EIS from Ms. Martha Anderson, a landowner in Bryan County, Oklahoma, who is upset about the loss of trees on her property due to the use of construction right-of-way and/or extra temporary workspaces. The subject property has two existing pipeline easements and the proposed project would overlap some of the existing Kinder Morgan right-of-way during construction. Also, Ms. Anderson was displeased about Midcontinent using threatening language regarding obtaining use of the property.

151. Slight adjustments to the location of the proposed route or additional temporary workspaces are possible, even if the certificate is approved and construction begins. This process is typically related to site-specific conditions and landowners may continue to work with the pipeline company regarding possible adjustments, such as those to avoid or minimize impacts to large trees, if practical and feasible.

152. As stated in the final EIS (section 2.2.2), our regulations give primary consideration to the use, enlargement, or extension of existing right-of-ways rather than developing new rights-of-way in order to reduce impacts on potentially sensitive resources. As shown in Appendices C and D, Midcontinent proposes to overlap multiple existing pipeline, low-voltage powerlines, and high-voltage powerlines, in areas where overlap can be done safely. This overlap of rights-of-way in conjunction with the reductions in the project's temporary and permanent rights-of-way would reduce the overall land consumption of the project resulting in a reduction of both landowner and environmental impacts.

153. As stated above, the Commission does not get involved with negotiations between the pipeline companies and the landowner over the value of the land and its uses. Natural gas pipeline companies do not have authority under the NGA to use the power of eminent domain until they receive an NGA section 7(c) certificate approving the project.

154. Staff received a comment from D. H. Jones, a landowner, regarding ambient noise testing near the proposed Lamar Compressor Station. Mr. Jones states that noise modeling data depicted in the final EIS is incorrect due to faulty survey methods conducted by the Midcontinent. Further, Mr. Jones requests that additional noise modeling be submitted to the Commission and be available for public comment prior to the issuance of a certificate to Midcontinent.

155. The final EIS indicates that the accuracy of Midcontinent's noise data for the Lamar Compressor Station has been questioned and that competing noise surveys were

submitted to the Commission. Our review of Midcontinent's noise survey (and resultant data used for analyses in the EIS) and the commenter-filed noise survey indicates that the two surveys used different field methods and that study results were not interpreted or presented in a consistent manner. In order to address this apparent discrepancy, Midcontinent committed to conduct an additional 24-hour ambient noise survey at the Ditzler Jones and Ray Martin properties located near the proposed Lamar Compressor Station prior to construction and file survey results with the Commission staff.

156. Further, the final EIS contains a condition that stipulates that Midcontinent should conduct noise surveys to verify that the noise attributable to the operation of each compressor station does not exceed a day-night sound level (L_{dn}) of 55 decibels on the A-weighted scale (dBA) at any Noise Sensitive Area. If these noise levels are exceeded, Midcontinent would install additional noise controls to meet the required 55 dBA operational noise level.

157. While the new ambient noise survey for the Ditzler Jones and Ray Martin properties will not be completed prior to the issuance of a certificate, the results of the new survey will be made publicly available on the Commission's eLibrary system.

158. In this order we are requiring Midcontinent to limit the project disturbance to a 50-foot wide permanent right-of-way and a 100 foot construction right-of-way. The burden that multiple pipeline easements have on individual landowners, as well as concerns regarding excessive use or loss of property for the proposed project, were indicated by our receipt of 34 comments from affected landowners during the scoping and draft EIS comments periods. Staff evaluated each landowner's concerns and, where practical, analyzed route alternatives to reduce impacts to the environment and to landowners. To reduce impacts on landowners with existing easements already on the property, we are requiring that Midcontinent utilize 10 feet of adjacent pipeline right-of-way as part of their 100-foot wide nominal construction right-of-way and for any additional temporary workspaces where needed, also utilize the adjacent right-of-way where possible.

Alternatives

159. The final EIS addressed alternatives, including major alternatives and the analysis found no reasonable major route alternatives that would be environmentally preferable to the proposed route. Staff also evaluated the No Action Alternative, the Postponed Action Alternative, alternative energy sources, and the potential effects of energy conservation, system alternatives, route alternatives, route variations, and aboveground facility site alternatives to determine whether they would be technically and economically feasible and environmentally preferable to the proposed action. During the Pre-filing, scoping, and draft EIS comment periods, public and agency comments resulted in Midcontinent adopting 184 route variations. Staff identified and evaluated 22 additional route variations in response to public comments for the proposed project. Based on the

recommendations in the final EIS, we are requiring that Midcontinent adopt four additional route variations that we believe would result in environmental benefits compared to the analogous portions of the proposed project.

Water Resources

160. Construction of the proposed project pipeline would affect 368 wetland areas resulting in a total of approximately 321.9 acres of wetland disturbance, including approximately 217.6 acres of forested wetlands and approximately 104.4 acres of scrub-shrub or emergent wetlands. No wetlands would be affected by the proposed aboveground facilities. During operations, approximately 86.4 acres of wetlands, including approximately 82.5 acres of currently forested wetlands, would be converted to other wetland types in the maintained portion of the permanent pipeline right-of-way. Special-status wetlands potentially affected by the proposed project include lands in the NRCS-administered Wetland Reserve Program and high-quality bald cypress-tupelo forested wetlands.

161. The proposed project would cross 231 perennial streams, 774 intermittent streams, and 41 lakes or ponds. As proposed, most waterbody crossings would be accomplished using open-cut methods. Potential effects to most major and sensitive waterbodies would be largely avoided through implementation of horizontal directional drill (HDD) installation techniques, which would be used to accomplish pipeline installation across 39 waterbodies. Waterbodies that would be crossed using HDD include 26 of the 40 major waterbody crossings and all navigable waterways; all of the streams designated as Louisiana Natural and Scenic Rivers or National Rivers Inventory-listed; and the majority of the impaired waterbodies that occur along the proposed Project route.

Vegetation and Wildlife

162. The construction and operation of the proposed project would affect four primary types of upland vegetative communities: upland forest, pine plantation, agricultural land, and open lands. Approximately 56 percent of the upland vegetation resources that would be affected during construction would consist of pine plantation and upland forest, with agricultural and open lands making up the remainder. Several extensive forested tracts and areas containing exotic and/or invasive plant species would also be crossed by the proposed pipeline route, as well as vegetative communities of special concern. Based on our analysis, the total estimated area of contiguous, extensive forested tracts that would be impacted by the proposed project is approximately 584.2 acres during construction and 292.1 acres during operation. Impacts to forested areas, including large forested tracts, would be minimized by routing the proposed project along existing rights-of-way and through other previously disturbed areas, such as agricultural and open lands, where possible.

163. The wetlands and upland vegetation communities crossed by the proposed project route support habitats that provide cover and forage for a variety of wildlife species including birds, mammals, reptiles, and amphibians. Physical disturbance, displacement, and clearing of herbaceous upland and wetland habitats would affect wildlife at or near the time of construction, but such effects would be largely temporary and many habitats would generally recover quickly following construction. Upland and wetland forested habitats would be affected most substantially, with a long-term conversion of wooded areas to successional stages in the temporary construction right-of-way and a permanent conversion to scrub-shrub or herbaceous levels within the permanent pipeline right-of-way. The proposed project route would be collocated with or parallel to existing utility rights-of-way for approximately 53 percent of the proposed mainline pipeline route. Collocation would minimize impacts to previously undisturbed vegetation and wildlife habitats, and Midcontinent would further minimize impacts to wildlife habitats through implementation of its Plan and Procedures.

164. The waterbodies that would be traversed by the proposed project provide habitat for a variety of aquatic species, including warm water fishes and mussels. Potential impacts to fisheries and aquatic habitats would include sedimentation and turbidity, loss of cover, introduction of pollutants into the aquatic environment, potential blockage of fish migrations and interruptions of spawning, and entrainment or loss of stream flow during hydrostatic testing. Direct impacts would be avoided by the use of HDD installation at many waterbody crossings, and aquatic habitat impacts at other crossing locations would be largely temporary, as crossings would be completed in less than 48 hours in most instances.

Threatened and Endangered Species

165. In consultation with the FWS and state wildlife management agencies, Staff identified 22 federally-listed threatened, endangered, or candidate species that could potentially be affected by the proposed project. In addition, the bald eagle, which is federally protected under the Bald and Golden Eagle Protection Act, was identified as potentially occurring within the project area. Based on our review of these species and the survey reports prepared by Midcontinent, Staff has determined that these species and their preferred habitats either do not occur along the proposed project route, their potential habitats would be avoided through special construction procedures, or that adverse effects would be unlikely. Additionally, the final EIS included numerous recommendations for development and implementation of measures to minimize the potential for project-related effects to various species, including measures to protect the interior least tern and development of site-specific crossing plans at several streams in consultation with FWS to avoid impacts to listed aquatic species. Midcontinent has committed to developing a program in consultation with FWS regarding the training of construction workers and contractors in the identification of least terns and their nesting habitat. Field surveys have been completed along approximately 96.6 percent of the

proposed project route, but completion of surveys and habitat evaluations along the remaining portions of the proposed project route, would be required to complete the process of compliance with section 7 of the Endangered Species Act (ESA). The FWS indicated in its letter dated May 28, 2008, that it concurred with Staff's conclusions regarding federally threatened and end angered species in Louisiana and that no further ESA coordination would be necessary in Louisiana. Staff concludes that project effects would be not likely to adversely affect any federally listed species.

Land Use and Visual Impacts

166. As proposed, construction of the proposed project would affect approximately 8,310.3 acres of land, including 5,884.6 acres for the project mainline construction right-of-way; 24.3 acres for the CenterPoint Lateral construction right-of-way; 102.2 acres for the aboveground facilities; and 2,299.2 acres for extra work areas (extra workspaces, pipe storage and contractor yards, and access roads). In accordance with the recommendation in the draft EIS, Midcontinent committed to limit its nominal construction right-of-way width to 100 feet along upland sections of the proposed project mainline. This would reduce the overall project land requirements by more than 1,000 acres compared to Midcontinent's original proposal. During operation of the proposed project, the permanent pipeline right-of-way, aboveground facilities, and permanent access roads would encumber approximately 3,158.3 acres.

167. Approximately 33 residential structures are located within 50 feet of proposed project construction work areas, but Midcontinent would attempt to maintain a minimum separation of 25 feet between residences and any construction work area wherever feasible. Where maintenance of such a separation is not feasible, Midcontinent has developed site-specific residential construction plans for each residence located within 25 feet of proposed construction work areas that would minimize impacts to these structures. Staff has reviewed these plans and find them to be acceptable.

168. Visual resources along the proposed project route would be affected by the installation of certain aboveground facilities and through the alteration of existing vegetative patterns associated with the clearing and maintenance of the construction and permanent pipeline ROWs. However, the impact is not expected to be significant in most areas, and we are including a condition (see No. 33) requiring Midcontinent to develop and finalize site-specific visual screening plans to minimize any visual impacts to adjacent landowners prior to construction of the Lamar and Delhi Booster Compressor Stations.

Cultural Resources

169. Where survey permission was obtained, Midcontinent has conducted cultural resource surveys and prepared associated technical reports covering approximately 96.6

percent (488.6 miles) of the proposed project mainline route; the full length of the proposed CenterPoint Lateral route; 144 of the 157 proposed project access roads; 21 of the 29 proposed offsite pipe storage and contractor yards; 10 of the 14 proposed meter stations, and all of the proposed compressor station facilities. In total, these surveys identified 105 prehistoric sites (not including 37 isolated finds), including 1 site eligible for listing on the National Register of Historic Places (NRHP) and 11 sites potentially eligible for listing on the NRHP. Midcontinent indicated that the eligible site would be avoided. If avoidance of the other sites is not feasible, Phase II testing would be conducted to further characterize the sites and determine their NRHP eligibility status. Midcontinent also identified 47 historic sites (22 sites contained both prehistoric and historic characteristics) and four architectural sites within the project area of potential effect. Only one site, which had both prehistoric and historic components, was recommended to be eligible for listing in the NRHP.

170. Midcontinent contacted 11 Native American groups regarding the proposed project, and although some requested additional consultation or information, none have expressed opposition to the proposed project. The cultural resource survey reports for the surveyed portions of the project have been submitted to the various state historic preservation officers (SHPOs) for review, but consultations with the SHPOs regarding the unsurveyed portions of the proposed project route are still pending. To ensure that all our responsibilities under section 106 of the National Historic Preservation Act are met, we are recommending that Midcontinent defer construction until surveys and evaluations of areas not previously accessed are completed, all survey reports and any necessary treatment plans have been reviewed by appropriate parties, and the Commission provides written notification to proceed.

Air Quality & Noise Impacts

171. Impacts to noise quality associated with construction of the proposed project would generally be temporary, minor, and limited to daylight hours, except at HDD sites, where drilling and related construction equipment would likely operate on a continuous basis. To minimize the potential for HDD-related construction noise, we are requiring in Condition No. 35 that Midcontinent develop a Noise Analysis and Mitigation Plan for selected HDD entry and exit locations where drilling would occur 24 hours per day.

172. The proposed compressor stations would generate noise on a continuous basis during operations. However, the predicted noise levels attributable to operations of the new compressor stations typically would not result in significant effects on the Noise Sensitive Areas nearest to those facilities as the largest increase in noise level would be 4.2 dBA and overall noise levels would not exceed 55 dBA. To verify the predictions, we are requiring in Condition 36 that Midcontinent confirm through noise surveys that the 55dBA threshold is not exceeded and to report on what additional noise controls would be utilized, if needed.

Conclusion

173. We have reviewed the information and analysis contained in the final EIS regarding the potential environmental effect of the project. Based on our consideration of this information, we agree with the conclusions presented in the final EIS and find that Midcontinent's project is environmentally acceptable if the project is constructed and operated in accordance with the recommended environmental mitigation measures in the appendix to this order. The Commission adopts the findings and conclusions of the final EIS. We are including the environmental mitigation measures recommended in the final EIS as conditions to the authorization issued to Midcontinent in this order.

174. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this certificate. We encourage cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[107]

175. The Commission on its own motion, received and made a part of the record all evidence, including the application, as supplemented, and exhibits thereto, submitted in this proceeding and upon consideration of the record,

<u>The Commission orders</u>:

(A) In Docket No. CP08-6-000, a certificate of public convenience and necessity is issued to Midcontinent to construct, install, and operate an approximately 506-mile pipeline system from near Bennington, Oklahoma to near Butler, Alabama and to lease 272,000 Dth/d of capacity in Enogex's Oklahoma intrastate pipeline system, as described and conditioned herein and as more fully described in the application. Midcontinent is also issued blanket construction and transportation certificates under Subpart F of Part 157 and Subpart G of Part 284 of the Commission's regulations.

(B) In Docket No. CP08-9-000, a limited-jurisdiction certificate of public convenience and necessity is issued to Enogex to operate 272,000 Dth/d of capacity on its Oklahoma intrastate pipeline system to Midcontinent. This limited jurisdiction certificate will enable Enogex to operate the leased capacity being used for NGA jurisdictional

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[107] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply v. Public Service Commission*, 894 F.2d 571 (2d Cir. 1990); and *Iroquois Gas Transmission System, L.P.*, 52 FERC ¶ 61,091 (1990) and 59 FERC ¶ 61,094 (1992).

services subject to the terms of the lease and subject to Midcontinent's open-access tariff, and will require Enogex to operate the leased capacity in a manner that ensures Midcontinent's ability to provide services, including interruptible transportation, using the leased capacity on an open-access, non-discriminatory basis. Enogex shall not shift any unrecovered costs of leased capacity to customers for whom it is providing jurisdictional interstate services under section 311 of the NGPA.

(C) The certificate authority in Ordering Paragraph (A) shall be conditioned on the following:

(1) Midcontinent's completing the authorized construction of the proposed facilities and making them available for service within three years of the issuance of this order pursuant to paragraph (b) of section 157.20 of the Commission's regulations;

(2) Midcontinent's compliance with all applicable Commission regulations, including, but not limited to, Parts 154 and 284, and paragraphs (a), (c), (e), and (f) of section 157.20;

(3) Midcontinent's executing firm service agreements for the capacity levels and terms of service requested, in signed precedent agreements, prior to construction;

(4) Midcontinent's not shifting any of its costs associated with the leased capacity to customers that do not use the leased capacity;

(5) Midcontinent's maintenance of separate accounting records to ensure that costs and revenues associated with the leased capacity from Enogex can be identified in any future proceeding and that Midcontinent's other customers are not subsidizing shippers who use capacity leased from Enogex; and

(6) Midcontinent's compliance with the environmental conditions listed in the appendix to this order.

(D) Midcontinent shall notify the Commission's environmental staff by telephone, email, and/or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Midcontinent. Midcontinent shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(E) Midcontinent's initial rates and tariff are approved, as conditioned and modified herein in the body of this order.

(F) Midcontinent's incremental recourse rates for the capacity lease are approved as initial section 7 rates, as discussed in the body of this order.

(G) Midcontinent must file actual tariff sheets that comply with the requirements contained in the body of this order no less than 60 days and no more than 90 days prior to the commencement of interstate service.

(H) Midcontinent is directed to file its negotiated rate agreements no less than 30 days or more than 60 days before service commences.

(I) Within three years after its in-service date, as discussed herein, Midcontinent must make a filing to justify its existing cost-based firm and interruptible recourse rates. In the alternative, in lieu of such filing, Midcontinent may make an NGA section 4 filing to propose alternative rates to be effective no later than three years after the in-service date for its proposed facilities.

(J) Midcontinent shall adhere to the accounting requirements discussed in the body of this order.

(K) All untimely motions to intervene in Docket Nos. CP08-6-000 and CP08-9-000 are granted.

(L) All motions for consolidation and for evidentiary hearing and or technical conference are denied.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix—Environmental Conditions

As recommended in the EIS, this authorization includes the following conditions:

1. Midcontinent shall follow the construction procedures and mitigation measures described in its application, supplemental filings (including responses to staff information requests), and as identified in the EIS, unless modified by the Order. Midcontinent must:

    a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;
    b. justify each modification relative to site-specific conditions;
    c. explain how that modification provides an equal or greater level of d. environmental protection than the original measure; and
    receive approval in writing from the Director of the OEP **before using that modification**.

2. The Director of OEP has delegated authority to take whatever steps are necessary to ensure the protection of all environmental resources during construction and operation of the project. This authority shall allow:

    a. the modification of conditions of the Commission's Order; and
    b. the design and implementation of any additional measures deemed necessary (including stop work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from project construction and operation.

3. **Prior to any construction**, Midcontinent shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, EIs, and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs before becoming involved with construction and restoration activities.

4. The authorized facility location shall be as shown in the EIS, as supplemented by filed alignment sheets, and shall include all of the staff's recommended facility locations. **As soon as they are available, and prior to the start of construction**, Midcontinent shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental

conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

Midcontinent's exercise of eminent domain authority granted under NGA section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Midcontinent's right of eminent domain granted under NGA section 7(h) does not authorize it to increase the size of its natural gas pipeline to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

5. Midcontinent shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, and staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, and documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **prior to construction** in or near that area.

   This requirement does not apply to route variations required herein or minor field realignments per landowner needs and requirements, which do not affect other landowners or sensitive environmental areas such as wetlands.

   Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;
   b. implementation of endangered, threatened, or special concern species mitigation measures;
   c. recommendations by state regulatory authorities; and
   d. agreements with individual landowners that affect other landowners or would affect sensitive environmental areas.

6. **Within 60 days of the acceptance of this certificate** and **prior to construction**, Midcontinent shall file an initial Implementation Plan with the Secretary for review and written approval by the Director of OEP describing how Midcontinent will implement the mitigation measures required by the Order. Midcontinent must file revisions to the plan as schedules change. The plan shall identify:

a. how Midcontinent will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;
b. the number of EIs assigned per spread, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;
c. company personnel, including EIs and contractors, who will receive copies of the appropriate material;
d. what training and instructions Midcontinent will give to all personnel involved with construction and restoration (initial and refresher training as the project progresses and personnel change), with the opportunity for OEP staff to participate in the training session;
e. the company personnel (if known) and specific portion of Midcontinent's organization having responsibility for compliance;
f. the procedures (including use of contract penalties) Midcontinent will follow if noncompliance occurs; and
g. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:
   (1) the completion of all required surveys and reports;
   (2) the mitigation training of onsite personnel;
   (3) the start of construction; and
   (4) the start and completion of restoration.

7. Midcontinent shall employ one or more EIs per construction spread. The EIs shall be:

   a. responsible for monitoring and ensuring compliance with all mitigative measures required by the Order and other grants, permits, certificates, or other authorizing documents;
   b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract and any other authorizing document;
   c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;
   d. a full-time position, separate from all other activity inspectors;
   e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and
   f. responsible for maintaining status reports.

8. Midcontinent shall file updated status reports with the Secretary on a **weekly** basis **until all construction-related activities, including restoration, are complete for**

each phase of the project. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. the current construction status of each spread, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally sensitive areas;
b. a listing of all problems encountered and each instance of noncompliance observed by the EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);
c. a description of corrective actions implemented in response to all instances of noncompliance, and their cost;
d. the effectiveness of all corrective actions implemented;
e. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and
f. copies of any correspondence received by Midcontinent from other federal, state or local permitting agencies concerning instances of noncompliance, and Midcontinent's response.

9. Midcontinent must receive written authorization from the Director of OEP **before commencing service** for each phase of the project. Such authorization will only be granted following a determination that rehabilitation and restoration of areas affected by the project are proceeding satisfactorily.

10. **Within 30 days of placing the certificated facilities in service**, Midcontinent shall file an affirmative statement with the Secretary, certified by a senior company official:

a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or
b. identifying which of the certificate conditions Midcontinent has complied with or will comply with. This statement shall also identify any areas affected by the project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

11. Midcontinent shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the project and restoration of the right-

of-way. **Prior to construction**, Midcontinent shall mail the complaint procedures to each landowner whose property would be crossed by the Project.

a. In its letter to affected landowners, Midcontinent shall:

(1) provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;
(2) instruct the landowners that, if they are not satisfied with the response, they should call Midcontinent's Hotline; the letter should indicate how soon to expect a response; and
(3) instruct the landowners that, if they are still not satisfied with the response from Midcontinent's Hotline, they should contact the Commission's Enforcement Hotline at (888) 889-8030, or at hotline@ferc.gov.

b. In addition, Midcontinent shall include in its weekly status report a copy of a table that contains the following information for each problem/concern:

(1) the date of the call;
(2) the identification number from the certificated alignment sheets of the affected property and approximate location by MP;
(3) the description of the problem/concern; and
(4) an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

12. Midcontinent shall not exercise the eminent domain authority granted under section 7(h) of the NGA to acquire a permanent pipeline right-of-way exceeding 50 feet in width, and where collocated, the 50-foot-wide permanent right-of-way shall abut the existing right-of-way. ***(Section 2.2.1)***

13. **Prior to construction,** Midcontinent shall revise its Water Well Testing Program to include provisions for pre- and post-construction monitoring and mitigation, if required, for all wells and springs identified with 150 feet of the proposed construction work areas that are used for domestic water supply or agricultural use. ***(Section 3.3.1)***

14. Midcontinent shall file a report with the Secretary, **within 30 days of placing its pipeline facilities in service,** identifying all private and domestic water wells/systems and springs damaged by construction and how they were repaired. The report shall include a discussion of any complaints concerning well or spring yield and/or quality and how each problem was resolved. ***(Section 3.3.1)***

15. Midcontinent shall consult with the LDWF regarding the proposed HDD crossing of, and surface water withdrawal from, designated Louisiana Natural and Scenic Rivers (Dorcheat Bayou [MP LA 42.1], Bayou D'Arbonne [MP LA 106.6], and Bayou D'Loutre [MP LA 113.1]) and file copies of all permits, approvals, or comments that may be obtained, including plans to address any additional mitigation measures recommended by LDWF, with the Secretary **prior to construction at these crossings**. ***(Section 3.3.2)***

16. Midcontinent shall consult with NPS regarding its proposed HDD crossing of, and hydrostatic test water withdrawal from, the NRI-listed Bayou D'Arbonne (MP LA 90.6 and MP LA 106.6; two separate crossings), Bayou D'Loutre (MP LA 113.1), Big Black River (MP MS 12.7), Chickasawhay River (MP MS 137.8), Pearl River (MP MS 44.8), and Strong River (MP MS 76.1), and file the results of those consultations, including plans to address any additional mitigation measures recommended by NPS, with the Secretary **prior to construction at these crossings**. ***(Section 3.3.2)***

17. Midcontinent shall develop site-specific plans to cross Coulee Ditch (MP LA 134.2), Steen Creek (MP MS 47.3), Tallahala Creek (MP MS 115.6), and Souenlovie Creek (MP MS 134.6) in consultation with FWS and file these plans with the Director of OEP for review and written approval **prior to construction at these crossings**. ***(Section 3.3.2)***

18. Midcontinent shall develop site-specific plans to cross Bakers Creek (MP MS 19.4), Dabbs Creek (MP MS 63.2), Campbell Creek (MP MS 68.3), Oakohay Creek (MP MS 86.7), West Tallahala Creek (MP MS 98.1), Buckatunna Creek (MP MS 147.8), and Okatuppa Creek (MP AL 2.2) in consultation with FWS and file these plans with the Director of OEP for review and written approval **prior to construction at these crossings**. ***(Section 3.3.2)***

19. Midcontinent shall not begin an open-cut crossing of any of the waterbodies proposed to be crossed using HDD until it files an amended crossing plan with the Secretary for review and written approval by the Director of OEP. The amended crossing plan shall include site-specific drawings identifying all areas that would be disturbed using the proposed alternate crossing method and the results of agency consultations including the COE, EPA, FWS, NPS, and other applicable federal and state agencies. Midcontinent shall file the amended crossing plan **concurrent with the appropriate state and federal applications** required for implementation of the plan. ***(Section 3.3.2)***

20. Midcontinent shall develop site-specific plans to cross the forested wetlands at MP LA 96.7, MP LA 104.7, MP LA 151.1, and MP MS 14.2 prepared in consultation with the COE, FWS, LDWF, MDWFP, and other appropriate agencies.

Midcontinent shall identify and evaluate appropriate avoidance and/or minimization measures (e.g., implementation of an HDD, route variation, and/or development of site-specific forested wetland crossing and restoration plans) to reduce impacts to these forested wetlands. Midcontinent shall file the site-specific crossing plans, along with the results of the consultations, with the Director of OEP for review and written approval **prior to construction at these crossings**. ***(Section 3.4.2)***

21. Midcontinent shall develop site-specific plans to cross the mature cypress-tupelo forested wetlands at MP LA 115.5 and MP MS 144.8 prepared in consultation with the COE, FWS, LDWF, MDWFP, and other appropriate agencies. Midcontinent shall identify and evaluate appropriate avoidance and/or minimization measures (e.g., implementation of an HDD, route variation, and/or development of site-specific forested wetland crossing and restoration plans) to reduce impacts to these forested wetlands. Midcontinent shall file the site-specific crossing plans, along with the results of the consultations, with the Director of OEP for review and written approval **prior to construction at these crossings.** ***(Section 3.4.3)***

22. **Prior to construction**, and in consultation with LDWF, FWS, and EPA, Midcontinent shall file with the Secretary its final COE-approved compensatory wetlands mitigation plan. ***(Section 3.4.4)***

23. **Prior to construction within Bodcau WMA,** Midcontinent shall consult with the COE and LDWF and file with the Secretary copies of any agreements for Project-related use and impacts to lands held in the Bodcau WMA. In that filing, Midcontinent shall also document how it would implement any COE or LDWF-recommended measures to avoid, minimize, or mitigate unavoidable impacts to Bodcau WMA lands. ***(Section 3.5.3)***

24. Midcontinent shall consult with the FWS, NRCS, and the following state agencies: ODWC, TPWD, LDWF, MDWFP, ADCNR, regarding its Draft Control Plan for Noxious and Invasive Species. **Prior to construction,** Midcontinent shall file with the Secretary a finalized version of its Control Plan for Noxious and Invasive Species that identifies all agency recommended measures that would be implemented during construction and operations to control exotic and invasive plant species. ***(Section 3.5.3)***

25. Midcontinent shall file a Migratory Bird Conservation Plan developed in consultation with the FWS. The plan shall consider the effects of forest fragmentation on migratory birds and include measures to prevent, minimize, or mitigate such effects. ***(Section 3.6.1)***

26. **Prior to construction,** Midcontinent shall file with the Secretary the results of the FWS-approved preconstruction surveys for the interior least tern. These surveys shall include evaluation of nesting habitat located within 650 feet of any proposed construction work area at the Red and Mississippi River crossings. If interior least terns are observed during the preconstruction surveys, Midcontinent shall not conduct any construction activity within 650 feet of interior least terns or their actively-used habitat. Midcontinent shall immediately notify the Commission staff and the FWS if interior least tern nesting colonies are observed within 650 feet of any work area at any time prior to or during construction. ***(Section 3.7.1)***

27. Midcontinent shall not begin any construction activities **until**:

    a. Midcontinent completes any outstanding species-specific surveys, files all applicable results and agency correspondence with the Secretary, and the Commission receives comments from the FWS regarding the preconstruction survey reports;
    b. The Commission completes section 7 consultations with the FWS; and
    c. Midcontinent receives written notification from the Director of the OEP that construction and/or implementation of conservation measures may begin. ***(Section 3.7.1)***

28. Midcontinent shall consult further with the ODWC, TPWD, LDWF, MDWFP, and the ADCNR regarding state-listed and rare species to determine the need for additional surveys or mitigation that would further minimize or avoid potential impacts to such species. Midcontinent shall file the results of that consultation, as well as any associated survey reports, with the Secretary **prior to construction**. ***(Section 3.7.2)***

29. **Prior to construction across any levee managed by the Caddo, Tensas Basin, and 5th Louisiana Levee Districts; the Louisiana Levee Board; the Louisiana Department of Transportation; and the COE,** Midcontinent shall file with the Secretary the applicable levee crossing permits and authorizations. ***(Section 3.8.4)***

30. Midcontinent shall consult with the PHWD regarding the proposed crossing of the Archusa Creek Water Park and file copies of any easement agreement, permits, approvals, or comments that may be obtained, including plans to address any additional mitigation measures recommended by the PHWD, with the Secretary **prior to construction within Archusa Creek Water Park boundaries.** ***(Section 3.8.4)***

31. **Prior to construction on WRP lands,** Midcontinent shall file with the Secretary the applicable documentation of meetings, special considerations, and agreements

reached as a result of consultation with the NRCS regarding the proposed construction activities on WRP lands. ***(Section 3.8.4)***

32. Midcontinent shall consult with the Mississippi Secretary of State and associated managing local school boards regarding the proposed crossings of all Sixteenth Section Lands and file copies of any easement agreement, permits, approvals, or comments that may be obtained, including plans to address any additional mitigation measures recommended by these entities, with the Secretary **prior to construction across Sixteenth Section Lands.** ***(Section 3.8.4)***

33. **Prior to construction**, Midcontinent shall file with the Secretary final site screening plans for the Lamar and Delhi Booster Compressor Stations and include copies of any screening plan agreements and correspondence with community groups. Midcontinent shall also file final site screening plans for the CEGT and ANR meter stations / interconnect facilities and the pig launcher/receiver facility located at MP TX 123.4. ***(Section 3.8.7)***

34. Midcontinent shall defer implementation of any treatment plans/measures (including archaeological data recovery); construction of facilities; and use of all staging, storage, or temporary work areas and new or to-be-improved access roads **until:**

    a. Midcontinent files with the Secretary cultural resources survey and evaluation reports, any necessary treatment plans, and the comments of the Oklahoma, Texas, Louisiana, Mississippi, and Alabama SHPOs on the reports and plans; and
    b. The Director of OEP reviews and approves all cultural resources survey reports and plans and notifies Midcontinent in writing that treatment plans/procedures may be implemented and/or construction may proceed.

    All material filed with the Secretary containing <u>location, character, and ownership information</u> about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: <u>"CONTAINS PRIVILEGED INFORMATION - DO NOT RELEASE."</u> ***(Section 3.10.4)***

35. **Prior to construction**, Midcontinent shall file with the Secretary, for review and written approval by the Director of OEP, a Noise Analysis and Mitigation Plan for the entry and exit locations for the HDD sites listed in Table 3.11.2-2 of the Final EIS where drilling would occur 24 hours per day. The plan shall include:

    a. the estimated number of days of drilling required for each location;
    b. a list indicating the direction and distance of the NSAs within 0.5 mile;
    c. a topographic map showing the location of the NSAs within 0.5 mile;

d. the existing day-night average noise (L_{dn}) at the NSAs nearest to each drill location, and the predicted noise impacts at the NSAs during drilling activities; and

e. a description of any noise mitigation that would be implemented prior to the start of drilling activities to reduce noise impacts, or alternate measures proposed by Midcontinent, such as temporary relocation or compensation. ***(Section 3.11.2)***

36. Midcontinent shall conduct noise surveys to verify that the noise attributable to operation of each of the compressor stations does not exceed an L_{dn} of 55 dBA at any NSA following the installation of all authorized compressor units at each station and file the results of those surveys with the Secretary **no later than 60 days** after placing all authorized compressor units in service or prior to the start of the next phase of construction, whichever is sooner. If the noise attributable to operation of any of the compressor stations exceeds 55 dBA L_{dn} at any NSA, Midcontinent shall file a report on what additional noise controls are needed to meet that level and install any required controls **within one year** of the in-service date of the associated compressor unit(s) or prior to the start of the next phase of construction, whichever is sooner. Midcontinent shall confirm compliance with the L_{dn} of 55 dBA requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls or **prior to the start of the next phase of construction,** whichever is sooner. ***(Section 3.11.2)***

37. Midcontinent shall incorporate the Carswell Route Variation, as described in the Final EIS, into its proposed project. Midcontinent shall file with the Secretary, for review and written approval by the Director of OEP, revised construction alignment sheets that show the modified route and workspaces, **prior to construction in this area**. ***(Section 4.4.1)***

38. Midcontinent shall incorporate the Bridges Route Variation II, as described in the Final EIS, into its proposed project. Midcontinent shall file with the Secretary, for review and written approval by the Director of OEP, revised construction alignment sheets that show the modified route and workspaces, **prior to construction in this area**. ***(Section 4.4.1)***

39. Midcontinent shall incorporate the Bridgers Route Variation II, as described in the Final EIS, into its proposed project. Midcontinent shall file with the Secretary, for review and written approval by the Director of OEP, revised construction alignment sheets that show the modified route and workspaces, **prior to construction in this area.** Midcontinent shall also provide an adequate water supply for livestock operations at the affected property **until the existing water source is restored.** ***(Section 4.4.1)***

40. Midcontinent shall incorporate the Twin Lakes Route Variation II, as described in the Final EIS, into its proposed project. Midcontinent shall file with the Secretary, for review and written approval by the Director of OEP, revised construction alignment sheets that show the modified route and workspaces, **prior to construction in this area.** ***(Section 4.4.1)***

120 FERC ¶ 61,291
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Gulf South Pipeline Company, LP	Docket Nos.	CP07-32-000 CP07-32-001 CP07-105-000
Destin Pipeline Company, L.L.C.		CP07-110-000

ORDER ISSUING CERTIFICATES AND GRANTING ABANDONMENT

(Issued September 28, 2007)

1. On December 11, 2006, Gulf South Pipeline Company, L.P. (Gulf South) filed, in Docket No. CP07-32-000, an application under section 7(c) of the Natural Gas Act (NGA) for authorization to construct and operate its proposed Southeast Expansion Project. The proposed project consists of approximately 111 miles of pipeline and 45,080 horsepower (hp) of compression in Mississippi and Louisiana. On March 5, 2007, Gulf South filed an amendment to the December 11, 2006 application, proposing to coat the involved pipe internally along the entire length of the project to reduce the pipe's roughness and increase its capacity.

2. On March 16, 2007, Gulf South filed, in Docket No. CP07-105-000, an application under NGA section 7(c) for authorization to lease 260,000 Mcf per day of capacity from Destin Pipeline Company, L.L.C. (Destin). In a companion application also filed March 16, 2007, in Docket No. CP07-110-000, Destin requested authorization under NGA section 7(b) to abandon by lease 260,000 Mcf per day of capacity to Gulf South.

3. For the reasons stated below, we are granting the requested authorizations, subject to conditions.

Background and Proposal

A. Gulf South's Southeast Expansion Facilities

4. Gulf South is a natural gas company which owns and operates approximately 7,500 miles of pipeline facilities extending from southern and eastern Texas through Louisiana, Mississippi, southern Alabama and western Florida. The Commission recently approved Gulf South's East Texas to Mississippi Expansion Project, a 239-mile pipeline with a capacity of up to 1.7 Bcf per day extending from East Texas to Harrisville, Mississippi.[1]

5. Gulf South states that gas supplies being produced in Texas, Oklahoma, Arkansas, and Louisiana and moving to the Perryville-Harrisville hub currently exceed the capacity of existing pipelines to deliver those supplies further east. Gulf South explains that this gas production is forecast to grow for at least the next decade, and as increasing amounts of gas are delivered to the Perryville-Harrisville area, constraints on pipelines are beginning to develop. Without additional pipeline infrastructure from the Perryville-Harrisville area, avers Gulf South, the effects of existing and developing pipeline capacity constraints will worsen as additional gas production comes on line. Gulf South states that the Southeast Expansion Project will provide new and efficient take-away capacity for these new gas supplies for delivery to major pipelines serving the Northeast, Florida, and other parts of the Southeast, and enhance its ability to deliver gas to the east side of its own system, as well. Moreover, avers Gulf South, the Southeast Expansion Project will also allow markets that have historically relied on offshore production to access competitive onshore supplies to meet their gas needs.

6. In this application, Gulf South requests authorization to construct approximately 111 miles of 42-inch outside diameter pipeline extending from the end point of its new East Texas to Mississippi Expansion Project at Harrisville, in Simpson County, Mississippi to a new interconnect with Transcontinental Gas Pipe Line Corporation (Transco) in Choctaw County, Alabama (Transco Station 85). At various points along the pipeline route, Gulf South proposes to construct interconnects with Destin Pipeline Company, Tennessee Gas Pipeline Company, and Southern Natural Gas Company.

7. In addition to the pipeline facilities, Gulf South proposes to install a total of 45,080 hp of compression at three new compressor stations in Richland Parish, Louisiana (Delhi Compressor Station), Simpson County, Mississippi (Harrisville Compressor Station), and Clarke County, Mississippi (Destin Compressor Station). At the Delhi

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[1] *See Gulf South Pipeline Company, L.P.*, 119 FERC ¶ 61,281 (2007).

Compressor Station, Gulf South would install 18,940 hp of compression comprising four reciprocating units to provide pressure maintenance for gas entering the Southeast Expansion Project from other pipelines. Gulf South would install 18,940 hp of compression, likewise consisting of four reciprocating units at the Harrisville Compressor Station, which would be a mainline station. At the Destin Compressor Station, Gulf South would install 7,100 hp of compression, comprising two reciprocating units, to provide pressure maintenance to facilitate deliveries into the Destin pipeline system.

8. The expansion facilities, including the pipeline and compression, would provide Gulf South the ability to increase its system capacity by 1.268 Bcf a day at a normal operating pressure of 1,249 psig. Gulf South has entered into precedent agreements with customers to transport 660,000 Mcf a day at negotiated rates with terms ranging from five to ten years, and expects to lease additional capacity to Gulf Crossing Pipeline Company (Gulf Crossing), at a future date.[2] Gulf South estimates the cost of these facilities at $406,276,900.

1. **Proposed Rates**

9. Gulf South proposes to charge an incremental recourse rate for transportation service on the Southeast Expansion Project. The proposed FTS maximum reservation rate of $5.6524 per Dth is based on a proposed cost of service of $86,013,236[3] and design determinants of 1,268,100 Dth per day, reflecting the design capacity of the project. In developing the cost of service, Gulf South has used a rate of return of 10.41 percent, based on its rate case settlement in Docket No. RP97-373, and a depreciation rate of 4.0 percent. The proposed ITS maximum rate of $0.1858 per Dth is the 100 percent load

[2] Gulf Crossing is a new entity which has filed an application with the Commission in Docket No. CP07-398-000 requesting authorization to construct a 353.2-mile long pipeline from Sherman, Texas to an interconnect with Gulf South at Gulf South's Tallulah Compressor Station (part of the East Texas to Mississippi Expansion Project), and to lease up to 1.4 Bcf a day of natural gas capacity on Gulf South from Tallulah to the Transco interconnect at the terminus of the Southeast Expansion Project. In Docket Nos. CP07-401-000 and CP07-402-000, Gulf South has requested authorization to construct pipeline looping between its Tallulah Compressor Station and the Harrisville Compressor Station, and to lease up to 1.4 Bcf on its system to Gulf Crossing.

[3] Gulf South's year one cost of service reflects O&M expenses of $3,932,214, depreciation expenses of $16,251,074, income tax expenses of $16,956,646, other tax expenses of $7,500,000 and a return allowance of $41,373,302.

factor equivalent of the FTS rate. Gulf South proposes an incremental fuel rate of 0.34 percent for all transportation utilizing the Southeast Expansion Project, maintaining that the fuel associated with the Southeast Expansion Project will be incremental to the compression used on Gulf South's existing system.

2. Amendment to the Application

10. On March 5, 2007, Gulf South filed an amendment to its original application. Gulf South states that since it filed its application, several new interstate pipeline projects to be located in northeastern Louisiana and central Mississippi have been announced by their sponsors. Gulf South anticipates that a market for increased gas deliveries into its system will develop in the future and that there may be a need to increase the capacity of the Southeast Expansion Project facilities beyond the original proposal to the Commission. To accommodate greater volumes of gas that could be introduced into its system, Gulf South proposes to coat its pipe internally along the entire length of the project to reduce its roughness, which, it explains, will increase the capacity of the expansion facilities in a cost-effective manner to take advantage of future market needs and opportunities without the need to construct new facilities.[4]

11. Gulf South estimates that these modifications will increase the cost of the original proposal by $5 million. Because it is uncertain when the increased volumes that it anticipates would flow into its system, Gulf South does not at this time propose to modify the requested certificated system capacity or to recalculate the rates it proposed in the December 11, 2006 application. Instead, Gulf South proposes to absorb the costs associated with the internal coating.[5]

B. The Destin Lease

12. Destin owns and operates an open-access pipeline system that transports natural gas from the Outer Continental Shelf to onshore connections with six interstate pipelines in Mississippi. Gulf South and Destin have entered into a lease agreement under which Gulf South will initially lease from Destin 260,000 Mcf per day of capacity on Destin's existing system. The lease agreement, however, provides Gulf South with an option to

[4] Gulf South estimates that it would have to construct approximately 10.5 miles of additional pipeline looping to be able to reach the same level of capacity possible with the proposed modification.

[5] Gulf South would, however, begin to depreciate these costs upon the project's in-service date.

increase the leased capacity from 260,000 Mcf per day up to 700,000 per day. Gulf South states that, in conjunction with the proposed Southeast Expansion Project facilities, the leased capacity will enable Gulf South to provide access to Florida markets.

13. The lease agreement provides that Gulf South has the right to use the leased capacity on a firm basis, and Gulf South explains that it will use the leased capacity to provide open access service to its customers under its FERC Gas Tariff. Gulf South states that it has designed incremental rates to recover the lease payments only from those shippers that will use the capacity. Under the lease agreement, the primary receipt points for gas from Gulf South into Destin will be Gulf South/Destin interconnections at Gulf South's new Destin Compressor Station in Clarke County, Mississippi, and at Gulf South's Index 300 line, near Pascagoula, Mississippi. The primary delivery points will be at Destin interconnections with the systems of Florida Gas Transmission Company and Gulfstream Natural Gas. The primary term of the lease is ten years. Upon termination of the lease, the lease capacity will revert to Destin. Destin will retain operational control of the facilities.

Notice and Interventions

14. Notices of the Gulf South Southeast Expansion application and the proposed amendment to the application were published in the *Federal Register* on December 29, 2006 (71 Fed. Reg. 78417) and March 16, 2007 (72 Fed. Reg. 12602), respectively. Southern Company Services, Inc., the City of Vicksburg, Mississippi, Wilmut Gas Company, Mobile Gas Service Corporation, CenterPoint Energy Entex, Atmos Energy Corporation, Florida Power Corporation dba Progress Energy Florida, Inc., Carolina Power & Light Company dba Progress Energy Carolinas, Inc., Florida Power & Light Company, Southern Natural Gas Company, and the United Municipal Distributors Group filed timely, unopposed motions to intervene in the application proceeding. Timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.[6] Destin filed a motion to intervene out-of-time. Destin has shown an interest in this proceeding, and its participation will not delay the proceeding or prejudice the rights of any other party. Accordingly, for good cause shown, we will permit Destin's late intervention.[7] The Commission received no additional intervention requests in response to the notice of the proposed amendment.

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[6] 18 C.F.R. § 385.214 (2007).

[7] 18 C.F.R. § 385.214(d) (2007).

15. Notice of the Gulf South application in Docket No. CP07-105-000 and the Destin application in Docket No. CP07-110-000 regarding the lease of capacity on Destin's system were published in the *Federal Register* on April 2, 2007 (72 Fed. Reg. 15677 and 72 Fed. Reg. 15674, respectively). Mobile Gas Service Corporation, the City of Vicksburg, Mississippi, Florida Power Corporation dba Progress Energy Florida, Inc., Wilmut Gas Company, Destin, and SG Resources Mississippi, L.L.C. (SGRM) filed timely, unopposed motions to intervene in the Gulf South proceeding. SGRM also filed an unopposed motion to intervene in the Destin proceeding. SGRM and Destin included comments with their motions.

Discussion

16. Because the facilities proposed by Gulf South will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, their construction and operation, as well as Gulf South's acquisition of capacity by lease, are subject to the requirements of section 7(c) of the NGA. The proposed abandonment of capacity by Destin is subject to the requirements of section 7(b).

A. The Southeast Expansion Facilities

1. Certificate Policy Statement

17. On September 15, 1999, the Commission issued its Certificate Policy Statement to provide guidance as to how it will evaluate proposals for certificating new construction.[8] The Certificate Policy Statement established criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new pipeline facilities, the Commission balances the public benefits against the potential adverse consequences. Our goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

[8] *Certification of New Interstate Natural Gas Pipeline Facilities* (Certificate Policy Statement), 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000).

18. Under this policy, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers.

19. The Commission also considers potential impacts of the proposed project on other pipelines in the market and those existing pipelines' captive customers, or landowners and communities affected by the route of the new pipeline. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered.

20. As discussed below, there will be no presumption of rolled-in rate treatment for this project's costs in future rate cases. Therefore, approval of Gulf South's proposed Southeast Expansion Project will meet the threshold test that its existing customers not subsidize the project. Furthermore, the project will not degrade any present services to existing customers. The project will likewise have no adverse impact on existing pipelines or their captive customers as the new facilities will be transporting new domestic sources of gas so that the project will not replace existing customers' service on existing pipelines.

21. We are also satisfied that Gulf South has taken appropriate steps to minimize adverse impacts on landowners. Gulf South states that it has designed the pipeline route so that the majority of the right-of-way for the Southeast Expansion Project (approximately 73 miles) will follow existing pipeline rights-of-way, and that it has attempted to locate its Delhi, Harrisville, and Destin compressor stations in remote areas to minimize potential impacts on landowners. Gulf South states also that it has worked with landowners to understand and accommodate their concerns, and that it is committed to securing any needed rights-of-way through negotiation wherever possible.

22. The Southeast Expansion Project, as amended and conditioned, will benefit the public because it will provide an important new outlet to the interstate market for natural gas from capacity constrained production areas that are expected to serve as rich supply sources. The project will likewise help create market alternatives, and enhance gas supplies available to customers on other connected pipelines. Therefore, consistent with the criteria discussed in the Certificate Policy Statement and section 7(c) of the NGA, we find that the benefits of the project will outweigh any potential adverse effects, and that the proposed project is required by the public convenience and necessity.

23. Consistent with our standard practice, we will condition our certificate authorization so that construction cannot commence until after Gulf South executes contracts that reflect the levels and terms of service represented in its precedent agreements.[9]

2. Gulf South's Rates

24. The Commission has reviewed the proposed cost of service and proposed initial incremental recourse rates for these facilities and the associated pro forma tariff sheets reflecting stated rates for Rate Schedules FTS, ITS and NNS. Gulf South proposes to charge customers who use both the expansion and the existing facilities an incremental rate for service on the expansion facilities plus the generally applicable system rates for service provided on the existing system.

25. Although Gulf South's Southeast Expansion Project will deliver supplies to markets in the Northeast and Southeast through new interconnects with Transco in Alabama and Destin in Mississippi, several factors lead us to a finding that the proposed expansion, like Gulf South's recently-certificated East Texas to Mississippi Expansion Project, will be integrated and operated as part of Gulf South's existing pipeline system. The Southeast Expansion Project will begin at the intersection of Gulf South's existing Index 130 line and the East Texas to Mississippi Expansion Project at Harrisville, Mississippi. The primary receipt point for 500,000 Dth per day of the 660,000 Dth per day of capacity under contract is also located at Harrisville. Expansion shippers will be able to use Gulf South's existing facilities on a secondary basis, and existing shippers will be permitted to use the expansion facilities on a secondary basis. In addition, as part of the Southeast Expansion Project, Gulf South is proposing to install 18,940 horsepower of compression at its Delhi Compressor Station, located upstream of the Southeast Expansion Project, in order to provide pressure maintenance for gas coming into the project from other pipelines in the Perryville area. Three Southeast Expansion Project shippers have primary receipt points on Gulf South's existing system or the East Texas to Mississippi Expansion and will have to use those facilities to transport their gas supplies to the Southeast Expansion Project. As we explained in the East Texas to Mississippi proceeding, the Commission has not permitted incremental plus pricing under similar circumstances,[10] and we will therefore require Gulf South to modify its proposal as discussed below.

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[9] *See, e.g., Tennessee Gas Pipeline Company*, 101 FERC ¶ 61,360, P 21 (2002).

[10] *See Gulf South Pipeline Company, L.P.*, 119 FERC ¶ 61,281, P 32 (2007).

26. For integrated mainline expansion facilities, such as those proposed by Gulf South here, the Commission has permitted pipelines to charge an incremental rate for service utilizing such facilities if such rate is higher than the generally applicable firm transportation rate.[11] However, pipelines have been required to charge their generally applicable transportation rate if that rate is higher than the cost-based incremental rate for service utilizing the expansion.[12] Here, the bulk of the contracted-for capacity is to be received at receipt points in Zone 3 and delivered to new delivery points in Zone 3.[13] The generally applicable FTS firm transportation rate for transportation within Zone 3 is $4.9383 per Dth/m ($0.162 per Dth/d) compared to the proposed incremental rate of $5.6524 per Dth/m ($0.186 per Dth/d).

27. However, in calculating its proposed incremental rate, Gulf South used a 4.0 percent depreciation rate for the Southeast Expansion Project, whereas the system-wide depreciation rate agreed to in Gulf South's last rate case settlement is 2.3 percent.[14] The Commission's policy is to require that a pipeline depreciate proposed new facilities at its approved system-wide depreciation rate where, as here, the new facilities will be integrated into and operated as part of the pipeline's existing system facilities.[15]

28. Further, Gulf South's revised Exhibit N, filed on May 25, 2007, indicates that Gulf South proposed to allocate $8,000,000 of the expansion project's cost of service to interruptible transportation.[16] However, in calculating its proposed incremental recourse

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[11] *See East Tennessee Natural Gas Company,* 98 FERC ¶ 61,331 (2002).

[12] *See Trunkline Gas Company,* 119 FERC ¶ 61,078 (2007).

[13] The Commission notes that because the proposed interconnects with Transco and Destin do not currently exist, they are not currently within a rate zone; however, it appears that they too will be located within Zone 3.

[14] *See Koch Gateway Pipeline Company,* 84 FERC ¶61,143 (1998); Koch Gateway Pipeline Company, "Offer of Settlement and Stipulation and Agreement", RP97-373-012, Appendix C, March 30, 1998.

[15] *Texas Eastern Transmission, LP,* 101 FERC ¶ 61,120 (2002).

[16] *See also* Gulf South's April 19, 2007 response to data request. Commission policy requires that a pipeline credit 100 percent credit of interruptible revenues, net of variable costs, to firm and interruptible customers or establish projected interruptible volumes and allocate costs to the projected interruptible volumes. *See, e.g., Creole Trail LNG, L.P. and Cheniere Creole Trail Pipeline, L.P.*, 115 FERC ¶ 61,331, at P 27 (2006); *Entrega Gas Pipeline Inc.*, 112 FERC ¶ 61,177, at P 51 (2005).

rates, Gulf South failed to use the full actual expansion capacity, as required by Commission policy. [17]

29. Taking the above considerations into account, we have calculated a revised firm incremental rate of $4.6728 per Dth/m ($0.154 per Dth/d), which is lower than Gulf South's existing, generally applicable rate for Zone 3 service. Therefore, we will reject Gulf South's proposal to charge incremental rates as initial rates for services using the expansion capacity and require Gulf South to use its generally applicable firm and interruptible system rates as initial recourse rates for service on the expansion facilities.

30. One would normally expect that if the cost-based incremental rate associated with an expansion is lower than the existing system rate, rolling in the costs and revenues associated with the expansion would result in lower system rates for all customers. Here, however, less than 55 percent of Gulf State's expansion capacity is subscribed on a firm basis under precedent agreement. If the 660,000 Dth/d of service currently subscribed under precedent agreement were provided at the maximum approved recourse rate, annual revenues would equal $39,477,487, which is considerably less than Gulf South's projected cost of service of approximately $86,013,236 in year 1, $82,752,820 in year 2 and $78,486,130 in year 3. Affording rolled-in rate treatment under these circumstances could result in existing customers subsidizing the costs of the expansion. Therefore, we will not make a predetermination regarding future rate treatment at this time. When Gulf South files a future section 4 proceeding to recover the costs associated with the expansion project, it will have to demonstrate that its proposed rate treatment will not result in the subsidization of this expansion by existing shippers. In addition, because Gulf State's precedent agreements provide for service to be provided at negotiated rates, Gulf South bears the risk for any revenue shortfall in its next rate case. Project costs will be compared to the revenues that would be generated if Gulf South were charging the maximum recourse rate for all service being provided at negotiated rates.[18]

31. We direct Gulf South to file actual tariff sheets reflecting the revision as directed by this order at least 30 days but no more than 60 days prior to the in-service date of the new facilities.

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[17] *See, e.g., Portland Natural Gas Transmission System*, 76 FERC ¶ 61,123 (1996); *Pacific Gas Transmission Co.*, 70 FERC ¶ 61,016, at p. 61,045, *reh'g denied*, 71 FERC ¶ 61,268 (1995).

[18] *See Natural Gas Pipeline Company of America*, 120 FERC ¶ 61,004, at P 18 (2007).

3. Fuel

32. Gulf South proposes an incremental fuel rate of 0.34 percent for services using the proposed expansion capacity. However, as discussed above, we have found the Southeast Expansion Project will be an integrated part of the Gulf South system and are rejecting Gulf South's proposal to charge incremental rates for its services using the expansion capacity because properly calculated incremental rates would be lower than Gulf South's generally applicable rates. Therefore, Gulf South must use its currently-effective system fuel rate for services utilizing either the Southeast Expansion Project facilities alone or both the expansion facilities and existing facilities. We direct Gulf South to file actual tariff sheets reflecting this revision at least 30 days but no more than 60 days prior to the in-service date of the new facilities.

4. Negotiated Rates

33. Gulf South indicates that, prior to the in-service date of the Southeast Expansion Project, expansion shippers will execute firm transportation agreements at negotiated rates with terms ranging from 5 to 10 years, and that Gulf South will file these agreements with the Commission in accordance with Section 23 of Gulf South's tariff. In certificate proceedings we establish initial recourse rates, but do not make determinations regarding specific negotiated rates for proposed services.[19] Rather, the Commission authorizes the applicable initial recourse rates in the certificate proceeding (which, in this case, will be Gulf South's generally applicable system-wide transportation rates), and addresses issues regarding the allocation of costs and revenues between recourse rate and negotiated rate shippers in the context of a general NGA Section 4 rate proceeding.

34. All service agreements containing a negotiated rate must comply with the Commission's Alternative Rate Policy Statement[20] and the Commission's decision in

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[19] *CenterPoint Energy – Mississippi River Transmission Corp.*, 109 FERC ¶ 61,007, at P 19 (2004); *ANR Pipeline Co.*, 108 FERC ¶ 61,028, at P 21 (2004); *Gulfstream Natural Gas System, LLC*, 105 FERC ¶ 61,052, at P 37 (2003); *Tennessee Gas Pipeline Co.*, 101 FERC ¶ 61,360, at n. 19 (2002).

[20] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines* (Alternative Rate Policy Statement), 74 FERC ¶ 61,076 (1996), *reh'g and clarification denied*, 75 FERC ¶ 61,024 (1996), *reh'g denied*, 75 FERC ¶ 61,066 (1996); *petition for review denied, Burlington Resources Oil & Gas Co. v. FERC*, Nos. 96-1160, *et al.*, U.S. App. Lexis 20697 (D.C. Cir. July 20, 1998).

NorAm Gas Transmission Company (*NorAm*).[21] Gulf South must file either its negotiated rate contracts or numbered tariff sheets at least 30 but not more than 60 days prior to the commencement of service on the new pipeline, stating for each shipper paying a negotiated rate, the exact legal name of the shipper, the negotiated rate, the applicable receipt and delivery points, the volume to be transported, the beginning and ending dates of the contract term, and a statement that the agreements conform in all material respects with the pro forma service agreements in Gulf South's FERC Gas Tariff. Gulf South must also disclose all consideration linked to the agreements, and maintain separate and identifiable accounts for volumes transported, billing determinants, rate components, surcharges, and revenues associated with its negotiated rates in sufficient detail so that they can be identified in Statements G, I, and J in any future NGA section 4 or 5 rate case.

B. <u>The Destin Lease</u>

35. Historically, the Commission views lease arrangements differently from transportation services under rate contracts. The Commission views a lease of interstate pipeline capacity as an acquisition of a property interest that the lessee acquires in the capacity of the lessor's pipeline.[22] To enter into a lease agreement, the lessee generally needs to be a natural gas company under the NGA and needs section 7(c) certificate authorization to acquire the capacity. Once acquired, the lessee in essence owns that capacity and the capacity is subject to the lessee's tariff. The leased capacity is allocated for use by the lessee's customers. The lessor, while it may remain the operator of the pipeline system, no longer has any rights to use the leased capacity.[23]

36. The Commission's practice has been to approve a lease if it finds that: (1) there are benefits for using a lease arrangement; (2) the lease payments are less than, or equal to, the lessor's firm transportation rates for comparable service over the terms of the lease on a net present value basis; and (3) the lease arrangement does not adversely affect existing customers.[24] The lease agreement between Gulf South and Destin satisfies these requirements.

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[21] *NorAm Gas Transmission Co.*, 77 FERC ¶ 61,011 (1996).

[22] *Texas Eastern Transmission Corp.*, 94 FERC ¶ 61,139, at p. 61,530 (2001).

[23] *Texas Gas Transmission, LLC*, 113 FERC ¶ 61,185, at P 10 (2005).

[24] *Texas Gas Transmission, LLC*, 113 FERC ¶ 61,185, at P 10 (2005); *Islander East Pipeline Company, L.L.C.*, 100 FERC ¶ 61,276, at P 69 (2002).

37. First, the Commission has found that capacity leases in general have several potential public benefits. Leases can promote efficient use of existing facilities, avoid construction of duplicative facilities, reduce the risk of overbuilding, reduce costs, and minimize environmental impacts.[25] In addition, leases can result in administrative efficiencies for shippers.[26] Here, the lease arrangement will enable Gulf South's Southeast Expansion Project shippers to have seamless access to Florida markets by utilizing available unsubscribed capacity on Destin without the need for additional pipeline construction and environmental or landowner impacts.

38. Second, the payments Gulf South will make to Destin under the lease are less than Destin's generally applicable maximum firm transportation rates. Each month Gulf South will pay lease charges consisting of a demand charge of $0.065 per Dth, which is less than Destin's maximum tariff rate of $0.237 per Dth for service over the same path.

39. Third, the lease arrangement will not adversely affect Gulf South or Destin's existing customers. The proposed lease of capacity will use available unsubscribed capacity on Destin's system. Therefore, the lease arrangement will not result in adverse operational impacts on existing Gulf South or Destin customers or on any other pipelines or its customers. Gulf South has designed incremental firm and interruptible rates, based on the lease charges Gulf South will pay Destin under the lease to recover the costs of the leased capacity from only those shippers that will use the lease capacity. In addition, each shipper using the leased capacity will pay the applicable fuel retention rate on Destin[27] in addition to Gulf South's fuel rate. Only shippers using the lease capacity will be subject to the proposed incremental rates and Gulf South will not be allowed to shift any costs associated with the leased capacity, including fuel costs, to its existing customers.

40. The lease will have no negative impacts on Destin's existing customers since it uses available unsubscribed capacity and there will be no capital expenditures required by Destin, other than the construction of certain facilities at Destin's interconnect with Florida Gas Transmission, for which Gulf South will reimburse Destin. Gulf South will be responsible for fuel gas, including lost and unaccounted-for gas associated with the

[25] *See, e.g., Dominion Transmission, Inc.,* 104 FERC ¶ 61,267, at P 21 (2003); *Islander East Pipeline Company,* 100 FERC ¶ 61,276, at P 70 (2002).

[26] *Wyoming Interstate Company, Ltd.,* 84 FERC ¶ 61,007, at p. 61,027 (1998), *order denying reh'g,* 87 FERC ¶ 61,011 (1999).

[27] Destin's fuel rate will be capped at 0.3 percent during the Primary Term of the lease.

leased capacity. Destin's existing customers, therefore, will not subsidize the incremental fuel costs associated with the project.

41. Based on the benefits the proposed lease will provide to the market and the lack of adverse effect on existing customers and other pipelines, we find that the public convenience and necessity requires approval of the proposed lease agreement. We approve Gulf South's proposed incremental recourse rates for the leased capacity.[28] As we explained with reference to Gulf South's rate proposal, all service agreements containing a negotiated rate must comply with the Commission's Alternative Rate Policy Statement and the Commission's decision in the *Noram* proceeding. Gulf South's application states that it has an option to increase the leased capacity to an amount in excess of 260,000 Dth per day, but not to exceed 700,000 Dth per day. This order authorizes Gulf South to lease 260,000 Dth per day. If Gulf South elects to exercise its option and increase its lease capacity, it must file an amendment and receive Commission approval.

42. Destin shall treat the capacity lease as an operating lease for accounting purposes. Destin is directed to record the monthly receipts in Account 489.2, *Revenues from Transportation of Gas of Others Through Transmission Facilities.* We have authorized similar accounting treatment for transportation capacity lease arrangements in other cases.[29] Further, during the term of the lease with Gulf South, Destin will not be allowed to reflect in its system rates any of the costs (*i.e.,* the fully-allocated cost of service, including actual fuel costs) associated with the leased capacity.

C. SGRM's Comments

43. SGRM is constructing the Commission-authorized Southern Pines Energy Center natural gas storage facility in Greene County, Mississippi. Upon completion of the project, a 24-inch diameter lateral pipeline will connect the Southern Pines facility with the Destin system within the path defined by the capacity lease. SGRM believes that implementation of the lease could enhance the transportation alternatives available to its Southern Pines storage customers, in that it will provide direct access to the Gulf South system.

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[28] *See, e.g., Gulf South Pipeline Company, L.P.,* 119 FERC ¶ 61,281 (2007), and *Texas Gas Transmission, LLC,* 113 FERC ¶ 61,185 (2005).

[29] *See Millennium Pipeline Company, L.P.,* 97 FERC ¶ 61,292 (2001) and *Trunkline Gas Company,* 80 FERC ¶ 61,356 (1997).

44. Although SGRM generally supports the lease, it expresses concern that the lease does not include any provision for firm deliveries to, or firm receipts from, the lateral connecting Southern Pines with Destin. The lateral is not named as a primary point in the lease, and service to points other than the primary points would be available only "on a preferential interruptible basis consistent with firm shippers' use of such Secondary Delivery Points pursuant to section 6.2 of Destin's Tariff GT&C."[30] SGRM is apprehensive that, depending on the amount of capacity ultimately established in the lease, the lease could largely preclude firm service to and from the Destin/Southern Pines interconnect, thereby relegating Southern Pines' customers to interruptible service that would almost certainly not meet their service quality needs.

45. Also of concern to SGRM is whether the language of the lease arrangement would limit third party access to the leased capacity when it is not being used by the Gulf South shipper that has subscribed to it. If the lease agreement would limit access, avers SGRM, the arrangement would be inconsistent with Commission policy requiring that unused leased capacity be made available on an open access basis to the lessee's customers. SGRM suggests as well that section 2.1 of the lease improperly provides that use of the leased capacity on anything other than a primary firm basis would be subject, not to lessee Gulf South's tariff, but rather to lessor Destin's tariff, specifically to section 6.2 of Destin's GT&C. This, SGRM asserts, is inconsistent with well-established Commission policy that interstate pipeline capacity leased to a third party interstate pipeline must be governed by the lessee pipeline's tariff.

46. In sum, SGRM asserts that the lease should be amended to identify the Destin/Southern Pines interconnect as both a primary receipt and a primary delivery point, and to provide explicitly that the tariff provisions governing use of the leased capacity are Gulf South's Rate Schedules FTS for firm and secondary services and ITS for interruptible service.

47. The Commission will not require the parties to the lease to include the Destin/Southern Pines interconnect as both a primary receipt and a primary delivery point. The specific points in the lease were negotiated by the parties and the rate for the lease reflects the economic value the parties placed on that discrete segment of capacity. SGRM and its customers are free to seek firm service arrangements with Destin for the use of such capacity, but have apparently not yet done so. Under the circumstances, the Commission does not see any reason to require the parties to alter the agreement. In addition, the Commission does not read section 2.1 of the lease as providing that the leased capacity will be governed by Destin's tariff when Gulf South's firm shippers are

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[30] Lease, Section 2.1.

not utilizing it. As SGRM notes, it is well-established Commission policy that interstate pipeline capacity leased to a third-party interstate pipeline must be governed by the lessee pipeline's tariff.[31] The reference to section 6.2 of Destin's tariff in section 2.1 of the lease is to identify the delivery points Gulf South's leased capacity will be entitled to utilize on a secondary basis, not how capacity at those points will be allocated.[32] Clearly, when Gulf South is providing service on the leased capacity, Gulf South's tariff will govern that process, and consistent with the Commission's open-access policy, Gulf South will be required to make that capacity available to others when it is not being used. Finally, the Commission stresses that this order is approving only the lease of 260,000 Dth per day. Gulf South will be required to file an amendment if it intends to increase the capacity of the lease. Any additional concerns SGRM may have about access to interstate pipeline capacity may be addressed at that time.

Environment

48. On June 20, 2006, Gulf South filed a request with the FERC to implement the Commission's Pre-filing Review Process for the Southeast Expansion Project. The Commission approved using its Pre-filing Review Process, and issued a *Notice of Intent to Prepare an Environmental Impact Statement, Request for Comments on Environmental Issues, and Notice of Public Scoping Meetings* (NOI) on September 5, 2006. The NOI was sent to affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; Native American tribes; local libraries and newspapers; and other interested parties.

49. During the prefiling review, several public meetings were held along the proposed pipeline route. In addition, in response to our NOI, we received numerous written comments from landowners, concerned citizens, and government agencies regarding the proposed projects. These comments expressed concerns with the location of the proposed pipeline and the affects of the proposed project on numerous resources and land uses including soils, waterbodies, wetlands, wildlife, vegetation, threatened and endangered species, safety and reliability and timber production.

50. As required by the National Environmental Policy Act (NEPA) and the Commission's implementing regulations, a draft Environmental Impact Statement (draft EIS) was issued on April 13, 2007. Following a 45-day public comment period, a final EIS was issued on August 3, 2007. The final EIS was prepared in cooperation with the

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[31] *See, e.g., Texas Gas Transmission, LLC,* 113 FERC ¶ 61,185, at P 10 (2005).

[32] According to section 6.2 of Destin's tariff, Gulf South will have the right to utilize all active delivery points on Destin's system.

U.S. Army Corps of Engineers, the U.S. Environmental Protection Agency (EPA), and the U.S. Fish and Wildlife Service (FWS). The Final EIS was issued on August 3, 2007. The EPA published a *Notice of Availability of the Final Environmental Impact Statement for the Proposed East Texas Expansion Project* in the *Federal Register* on August 10, 2007. Several hundred electronic and paper copies of the EIS were mailed to affected property owners, federal and state resource agencies, interested individuals and organizations, and other parties as indicated on the environmental mailing list.

51. The final EIS describes and assesses the potential impacts including potential cumulative impacts to geology, soils, water resources, wetlands, vegetation, fish and wildlife, threatened and endangered species, land use, socioeconomics, cultural resources, air quality and noise, and safety resulting from construction and operation of the proposed project. The final EIS also addresses comments provided by federal and state resource agencies during the draft EIS public comment period. Comments received during the draft EIS comment period generally expressed concern with restoration of disturbed soils, crossing of waterbodies and wetlands, impacts to threatened and endangered species, land use, and right-of-way considerations.

52. Based on information provided by Gulf South, consultations with federal, state, and local agencies and individual members of the public, and information obtained through literature research, field investigations, alternatives and environmental analyses, the final EIS concluded that if constructed in accordance with the mitigation measures recommended in the final EIS, the construction and operation of the Southeast Expansion Project would result in limited adverse environmental impact.

A. Land Use and Special Interest Areas

53. Construction of the proposed project would affect approximately 1,726 acres of land, including 1,240 acres for the pipeline construction right-of-way, 146 acres for the aboveground facilities, and 340 acres for extra work areas (additional temporary work spaces, pipe storage and contractor yards, and access roads). Following construction, all affected areas outside the permanent pipeline right-of-way and aboveground facility sites would be restored and allowed to revert to preconstruction conditions and uses.

54. The Commission received numerous comments expressing an interest in minimizing impacts associated with the construction and operation of the proposed pipeline, particularly in the instances where multiple utility rights-of-way may occur within a common corridor. In order to reduce the amount of land required for construction and operation of the proposed project, Environmental Condition Number 13 requires that Gulf South make use of up to 10 feet of existing pipeline rights-of-way for use of spoil storage as part of its 100-foot-wide nominal construction right-of-way.

55. Similarly, Environmental Condition Number 12 requires that Gulf South shall not exercise eminent domain authority granted under the NGA to acquire a permanent right-of-way greater than 50 feet in width. Gulf South proposed to use a 60-foot wide permanent pipeline right-of-way; however, the final EIS concluded that a 60-foot wide permanent right-of-way is wider than the industry standard and Gulf South was not able to justify the need for the additional width.

56. The proposed project would cross Conservation Reserve Program areas administered by the Farm Service Agency (FSA). To minimize impacts to these resources, we are requiring in Environmental Condition Number 27 that Gulf South complete consultation with the FSA regarding vegetation restoration methods.

57. Visual resources along the proposed Project route would be affected by the installation of some aboveground facilities and alteration of existing vegetative patterns associated with clearing and maintenance of the construction and permanent pipeline rights-of-way. The installation of the proposed aboveground facilities would not result in significant visual effects on residences; however, Environmental Condition Number 28 requires that prior to construction, Gulf South file with the Commission a visual screening plan to reduce the long-term adverse effects for residences in the area of the proposed Delhi Compressor Station.

B. Water Resources, Wetlands, and Vegetation

58. The proposed Project would cross 103 perennial streams, 196 intermittent streams, and 9 ponds. Most minor and intermediate waterbodies and 7 ponds would be crossed using open-cut methods. Potential effects to major and sensitive waterbodies would be largely avoided through implementation of horizontal directional drill (HDD) installation techniques, which would be used to accomplish pipeline installation across 29 waterbodies. Waterbodies that would be crossed using HDDs include each of the navigable rivers (including the Leaf and Chickasawhay Rivers, and Bucatunna and Okatuppa Creeks), two Nationwide Rivers Inventory (NRI)-listed streams (the Chickasawhay and Strong Rivers), the rivers most likely to contain habitat for federally-listed species (including Dabbs Creek, Leaf River, West Tallahala River, Chickasawhay River, Bucatunna Creek, and Strong River), and all three of the impaired waterbodies (Tallahala, Campbell, and Dabbs Creeks) that occur along the proposed project route. To ensure that impacts related to the crossing of the NRI-listed streams would be sufficiently minimized, we are requiring in Environmental Condition Number 16 that Gulf South consult further with the National Park Service (NPS) and file a report summarizing these consultations and identifying any mitigation measures Gulf South would implement. Several ponds are located in the immediate vicinity of the proposed pipeline, including some that are fed by waterbodies proposed to be crossed and could be adversely affected

by construction activities. We are requiring that Gulf South prevent sediment and heavily silt-laden water from entering these specifically identified ponds.

59. Construction of the proposed Project pipeline would affect 145 wetland areas, resulting in a total of approximately 68.9 acres of wetland disturbance, including approximately 38.6 acres of forested wetlands, 2.2 acres of mixed-type wetlands that include a forested wetland component, and an additional 28.07 acres of shrub-scrub, emergent, and open water wetlands. No wetlands would be affected by the construction or operation of the aboveground facilities. During operations, approximately 16.4 acres of forested wetlands and 0.9 acre of mixed-type wetlands containing a forested component would be contained within the maintained portion of the proposed permanent pipeline right-of-way. Potential impacts to wetlands will be avoided, minimized and mitigated through Gulf South's incorporation of numerous route variations, implementation of agency recommendations and requirements, and development of site-specific crossing plans.

60. Construction and operation of the proposed project would affect agricultural, pasture, loblolly pine-hardwood forest, hardwood slope forest, pine plantation, and open lands vegetative communities. Some vegetative communities of special concern, extensive forested tracts, and areas containing exotic and/or invasive plant species would also be affected by construction of the proposed project. Gulf South would minimize impacts to vegetation by adhering to measures described in its Upland Erosion Control, Revegetation, and Maintenance Plan. Additionally, Environmental Condition Number 21 requires Gulf South to finalize its Exotic and Invasive Species Control Plan.

C. Federally-listed Species

61. The final EIS explained that construction and operations-related activities would result in no effect to the red-cockaded woodpecker and the inflated heelsplitter; is not likely to adversely affect the Louisiana black bear, eastern indigo snake, yellow-blotched map turtle, ringed map turtle, Gulf sturgeon (including its critical habitat), bald eagle, and the wood stork; and may affect the gopher tortoise.

1. The Gopher Tortoise

62. FERC staff requested the initiation of formal consultation concerning potential impacts to the gopher tortoise with the FWS as required by section 7 of the Endangered Species Act. In its Biological Opinion (BO) issued on July 6, 2007, the FWS: concurred with our determinations of "not likely to adversely affect"; determined that the proposed project is not likely to jeopardize the continued existence of the gopher tortoise, and is not likely to adversely modify designated critical habitat; and issued an incidental take statement. The FWS also identified several non-discretionary terms and conditions

applicable to the gopher tortoise which must be adhered to for an exemption from prohibitions of section 9 of the Endangered Species Act.

63. Specifically, Gulf South must relocate gopher tortoises via mechanical excavation from their burrows within the FWS-required window of April 1 through October 15, 2007. If Gulf South is not able to complete gopher tortoise relocation activities within this window, it must stop the relocation activities until after April 1, 2008, unless granted an extension of time by the Commission in consultation with the FWS. Construction in the identified gopher tortoise habitat areas cannot commence until relocation activities have been completed. In order to provide Gulf South with the maximum amount of time to relocate gopher tortoises and allow project construction to proceed, we specify that upon acceptance of its certificate, Gulf South can begin the gopher tortoise activities approved by the FWS in its BO in those areas where right-of-way acquisition is complete and access roads identified in the FEIS can be used.

2. <u>Other Species</u>

64. Subsequent to FWS's BO, Gulf South made several modifications to the proposed project which have not yet been reviewed by the FWS. To ensure consultations are completed before construction is authorized, Environmental Condition Number 23 requires that Gulf South not begin construction on modified work areas not previously identified until all necessary consultations with the FWS are complete.

D. <u>Noise Quality</u>

65. Impacts to noise quality associated with construction of the proposed project will generally be temporary, minor, and limited to daylight hours, except at HDD sites, where drilling and related construction equipment will likely operate on a continuous basis for up to several days. However, with Gulf South's proposed noise reduction measures at the HDD sites, HDD activity impacts would be minor and temporary at all nearby noise sensitive areas (NSAs).

66. The proposed three new compressor stations will generate noise on a continuous basis during operations. However, the predicted noise levels attributable to operations of the new compressor stations should not result in significant effects on the NSAs nearest to those facilities. To ensure that noise levels are within acceptable limits, Environmental Condition Number 30 requires Gulf South to file noise survey reports within 60 days after placing the compressor stations in service to confirm that noise levels are below 55dBA.

E. Conclusion

67. We have reviewed the information and analysis contained in the final EIS regarding the potential environmental impacts of the proposed project. Based on this information, we conclude that construction and operation of the proposed project, if constructed and operated in accordance with the conditions set forth in the appendix to this order, would result in limited adverse environmental impact

68. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this certificate. The Commission encourages cooperation between interstate pipelines and local authorities. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or unreasonably delay the construction or operation of facilities approved by this Commission.[33] Gulf South shall notify the Commission's environmental staff by telephone, email, or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Gulf South. Gulf South shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

69. The Commission on its own motion received and made a part of the record in this proceeding all evidence, including the application, as supplemented, and exhibits thereto, submitted in support of the authorization sought herein, and upon consideration of the record,

The Commission orders:

(A) A certificate of public convenience and necessity is issued to Gulf South pursuant to section 7(c) of the NGA and Part 157 of the Commission's regulations to construct, install, and operate natural gas facilities as described and conditioned herein, and as more fully described in the application.

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[33] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *National Fuel Gas Supply v. Public Service Commission*, 894 F.2d 571 (2d Cir. 1990); and *Iroquois Gas Transmission System, L.P., et al.*, 52 FERC ¶ 61,091 (1990) and 59 FERC ¶ 61,094 (1992).

(B) The certificate authority in Ordering Paragraph (A) shall be conditioned on the following:

(1) Gulf South's completing the authorized construction of the proposed facilities and making them available for service within one year of the issuance of this order pursuant to paragraph (b) of section 157.20 of the Commission's regulations;

(2) Gulf South's compliance with all applicable Commission regulations, including paragraphs (a), (c), (e), and (f) of section 157.20;

(3) Gulf South's compliance with the environmental conditions listed in the appendix to this order; and

(4) Gulf South's executing firm service agreements equal to the level of service represented in its precedent agreements with its customers for service prior to construction.

(C) Gulf South shall notify the Commission's environmental staff by telephone, email, and/or facsimile of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Gulf South. Gulf South shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(D) Gulf South is directed to use its generally applicable system-wide transportation rates as initial section 7 rates for service on the expansion facilities, as discussed in the body of this order.

(E) Gulf South must file actual tariff sheets in accordance with section 154.207 of the Commission's regulations that comply with the requirements contained in the body of this order not less than 30 days and not more than 60 days prior to the commencement of interstate service.

(F) Gulf South is directed to file either its negotiated rate agreements or a tariff sheet describing the transaction not less than 30 days and not more than 60 days before service commences.

(G) Authority is granted to Destin to abandon by lease the subject capacity described in the body of this order to Gulf South.

(H) A certificate of public convenience and necessity is issued to Gulf South authorizing it to lease the subject capacity from Destin, as described and conditioned herein.

(I) Gulf South's incremental recourse rates for the capacity lease are approved as initial section 7 rates as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Acting Deputy Secretary.

Appendix – Environmental Conditions

As recommended in the EIS, this authorization includes the following conditions:

1. Gulf South shall follow the construction procedures and mitigation measures described in its application, supplemental filings (including responses to staff information requests), and as identified in the EIS, unless modified by the Order. Gulf South must:

   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary;

   b. justify each modification relative to site-specific conditions;

   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and

   d. receive approval in writing from the Director of OEP **before using that modification.**

2. The Director of OEP has delegated authority to take all steps necessary to ensure the protection of life, health, property, and the environment during construction and operation of the Project. This authority shall include:

   a. the modification of conditions of the Commission's Order; and

   b. the design and implementation of any additional measures deemed necessary (including stop work authority) to assure continued compliance with the intent of the environmental conditions as well as the avoidance or mitigation of adverse environmental impact resulting from Project construction and operation.

3. **Prior to any construction**, Gulf South shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, Environmental Inspectors (EIs), and contractor personnel will be informed of the EIs authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs before becoming involved with construction and restoration activities.

4. The authorized facility location(s) shall be as shown in the final EIS, as supplemented by filed alignment sheets, and shall include all of the staff's recommended facility locations. **As soon as they are available, and prior to the start of construction**, Gulf South shall file with the Secretary any revised detailed survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities

approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these alignment maps/sheets.

Gulf South's exercise of eminent domain authority granted under NGA section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Gulf South's right of eminent domain granted under NGA section 7(h) does not authorize it to increase the size of its natural gas pipeline to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

5. Gulf South shall file with the Secretary detailed alignment maps/sheets and aerial photographs at a scale not smaller than 1:6,000 identifying all route realignments or facility relocations, staging areas, pipe storage yards, new access roads, and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type and documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally-sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs. Each area must be approved in writing by the Director of OEP **prior to construction** in or near that area.

   This requirement does not apply to route variations required herein or minor field realignments per landowner needs and requirements that do not affect other landowners or sensitive environmental areas, such as wetlands.

   Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

   a. implementation of cultural resources mitigation measures;
   b. implementation of endangered, threatened, or special concern species mitigation measures;
   c. recommendations by state regulatory authorities; and
   d. agreements with individual landowners that affect other landowners or would affect sensitive environmental areas.

6. **Within 60 days of the acceptance of this certificate and prior to construction,** Gulf South shall file an initial Implementation Plan with the Secretary for review and written approval by the Director of OEP describing how Gulf South will implement

the mitigation measures required by the Order. Gulf South must file revisions to the plan as schedules change. The plan shall identify:

a. how Gulf South will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to on-site construction and inspection personnel;

b. the number of EIs assigned per spread and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

c. company personnel, including EIs and contractors, who will receive copies of the appropriate material;

d. the training and instructions Gulf South will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel changes), with the opportunity for OEP staff to participate in the training session;

e. the company personnel (if known) and specific portion of Gulf South's organization having responsibility for compliance;

f. the procedures (including use of contract penalties) Gulf South will follow if non-compliance occurs; and

g. for each discrete facility, a Gantt or PERT chart (or similar project scheduling diagram), and dates for:

(1) the completion of all required surveys and reports;

(2) the mitigation training of on-site personnel;

(3) the start of construction; and

(4) the start and completion of restoration.

7. Gulf South shall employ one or more EIs per construction spread. The environmental inspectors shall be:

a. responsible for monitoring and ensuring compliance with all mitigative measures required by the Order and other grants, permits, certificates, or other authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. a full-time position, separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

8. Gulf South shall file updated status reports with the Secretary on a **weekly basis until all construction-related activities, including restoration, are complete for each phase of the Project**. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

   a. the current construction status of each spread, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally-sensitive areas;

   b. a listing of all problems encountered and each instance of non-compliance observed by the EI(s) during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

   c. a description of corrective actions implemented in response to all instances of non-compliance, and their cost;

   d. the effectiveness of all corrective actions implemented;

   e. a description of any landowner/resident complaints that may relate to compliance with the requirements of the Order, and the measures taken to satisfy their concerns; and

   f. copies of any correspondence received by Gulf South from other federal, state, or local permitting agencies concerning instances of non-compliance, and Gulf South's response.

9. Gulf South must receive written authorization from the Director of OEP **before commencing service from** the Project. Such authorization will only be granted following a determination that rehabilitation and restoration of areas affected by the Project are proceeding satisfactorily.

10. **Within 30 days of placing the certificated facilities in service**, Gulf South shall file an affirmative statement with the Secretary, certified by a senior company official:

a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; and

b. identifying which of the certificate conditions Gulf South has complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for non-compliance.

11. Gulf South shall develop and implement an environmental complaint resolution procedure. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the Project and restoration of the right-of-way. **Prior to construction,** Gulf South shall mail the complaint procedures to each landowner whose property would be crossed by the Project.

a. In its letter to affected landowners, Gulf South shall:

(1) provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

(2) instruct the landowners that if they are not satisfied with the response, they should call Gulf South's Hotline; the letter should indicate how soon to expect a response; and

(3) instruct the landowners that if they are still not satisfied with the response from Gulf South's Hotline, they should contact the Commission's Enforcement Hotline at (888) 889-8030, or at hotline@ferc.gov.

b. In addition, Gulf South shall include in its weekly status a table that contains the following information for each problem/concern:

(1) the date of the call;

(2) the identification number from the certificated alignment sheets of the affected property and approximate location by MP;

(3) the description of the problem/concern; and

(4) an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

12. Gulf South shall not exercise eminent domain authority granted under section 7(h) of the NGA to acquire a permanent right-of-way greater than 50 feet in width. ***(Section 2.2.1)***

13. **Prior to construction**, Gulf South shall file with the Secretary for review and written approval by the Director of OEP:

    a. revised alignment sheets and cross-section diagrams showing the use of at least 10 feet of Transcontinental Pipe Line Company's (Transco's) and Crosstex Mississippi's (Crosstex's) maintained permanent right-of-way for at least spoil storage, as part of its 100-foot-wide construction right-of-way; and

    b. site-specific justification by milepost for areas where Gulf South believes use of the existing maintained permanent right-of-way to be infeasible for spoil storage. ***(Section 2.2.1)***

14. Gulf South shall conduct, with the well-owner's permission, pre- and post-construction well monitoring of well yield and water quality for wells identified in Table 3.3.1.1-1. **Prior to construction**, Gulf South shall file with the Secretary, for review and written approval by the Director of OEP, a well monitoring and mitigation plan that describes standard testing procedures, and the measures that would be taken should a well be impacted such that it is no longer operable or that it becomes impaired. Gulf South shall offer this plan to the landowners before construction. Gulf South shall also file a report with the Secretary, **within 30 days of placing its pipeline facilities in service**, identifying all private or domestic water wells or systems damaged by construction and describing how they were repaired. The report shall include a discussion of any complaints concerning well yield or quality and how each problem was resolved. ***(Section 3.3.1.2)***

15. **Prior to construction,** Gulf South shall file along with its site-specific construction plans for the Delhi, Harrisville, and Destin Compressor Stations a description of the measures that it would take to avoid impacts to waterbodies affected by these facilities. ***(Section 3.3.2.1)***

16. **Prior to construction,** Gulf South shall complete consultation with the NPS regarding its proposed HDD crossings of, and hydrostatic test water withdrawals from, the NRI-listed Strong and Chickasawhay Rivers, and file copies of those consultations with the Secretary. If applicable, Gulf South shall also file plans to address any additional mitigation measures recommended by the NPS. ***(Section 3.3.2.1)***

17. **Prior to construction,** Gulf South shall file with the Secretary copies of approvals or concurrences from the ADCNR indicating that in-stream construction between December 1 and May 31 is acceptable. ***(Section 3.3.2.2)***

18. Gulf South shall prevent sediment and heavily silt-laden water from entering ponds adjacent to areas disturbed by construction activities. Gulf South shall conduct the open-cut crossing of the waterbodies feeding these ponds (at the following mileposts: 6.8, 12.5, 15.0, 25.0, 40.9, 41.6, 51.2, 53.4, 59.5, 60.0, 63.5, 65.1, 75.1, 77.1, 86.9, 87.1, 98.6, and 110.0) in a manner that prevents sediment and heavily silt-laden water from entering the ponds. ***(Section 3.3.2.2)***

19. Gulf South shall not begin an open-cut crossing of any of the waterbodies proposed to be crossed using HDD until it files an amended crossing plan with the Secretary for review and written approval by the Director of OEP. The amended crossing plan shall include site-specific drawings identifying all areas that would be disturbed using the proposed alternate crossing method. Gulf South shall file the amended crossing plan concurrent with the appropriate state and federal applications required for implementation of the plan. ***(Section 3.3.2.3)***

20. **Prior to construction,** Gulf South shall consult further with the Mississippi Department of Wildlife, Fisheries, and Parks (MDWFP), the Louisiana Department of Wildlife and Fisheries (LDWF), the Alabama Department of Conservation and Natural Resources (ADCNR), the Natural Resource Conservation Service (NRCS), and other appropriate agencies, regarding seeding and vegetation restoration practices for the proposed Project. Gulf South shall file a report with the Secretary for review and written approval by the Director of OEP that describes the outcome of these consultations and identifies the agency-recommended seeding and vegetation restoration practices that Gulf South plans to implement. ***(Section 3.5.2)***

21. **Prior to construction,** Gulf South shall file with the Secretary, for review and written approval by the Director of OEP, an Exotic and Invasive Species Control Plan developed in consultation with the FWS, the LDWF, the MDWFP, the ADCNR, and the NRCS. This plan shall identify the specific measures that Gulf South would implement during construction and operation to control exotic and invasive plant species. ***(Section 3.5.4)***

22. **Prior to construction,** Gulf South shall file a revised Conservation Strategy for the Gopher Tortoise and Eastern Indigo Snake that incorporates all non-discretionary terms and conditions of the FWS's BO for this Project, as well as conservation recommendations 1 and 2. ***(Section 3.7.1)***

23. Gulf South shall not begin construction activities on modified work areas **until:**

    a. the staff completes Section 7 consultations with the FWS; and

b. Gulf South has received written notification from the Director of OEP that construction or use of mitigation may begin. ***(Section 3.7.1)***

24. Gulf South shall continue to consult with the LDWF, the MDWFP, and the ADCNR to determine the need for surveys or mitigation that would substantially minimize or avoid potential impacts to state-listed species. Gulf South shall file copies of the results of these consultations, as well as any associated survey reports and mitigation plans with the Secretary, **prior to construction.** ***(Section 3.7.2)***

25. **Prior to construction**, Gulf South shall consult with the Delhi Municipal Airport officials and the FAA regarding impacts of the proposed Project, specifically the proposed Delhi Compressor Station, on airport operations, and file a site-specific construction plan that addresses any concerns identified by those authorities with the Secretary. ***(Section 3.8.4)***

26. **Prior to construction**, Gulf South shall consult with the Thigpen Field Airport officials and the FAA regarding impacts of the proposed Project on airport operations, and file a site-specific construction plan that addresses any concerns identified by those authorities with the Secretary. ***(Section 3.8.4)***

27. Gulf South shall consult with the FSA to determine appropriate seed mixes and/or revegetation efforts that should be implemented on CRP lands to minimize and mitigate construction and operations impacts. Gulf South shall also retain and have available for inspection any records of consultation(s) with the FSA indicating specific measures agreed upon by Gulf South and the FSA that would be implemented on CRP lands. ***(Section 3.8.4)***

28. **Prior to construction,** Gulf South shall file with the Secretary for review and written approval by the Director of OEP a visual screening plan to reduce the long-term adverse effects on the visual quality of residences located along Highway 17 that would result from installation of the Delhi Compressor Station. ***(Section 3.8.6.1)***

29. Gulf South shall **defer** implementation of any treatment plans/measures (including archaeological data recovery), construction of facilities, and use of all staging, storage, or temporary work areas and new or to-be-improved access roads **until**:

a. Gulf South files with the Secretary cultural resources survey and evaluation reports, any necessary treatment plans, and the Mississippi and Alabama SHPO comments on the reports and plans; and

b. The Director of OEP reviews and approves all cultural resources survey reports and plans and notifies Gulf South in writing that treatment plans/procedures may be implemented and/or construction may proceed.

All material filed with the Secretary containing location, character, and ownership information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "**CONTAINS PRIVILEGED INFORMATION - DO NOT RELEASE.**" ***(Section 3.10.4)***

30. Gulf South shall file noise surveys with the Secretary **no later than 60 days** after placing each of the Delhi, Harrisville, and Destin Compressor Stations in service. If the noise attributable to operation of all of the equipment at any compressor station at full load exceeds a day-night sound level (L_{dn}) of 55 decibels on the A-weighted scale (dBA) at any nearby NSA, Gulf South shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within one year of the in-service date.** Gulf South shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. ***(Section 3.11.3)***

ORIGINAL

GULF SOUTH PIPELINE

December 3, 2008

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: **Gulf South Pipeline Company, LP**
Docket No. CP07-32-007
Compliance Filing

Dear Ms. Bose:

Gulf South Pipeline Company, LP ("Gulf South") hereby submits as part of its Federal Energy Regulatory Commission ("Commission") Gas Tariff, Sixth Revised Volume No. 1, an original and five (5) copies of the tariff sheets listed below to be effective May 27, 2008:

Sixth Revised Volume No. 1
Second Substitute Fourteenth Revised Sheet No. 20
Second Substitute Eleventh Revised Sheet No. 21
Second Substitute Eleventh Revised Sheet No. 23
Second Substitute Ninth Revised Sheet No. 24
Substitute Original Sheet No. 24B

Statement of Nature, Reasons and Basis

On November 18, 2008, the Commission issued an order rejecting Gulf South's revised tariff sheets,[1] which Gulf South had submitted in an attempt to comply with the Commission's letter order issued June 30, 2008.[2] In the November 18 Order, the Commission stated that "the incremental rate established for the Southeast Expansion Project applies to those parties contracting for firm primary receipt and delivery point capacity on the expansion facilities."[3] Further, the Commission stated that "shippers that currently pay the generally applicable rate for

[1] *Gulf South Pipeline Co., LP*, 125 FERC ¶ 61,199 (2008)("November 18 Order").
[2] *Gulf South Pipeline Co., LP*, 123 FERC ¶ 61,322 (2008).
[3] November 18 Order at P 11.

capacity in Gulf South's Zone 3 and utilize the expansion facilities on a secondary basis may not be required to pay the additional incremental rate to do so."[4] Gulf South has modified its Southeast Expansion rate sheet (Sheet No. 24B) consistent with these holdings.[5] Accordingly, the Commission should accept the modified rate sheet as just and reasonable.

In addition, Gulf South is submitting other substitute tariff sheets for those that were rejected in the November 18 Order without discussion, which contained language that must be deleted in order to completely remove incremental-plus pricing of the Southeast Expansion Project from all of Gulf South's rate sheets.[6]

Components of the Filing

Pursuant to the provisions of Section 154.201 of the Commission's Regulations, Gulf South includes with this filing the following items:

- The proposed tariff sheets;
- A marked version of the tariff sheets showing additions and deletions; and
- A diskette containing the proposed tariff sheets.

Consistent with Section 385.2005(a) of the Commission's regulations, the undersigned has read this filing and knows its contents are true as stated to the best of his knowledge and belief; and the undersigned certifies that the paper copies contain the same information as contained on the enclosed diskette.

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[4] *Id.*

[5] In a separate filing in the near future, Gulf South will submit additional information to support its argument that a portion of the Southeast Expansion Project's facilities should be designated as Zone 4 facilities. If the Commission determines that Zone 4 designation is appropriate, Gulf South will make any necessary corresponding revisions to its rate sheets.

[6] The substitute sheets submitted herein are effective as of May 27, 2008. Gulf South also previously filed revised rate sheets in its ACA filing (Docket No. RP08-525-000) which became effective after the substitute sheets, on October 1, 2008. The revised sheets dated October 1, 2008 and submitted in the ACA filing already incorporate the deletion included in this filing.

Service

Pursuant to Section 385.2010 of the Commission's regulations, Gulf South has served copies of this filing upon each person designated on the official service list compiled by the Secretary in this proceeding. In addition, copies of the instant filing are available during regular business hours for public inspection in Gulf South's offices in Houston, Texas.

Respectfully submitted,

GULF SOUTH PIPELINE COMPANY, LP

J. Kyle Stephens

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES - RATE SCHEDULE FTS

The Maximum Reservation Charge (per Dth of Contract Quantity)

Zone	1	2	3	4
1	$ 6.0918	$7.8456	$10.2702	$11.1295
2	$ 7.8456	$4.3075	$ 6.7321	$ 7.5914
3	$10.2702	$6.7321	$ 4.9383	$ 8.2222
4	$11.1295	$7.5914	$ 8.2222	$ 5.7976

The Minimum Reservation Charge for all paths is $0.00.

The Minimum Commodity/Usage Charge (per Dth)

Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0054	$0.0024	$0.0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted on commodity charges.

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

Gulf South may from time to time identify point pair transactions where the fuel rate shall be zero ("Zero Fuel Point Pair Transactions").

Lake Charles Transactions and Zero Fuel Point Pair Transactions will be assessed the lost and unaccounted for charge of .27%.

The above charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE FTS - SMALL CUSTOMER RATE OPTION

The Maximum Commodity/Usage/ (per Dth)

Zone	1	2	3	4
1	$0.6012	$0.7803	$1.0217	$1.1044
2	$0.7803	$0.4272	$0.6687	$0.7514
3	$1.0217	$0.6687	$0.4896	$0.8137
4	$1.1044	$0.7514	$0.8137	$0.5723

The Minimum Base Commodity/Usage Charge (per Dth)

Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0064	$0.0024	$0.0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted below the minimum Commodity/Usage Charge.

Average system rate = $0.7242, 33.3% load factor.

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

Gulf South may from time to time identify point pair transactions where the fuel rate shall be zero ("Zero Fuel Point Pair Transactions").

Lake Charles Transactions and Zero Fuel Point Pair Transactions will be assessed the lost and unaccounted for charge of .27%.

The above charges shall be increased to include an incremental transportation charge of: $0.065 per Dth for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE FTS-SUMMER SEASON OPTION

The Maximum Reservation Charge (per Dth of Contract Quantity)

Zone	1	2	3	4
1	$ 6.0518	$7.8456	$10.2702	$11.1295
2	$ 7.8456	$4.3075	$ 6.7321	$ 7.5914
3	$10.2702	$6.7321	$ 4.9383	$ 8.2222
4	$11.1295	$7.5914	$ 8.2222	$ 5.7976

The Minimum Reservation Charge for all paths is $0.00.

The Minimum Commodity/Usage Charge (per Dth)

Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0064	$0.0024	$0.0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted on commodity charges.

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

Gulf South may from time to time identify point pair transactions where the fuel rate shall be zero ("Zero Fuel Point Pair Transactions").

The above charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

Gulf South Pipeline Company LP
FERC Gas Tariff
Sixth Revised Volume No. 1

2 Sub Ninth Revised Sheet No. 24
Superseding
Eighth Revised Sheet No. 24

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE NNS

	RESERVATION CHARGE (per Dth of Contract Quantity)		COMMODITY / (per Dth)	
	Maximum 1	Minimum	Maximum 1	Minimum
RATE SCHEDULE NNS 2/	$6.84	$0.00	$.0064	$.0064
SMALL CUSTOMER RATE OPTION			$.6810	$.0064

The 100% Load Factor rate is $.23170.

The above Commodity charges for the Small Customer Rate Option shall be increased to include an incremental transportation charge of: $.1659 per Dth for utilization of the Southeast Expansion Facilities.

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%

The above Reservation charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

The above Commodity charges for the Small Customer Rate Option shall be increased to include an incremental transportation charge of: $0.065 per Dth for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

For receipts from or deliveries to SLN's 15912, 17149, 17153, 17154, 17155, 17156, 17157, 17158, 21262, 21264 (Mobile Bay), the above rates shall be increased to include an incremental transportation charge of:

	Reservation Charge (per Dth of Contract Quantity)		Commodity (per Dth)	
	Maximum	Minimum	Maximum	Minimum
Rate Schedule NNS	$0.7612	$0.00	$0.0001	$0.0001
Small Customer Rate Option			$0.0752	$0.0001

The above rates are stated at 14.73 psia. For billing purposes the above rates may require adjustment based on the measurement pressure base provided in a contract.

For receipts from or deliveries to SLN 464 (Bastian Bay), the above rates shall be increased to include an incremental transportation charge of:

	Reservation Charge (per Dth of Contract Quantity)		Commodity (Per Dth)	
	Max.	Min.	Max.	Min.
Rate Schedule NNS	$0.652	$0.000	$0.000	$0.000
Small Cust. Rate Option			$0.064	$0.000

Issued by: J. Kyle Stephens, Vice President of Rates
Issued on: December 3, 2008 Effective on: May 27, 2008
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. CP07-32-005, issued November 18, 2008, 25 FERC ¶ 61,199

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
APPLICABLE TO SOUTHEAST EXPANSION FIRM
TRANSPORTATION SERVICES RATES SCHEDULES FTS and NNS

Firm transportation Customers that contract for firm primary capacity on the Southeast Expansion facilities shall be charged an incremental daily rate as set forth below. Such incremental rate shall not be applicable to firm customers utilizing the Southeast Expansion facilities on a supplemental basis.

	Max.	Min.
Incremental Daily Rate	$0.1659	$0.0000

Other charges may apply for use of the Southeast Expansion facilities pursuant to Rate Schedules FTS and NNS as set forth on Sheet Nos. 20, 20A, 21, 21A, 23, 23A, 24, and 24A.

Issued by: J. Kyle Stephens, Vice President of Rates
Issued on: December 3, 2008 Effective on: May 27, 2008
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. CP07-32-005, issued November 18, 2008, 25 FERC ¶ 61,199

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES - RATE SCHEDULE FTS

The Maximum Reservation Charge (per Dth of Contract Quantity)

Zone	1	2	3	4
1	$ 6.0518	$7.8456	$10.2702	$11.1295
2	$ 7.8456	$4.3075	$ 6.7321	$ 7.5914
3	$10.2702	$6.7321	$ 4.9383	$ 8.2222
4	$11.1295	$7.5914	$ 8.2222	$ 5.7976

The Minimum Reservation Charge for all paths is $0.00.

The Minimum Commodity/Usage Charge (per Dth)

Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0064	$0.0024	$0,0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted on commodity charges.

~~The above charges shall be increased to include an incremental transportation charge of: $5.0474 (per Dth of Contract Quantity) for utilization of the Southeast Expansion Facilities.~~

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the Applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

Gulf South may from time to time identify point pair transactions where the fuel rate shall be zero ("Zero Fuel Point Pair Transactions").

Lake Charles Transactions and Zero Fuel Point Pair Transactions will be assessed the lost and unaccounted for charge of .27%.

The above charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE FTS - SMALL CUSTOMER RATE OPTION

The Maximum Commodity/Usage/ (per Dth)

Zone	1	2	3	4
1	$0.6012	$0.7803	$1.0217	$1.1044
2	$0.7803	$0.4272	$0.6687	$0.7514
3	$1.0217	$0.6687	$0.4896	$0.8137
4	$1.1044	$0.7514	$0.8137	$0.5723

The Minimum Base Commodity/Usage Charge (per Dth)

Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0064	$0.0024	$0.0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted below the minimum Commodity/Usage Charge.

Average system rate - $0.7242, 33.3% load factor.

~~The above charges shall be increased to include an incremental transportation charge of $.1659 per Dth for utilization of the Southeast Expansion Facilities.~~

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

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Lake Charles Transactions and Zero Fuel Point Pair Transactions will be assessed the lost and unaccounted for charge of .27%.

The above charges shall be increased to include an incremental transportation charge of: $0.065 per Dth for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE FTS-SUMMER SEASON OPTION

The Maximum Reservation Charge (per Dth of Contract Quantity)

Zone	1	2	3	4
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The Minimum Reservation Charge for all paths is $0.00.

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Zone	1	2	3	4
1	$0.0043	$0.0064	$0.0086	$0.0066
2	$0.0064	$0.0024	$0.0046	$0.0026
3	$0.0086	$0.0046	$0.0025	$0.0027
4	$0.0066	$0.0026	$0.0027	$0.0004

Discounts can not be granted on commodity charges.

~~The above charges shall be increased to include an incremental transportation charge of: $1.0474 (per Dth of Contract Quantity) for utilization of the Southeast Expansion Facilities.~~

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%.

For transactions where gas is both received and delivered at points located on pipeline Indices 192, 193, 194, 195, 196 and 198, in the Lake Charles, Louisiana area, the fuel rate shall be zero ("Lake Charles Transactions").

Gulf South may from time to time identify point pair transactions where the fuel rate shall be zero ("Zero Fuel Point Pair Transactions").

The above charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
RATE SCHEDULE NNS

	RESERVATION CHARGE (per Dth of Contract Quantity)		COMMODITY / (per Dth)	
	Maximum 1	Minimum	Maximum 1	Minimum
RATE SCHEDULE NNS 2/	$6.84	$0.00	$.0064	$.0064
SMALL CUSTOMER RATE OPTION			$.6810	$.0064

The 100% Load Factor rate is $.23170.

~~The above Reservation charges shall be increased to include an incremental transportation charge of: $5.0474 (per Dth of Contract Quantity) for utilization of the Southeast Expansion Facilities.~~

The above Commodity charges for the Small Customer Rate Option shall be increased to include an incremental transportation charge of: $.1659 per Dth for utilization of the Southeast Expansion Facilities.

The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 26 of the General Terms and Conditions and the applicable Fuel and Company Used Gas allowance of 1.60%

The above Reservation charges shall be increased to include an incremental transportation charge of: $1.97708 (per Dth of Contract Quantity) for utilization of the Destin lease.

The above Commodity charges for the Small Customer Rate Option shall be increased to include an incremental transportation charge of: $0.065 per Dth for utilization of the Destin lease.

An incremental Fuel and Company Used Gas allowance will apply to transactions utilizing the Destin lease at the fuel rate charged pursuant to the Destin FT-1 rate schedule, currently 0.2%, not to exceed three tenths (0.30%) percent.

For receipts from or deliveries to SLN's 15912, 17149, 17153, 17154, 17155, 17156, 17157, 17158, 21262, 21264 (Mobile Bay), the above rates shall be increased to include an incremental transportation charge of:

	Reservation Charge (per Dth of Contract Quantity)		Commodity (per Dth)	
	Maximum	Minimum	Maximum	Minimum
Rate Schedule NNS	$0.7612	$0.00	$0.0001	$0.0001
Small Customer Rate Option			$0.0752	$0.0001

The above rates are stated at 14.73 psia. For billing purposes the above rates may require adjustment based on the measurement pressure base provided in a contract.

For receipts from or deliveries to SLN 464 (Bastian Bay), the above rates shall be increased to include an incremental transportation charge of:

	Reservation Charge (per Dth of Contract Quantity)		Commodity (Per Dth)	
	Max.	Min.	Max.	Min.
Rate Schedule NNS	$0.652	$0.000	$0.000	$0.000
Small Cust. Rate Option			$0.064	$0.000

Gulf South Pipeline Company LP
Sixth Revised Volume No. 1

Substitute Original Sheet No. 24B
Original Sheet No. 24B
(Rejected)
Issued: July 15, 2008
Page 1

~~GULF SOUTH PIPELINE COMPANY LP~~
~~STATEMENT OF EFFECTIVE RATES~~
~~APPLICABLE TO INCREMENTAL SOUTHEAST EXPANSION FIRM~~
~~TRANSPORTATION SERVICES RATES SCHEDULES FTS and NNS~~

~~Firm transportation services using receipts from or delivery to GSP's 33188, 33130, 33129, 33163, 33164, 33165, 33166, and 33331 accessed via the Southeast Expansion and any paths which utilize the Southeast Expansion facilities shall be charged a daily rate of $0.1659 per Dth.~~

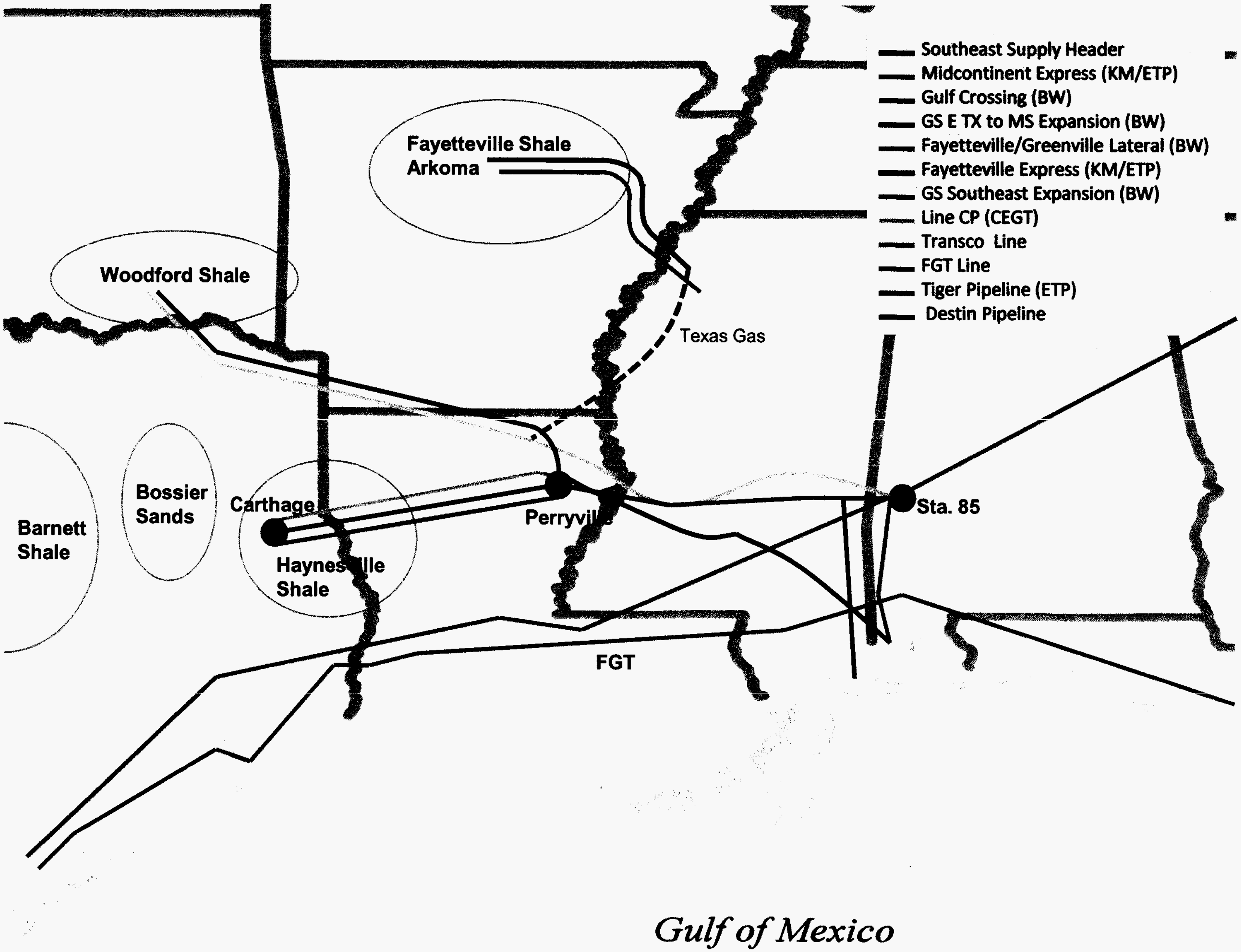
~~The above charges shall be increased to include the ACA unit rate of $.0019 per Dth pursuant to Section 35 of the General Terms and Conditions.~~

GULF SOUTH PIPELINE COMPANY LP
STATEMENT OF EFFECTIVE RATES
APPLICABLE TO SOUTHEAST EXPANSION FIRM
TRANSPORTATION SERVICES RATES SCHEDULES FTS and NNS

Firm transportation Customers that contract for firm primary capacity on the Southeast Expansion facilities shall be charged an incremental daily rate as set forth below. Such incremental rate shall not be applicable to firm customers utilizing the Southeast Expansion facilities on a supplemental basis.

	Max.	Min.
Incremental Daily Rate	$0.1659	$0.0000

Other charges may apply for use of the Southeast Expansion facilities pursuant to Rate Schedules FTS and NNS as set forth on Sheet Nos. 20, 20A, 21, 21A, 23, 23A, 24, and 24A.


Southeast Supply Header
Midcontinent Express (KM/ETP)
Gulf Crossing (BW)
GS E TX to MS Expansion (BW)
Fayetteville/Greenville Lateral (BW)
Fayetteville Express (KM/ETP)
GS Southeast Expansion (BW)
Line CP (CEGT)
Transco Line
FGT Line
Tiger Pipeline (ETP)
Destin Pipeline
Fayetteville Shale
Arkoma
Woodford Shale
Texas Gas
Bossier Sands
Barnett Shale
Carthage
Perryville
Sta. 85
Haynesville Shale
FGT
Gulf of Mexico

Natural Gas Market Centers: A 2008 Update

This special report looks at the current status of market centers in today's natural gas marketplace, examining their role and their importance to natural gas shippers, pipelines, and others involved in the transportation of natural gas over the North American pipeline network. Questions or comments on the contents of this article should be directed to James Tobin at james.tobin@eia.doe.gov or (202) 586-4835.

Natural gas market centers first began to develop in the late 1980s following the implementation of the initial open-access transportation initiative under the Federal Energy Regulatory Commission's (FERC) Order 436 (1985).[1] Market centers since have become a key component of the North American natural gas transportation network (see box, "Market Center Development"). Located at strategic points on the pipeline grid, these centers offer essential transportation service for shippers between pipeline interconnections, as well as provide these shippers with many of the physical and administrative support services formerly handled by the natural gas pipeline company as "bundled" sales services.[2]

The day-to-day operations of a market center are usually managed by two separate parties: the center's administrator, who provides customer contact and handles administrative tasks, and a pipeline operator who carries out the physical operations at the direction of the administrator. Both the operational infrastructure among market centers and the services offered vary considerably (see box, "Market Center Configurations").

The key services offered by most market centers include the physical coverage of short-term receipt/delivery balancing needs such as parking and loaning services, compression services, and pooling (see box, "Market Center Services"). Many of these market centers also provide new and innovative services that expedite and improve the natural gas transportation process. For instance, many market centers include access to internet-based natural gas trading platforms and capacity release programs, in addition to interactions that support title transfer services between parties who buy, sell, or move their natural gas through the center.

Overview

For a market center to be successful, liquidity is very important. A market center's location must be able to sustain sufficient trading interest among natural gas customers to successfully generate enough transportation and other service revenues to support its business interests. It cannot remain in business in the long-term if it cannot provide shippers (buyers/sellers) the opportunity to route their shipments to alternative destinations with the best price opportunities and provide basic support services such as title transfer, parking, and loaning of natural gas on a short-term basis.

In 2008, there were 33 operational market centers in the United States and Canada (Table 1, Figure 1), 9 in Canada and 24 in the United States.[3] While the number of operational centers in the United States and Canada has remained essentially the same since the late 1990s, there have been significant expansions at many of these market centers, especially at several strategic locations along the natural gas pipeline transportation network. For instance:

- **At least four existing market centers in the United States experienced more than a doubling of daily throughput volumes or pipeline interconnection capacity (Table 2).** The Perryville Hub, owned and operated by Centerpoint Energy Inc., experienced the largest growth. Located in northern Louisiana, this market center has benefited from being along a major natural gas transportation corridor. This corridor links the expanding production of the east Texas' Barnett shale and Bossier formation areas with many new and existing major interstate natural gas pipeline interconnections that provide transportation to the Southeast and Northeast regions.

- **One new market center became active in the United States (Table 1) during the past 5 years.** The newest market center is the White River Hub, located in western Colorado, owned by a partnership between Enterprise Products Partners, LP and Questar Gas Company. The White River Hub was created to provide natural gas producers in the Piceance and Uinta basins access to the multiple intrastate and interstate pipelines

[1] See Energy Information Administration, *Natural Gas: Major Legislative and Regulatory Actions (1935 - 2008)* http://www.eia.doe.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ferc436.html

[2] In 1992, the Federal Energy Regulatory Commission issued its Order 636, which required interstate natural gas pipeline companies to transform themselves from buyers and sellers of natural gas (bundlers) to strictly common-carrier transporters offering unbundled services.

[3] The Energy Information Administration (EIA) last examined market centers in 2004. See EIA, *Natural Gas Market Centers and Hubs: A 2003 Update*. The Federal Energy Regulatory Commission previously explored the subject with its report "The Development of Market Centers and Electronic Trading in Natural Gas Market," Office of Economic Policy Discussion Paper 99-01, 1999.

Table 1. Administrative Profile of Operational Natural Gas Market Centers in the United States and Canada, 2008

Region/ State/ Province	Market Center	Administrator	On Line Customer Service System	Type of Infrastructure	Type of Operation	Year Started	Associated Processing Plant	Associated Storage	
								Sites Names	Type of Storage Field(s)
Central									
Colorado	Cheyenne Hub	Colorado Interstate Gas Co	CIG-Xpress	Header	Market Hub	2000	No	Young/Ltigo/Huntsman	Indirect
Colorado	White River Hub	White River Hub LLC	Questor	Header	Production Hub	2008	Meeker	None	N/A
Kansas	Mid-Continent Center	Oneok Gas Transportation LLC	Caminus	Partial Pipeline	Market Center	1995	Spivey/Frontier	Brehm, Konold	Depleted Field
Wyoming	Opal Hub	Williams Field Services Co	GasKit	Header	Production Hub	1999	Opal	None	N/A
Midwest									
Illinois	ANR Joliet Hub	ANR Pipeline Co	Gems	Partial Pipeline	Market Center	2003	Aux Sable	Linepack & Michigan Sites	Various
Illinois	Chicago Hub	Enerchange Inc	"Gas Exchange"	Partial Pipeline	Market Center	1993	No	Unused WG capacity	Mixed
Northeast									
New York	Iroquois Center	Iroquois Gas Trans Co	Iroquois OnLine	Entire Pipeline	Market Center	1996	No	Avg. 200MMcf/d - Linepack	Linepack
Pennsylvania	Dominion Hub	Dominion Transmission Inc	EScript	Entire Pipeline	Market Center	1994	No	All Dominion Sites	Depleted Field
Southwest									
Louisiana	Egan Hub	Egan Hub Partners LP	LINK System	Header	Storage Hub	1995	No	Egan storage	Salt Dome
Louisiana	Henry Hub	Sabine Hub Services Inc	HubLink	Header	Market Center	1988	No	Jefferson Island	Salt Dome
Louisiana	Jefferson Island	Jefferson Island Storage & Hub LLC	Latitude	Header	Storage Hub	1998	No	Jefferson Island	Salt Dome
Louisiana	Nautilus Hub	Enbridge Offsore Pipelines	Quorum System	Header	Production Hub	2000	Neptune	None	N/A
Louisiana	Perryville Center	Centerpoint Energy Gas Trans	ServiceLynx	Partial Pipeline	Market Center	1994	No	Ruston, Ada, Childes	Depleted Field
New Mexico	Blanco Hub	Transwestern Gas Pipeline Co	TW Transfer	Header	Production Hub	1993	Kutz/Milagro	System Linepack	Linepack
East Texas	Aqua Dulce Hub	ConocoPhillips Inc	Fax-phone only	Header	Production Hub	1990	King Ranch	None	N/A
East Texas	Carthage Hub	DCP Midstream Partners LP	Fax-phone only	Header	Production Hub	1990	Carthage	Indirect	N/A
East Texas	Katy (DCP) Hub	DCP Midstream LP	Fax-phone only	Header	Production Hub	1995	Katy	None	N/A
East Texas	Katy Storage Center	ENSTOR Energy Inc	Latitude	Header	Storage Hub	1993	No	Katy	Depleted Field
East Texas	Moss Bluff Hub	Moss Bluff Hub Partners LP	LINK System	Header	Storage Hub	1994	No	Moss Bluff	Salt Dome
West Texas	Waha (EPGT) Texas Hub	Enterprise Products Pipeline LP	StarWeb	Partial Pipeline	Production Hub	1995	Waha	Boling	Salt Dome
West Texas	Waha (DCP/Atmos) Hub	DCP Midstream LP	CAMINUS	Header	Production Hub	1995	No	None	N/A
Western									
California	California Energy Hub	Southern California Gas Co	ENVOY	Entire Pipeline	Market Center	1994	No	All SoCal fields-Interruptible	Depleted Field
California	Golden Gate Center	California Gas Transmission Co	PipeRanger	Entire Pipeline	Market Center	1996	No	All PG&E- Interr & Linepack	Depleted Field
Oregon	GTNW Market Center	Gas Transmission - NW	Pacific Express	Entire Pipeline	Market Center	1994	No	System Linepack Only	N/A
Canada									
Alberta	AECO-C Hub	Encana Energy Co	AECO-LINK	Entire Pipeline	Market Center	1990	No	Suffield, Countess	Depleted Field
Alberta	Alberta Hub	ENSTOR Energy Inc	Latitude	Header	Storage Hub	1997	No	Alberta Hub	Depleted Field
Alberta	Alberta Market Centre	Alco Midstream Ltd	Fax-phone only	Header	Storage Hub	1998	No	Carbon Facility	Depleted Field
Alberta	Crossfield Hub	Crossalta Gas Storage & Services	Fax-phone only	Header	Storage Hub	1995	No	East Crossfield	Depleted Field
Alberta	Empress Center	Transcanada Gas Pipelines Ltd	NRGhighway	Header	Market Hub	1986	No	Linepack	Depleted Field
Alberta	Intra-Alberta Center	Transcanada Gas Pipelines Ltd	NGX Trading Sys	Partial Pipeline	Market Center	1994	No	Indirect	Depleted Field
British Columbia	Sumas Center	Spectra Energy Corp	Yes-Non Specific	Partial Pipeline	Market Hub	1994	McMahon,Kwoen	Aitken Creek- Indirectly	Depleted Field
Alberta2Quebec	TransCanada Center	Transcanada Gas Pipelines Ltd	NRGhighway	Entire Pipeline	Market Center	1998	No	Indirect only	N/A
Ontario	Dawn Market Center	Spectra Energy Corp	Unionline	Entire Pipeline	Market Center	1985	No	Dawn (18 Pools)	Depleted Field

N/A = Not applicable, Interr = interruptible, WG = working gas. See Table 2 and Figure 2 for additional detail.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Hubs Database, December 2008.

Market Center Development

The installation of market centers and hubs is a relatively recent development in the natural gas industry. Although the concept first evolved in the late 1980s, it was fast tracked after the issuance of FERC Order 636 issued in 1992. Market centers and hubs quickly became a key element in providing novice natural gas shippers with many of the physical capabilities and administrative support services formerly handled by the interstate pipeline company as "bundled" sales services.

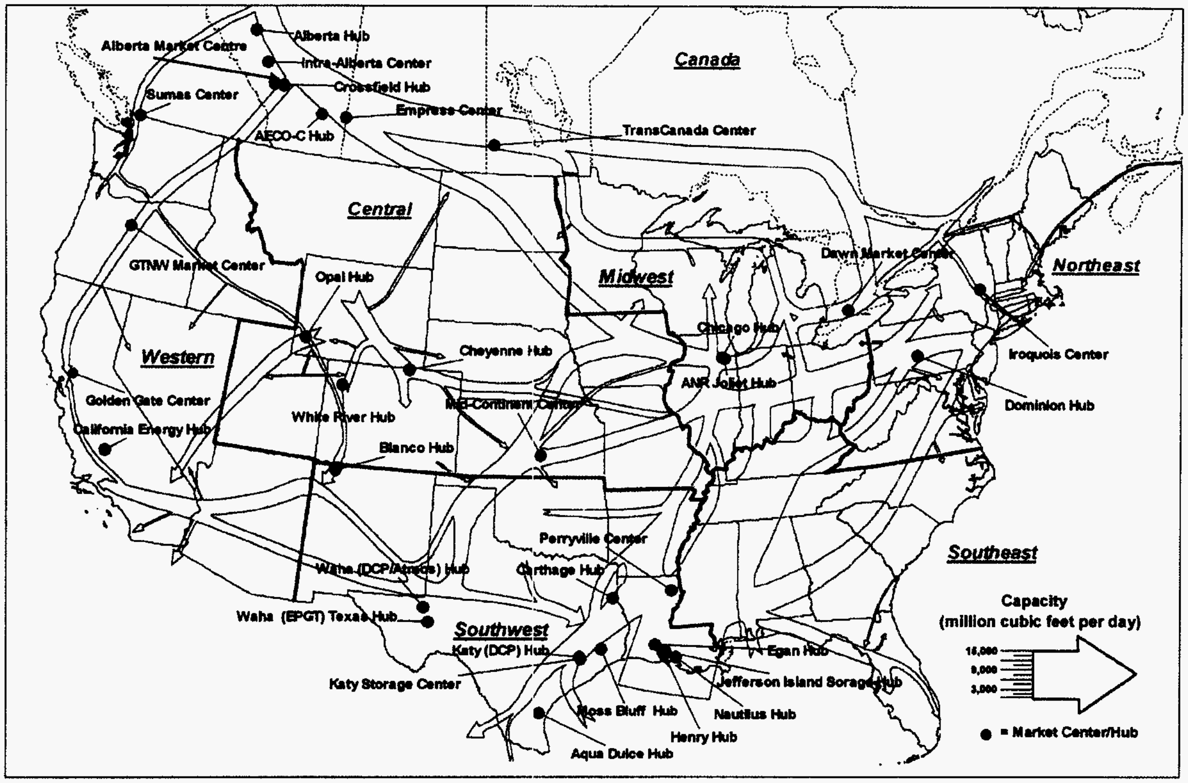
As it implemented Order 636 in 1993, FERC promoted the market center concept. It was suggested that such centers could provide the services that pipeline shipper/customers needed to manage their portfolios of supply, transportation, and storage services previously provided by the merchant pipeline company. Their facilities also could increase the interchange of natural gas across pipeline systems and permit a market to develop for the trading of natural gas volumes, storage, and pipeline capacity. Furthermore, because services would be priced separately, it was suggested that additional efficiencies could develop as competition among centers and pipelines developed over time.

Indeed, the interstate natural gas pipeline system did experience a significant increase in pipeline interconnections after Order 636. Although most of these connections were developed singly, as individual pipeline companies expanded their transportation services and supply sources, market center development nevertheless spurred many additional interconnections.

Nevertheless, the market center concept did not resolve all issues, and so in 2000, FERC issued Order 637. Its purpose was to lessen the impact of imbalance penalties on shippers and the issuance of operational flow orders (OFOs) by interstate pipeline companies. Order 637, in part, required that the (interstate) pipeline transporter "must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of shippers to manage transportation imbalances."

By 1998, 36 market centers had been established within the U.S. natural gas pipeline grid. By 2003, however, 13 of these had closed their doors as the concept matured and those that were unable to develop a trading base were eliminated. Currently, 24 market centers in the United States provide hub services to customers, the majority of which are located in the States of Texas and Louisiana.

Figure 1. Natural Gas Centers/Hubs Relative to Natural Gas Transportation Corridors, 2008



DCP = DCP Midstream Partners LP; EPGT = Enterprise Products Texas Pipeline Company.
Note: The relative widths of the various transportation corridors are based upon the total level of interstate pipeline capacity (2008) for the combined pipelines that operate on the generalized route shown.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Market Hubs Database, December 2008.

that now serve the expanding production fields located within the surrounding area.

- **Currently, there are six proposed market centers that may be placed in service during the next 4 to 5 years (Table 3).** With the exception of the Marcellus Eastern Access Hub, proposed by Equitable Midstream LP to serve the western Pennsylvania /West Virginia production area, these potential market centers are predicated upon the development of high-deliverability underground natural gas storage facilities. Of the other "proposed" market centers/hubs, one is in Alabama, two in Mississippi, and two are in Texas. All of the latter five are currently under construction or have been approved by regulatory authorities.

On the other hand, four market centers in the United States have also been deactivated since 2003 (Table 3). The largest of these, the Ellisburg-Leidy Center, served the New York and Pennsylvania areas and ceased formal operations in 2005. Its administrator, National Fuel Gas Supply Company, instead opted to provide hub-like services within its normal system operations instead. Another market center, the Encina Hub located in the Waha area of west Texas, ceased operations in 2006 when its support pipeline was sold and its operations integrated with other hubs in the Waha area.

Between 2003 and 2008, the operational profile of many of the U.S natural gas market centers changed markedly. Estimates indicate that transportation activities at U.S. market centers increased on average about 39 percent, with at least 16 of the 24 showing an increase in average daily throughput activity of 10 percent or more (Table 2).[4] In addition, while the average number of interconnections per market center increased only slightly, six market centers added two or more interconnections during the period. Consequently, total average pipeline interconnect capacity increased by about 50 percent, with three market centers at least doubling their interconnect capacity. Three experienced no growth in interconnect capacity. Only one,

[4]Based primarily on anecdotal information received from market center contacts developed in researching this report. While no specific data were provided that could validate their performance evaluations, the contacts offered their best estimates based on a firm working knowledge of transportation service activities occurring at their center during the past 5 years.

Table 2. Operational Profile of Natural Gas Market Centers in the United States and Canada, by Percent Change in Total Interconnect Capacity, 2003 and 2008

Region/ State/ Province	Market Center	Estimated Average Daily Throughput (MMcf/d)			Number of Pipeline Interconnects			Pipeline Interconnect Capacity (MMcf/d)								
								Total[1]			Delivery			Receipt		
		2003	2008	Percent Change	2003	2008	Percent Change	2003	2008	Percent Change	2003	2008	Percent Change	2003	2008	Percent Change
United States																
Louisiana	Perryville Center	600	1,800	200	11	17	55	2,351	11,800	402	2,251	11,800	424	1,601	6,300	294
Louisiana	Egan Hub	1,000	2,000	100	7	10	43	1,650	4,545	175	1,650	4,545	175	1,650	4,227	156
Colorado	Cheyenne Hub	1,100	1,800	64	5	7	40	2,854	6,396	124	2,854	6,396	124	1,780	2,625	47
Wyoming	Opal Hub	750	1,450	93	4	8	100	3,250	6,038	86	3,250	4,588	41	1,100	1,450	32
East Texas	Moss Bluff Hub	1,000	1,600	60	6	6	0	1,425	2,425	70	1,425	2,425	70	1,425	2,425	70
Louisiana	Henry Hub	600	900	50	14	14	0	2,470	3,670	49	1,865	3,220	73	2,120	3,135	48
California	California Energy Hub	550	900	64	5	12	140	4,600	6,784	47	1,000	1,600	60	4,600	5,184	13
Pennsylvania	Dominion Hub	2,180	2,500	15	16	17	6	5,893	8,348	42	5,213	6,915	33	3,351	4,111	23
Illinois	ANR Joliet Hub	400	600	50	10	10	0	3,900	5,390	38	2,300	3,590	56	2,600	2,725	5
California	Golden Gate Center	1,900	2,000	5	8	9	13	4,545	6,017	32	900	932	4	4,245	6,017	42
New Mexico	Blanco Hub	850	1,200	41	10	10	0	3,455	4,200	22	2,130	2,700	27	1,575	2,200	40
West Texas	Waha (DCP/Atmos) Hub	300	300	0	10	10	0	1,950	2,330	19	650	1,950	200	1,300	1,400	8
Oregon	GTNW Market Center	2,100	2,300	10	4	4	0	5,675	6,380	12	3,330	3,445	3	3,706	4,481	21
Louisiana	Jefferson Island Hub	420	500	19	8	9	13	2,045	2,295	12	1,833	2,083	14	2,045	2,295	12
East Texas	Carthage Hub	550	600	9	9	11	22	1,520	1,700	12	1,275	1,500	18	715	800	12
East Texas	Aqua Dulce Hub	400	400	0	9	9	0	1,528	1,690	11	873	1,035	19	655	655	0
Illinois	Chicago Hub	100	100	0	7	8	14	2,175	2,375	9	1,335	1,535	15	2,175	2,375	9
New York	Iroquois Center	950	1,400	47	4	4	0	1,950	2,050	5	750	750	0	1,200	1,500	25
East Texas	Katy Storage Center	1,200	1,400	17	13	13	0	2,580	2,615	1	2,605	2,615	0	2,580	2,400	-7
East Texas	Katy (DCP) Hub	120	300	150	9	9	0	1,430	1,430	0	1,350	1,350	0	1,030	1,030	0
Louisiana	Nautilus Hub	270	350	30	8	8	0	2,519	2,519	0	1,950	1,950	0	600	600	0
West Texas	Waha (EPGT) Texas Hub	250	250	0	10	10	0	1,825	1,825	0	1,135	1,135	0	1,825	1,825	0
Kansas	Mid-Continent Center	340	340	0	12	8	-33	1,275	735	-42	467	230	-51	1,275	632	-50
Colorado	White River Hub	N/A	N/A	N/A	N/A	7	N/A	N/A	4,905	N/A	N/A	2,560	N/A	N/A	2,560	N/A
	Overall Averages	**780**	**1,087**	**39**	**9**	**10**	**11**	**2,733**	**4,103**	**50**	**1,843**	**2,952**	**60**	**1,963**	**2,623**	**34**
Canada																
Ontario	Dawn Market Center	5,000	9,300	86	9	10	11	6,100	12,800	110	4,100	6,600	61	4,400	10,280	134
British Columbia	Sumas Center	1,200	1,000	-17	5	7	40	2,085	2,335	12	2,085	2,335	12	1,880	1,880	0
Alberta2Quebec	TransCanada Center	5,500	5,500	0	19	19	0	16,016	16,334	2	8,916	10,334	16	6,500	6,000	-8
Alberta	AECO-C Hub	10,000	10,000	0	4	4	0	20,400	20,400	0	12,000	12,000	0	12,000	12,000	0
Alberta	Alberta Hub	900	900	0	1	1	0	650	650	0	650	650	0	650	650	0
Alberta	Alberta Market Centre	550	550	0	4	4	0	1,730	1,730	0	1,730	1,730	0	1,180	1,180	0
Alberta	Crossfield Hub	450	450	0	1	1	0	450	450	0	450	450	0	450	450	0
Alberta	Empress Center	5,400	5,400	0	3	3	0	15,190	15,190	0	8,690	8,690	0	6,500	6,500	0
Alberta	Intra-Alberta Center	11,000	11,000	0	3	3	0	18,600	18,600	0	6,600	6,600	0	12,000	12,000	0

[1] Total capacity will not necessarily equal the sum of Delivery and Receipt capacities because many interconnects are bi-directional, yet are included in the total only once.

MMcf/d = Million cubic feet per day.

Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Hubs Database, December 2008.

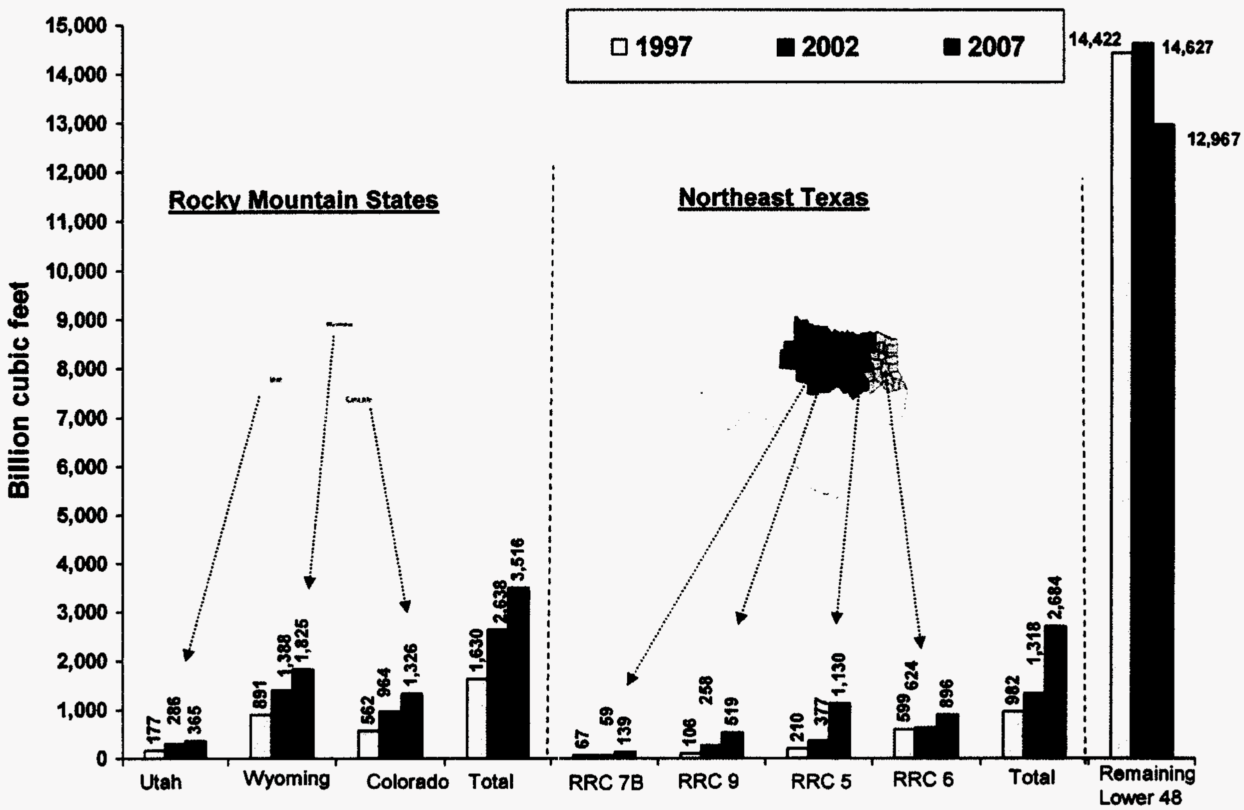
Table 3. Natural Gas Market Centers - Proposed New Sites and Inactivated Sites, 2003 - 2011

State	Year of Action	Market Center	Administrator	Type of Infrastructure	Type of Operation	Associated Storage		Comments
						Sites Names	Type of Storage Field(s)	
Proposed								
Alabama	2012	Mobay Storage Hub	Falcon Gas Storage Inc	Header	Storage Hub	Mobay	Depleted Field	Currently under construction
Mississippi	2011	Mississippi Hub	Bay Gas Storage Co	Header	Storage Hub	Mississippi Hub	Salt Dome	Phase 1 currently under construction
Mississippi	2012	Copiah Storage Hub	Market Hub Partners Inc	Header	Storage Hub	Copiah	Salt Dome	Approved by FERC, construction to commence in April 2009
Pennsylvania	2011	Marcellus Eastern Access Hub	Equitable Midstream LP	Partial Pipeline	Market Center	None	N/A	Depends upon future development of shale gas in the area.
Texas	2009	Waha (ENSTOR) Hub	ENSTOR Energy Inc	Header	Storage Hub	Waha	Salt Dome	Phase 1 currently under construction
Texas	2010	Houston Hub & Transportation	ENSTOR Energy Inc	Header	Market Hub	Houston Hub	Salt Dome	Approved by FERC, construction has not begun
Inactivated								
Pennsylvania	2005	Ellisburg-Leidy Center	National Fuel Gas Supply Co	Partial Pipeline	Market Center	All NFGS fields	Depleted Field	Hub services incorporated into pipeline marketing
Texas	2004	Spindletop Storage Hub	Centana Intrastate Pipeline Co	Header	Storage Hub	Spindletop	Salt Dome	Expense of administrating hub activities not supported
Texas	2005	Waha (Atmos) Hub	Atmos Pipeline - Texas	Header	Market Hub	Indirect access	Salt Dome	Merged operations with DCP Midstream Waha hub
Texas	2006	Waha (Encina) Hub	Sid Richardson Gas Co	Partial Pipeline	Production Hub	None	N/A	Pipeline sold in 2005

N/A = Not applicable.

Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Hubs Database, December 2008.

Figure 2. Natural Gas Production Growth Areas, 1997, 2002, and 2007



RRC = Texas Railroad Commission District.
Source: Energy Information Administration, U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves: 1997, 2002, and 2007 Annual Reports.

the Mid-Continent market center located in Kansas, lost both interconnections and capacity.[5]

The percentage of natural gas transported on the national pipeline grid that goes through a natural gas market center has also increased. Based on annual natural gas transportation volume information reported to the FERC by interstate pipeline companies, the average daily volume of natural gas transported by individual pipelines on the entire interstate network in 2007 was about 101 billion cubic feet per day (Bcf/d).[6] Estimates of average daily volumes processed through the 24 market centers approximated 25 percent of that figure, or about 25 Bcf/d.[7] This figure represents a 4-percent increase over 2003 in the portion of natural gas transported nationwide that saw some part of its journey handled by a market center.

Growth Patterns

Natural gas market centers located in areas of expanding natural gas production and along strategic transportation routes downstream of these areas have experienced the greatest levels of growth since 2003. These market centers benefited not only from increased levels of natural gas transportation flows and new natural gas pipeline capacity,

[5]Actually, the Mid-Continent market center lost interconnections, thus receipt/delivery capacity, when it and its supporting Oneok Pipeline system were sold to Oneok Partners LP and the relationship was restructured.

[6]See Federal Energy Regulatory Commission Form 2/2A, "Major and Non-major Natural Gas Pipeline Annual Report," Gas Account data, "Deliveries of Gas to Others for Transportation (Account 858)," 2003 & 2007, http://www.ferc.gov/docs-filing/eforms/form-2/data.asp#skipnavsub.

[7]Both this estimate and the 2007 Federal Energy Regulatory Commission average day transport volume of 101 billion cubic feet per day includes some double counting of volumes since a shipment of natural gas may flow through several natural gas pipelines or market centers on its way to the final consumer. Such double counted volumes cannot be discretely identified or eliminated.

but they also attracted additional natural gas trading and new shipper/customers who had a need for the many types of services that these market centers offered.

Two major regions of the United States, the Southwest and Central regions (Figure 1) have been most affected. In the Southwest Region, it has been the areas of northeast Texas and northern Louisiana, while in the Central Region it has been the areas of western Colorado and Wyoming that have seen major production growth and a corresponding increase in market center expansion.

Southwest Regional Centers

During the 10-year period between 1997 and 2007, the area encompassing northeastern Texas experienced more growth than all others in the United States, with natural gas production increasing by 173 percent (Figure 2). Since 2003 alone, natural gas production in this part of the State[8] grew 104 percent, increasing from 1.3 billion cubic feet (Bcf) in 2002 to 2.7 Bcf in 2007(this area contains most of the highly prolific Barnett shale and Bossier formation).

More than half (13) of the currently active U.S. gas market centers are situated in the Southwest region; all but one of those 13 being located in Texas and Louisiana (Figure 1). In addition to being the largest natural gas production area in North America, where supplies from a large number of sources are aggregated and traded, the region has a large number of interstate and intrastate pipeline interconnections and 64 underground storage facilities, 8 of which are associated with one or more market centers (Table 1).

The most publicized natural gas market center in North America, the Henry Hub, is located in southwestern Louisiana (Figure 1). The Henry Hub has an extensive receipt and delivery capability with almost 200 customers regularly conducting business at the site through its 11 interconnecting pipeline systems.[9] The Henry Hub also provides its customers access to the high-deliverability Jefferson Island salt storage cavern facility, which itself operates a separate and distinct market center operation (Table 1). Since 2003, this hub has increased its interconnection capacity by about 50 percent, although it did not add any additional interconnecting pipelines (Table 2). Seven of its 14 interconnections increased in capacity, contributing to an estimated average daily throughput increase of about 50 percent over the period.

Two additional market centers operate along the southern Louisiana coast, the Egan Hub Storage Center and the Nautilus Hub. Because the Nautilus Hub confines its operations primarily to supporting the interconnection of offshore Gulf of Mexico production with eight major interstate pipelines onshore, its average daily throughput growth has been relatively small over the past 5 years as offshore production volumes have declined. The Egan Storage Hub, on the other hand, located onshore and benefiting from its location along the route of several interstate pipeline expansions serving the growing production from east Texas fields, has more than doubled its interconnect capacity with the addition of three new interconnections over the past 5 years (Table 2).

The most significant impact from growing east Texas natural gas production in the Southeast Region has been the large-scale development of new natural gas pipelines extending through northern Louisiana and expansion of several existing ones. Strategically situated in this area, Centerpoint Energy Company's Perryville Hub (Figure 4) has become one of the largest natural gas market centers in North America as a result, with access to 17 pipeline interconnections (15 interstate and 2 intrastate), over 10 Bcf/d of delivery capacity, and more than 6 Bcf/d of receipt capacity (Table 2).

During the past several years alone, at least 3.3 Bcf/d of new interstate natural gas pipeline capacity was installed in and around the Perryville area, much of it with interconnections at the Perryville Hub. In 2009 and 2010, an additional 5.2 Bcf/d of new pipeline capacity is scheduled to be built, much of it potentially accessible through the Perryville Hub.

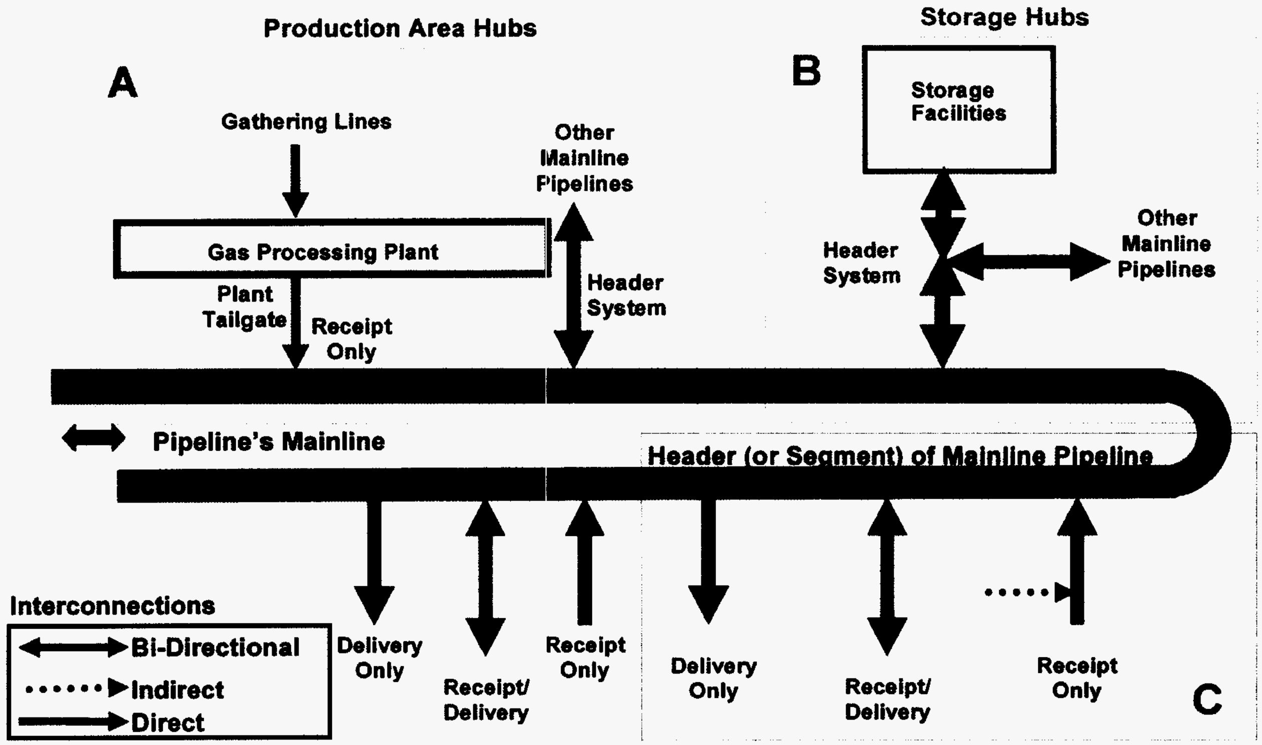
The impetus for this recent and future pipeline construction has been the rapid and extensive expansion of unconventional shale natural gas in east Texas and the anticipated development of similar resources in the Haynesville Shale Basin of northern Louisiana.

Because most of the natural gas created by the heavy development of the Barnett Shale and Bossier Trend formations has moved eastward into Louisiana, the several market centers located in eastern Texas have not been affected to any great extent. The Carthage Hub, which sits directly on the natural gas transportation route directly linking northeast Texas production and major interstate pipeline interconnections in Louisiana, Mississippi, and Alabama, has added a couple of new pipeline interconnections to its portfolio, but its estimated average daily throughput rate is only slightly more than it was in 2003. As a plant tailgate hub (Figure 3, box A), the capacity of its associated natural gas processing plants limits its throughput. Much of the natural gas flowing along the corridor at this point has already been processed further

[8] Includes Texas Railroad Commission (RRC) district 5, 6, 7B, and 9.

[9] The Henry Hub is also the specified delivery point for New York Mercantile Exchange (NYMEX) natural gas futures contracts, although it is not affiliated with the NYMEX.

Figure 3. Generalized Market Center/Hub Operational Schematic



Note: Storage, Gathering, and Gas Processing Plant facilities are not associated with all market centers/hubs.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

Market Center Configurations

Essentially, a natural gas market center exists to provide its customers (shippers and gas marketers primarily) with receipt/delivery access to two or more pipeline systems, provide transportation between these points, and offer administrative services that facilitate that movement and/or transfer of gas ownership. But the infrastructure associated with the market center itself may be configured in several different ways (Figure 3). For instance:

Full Pipeline System – Some market centers are associated with and use all, or a sizable portion, of an entire pipeline system to carry out their operations and provide transportation services to and between all pipeline interconnect points that are part of their system. Its configuration may encompass all or part of the operations and facilities included on Figure 3.

Header System (non-storage) – This form of market center operates using a short portion of a mainline pipeline, or a stand-alone lateral, where two or more pipeline interconnections are concentrated within a relatively short distance from each other. (Figure 3, box C)

Storage Header System – The bi-directional laterals that connect the underground storage facility to the mainline intra- or interstate pipelines are also used to transport a shipper's natural gas between these interconnects (Figure 3, box B). Depending upon the hub services needed by the customer, the transported natural gas may or may not move through the associated storage facilities.

Production Area Header Systems – These market center operations dispatch production volumes onto the mainline transmission grid from interconnections on the header system with other mainline intrastate pipelines, or from the tailgate of a natural gas processing plant (Figure 3, box A). Such centers confine their activities mostly to providing hub services to natural gas producer clients.

Currently, 18 of the 33 active North American market centers can be categorized as header systems, with relatively short distances between pipeline transfer points and other facilities such as storage. The remaining 15 natural gas market centers are associated with and use all, or a sizable portion, of a single pipeline system to carry out their operations and provide transportation services (Table 1).

upstream, and is flowing on large mainline pipelines leading out of the State.

Some of the additional flows of growing northeast Texas production are being transported on a southerly route to interstate interconnections in south Texas and southern Louisiana through market centers located in the Katy area of southeastern Texas (Figure 4). This movement has contributed to greater throughput at these several market centers but has not fostered the addition of any new pipeline interconnections or greater receipt/delivery capacity at existing interconnections. Nevertheless, these market centers are attractive to shippers because they provide interconnections among at least 21 pipelines, including a number of the major interstate pipelines such as Texas Eastern Transmission and Tennessee Gas Pipeline companies, major transporters of natural gas to the Midwest and Northeast markets.

The Carthage area of northeastern Texas, as well as the Katy area to the south, also receives natural gas flowing from the west Texas Waha area. Three major Texas intrastate natural gas pipelines transport natural gas from two market centers located at Waha to east Texas, EPGT Texas Pipeline, directed to the Carthage area, and the Guadalupe and the Oasis pipelines directed to the Katy area.

Central Regional Centers

A number of new natural gas pipelines have been built in the Central region over the past 5 years because of the continuing expansion of natural gas exploration, development, and production of both conventional and unconventional resources in Colorado, Utah, and Wyoming.[10] In addition, several existing natural gas pipeline systems in the region have expanded as well. In turn, the existing natural gas market centers located in the area, specifically the Opal Hub in southwestern Wyoming and the Cheyenne Hub in northeastern Colorado, have added major new interconnections and have expanded their receipt and delivery capabilities during the period (Table 2). In addition, the White River Hub, placed in service in late 2008, addressed the need for market center services for producers and pipelines located in the Uinta/Piceance Basin area of western Colorado and eastern Utah.

Natural gas production in these three States grew 33 percent over the past 5 years and by 116 percent since 1997 (Figure 2). In the Green River Basin of western Wyoming, which accounts for about 90 percent of the State's current natural gas production and where natural gas production has increased 11 percent since 2003,[11] the Opal Hub has experienced a 93 percent increase in estimated daily throughput, added four interconnects, and nearly doubled its receipt/delivery capability (Table 2). The Opal Hub, located at the southern end of the Green River Basin, provides more than 1.45 billion cubic feet (Bcf) of processed natural gas daily to Northwest Pipeline, Colorado Interstate Gas, and the Kern River Transmission systems among others (Figure 5).[12]

The Cheyenne Hub, located in eastern Colorado, has not only profited from the increased natural gas production in the Green River Basin that flows eastward, it has been the destination of a large portion of the natural gas coming out of the Uinta/Piceance Basin expansion. These new flows into the Cheyenne Hub have more then compensated for the one-third decrease in Wyoming's Powder River Basin coalbed methane production, much of which is directed toward the hub. The Cheyenne Hub began operations in 2000 to support the growing need for natural gas transportation out of the Powder River Basin and to provide trading services for eastern Wyoming and northern Colorado area producers and other market makers.

Two new large-capacity pipelines supporting the Cheyenne Hub expansion, the Cheyenne Plains and the Rockies Express, have begun operations with interconnections at the Cheyenne Hub. In addition to these two new pipeline systems, the Trailblazer Pipeline, which increased its capacity in 2002 by 56 percent, or 350 million cubic feet per day, begins at the Cheyenne Hub, also providing customers with access to the Midwest gas market.

The new White River Hub, a partnership between Enterprise Products Partners, LP and Questar Gas Company, operates an 11-mile header system pipeline and offers market center services to producers and pipelines located primarily in the Piceance Basin area of western Colorado (Table 1). Natural gas production in this area of Colorado increased from 14 percent of total Colorado production in 2003 to 28 percent in 2007, supporting development of the White River Hub.

With seven interconnections among area pipelines and gathering operations and a natural gas processing plant, the White River Hub operation essentially formalizes business services that previously had developed among area pipeline interconnection operators. As reference points these

[10]Energy Information Administration, GasTran Natural Gas Transportation Information System, Natural Gas Pipeline Projects Database, 2008.

[11]Based on data for Wyoming, Colorado, and Utah, contained in a presentation of the Wyoming Pipeline Authority, *Rockies Natural Gas Resources*, "Wyoming - Top Five Producing Counties" http://www.wyopipeline.com/information/presentations/2008/May/Final%20Seattle%20Presentation%20May%2013%202008.pdf.

[12]In May 2003, the Kern River Transmission System doubled its pipeline capacity between Wyoming and California.

Market Center Services

The types of services offered by market centers vary significantly. No two operations are identical in the services offered, and in fact, the features of similarly named services often differ in meaning and inclusions. The list below describes most of the broad types of services offered.

Transportation/Wheeling - Transfer of natural gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over the transmission of a market center pipeline.

Parking - A short-term transaction in which the market center holds the shipper's natural gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in linepack.

Loaning - A short-term advance of natural gas to a shipper by a market center that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.

Storage – Holding natural gas longer than parking, such as seasonal storage. Most often confined to available interruptible storage capacity only.

Peaking - Short-term (usually less than a day and perhaps hourly) sales of natural gas to meet unanticipated increases in demand or shortages of natural gas experienced by the buyer.

Balancing - A short-term interruptible arrangement to cover a temporary imbalance situation. The service is often provided in conjunction with parking and loaning.

Pooling/Volume Aggregation - A pooling transportation service that allows customers to aggregate natural gas from various points within a supply area and have it delivered into downstream firm or interruptible transportation contracts at designated delivery point pooling stations.

Title Transfer - A service in which changes in ownership of a specific natural gas package are recorded by the market center. Title may transfer several times for some natural gas before it leaves the center. The service is an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic Nomination – Customers may connect with the market center electronically to enter natural gas transportation nominations, examine their account position, and access bulletin board services. Such systems may also facilitate trading among buyers and sellers and support direct negotiation among parties.

Administration - Assistance to shippers with aspects of natural gas transfers, such as nominations and confirmations.

Compression – Provide compression needed to increase pressure of natural gas received off of a lower pressure system so that it can be transferred to a pipeline operating at a higher pressure. If needed additional compression is bundled with transportation, it is not a separate service.

Hub-to-Hub Transfers - Arranging simultaneous receipt of a customer's natural gas into a connection associated with one center and simultaneous delivery at a distant connection associated with another center.

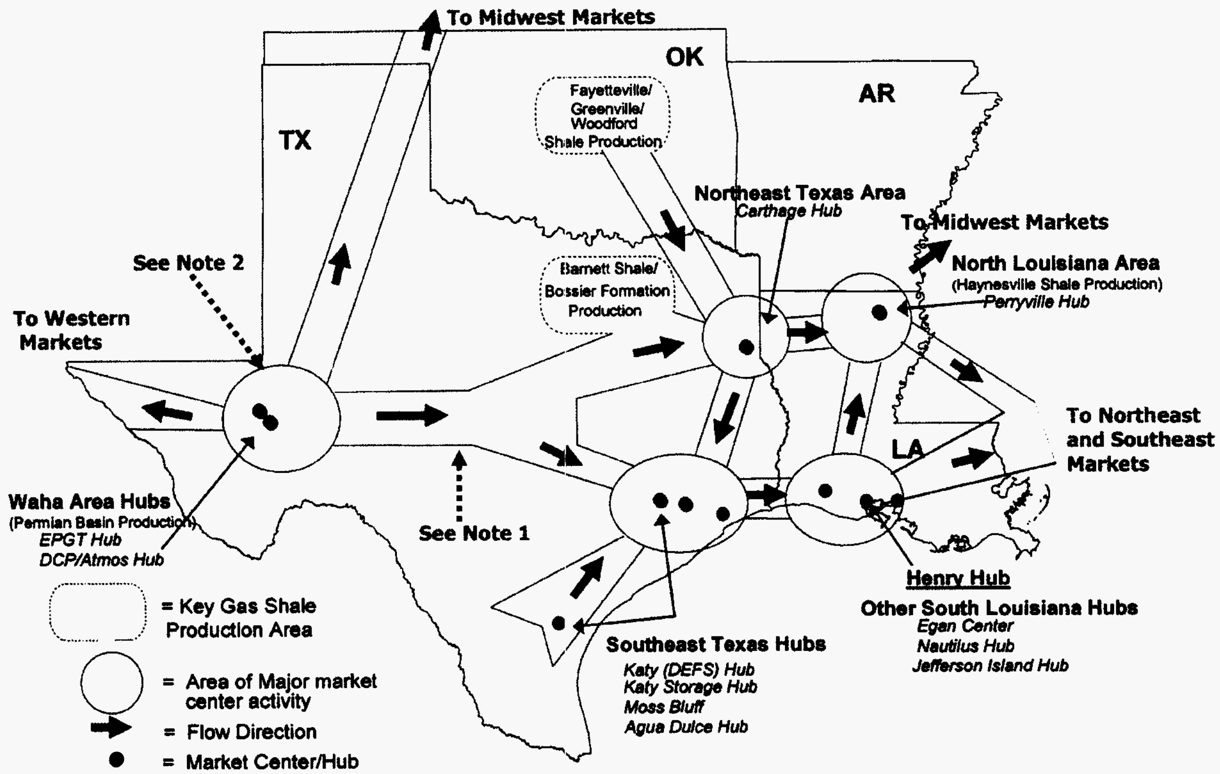
Transportation and title transfer remain the most important market center operations and services provided the customer. For instance, when a shipper with contracted capacity on one pipeline wants to deliver natural gas to an end user located off another pipeline, the shipper can make arrangements to transport the natural gas on the other pipeline through the market center administrator. If two parties consummate a trade through the market center, the administrator will handle the title transfer and other administrative details, including providing the operator of the center's pipeline facilities with the physical flow details involved in the deal.

Needed capacity on the receiving pipeline may be acquired at the center if trading services (or traders) are available. Similarly, the shipper can use the center's services to revise its nominations (or temporarily release some capacity) on either pipeline, with the center handling the administrative requirements, including confirmations, associated with the transactions. To cover any imbalances that might occur when the receipt/delivery volume exceeds nominated capacity on either pipeline, the shipper can execute an operational balancing agreement with the center.

When the shipper experiences a sudden increase in demand, the center may also provide the necessary incremental support from storage. If the shipper temporarily exceeds its storage allotment at the center, the center can offer natural gas loaning, with the shipper responsible for its replacement within a specified period. Similarly, storage withdrawal and loaning by the center can also be used to cover shortfalls when purchased production flowing into the downstream pipeline does not equal transportation nominations. Most centers provide a real-time tracking service to notify shippers immediately when such imbalances are imminent.

Market centers require pre-approved credit and/or proven creditworthiness of their potential customers and normally operate under standardized contract provisions. The advantage of a standardized contract is that it is well understood and so minimizes transaction costs and provides a clear understanding of legal responsibilities. Pre-approved credit and/or creditworthiness support the ease of trading and finalization of contracts.

Figure 4. Concentrations of Natural Gas Market Center Activities in Texas and Louisiana, 2008



DCP = DCP Midstream LP; EPGT = Enterprise Products Texas Pipeline Company.
Note 1: Corridors shown are illustrative only and are not intended to reflect actual pipeline capacity or flow levels.
Note 2: Some flows out of the San Juan Basin, destined for California, Arizona, and north and east Texas, are directed through the Waha area hubs.
Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Market Hubs Database, December 2008.

informal operations were often referred to as the Greasewood Hub and the Meeker Hub, but they were not market centers (see box, "Trading and Price Reporting").

Although its business location is in northern New Mexico, the Blanco Hub, operated by Transwestern Gas Pipeline Company, is a primary provider of market center services to pipelines and producers flowing natural gas production from the portion of San Juan Basin located in southwestern Colorado. While natural gas production in southwest Colorado decreased 11 percent between 2003 and 2007, the area still represents more than 30 percent of the State's overall annual natural gas production.[13] Natural gas production in the New Mexico portion of the San Juan Basin also decreased 11 percent during that period.

Despite this decrease in production in the area and no additional interconnections being installed, activity at the Blanco Hub grew during the period, with estimated daily throughput showing a 41-percent increase and receipt/delivery capability growing 22 percent (Table 2).

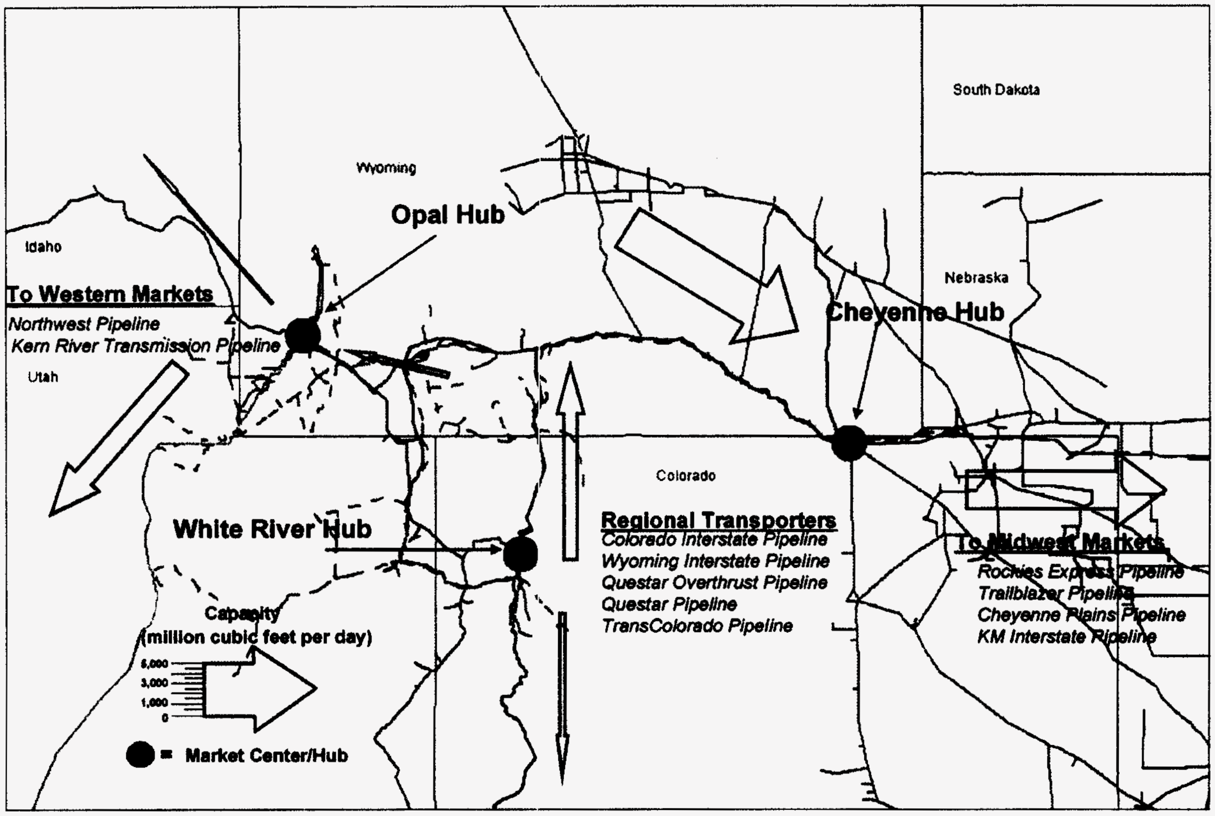
[13]Based on data in "Colorado - Top Five Producing Counties." See footnote 11.

One reason for this increase in market center activity is that the Blanco Hub is a destination point for the TransColorado Gas Transmission pipeline system. This pipeline extends 300 miles from the Greasewood area (White River Hub) of northwest Colorado (Piceance Basin) to a point of interconnection with El Paso Natural Gas, Transwestern, and Southern Trails interstate pipelines at the Blanco Hub.

Western Regional Centers

In the Western Region, activities at the three existing market centers grew primarily because of increases in interconnect capacity and number (Figure 1). The California Energy Hub, operated by Southern California Gas Company, was the only market center in the region to see a significant increase in estimated daily throughput volume, up 64 percent (Table 2). The California Energy Hub also experienced a major increase (47 percent) in interconnect capability as two new interstate pipelines became associated with the market center: the North Baja Pipeline system and Questar's Southern Trails Pipeline system. Several additional interconnection locations along the existing interstate system

Figure 5. Rocky Mountain Natural Gas Hubs and Target Markets, 2008



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division, Natural Gas Market Hubs Database, December 2008.

as well as several new intrastate production receipt points also were added to its venue. In addition, between 2003 and 2007 natural gas deliveries into southern California increased by at least 6 percent,[14] providing support for expansion of the California Energy Hub.

The other two market centers in the Western region, the Gas Transmission Northwest (GTNW) Market Center and the PG&E Golden Gate Market Center, saw only limited growth during the period (Table 2). This minimal growth reflects the stabilization of natural gas pipeline capacity originating in western Canada, which serves the west coast of the United States, primarily California. Since 2003, the decrease in natural gas shipments along this route has negated the need for new pipeline capacity. Indeed, over the 5-year period, deliveries of natural gas into northern California were between 545 and 600 Bcf per year, whereas in the prior 5 years, annual flows were in the range of 640 to 680 Bcf. Nonetheless, the two market centers did manage to experience a small increase in average daily throughput volumes.

The Sumas Center primarily supports the western U.S. natural gas market although its operational center is actually located in Canada near the British Columbia/Washington State border. It is a principal source for trading and transportation of Canadian natural gas flowing on the Northwest Pipeline Company system destined for the States of Washington, Oregon, and Idaho. The Sumas Center was the only market center that reported a decrease in average daily throughput volume over the period. However, it did experience a 10-percent increase in its customer base with two new pipeline interconnects and a 12-percent increase in interconnect capacity.

Midwest Regional Centers

The ANR Joliet Hub, located in northern Illinois, was the only one of the two market centers found in the Midwest Region that experienced any significant growth in its operations and transactions (Figure 1). Its average daily

[14]Energy Information Administration, *Natural Gas Annual(s)*, 2007- January 2009, DOE/EIA-0131 (Washington, DC), http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html.

Trading and Price Reporting

While many of the market centers referred to in this report have names similar to a number of natural gas trading points reported on in the trade press or posted on electronic future or spot market boards, they are not related operations. Market centers themselves are not the source of the price or volumetric information reported by these entities, although they do not prohibit their customers from reporting their trading volumes and prices to the public. In many cases, they welcome such reporting since it publicizes the liquidity of the trading area or of the market center itself.

The volumes and prices publically quoted in the trade press are usually a compilation of trading activities carried out and reported by energy marketers, traders, and pipeline customers who agree to report any transactions they perform within a defined common trading area, to the publishers on a regular basis. Their incentive for doing so is that they recognize that this reporting by them and others helps to provide price transparency to the market and thereby a basis for future price setting. Spot and futures prices and volumes reported by the electronic trading platforms such as New York Mercantile Exchange (NYMEX), Intercontinental Exchange (ICE) or TradeSpark, among others, are based on trading activities held specifically on their platforms by their customers.

Because the trading volumes reported by non-market center parties include trading areas beyond the market center, even though the "center/hub" labels are the same or similar, the estimated average daily volume (Table 2) provided through the actual market center does not agree with that reported in the trade press or electronic platform. For instance, the daily trading volume for the "Henry Hub" reported in the trade press often currently exceeds 1,600 million cubic feet per day (MMcf/d) while that reported by the center's administrator as running through the hub on a daily basis in 2008 was only about 900 MMcf/d.

While the primary business of a market center is the administrative processing and transporting of natural gas between interconnecting pipelines on behalf of traders and shippers, many market centers also provide their customers access to a proprietary Internet-based natural gas trading and nominations platform (Table 1). This service gives their customers the capability to transact much of their business with the market center online with relative ease. For instance, with it a shipper may quickly determine the amount of firm or interruptible capacity currently available through the center, submit nominations for available capacity, and then arrange for transportation of the gas.

In addition, many of these market center online platforms also offer anonymous natural gas trading support services. Customers are provided details of the transaction, bid and ask prices are communicated between parties, and when a deal is consummated, the market center administrator handles the title transfer and other administrative details, including providing the operator of the center's pipeline facilities with the physical flow details involved in the deal.

throughput volume increased by one-half while its total interconnection capacity grew by 38 percent (Table 2). Four of the 10 natural gas pipelines that interconnect at the Joliet Hub, Alliance Pipeline, Natural Gas Pipeline Company of America (NGPL), NICOR (Northern Illinois Gas Company), and NIPSCO (Northern Indiana Gas Company) increased their access capacity. Though the NICOR Chicago Hub, the remaining market center in the region, added one more interconnection, its size was relatively small, and the reported average daily throughput volume since 2003 did not noticeably change.

Neither the Joliet nor the Chicago hubs currently provide their customers access to the newest large capacity pipeline traversing the Midwest region, the Rockies Express Pipeline system (REX). The REX system crosses the State of Illinois well to the south of these two centers. If and when either of the two centers provides access to REX it will be indirectly, perhaps through the NGPL Pipeline, which interconnects with the REX in northeast Nebraska and interconnects with both centers in northern Illinois.

Northeast Regional Centers

Only two market centers within the Northeast Region are currently operational, down from three in 2003. In 2005, the Ellisburg-Leidy Center, which served natural gas shippers delivering to markets in the New York and Pennsylvania areas, ended its operations. The National Fuel Gas Supply Company, a major regional interstate pipeline company and the administrator/operator of the Ellisburg-Leidy Center, cited a lack of trading activity and customers as the reasons for closing down the market center operation. Nonetheless, it continues to provide hub services within its normal pipeline system operations.

The Dominion Hub is the larger of the two remaining market centers in the region (Figure 1). It provides interconnections with 15 intrastate and interstate pipelines as well as two pooling points (Table 2), an addition of one interconnection since 2003. The market center uses the entire Dominion Transmission Company pipeline grid, which has operations in Pennsylvania, New York, and Ohio, to serve its customers. It also has access to the 15 storage fields located on the Dominion system.

A major operational area of the Dominion Market Center is the Leidy area of north central Pennsylvania, a region of major pipeline connectivity in the Northeast Region. A number of major interstate pipelines traverse the general area including the Tennessee Gas Pipeline, Texas Eastern Transmission Pipeline, and Transcontinental Gas Pipeline, all of which are interconnected through the Dominion Market Center. In fact, these three systems, which have undergone expansions in the region since 2003, account for three of the six interconnections at the Dominion Market Center that have increased in capacity between 2003 and 2008. Although seven of the interconnections at the Dominion Market Center were downsized during the period for various reasons, the net additions to interconnection capacity produced a 42-percent increase over the 5-year span (Table 2).

The other remaining market center in the Northeast region, the Iroquois Market Center provides shippers of primarily western Canadian natural gas with transportation and hub services between the New York/Canadian border and the New York metropolitan area (Figure 1). Between 2003 and 2007, it experienced a 47-percent growth in estimated average daily throughput volume, although the supporting pipeline system itself did not undergo any significant expansion during the period. A large user of line-packing to maximize its daily throughput, the Iroquois Pipeline system provides the market center operations with available space to support its parking, loaning, and operational balancing services.

The Iroquois Market Center provides access to only four interconnections besides its own supporting pipeline system. Since 2003, the only increase in interconnection capacity has been to add receipt capacity at one of the existing interconnects (Algonquin Pipeline).

Canadian Market Centers

Of the nine market centers currently operating in Canada, six are located in the Province of Alberta, which is the dominant gas production area in Canada (Figure 1). These centers, which provide Alberta natural gas producers and shippers with trading opportunities and interhub transportation between the TransCanada (Nova) Pipeline system and the rest of Canada, all indicated that there were no appreciable changes in operational capabilities or their status since 2003 (Table 2). One of the principal reasons for this static condition was that the TransCanada Pipeline's mainline system, which is the primary delivery interconnection, has actually decreased its overall system capacity between the Alberta border and eastern Canada because of lower shipper demand.

The TransCanada (Market) Center, which administers the hub services provided on the TransCanada Pipeline System between Alberta and eastern Canada, itself reported only a 2-percent change in its overall interconnect capacity, brought about by increases at several border points interconnecting with expanded U.S. pipeline systems.

Only the Dawn Market Center, located in eastern Ontario, Canada (Figure 1), reported a significant change in its operational status, with its estimated average daily throughput increasing more than 85 percent since 2003. Moreover, total interconnect capacity more than doubled at the Dawn facility (Table 2) though it only added one new interconnection in the past 5 years. Of the nine existing interconnecting pipelines at the Dawn Center, only one did not add interconnect capacity during the same period.

A major attraction of the Dawn Center has been its expanding underground storage base. Currently, the center has access to more than 150 Bcf of high-deliverability working gas storage capacity and 2 Bcf/d of storage withdrawal capability from its 18 storage pools, to serve its customers. And its location and interconnections along the TransCanada mainline, as well as its access to several major U.S. pipelines via Michigan, have made the Dawn Center convenient to both U.S. and Canadian natural gas shippers, contributing to its steady growth.

Over the past 5 years one of the major contributors to the growth of the Dawn Center has been the expanding use of the Vector Pipeline system. The Vector Pipeline system serves as a conduit for western Canadian natural gas that has been processed at the Aux Sable plant in Illinois and destined for eastern Canada via the Dawn Center. The Dawn Center also provides customers shipping natural gas through the Empress Hub, located at the Alberta border, with interhub transfer services between Alberta (production) and Ontario (storage), arranging transportation on the TransCanada Pipeline system (see box, "Market Center Services").

Outlook

While the number of market centers has not expanded significantly during the past 10 years, several new ones have been put in service located at strategic points on the pipeline grid. The latest, the White River hub located in western Colorado, can provide up to 2.6 Bcf/d of transportation service to producers, marketers, and shippers who need access to downstream markets for natural-gas volumes produced in the Piceance Basin.

Besides the six proposed natural gas market centers listed on Table 3, there are several areas of the country that have the potential to accommodate new market center operations. For instance, with the expansion of the Rockies Express Pipeline through the Midwest, several major natural gas pipelines serving the northeast have made proposals to build new interconnections with the Rockies Express Pipeline, which is currently slated to end in the vicinity of Lebanon, in eastern Ohio.[15]

At least six major natural gas pipeline systems currently traverse the area around Lebanon, Ohio. Indeed, prior to 1998 the East Ohio Pipeline Company operated a natural gas market center, which accommodated interconnects with many of these pipeline systems. However, because of a lack of trading interest at the site, it was closed in the late 1990s. Nevertheless, with the development of the large capacity Rockies Express Pipeline, with its flow of Rocky Mountain and other new Central Region sourced natural gas, there is a good possibility a new market center could develop in the area.

Another area of potential market center development is in northern Louisiana. Currently, the Perryville Hub, administered and operated by Centerpoint Energy Inc. is the only market center in the area (Figure 4). In 2007, an alternative to the Perryville Hub, the "Eagle Hub" was proposed by Lehman Brothers Partners Inc. However, because of the collapse of Lehman Brothers in 2008, and the sale of its natural gas assets to EDF Development Inc, the project has been put on hold. The original proposal recognized the potential need for another market center in the northern Louisiana area, which could be acted on by another party in the future, especially if natural gas production in the Barnett shale area of east Texas continues to expand and development of shale gas in the Haynesville formation in northern Louisiana takes place as anticipated.

Lastly, Enbridge Energy Partners LP, among others, has sought interest from area shippers in the possibility of creating additional market centers in the Carthage area of northeast Texas and in the Orange County area of southeast Texas, to accommodate production expansions. To date, however, not enough interest to open these new market centers has been found, but that may change in the future.

[15]The sponsors of the Rockies Express Pipeline have proposed extending the system as far east as New Jersey by 2010.

Florida Gas Transmission Company, LLC
Transportation Service Proposal
to
Florida Power & Light Company
March 17, 2009

Florida Gas Transmission Company, LLC ("FGT") hereby submits the following proposal to Florida Power & Light Company ("FPL"), regarding expansion of the FGT system to provide incremental firm transportation service capacity to FPL's Cape Canaveral ("Cape") and Riviera Beach ("Riviera") Plants (the "Proposal"). If FPL agrees with the terms of this nonbinding Proposal, FGT and FPL will develop and negotiate such documents as may be required by and mutually agreed to by both parties to enter into binding agreements. As one of the provisions of such agreements, FGT would be willing to commit to go forward with the Project even if FPL were the only shipper committed to the expansion in advance. All terms presented below are solely for discussion purposes only and do not constitute an offer or create any binding agreement. All terms of discussion between FPL and FGT are confidential pursuant to the terms of the May 8, 2008 Confidentiality Agreement.

A. <u>BENEFITS OF THIS PROPOSAL FOR FPL</u>

FGT is proposing to utilize its existing pipeline system to serve the incremental requirements of FPL at both the Cape and Riviera Plants. This will gain FPL the following benefits:

1. FGT has a proven track record of successful expansion projects to serve FPL and the Florida market. FGT personnel have the knowledge and expertise necessary to meet the unique challenges associated with the construction of infrastructure in Florida.

2. By using existing right-of-way for the vast majority of the incremental facilities required, FGT will minimize the environmental impact associated with an expansion project of this size and scope. In addition, FGT is a familiar partner with the various environmental agencies within Florida.

3. FPL will be able to utilize the capacity under this proposal to supply other FPL plants throughout Florida should there be a problem at the Cape or Riviera Plants during construction or operation.

4. The FGT pipeline system can provide FPL with valuable operational flexibility. FPL will have the opportunity to direct gas supply to other FPL plants or Florida end-users should daily demand forecasts change or generation plant outages occur.

B. FIRM TRANSPORTATION SERVICE

1. **Type of Service:** FGT shall provide FPL with firm transportation service for the incremental transportation capacity.

2. **Firm Transportation Service Contract Quantity:** The maximum daily transportation quantity ("MDTQ") will be 400,000 MMBtu/day.

3. **Proposed Maximum Delivery Quantities at Each Primary Firm Delivery Point (MMBtu):**

Delivery Point	MDQ	Maximum Hourly Quantity
Cape	200,000	12,000
Riviera	200,000	12,000

4. **Cape and Riviera Minimum Delivery Pressure:** FGT will deliver gas to FPL at the Cape and Riviera Plant sites at a minimum delivery pressure of 650 psig.

5. **Firm Service Delivery Flexibility and Reliability:** Upon in-service of the FGT Phase VIII Expansion, the firm transportation service maximum daily quantities at all FPL delivery points on FGT will total over 3.0 Bcf/day. FPL will have the flexibility to shift the 400,000 MMBtu/day of incremental firm transportation service volumes, within the limits of the capacity of the FGT system, to other FPL plants on a primary firm scheduling priority basis.

   FPL will also have the flexibility to use the firm capacity, within the limits of the capacity of the FGT system, at all delivery points on the FGT system on an alternate firm scheduling priority basis pursuant to procedures set out in the FGT FERC Gas Tariff ("Tariff"). This alternate point capability will provide FPL the flexibility in the future to use the FGT firm transportation service capacity at existing FPL plant sites or other generation sites throughout the state of Florida.

6. **In Service Date(s):** FGT is willing to work with FPL to phase-in the in-service date(s) of the pipeline facilities and firm transportation service capacity to more closely match FPL's timing requirements in 2013 - 2014 for test gas and incremental firm-service transportation capacity at the FPL Cape and Riviera plant sites, provided that the economics and terms and conditions are mutually acceptable to both parties.

7. **Term of the Firm Transportation Service Agreement:** The primary term of the service agreement shall be twenty five (25) years.

8. **Supply Area Access:** The potential receipt point options will include available system capacity at the following points: (1) Southeast Supply Header interconnects in George County, MS or Mobile County, AL, (2) Destin Pipeline interconnect in George County, MS, (3) FGT / Transco Pascagoula Lateral [Gulf LNG supply] interconnect with FGT's existing 30-inch Mobile Bay Lateral in Mobile County, AL, (4) Transco / FGT Citronelle interconnect in Mobile County, AL, (5) other Zone 3 receipt points with available capacity, (6) any available supply area capacity resulting from turn-back capacity.

   FPL will have alternate receipt point access to all points on the FGT pipeline system, including the SNG-Cypress interconnect in Florida, pursuant to procedures set out in the FGT Tariff.

   To the extent FPL desires FGT to provide additional supply area access such as the Transco Station 85 area, or other options, FGT is willing to provide other supply area facilities, expansion or enhancement to increase receipt point capacity; provided that the economics and the terms and conditions for the construction of such a supply facility, expansion or enhancement are mutually acceptable to both parties.

9. **Transportation Rate:** The estimated transportation rate is provided below. The rate reflected below is a 100% load factor rate and is not inclusive of any applicable surcharges.

	Volume MMBtu/d	Supply	Rate $ per MMBtu*	Delivery Point(s)
	400,000	West	$1.68	Cape & Riviera

   * The rate is based on current indicative price quotes from suppliers of steel pipe in the quantity, dimensions, quality and timing required for this expansion. FGT is willing to include a provision that FGT will adjust the rate, upward or downward, based on the actual price of steel pipe.

10. **Fuel:** Fuel will be pursuant to FGT's FERC Gas Tariff for the Market Area.

11. **Measurement and Regulator Station Equipment to be Provided and Installed by FGT:** The measurement and regulator station equipment to be installed by FGT at the Cape and Riviera Plants will consist of a tap, 100 feet of connection piping, and inlet and outlet filter separator, ultrasonic measurement, electronic flow measurement, a chromatograph, a building, pressure regulation, flow control, over pressure protection and station fencing and rock.

12. **FPL Termination:** FPL will have the right to terminate the precedent agreement pertaining to this service proposal if FPL does not obtain all necessary permits and approvals to construct and operate the Cape and Riviera Plants in a form acceptable to FPL, by specified dates mutually acceptable to both parties.

    FPL shall pay FGT a termination fee for FGT's pre-construction expenses, including reasonable costs incurred or committed to binding obligations entered into prior to the date such termination notice is received by FGT, up to a defined maximum amount. FGT will provide FPL a termination fee schedule.

    In lieu of a termination fee, FGT is willing to consider a minimum revenue or volume commitment at terms and conditions that are acceptable to FGT.

13. **Project Status Information:** FGT will keep FPL appraised on a regular basis of its progress in obtaining regulatory approvals and permits in preparation for the construction of the expansion facilities.

C. OTHER PROVISIONS

1. **Binding Agreements/Approvals:** This Proposal is not intended to, and does not, create a legally binding commitment or obligation on the part of FGT or FPL. The creation of such legally binding obligations are subject, among other things, to the negotiation, execution and delivery of definitive agreements and the receipt of any necessary approvals, including management and Board approvals by each respective company and the receipt of all necessary permits and applicable state and federal regulatory approvals in a form acceptable to FPL and FGT.

2. **Expansion/Open Season:** FGT will conduct an open season process, in which any turn-back of existing firm capacity and other requests for new incremental capacity will be considered. FGT may include other shippers with any FERC filing required to serve FPL.

Month	NYMEX NG Henry Hub(1)	*Basis Swap By Location (1)(2)* ANR SE	Columbia M/L	FGT Z3	Transco 85
Jul-09	$3.7150	($0.0950)		$0.1300	$0.0325
Aug-09	$3.8900	($0.1275)		$0.1850	($0.0475)
Sep-09	$4.0700	($0.1275)		$0.0800	($0.0475)
Oct-09	$4.4300	($0.1275)		$0.0450	($0.0475)
Nov-09	$5.0000	($0.0900)		($0.0475)	$0.0050
Dec-09	$5.7270	($0.0900)		($0.0475)	$0.0050
Jan-10	$6.0490	($0.0900)		($0.0475)	$0.0050
Feb-10	$6.0820	($0.0900)		($0.0475)	$0.0050
Mar-10	$6.0240	($0.0900)		($0.0475)	$0.0050
Apr-10	$5.8890	($0.0900)	($0.1400)	$0.0575	($0.0525)
May-10	$5.9370	($0.0900)	($0.1400)	$0.0575	($0.0525)
Jun-10	$6.0470	($0.0900)	($0.1400)	$0.0575	($0.0525)
Jul-10	$6.1670	($0.0900)	($0.1400)	$0.0575	($0.0525)
Aug-10	$6.2600	($0.0900)	($0.1400)	$0.0575	($0.0525)
Sep-10	$6.3130	($0.0900)	($0.1400)	$0.0575	($0.0525)
Oct-10	$6.4190	($0.0900)	($0.1400)	$0.0575	($0.0525)
Nov-10	$6.7690	($0.1050)		($0.0425)	($0.0500)
Dec-10	$7.1790	($0.1050)		($0.0425)	($0.0500)
Jan-11	$7.4040	($0.1050)		($0.0425)	($0.0500)
Feb-11	$7.4040	($0.1050)		($0.0425)	($0.0500)
Mar-11	$7.2340	($0.1050)		($0.0425)	($0.0500)
Apr-11	$6.7590	($0.1400)		$0.0550	($0.0600)
May-11	$6.7440	($0.1400)		$0.0550	($0.0600)
Jun-11	$6.8340	($0.1400)		$0.0550	($0.0600)
Jul-11	$6.9390	($0.1400)		$0.0550	($0.0600)
Aug-11	$7.0140	($0.1400)		$0.0550	($0.0600)
Sep-11	$7.0440	($0.1400)		$0.0550	($0.0600)
Oct-11	$7.1240	($0.1400)		$0.0550	($0.0600)
Nov-11	$7.3640	($0.0350)		$0.0650	($0.0250)
Dec-11	$7.6590	($0.0350)		$0.0650	($0.0250)
Jan-12	$7.8640	($0.0350)		$0.0650	($0.0250)
Feb-12	$7.8590	($0.0350)		$0.0650	($0.0250)
Mar-12	$7.6340	($0.0350)		$0.0650	($0.0250)
Apr-12	$7.0590	($0.0600)		$0.0650	($0.0300)
May-12	$7.0190	($0.0600)		$0.0650	($0.0300)
Jun-12	$7.0990	($0.0600)		$0.0650	($0.0300)
Jul-12	$7.1940	($0.0600)		$0.0650	($0.0300)
Aug-12	$7.2640	($0.0600)		$0.0650	($0.0300)
Sep-12	$7.2940	($0.0600)		$0.0650	($0.0300)
Oct-12	$7.3740	($0.0600)		$0.0650	($0.0300)
Nov-12	$7.6090	($0.0650)			$0.0300
Dec-12	$7.8990	($0.0650)			$0.0300

Min	$3.7150	($0.1400)	($0.1400)	($0.0475)	($0.0600)
Max	$7.8990	($0.0350)	($0.1400)	$0.1850	$0.0325
Average	$6.5871	($0.0902)	($0.1400)	$0.0389	($0.0333)

Footnote:

(1) Sources: Quotes.ino.com 6/11/09; Intercontinental Exchange (ICE) for Basis Swap information for Columbia Mainline (M/L) 6/11/09

(2) ANR SE and Columbia Mainline (M/L) Basis Swaps are being used for Perryville Hub due to their close proximity and direct connections to the area.
The Columbia Mainline (M/L) Basis Swap information is based on the bid/offer of -$.1475/-$.1400 posted on ICE on 6/11/09.