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WILLIAM L. HYDE

April 26, 1993

REPLY TO: Tallahassee

VIA HAND DELIVERY

Steve C. Tribble, Director
Division of Records & Reporting
Room 111
Florida Public Service Commission
101 E. Gaines Street
Fletcher Building
Tallahassee, FL 32399-0850

RE: Application for Determination of Need for an Intrastate Natural Gas Pipeline, Docket No. 920807-GP

Dear Mr. Tribble:

On behalf of Intervenor Florida Gas Transmission Company, I am submitting the original and fifteen (15) copies of the Pre-filed Rebuttal Testimony of Dr. Paul Carpenter with attached exhibits. Included as Exhibit 14 is a map of Florida Gas Transmission Company's natural gas pipeline system. A color-coded and more legible version of this same document will be filed tomorrow as a substitute Exhibit 14. I hope and trust that this will not cause any undue problems.

Of course, if you have any questions or if I can be of any further assistance, please do not hesitate to give me a call.

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Very truly yours,

PEEPLES, EARL & BLANK, P.A.

William L Hyde

William L. Hyde
For the Firm
Attorneys for Florida Gas Transmission Company

:nl
Enclosures

cc: All Counsel of Record

DOCUMENT NUMBER-DATE
04540 APR 26 93
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Application for Determination of Need for an Intrastate Natural Gas Pipeline by SunShine Pipeline Partners	)))))	Docket No.: 920807-GP Filed: April 26, 1993

REBUTTAL TESTIMONY

OF

PAUL R. CARPENTER

FOR

FLORIDA GAS TRANSMISSION

DOCUMENT NUMBER-DATE
04540 APR 26 93
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 920807-GP

REBUTTAL TESTIMONY OF

PAUL R. CARPENTER

ON BEHALF OF FLORIDA GAS TRANSMISSION

Q. Please state your name address and position.

A. My name is Paul R. Carpenter. My business address is 125 Summer Street, Boston, Massachusetts 02110. I am the President of Incentives Research, Inc.

Q. Did you file direct testimony and exhibits in this proceeding on April 12, 1993?

A. Yes, I did.

Q. What is the scope and purpose of your rebuttal testimony?

A. I will be updating and elaborating on my direct testimony based on new information received since that testimony was filed. I will also be responding to portions of the written and deposition testimony of FPC witnesses Watsey and Pollard and SunShine witnesses Burgin and Rose.

Q. What types of new information have been made available since your direct testimony was filed?

A. SunShine has provided additional financial and contractual information on its project, and direct testimony and documents have been produced by FPC which outline its economic and strategic evaluation of the project relative to the alternatives. Included among these documents were the results of a FPC task force entitled "Natural Gas Transportation Study and Recommendations," December 3, 1992 ("The

FPC Task Force Study"), which I have attached to this testimony as Exhibit ___ (PRC-7). An evaluation of the SunShine project for FPC by John J. Hibbs & Associates, December 1992, ("The Hibbs Study") was also produced and is attached as Exhibit ___ (PRC-8). Additionally we have now heard the deposition testimony of SunShine and FPC witnesses.

Q. Dr. Carpenter, could you begin by very briefly reiterating the conclusions you reached in your direct testimony based on your evaluation of the economic evidence presented by SunShine at that time?

A. Yes. I suggested in my direct testimony that the FPSC had essentially two alternative approaches to need determination available to it in this proceeding: (1) a traditional approach requiring a showing of net economic benefits and cost-effectiveness; and (2) a market-based approach requiring the demonstration of signed contracts and precedent agreements sufficient to indicate that shippers are willing to financially commit to pay a significant share of the project's fixed costs, and that the project sponsors are willing to bear project economic risks without any of the competitive distortions and ratepayer cross-subsidies that might result from FPC's equity investment in the project and/or its proposed regulatory treatment of that equity.

Based on my review of SunShine's application and evidence, I concluded that it had not made a sufficient showing to justify a finding of need under either approach. In particular, Mr. Rose's analysis of the demand for SunShine based on the potential growth in gas demand

for electric generation in Florida was overstated and not tied to the economics *or timing* of the SunShine project relative to its alternatives, including FGT. With respect to the market-based approach, I concluded that the precedent agreements submitted by SunShine were insufficient to demonstrate a market need for the project. At minimum, they indicate that the requested certification is premature. In addition, FPC's planned equity investment in the project is inconsistent with reliance on a "let the market decide" policy because it creates incentives for cost- and risk-shifting to FPC's electric ratepayers, and hence cross-subsidization of the project. These cost and risk-shifting incentives are illustrated by FPC's proposed regulatory treatment which would essentially guarantee it a high return on investment while passing the economic and financial risks associated with FPC's ownership position in the project onto its ratepayers. I recommended that under these conditions, the Commission must either employ the traditional approach, or require as conditions of certification that FPC's proposed regulatory treatment would be denied and that its equity investment in the project would be either prohibited or segregated from its other regulated assets in such a way that FPC and Coastal shareholders would bear all of the risks of undersubscription or underutilization of the project.

Q. Was there anything in the additional documents and testimony that you have seen which would alter these conclusions and recommendations?

A. No. If anything, they provide additional confirmation of my prior conclusions, as I will detail below.

Q. Dr. Carpenter, what is your understanding of the current status of shipper commitments to SunShine as illustrated by signed precedent agreements for firm capacity?

A. Since I filed my direct testimony, to my knowledge no new precedent agreements of significance have been executed for SunShine. However, a modified precedent agreement between FPC and ANR Southern was signed on April 8, 1993.

Q. What was the nature of the modification, and how does it affect the subscription levels you summarized on pages 14-15 of your direct testimony?

A. Originally, FPC had agreed to a MDQ of 120,000 MMBtu per day for the Anclote power plant to commence in 1995, and an additional 45,000 MMBtu per day for each of the two proposed Polk County units, the first of which would commence in 1998 and the second in 1999. The modified agreement between FPC and ANR Southern now includes the provision of a "Flexible FT" service for the Anclote plant in 1995. The initial level of FT commitment for Anclote has been reduced to 100,000 MMBtu per day, while the new flexible FT service involves a capacity commitment of 20,000 MMBtu per day year-round and an additional 20,000 MMBtu per day in the summer months. Thus the total FPC commitment for Anclote now ranges from 120,000 to 140,000 MMBtu per day depending on the season.

When coupled with the commitment from Peoples Gas, this raises the total commitment level slightly in the summer months. Thus, based on the signed precedent agreements to date, firm and (flexible

firm) MDQ for the project in 1995 now ranges from 157,500 MMBtu per day year-round to 190,000 MMBtu per day in the summer months. This represents from 63 to 76 percent of its design capacity in 1995. However, SunShine is still short of even the minimum threshold of 219,000 MMBtu per day in 1995 contained in the FPC precedent agreement. For the 1998 and 1999 period the level of MDQ commitment still ranges from only 50 to 55 percent of SunShine's planned capacity.

Q. Doesn't this seem to be a relatively high level of shipper commitment to the project?

A. No it is not, particularly when one compares these levels to the volumes which are necessary for SunShine to be able to recover its cost of service at the rates which are promised in the precedent agreements. As I pointed out in my direct testimony, the 52.5 cent per MMBtu initial rate for SunShine is a levelized rate that is based on 100 percent load factor utilization of the project in its expanded 1999 configuration. Thus, the relevant commitment levels to consider are those associated with the 1999 volumes. The precedent agreements that have been signed to date indicate that the project is only half-subscribed in this time period.

Furthermore, because the project's promised rates are based on capturing the economies of scale associated with the expanded 1999 configuration, once construction is started and if only 250,000 MMbtu per day of demand materializes by 1999, there is no *economic* option available to the sponsors to "down-size" the project to match the

demand and avoid losing massive amounts of money. According to SunShine's complete pro-forma financial simulation of the SunShine project, which I have attached as Exhibit ___ (PRC-9) to this testimony, the full subscription ***and*** utilization of the project in 1999 is essential to achieving break-even cost recovery at the rates which have been negotiated.

Q. What are the implications of this fact and the current 1999 subscription levels on SunShine for this proceeding?

A. The economics and timing of the project, its current subscription level, and the rates which have been offered combine to indicate that this is a very risky venture as proposed. This perhaps explains why FPC has recently signed a letter-agreement with ANR Southern which gives FPC the right to opt out of its equity partnership agreement if it does not receive FPSC approval for its proposed regulatory treatment by December 31, 1993 , a proposal which would guarantee its rate of return and pass project risks onto its electric ratepayers. I have attached this March 16, 1993 letter agreement to this testimony as Exhibit ___ (PRC-10). FPC, as an equity owner in the project, is unwilling to bear the risk that the project may not be needed, although it is happy to participate in the project if it can force its electric ratepayers to bear those risks. If FPC really had confidence in the need for SunShine, it would not require such an "out" as a condition of its equity participation in the project. Indeed, there is a fundamental contradiction in FPC's position in this proceeding. On the one hand, it is confident that the project deserves a certificate of need based on

demand forecasts, yet on the other hand it is not confident enough in those forecasts to commit its own resources to the project without indemnification by its ratepayers. This is a clear "market-based" signal to the Commission that SunShine may not be needed in the time frame or at the scale in which it is proposed to be constructed.

Q. Dr. Carpenter, you have stated here, and in your prior testimony, that the project needs to achieve full, 100 percent load factor utilization over its 25-year lifetime in order to recover its cost of service at the 52.5 cent rate. How does this square with the minimum subscription condition of 219,000 MMBtu per day in the precedent agreements?

A. It does not, and there appears to be some confusion on this point. In his deposition testimony on April 7, 1993 (p.64), SunShine witness Burgin was asked "where did the 219 come from?" His response was that "it was the basis for our overall rate that we have offered to potential shippers." However, the SunShine pro forma financial simulation shows that 250,000 MMBtu per day is required in 1995 (along with 424,500 and 549,500 MMBtu per day in 1998 and 1999 respectively) to recover the project's costs at the 52.5 cent rate over the project's life. (See the first page of Exhibit ___ (PRC-9)). In other words, if SunShine fails to secure shippers for the 1998 and 1999 expansions at the stated levels, as well as achieve shippers' commitments and utilizations of 250,000 MMBtu in 1995, the project will not recover its costs. Mr. Burgin appears to be incorrect based on the financial statements submitted by SunShine.

Q. Is there any indication in the documents you have examined where the

219,000 level actually came from?

A. Yes, there is. In Exhibit 5 to the Hibbs Study, Exhibit ___ (PRC-8), are financial simulations of the project as it was evaluated by FPC in late-1992. These simulations, as well as the ANR/SunShine proposal reviewed by the FPC Task Force Study (an attachment to Exhibit ___ (PRC-7)), were for a different pipeline configuration and size than the project proposed by SunShine in this proceeding. It appears that for the purpose of entering into its precedent agreement, FPC evaluated a project which would have a maximum capacity of only 400,000 MMBtu per day in 1999 instead of the current proposal's 550,000 MMBtu per day 1999 configuration. The projected capital costs of the project actually analyzed by FPC were only $463.7 million instead of the current proposal's capital cost of $618.9 million. The financial simulations analyzed by Hibbs for FPC indicated that for the *smaller* project, 219,000 MMBtu per day in 1995, increasing to 399,000 MMBtu per day by 1999, was sufficient to recover the project's cost of service over its lifetime at the 52.5 cent rate. Based on the larger project proposed by SunShine in this proceeding, 219,000 MMBtu per day in 1995 is no longer sufficient to make the project economic at the promised 52.5 cent rate. The 219,000 threshold in 1995 has no relevance to the economic viability of the SunShine project as it is currently proposed.

Q. How significant is this change in the project's scale for the economics of the project if it fails to achieve the increased subscription and utilization level necessary to support it?

A. The change is potentially very significant to the project's economics. To see how large the effects might be, I have calculated what the revenue shortfall for the project would be on a present value basis if it only attracted the volumes contemplated as necessary to support the smaller project at the 52.5 cent rate. Recall that these volumes were 219,000 MMBtu per day in 1995 increasing to 399,000 MMBtu per day starting in 1998. As Exhibit ___ (PRC-11) indicates, the 1995 present value of the pre-tax revenue shortfall from such an outcome would be $200 million. This is greater than the total equity to be invested in the project under the proposed 75/25 debt/equity capital structure. Note that the volume levels assumed in this analysis are greater than the volumes currently committed to the larger project via precedent agreements. Thus, the significance of the current subscription shortfall to the economics of the project is even greater than these figures would suggest.

Q. What are the implications of this apparent change in the scope and economics of the project for this proceeding?

A. There are several implications. First, the project proposed by SunShine in this proceeding requires a higher level of shipper commitment for economic viability than the proposal evaluated by FPC when it made its decision to sign a precedent agreement. The Commission should weigh this in considering whether the amount of precedent agreement commitment is currently sufficient to show a need for the project. Second, this change in the project's scope raises significant questions as to the process by which FPC determined that

SunShine was the preferred option for meeting its gas transportation needs, and whether the precedent agreement that it signed is a true indication of the market's evaluation of the larger SunShine project. This is particularly troubling in light of FPC's request that it be given an equity return guarantee at the expense of its ratepayers, and when it is apparent from the deposition testimony of Mr. Pollard that a later competing offer from FGT was not considered by FPC.

Q. Dr. Carpenter, you indicated in your direct testimony in response to Mr. Rose's year 2000 and 2010 forecasts that the SunShine project may be premature based on the evidence from currently signed precedent agreements and from the Florida utilities' plans for electric generation capacity expansion. Have you had a chance to examine the potential for conversion of existing power plants to gas in the 1995 to 1999 time period?

A. Yes, I have. Exhibit ___ (PRC-12) is a list of the existing power plants in the state of Florida that are owned by the four investor-owned utility companies in the state. The plants are ranked according to their 1991 utilization. In the shaded box at the top of the exhibit are the seven nuclear and coal baseload plants with capacity factors of greater than 70%. In the shaded box at the bottom of the exhibit are peaker units, plants with capacity factors of 5% or less -- new firm gas service at these coal and nuclear baseload and peaking plants is unlikely to be economic. In the middle of the exhibit are the oil- and gas-fired intermediate units along with a few coal units and one nuclear unit that was down for much of the year.

It is presumably these oil-fired intermediate units that Mr. Rose represents as having the greatest potential for conversion. To isolate those plants that are truly candidates for conversion to gas delivered by SunShine, the exhibit shades those plants that are: (1) already predominantly using gas, (2) already connected to FGT and thus had the opportunity to subscribe for firm gas transportation in Phase III if such firm transportation was desired, and (3) the units that are nuclear or coal-fired. The five remaining unshaded plants represent the possible candidates for conversion.

Of these five, the Fort Myers plant is in Lee County and thus is a substantial distance from both FGT and the proposed SunShine project. Hookers Point and Phillips are small, low utilization plants -- it is unlikely that firm gas service at those plants would be economic. That leaves Anclote and Florida Power & Light's Manatee plant. While it is presumably possible for SunShine to extend a lateral to Manatee, I understand that FGT's line runs within 13 miles of the plant.

The state's three largest non-investor-owned utilities, Jacksonville Electric Authority, Orlando Utilities Commission and Seminole Electric Cooperative, rely on a mix of coal, nuclear and gas-fired plants. They have no major oil-fired plants that would be candidates for conversion.

Q. Is there other evidence of the SunShine project's premature timing?

A. Yes, there is. The primary near-term load which appears to determine the 1995 timing of the SunShine project is the conversion of FPC's

Anclote power plant to natural gas. Over 73 percent of SunShine's 1995 commitment level is due to Anclote alone.

Q. What does FPC's analysis say about the economics of the Anclote conversion?

A. The results of FPC's analysis of the Anclote conversion are described in its Task Force Study (Exhibit ___ (PRC-7)) on pp.II-12 - II-14. It states that:

> The expected present worth revenue requirements savings of the Anclote conversion including fuel savings and the capital cost of conversion, is $30 million (1992)... This includes savings resulting from the fact that the Crystal River Units 1 and 2 will not be required to burn low-sulfur coal. Based on the levelized annual revenue requirement for the conversion cost of $17 million (1992$), the annual cost to FPC's customers is approximately $2 million in 1996, $3 million in 1997 and $2 million in 1998. The annual net benefit to FPC's customers begins in 1999 with a net benefit of approximately $2 million... If Crystal River Units 1 and 2 are required to burn low-sulfur coal, the savings from the Anclote gas conversion may be eliminated.
>
> In order to test the sensitivity of the results of changes in the assumed price of natural gas, the price of gas varied by ± 20%. The results of these sensitivities indicated that the Anclote gas conversion would result in a savings of $155 million if the price of natural gas is 20% lower than expected. If the

price of gas is 20% higher than expected, the Anclote conversion would result in increased costs of $91 million.

Based on FPC's own analysis, the net economic benefit of the Anclote conversion is very sensitive to the forecast of and variability in natural gas prices, is dependent on a response to the Clean Air Act that assumes that the Crystal River Units are not converted to low-sulfur coal, and the stream of net benefits does not become positive until 1999 at the earliest.

Q. Has any other analysis by FPC echoed these conclusions regarding Anclote?

A. Yes. The FPC Task Force Study also reports the results of an evaluation of the project by analysts of Florida Progress Corporation, the holding company parent of FPC. (See pp. V-2 - V-4 of Exhibit ___ (PRC-7)). These analysts recommend against committing to the SunShine project partly because of its timing relative to the economics of converting Anclote to gas and the need to maintain flexibility in FPC's compliance response to the Clean Air Act. As they state in their recommendations:

> The primary objective in selecting a gas transportation vendor is to secure gas transportation for the planned Polk county units at the lowest cost with the lowest risk. Given the nature of the options available to FPC, there are two additional considerations which deserve to share the status of primary objectives. The first of these is to preserve flexibility regarding the conversion of Anclote to gas. The second is the

preservation of flexibility relative to the possible future conversion of the Polk units to coal...

The selection of ANR (SunShine) would require the early conversion of Anclote to gas, thus preempting by several years the need to make this decision for Clean Air Act compliance. At present, the Anclote conversion is an option for compliance, but has not been identified or recommended as the best option. Furthermore, projections indicate that the conversion is likely to increase rates to consumers during 1996-1998. *Therefore, the proposed timing cannot be supported on economic grounds.* The selection of FGT would provide greater flexibility for the timing of the conversion and, in principle, make it optional...

FPC should proceed immediately to enter into an agreement with FGT for gas transportation. *An essential first step in this process should be a reevaluation of the proper timing for the conversion of Anclote to gas.* Although the proposed delivery of gas to Anclote in March 1997 by FGT is preferable to the 1995-96 delivery required by ANR, FGT's inherent flexibility may provide further opportunity for improvement. [Emphasis added.]

As seems apparent from these analysts' conclusions and recommendations, the need for the conversion of Anclote in the 1995 time period has not been established by FPC or SunShine. Since the need for SunShine in this time period is heavily dependent on the

timing of Anclote, this evidence raises serious doubts about whether FPC's precedent agreement with ANR for 120,000 - 140,000 MMBtu per day in 1995 is sufficient or credible for the purposes of establishing the need for SunShine in this proceeding.

This evidence also illustrates what can happen when a potential shipper on a proposed pipeline is also an equity owner. It is no longer possible to interpret the evidence of project commitment in an owner/shipper's precedent agreement as evidence that the project is needed. It is clear that FPC is using the Anclote conversion as "leverage" for SunShine. As an equity owner in the project FPC's incentives will be to try insure its success, where the price of this insurance compromises FPC's resource planning for its Anclote facility. These effects may be subtle to detect, but the incentives are undeniably present. In this case there is direct evidence from Florida Progress Corporation's own analysis that, at a minimum, the timing of the SunShine project is premature.

Q. What about the point raised by Mr. Burgin on page 17 of his direct testimony that unless SunShine is built now it is unlikely that there will ever be a second pipeline in Florida?

A. Mr. Burgin's fears are groundless. There is no reason why SunShine, or another competitive proposal, would not be forthcoming for service in the year 2000 time frame, particularly if the demand forecasts for the year 2000 and 2010 presented by Mr. Rose hold true. Indeed, one of the options that was presented to FPC by ANR in its October 28, 1992 proposal was for 239,000 MMBtu per day in 1999 with an

increase to 464,000 MMBtu per day in 2000. (See "Option 4" in the proposed term sheet attached to the letter from Mr. Burgin to Mr. Watsey attached as Exhibit ___ (PRC-13)). As the Florida Progress Corp. analysts concluded:

> As the present circumstances demonstrate, the threat of competition can be as effective as the actual existence of competition. The potential for competition has existed and will continue to exist in Florida and exert a subtle pressure on FGT. As the market grows and existing transportation contracts expire there will be many potential opportunities for the entry of competitors if they can compete successfully with FGT. Placed into this context, the present situation cannot fairly be characterized as a now-or-never opportunity to "create" competition. (Exhibit ___ (PRC-7) on p.V-4)

Similarly, in this proceeding it would be a mistake to conclude that if the Commission denied SunShine's application for a need determination at this time that the possibility of a second pipeline in the future would be foreclosed. This decision need not and should not be made solely on the simplistic assumption that "two pipelines are better than one."

Q. If the SunShine project were delayed until the demand materialized in the late 1990's, wouldn't customers who were counting on SunShine capacity in the interim be harmed?

A. Not in my opinion. The only other customer to have signed a SunShine precedent agreement for the interim period, other than FPC

for its Anclote plant, is Peoples Gas System. But Peoples demand of 35,700 to 50,000 MMBtu per day in 1995 is small relative to the size of the SunShine project, and as I understand it, FGT would be able to accommodate requests by Peoples, which is an existing customer of FGT, for increased pipeline capacity in mid-1996 through its Phase IV expansion. Since FGT's Phase IV expansion would be accomplished primarily through the addition of varying amounts of compression, it would be able to tailor its expansion flexibly to meet the needs of individual customers at particular locations on its system during this time frame.

Q. Dr. Carpenter, in their discussion of the benefits of SunShine several witnesses have mentioned the access of SunShine to various upstream supply sources as an advantage of the project relative to FGT. Do you have any information concerning the upstream supply sources to which FGT is connected?

A. Yes. I have attached a map of FGT's system and a list of its pipeline interconnections and their respective capacities as Exhibit ___ (PRC-14). As the exhibit indicates, FGT has interconnections with 14 inter- and intrastate pipelines in the state of Louisiana with a combined capacity of 2,685 MMcf per day and 8 pipelines in the state of Texas with a combined capacity of 1,065 MMcf per day. Combining these interconnects with "Other" interconnections of 260 MMcf per day, FGT's system provides over 4 Bcf per day of upstream interconnection capacity.

Unlike SunShine, FGT is also directly connected to United's

system with an interconnection capacity of 240 MMcf per day in Louisiana and 90 MMcf per day in Texas. Thus, it would be unnecessary (although certainly feasible) to employ displacement transactions to receive gas off of United into FGT. For these reasons, there is no evidence that SunShine offers different or better access to upstream supplies and capacity than does FGT.

Q. Does this complete your rebuttal testimony?

A. Yes it does.

FPC Natural Gas Task Force Study

NATURAL GAS TRANSPORTATION STUDY AND RECOMMENDATIONS

Florida Power Corporation

December 3, 1992

Section I: INTRODUCTION

Following the decision in early 1991 to construct natural gas fueled combined cycle units at the Polk County site, a task force was organized to assess the attendant natural gas supply and transportation requirements. The first objective was to determine if the supply base of natural gas in the U.S. was adequate to meet the projected demands from the present until the year 2010 and allow FPC to reasonably project that a reliable supply of competitively priced natural gas would be available for the Polk County units.

Natural Gas Supply/Demand

Many in-depth studies on supply, demand and market outlook have been conducted by respected organizations in the natural gas industry and governmental agencies including American Gas Association, Gas Research Institute, Energy Information Administration, EEI/EPRI, Data Resources, Inc., Energy Modeling Forum, Enron Corporation and the Potential Gas Committee. Volumes of data have been generated and are available for reference, as needed. They all conclude that reasonably priced natural gas supplies will be available for the projected requirements including substantial growth in natural gas fired electric generation.

The supply/demand situation has been and will continue to be monitored as an essential component to our overall supply and transportation requirements.

Primary energy use in the U.S. is projected to grow about 16.5% (0.8% annually) from 1990 to 2010. Natural gas consumption, however, is projected to climb roughly twice as fast or about 34% (1.5% annually) over the same 20- year period and increase its share of primary energy consumption from 23.9% in 1990 to 26.6% by 2000 and beyond.

Three-fourths of the demand is projected to occur in electricity generation and natural gas vehicles.

Historically, most electric utilities that burn gas have been able to switch to residual oil when gas supply was constrained or priced higher than oil. It remains to be seen if environmental constraints might limit the impact that fuel switching has on gas demand.

Projections are that one-third to one-half of the electric generation coming on line between now and 2010 will be fueled by natural gas, primarily driven by the 1990 Clean Air Act. Some states, particularly in the mid-West, have mandated that utilities add scrubbers to their coal units and continue to burn coal to save mining jobs. While financial incentives are provided to help those utilities with the tremendous costs involved, the strategy might be risky if environmental constraints are tightened, especially relating to carbon dioxide emissions and air toxics.

INTRODUCTION

Earlier this year, the number of rigs drilling for oil and natural gas in the Gulf of Mexico reached a historic low of close to 600 rigs. The rig count reached this level for two primary reasons: first, the price of natural gas at the wellhead was extremely depressed for the prior two years while oil prices also remained relatively low also; and second, increasing environmental requirements continue to add to the cost of exploration and development which raises the total cost of production. Most of the major oil and gas companies have deployed increasingly larger percentages of their capital resources to foreign fields where they are welcomed with open arms and where the cost of recovering gas and oil is much cheaper. It should be noted, however, that because of natural gas price increases over the past several months, the drill rig count has reversed its downward trend, and the number of active rigs has increased significantly to the 800-plus range.

Increasing pipeline access for low-cost, low-priced Canadian gas to U.S. markets will act as a dampener on gas price increases that will result from growing U.S. gas demand.

In summary, the natural gas market will grow at a manageable rate, and reliable, competitively-priced gas should be available to meet our requirements. Some short-term volatility in supply and price is expected to occur from time to time.

Natural Gas Transportation

The second objective was to evaluate the alternatives available for transporting natural gas to the Polk County Site. Several options were examined including a pipeline from the Mobile Bay producing area under the Gulf of Mexico to FPC's Anclote Plant. Each option was evaluated with respect to "must" and "want" criteria utilizing the Kepner-Tregoe (K-T) Decision Analysis process. In order to assure objectivity, Walt Lockwood, FPC's expert on K-T, acted as facilitator.

"Must" criteria for the pipeline included initial operation meeting scheduled testing of the first Polk County unit, adequate capacity and reliability. "Want" criteria included expansion capability, cost competitiveness, supply access, operating flexibility, regulatory support and appropriate degree of FPC control. The conclusion reached from the analysis indicated that a competitive pipeline project would be superior to expansion of the only major natural gas pipeline in Florida, but also recognized that the competitive pipeline approach would likely involve a slightly higher degree of risk.

Further evaluation also indicated that an intrastate pipeline regulated by the Florida Public Service Commission (FPSC) would be more desirable than an interstate pipeline regulated by the Federal Energy Regulatory Commission (FERC). Preliminary activity was initiated to prepare for a bill to be filed authorizing the FPSC to regulate intrastate natural gas pipelines.

INTRODUCTION

Execution of our overall strategy for the Polk County units required that a Determination of Need (DON) proceeding be filed before the FPSC which, was subsequently scheduled in November 1991.

Meanwhile, it became evident that the potential for burning more natural gas at existing plants should be evaluated because a large initial load, the "anchor load," would be necessary to attract a competitive pipeline project. It was determined that the Anclote Plant could be converted to burn gas as well as oil and that the additional amount of gas this would require, along with other, smaller customers' needs, would be sufficient to justify a competitive project.

A review of the existing natural gas pipeline systems and contacts with major producers and pipelines resulted in ANR Pipeline Company, a division of Coastal Corporation (ANR) and United Gas Pipeline Company (United) emerging as the most likely to be able to provide the service we required. FPC initially opted to work with a join-venture pipeline project proposed by for an ANR and United, which became known as the SunCoast Pipeline. FPC signed a letter of intent to be a customer of the SunCoast Pipeline in December, 1991, and obtained an option to become up to a 33-1/3% equity participant. As FPC believed, its requirements for gas transportation to Anclote and Polk County formed a sufficient "anchor load" to induce ANR and United to spend the time, effort and capital to develop a pipeline project that would serve FPC's needs and bring competition to Florida gas markets.

The DON hearings were held before the FPSC in November 1991, resulting in a subsequent order authorizing Polk County Units 1 and 2. A cornerstone of FPC's testimony was the fact that the Polk County units and Anclote would serve as the "anchor load" for a new competing pipeline project. FPC also advised the FPSC staff that it might become an equity participant in the new pipeline as further support for its development and construction. (See Section II for details).

Concurrently, a drive spearheaded by United was underway to prepare legislation for filing in the 1992 Legislative Session. FPC sublimated its legislative efforts to those of United as the most efficient and cost-effective way to promote enactment of a Florida gas regulatory statute. The bill was not passed into law in the regular session, primarily due to opposition from the REAs, the railroads and Tampa Electric Company. Through the extraordinary efforts of many people and a very significant lobbying effort in which FPC played an important role, the bill was placed on the agenda for the special session and was voted out favorably by a 38-2 margin in the Senate and 110-0 in the House. The Natural Gas Transmission Pipeline Siting and Regulatory Act was signed into law by Governor Chiles on June 24, 1992.

Beginning in June 1991, discussions had been held with Florida Power & Light Company (FPL) about the possibility of FPL becoming a customer of and/or partner in a new pipeline project. FPL had a need for an incremental 200 MMbtus/day of gas supply and expressed interest in the SunCoast project. In July 1992, however, FPL advised that they

would commit their requirements to Florida Gas Transmission Company (FGT). Immediately thereafter, the SunCoast Project and partnership, as it was then constituted, was disbanded.

FPC continued discussions independently with ANR and United, and with Koch Industries, who was negotiating to buy United. As it had throughout the negotiations with the SunCoast project sponsors, FPC continued to leverage the volumes at Anclote to secure the best possible terms and conditions for our total gas transportation requirements, and with respect to our potential status as a minority equity owner in the partnership that would develop the new pipeline.

In October 1992, a letter was sent to ANR, United, and FGT advising that their best and final proposals should be forwarded to FPC no later than October 28, 1992, the intent being to bring closure to the many months of discussions and exchanges of information that had taken place. The proposals are thoroughly evaluated and analyzed in this document.

The primary strategic thrust of this entire effort from its inception in May, 1991, has been, and is, to provide the lowest cost natural gas to the burners at the Polk County units so that we can produce electricity at a lower cost than our neighboring generators.

Recent Developments

United Gas Pipeline Company

Koch Industries of Wichita, Kansas closed a transaction to acquire United on November 4, 1992. The deal was for all cash including paying off approximately $300,000,000.00 of debt due March 31, 1993.

Koch Industries has revenues of approximately $19 billion annually and virtually no debt. They plan to upgrade the United system and aggressively market the capacity which has been grossly underutilized for many years.

Most of United's upper management was terminated effective November 10, 1992. There is concern in the industry about the effects of this upheaval on the United system going into the winter peak season.

FGT Phase III Settlement

On August 25, 1992, FGT filed a proposed settlement with FERC of the outstanding issues on their Phase III expansion project. This settlement provides some details of the contract terms and rate provisions agreed to by the parties including Florida Power & Light and several cogenerators in the state. A copy is included in the Appendix.

INTRODUCTION

FGT Phase IV

In addition to proposing a Phase IV expansion project to Florida Power, trade press articles indicate that FGT is also marketing to other potential customers.

Section II:
ROLE OF NATURAL GAS IN INTEGRATED RESOURCE PLANNING (IRP)

1991 RESOURCE AND GENERATION NEED SUMMARY

In August 1991, Florida Power Corporation petitioned the FPSC for a DON to construct four natural gas-fired combined cycle (CC) generating units in Polk County during the years 1998-2000. In that petition, an integrated resource study demonstrated that FPC would require additional generating resources to meet customer load growth in the years following 1997.

FPC's use of Integrated Resource Planning (IRP) led to the development of a balanced, cost-effective portfolio of resources for supplying its customers' needs. The integrated resource plan, which includes the proposed Polk County CC units, first makes aggressive use of the demand-side management resources inherent in FPC's service area. The plan further diversifies the resource portfolio by placing a significant reliance on capacity and energy from qualifying facilities (QFs), out-of-state purchases, and the installation of new transmission resources.

FPC's 1991 IRP study called for meeting 1,445 megawatts (MW) of demand, almost 30 percent of projected load growth, with demand-side management programs. An additional 751 MW, about 15 percent of load growth, will be provided by QFs, all of which have signed contracts with FPC. FPC also will install about 364 MW of combustion turbine (CT) peaking capacity in November 1992 and 404 MW of CT peaking capacity in November 1993. Additional capacity equivalent to 984 MW will be added with the completion of a 500-kilovolt (kV) tie line to Southern Company, a purchase from Southern Company, and the addition of interruptible load customers. The integrated resource study demonstrated that the remainder of FPC's load growth, approximately 940 MW, can be supplied in a cost-effective manner by the Polk County units.

The proposed Polk County plants will be sited on a parcel of mined phosphate lands. This site was chosen by a lengthy, careful search conducted in consultation with community and environmental interests. The existing site has clay settling ponds and other topographic features that are readily adaptable to power plant use. Moreover, the site can accommodate more than 2,000 additional MW of future electrical generating capacity, as well as coal gasification (CG) facilities. Finally, the site is centrally located with respect to FPC's load and will require minimal additional transmission construction.

The Polk County units, together with the proposed conversion of existing FPC generation, will require FPC to make a substantial commitment to the use of natural gas. This commitment is driven by and will play a key role in FPC's compliance strategies for meeting the Clean Air Act (CAA) requirements for the year 2000.

ROLE OF NATURAL GAS IN IRP

On February 25, 1992, the FPSC approved its Hearing Officer's recommendations on FPC's petition for a DON for the first two Polk County CC units (470 MW). The additional 470 MW of natural gas-fired CC capacity will require further FPSC consideration at a later date.

FPSC'S ORDER ON FPC'S PETITION FOR DON

On February 25, 1992, the FPSC issued a DON for the first 470 MW of Polk County CC power plants, to be fueled primarily with natural gas. Betty Easley, Hearing Commissioner, and the FPSC, which has sole responsibility for the determination of need for the facility, concluded in an order in Docket No. 910759-EI that

> *[T]he first two proposed combined cycle units on Florida Power Corporation's proposed Polk County site will contribute to electric system reliability and integrity... [T]he addition of the first two units will enable Florida Power to meet...winter reserve margin criteria and to withstand the outage of its largest unit at time of system peak. The combined cycle technology chosen is a sufficiently mature and reliable generating option for Florida Power's system. The first two Polk County units will contribute to diversifying Florida Power's system fuel mix, and thus contribute to the integrity of Florida Power's system.*

The FPSC also concluded that

> *While the issues of gas transportation to the Polk County site are somewhat more complex, I also conclude that adequate assurances have been provided in this proceeding that gas transportation capacity will be available to serve the needs of the first two Polk County units. Florida Power contends, and I agree, that construction of a second natural gas pipeline into peninsular Florida will provide a variety of strategic benefits for the state. While the strategic benefits alone cannot lead to a determination of the need for the proposed power plants, certainly the Commission may consider them in this proceeding. I have so considered them in light of the new pipeline's contribution to fuel diversity for Florida Power and the State, and in light of the lead times associated with construction of the pipeline and the plants.*
>
> ****
>
> *A commitment of one or more key shippers to use approximately one-third to one-half of the pipeline capacity is necessary to anchor the new pipeline (FF102).*
>
> ****
>
> *Because six or seven years are typically need to bring a new pipeline of this size into service, it is necessary to make the decision of the units necessary to*

"anchor" the pipeline now. (FF105) Anclote plus two Polk Units will use approximately half the pipeline capacity, and, therefore, they should act as a strong anchor load.

On March 26, 1992, the Florida Industrial Cogeneration Association (FICA) filed a notice of appeal of the Commission's Order No. 25805 granting FPC's petition for a determination of need. On April 7, 1992, the Florida Supreme Court stayed the appeal pending disposition of a motion for reconsideration filed by the Floridians for Responsible Utility Growth (FRG).

On June 11, 1992, the FPSC denied the motion for reconsideration filed by FRG, leaving its original February order unchanged. FRG agreed to not pursue an appeal, leaving FICA as the sole appellant.

On September 17, 1992 FPC and FICA agreed to a negotiated settlement which resulted in FICA withdrawing their appeal before the Florida Supreme Court.

The FPSC's final order determining FPC's need for two natural gas fired CC plants at the Polk County site (one in 1998 and one in 1999), for a total of 470 MW, is now uncontested.

1992 RESOURCE PLAN

During 1992, additional information on resources and assumptions used in the 1991 IRP study were revised to forecast a new 1993 generation expansion plan. The revised assumptions include: updates on DSM programs, revised CAA compliance limits, new customer demand and energy forecasts, revised fuel forecast, increased cogeneration capacities, new 500 kV tie line information and updated FPC existing capacity requirements. The following is a summary of these changes:

Demand-Side Management (DSM)

The DSM requirements through the year 2001 have remained at 1445 MW. A slight adjustment in the timing and scope of some of the programs has been made to reflect more appropriate DSM programs.

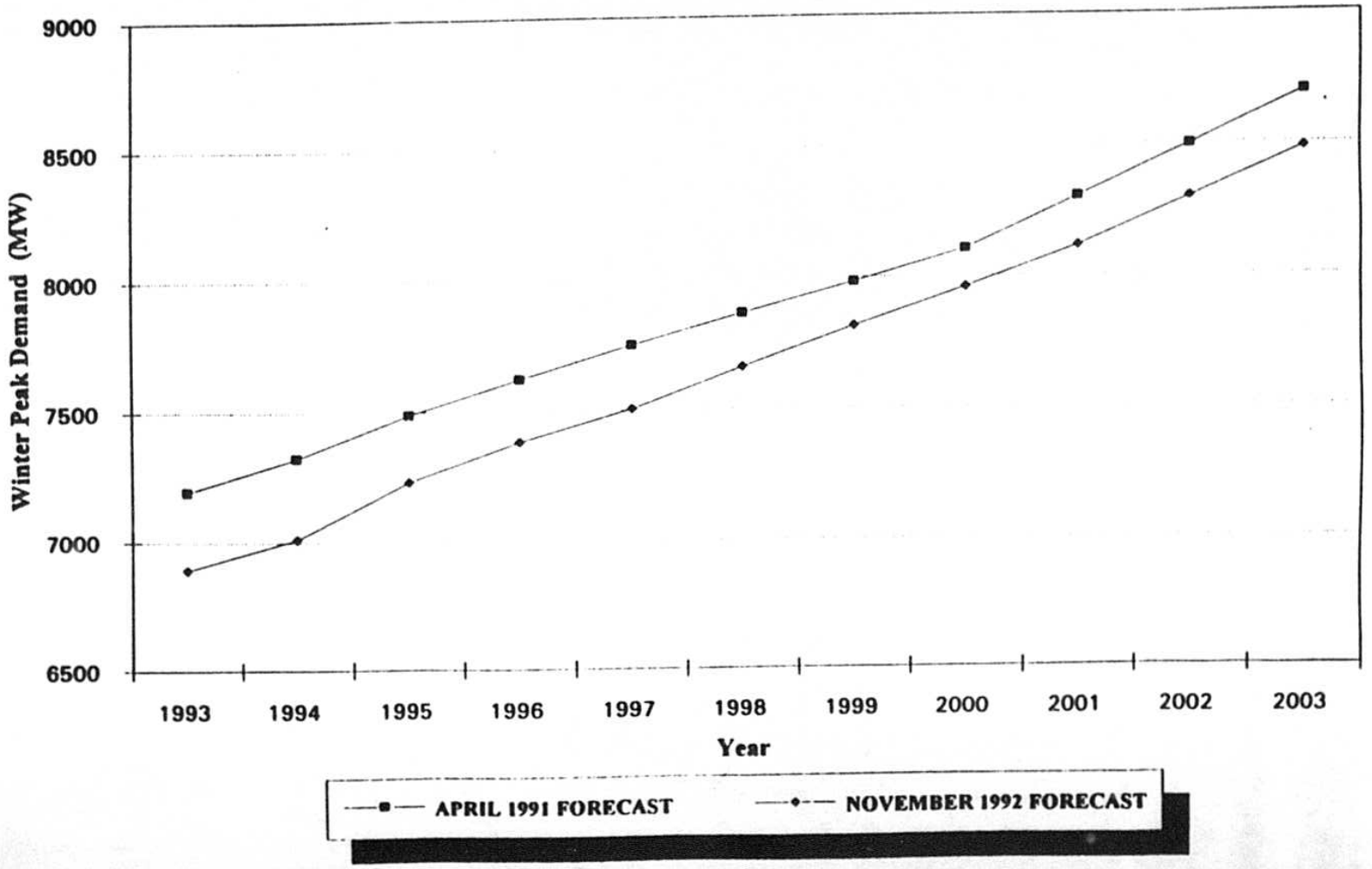
Sulfur Dioxide (SO_2) Emissions

The CAA compliance limit for sulfur dioxide (SO_2) has been revised to 123,903 tons from the initial 130,000 ton approximation used in the 1991 IRP study. See Appendix II for the compliance limit calculation of 123,903 tons. The 1991 IRP Study assumed that Anclote would remain on low-sulfur oil. The current studies show that Anclote will be dual fuel capable utilizing natural gas and residual oil, after the completion of a gas pipeline to the plant.

Comparison of Demand Forecasts

Winter Peak Demand

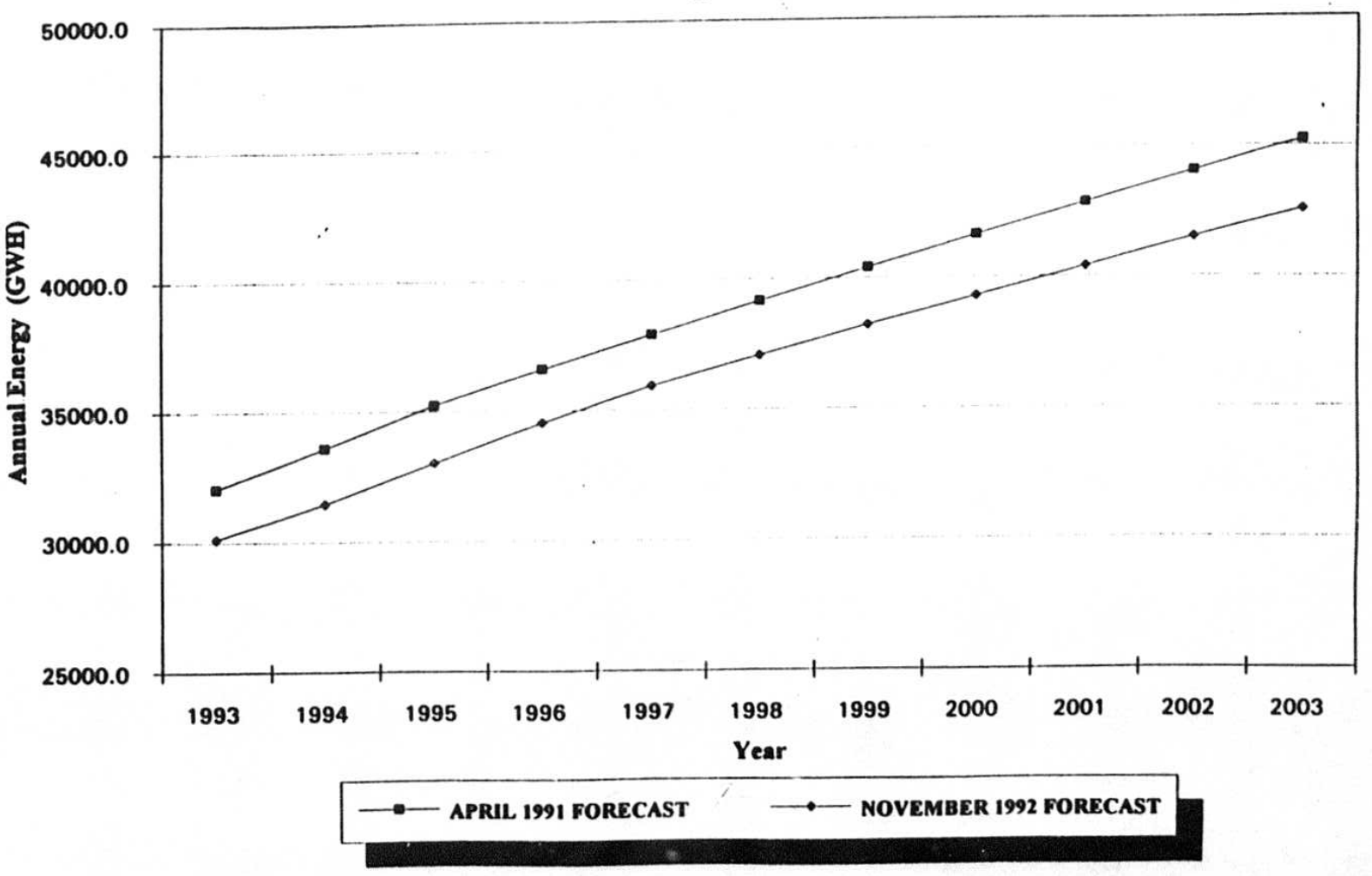
Figure II - 1



Comparison of Energy Forecasts

Annual Energy (System Requirements)

Figure II - 2



ROLE OF NATURAL GAS IN IRP

Demand and Energy

System demand and energy requirements have been reduced significantly from the 1991 IRP study due to prolonged economic downturns and reduced wholesale requirements. There has been an approximate 250 MW reduction in winter demand and 2,000 GWh reduction in annual energy from the 1991 IRP study. Comparisons of the demand and energy forecasts are shown in Figures II-1 and II-2.

Cogeneration Capacity from QFs

The cogeneration contracts initiated in 1990 were forecasted to have a 25% failure rate. Current 1992 projections appear to show most of the contracted capacity will come on line. FPC expects to receive 177 MW more cogeneration capacity above the level assumed in the 1991 IRP Study.

New 500 kV Tie Line

The 1992 500 kV tie line studies have projected an in-service date of 2003 for the new tie line addition. This date is a revision of the 1997 date used in the 1991 IRP study.

FPC's Existing Capacity

The retirement schedule used in the 1991 IRP Study was accelerated and modified during 1992. There is a possibility that the Turner steam plant may be placed in extended cold shutdown (ECS) in 1993. The 1991 IRP Study showed the Higgins site and Avon Park peakers retiring in years 2000 and 2001, respectively. The proposed ECS units at Turner replace the Higgins steam retirement while the retirement of peakers has been deferred.

Fuel Forecasts

The current forecast for fuel prices is lower than the forecast used in the 1991 IRP Study was reduced for 1992. The escalation rate for fuels was lowered from 5.1% in the 1991 IRP to 4.2% in the 1992 forecast. Natural gas prices in 1995 were lowered from 330¢/MMbtu to 215¢/MMbtu. Residual oil prices (high sulfur: 2.5%) were lowered from 349¢/MMbtu to 238¢/MMbtu. Coal prices (compliance coal: 0.7% sulfur) were lowered from 221¢/MMbtu to 214¢/MMbtu in 1995. The fixed-demand charge used for fuel cost estimation for natural gas transportation was raised from 30¢/MMbtu fixed in 1999 to 70¢/MMbtu escalating with inflation.

Existing Unit Gas Consumption

Currently, Bartow Unit 3, Higgins Units 1 & 2, all of the Suwannee steam units and Turner 3 and 4 are capable of consuming gas. The peakers at Avon Park and Higgins are also capable of consuming gas. Only interruptible gas is available at these units. FPC is negotiating a long-term gas contract to supply 10,000 MMbtus/day to Suwannee steam units beginning in 1994 with South Georgia Natural Gas Company.

In addition, the 40 MW cogeneration project being built at the University of Florida will be operated on natural gas supplied by Gainesville Regional Utilities in November 1993.

Future expansion of gas to fuel FPC's existing units (with gas capability) will involve transportation through FGT or a competing pipeline supplier. If a competing pipeline supplier were selected as transporter of gas supplies for these units, FPC would also require transportation by FGT through a part of its system, or under a contract with a distributor, such as People Gas, to utilize a part of the FGT system. The largest benefit to FPC from the increased use of gas, other than at the primary sites, would be at Bartow. Bartow Unit #3, with a capacity of 215 MW, could provide opportunities to utilize gas more effectively, while helping to reduce SO_2 emissions at that site.

PROPOSED 1993 TEN-YEAR SITE PLAN

Overview

Utilizing the new information presented in the previous discussion, "1992 Resource and Assumption Update", a proposed 1993 Ten-Year Site Plan is being developed. The major revision in this plan from the 1991 IRP study will be to defer Polk County 3 & 4 and to convert the Anclote Plant to natural gas.

Florida Power's proposed 1993 Ten-Year Supply-Side Expansion Plan is shown in Figure II-3.

ROLE OF NATURAL GAS IN IRP

Figure II-3

1993 Ten-Year Supply-Side Expansion Plan

As of January	New FPC Peaking (MW)	QF Additions (MW)	500 kV Tie Line (MW)	Polk County CC (MW)	Anclote Gas Conversion (MW)	Plant ECS/ Retirement (MW)
1993	364	68				[1]145
1994	424	312				
1995		439				
1996		139			1034 [2]	
1997		4				
1998				235		
1999				235		
2000						
2001						
2002						
2003			500			

[1] Turner Steam Plant proposed to be placed in Extended Cold Shutdown.
[2] Anclote gas conversion will not add net new capacity to the FPC system and can be scheduled to meet earlier in-service dates of the pipeline, if required.

Polk County 1 and 2

FPC's need for the Polk County 1 & 2 units has been approved by the FPSC and the units are reflected in FPC generation capacity plans as two natural gas fired CC units with capacities of 235 MW each. In-service dates for those units are in November of 1998 and 1999, respectively.

Polk County 3 & 4 Deferral

Due to the reduction in demand and energy and the increase in cogeneration capacity from QFs, the current 10-year generation plan shows adequate reliability without the addition of Polk County 3 & 4 within the 10-year planning horizon. FPC's current expansion plans show no generation capacity additions, beyond Polk County 1 & 2. Since the typical lead time for CC units is three to five years, given adequate supplies of natural gas, the Polk County units 3 & 4 in-service dates could be changed depending upon system requirements. Gas supplies should be flexible enough to accommodate these possible changes.

Cogeneration Capacity from QFs

FPC anticipates that approximately 962 MW of additional QF capacity will be constructed and on line between the years 1993 and 1996. The total QF capacity on FPC's system by 1997 will be 1,096 MW.

Emission Compliance Strategies

FPC's generation expansion plans are designed to meet the CAA's sulfur dioxide (SO_2) limits in the year 2000 and beyond. FPC's emissions compliance strategies include both increasing use of natural gas on FPC's system and burning lower sulfur fuels at other facilities. The three major options which FPC has available as part of the company's CAA compliance strategies are:

1. Fuel switch Crystal River 1 & 2 to low-sulfur coal.

2. Burn natural gas in place of higher sulfur fuels (Anclote gas conversion, Polk County combined cycle units on natural gas).

3. Burn low-sulfur oils.

Preliminary compliance plans indicate that two of the above three options will be required. Due to the dynamics of economic dispatch and load forecasting, there is uncertainty in projecting SO_2 emissions in the year 2000. However, if FPC can position itself to meet future load growth beyond 2000 with clean fuels and efficient technologies, the company can avoid more costly compliance measures such as scrubbing coal plants.

FPC's two major compliance scenarios are:

1. Convert the Anclote to 100% natural gas while retaining oil burning capability and switch the Bartow plants to low-sulfur oil.

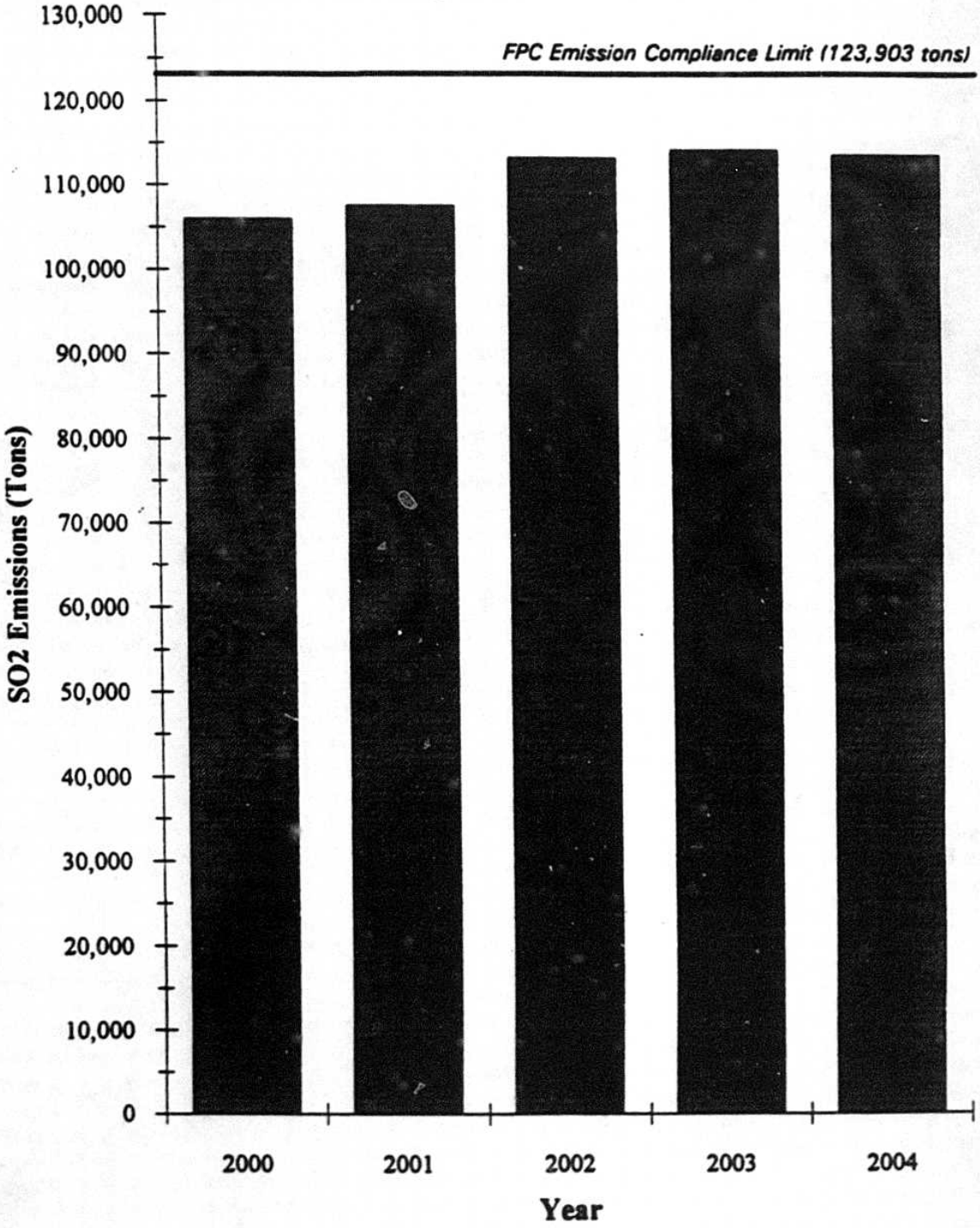
2. Convert Crystal River 1 & 2 to low-sulfur coal and switch the Bartow plants to low-sulfur oil.

FPC's 1993 CAA compliance plan calls for converting Anclote to 100% natural gas (see following section titled "Economic Analysis of Anclote Gas Conversion") and switching Bartow to low-sulfur oil. Figure II-4 shows FPC's SO_2 emission for years 1997 - 2004.

FPC's Annual SO2 Emission Forecast

Anclote Plant on 100% Gas

Figure II - 4



Some of the advantages and disadvantages of this plan to convert Anclote to 100% natural gas and switch Bartow to low-sulfur oil are:

Advantages

1. SO_2 emissions are reduced by a projected 2,500 to 5,000 tons compared to converting Crystal River 1 & 2 to low-sulfur coal.

2. Defers approximately $20 million (1991 cost) to convert the Crystal River 1 & 2 coal precipitators.

3. Allows for flexibility in meeting future energy growth with clean generation from Anclote.

4. Helps secure a competitive pipeline for providing competitive gas pricing.

5. Adds fuel flexibility to FPC's system.

Disadvantages

1. Savings on emission values could be offset by higher than expected natural gas prices.

2. Regulators may mandate burning lower sulfur coals at coal burning facilities regardless of other compliance efforts.

3. Long-term, firm natural gas transportation commitments must be made to insure delivery of natural gas.

4. Capital cost of $20 million is required to convert Anclote to natural gas firing capability.

With the updated assumptions of the 1993 proposed Ten-Year Site Plan and the conversion of Anclote to natural gas, FPC's projection of SO_2 emissions will be lowered from 122,000 tons to 106,000 tons in 2000.

Economic Analysis of Anclote Gas Conversion

The determination as to whether to convert Anclote to burn natural gas has been an integral part of Florida Power's planning process. Consideration for new gas transportation capacity into the State, system fuel flexibility and the CAA have to a series of studies to evaluate the advantages of the Anclote gas conversion.

ROLE OF NATURAL GAS IN IRP

For the purpose of this analysis, the base case assumes no gas conversion at Anclote. The natural gas required for the Polk County units is transported by FGT. The price that is assumed for transportation and natural gas at Polk County is higher than the alternative price which includes the Anclote gas requirements.

Various alternatives utilizing Anclote on natural gas were considered. A description of the alternatives is shown in Appendix II. The economics and the strategic value of each alternative were considered. The alterative that maximizes FPC's benefits included the following:

1. Anclote was assumed to be converted to burn gas by January 1996 (in order to provide an anchor customer for a new gas transportation system).

2. From January 1996 to December 1999, Anclote was assumed to have 120,000 MMbtus/day of firm gas supply available. Residual oil with a 2.5% sulfur content (high-sulfur oil) was used as a supplemental fuel.

3. After December 1999, the firm gas supply at Anclote was increased by 45,000 MMbtus/day to a total of 165,000 MMbtus/day. The residual fuel oil was changed to 1% sulfur content (low-sulfur oil). The combination of additional gas and switching to low-sulfur oil as a supplemental fuel results in a reduction of SO_2 emissions large enough to eliminate the need to convert the Crystal River Units 1 and 2 to a lower sulfur content coal.

4. The economic analysis was based upon a study period from 1992-2004. The demand and energy forecast and the fuel forecast reflect changes that have been made since the 1991 IPR study.

The phased approach to the Anclote gas conversion has several advantages. One of the advantages is the use of natural gas at lower load levels which will improve the ability of the plant to meet particulate and opacity standards. This will allow Anclote to use the high-sulfur oil as a supplemental fuel in the first four years and results in lower system fuel costs due to the lower cost of high-sulfur oil. In the year 2000, the mixture of natural gas and low-sulfur oil will also result in lower SO_2 emissions than burning low-sulfur oil exclusively.

The expected present worth revenue requirements savings of the Anclote gas conversion including fuel savings and the capital cost of conversion, is $30 million (1992). The annual expected fuel savings and the customer impact analysis are shown in Figure II-5. This includes savings resulting from the fact that the Crystal River Units 1 and 2 will not be required to burn low-sulfur coal. Based on the levelized annual revenue requirement for the conversion cost of $17 million (1992 $), the annual cost to FPC's customers is approximate $2 million in 1996, $3 million in 1997 and $2 million in 1998. The annual net benefit to FPC's customers begins in 1999 with a net benefit of approximate $2 million. The cumulative present worth net benefit to cost ration is 2.32 at the end of the study period. If

ROLE OF NATURAL GAS IN IRP

Crystal River Units 1 and 2 are required to burn low-sulfur coal,the savings from the Anclote gas conversion may be eliminated.

In order to test the sensitivity of the results of changes in the assumed price of natural gas, the price of gas varied by $\pm$ 20%. The results of these sensitivities indicated that the Anclote gas conversion would result in a savings of $155 million if the price of natural gas is 20% lower than expected. If the price is 20% higher than expected, the Anclote conversion would result in increased costs of $91 million. It should be noted that the price of one fuel does not usually move independently from other fuels. However, this sensitivity analysis does show that the viability of the Anclote conversion obviously depends upon the price of natural gas. Decreases in price make the conversion more beneficial, while increases in price make it less beneficial.

Customer Impact Analysis For Anclote Gas Conversion In 1996

Figure II – 5

Year	(1) Annual Fuel Bnft	(2) Cumulative PW* Fuel Bnft	(3) Annual Rev Req**	(4) Cumulative PW Rev Req	(1)–(3) Annual Net Benefit	(2)–(4) Cum PW Net Benefit	(2)/(4) Cumulative Benf/Cost
1993							
1994							
1995							
1996	1,021,051	704,281	2,921,166	2,014,906	(1,900,115)	(1,310,625)	0.35
1997	(1,683)	703,223	2,921,166	3,851,145	(2,922,849)	(3,147,922)	0.18
1998	1,017,526	1,286,122	2,921,166	5,524,561	(1,903,640)	(4,238,439)	0.23
1999	5,031,706	3,912,986	2,921,166	7,049,592	2,110,540	(3,136,606)	0.56
2000	13,534,130	10,352,118	2,921,166	8,439,394	10,612,964	1,912,723	1.23
2001	14,384,577	16,589,016	2,921,166	9,705,960	11,463,411	6,883,056	1.71
2002	12,632,561	21,580,591	2,921,166	10,860,217	9,711,395	10,720,374	1.99
2003	14,659,827	26,859,567	2,921,166	11,912,123	11,738,661	14,947,444	2.25
2004	9,301,390	29,911,980	2,921,166	12,870,755	6,380,224	17,041,225	2.32

* Present worth to 1/1993

** Based on conversion cost of $16,610,000 in 1992 and levelized fixed charge rate of 15.11%.

Anclote Conversion Costs

Anclote Units 1 & 2 currently operate on residual fuel oil and can be modified to also operate on 100% natural gas or a mixture of oil and gas. The modifications necessary include extensive changes to both the fuel supply and fuel management system. Beyond these systems the remainder of the plant is unaffected. A switch to natural gas will result in a heat rate penalty of approximately 5% due to the difference in fuel chemistry. However, this penalty is partially offset by a maintenance savings of approximately 1.4%. Based on flexibility in maintenance scheduling, Anclote Units 1 and 2 could be modified in 1996 or sooner, depending on the in-service date for the pipeline that transports the plant's gas supply. The scheduling dates of the Anclote conversion would be set to maximize FPC's benefits. A cost estimate for this conversion is shown in Figure II-6.

Figure II-6

BUDGETARY COST ESTIMATE
(1992 Dollars)

FPC Contract Engineering	$1,180,000
Gas Burners	$760,000
Oil Burners	$800,000
Flame Scanners	$360,000
Gas and Oil Piping	$450,000
Atomizing Steam System	$120,000
Windbox and Air Dampers	$2,070,000
Burner Management System	$4,000,000
Construction and Supervision	$4,600,000
GAC and AFUDC	$760,000
Contingency for Undefined Work	$1,510,000
TOTAL	**$16,610,000**

ROLE OF NATURAL GAS IN IRP

Strategic Implications of Anclote Gas Conversion

The conversion of Anclote to be natural gas capable has significant strategic implications for Florida Power. The current trends in environmental regulation favor the conversion of oil and coal fired units to natural gas. With more stringent regulations likely, including limits on carbon dioxide, mercury, and other trace elements in fossil fuels, the conversion of a major base load plant to burn natural gas will provide a means to improve system wide environmental performance. The conversion of Anclote has a low technological risk with a relatively small financial risk. The environmental benefit of the conversion will be significant and will provide FPC with a major component of an overall environmental compliance strategy.

An evaluation of the advantages of burning natural gas at Anclote should not be limited to a strict financial analysis the cost complying with the sulfur dioxide limits of the CAA 1990. Future regulations will include stringent environmental limitations that will force utilities to consider natural gas as a primary fuel.

Polk County Site Fuel Flexibility

The Polk County project is being designed with the flexibility to switch from natural gas to coal, if needed. This change will be possible because both the site and the generation technology have been specifically chosen with this feature in mind. The use of coal imposes a different set of infrastructure requirements on a site than does natural gas. Natural gas is relatively easy to handle. Delivery is by underground pipeline and there are no special requirements for either fuel storage or waste product disposal. It is a low-profile fuel. Coal, on the other hand, involves bulk transport by rail or ship, requiring on-site storage and generates significant amounts of waste by-products. These differences are recognized and can be accommodated at the Polk County Project to its maximum design capacity (3,000 MW).

Permitting of the site and initial site construction for the first 470 MW of generating capacity is currently in progress. Although CC units fueled by natural gas are designated as the technology of choice, our license application also addresses the long-term potential of the site, including the likelihood of a future switch to coal. FPC is seeking approval, in this process, for the first phase of generation as well as recognition of the full capabilities of the site. By doing this, we are notifying the agencies and community, from the start, of our long-term vision of the project including the probable switch to coal sometime in the future.

If a switch from natural gas to coal becomes necessary, the CC plants in our plan can accommodate this change. Synthetic gas can be produced from coal by a process known as coal gasification. Syn-gas, while lower in specific energy content than natural gas (350 vs. 1,000 Btu/cu-ft), is an effective and acceptable fuel for use in combined cycle units. The units which will be used at the Polk County Project will be capable of burning either fuel. From a design perspective, the gasification facility can either stand alone, supplying gas

essentially over the fence, or it can be integrated with the CC units. The non-integrated approach is simpler and permits independent ownership and operation, while the integrated design improves overall process efficiency.

The gasification of coal is a process which exists today at commercial demonstration levels throughout the world, and additional projects are planned for operation during this decade. By the turn of the century, a significant experience base should exist which will ensure that a switch to coal gasification represents no unusual level of risk. The initial installation of natural gas CC units with capability to switch to coal gasification as conditions dictate is an approach to generation expansion that is widely accepted in our industry.

Summary

The current trends in environmental regulation favor the conversion of oil and coal-fired units to natural gas. With more stringent regulations likely, including limits on carbon dioxide, mercury and other trace elements in fossil fuels, the conversion of existing plants to natural gas and the construction of new plants burning natural gas will be necessary. The use of natural gas provides a means to improve system wide environmental performance with small technological risks and relatively low financial risks.

The use of natural gas at Polk County has been an important component in the Integrated Resource Planning process. Natural gas fired CC units provide the lowest cost generation expansion alternative. In addition, the environmental benefits of the Anclote conversion to natural gas will be significant and will provide FPC with a major component of an overall environmental compliance strategy.

An evaluation of the advantages of burning natural gas at Anclote should not be limited to a strict financial analysis of the cost of complying with the sulfur dioxide limits of the CAA. Future regulations will include more stringent environmental limitations that will force utilities to consider natural gas a primary fuel. The conversion of a major base load plant and the addition of new CC units fueled with natural gas, will allow FPC to generate a significant portion of the company's total energy production with natural gas.

Section III: STRATEGIC AND POLICY CONSIDERATIONS

BENEFITS OF PIPELINE-TO-PIPELINE COMPETITION

Many of the benefits of competition in the market for natural gas transportation service to serve Florida gas consumers are already available to FPC, as well as other Florida natural gas customers, as a result of FGT's reaction to the "threat" of the SunCoast Project (and now SunShine Project). The transportation proposal originally offered to FPC by FGT in its Phase III expansion has been significantly improved upon, to include a rate cap not previously available and rolled-in pricing of laterals to Anclote and Polk County. The value of the rate reduction is approximately $10 million. The potential value of the rate cap, should rates increase to the cap, is $50 million. The laterals would have required $29 million in capital contributions from FPC to enable it to receive natural gas service at the affected facilities. Therefore, FGT has offered approximately $90 million in concessions beyond its earlier proposal. Additionally, FGT has improved its proposed supply access beyond the Mobile Bay area, to include more producing regions. Concurrently, both ANR and United have continued to improve their SunShine and SunCoast proposals by trimming proposed rates and lowering caps on both transportation charges and fuel use.

The history of FGT in Florida has shown that its general treatment of customers is not fully responsive to needs. Lacking competition, FGT has built facilities incrementally at levels which keep its pipeline at or near full capacity and generally has implemented operating terms and conditions which are comparatively restrictive. The introduction of a new pipeline into Florida's gas markets would produce ongoing competitive pressure on both FGT and the new pipeline regarding the terms and conditions they offer to customers. This could favorably impact the flexibility offered under capacity release programs, induce rate discounting, improve receipt point options, speed up incremental expansions, and encourage offering and delivery of new services, where a single pipeline will tend to avoid discounting and offer restrictive terms and conditions of service in order to optimize income. Two pipelines will be required to expand and improve services in order to compete for growing gas markets and to retain short-term customers.

It is likely that over time FPC will require gas supplies in excess of its initial subscription to transportation capacity on a new western Florida pipeline. FPC will likely be transporting future gas supplies through the FGT pipeline, whether or not a competing pipeline is built. Therefore, the continuing competition that will only exist if a second pipeline is constructed should operate to make FPC's fuel costs lower than would be the case if FGT's monopoly is preserved.

A competitive pipeline can also help FPC with its gas supply purchasing strategy. Producers will not have the same transportation positions nor the same capabilities to

deliver gas supplies into two competing pipelines. For example, a large producer may be restricted by the physical capabilities of a pipeline from delivering more natural gas into that system. The producer may have the physical capability, however, to deliver that gas into a pipeline which can provide ultimate delivery to FPC. It is likely that a producer in that situation will be willing to discount gas prices in order to sell the gas. FPC, by understanding the producers' positions, will be able to play producers against each other (gas on gas competition) in order to secure more favorable purchasing arrangements.

A competitive project which has an intrastate component as opposed to a wholly interstate FERC regulated pipeline will also provide a type of regulatory competition between the FPSC and FERC. The FPSC regulators will be acutely aware of the rules and regulations promulgated by the FERC and will feel some pressure to ensure that an intrastate facility is not competitively disadvantaged by restrictive rule making or rate setting.

Another significant advantage to FPC resulting from the existence of a second pipeline is the impact it will likely have on FGT's restructuring under FERC Order 636. As an example, FGT could elect to have its gathering systems treated incrementally (separately) and thereby require separate transportation rates across the gathering systems which would be outside the proposed transportation rate cap. Certainly if the Florida customers are captive to a single pipeline system, there would be less competitive pressure to prevent FGT from such a strategy. Conversely, competitive pipelines will tend to pursue service and pricing strategies that result in lower cost to their customers.

In summary, the heated competition witnessed during the quest to build new facilities is only a prelude to the sustained competition that will exist if Florida gas markets are served by competing pipelines.

What happens if the competing project fails?

FPC has a back-up strategy in the event that it contracts for transportation capacity with a new competitive pipeline that is never placed into service. FPC has positioned itself, in part through its equity participation, to know with adequate lead time whether or not the new pipeline will have sufficient subscriptions from customers and the appropriate regulatory and financing approvals to process with construction. FPC's Precedent Agreement with the new pipeline will allow termination of FPC's obligations so that FPC can then contract with FGT in order to ensure that supplies of natural gas can be delivered to its facilities when required.

STRATEGIC AND POLICY CONSIDERATIONS

The Task Force strongly believes that FPC's 210,000 - 255,000 MMbtus/day load will be a sufficient attraction to FGT to enable FPC to negotiate for and receive from FGT an offer comparable to its October 28, 1992 proposal, at the least. FGT will be hard-pressed to refuse to negotiate on the terms and conditions it has previously offered to FPC.

Even if FGT refuses to renew its October 28 offer, the only effect on FPC will be the possibility of having to accept the terms and conditions generally available to the other customers on the FGT system. This will mean that the rate cap will be increased to the system rate cap. It is also possible that the cost of the laterals will require capital contribution on the part of FPC as opposed to the current proposal which has them rolled-in to the total pipeline cost. However, FERC regulatory policy will not permit FGT to discriminate against FPC when compared to other FGT customers. Thus, even in the worst case, FPC will enjoy equal transportation treatment and will then be able to compete on its capability to do a better job than its competitors in implementing its fuel purchasing strategy.

ACCESS TO GAS SUPPLIES

The current FGT pipeline is, for practical purposes, the only mainline natural gas pipeline that transports natural gas into the State of Florida. It has the capacity to deliver about 925,000 MMbtus/day. If Phase III is approved by FERC and constructed by FGT, capacity will be expanded to about 1,450,000 MMbtus/day in 1994 or 1995. This capacity is fully contracted for on a firm basis. Therefore, in order to provide gas supplies to Anclote and Polk County (a total of up to 255,000 MMbtus/day) additional pipeline capacity will have to be constructed to serve western Florida by either FGT or a pipeline competitor. This new capacity will not be constructed unless customers contract for the full proposed capacity to support regulatory approval and financing of the pipeline project.

Credit Rating Implications

FPC's commitment to contract long-term for gas transportation will result in the credit rating agencies imputing debt to FPC, based on the 25-year stream of payments. The payment streams of each proposal are summarized in Section IV and Appendix IV of this report. Based on our current estimates, the impact on FPC's debt ratios will be significant - in excess of a 1% increase in FPC's debt/capitalization ratio.

To the extent the payments in each proposal are similar, the impact on FPC's ratings are similar. The one significant change in the payment streams would be the delay of the Anclote

conversion under the FGT alternative, which would delay the onset of our payment obligations.

CLEAN AIR ACT

Clean Air Act Amendment Summary

Under Title IV of the 1990 amendments to the CAA, Congress authorized the U.S. Environmental Protection Agency (EPA) to establish the Acid Rain Program. The principal goal of this program is to achieve significant environmental benefits through reductions in sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions, the primary components of acid rain. To achieve this goal at the lowest cost to society, the program will employ both traditional and innovative market-based approaches for controlling air pollution. In addition, the program will encourage energy conservation and promote pollution prevention.

The legislation sets as its primary goal the reduction of annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these SO_2 reductions, the law requires a two-phase approach which involves the trading of annual SO_2 emission allowances and gradually tightening the restrictions placed on fossil fuel-fired power plants.

Phase I begins in 1995 and affects 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. Phase II, which begins in the year 2000, tightens the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired by coal, oil, and gas. All existing utility units with an output capacity of 25 MW or greater and all new utility units will be affected by Phase II.

FPC does not have any plants that are affected by Phase I. Compliance with Phase II has been an integral part of the Integrated Resource Planning process since this legislation was proposed in 1990.

FPC Compliance Strategy

There are eleven titles in the 1990 amendments to the CAA, and most have at least some effect on the electric utility industry. Most attention to date has been focused on Title IV (Acid Rain) and Title V (Permits). These titles will dramatically affect the cost of environmental compliance, influence the way FPC dispatches its units, and strongly influence future plans for meeting generation needs.

STRATEGIC AND POLICY CONSIDERATIONS

The FPC Clean Air Act Strategy Team (CAAST) was established to develop a comprehensive plan to achieve compliance with the CAA sulfur dioxide emission limitations. Secondarily, it provides a forum for the discussion and analysis of other related CAA issues. Although FPC is a Phase II utility with respect to Acid Rain compliance, there are many issues which must be addressed today in order to achieve a workable strategy by 2000.

The goal of the CAAST is to adopt a compliance plan which will meet the requirements of the CAA and define the environmental envelope for operations and future generation planning.

The preparation of a compliance plan is a key element of the company's Strategic Plan. Major strategies affected by the CAA compliance plan are Strategies 1 and 4.

- Strategy 1

  Position FPC to compete effectively in the electric energy supply market.

- Strategy 4

  Take initiatives that will ensure FPC is recognized as an environmental leader in the eyes of our community, employees, peers, regulators and shareholders.

FPC must submit its compliance plan to the EPA by January 1, 1996. In order to meet that date and to provide time for FPSC review, the CAAST proposes to submit a compliance plan to FPC senior management by January, 1995.

The CAAST has not completed its recommendations, but the overall strategy for FPC's compliance has been to reduce the total system emissions to a value close to the number of allocated emission credits. This will be accomplished by switching fuels at several plants and by adding gas fired CC units at the Polk County site. Additional reductions in system emissions can be obtained by operating the system out of an economic dispatch based upon fuel costs. Both fuel and emission costs can be considered together, and the system can be operated with an "environmental" dispatch. Additional emission credits can be purchased on the open market when the cost of such purchases is less expensive than the additional cost of the environmental dispatch.

The cornerstone of FPC's CAA compliance strategy is the reliance on lower sulfur content fuels, especially natural gas. The addition of gas fired CC units at Polk County will provide base and intermediate load generation with no sulfur dioxide emissions. The conversion of the Anclote Plant to burn natural gas will provide additional capacity with low sulfur dioxide emissions. The dual fuel capability at Anclote will allow flexibility

in mixing oil with natural gas to allow the lowest cost fuel option within the constraints of the CAA.

FPC Compliance Plan

The Environmental Protection Agency (EPA) has indicated that FPC's final allocation of SO_2 allowances will be 123,903 tons/year. As of October 1, 1992, this was not a final allocation, but the official allocation should be very close to this number. The basis for this allocation is shown in Appendix II.

The design of the FPC system for CAA compliance purposes assumes that the total of all of the FPC unit SO_2 emissions will not exceed this number of allowances. FPC's compliance plan is based upon increased consumption of natural gas, and the use of lower sulfur fuels. The details of the compliance strategy are discussed in Section II.

REGULATION OF GAS PIPELINES

All natural gas consumed in the State of Florida is produced outside the state. Therefore, any natural gas pipeline providing transportation service to Florida markets will be engaged in the transportation of gas in interstate commerce, and will as a result be subject to federal regulation pursuant to the Natural Gas Act of 1938, as amended, (the "Natural Gas Act"), unless its facilities and services come within the exception to federal jurisdiction set out in Section 1(c) (the so-called "Hinshaw Amendment"). Under the Hinshaw Amendment, if all of the gas a pipeline transports is received by it within or at the boundary of a state and all of such gas is consumed within such state, and if the rates and services of such pipeline are subject to regulation by a state commission, such pipeline is exempt from regulation under the Natural Gas Act. The only major existing natural gas pipeline serving Florida, FGT does not have a Hinshaw exemption, but instead operates as an interstate pipeline and is subject to Natural Gas Act regulation administered and enforced by the FERC.

The developer of a new, competitive pipeline serving Florida can choose either to configure its facilities so as to be subject exclusively to FERC regulation, to be subject exclusively to regulation by the FPSC as a Hinshaw pipeline, subject to the provisions of the "Florida Natural Gas Transmission Siting Act", and the "Natural Gas Transmission Pipeline Regulatory Act", provided it can interconnect to an interstate pipeline at or within the border of the State of Florida, or to be subject to FERC regulation for an interstate pipeline project and to FPSC regulation for an affiliated but separately owned intrastate pipeline project interconnected to the interstate project.

STRATEGIC AND POLICY CONSIDERATIONS

Intrastate Regulation

Construction of a new intrastate pipeline in Florida is subject to a two step regulatory process. The first step involves applying for and obtaining from the FPSC a certificate of need for the pipeline. No regulations have as yet been promulgated by the FPSC with respect to the processing of applications for pipeline certificates of need. However, the statute requires that a hearing be held within 75 days after the FPSC receives a request for such a certificate, and that a decision on such a request be rendered within 90 days after filing. In determining need for a pipeline, the FPSC "shall take into account the need for natural gas delivery reliability, safety, and integrity, the need for abundant, clean-burning natural gas to assure the economic well-being of the public, the appropriate commencement and terminus of the line, and other matters within" the FPSC's jurisdiction "deemed relevant to the determination of need."

Once a certificate of need has been obtained for a proposed pipeline, an environmental certification of the right-of-way or corridor where the facilities will be located must be obtained from the Natural Gas Transmission Pipeline Siting Board, consisting of the Governor and Cabinet, pursuant. An application for environmental certification must specify the beginning and ending points of the pipeline, the location of the proposed right-of-way or a corridor (not to exceed 1/3 mile in width) in which the pipeline will be constructed, and all structures and maintenance and access roads to be constructed, and the application may include metering and compressor stations and other facilities directly related to the transportation of gas which will serve the pipeline. The statute implies that an application must also include appropriate information about the environmental impacts of the construction of the pipeline in the proposed right-of-way or corridor; however, the nature and extent of the environmental information that must accompany or be included in an application is not specifically described in the Florida Act. The filing fee for an application for environmental certification is $240,000.00 plus $500.00 per mile if the pipeline will be located in existing utility, railroad, highway, water or sewer right-of-way, and $1,000.00 per mile outside existing right-of-way, not to exceed $840,000.00. A post certification fee is also required based on the length of the pipeline up to $175,000.00 for a length greater than 150 miles. Fees are also charged for amendments to the application and for realignment of the route.

Applications for environmental certification are processed by the Department of Environmental Regulation ("DER") and the hearings required by the statute are conducted by a hearing officer designated by the Director of the Division of Administrative Hearings. Before processing can commence, and within 45 days after the DER determines that the application is complete, the DER must determine whether the application is sufficient for processing.

Copies of complete applications are provided to "affected agencies", including but not limited to the Department of Community Affairs, the Game and Fresh Water Fish Commission, the

Department of Transportation, the Department of State, Division of Historical Resources, each water management district and in each local government in which a portion of the proposed corridor is located, for review and submission of preliminary statements of issues or reports.

Subject to certain contingencies resulting in extension of the statutory processing schedule, the hearing officer is directed to conduct an environmental certification hearing no later than 215 days after receipt of a complete application by the DER. Parties can file alternative route proposals for consideration no later than 50 days prior to the hearing. Local governments are also authorized, but not required, to hold public hearings. Within 60 days after the transcript of the certification hearing is complete, the hearing officer must issue a recommended decision. The Board is directed to act on the application with 60 days after receipt of the recommended decision.

If the Board denies certification, it must set out in writing the action the applicant must take to secure approval by the Board. If the certification is issued, it is the only environmental certification required for construction of the pipeline.

The rates and terms of service of Florida intrastate pipelines are subject to the jurisdiction of the FPSC, whose duty it is "to ensure that all rates and services made, demanded or received by any natural gas transmission company are just and reasonable and are not unreasonably preferential, prejudicial, or unduly discriminatory." Pipelines establish initial rates and terms of service through negotiations with customers and filing written statements or schedules of such rates with the FPSC. The FPSC may suspend the applicability of rates filed by a pipeline for a period not to exceed 8 months, during which the FPSC is to determine whether such filed rates are just and reasonable. If such determination has not been made by the end of the specified suspension period the pipeline may put such rates into effect, subject to refund if they are later determined by hearing to be excessive. Subsequent changes in the rates proposed by the pipeline are subject to similar provisions. There are no statutory provisions specifically dealing with rates charged by Florida intrastate pipelines to affiliated entities in which the pipeline holds an ownership interest.

Rates charged by pipelines to other natural gas pipeline companies, transportation customers and industrial, power plant and other similar large volume contract customers, excluding direct sales for resale to gas distribution utilities at city gates, unless suspended or modified by the FPSC after filing, are deemed to be just and reasonable and approved by the FPSC if both the pipeline and the customer file an affidavit to the effect that neither party had an unfair advantage in negotiating the rates, the rates are substantially the same as rates charged by the pipeline to two or more such customers under the same or similar conditions of service, or that competition does or did exist either with another supplier of natural gas or with a supplier of an alternate form of energy. The FPSC may suspend such rates to such "large" customers for up to 6 months, during which time the FPSC "must" find the filed rate or a "modified" rate

to be just and reasonable. Nothing in the section dealing with rates chargeable to such "large" customers precludes the FPSC from determining the reasonable and prudent costs to be recovered through rates from an electric utility's ratepayers pursuant to the provisions of Chapter 366, Florida Statutes.

A Florida intrastate pipeline must construct any necessary pipeline lateral facilities and related facilities for interconnection with a customer if the customer agrees to fully compensate the pipeline for reasonable costs incurred. However, although a Florida intrastate pipeline must provide transportation access to customers on a basis that is not unreasonably preferential, prejudicial, or unduly discriminatory, such access is subject to the availability of capacity; thus it appears that a pipeline is not required to add capacity at the demand of a customer.

Interstate Regulation

Federal regulation of interstate gas transportation service under the Natural Gas Act is pervasive, extending to such matters as rates and terms of service, a mandatory system of accounts, relationships among affiliates and the issuance of certificates of public convenience and necessity prior to construction of new facilities or provision of services. Federal regulation of sales of natural gas in interstate commerce has steadily receded since enactment of the Natural Gas Policy Act in 1978. The Natural Gas Decontrol Act of 1989 will terminate all statutory and regulatory price controls on natural gas effective January 1, 1993. FERC Order No. 636 directs interstate pipeline companies to separate their gas marketing function from their gas transportation function, so that pipelines selling gas must procure and price transportation service separately from the cost of the gas commodity; the quid pro quo for this required restructuring is that pipeline companies are no longer required to sell their gas at the weighted average acquisition cost, and may now earn a profit margin on gas sales.

In order for ANR, FGT or United to provide transportation service for FPC's Anclote and Polk County generating units, new pipeline facilities must be constructed. In each case, FERC regulated facilities will be required so that a certificate of public convenience and necessity (CPCN) under Section 7(c) of the Natural Gas Act will have to be obtained, and in each case the new facilities could be entirely subject to FERC regulation.

An application for a CPCN under Part 157 of the FERC's Natural Gas Act regulations must include a description of the facilities to be constructed and the service to be provided, evidence that the facilities and service are required in an identified market, pro forma rates and terms of service, the means by which the facilities will be financed and a comprehensive environmental report on the route over which the facilities will be constructed. A filing fee is required; the fee for a 1992 filing is $34,550, but the fee is adjusted annually. Under current FERC practice, the Commission staff's review of the feasibility of the proposal and

the justness and reasonableness of the pro forma rates and terms of service is processed separately from the environmental evaluation of the proposal, which for significant new facilities requires substantially more time. The FERC environmental staff is charged with administering the provisions of the National Environmental Policy Act of 1973, which requires the preparation of either an environmental assessment ("EA") or an environmental impact statement ("EIS"), depending upon the staff's determination of the probable extent of environmental impact that will result from the construction of the proposed facilities. In the case of a major project, the FERC's environmental staff normally requires that the applicant agree to pay for having the project's environmental review done for the FERC by a private contractor, which can result in significant additional cost above the initial filing fee.

FERC has recently taken the position that if the proponent of new pipeline facilities has binding commitments from shippers for all or substantially all of the facilities' capacity, a CPCN will be issued, subject only to the completion of the EA or EIS and the issuance of an order establishing required environmental mitigation measures. If the proponent does not have binding commitments for all of the capacity of the proposed facilities, the FERC will issue a CPCN that puts the proponent "at risk" for the recovery of the cost of the unsubscribed portion of the capacity; therefore, most pipeline project proponents are unwilling to construct facilities if any substantial portion of the capacity is not subscribed by shippers.

The FERC has the power under Section 7(e) of the Natural Gas Act to condition a CPCN issued for new facilities so as to require the proponent either to make substantial changes to the project facilities and/or to the pro-forma rates and terms of service, or to forego construction under the certificate. The FERC also uses its Section 7(e) conditioning power to require project proponents to include in their construction of facilities environmental mitigation measures developed in the course of the preparation of the EA or EIS for the project. Such measures can significantly alter the pipeline route or the configuration of facilities, and add substantial cost to the project.

For practical purposes, in order for a project proponent to receive a CPCN it must agree to operate the facilities on an open and non-discriminatory access basis, pursuant to the FERC's Part 284 regulations developed in Order No. 436. Although the project proponent can enter into commitment agreements with shippers (known as "precedent agreements") that contain specifically negotiated terms and conditions, if all of the proposed capacity is not subscribed to at the time the FERC issues the CPCN, the proponent will probably be required to hold an "open season" during which parties desiring capacity can submit requests, and generally such requesting parties are entitled to the benefit of any terms and conditions in existing precedent agreements between the proponent and shippers that contain terms that are better than those contained in the pro forma tariffs filed with the application.

Sections 4 and 5 of the Natural Gas Act basically set out the requirements that rates charged by interstate pipelines, and the terms and conditions of their services, must be "just and

reasonable" and not unduly preferential or discriminatory as among classes of service or customers similarly situated. The rates charged by pipelines are developed and filed by the pipelines, and are then subject to review by the FERC under the above-stated standards. The FERC can suspend the effectiveness of a rate filing for up to 5 months, and if by the end of the designated suspension period the Commission has not made a determination as to whether the rates meet the Section 4 standard, the pipeline can put the filed rates into effect, subject to refund.

Pipelines can, and normally do, reserve the right to unilaterally file changes to their established rates. Customers, as well as the FERC rate staff and the state commissions of those states in which the pipeline provides service, have the right to intervene in a pipeline's rate case and protest any aspect of a proposed change. Pipeline rates and the terms and conditions of service offered are contained in tariffs, and the tariff as a whole is subject to the "just and reasonable" standard of Section 4.

The FERC can, on its own motion or the motion of a state commission, under Section 5 of the Natural Gas Act, investigate a pipeline's rates and terms of service to determine whether or not they meet the Section 4 standards. If the FERC, after hearing, determines that the rates and/or terms of service violate the Section 4 standards, it "shall determine the just and reasonable rate, charge, classification, rule, practice, or contract to be thereafter observed and in force, and shall fix the same by order." Thus, any rate change effected pursuant to Section 5 operates only prospectively.

The FERC may not require an interstate pipeline to expand its facilities or provide a service to any person, with one exception: under Section 7(a) of the Natural Gas Act, a pipeline can be compelled to provide service to a gas distribution company and to extend its transportation facilities to communities located immediately adjacent to or served by the pipeline if the FERC finds that "no undue burden" would result to the pipeline. The power to compel the provision of service and extension of facilities under Section 7(a) does not extend to "enlargement" of a pipeline's facilities, nor can a physical interconnection be required if it would impair the pipeline's ability to render adequate service to its existing customers.

The nature of the business conducted and services offered by interstate pipelines has been and will be significantly altered by FERC Order No. 636, the provisions of which, and of related Order No. 636-A, are summarized in Appendix III. The principal effects of Order No. 636 on FPC's efforts to obtain transportation capacity for its gas supplies over new or existing interstate pipelines are three: First, the universal rate design for pipelines will be "straight fixed-variable" or "SFV", pursuant to which all fixed costs, including debt retirement and return on equity, are collected through a demand or reservation charge payable whether or not firm capacity rights are used, and only costs that vary with throughput are charged based on usage.

Second, Order No. 636 provides a mechanism pursuant to which shippers presently holding firm capacity rights can elect to relinquish all or some of those rights if another shipper is willing to assume such capacity rights at a rate equal to or higher than (up to the authorized maximum) the rate applicable to the existing shipper's use of its capacity. Third, every pipeline will be required to implement a "capacity release" program, pursuant to which shippers can release some or all of their firm capacity at any time to parties desiring transportation service on a pipeline on a bid basis, thus creating a secondary market for firm capacity rights on interstate pipelines.

Conclusion

Both Florida and federal regulation will have an impact on FPC's gas transportation capacity rights, unless FPC chooses the FGT alternative, in which case only federal regulation will apply. Florida regulation is preferable to FERC regulation for two principal reasons: First, the Florida Natural Gas Transmission Siting Act specifies time limitations and procedures for the environmental review and approval of a pipeline project, while there are no time limits on nor specific procedures applicable to FERC's environmental processing; Second, FPC will be able to exert greater influence over regulatory policy and changes in the structure and nature of Florida regulation of natural gas pipelines than it can with respect to federal regulation and regulatory policy. Past experience demonstrates that the special concerns of Florida's gas markets often are paid little or no attention by the FERC. Therefore, it is in FPC's interest that the pipeline which provides FPC transportation capacity within the boundaries of Florida is subject to the jurisdiction of the FPSC.

URGENCY TO PROCEED

One principle issue with respect to FPC's need to decide on its strategy for securing natural gas transportation is the criticality of the timing should FPC determine to proceed with a competitive pipeline alternative. Each day that FPC delays its commitment to a competitive project and thus denies that project marketing credibility, it increases the risk that the competing pipeline will lose customers who are currently being solicited by FGT under its announced Phase IV expansion. Some of these customers do not have the flexibility to delay much longer and must soon make some commitment for their future gas requirements.

There presently exists a sufficiently large load for a new pipeline to support such a development. However, the proposed capacity of the new pipeline, sized to meet the available uncommitted market, is near the margin of project economics. FGT clearly believes that if its Phase IV marketing causes any of the available load to commit to FGT, it will have effectively eliminated competition and extended its monopoly.

STRATEGIC AND POLICY CONSIDERATIONS

Another matter with respect to which timing is critical is the need to file applications for required regulatory authorizations for a competitive pipeline before FGT receives approval of its Phase III from FERC, which is estimated to be sometime early in 1993. Should a filing for a competitive project be made in advance of the FGT approval, it will create environmental pressure on FGT's certificate order at FERC due to the dual use of the proposed right-of-way where both pipelines look to occupy similar corridors. If delays in FGT's certification were to occur, it is also possible that loads could shift to a competitive pipeline, thereby increasing through-put and lowering transportation costs for customers on that pipeline.

In any event, FPC will be well served to promptly determine its choice of alternatives and proceed with a commitment for transportation using the current competitive environment to secure the best rates, concessions, terms and conditions it can negotiate. It is not too early to secure such transportation commitments in order to ensure timely service to Polk County as well as to Anclote, where use of natural gas in 1996 has become more and more of a necessity due to the CAA requirements.

FPC's gas load has provided the basis upon which ANR and United have been willing to spend several millions of dollars in project design, lobbying for Florida pipeline legislation and marketing the balance of the project's capacity. These marketing efforts, it is now clear, cannot succeed until the other potential shippers who will utilize the balance of the new pipeline's capacity know that FPC has committed to the project by executing a precedent agreement. Unless the competing project's capacity is fully subscribed (approximately 220,000 MMbtus/day), neither ANR nor United will proceed with development.

SECTION IV: ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

PROPOSALS

ANR Proposal

See Appendix IV A. for copy of ANR's proposal, supplemental information and a map of the proposed SunShine project.

General

ANR proposed four options at different levels of volume and rates. Only Option 1 was evaluated since it matched the volume levels that Florida Power requested.

Rates

The initial rate proposed by ANR was 67.3¢/MMbtu. (Additional upstream costs are required and are included in the evaluation).

Fuel

Fuel was estimated at .9% at the 1999 volume level. This value is relatively low due to the large diameter (30-inch) design of the system with relatively low projected system volume of about 399,000 MMbtus/day on the intrastate portion.

Rate Caps

The initial rate is capped at 71.8¢/MMbtu with 45% escalated at the lesser of the GNP Implicit Price Deflator or 4% for twenty years. Adjustments to this cap cannot drive the cap above 84¢. Fuel is capped at 1.5% with provisions for adjustments without overall cost impact to FPC.

If upstream rates exceed the United proposed rates for upstream access to supplies (11.6¢ escalating to 20¢) and the ANR rate reaches 83.5¢ then ANR would take one of several actions to limit FPC's cost exposure to upstream rates as further discussed in their proposal.

Rate caps apply during the first 20 years of service.

FPC Volumes

- Initial delivery of 120,000 MMbtus/day for Anclote in 1995 (estimate based on pipeline in service date)

SECTION IV: ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

INTRODUCTION

The Task Force has been reviewing transportation alternatives since mid-1991. On October 21, 1992, FPC advised ANR, United and FGT to provide their final and best proposals for transportation service to Anclote and Polk County. The economic evaluation of the three proposals was based on "proposed" rates, as well as the rate caps provided. In addition, several sensitivity studies were done and decision analysis techniques were used to develop an evaluated cost for each proposal, and a review of the Advantages and Disadvantages of each of the proposals was developed for those items which were not readily quantifiable.

Some of the important aspects of any pipeline project are:

- Ability to provide sufficient volumes at the delivery locations.
- Access to sufficient natural gas supplies at the producing end, either directly or through upstream pipeline interconnects.
- Flexibility in hourly flow rates, receipt point designation, delivery points, capacity reassignment and many other tariff and operating provisions.
- Rates and rate structures.
- Regulatory process required.
- Financial capability of the pipeline developer.
- Timing of project versus end-users needs.
- Sufficient total capacity to allow reasonable rates based on economies of scale.
- Adequate minimum load to justify project, both in volume and term.

These aspects will be reviewed in the comparison of FPC's alternatives which follows.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

- Initial delivery of 45,000 MMbtus/day for Polk 1 is August 1998.
- Initial delivery of 45,000 MMbtus/day for Polk 2 is August 1999.
- Demand charges will be assessed as each increment of capacity goes into service.

Term

25 years from initial deliveries.

System Volumes

The rates and other terms are based on total intrastate volumes of 219,000 MMbtus/day in 1995 (or initial in-service date) and 399,000 MMbtus/day in 1999. Additional volumes are required upstream on the interstate portion of the project (105,500 MMbtus/day).

Supply Area Access - (See map and diagram in Appendix IV-A)

The SunShine Interstate line begins at Chevron's Pascagoula plant where it would interconnect with the Chandeleur offshore pipeline and the United Gas Pipeline system. As SunShine proceeds east it would interconnect with United's Gateway and Transco's Transabama pipelines. Supply areas in Texas and Louisiana can be reached directly from United or indirectly from Transco via Transabama. Gateway and Transabama provide direct access to Mobile Bay supplies. Chevron Pascagoula provides access to offshore supplies connected to the Chandeleur pipeline as well as fields which Chevron and others plan to develop in the Mobile Bay Area and the Eastern Gulf of Mexico.

Expansion Potential

The ANR proposal features a 30-inch pipeline with a relatively low amount of compression. This provides the potential for additional capacity at relatively low cost. For example, the difference in daily volume between Option 1 and 4 in the ANR proposal is about 65,000 MMbtus/day. This increased volume results in a decrease in rates of about 4.5¢ and an increase in fuel from .9% to 1.1%. Capital cost is increased by about $32 million or about 5% for a 16% increase in thruput.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Future FPC Requirements

In accordance with previously negotiated precedent agreements, FPC has the option to request an additional 90,000 MMbtus/day or more. This volume can be utilized at Polk 3 & 4 or for additional volume at Anclote. ANR has expressed a willingness to build laterals to Suwannee Plant (for 20,000 MMbtus/day) or to Bartow and/or Higgins (for 45,000 MMbtus/day).

Penalties for Transportation Volume Imbalances

Under the ANR Precedent Agreement and SunShine's pro-forma tariff, ANR agrees to provide interruptible service in excess of the firm service MDQ if capacity is available. According to SunShine's pro-forma tariff (which has not yet been the subject of negotiations) if FPC overruns its MDQ without authority (i.e., without using available interruptible capacity), FPC will be assessed an overrun charge equal to the daily equivalent of the reservation charge for each MMbtu of gas in excess of the MDQ that is delivered to SunShine for FPC's account. FPC will be assessed a penalty of $25 per MMbtu for gas taken in excess of 102% of the MDQ. However, FPC is permitted a daily dispatching variation of up to 10,000 MMbtu above MDQ for which FPC will only be charged at the applicable interruptible service rate.

Imbalances between receipts of gas for FPC's account and deliveries to FPC will be "cashed out" on a monthly basis by the purchase by FPC from SunShine of excess gas taken, and the sale by FPC to SunShine of excess gas delivered above gas taken by FPC. Prices for these transactions will be stated in SunShine's tariff, but have not yet been set.

Delivery Rate and Pressure.

FPC is entitled to request and receive up to 85% of its maximum daily quantity entitlement at any delivery point during any 14 consecutive hour period during any 24-hour period, provided that such 14-hour periods will be separated by not less than 10 hours. Delivery pressures are not specified, but FPC believes that it can obtain ANR's agreement to any delivery pressure it will require.

Interruptible Transportation Service

If ANR agrees with any other similarly situated SunShine shipper to provide interruptible transportation service at rates more favorable than the rates for FPC's firm service, then ANR must offer to provide interruptible service on equivalent terms to FPC.

Most Favored Nations Treatment

FPC is entitled to notice from ANR as to any more favorable terms and conditions provided by SunShine to any other firm shipper, and FPC may elect to receive firm transportation service on such more favorable terms and conditions.

FPC's Right to Additional Transportation Service Requiring Expansions of the SunShine Facilities

If FPC offers ANR the opportunity to transport additional quantities of gas on the SunShine pipelines, and ANR would require, but declines to construct, additional facilities to provide such service, FPC has the right to either pay for and own such additional facilities (which shall be operated and maintained by ANR), or to require ANR to construct such facilities, for which FPC must pay an incremental rate for service designed to cover the costs of the facilities.

Receipt and Delivery Points

The pro forma tariffs for the SunShine pipelines provide FPC as shipper with adequate flexibility as to points at which FPC's gas supply can be delivered to the pipeline for transportation, and as to points at which FPC's gas supply will be delivered to FPC or for FPC's account by the pipeline, including the right to receive FPC's gas supply not needed at one FPC facility at another FPC facility accessed by the SunShine system.

Assignment and/or Release of Capacity Rights

The pro forma tariff for the intrastate portion of the SunShine Project provides for FPC as shipper to have the right to assign excess capacity rights to third parties. The Project has not yet developed a capacity release provision for its interstate portion; however, by the time its interstate tariff is approved, the FERC will have reviewed and approved the Order No. 636 capacity release programs of most, if not all, existing pipelines so that a set of relatively standard provisions will have been developed which will more than likely be required of these pipelines to gain tariff approval.

Precedent Agreements

FPC negotiated the operating terms and conditions applicable to both the ANR and United proposals jointly with those two companies when they were joint venturers in the SunCoast Pipeline Project; therefore, such terms and conditions are for all intents and purposes identical. A copy of the most current draft of the

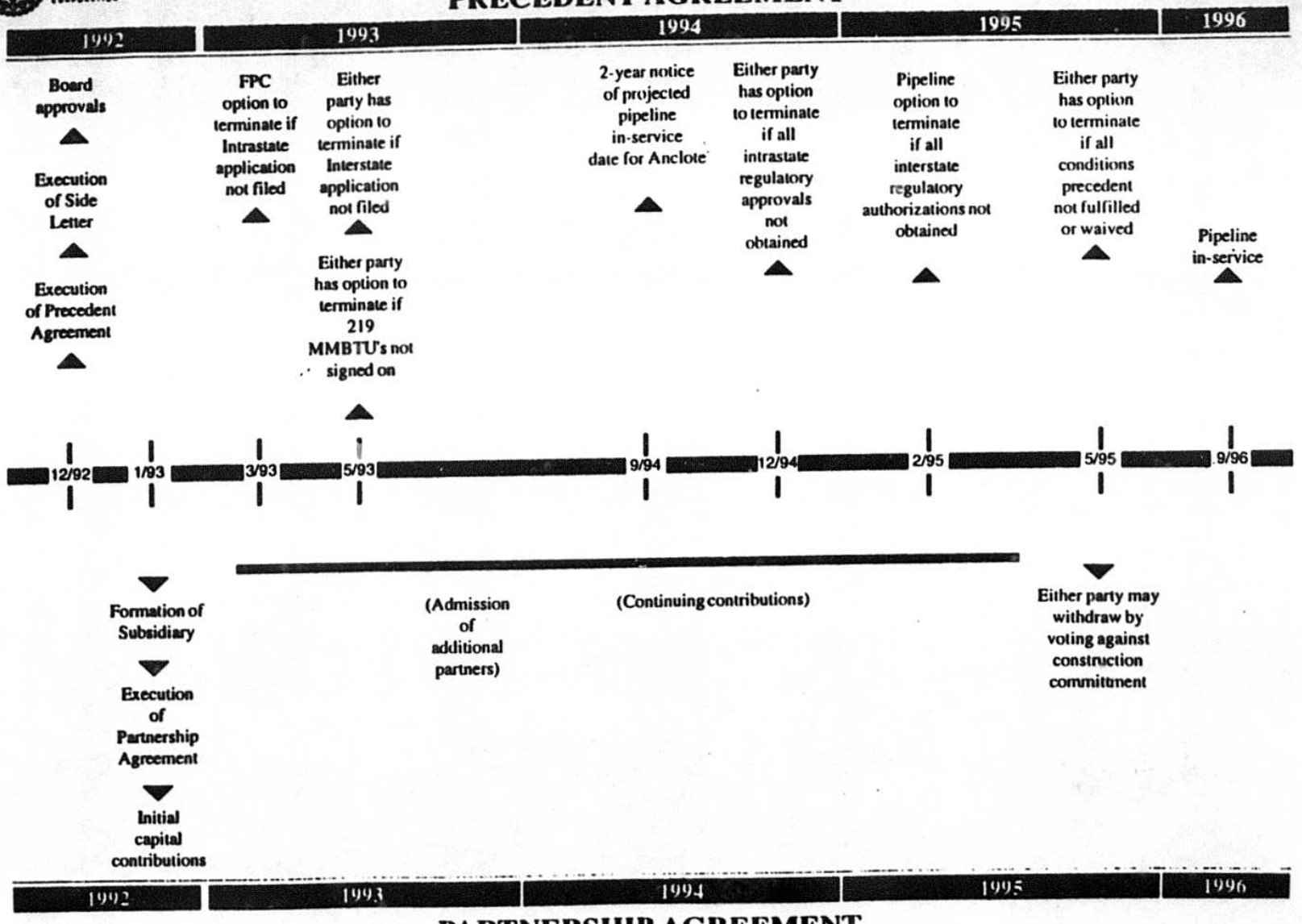
ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Precedent Agreements for capacity on both the interstate and intrastate segments of the ANR SunShine pipelines (which FPC believes would also be applicable to the United SunCoast Pipeline) are contained in Appendix IV-B. The significant operating terms and conditions for these proposals are described above. The key dates by which conditions precedent to the obligations of the parties must be satisfied or waived are set out in Figure IV-1. Of these conditions, the most important is the provision allowing termination if the project's full capacity is not contracted by May 1, 1993.

Florida Power

Figure IV - 1

PRECEDENT AGREEMENT



PARTNERSHIP AGREEMENT

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Advantages/Disadvantages of the ANR Proposal

Advantages of the ANR Proposal

1. Brings a Competitive Pipeline

ANR's SunShine pipeline will provide competition to the existing FGT pipeline. To date, the competition for FPC's business for Anclote and Polk County has been strong. This has resulted in lower costs to FPC in pipeline rates (as demonstrated in the economic evaluation of the three proposals). For example, the original FGT proposal to FPC had no rate caps and required reimbursement for laterals required to Anclote and the Polk County site (about $29 million). The current FGT proposal includes rate caps and has dropped the requirement for lateral reimbursement. Even though FPC may commit under a long-term contract for specific requirements to SunShine, competition between FGT and SunShine would continue in several ways. This could take the form of competition for additional firm FPC load to serve facilities other than Anclote that are converted to gas as part of the Company's CAA compliance strategy, and interruptible load (even indirectly through Florida's Electric Power Coordinating Group's broker system). Released and reassigned firm pipeline capacity would have enhanced competitive value with two pipelines. Negotiations for changes in tariff provisions at the FERC and FPSC level would be made in the context of what the other pipeline offers.

2. Predominantly State Regulation

The intrastate portion of the ANR SunShine project will be regulated by the FPSC. This provides regulation which is sensitive to the needs of Florida's consumers and local problems, as compared to the national agenda of the FERC. This should provide long-term benefits to customers of the SunShine Pipeline in terms of how construction permitting is processed, how tariff provisions are developed and how rate cases are handled.

3. Multiple Upstream Pipeline Options

The SunShine design provides for interconnects with United, Transabama, Gateway and Chevron Pascagoula. The design gives FPC multiple options for arranging upstream supplies. The options range from 100% of supply through United pipeline to 100% of supply through Transabama (Mobile Bay supplies). ANR, through United or Transco, provides access to

multiple supply areas from West Texas to the Carthage market center, to the South Louisiana Henry Hub area (famous as the NYMEX exchanged delivery point for futures markets) and to the eastern region of Mobile Bay. Once transportation has been arranged for on the SunShine Interstate pipeline, FPC would have the option to contract long-term or short-term for upstream transportation, rely strictly on interruptible transportation upstream, let the gas suppliers manage upstream transport or, more likely, develop a portfolio approach which would match FPC's portfolio of supply arrangements.

4. Thirty-Inch Pipeline Provides for Low Cost Expansion

ANR has proposed a 30-inch pipeline with limited compression in contrast to United's 26-inch pipeline and FGT's addition of compression to its Phase III project. The SunShine pipelines will provide opportunities for lower cost future expansions to meet FPC's and other customers' future requirements.

5. Advanced State of Design and Environmental Work

ANR's project team has been involved in trying to put together a competitive pipeline project in Florida since about 1985. The current SunShine Project is well along in design and environmental planning. The SunShine Project staff includes E. J. Burgin, who was involved in the original construction of both the FGT and South Georgia Natural Gas pipelines. Mr. Burgin has and will continue to head the project, but significant delay could result in his leaving which would be unfortunate. ANR should be able to hit the ground running once sufficient customer commitment has been established.

7. Option to Become a Partner

ANR provided an option for FPC to become a partner. The advantages of this option are described in Section VI.

Disadvantages of the ANR Proposal

1. Need To Obtain Other Customers

A minimum volume commitment is needed before non-recourse financing can be obtained and construction can be started. ANR has established a starting volume (for the intrastate portion) of about 219,000 MMbtus/day under contract before they will be able to proceed. FPC's initial volume

of 120,000 MMbtus/day is the majority of this but contracts for an additional 99,000 MMbtus/day will be required.

2. Uncertain Upstream Pipeline Costs

The ANR proposal allows significant upstream flexibility since supply regions other than Mobile Bay are accessed either through United or Transco. However, upstream transportation cost to access the Texas and Louisiana supply regions is not locked in as part of ANR's proposal. This poses some risk due to the unknown cost, terms and conditions, etc. of upstream pipeline transportation. This risk (of high upstream transportation cost) is mitigated by ANR's offer to limit the cost of upstream transportation to that proposed by United as part of the SunCoast proposal (if ANR's rates are also at the cap). In addition, FPC has the option to shift upstream transport between United, Transco and Mobile Bay sources based on the on the overall cost of gas supply and transportation.

3. Possibility of Project Failure

Problems could occur which would result in the SunShine Project not being completed. These problems include regulatory and environmental problems or the lack of sufficient customer commitment in the volumes and time frame required. FPC has the right to cancel its commitment at various points in the development of the project, with sufficient time remaining to contract with FGT for the Polk County load.

United Proposal

See Appendix IV-C for copy of United's proposal, supplemental information and a map of the proposed SunCoast Project.

General

United (and Koch) proposed two options, a 26-inch line and a 30-inch line. The projected volumes for each proposal were the same but the rates were higher for the 30-inch case. Although not quantified in the proposal, the advantage of the 30-inch line is its ability to handle additional future expansions at lower cost than a 26-inch line would handle. The 26-inch line was expected to be limited to 500,000 MMbtus/day without adversely affecting the rates.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Rates

The initial rates proposed by United were:

26-inch	30-inch
75.4¢/MMbtu	79.5¢/MMbtu

Fuel

Fuel was estimated to be:

26-inch	30-inch
3.43%	3.14%

Both the rates and fuel percentages assume that 70% of supplies are accessed through United and 30% through Gateway or Pascagoula.

Rate Caps

The initial rates are capped as follows:

26-inch	30-inch
78.4¢/MMbtu	82.0¢/MMbtu

Rate caps would go up with cost increases with specific provisions for the existing United Pipeline system (United rates would go up at the lesser of the GNP deflator or 4% per year until they reach jurisdictional rates of 20¢/MMbtu). The overall rates are capped at 87¢/MMbtu for the first 20 years. Fuel is capped at 3.5% assuming the 70/30 United/Gateway mix.

FPC Volume

- Initial delivery of 120,000 MMbtus/day for Anclote in 1995 (estimated based on in-service date for the pipeline).
- Initial delivery of 45,000 MMbtus/day for Polk 1 in August 1998.
- Initial delivery of 45,000 MMbtus/day for Polk 2 in August 1999.

- Demand charges will be assessed as each increment of capacity goes into service.

Term

25 years from initial deliveries.

System Volumes

The rate and other terms are based on total intrastate volumes of 194,000 MMbtus/day initially, up to 374,000 MMbtus/day in 1999.

Supply Area Characteristics

Up to 70% of supply can be accessed through the United System with up to 26% coming from Texas and 44% from Louisiana. The remaining 30% would come from Gateway or Pascagoula. The Gateway pipeline is connected to Mobile Bay processing plants. Pascagoula is the connection point to Chevron's future Mobile Bay and Eastern Gulf developments as well as the existing offshore Chandeleur pipeline.

Expansion Potential

The 26-inch pipeline can be economically expanded to 500,000 MMbtus/day. The 30-inch pipeline does not have limits stated, but obviously it could be expanded to handle volumes well in excess of the 26-inch line with more favorable economics.

Future FPC Requirements

United proposed that it retain a right of first refusal for any of FPC's future natural gas requirements. Similar options to those available through ANR could most likely be developed.

Penalties for Transportation Volume Imbalances

United has not submitted current pro-forma tariff for the SunCoast pipeline, so that such provisions are not presently known, but would be subject to negotiations.

Delivery Rate and Pressure

FPC anticipates that terms similar to those available from ANR will be applicable from United's SunCoast pipeline.

Interruptible Transportation Service

FPC anticipates that terms similar to those available from ANR will be applicable to United's SunCoast pipeline.

Most Favored Nations Treatment

FPC is entitled to notice from United as to any more favorable terms and conditions provided to any other firm shipper on the SunCoast pipeline, and FPC may elect to receive firm transportation service on such more favorable terms and conditions.

FPC's Rights to Additional Transportation Service Requiring Expansions of the SunCoast Facilities

If FPC offers SunCoast the opportunity to transport additional quantities of gas and SunCoast would require, but declines to construct, additional facilities to provide such service, FPC has the right to either pay for and own such additional facilities (which shall be operated and maintained by United), or to require SunCoast to construct such facilities, for which FPC must pay an incremental rate for service designed to cover the cost of the facilities.

Receipt and Delivery Points

FPC anticipates that terms similar to those available form ANR will be applicable to United's SunCoast pipeline.

Assignment and/or Release of Capacity Rights

The early drafts of the tariff for SunCoast intrastate service provided for flexible capacity assignment rights, and FPC anticipates that SunCoast will incorporate similar provisions in its final tariff. Like the FGT and the SunShine Interstate Pipeline, the United will have to adopt capacity release provisions for its interstate pipeline system in accordance with FERC Order No. 636.

Precedent Agreements

United proposed to model its agreements after those negotiated by the previous SunCoast Partners (ANR & United). See discussion of the ANR precedent agreements on page IV-5, the key dates by which conditions precedent must be satisfied or waived as set out in Figure IV-1 and the ANR agreements in Appendix IV-B.

Advantages/Disadvantages of the United Proposal

Advantages of the United Proposal

1. Brings a Competitive Pipeline

United, like ANR, would build a pipeline that would provide competition to the existing FGT pipeline. See discussion of benefits of competition on Page IV-6.

2. Predominantly State Regulation

The United SunCoast Project will be regulated by the FPSC. This provides regulation which is more sensitive to the needs of Florida's consumers and local problems when compared to the national agenda of the FERC. This should provide long-term benefits to customers of the SunCoast pipeline in terms of how construction permits are processed, how tariff provisions are developed and how rate cases are handled.

3. Supply Area Access

United's upstream system provides excellent access to most of the major natural gas supply basins in the U.S., including Texas, Louisiana, Mississippi and the Mobile Bay area. Since the United system is in general under-utilized, flexibility to change supply regions and source should be greatly enhanced when compared to FGT's generally capacity constrained system.

4. All Transportation Obtained From One Entity

Good integration of United with the SunCoast system should provide FPC with simpler administration of the transportation agreements. Tariff provisions, scheduling, notices, etc. would all be uniform except for differences caused by state vs. federal regulations of SunCoast and United.

5. Option to Become a Partner

United provided an option for FPC to be come a partner. The advantages of this option are described in Section VI.

Disadvantages of the United Proposal

1. United Management Transition

Following the recent take-over by Koch, many management changes occurred at United including the dismissal of virtually all top management. If FPC were to contract with United, some delay could be expected in their implementation of SunCoast due to this management transition.

2. Need to Obtain Other customers

A minimum volume commitment is needed before Koch would be willing to obligate funds so that construction can be started. United has established a starting volume (for the Intrastate portion) of about 194,000 MMbtus/day under contract before they will be able to proceed. FPC's initial volume of 120,000 MMbtus/day is the majority of this, but contracts for an additional 74,000 MMbtus/day will be required.

3. Twenty-Six Inch Pipe Limits Future Low-Cost Expansion

United's lowest cost proposal provides for a 26-inch pipeline design. This allows for competitive rates with a lower volume but would most likely limit United's ability to expand for future growth when compared to the 30-inch alternative.

4. Possibility of Project Failure

Problems could occur which would result in the SunCoast Project not being completed. These problems include regulatory or environmental problems or the lack of sufficient customer commitment in the volumes and time frame required. FPC has the right to cancel its commitment at various points in the development of the project with sufficient time remaining to contract with FGT for the Polk County load.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

FGT Proposal

See Appendix IV-D for copy of FGT's proposal, supplemental information and a map of the proposed Phase IV project.

FGT Alternative

FGT solicited subscriptions to capacity on its Phase III expansion in late 1991. The provisions of the Service Agreement are supplemental, and in some respects modified, by the Precedent Agreements executed by FGT and each shipper that subscribed to the proposed new capacity; therefore, the operating terms and provisions of FGT's FTS-2 Service Agreement would be supplemented and modified by a Precedent Agreement with FPC incorporating the terms and provisions set out in FGT's October 28, 1992 proposal to FPC. The significant terms and conditions of the FGT proposal, based upon the assumption that FGT's Phase III tariff would apply to the capacity contracted for by FPC, are:

Transportation Capacity and Service Obligations

FGT agrees to make transportation capacity available to FPC in three increments: 120,000 MMbtus/day in March 1997 for Anclote, 45,000 MMbtus/day in August 1998 for the first Polk County unit and 45,000 MMbtus/day for the second Polk County unit. Demand charges will be assessed as to each increment of capacity when that increment goes in-service.

Term of Transportation Service

The FGT transportation capacity would be available for a term commencing with the in-service date of the facilities required to serve FPC's Anclote facility and ending on August 31, 2019. FPC would have the right to extend the service in ten year increments by two years advance notice.

General

FGT proposed two options with different supply access designs and rates. Option A provided a diverse mix of supply regions similar to the United proposal. Option B limited supply access to the Mobile Bay area but with lower transport rates than Option A. Because of the restrictive nature of Option B's supply access it was not evaluated further.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Rates

The initial rate was proposed to be the same as the FTS-2 rate proposed for Phase III settlement, which is now pending approval by the FERC. This proposed rate is 78.6¢/MMbtu; however, it would presumably be reduced somewhat if FPC added the Anclote and Polk Units 1 & 2 to FGT's volumes. FGT has proposed that FPC reimburse them for meter station costs of about $2.1 million.

Fuel

Fuel provided for compressors is estimated by FGT to be 4%.

Rate Caps

The initial rate cap is 77¢/MMbtu. This value is fixed for the first 3 years. Thereafter, 30% of the rate cap is escalated at the GDP inflator. This is limited to a maximum of 82¢/MMbtu. Rate caps are in effect for 20 years and can be adjusted for changes in taxes. No cap on compressor fuel percentage was offered.

System Volumes

This proposal depends on FERC approval of FGT's Phase III expansion project sized at about 525,000 MMbtus/day. FPC volumes would add 210,000 MMbtus/day after August 1999 and would be another incremental expansion of FGT's system.

Supply Area Characteristics

Up to 19% of supply can be purchased in Texas, 35% in Louisiana and the remaining 46% in the Mobile Bay area. As part of the Phase III project, FGT will provide access to Mobile Bay supplies through Transabama with the cost of this upstream transport rolled into the proposed rates. Upstream transport through Southern Natural Gas is also rolled into the Phase III FTS-2 rates.

Expansion Potential

The additional capacity to serve FPC's Anclote and Polk County loads would primarily be provided by a further expansion of FGT's proposed Phase III expansion, and accomplished by the installation of additional compression (see map behind the FGT proposal). This implies that additional volume requirements in the future would require looping or parallel pipe construction in order to limit the amount of compressor fuel required to reasonable levels.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Future FPC Requirements

No specific mention of how FGT would meet any increased requirement for FPC was made. Because FGT already has meter stations at several FPC stations the movement of natural gas to these locations could be facilitated and allow for more effective use of the transportation capacity available, constraints on FGT's existing system are reduced.

Penalties for Transportation Volume Imbalances

FGT's tariff provides for an overrun charge of $.7859 per MMbtu for the first 15 years of service, and $.6199 per MMbtu for years 16 - 25, for gas taken in excess of 104% of nominated quantities.

With respect to imbalances between receipts of gas for FPC's account and deliveries of gas to FPC, a period of 45 days is provided to "work off" imbalances in excess of 5% of nominations, and 60 days for any lesser imbalances. If FPC causes FGT to receive more gas than FGT delivers to FPC, the penalty is FGT's retention of excess volumes. If FPC takes more gas from FGT than FGT receives for FPC's account, the penalty is a charge equal to twice the tariff commodity rate.

Assignment and/or Release of Capacity Rights

FGT's tariff contains provisions for permanent capacity relinquishment and temporary capacity release that are consistent with FERC Order No. 636. Any relinquishment of capacity only relieves the capacity holder of obligations to pay for such capacity to the extent that its rate obligations are assumed and paid by an acquiring party. Temporary releases provide a credit to the capacity holder for its rate obligations equal to the rate paid by the party acquiring the capacity. If capacity relinquishment or release is handled by FGT through its electronic bulletin board, FGT may retain 10% of the amount paid by the acquiring parties as a fee.

Delivery Rate and Pressure

The Service Agreement dated December 12, 1991, between FGT and Florida Power and Light Company (FPL), as amended, provides for maximum hourly, 4-hour, 14-hour and 24-hour rates of delivery for specific FPL facilities; it is, therefore, reasonable to assume that similar provisions would be available to FPC. The FGT Service Agreement for Phase III capacity expressly relieves FGT from any obligation to deliver gas at any pressure level to any delivery point.

This may require FPC to install compressors at Polk County to maintain inlet pressure to the combined cycle turbines.

Receipt and Delivery Points

Adequate delivery point flexibility is provided, including the right to move gas supply not needed at one FPC facility to another FPC facility accessed by FGT's system. Receipt points for FPC's gas supply into FGT's system are limited by quantity to certain FGT system zones under Option A, and all FPC's gas supply must be received at FGT's Mobile Bay facilities under Option B.

Interruptible Transportation Service

No provision.

Most Favored Nations Treatment

FGT refused to provide.

FPC's Right to Additional Transportation Service requiring Expansions of FGT's Facilities

FGT will construct if FPC agrees to pay an incremental rate sufficient to cover full cost of such facilities.

Precedent Agreements

FGT has not provided FPC with draft agreements as part of the proposal but references the need for these to be final by January 18, 1993. The exact details of the agreements would be negotiated subsequent to signing the proposed Letter of Intent with FGT.

Advantages/Disadvantages of the FGT Proposal

Advantages

1. Existing Florida Infrastructure

   FGT has an extensive pipeline system throughout Florida. This will be increased from a current capacity of 925,000 MMbtus/day to about 1,450,000 MMbtus/day. If the Phase III project is approved by FERC and completed as proposed in 1995, FGT's proposal to FPC would be accomplished by addition of several compressors to their pipeline system,

limited looping in the supply areas, and construction of laterals to Anclote and the Polk County site. Part of FGT's incremental expansion for FPC's requirements would probably be easier to permit and build than the grassroots construction required by the ANR or United projects (assuming, of course, that the Phase III project has been approved and constructed in 1995). In addition, since FGT already has meter stations at Bartow, Turner, Higgins, Avon Park and University of Florida, they provide additional flexibility in utilizing the natural gas supplied, provided constraints on FGT's existing system are reduced.

2. Good Supply Access

FGT's proposal provides for proportional access to the South Texas, South Louisiana and Mobile Bay regions. In addition, through their multiple (although limited in capacity) upstream pipeline interconnects, supplies from other regions (such as Carthage, Texas and Alabama's Coal Bed Methane areas) can be transported.

3. All Transportation Obtained From One Entity

The FGT proposal provides direct access to natural gas supply either by direct connection to production or through FGT managed upstream pipeline contracts. Transabama and Southern Natural Gas both provide Firm Transportation to FGT as part of the Phase III project. FGT customers will be able to nominate (with capacity constraints) receipt points on these upstream pipelines as if they were part of the FGT system.

Disadvantages

1. No Competitive Pipeline

If FGT is chosen to provide FPC's natural gas transportation requirements then FGT's monopoly position within Florida will be maintained and the potential for future inroads by competitors will be greatly reduced. FPC's requirements for 210,000 MMbtus/day represent a substantial block of load (representing about 1,500 MW of electric generation). Most new natural gas fired electric generators are expected to be built in relatively small sizes (50 MW - 250 MW range) by a more diverse group of owners over a wide geographic area and with different "in-service" dates. This will make a pipeline competitor's ability to aggregate a sufficient block of load even more difficult in the future even if the demand for natural gas in Florida grows steadily over time.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

FPC's gas transportation requirements for future facilities and future conversions of existing facilities (such as Bartow, Higgins, Avon Park) will be negotiated with FGT without the benefit of competitive pressure.

2. Contract Will be Subject to Ongoing Revisions/Disapprovals by FERC

FGT is a totally FERC regulated interstate pipeline; therefore, a large part of their proposal is subject to FERC approval. This subjects most business done with FGT to scrutiny not only by the FERC but all of FGT's customers, natural gas suppliers, other pipelines, or any other person who intervenes and can demonstrate an interest in the proceedings. In the past, as FERC changes policy, long-term contract have been revised and their purpose frustrated by changes in the pipe line's tariffs. This is very likely to continue.

3. Political/Regulatory Fallout

FPC spent considerable resources and goodwill to promote the passage of a law providing for state regulation of an intrastate pipeline. In addition, the FPSC and its staff have supported passage of this legislation and the prompt filing of a competing pipeline application. If no competing line is proposed, FPC's future credibility on other political issues could be questioned. FPC also promoted the development of the competitive pipeline as one of the reasons for an early DON for the Polk County Units. If the competitive pipeline is abandoned in favor of FGT then potentially this could, at a minimum, harm FPC's credibility with the FPSC.

4. Limited Future Low-Cost Expansion

FGT's proposal primarily adds compression to provide incremental volumes to FPC. This slightly lowers transportation rates, but increases the amount of gas which has to be provided for compressor fuel. Future expansions will most likely be more costly since the expansion for FPC appears to have filled up any designed in expansion room from Phase III.

5. Rate Cap Subject to Tax Adjustments and No Cap on Fuel Use

FGT's rate cap is subject to escalation resulting from any increase in corporate income taxes and, therefore, the rates could be higher than those evaluated. The compressor fuel is not subject to a cap and could be higher than estimates.

6. No Option to Become a Partner

FGT's proposal does not provide for FPC to become a partner.

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Consultants Review

At an earlier stage of the Task Force's work, John J. Hibbs & Associates was retained to do an independent review of the design, cost and rate estimates for the proposed SunCoast Project (a partnership of ANR and United at the time) and also the proposed FGT Phase III expansion project. Excerpts from the report prepared by John J. Hibbs & Associates are included in Appendix IV-E.

This report concluded that, as a general matter, no major flaws in design, cost estimates, cost of service or rates were observed. Hibbs concluded that SunCoast's capital cost estimates were probably too high but the O&M estimates appeared too low, essentially compensating errors in the final rate calculation. He also concluded that the FGT estimates for construction cost were low and that either proposed rates would be higher or FGT would have to accept a lower return.

After the new proposals were received (October 28, 1992) and reviewed, Hibbs was requested to review the design, cost estimates and rates for the ANR proposal. Both ANR and United proposed systems similar to the previous SunCoast project but without the extension south to serve FPL. United proposed a lower cost 26-inch alternative to the 30-inch design. FGT's proposal consisted of an incremental addition of compression, limited looping of mainline, and lateral additions. Since preliminary economic analysis of the proposals favored the ANR proposal, Hibbs was requested to focus his review on ANR's SunShine project as proposed on October 28, 1992. Excerpts of Hibbs review are included in Appendix IV-F. This report concludes that, "as a general observation, no major flows in design, capital cost estimates, cost of service or rates for either SunShine or SITCO were observed". The report pointed out some concern that the operating cost estimate was too low. If the operating costs were to increase from the $3.3 million ANR estimate to Hibb's estimate of $12.5 million, the transportation rate on SunShine and SITCO could increase by as much as 10%. This would translate into an approximate 7% increase in FPC's overall cost of natural gas transportation (when compressor fuel and upstream transport cost are also considered).

Economic Evaluation

Methodology

Each proposals' projected transportation cost to FPC was evaluated based on FPC's requested volumes, fuel cost projections, proposed rates, and the proposed rate caps. The impact of required compressor fuel for each proposal was also factored in based on forecasted natural gas prices. In addition, sensitivity of the analysis to changes in some of the key assumptions was also tested. Finally, an evaluated cost for each proposal was developed by assigning probabilities to each sensitivity case utilizing

decision analysis techniques. The sensitivities reviewed and their assigned probability were as follows:

Escalation

High	6%	Probability	25%
Base	4%	Probability	50%
Low	2%	Probability	25%

Volume Utilized

Base	100%	Probability	50%
Low	80%	Probability	50%

Rates Charged

Expected Rates	Probability	70%
Rate Caps	Probability	30%

In addition, for ANR an additional sensitivity was developed because of the options available for upstream transportation:

United Supply

50% through United	Probability	90%
100% through United	Probability	10%

Appendix IV-G contains a detailed description of the assumptions and economic analysis of each proposal and the sensitivities reviewed.

Results

A table of the major economic features of each proposal is presented in Figure IV-2. A table of the net present value of each proposal as calculated under each sensitivity is presented in Figure IV-3. The base proposed values from Figure IV-3 are summarized here.

COMPARISON OF PROPOSALS

Figure IV-2

	ANR	UNITED	FGT
Size	30-inch	26-inch[2]	30-inch
Initial Rate ¢/MMbtus	74.8[1]	75.4	77.0
Compressor Fuel Percentage	1.9 [1]	3.5	4.0
Proposed Transport Cost NPV $ Million	457	492	496
Initial Rate Cap	79.3[1]	78.4	77.0[3]
Ultimate Rate Cap	95.0[1]	87.0	82.0+ Subject to Tax Adjustments
Compressor Fuel Cap Percentage	2.7[1]	3.5	4.5% (Estimate)
Rate Cap Cost NPV $ Million	520	511	514

(1) Assumes 50% of supply through United and 50% of supply through Gateway.
(2) Option for 30-inch line at higher rates.
(3) Fixed for three years.

Summary Of Gas Pipeline Proposals

Figure IV – 3

Rate Caps Analysis

	United–26	United–30	FGT–30	ANR–30
Base Assumptions	$510,714,631	$519,810,461	$513,791,704	$519,522,333
High Escalation Rate	$514,839,920	$520,839,920	$515,199,682	$519,522,333
Low Escalation Rate	$501,201,644	$516,571,885	$510,004,672	$501,011,940
Low Volume Consumption	$495,089,595	$504,702,372	$493,702,372	$507,468,734
Through United 100%				$567,998,723

Proposed Rates Analysis

	United–26	United–30	FGT–30	ANR–30
Base Assumptions	$492,177,380	$499,834,358	$495,771,864	$456,714,442
High Escalation Rate	$500,331,452	$504,155,328	$502,035,854	$456,714,442
Low Escalation Rate	$477,935,681	$490,582,164	$483,457,235	$439,039,798
Low Volume Consumption	$471,259,547	$485,995,041	$477,914,680	$448,232,280
Through United 100%				$499,498,670

ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

The proposals compare as follows in the base proposed case:

	Present Worth $ Millions	Difference PW $ Millions	Difference %
ANR	457	-	-
United	492	35	8
FGT	496	39	9

Figure IV-4 is a graph of the expected unit rates.

The proposed rate caps from Figure IV-3 are summarized here:

	Present Worth $ Millions	Difference PW $ Millions	Difference %
ANR	520	-	-
United	511	(9)	2
FGT	514	(6)	1

Figure IV-5 is a graph of the unit rate caps.

In order to combine the results of the various sensitivities, decision analysis was utilized. Probabilities were assigned to each sensitivity as discussed in the methodology section.

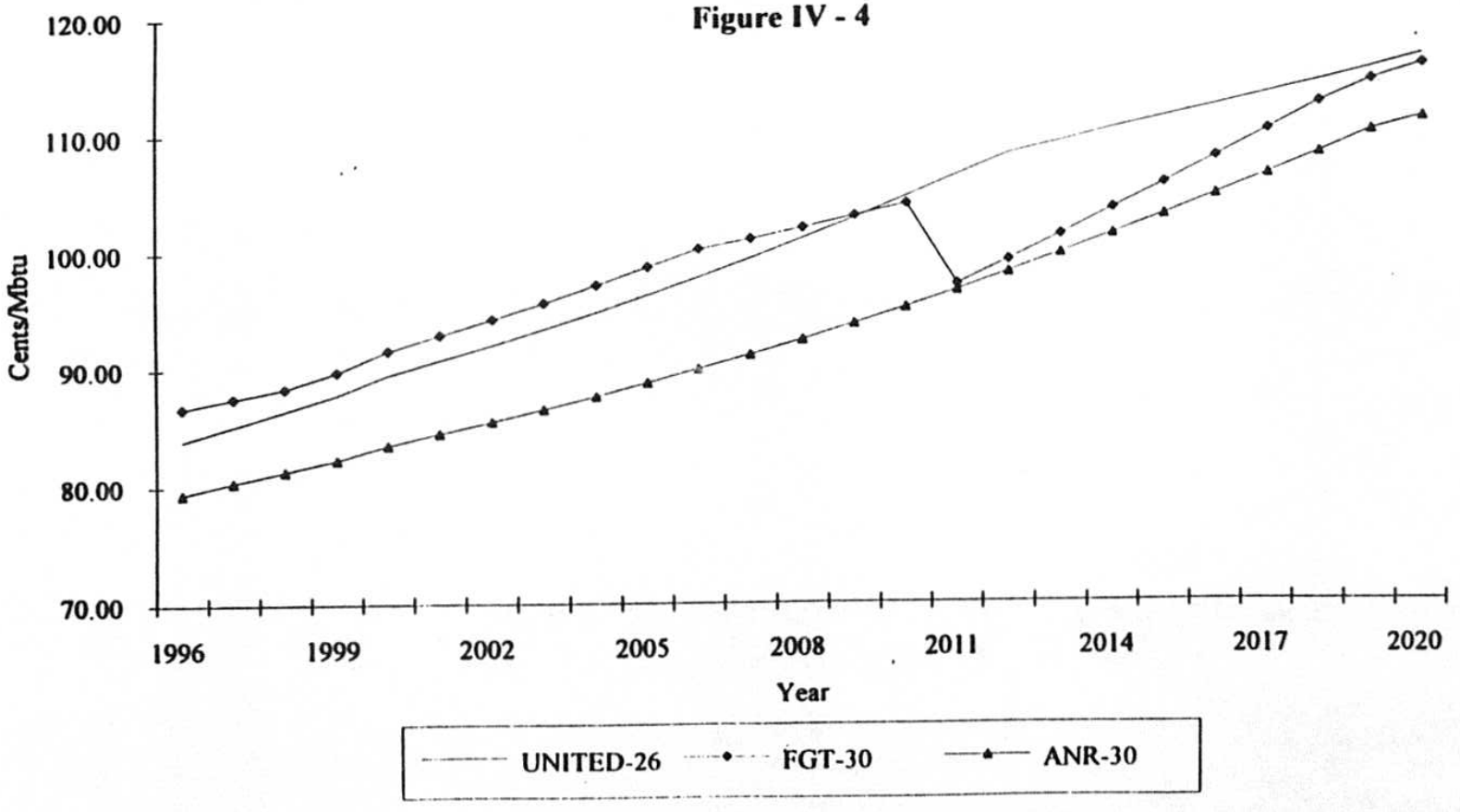
The evaluated cost of the proposals based on the decision analysis (see Appendix IV-H) is as follows:

	Present Worth $ Millions	Difference PW $ Millions	Difference %
ANR	475	-	-
United	488	13	3
FGT	491	16	3

Gas Pipeline Proposal Evaluations

Comparison Of Total Transportation Under Proposed Rates Analysis

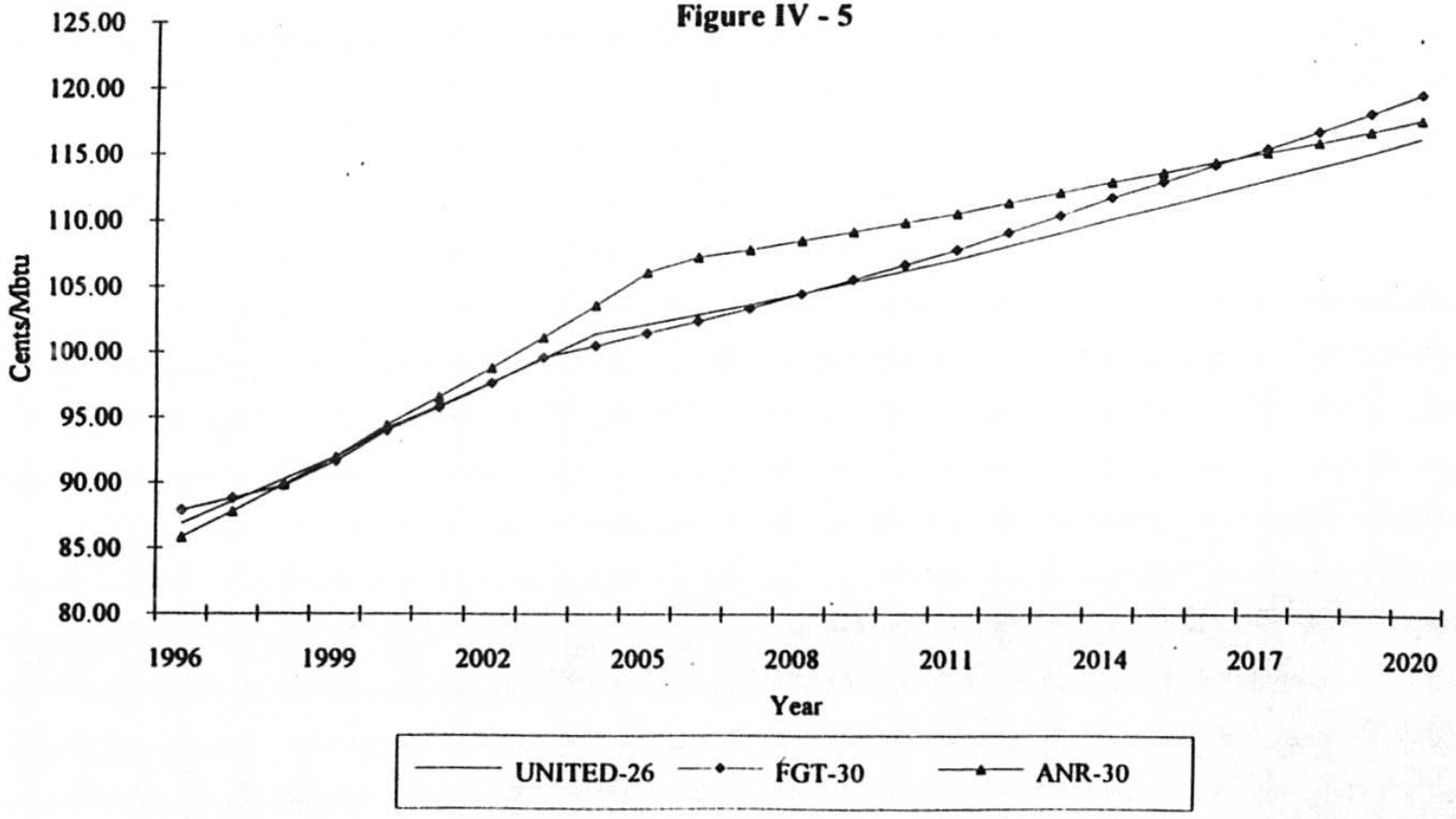
Figure IV - 4



Gas Pipeline Proposal Evaluations

Comparison Of Total Transportation Under Rate Caps Analysis

Figure IV - 5



ANALYSIS OF THREE GAS TRANSPORTATION ALTERNATIVES

Summary

All of the estimated costs presented are subject to some uncertainty and the differences in cost projected are highly dependent on the assumptions used to develop them.

As an example, the ANR project has been reviewed by an independent consultant. This review revealed a question as to the validity of ANR's O & M estimates. Based on the consultant's estimates, the proposed cost of the ANR proposal could increase by as much of 7%. Neither the United nor the FGT projects (as defined in their October 28, 1992 proposals) have been reviewed in detail by an independent consultant. The United proposal was prepared while the company was being acquired by Koch. Although Koch has agreed to stand by the United offer, many of the details of construction costs, design, etc., are not readily available for independent review. The FGT proposal is based on a Phase IV expansion which was proposed to FPC without details on the construction cost or design. (An earlier review of the FGT Phase III design raised questions about the validity of their construction cost estimates). Therefore, both the United and the FGT proposals may have areas that would result in different cost estimates than those expected based on their proposals.

The economic evaluation of the the three proposals was based on "proposed" rates as well as the rate caps provided. In addition, several sensitivity studies were done and decision analysis techniques were used to develop an evaluated cost for each proposal, and a review of the advantages and disadvantages of each of the proposals was developed for those items which were not readily quantifiable.

Because of the uncertainty of the proposed costs and the small differences in the evaluated costs, it can be concluded that the decision between natural gas transportation alternatives should be primarily based on other factors besides transportation rates.

Section V: RECOMMENDATIONS AS TO TRANSPORTATION

TASK FORCE RECOMMENDATION

The Task Force recommends that FPC proceed immediately to finally negotiate and enter into a precedent Agreement with ANR (SunShine and SITCO) for long-term, firm natural gas transportation service for Anclote and the first two Polk County CC units.

This recommendation is primarily based on the following:

- SunShine will introduce pipeline-to-pipeline competition into the state of Florida, which will provide long-range benefits to FPC over and above the cost savings resulting from the initial transportation contract as supported by John J. Hibbs & Associates, Inc., which can be found in Appendix IV-F.

- The SunShine Project is designed to allow for significant future low-cost expansion. This will provide benefits to FPC as our natural gas requirements grow in future years.

- The SunShine Pipeline will be predominantly state regulated. This is expected to result in more favorable regulatory response to pipeline customer concerns than FERC regulation would provide.

- The SunShine Project's feasibility has been established.

  - ANR is well along in its design and environmental work for the project and has a good understanding of the Florida marketplace for gas. Additionally, the project is led by Mr. E. J. Burgin, who is experienced and respected in this market (having participated in the management and construction of the original FGT pipeline).

  - A preliminary validation by Florida Progress of the "financials" for the project, using the supplied assumptions, indicates that the economic evaluation of the project appears reasonable. The cost and rate estimates provided by ANR have also been reviewed by a qualified, independent pipeline consultant.

  - ANR is financially capable, strongly committed to the project, and willing to go forward, whether or not FPC elects to participate as an equity partner.

Section V: RECOMMENDATIONS AS TO TRANSPORTATION

- Through SITCO, (the interstate pipeline), FPC will have multiple upstream pipeline options. This will provide FPC with the ability to realize gas purchasing savings.

- The "proposed" cost of a new pipeline placed in service by ANR is superior to the other two alternatives. The "proposed" case for ANR represents a $35 to $39 million net present value savings when compared to United and FGT.

- The SunShine Project precedent agreement gives FPC the option to terminate if SunShine is unable to attract enough customers to justify its construction, so that FPC will still have the opportunity to leverage its "anchor load" position to secure transportation on favorable terms over FGT's Phase IV Project. Therefore, the choice of ANR to provide FPC's transportation service is "hedged" by the opportunity to move to FGT if the SunShine Project fails, whereas choosing FGT as FPC's gas transporter kills off any realistic chance of realizing the future benefits of pipeline-to-pipeline competition.

FLORIDA PROGRESS ANALYSTS' RECOMMENDATION

The primary objective in selecting a gas transportation vendor is to secure gas transportation for the planned Polk county units at the lowest cost with the lowest risk. Given the nature of the options available to FPC, there are two additional considerations which deserve to share the status of primary objectives. The first of these is to preserve flexibility regarding the conversion of Anclote to gas. The second is the preservation of flexibility relative to the possible future conversion of the Polk units to coal. These objectives bear on the decision to select gas transportation as follows:

- Each of the offers have been reduced to a present value using decision analysis. The results indicate that with respect to cost, the offers are very close, but that FGT offers are slight advantage. The selection of FGT would lock in this value for FPC and its customers. The selection of ANR would expose FPC to the risk of failure of a new pipeline venture, following which there would be no assurance that the existing offers could be matched.

- The Gas Task Force has recognized that FGT presents the lowest risk alternative to assure gas delivery to the Polk site; this conclusion is affirmed. An expansion of FGT's existing system carries significantly lower risk than the new pipeline venture ANR would need to undertake to serve FPC.

RECOMMENDATION

- The selection of ANR would require the early conversion of Anclote to gas, thus preempting by several years the need to make this decision for Clean Air Act compliance. At present, the Anclote conversion is an option for compliance, but has not been identified or recommended as the best option. Furthermore, projections indicate that the conversion is likely to increase rates to customers during 1996-98. Therefore, the proposed timing cannot be supported on economic grounds. The selection of FGT would provide greater flexibility for the timing of the conversion and, in principle, make it optional.

- A crucial element of the development of the Polk site is the possible future conversion of the Polk units to coal. Securing gas transportation with FGT, with its much larger customer base, increase the likelihood that FPC could release its capacity to other customers if this became necessary in the future. Capacity release could be difficult or impossible on a smaller pipeline where FPC would be the largest customer.

As a result, when the objectives of lowest cost, lowest risk and preservation of flexibility are considered together, FGT emerges as the clearly preferred choice. By contrast, the selection of ANR would compromise, to a degree, each of the objectives.

Current plans indicate that FPC has no need for additional gas for at least ten years and an uncertain need for gas in the years beyond. The decision at hand is very likely to be the largest commitment to gas FPC will make within the next 20 years. This decision should be made based on maximizing value for FPC and its customers now.

FPC should proceed immediately to enter into an agreement with FGT for gas transportation. An essential preliminary step in this process should be a reevaluation of the proper timing for the conversion of Anclote to gas. Although the proposed delivery of gas to Anclote in March 1997 by FGT is preferable to the 1995-96 delivery required by ANR, FGT's inherent flexibility may provide further opportunity for improvement.

Pipeline Competition Issue

The selection of FGT would not, however, result in the introduction of a new pipeline into Florida at this time. Given that the issue of pipeline competition has been elevated from simply a consequence of this decision to an issue of considerable magnitude, it is appropriate to place this issue into perspective with the following points:

- As FPC and many other companies have proven, regulated monopolies are capable of meeting the needs of their customers in an efficient, cost-effective manner. Expressed or implied arguments which challenge FGT's ability to operate in this manner are untenable. It is inadvisable for FPC to adopt a public, proactive position in opposition to a concept so fundamental to its own core business.

RECOMMENDATION

- To the extent that introducing pipeline competition into Florida is a worthy pursuit, it must be recognized as being a secondary objective for FPC. As a matter of principle, secondary objectives should not be permitted to distract FPC from fully achieving recognized primary goals for the benefit of its customers.

- As the present circumstances demonstrate, the threat of competition can be as effective as the actual existence of competition. The potential for competition has existed and will continue to exist in Florida and exert a subtle pressure on FGT. As the market grows and existing transportation contracts expire there will be many potential opportunities for the entry of competitors if they can compete successfully with FGT. Placed into this context, the present situation cannot fairly be characterized as a now-or-never opportunity to "create" competition.

Once the issue of competition has been put into perspective, there does not appear to be a justification to undertake the risks associated with a new pipeline venture. As currently proposed, a new pipeline would be operating at the extreme margin of viable economic scale against a much larger, established competitor. Some industry observers apparently share this concern, as evidenced by a statement made in The Oil Daily on August 18, 1992: "Industry experts doubt more than one pipeline is economical in the state, given the ongoing expansion of the FGT system." The arguments for urgency to proceed stand as testimony that the customer base essential to the viability of a new pipeline may or may not exist. It is unnecessary and therefore inappropriate for FPC to select an option which exposes it to risks which are not counterbalanced by clearly visible rewards.

ANR PROPOSAL

AND SUPPORTING DATA

October 28, 1992

Mr. Stephen Watsey
Vice President, Purchasing and Stores
Florida Power Corporation
3201 Thirty-fourth Street South
P. O. Box 14042
St. Petersburg, Florida 33733

Re: SunShine Pipeline Company and
SunShine Interstate Transmission Company

Dear Mr. Watsey:

Pursuant to your letter dated October 21, 1992 to Mr. Charles M. Oglesby regarding our company's interest in providing natural gas service to Florida Power Corporation's existing Anclote Plant and the proposed new units in Polk County, Florida, please find enclosed a Term Sheet highlighting the major elements of the proposed long term transportation agreements between the above referenced companies and FPC.

We acknowledge that the Precedent Agreements dated September 11, 1992 that were previously sent to you will require modifications based on the enclosed Term Sheet and our recent discussions on relevant dates. However, we would anticipate that such Precedent Agreements as well as the proposed General Partnership Agreement previously negotiated between our representatives would form the framework of the overall transaction contemplated by our respective companies.

If there is a need to elaborate upon or clarify any particular point contained in the enclosure, please do not hesitate to call at your earliest convenience. Thanking you for the opportunity to participate in this process, I am

Very truly yours,

E. J. Burgin

TERM SHEET

General Parameters

- **Capacity**

  Option 1

  - SunShine Pipeline Company (SunShine) 219,000 MMBTU/day in 1995 with increase to 399,000 MMBTU/day in 1999
  - SunShine Interstate Transmission Company (SITCO) 324.500 MMBTU/day in 1995 with increase to 504,000 MMBTU/day in 1999

  Option 2

  - SunShine Pipeline Company (SunShine) 239,000 MMBTU/day in 1995 with increase to 419,000 MMBTU/day in 1999
  - SunShine Interstate Transmission Company (SITCO) 344.500 MMBTU/day in 1995 with increase to 524,000 MMBTU/day in 1999

  Option 3

  - SunShine Pipeline Company (SunShine) 219,000 MMBTU/day in 1995 with increase to 444,000 MMBTU/day in 2000
  - SunShine Interstate Transmission Company (SITCO) 324.500 MMBTU/day in 1995 with increase to 549,000 MMBTU/day in 2000

  Option 4

  - SunShine Pipeline Company (SunShine) 239,000 MMBTU/day in 1999 with increase to 464,000 MMBTU/day in 2000
  - SunShine Interstate Transmission Company (SITCO) 344,500 MMBTU/day in 1999 with increase to 569,000 MMBTU/day in 2000

- **Capital**

  Option 1

  - $641.8 MM Total Project

  Option 2

  - $656.3 MM Total Project

Option 3

- $655.7 MM Total Project

Option 4

- $673.6 MM Total Project

- Rates and Volumes

Option 1

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999

Rate: $0.673/MMBtu
Estimate Fuel: 0.9%

Option 2

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999
Ellaville	20,000	1996

Rate: $0.66/MMBtu
Estimate Fuel: 0.9%

Option 3

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999
Anclote	45,000	2000

Rate: $0.641/MMBtu
Estimate Fuel: 1.0%

Option 4

Florida Power Corp. Volumes/Day MMBtu

"Option 1, 2 and 3" Volumes

Rate: $0.628/MMBtu
Estimate Fuel: 1.1%

- Facilities
  - SunShine will begin at an interconnection with SITCO and extend down the west coast of Florida terminating in Polk County. Laterals will be constructed to serve subsequent volumes not on the mainline route.
  - SITCO will extend from the terminus of Chandeleur Pipeline Company and the outlet of the Chevron Magnolia Plant to a point of interconnection with SunShine at the Okaloosa/Walton county line. The system will also have direct interconnections with Gateway Pipeline, Mobile Bay Pipeline and United Gas Pipe Line
- Regulatory Authority
  - SunShine will be a non-discriminatory transporter built as a Hinshaw exempt Intrastate pipeline under Section 1(c) of the Natural Gas Act (NGA). Its construction and operation will be regulated by the Florida Public Service Commission
  - SITCO will be an open access, transportation only pipeline built and operated under the regulation of the Federal Energy Regulatory Commission (FERC) pursuant to Section 7(c) of the NGA

Rates

Option 1

- SunShine initial rate of 52.5¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.8¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 67.3¢/MMBTU for SunShine and SITCO.

Option 2

- SunShine initial rate of 51.72¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.27¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 66.00¢/MMBTU for SunShine and SITCO.

Option 3

- SunShine initial rate of 49.96¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.17¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 64.1¢/MMBTU for SunShine and SITCO.

Option 4

- SunShine initial rate of 49.08¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 13.72¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 62.80¢/MMBTU for SunShine and SITCO.

- Aggregate initial rate cap of:

  Option 1

  71.8¢/MMBTU

  Option 2

  70.5¢/MMBTU

  Option 3

  70.6¢/MMBTU

  Option 4

  69.3¢/MMBTU

- Aggregate rate cap shall be exclusive of surcharges and fuel

- 45% of the aggregate rate cap and each successive rate cap shall be increased annually by the greater of the GNP Implicit Price Deflator or 4%

- For the first twenty years of the term of FPC's contract, the aggregate rate cap shall be capped at:

  84¢/MMBtu for Option 1.

  83.5¢/MMBtu for Option 2.

  83¢/MMBtu for Option 3.

  82¢/MMBtu for Option 4.

- Aggregate rate cap for the first contract year may be increased by the percentage increase in the GNP Implicit Price Deflator for the period between February 1, 1995 and the actual in-service date, if later

- Within the aggregate rate cap, rates on SunShine and SITCO may be adjusted from time to time through normal ratemaking procedures of the Florida Public Service Commission or the Federal Energy Regulatory Commission, respectively

- Subject to FERC ruling on the discriminatory nature of rate cap treatment, Sunshine reserves the right to adjust its rate cap accordingly to be in compliance with FERC policy

Agency Agreement

- At the request of Shipper, SunShine Marketing Company would act as agent to hold and manage capacity on SunShine and SITCO.

Fuel

- Total fuel on the combined SunShine and SITCO System to be capped at 2.5%.

INTERCONNECT SUMMARY

I. Chevron Pascagoula

- Physical Sunshine Interstate interconnect capacity will be available for:

	(MMcf/d Volume)
- Chandeleur	205
- Rainbow/Magnolia (Phase I)	300
- United Diversion/Backflow at Plant	95
Total Initial	600

- Metering will be designed for flexibility to increase capacity.

- Rainbow/Magnolia Phase II	+300
- Rainbow/Magnolia Phase III	+300
Total Additional At Pascagoula	+600
- Grand Total Future at Pascagoula	1,200

II. United/Gateway and Transco/Transabama

- Sunshine interstate will have interconnections with both United/Gateway and Transco/Transabama.
- Physical interconnect capacity for each will be 600 MMcf/d initially and each will be designed so that additional capacity can be added easily.
- Effectively, Sitco will have the same reserves access as United and Transco has.

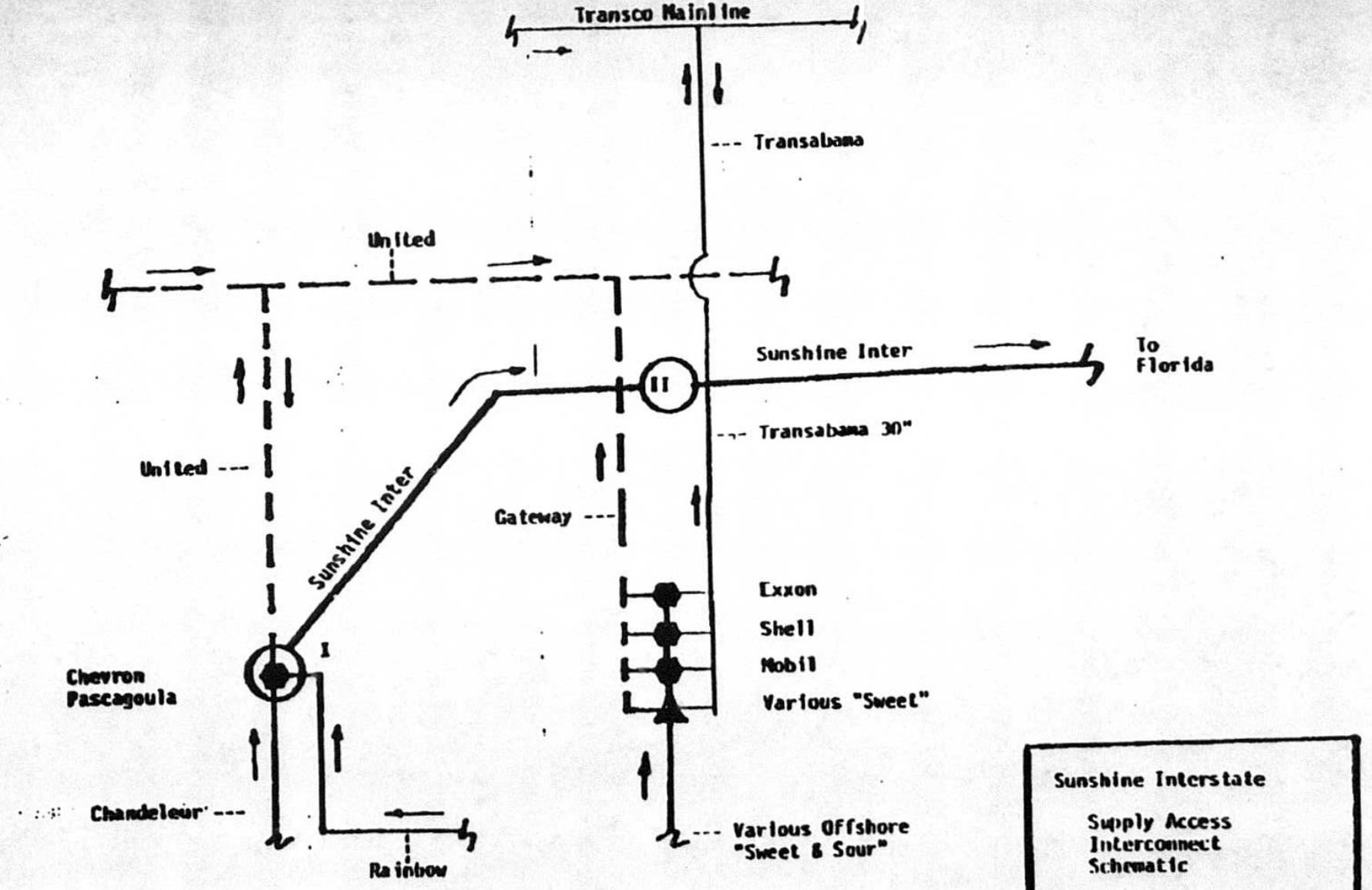
ALABAMA RESERVES ACCESS

	Current Proposed Capacity MMcf/d	Future Capacity MMcf/d
Shell Yellowhammer	240	240
Mobil	240	240
Exxon	300	600
Other "Sour" Norphlet	150	300
"Sweet" Miocene	100	200
Total Onshore Alabama	1,030	1,580

Example
Supply Access
Source & Disposition

Supply Source	3rd Party *	SIECO	Sunshine	Total
Chevron/Pascagoula	-	14¢	53¢	67¢
Alabama Sources	2-6¢ Gateway Transabama	14¢	53¢	69-73¢
Louisiana/Texas	5-11¢ United	14¢	53¢	72-78¢
Louisiana/Texas	5-11¢ Transco	14¢	53¢	72-78¢

*1) Third Party cost are estimates


Transco Mainline
--- Transalbama
United
Sunshine Inter
To Florida
II
--- Transalbama 30"
United ---
Sunshine Inter
Gateway ---
Exxon
Shell
Mobil
Various "Sweet"
I
Chevron Pascagoula
Chandeleur ---
Rainbow
--- Various Offshore "Sweet & Sour"
Sunshine Interstate
Supply Access Interconnect Schematic

SITCO/SunShine Pipeline Company
Construction Cost Rate Sensitivity

30" System (1996 In-Service)	Total Investment ($1994 Million)			25-Year Levelized Rate ($/Mcf)		
	Interstate	Intrastate	Total	Interstate	Intrastate	Total
CASES						
Base Case Capital	$176.8	$463.7	$640.5	$0.1482	$0.5249	$0.6731
5% Capital Reduction	168.4	441.6	610.0	0.1413	0.5006	0.6419
10% Capital Reduction	160.7	421.5	582.2	0.1351	0.4787	0.6138
15% Capital Reduction	153.7	403.2	556.9	0.1295	0.4586	0.5881
20% Capital Reduction	147.3	386.4	533.7	0.1243	0.4403	0.5646

The above reduction of capital costs is applied to total capital (i.e. for the initial investment and the incremental buildup).

The relationship of rates to total capital were calculated for the Base Case, the 10% and 20% capital reduction case, for the Intrastate project. These relationships were applied to all other studies and, therefore, the numbers are approximate and subject to rounding.

E. J. Burgin
10/12/92

November 6, 1992

Mr. Stephen Watsey
Vice President, Purchasing and Stores
Florida Power Corporation
3201 Thirty-fourth Street South
P. O. Box 14042
St. Petersburg, Florida 33733

Re: SunShine Pipeline Company and
SunShine Interstate Transmission Company

Dear Mr. Watsey:

This is to revise and supplement my letter to you of October 28, 1992:

Fuel. Total compressor and unaccounted for fuel on the combined SunShine and SITCO System will be capped at 1.5%. However, in the event SunShine or SITCO expand their respective systems in the future such that it results in greater fuel usage than the combined 1.5% cap but combined lower rates, then the 1.5% fuel cap will be permitted an upward adjustment to actual usage so long as the overall impact is to keep the combined cost (rate plus fuel) less than or equal to the combined cost prior to system expansion.

Rate Cap. In the event that the combined transportation rates on SunShine Pipeline Company ("SunShine") and SunShine Interstate Transmission Company ("SITCO") escalate to 83.5¢ per MMBTU and the transportation costs upstream of SITCO exceed the 11.6¢ per MMBTU escalated up to a maximum of 20¢ per MMBTU (per the United Gas Pipe Line Company escalating schedule of rates), plus fuel equivalent to 2.3 of the transported volume, FPC may notify SunShine that FPC desires SunShine to take one of the following measures: (1) lower the cap on the Aggregate Rate Cap from 84¢ per MMBTU plus 1.5% for fuel to 82.1¢ per MMBTU plus 1.5% for fuel; (2) FPC designates SunShine Marketing Company ("SMC") as its agent to arrange for either supply or transportation or a combination thereof upstream of SITCO and SITCO, within six (6) months of being designated as FPC's agent, will reduce FPC's transportation rate upstream of SITCO to a maximum of 15.4¢ per MMBTU; (3) mutually agreeable combinations of options (1), and (2); (4) other mutually agreeable methods to reduce FPC's upstream cost.

Upon receiving FPC's notice, SunShine will have thirty (30) days to respond to FPC as to which of the above options it selects and such option will be implemented within forty-five (45) days from the date SunShine receives FPC's notice.

In addition, this letter will confirm the representations that I made this morning in a telephone conversation with Mr. Dale Williams regarding the Aggregate Rate Cap escalation as described on Page 5 of The Term Sheet forwarded to you on October 28, 1992. The language contained in point 2 on Page 5 contained a typographical error. The language should read "45% of the aggregate rate cap and each successive rate cap shall be increased annually by the lesser of the GNP Implicit Price Deflator or 4%."

If there is a need to elaborate or clarify any particular point contained in this letter, please do not hesitate to call at your earliest convenience.

Very truly yours,

E. J. Burgin

Proposed as Separate Letter or as Penultimate Paragraph to 11/6/92 Letter

SunShine recognizes that it is in FPC's and its mutual interest for FPC to immediately secure transportation upstream of SITCO on the best terms available. To this end, for a one year period from the date the Precedent Agreements are executed, SunShine proposes that FPC allow SunShine to negotiate with various parties for upstream gas supply and transportation for the benefit of FPC. SunShine will exercise good faith in the performance of such negotiations and will not represent itself as agent for FPC, nor act under any form of power of attorney nor be able to bind FPC in any manner. SunShine will present to FPC a detailed Term Sheet for any upstream transportation it negotiates on behalf of FPC for FPC's approval which will be exercised in FPC's sole discretion and in good faith.

Market Potential for ANR Pipeline

The potential new customers on the intrastate line and their volumes are as follows (for the ANR proposal):

	1995	1999
FPC	120,000	210,000
Peoples Gas	65,000	65,000
Leesburg	10,000	10,000
Seminole Fertilizer	24,000	24,000
SEC Hardee	-0-	90,000
	219,000	**399,000**
Other potential customers include:		
City of Tallahassee Gainesville Regional Utilities Lakeland Municipal Utilities City of Kissimmee City of St. Cloud Orlando Utilities Commission Teco Power Services Other Cogeneration and Independent Power Projects		

PRECEDENT AGREEMENT

This precedent Agreement ("Agreement"), made this ___ day of _____ 1992, by and between FLORIDA POWER CORPORATION, a Florida corporation ("Shipper") and ANR SOUTHERN PIPELINE COMPANY, a Delaware corporation (ANR Southern"), (hereinafter shipper and ANR Southern are sometimes referred to individually as a "Party" or collectively as the "Parties").

W I T N E S S E T H:

WHEREAS, ANR Southern intends to design, construct, own and operate a natural gas pipeline (the "ANR Southern Interstate Facilities") that extends from a point in the Mobile Bay vicinity to an interconnection with the proposed intrastate facilities which ANR Southern intends to construct, own and operate within the state of Florida;

WHEREAS, ANR Southern plans to design, construct, own, and operate a natural gas pipeline and appurtenant facilities (the "Florida Facilities") for the transportation of natural gas within the state of Florida, which Florida Facilities shall extend from the interconnect with the ANR Southern Interstate Facilities in Florida to various locations within the state of Florida; and

WHEREAS, Shipper desires to receive firm transportation service (the "FT service") on and across the ANR Southern Interstate Facilities pursuant to the terms of the Service Agreement (defined below) and a FERC Gas Tariff to be filed with the Federal Energy Regulatory Commission or successor agency (FERC") in substantially the same form and substance as the Pro Forma Tariff attached hereto as Exhibit C.

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, shipper and ANR Southern agree as follows:

1. Firm Service Obligation. Subject to the terms and conditions of this Agreement, and terms and conditions which may be imposed by the FERC, ANR Southern hereby agrees to provide to Shipper through the ANR Southern Interstate Facilities FT service as follows:

a. Transportation of a maximum daily quantity ("MDQ") of 120,000 MMBtus ("Shipper's Anclote Gas Supply") for delivery to the Florida Facilities for ultimate delivery to shipper's Anclote power generation unit, located in Pasco County, Florida, commencing on the date the ANR Southern Interstate Facilities

and any required upstream and downstream facilities are capable of providing such transportation on a firm daily basis;

b. Transportation of an additional MDQ of 45,000 MMBtus for delivery to the Florida Facilities for ultimate delivery to shipper's first power generation unit at its Polk County, Florida Powerpark, commencing on the later of August 1, 1998 or the date the ANR Southern Interstate Facilities and any upstream and downstream facilities are capable of providing such transportation on a firm basis; and

c. Transportation of an additional MDQ of 45,000 MMBtus for delivery to the Florida Facilities for ultimate delivery to Shipper's second power generation unit at its Polk County, Florida Powerpark, commencing on the later of August 1, 1999 or the date the ANR Southern Interstate Facilities and any required upstream and downstream facilities are capable of providing such transportation on a firm basis.

All of the increments of FT Service set out in subsections a., b. and c. of this Section 1 shall be provided: (i) pursuant to the terms and provisions of this Agreement and (ii) pursuant to a service agreement substantially in the form of the service agreement contained in the ANR Southern FERC Gas Tariff (the "Service Agreement"). The FT Service shall be from the point of receipt on the ANR Southern Facilities to the interconnect with the Florida Facilities, which point of receipt and point of delivery are specified in Exhibit "A" attached hereto. Upon the request of Shipper pursuant to the nomination procedures applicable to FT Service in the then effective FERC Gas Tariff of ANR Southern, ANR Southern shall deliver to the Florida Facilities a minimum of eighty-five percent (85%) of shippers's MDQ during any fourteen (14) consecutive hour period during any twenty-four (24) hour period; provided, however, that such fourteen (14) hour periods on consecutive days will be separated by not less than ten (10) hours. ANR Southern's obligation to provide such fourteen (14) hour service is subject to receipt of sufficient gas supplies for Shipper's account, force majeure or other capacity curtailments in accord with ANR Southern's Tariff. The initial term of each increment of the FT Service identified above in subsections a., b. and c. of this Section 1 shall be twenty-five (25) years from the date such increment of FT Service commences (collectively, the Initial Term"). The Initial Term of each increment of service shall be automatically extended from year to year thereafter;

provided, however, either Party may terminate the Service Agreement with respect to an increment of service by written notice to the other Party at least one (1) year prior to the expiration of the Initial Term of such increment of service or any anniversary date thereof.

2. Rates. For purposes of this Agreement, the following terms shall have the meanings set forth below:

"Contract Year" shall mean each twelve (12) month period beginning on the date described in Section 1.a. or any anniversary date thereof.

"Currently Effective Rate Per MMBtu" shall mean for each of ANR Southern Interstate Facilities and the Florida Facilities, the rate applicable to FT service for Shipper, from time to time.

"GNP Price Deflator" shall mean the GNP implicit price deflator computed and published by the United states Department of Commerce, Bureau of Economic Analysis in the "Survey of Current Business", or successor index as the United States Department of Commerce or successor agency or department shall develop as a replacement index.

"Rate" or Rates" (whether the initial letter is capitalized or not) shall mean the unit rates directly attributable to only the transportation service, and shall not include fuel, lost and unaccounted for gas, Annual Charge Adjustment ("ACA"), Gas Research Institute ("GRI") or other generally applicable surcharges required to be charged and collected.

Subject to the terms and conditions of this Agreement and to such terms and conditions which may be imposed by the FERC, ANR Southern shall provide the FT Service, and Shipper shall pay for the FT Service, as follows:

a. Subject to Section 2.b. and Section 2.c., Shipper shall pay an initial rate for the FT Service across the ANR Southern Interstate Facilities expressed herein as a unit rate of not more than 14.8¢ per MMBtu, which shall be initially adjusted to reflect actual final costs of constructing the Florida Facilities and which may be subsequently adjusted from time to time pursuant to FERC ratemaking procedures.

b. Shipper shall not be required to pay any amount attributable to the rates for the FT Service across

the ANR Southern Interstate Facilities in excess of the maximum applicable rate provided for in ANR Southern's rate schedule applicable to the FT Service included in ANR Southern's FERC Gas Tariff, as that rate may be on file from time to time.

c. Shipper shall not be required to pay an amount in excess of the Aggregate Rate Cap (defined below) for FT Service on the ANR Southern Interstate Facilities and the Florida Facilities (sometimes hereinafter individually or collectively referred to as the "pipeline" or "pipelines") for transportation of shipper's gas supplies to the delivery points on the Florida Facilities. The Aggregate Rate Cap for the first Contract Year, expressed herein as a unit rate, shall be not more than 68.8¢ per MMBtu. For each subsequent Contract Year the Aggregate Rate Cap shall be defined as and shall be recalculated by:

(i) multiplying the Aggregate Rate Cap for the prior Contract Year by forty-five percent (45%);

(ii) subtracting the product of Section 2.c.(i) from the Aggregate Rate Cap for the prior Contract Year;

(iii) multiplying the product of section 2.c.(i) by a fraction the numerator of which is the GNP Price Deflator for the calendar quarter immediately preceding such Contract Year and the denominator of which is the GNP Price Deflator for the corresponding calendar quarter of the immediately preceding Contract Year; and

(iv) adding the product derived pursuant to Section 2.c.(iii) and the remainder derived pursuant to section 2.c.(ii).

Notwithstanding the foregoing calculations, ANR Southern agrees that for the first ten (10) years of the Initial Term, the Aggregate Rate Cap shall never exceed 83.8¢ per; for the remainder of the Initial Term, the Aggregate Rate Cap shall be adjusted annually as follows:

(i) multiplying the Aggregate Rate Cap for the prior Contract Year by forty-five percent (45%);

(ii) subtracting the product of section 2.c.(i) from the Aggregate Rate Cap for the prior Contract Year;

(iii) multiplying the product of Section 2.c.(i) by the lesser of the following:

(a) a fraction, the numerator of which is the GNP Price Deflator for the calendar quarter immediately preceding such Contract Year, and the denominator of which is the GNP Price Deflator for the corresponding calendar quarter of the immediately preceding Contract Year; or

(b) four percent (4%); and

(iv) adding the product derived pursuant to Section 2.c.(iii) and the remainder derived pursuant to Section 2.c.(ii).

If at any time during the term of the Service Agreement the sum of the Currently Effective Rates per MMBtu (exclusive of fuel, lost and unaccounted for gas, and other surcharges) applicable to the ANR Southern Interstate Facilities and the Florida Facilities (hereinafter the "Aggregate Rate") exceeds the Aggregate Rate Cap (the difference between the Aggregate Rate and the Aggregate Rate Cap being hereinafter referred to as the "Excess Rate"), then the Aggregate Rate shall be reduced by an amount equal to the Excess Rate.

d. In addition to the rate provided for under Section 2.a. above, Shipper will compensate ANR Southern for any other charges applicable to Shipper under the then effective rate schedule applicable to the FT Service plus natural gas for fuel and lost and unaccounted for gas; provided, however, that in no event shall Shipper be required to provide compensation for fuel and lost and unaccounted for gas applicable to the ANR Southern Interstate Facilities and the Florida Facilities, in the aggregate, in an amount in excess of two and one-half percent (2.5%) of Shipper's MDQs at the delivery points specified in Exhibit A.

e. Subject to the limitations in Section 2., the Service Agreement shall provide that ANR Southern shall have the unilateral right to file for changes in its maximum rates or any other provisions in its FERC Gas Tariff and Service Agreement, including but not limited to, provisions relating to compensation for fuel and lost and unaccounted for gas applicable to the service hereunder, and that such changes shall be effective and applicable, subject to refund as determined by the FERC, after the required notice or at the end of any suspension period ordered by the FERC, and such maximum rates plus any provision for fuel and lost and unaccounted for gas shall be effective under the Service Agreement. Notwithstanding the foregoing, shipper shall have the right to intervene and protest any such rate filing by ANR Southern with respect to changes in ANR Southern's maximum rates, terms and conditions of service or any other provision in its currently effective gas tariff.

3. Terms of Service. Subject to the terms and conditions of this Agreement, ANR Southern agrees to provide the FT Service on substantially the same terms and conditions as those set forth in the Service Agreement and the Pro Forma FERC Gas Tariff attached hereto as Exhibit C.

4. Execution of Service Agreement. Concurrently with the fulfillment or waiver of all of the Conditions Precedent set forth below in Section 5, ANR Southern and Shipper shall execute and deliver the Service Agreement, to be effective as of the dates described in Section 1 above. Shipper shall become liable for payment of reservation charges with respect to each increment of service under the Service Agreement on the dates described in Section 1. above, except that with respect to the increments of service described in Sections 1b. and 1.c. above, in the event Shipper is unable to obtain the regulatory or environmental authorizations necessary to proceed with the construction of either or both of Shipper's proposed first and second power generation units at Shipper's Polk County, Florida Powerpark by the earlier of August 31, 1994 or fifteen (15) days prior to the scheduled vote of ANR Southern's Board of Directors on either (i) construction of the ANR Southern Interstate Facilities or (ii) acceptance of the term sheet with respect to financing construction of the ANR Southern Interstate Facilities, Shipper shall not be liable for the payment of reservation charges for FT Service for either or both of such increments of service, as the case may be, and ANR Southern and shipper shall have the respective obligations set forth in Section 6.c. hereof.

5. Conditions Precedent.

a. The obligation of ANR Southern to provide FT Service to Shipper in accordance with the terms of this Agreement and the Service Agreement is subject to the fulfillment, or waiver by ANR Southern, of each of the following conditions:

(i) On or before December 31, 1993, ANR Southern shall have received executed precedent agreements in which shippers agree, on the initial in-service date of the ANR Southern Interstate Facilities, to pay for firm transportation service through the ANR Southern Interstate Facilities under service agreements having a maximum daily quantity, in the aggregate, equal to at least 324,500 MMBtus;

(ii) On or before May 1, 1995, all of the Conditions Precedent in section 5 of the Precedent Agreement by and between Shipper and ANR Southern for transportation on the Florida Facilities are fulfilled or waived by the appropriate party;

(iii) On or before February 28, 1995, ANR Southern shall have been issued and shall have accepted all regulatory authorizations and approvals required by the FERC and all other necessary authorizations and approvals from federal, state, local, and/or municipal agencies, to construct, own and operate the ANR Southern Interstate Facilities and offer the transportation service consistent with the terms of this Agreement, except those authorizations and approvals normally obtained after the FERC authorizations and approvals have been issued and accepted, and all such authorizations and approvals shall have become final and subject to no further appeal; and

(iv) On or before May 1, 1995, the Board of Directors of ANR Southern shall have voted to construct the ANR Southern Interstate Facilities and perform the services contemplated by this Agreement, and ANR Southern shall have accepted a term sheet with respect to, and have obtained a commitment for the financing of, the construction of the ANR Southern Interstate Facilities in such amount

and on such terms and conditions as are acceptable to ANR Southern.

b. The obligation of Shipper to accept and pay for the FT Service in accordance with the terms of this Agreement and the Service Agreement is subject to the fulfillment, or waiver by shipper, of the following conditions:

(i) On or before May 1, 1995, all of the Conditions Precedent in Section 5 of the Precedent Agreement by and between shipper and ANR Southern for transportation on the Florida Facilities are fulfilled or waived by the appropriate party; and

(ii) On or before February 28, 1995, ANR Southern shall have been issued and shall have accepted all regulatory authorizations and approvals required by the FERC to construct, own and operate the ANR Southern Interstate Facilities and offer the transportation service consistent with the terms of this Agreement, and all such authorizations and approvals

shall have become final and subject to no further appeal.

c. If any of the Conditions Precedent in Section 5.b., as may be extended by Section 5.d., have not been fulfilled or waived by Shipper (the "Outstanding Conditions") thirty (30) days before the date upon which ANR Southern's Board of Directors is scheduled to approve (i) construction of the ANR Southern Interstate Facilities, or (ii) acceptance of the term sheet with respect to financing construction of the ANR Southern Interstate Facilities, ANR Southern's Board of Directors shall provide Shipper written notice at such time stating the date that ANR Southern's Board of Directors vote is scheduled to be taken. At least fifteen (15) days prior to such vote of ANR Southern's Board of Directors, Shipper shall be required to exercise, in writing, its right to terminate this Agreement or waive its right to terminate this Agreement with respect to any Outstanding Conditions. In the event that Shipper chooses not to waive its Outstanding Conditions and elects to terminate this Agreement, this Agreement shall terminate five (5) business days after ANR Southern receives the notice, unless the Outstanding

Conditions have been satisfied or have been waived by Shipper in writing during such five (5) day period.

d. With respect to the dates in the Conditions Precedent set forth in Section 5.a.(iii) and Section 5.b.(ii), the Parties contemplate that ANR Southern shall have been issued and accepted all of the regulatory and environmental authorizations and approvals required from the FERC to construct, own and operate the ANR Southern Interstate Facilities and offer the transportation service consistent with the terms of this Agreement (the "Regulatory Authorizations)", and the Parties further contemplate that the Regulatory Authorizations shall have become final and no longer subject to appeal as of the dates set forth in Section 5.a.(iii) and Section 5.b. (ii). ANR Southern agrees to provide shipper a true copy of each and every Regulatory Authorization received by it with full particulars as to the date of its issuance and any material procedural dates with respect thereto as promptly as practicable after its receipt by ANR Southern, but in no event later than three (3) business days thereafter. The Parties acknowledge and agree that the Regulatory Authorizations may not be acceptable to ANR Southern and Shipper, or either ANR

Southern or Shipper, or may be judicially challenged by third parties by rehearing before the FERC or by court appeal ("Third-Party Challenge"). ANR Southern further agrees to provide Shipper with notice of all such Third Party Challenges, if any, including such particulars as the date of filing and any material procedural dates with respect thereto as promptly as practicable after receipt of such notice by ANR Southern, but in no event less than three (3) business days thereafter.

If the Regulatory Authorizations contain any terms or conditions unacceptable to the Parties, or are subject to unacceptable risks associated with a Third-Party Challenge that may have a material adverse effect on either Party, each Party shall advise the other Party of any objections to the terms and conditions of the Regulatory Authorizations, or any unacceptable risks associated with any Third-Party Challenge that may have a material adverse effect on either Party (collectively, the "Objections"), in writing, as soon as practicable, but in no event later than fifteen (15) days after receipt by ANR Southern of the Regulatory Authorizations or notice of any Third-Party Challenges, as the case may be; provided that in all events Shipper shall have at least three (3) business days from the date it receives a copy of such

Regulatory Authorizations or notice of Third Party-Challenges to advise ANR Southern of any Objections thereto Shipper and ANR Southern shall waive their rights under Section 5.a.(iii) and Section 5.b.(ii), save and except any reserved Objections; provided, however, no waiver shall be required until all Regulatory Authorizations have been issued by FERC or the time for Third-Party Challenge has expired.

If ANR Southern has not accepted the Regulatory Authorizations, or ANR Southern has accepted the Regulatory Authorizations and there are reserved Objections, prior to the dates set forth in Section 5.a.(iii) and Section 5.b.(ii), the dates specified in Section 5.a.(iii) and 5.b.(ii) shall be extended for a period of thirty (30) days, or such longer period as the Parties may agree in writing (the "Regulatory Extension Period"), to resolve any reserved Objection to the satisfaction of the Party raising such Objection, or until such time as the Party raising such Objection waives its reserved Objection. After the Regulatory Extension Period, if a reserved Objection has not been fulfilled or waived by the Party raising such Objection, such Party may elect to terminate this Agreement by giving written notice to the other Party. In the event that a Party chooses not to waive its reserved Objections and elects to terminate this Agreement, this Agreement shall terminate five (5) business days after

such other Party receives the notice, unless the reserved Objection has been fulfilled or has been waived by the Party raising the Objection in writing during such five (5) day period. In no event shall the extension of time provided in Section 5.d. result in the dates specified in Section 5.a.(iii) and Section 5.b.(ii) being later than April 15, 1995, and the extension of time provided in Section 5.d. is subject, in all respects, to the rights of ANR Southern to require that Shipper make an election as provided for in Section 5.c.

6. Covenants of the Parties.

a. Upon the execution of this Agreement by the Parties, ANR Southern agrees that:

(i) ANR Southern shall exert commercially reasonable efforts to obtain financing for the construction and operation of the ANR Southern Interstate Facilities;

(ii) With respect to the ANR Southern Interstate Facilities, ANR Southern shall make applications for all necessary authorizations and approvals to construct and operate the ANR

Southern Interstate Facilities, and shall prosecute such applications with all reasonable diligence;

(iii) ANR Southern shall exert commercially reasonable efforts to obtain all necessary authorizations for the release and assignment of firm capacity held by Shipper on the ANR Southern Interstate Facilities to third parties in accordance with Order No. 636 issued by FERC (the "Capacity Release Program"), subject to terms and conditions for such Capacity Release Program, as set forth in the gas tariff.

(iv) In the event that ANR Southern enters into a precedent agreement or service agreement to provide comparable service to similarly situated shippers for ultimate consumption of natural gas within the State of Florida through the ANR Southern Interstate Facilities prior to the initial in-service date of the ANR Southern Interstate Facilities, on terms more favorable (in the reasonable judgment of ANR Southern to be exercised in good faith)

than the initial rates and material terms and conditions of service applicable to shipper provided for in this Agreement and the Service Agreement (the "Third Party Service"), ANR Southern shall promptly so notify Shipper, including in such notice an abstract of the initial rates and material terms and conditions of service applicable to Shipper related to the Third Party Service; provided, however, this provision shall in no way require ANR Southern to breach any confidentiality provision in any other precedent agreement. Shipper shall have the right, exercisable by notice to ANR Southern within thirty (30) days of receipt of ANR Southern's notice of such terms, to require that this Agreement and the Service Agreement be amended effective as of the date such Third Party Service commences to include the initial rate and all material terms and conditions of service applicable to Shipper in the respective contract related to the Third Party Service. Such amendment shall continue to be effective for a term coextensive with such Third Party Service. Except as specifically

amended pursuant to this Section, the terms and conditions of this Precedent Agreement and the Service Agreement shall remain in effect, and in the event that the term of such amendment expires prior to the term of the FT Service pursuant to this Precedent Agreement and the Service Agreement, after the expiration of such amendment, all of the terms and provisions of this Precedent Agreement and the Service Agreement shall be effective for the remaining term of the FT Service. Shipper shall not be entitled to select less than the initial rate and all of the material terms and conditions of service applicable to Shipper contained in the abstract. The rights of Shipper under this Section 6.a.(iv) shall become effective, if and only to the extent that, such other precedent agreement or service agreement provides for comparable service to similarly situated shippers. In the event that the Third Party Service does not commence, for whatever reason, the rate, terms and conditions of this Precedent Agreement and the Service Agreement originally

agreed to by the Parties shall apply to the FT Service.

b. Upon the execution of this Agreement by the Parties, Shipper agrees that Shipper shall affirmatively support all governmental and regulatory authorizations and approvals sought by ANR Southern for the construction and operation of the ANR Southern Interstate Facilities, and shall support ANR Southern in securing such governmental and regulatory authorizations.

c. Upon the execution of this Agreement by the Parties, ANR Southern and Shipper agree that under the circumstances described in the second sentence of Section 4. hereof, the following provisions shall apply:

(i) In the event Shipper is unable to obtain the regulatory or environmental authorizations necessary to proceed with the construction of Shipper's first and second power generation units at its Polk County, Florida Powerpark, Shipper shall offer to ANR Southern the right to contract for FT Service at the rate then

agreed to by the Parties shall apply to the FT Service.

b. Upon the execution of this Agreement by the Parties, Shipper agrees that Shipper shall affirmatively support all governmental and regulatory authorizations and approvals sought by ANR Southern for the construction and operation of the ANR Southern Interstate Facilities, and shall support ANR Southern in securing such governmental and regulatory authorizations.

c. Upon the execution of this Agreement by the Parties, ANR Southern and Shipper agree that under the circumstances described in the second sentence of Section 4. hereof, the following provisions shall apply:

(i) In the event Shipper is unable to obtain the regulatory or environmental authorizations necessary to proceed with the construction of Shipper's first and second power generation units at its Polk County, Florida Powerpark, Shipper shall offer to ANR Southern the right to contract for FT Service at the rate then

applicable under section 2. hereof for the natural gas supply for all of the gas fired electric power generation units to be constructed by Shipper in Shipper's service area up to an aggregate MDQ of 90,000 MMBtus. In the event Shipper obtains the necessary regulatory and environmental authorizations for one but not both of such first and second power generation units, Shipper shall offer to ANR Southern the right to contract for FT Service at the rate then applicable under Section 2. hereof for an aggregate MDQ of up 45,000 MMBTus. As applicable, the MDQ's of 90,000 MMBtus or 45,000 MMBtus described in the immediately preceding sentences of this Section 6.c. shall hereinafter be referred to as the "Replacement Gas Supply." Each offer by Shipper shall be made in writing and shall describe in reasonable detail the location of the proposed electric power generation unit or units, the MDQ of FT Service required and any other information pertinent to the nature and extent of such service.

(ii) Within thirty (30) days after receipt by ANR Southern of any offer by Shipper to contract for FT Service for all or a portion of the Replacement Gas Supply, ANR Southern shall determine, in the exercise of its good faith judgment, whether providing Shipper FT Service for the MDQ of Replacement Gas Supply over the term offered by Shipper will provide economic benefits to ANR Southern, which are reasonably sufficient to ANR Southern in the exercise of its good faith judgment, and shall so notify Shipper.

(iii) If ANR Southern determines that contracting with Shipper to provide FT Service for the offered Replacement Gas Supply will provide economic benefits to ANR Southern, which are reasonably sufficient to ANR Southern in its sole discretion, the Parties shall negotiate in good faith with respect to a Service Agreement for the FT Service.

(iv) Shipper shall be obligated to continue to offer to contract with ANR Southern to provide FT Service pursuant to Section 6.c.(i) above

until the Parties have entered into service agreements covering MDQ's of gas at least equal to the applicable Replacement Gas Supply, after which the obligations of the Parties under this Section 6.c. shall be deemed fully satisfied.

7. Expansion of the ANR Southern Interstate Facilities. ANR Southern and Shipper agree as follows with respect to the future expansion of the ANR Southern Interstate Facilities:

a. In the event that Shipper shall require firm transportation service in addition to the FT Service provided for in Section 1. above (the "Additional FT Service") for an additional supply or supplies of natural gas to fuel Shipper's future gas requirements, Shipper shall, with respect to MDQ's of Additional FT Service up to an aggregate MDQ of 300,000 MMBtus (inclusive of the MDQ's of FT Service provided for under Sections 1. and 6.c. hereof) and Shipper may, with respect to any MDQ's of Additional FT Service in excess of an aggregate MDQ of 300,000 MMBtus, tender a written offer to ANR Southern to provide such Additional FT Service (including the amount of Additional FT Service required and supporting

information in reasonable detail). If ANR Southern accepts such offer, ANR Southern shall provide such Additional FT Service pursuant to its then effective FERC Gas Tariff. ANR Southern shall notify Shipper as to whether or not it accepts such offer to provide the Additional FT Service described in Shipper's offer within thirty (30) days after receipt of such offer.

b. If ANR Southern determines that the ANR Southern Interstate Facilities do not have the capacity to provide the Additional FT Service for which Shipper has offered to contract with ANR Southern, as promptly as practicable, ANR Southern shall determine the cost of expanding the ANR Southern Interstate Facilities in order to provide capacity (the "Expanded Facilities") for the Additional FT Service and the rates applicable to service over the Expanded Facilities, and provide such information to Shipper together with ANR Southern's decision as to whether or not ANR Southern will construct and operate the Expanded Facilities and provide the Additional FT Service.

c. If ANR Southern is willing to construct and operate the Expanded Facilities and provide to Shipper the Additional FT Service, Shipper shall have sixty (60)

days from the date of its receipt of notification of such fact by ANR Southern to commence negotiations for a formal agreement with respect to such Additional FT Service.

d. If ANR Southern is not willing to construct and operate the Expanded Facilities and provide the Additional FT Service to Shipper, or if the Parties are unable to agree upon the terms and provisions of a service agreement with respect to such Additional FT Service, Shipper may elect, within sixty (60) days of receipt of notification, (i) to pay the cost of constructing the Expanded Facilities (which shall be owned by Shipper but operated and maintained by ANR Southern or its nominee pursuant to a mutually acceptable operation and maintenance agreement) or (ii) agree to pay the otherwise applicable rate plus the incremental rate designed to recover all costs associated with the Expanded Facilities. If Shipper exercises such election so that Expanded Facilities are constructed, ANR Southern shall negotiate with Shipper in good faith for formal agreements with respect to FT Service over such Expanded Facilities and the incremental rate for such FT Service, or the operation and maintenance of such Expanded Facilities,

as the case may be; provided, however, in the event the Parties are unable to agree upon the terms of service applicable to the construction of the Additional Facilities by ANR Southern, Shipper shall have the right to proceed under the provisions of the clause (i) of the first sentence of this Section 7.d.

e. ANR Southern and Shipper agree to cooperate with and assist one another for the purpose of obtaining any governmental and regulatory authorizations and approvals for the construction, operation and maintenance of the Expanded Facilities and the use thereof for the purpose of providing Shipper with the Additional FT Service.

8. Interruptible Transportation Service. In the event that ANR Southern enters into a precedent agreement or service agreement to provide comparable interruptible transportation service to a similarly situated shipper through the ANR Southern Interstate Facilities, which volumes are transported through the Florida Facilities for ultimate consumption of natural gas within the State of Florida, at rates more favorable than rates offered to Shipper by ANR Southern, such rates shall be offered to Shipper with respect to the volumes and term of service set forth in such precedent agreement or service agreement, as applicable, with such

similarly situated shipper. Shipper shall not be entitled to such rate unless Shipper transports the natural gas for its ultimate consumption within the State of Florida.

9. Termination. This Agreement shall become effective when executed by both ANR Southern and Shipper, and shall remain in effect unless and until terminated as hereinafter provided.

a. In the event that the condition set forth in Section 5.b.(i) of this Agreement has not been fulfilled or waived by the required date as may be modified by Section 5.c., then Shipper may terminate this Agreement by giving written notice to ANR Southern not later than five (5) business days after the non-occurrence of such condition by the required date, and this Agreement shall terminate upon the expiration of sixty (60) days from the receipt of such notice, unless within such period such condition has been fulfilled or has been waived by Shipper in writing.

b. In the event that the conditions set forth in Section 5.a.(i), Section 5.a.(ii) or Section 5.a.(iv) of this Agreement have not been fulfilled or waived by the required date, then ANR Southern may terminate this Agreement by giving written notice to Shipper not

later than five (5) business days after the non-occurrence of any such condition by the required date, and this Agreement shall terminate upon the expiration of sixty (60) days from the receipt of such notice, unless within such period such condition has been fulfilled or has been waived by ANR Southern in writing.

c. In the event that the conditions set forth in Section 5.a.(iii) or Section 5.b.(ii) of this Agreement have not been fulfilled or waived by the required date, as may be modified by Section 5.c. or Section 5.d., as applicable, then ANR Southern or Shipper, as the case may be, may terminate this Agreement pursuant to Section 5.d.

10. Assignment. This Agreement shall be binding upon ANR Southern, Shipper and their successors and assigns; provided, however, neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the written consent of the other Party (which consent shall not be unreasonably withheld or delayed) and any regulatory authorizations reasonably deemed necessary by ANR Southern. An assignment to an Affiliate of such Party desiring to make the assignment may be made without prior written consent subject to the receipt of any necessary

governmental authorizations; provided, however, any assignment by Shipper to an Affiliate of Shipper shall not relieve Shipper of any obligations, liabilities and responsibilities under this Agreement. Nothing contained herein shall prevent either Party from pledging, mortgaging or assigning its rights as security for its indebtedness and either Party may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under any Service Agreements. For purposes of this Agreement, the term Affiliate" shall mean when used with respect to an entity, any other entity (i) which directly or indirectly (through one or more intermediaries) controls, or is controlled by, or is under common control with, such first mentioned person or entity or (ii) which beneficially owns, holds or controls fifty percent (50%) or more of the interest of such first mentioned entity. The term "control" means the possession, either directly or indirectly, of the power to direct or cause the direction of the management policies of an entity, whether through ownership of stock, as general partner, by contract or credit arrangement or otherwise.

11. Modification or Waiver. No modification or waiver of the terms and provisions of this Agreement shall be made except by the execution by the Parties of a written amendment to this Agreement.

12. Notices. All notices, requests, demands, instructions and other communications required or permitted to be given hereunder shall be in writing and shall be delivered personally or mailed by certified mail, postage prepaid and return receipt requested or by telex or telecopier, as follows:

If to ANR Southern:

ANR Southern Pipeline Company
Coastal Tower
Nine Greenway Plaza
Houston, Texas 77046
Attention: Mr. E. J. Burgin
Telephone No. (713) 877-3388
Facsimile No. (713) 877-3714

If to Shipper:

Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733
Attention: Mr. Stephen Watsey, C.P.M.
Telephone No. (813) 866-4382
Facsimile No. (813) 866-4941

or to such other place within the United States of America as either Party may designate as to itself by written notice to the other. All notices given by personal delivery or mail shall be effective on the date of actual receipt at the appropriate address. Notice given by telex or telecopier shall be effective upon actual receipt if received during recipient's normal business hours or at the beginning of the next business day after receipt if received after the recipient's normal business hours.

13. Limitation of Liability. Shipper agrees that any liability relating to and any and all claims against ANR Southern shall be limited to the assets of ANR Southern, and, subject to applicable law, Shipper waives its rights to proceed against any of ANR Southern's Affiliates. Execution of this Agreement does not bind any Affiliate of ANR Southern or require any Affiliate to undertake any obligation in connection with this Agreement. Shipper and ANR Southern agree that neither party shall be liable to the other for incidental, consequential or indirect damages under this Agreement, whether arising in contract, tort or otherwise.

14. No Third Party Rights or Obligations. This Agreement shall not create any rights in third parties, and no provision hereof shall be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than ANR Southern and Shipper.

15. Survival. All of the terms and provisions of this Agreement shall survive the execution by the Parties of a Service Agreement, except those terms and provisions hereof that are inconsistent with the terms and provisions of such Service Agreement.

16. Governing Law. THE CONSTRUCTION, INTERPRETATION, AND ENFORCEMENT OF THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF THE

STATE OF TEXAS, EXCLUDING ANY CONFLICT OF LAW RULE WHICH WOULD REFER ANY MATTER TO THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF TEXAS.

17. Counterpart Execution. This Agreement may be executed by the Parties in any number of counterparts, each of which shall be deemed an original instrument, but all of which shall constitute but one and the same agreement.

18. Partial Invalidity. Except as otherwise expressly stated herein, in the event any provision contained in this Agreement shall for any reason be held invalid, illegal or unenforceable by a court or regulatory agency of competent jurisdiction by reason of a statutory change or enactment, such invalidity, illegality or unenforceability shall not affect the remaining provisions of this Agreement.

19. Confidentiality. Except as provided hereinbelow, neither ANR Southern nor Shipper, nor their respective Affiliates, directors, officers, and employees, advisors and representatives shall disclose to any third party the terms and conditions of this Agreement, including the information and agreements set forth on the Exhibit, without the other Party's written consent to such disclosure. This provision shall not apply to such disclosures

that, in the opinion of ANR Southern's or Shipper's counsel, as the case may be, are required by state or federal laws, rules or regulations (in which case, the Party making such disclosure shall advise the other Party prior to disclosure and, if requested by the other Party, shall use every effort to maintain the confidentiality of this Agreement, including, without limitation, seeking a protective order). The disclosure of any information pertaining to this Agreement within ANR Southern's or Shipper's internal organization (including Affiliates) and within the organization of any third party to which disclosure is authorized by ANR Southern or Shipper shall be limited to such personnel whose duties require their review or counsel with respect to this Agreement and the Party making such disclosure shall instruct such personnel to maintain the confidentiality of this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed in multiple originals by their duly authorized officers as of the date first written above.

ATTEST:

ANR SOUTHERN PIPELINE COMPANY

By:_____
Name:_____
Title:_____
[SEAL]

By:_____
Name:_____
Title:_____

ATTEST:

FLORIDA POWER CORPORATION

By:_____
Name:_____
Title:_____
[SEAL]

By:_____
Name:_____
Title:_____

EXHIBIT "A"

ATTACHED TO
PRECEDENT AGREEMENT
DATED _____ 1992

BETWEEN

FLORIDA POWER CORPORATION
AND
ANR SOUTHERN PIPELINE COMPANY

GATEWAY:

Points of Receipt:

Point of Delivery:

PRECEDENT AGREEMENT

This Precedent Agreement ("Agreement"), made this ___ day of _____ 1992, by and between FLORIDA POWER CORPORATION, a Florida corporation ("Shipper") and ANR Southern PIPELINE COMPANY, a Delaware corporation ("ANR Southern"), (hereinafter Shipper and ANR Southern are sometimes referred to individually as "Party" or collectively as the "Parties").

W I T N E S S E T H:

WHEREAS, ANR Southern intends to design, construct, own and operate a natural gas pipeline and appurtenant facilities (the "Florida Facilities") for the transportation of natural gas within the State of Florida, which Florida Facilities shall extend from the terminus of a proposed interstate natural gas pipeline and appurtenant facilities in Florida (the "ANR Southern Interstate Facilities") also to be constructed and owned by ANR Southern to various locations within the State of Florida;

WHEREAS, ANR Southern plans to provide natural gas transportation service through the Florida Facilities wholly within the State of Florida, subject to the provisions of Florida law governing natural gas pipelines and the rules and regulations of any agencies of the government of the State of Florida pursuant to such rules and regulations as such agencies may promulgate

(collectively, the "Florida Statutes") as a "Hinshaw" pipeline exempt from the regulatory jurisdiction of the Federal Energy Regulatory Commission or successor agency (FERC") pursuant to Section 1(c) (the "Hinshaw Exemption") of the Natural Gas Act ("NGA");

WHEREAS, Shipper desires to receive firm transportation service ("FT Service") on and across the Florida Facilities, which firm transportation service shall be rendered in accordance with the terms and conditions of the Service Agreement (defined below), and the gas tariff for the Florida Facilities on file with the Florida Public Service Commission or successor agency ("FPSC").

NOW THEREFORE, in consideration of the mutual covenants and agreements contained herein, Shipper and ANR Southern agree as follows:

1. Firm Service Obligation. Subject to the terms and conditions of this Agreement and to such terms and conditions as may be or become applicable to ANR Southern's transportation service pursuant to the Florida Statutes, ANR Southern hereby agrees to provide to Shipper through the Florida Facilities, FT Service as follows:

a. Transportation of a maximum daily quantity ("MDQ") of 120,000 MMBtus ("Shipper's Anclote Gas Supply"),

to Shipper's Anclote power generation unit located in Pasco County, Florida, commencing on the date the Florida Facilities and any required facilities upstream of the Florida Facilities are capable of transporting the quantity of gas contemplated by Section 5.a.(i) of this Agreement on a firm daily basis;

b. Transportation of an additional MDQ of 45,000 MMBtus ("Shipper's First Polk County Gas Supply") to Shipper's first power generation unit at its Polk County, Florida Powerpark, commencing on the later of August 1, 1998 or the date the Florida Facilities and any required facilities upstream of the Florida Facilities are capable of such transportation on a firm basis; and

c. Transportation of an additional MDQ of 45,000 MMBtus ("Shipper's Second Polk County Gas Supply") to Shipper's second power generation unit at its Polk County, Florida Powerpark, commencing on the later of August 1, 1999 or the date the Florida Facilities and any required facilities upstream of the Florida Facilities are capable of providing such transportation on a firm basis.

All of the increments of FT Service set out in subsections a., b. and c. of this Section 1 shall be provided: (i) pursuant to the terms and provisions of this Agreement and (ii) pursuant to a service agreement substantially in the form attached hereto as Exhibit A. (the "Service Agreement"). There shall be added to the MDQ for each increment of Shipper's FT Service additional capacity sufficient to transport additional quantities of gas required by ANR Southern as fuel and for lost and unaccounted for gas related to each such increment of FT Service. Shipper's FT Service shall be from the point of receipt of Shipper's Anclote Gas Supply, First Polk County Gas Supply and Second Polk County Gas Supply into the Florida Facilities to the points of delivery, which point of receipt and points of delivery are specified in Exhibit B attached hereto; provided, that Shipper shall have the right, in its sole discretion, to nominate all or any portion of the aggregate of the MDQs set out in subsections a., b. and c. of this Section 1 for delivery at any point or points of delivery specified in Exhibit B pursuant to the nomination procedures applicable to the FT Service; and provided further, that any nominated quantity above Shipper's firm MDQ (plus gas used for fuel and lost and unaccounted for gas) applicable to the nominated delivery point shall not have priority of service over any firm service for other shippers at such delivery point but will have priority over interruptible transportation service at that delivery point. ANR Southern shall, upon request by Shipper, deliver to Shipper's delivery points a minimum of eighty-five percent (85%) of Shipper's MDQ during any

fourteen (14) consecutive hour period during any twenty-four (24) hour period; provided, however, that such fourteen (14) hour periods on consecutive days will be separated by not less than ten (10) hours. ANR Southern's obligation to provide such fourteen (14) hour service is subject to receipt of sufficient gas supplies for Shipper's account, force majeure or other capacity curtailments in accord with ANR Southern's Tariff. The initial term of each increment of the FT Service identified above in subsections a., b. and c. of this Section 1 shall be twenty-five (25) years from the date each increment of FT Service commences (collectively, the "Initial Term"). The Initial Term of each increment of service shall be automatically extended from year to year thereafter; provided, however, either Party may terminate the Service Agreement with respect to an increment of service by written notice to the other Party at least one (1) year prior to the expiration of the Initial Term of such increment of service or any anniversary date thereof.

2. Rates. For purposes of this Agreement, the following terms shall have the meanings set forth below:

"Contract Year" shall mean each twelve (12) month period beginning on the date described in Section 1.a. or any anniversary date thereof.

"Currently Effective Rate Per MMBtu" shall mean for each of the ANR Southern Interstate Facilities and the Florida Facilities, the rate applicable to FT Service for Shipper, from time to time.

"GNP Price Deflator" shall mean the GNP implicit price deflator computed and published by the United States Department of Commerce, Bureau of Economic Analysis in the "Survey of Current Business" or successor index as the United States Department of Commerce or successor agency or department shall develop as a replacement index.

"Rate" or "Rates" (whether the initial letter is capitalized or not) shall mean the unit rates directly attributable to only the transportation service, and shall not include fuel, lost and unaccounted for gas, the Regulatory Assessment Fee ("RAF") paid to the State of Florida or other generally applicable surcharges required to be charged and collected.

Subject to the terms and conditions of this Agreement and to such terms and conditions as may be or become applicable to ANR Southern's rates pursuant to the Florida Statutes, ANR Southern shall provide the FT Service, and Shipper shall pay for the FT Service as follows:

a. Subject to Section 2.b. and Section 2.c., Shipper shall pay an initial rate for the FT Service across the Florida Facilities expressed herein as a unit rate of not more than 52.5¢ per MMBtu, which shall be initially adjusted to reflect actual final costs of constructing the Florida Facilities and which may be subsequently adjusted from time to time pursuant to the Service Agreement or the applicable ratemaking procedures set forth in the Florida Statutes.

b. Shipper shall not be required to pay any amount attributable to the rates set forth in 2.a. for the FT Service across the Florida Facilities in excess of the maximum applicable rate provided for in ANR Southern's rate schedule applicable to the FT Service included in ANR Southern's gas tariff, as that rate may be on file from time to time with the FPSC.

c. Shipper shall not be required to pay an amount in excess of the Aggregate Rate Cap (defined below) for FT Service on the ANR Southern Interstate Facilities and the Florida Facilities (sometimes hereinafter individually or collectively referred to as the "pipeline" or "pipelines") for

transportation of Shipper's gas supplies to the delivery points on the Florida Facilities. The Aggregate Rate Cap for the first Contract Year, expressed herein as a unit rate, shall be not more than 68.8¢ per MMBtu. For each subsequent Contract Year the Aggregate Rate Cap shall be recalculated by:

(i) multiplying the Aggregate Rate Cap for the prior Contract Year by forty-five percent (45%);

(ii) subtracting the product of Section 2.c.(i) from the Aggregate Rate Cap for the prior Contract Year;

(iii) multiplying the product of Section 2.c.(i) by a fraction the numerator of which is the GNP Price Deflator for the calendar quarter immediately preceding such Contract Year and the denominator of which is the GNP Price Deflator for the corresponding calendar quarter of the immediately preceding Contract Year; and

(iv) adding the product derived pursuant to Section 2.c. (iii) and the remainder derived pursuant to Section 2.c.(ii).

Notwithstanding the foregoing calculations, ANR Southern agrees that for the first ten (10) years of the Initial Term, the Aggregate Rate Cap shall never exceed 83.5¢ per MMBtu. Thereafter, for the remainder of the Initial

Term, the Aggregate Rate Cap shall be adjusted annually as follows:

(i) multiplying the Aggregate Rate Cap for the prior Contract Year by forty-five percent (45%);

(ii) subtracting the product of Section 2.c.(i) from the Aggregate Rate Cap for the prior Contract Year;

(iii) multiplying the product of Section 2.c.(i) by the lesser of the following:

(a) a fraction, the numerator of which is the GNP Price Deflator for the calendar quarter immediately preceding such Contract Year and the

denominator of which is the GNP Price Deflator for the corresponding calendar quarter of the immediately preceding Contract Year; or

(b) four percent (4%); and

(iv) adding the product derived pursuant to Section 2.c.(iii) and the remainder derived pursuant to Section 2.c.(ii).

If at any time during the term of the Service Agreement the sum of the Currently Effective Rates Per MMBtu (exclusive of fuel, lost and unaccounted for gas, and other surcharges) for transportation on the ANR Southern Interstate Facilities and the Florida Facilities (hereinafter the "Aggregate Rate") exceeds the Aggregate Rate Cap (the difference between the Aggregate Rate and the Aggregate Rate Cap being hereinafter referred to as the "Excess Rate"), then the Aggregate Rate shall be reduced by an amount equal to the Excess Rate.

d. In addition to the rate provided for under Section 2.a. above, Shipper will compensate ANR Southern for the RAF paid to the State of Florida and any

other charges applicable to Shipper under the then effective rate schedule applicable to the FT Service, plus natural gas for fuel and lost and unaccounted for gas; provided, however, that in no event shall Shipper be required to provide compensation for fuel and lost and unaccounted for gas applicable to the ANR Southern Interstate Facilities and the Florida Facilities, in the aggregate, in an amount in excess of two and one-half percent (2.5%) of Shipper's MDQs at the delivery points specified in Exhibit B.

e. Subject to the limitations in Section 2., the Service Agreement shall provide that ANR Southern shall have the unilateral right to file for changes in its maximum rates or any other provisions in its gas tariff including, but not limited to, provisions relating to compensation for fuel and lost and unaccounted for gas applicable to the service hereunder, and that such changes shall be effective and applicable, subject to refund as determined by the FPSC, as the case may be, after the required notice or at the end of any suspension period ordered by FPSC and such maximum rates plus any provision for fuel and lost and unaccounted for gas shall be effective under the Service Agreement.

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
100% OF SUPPLY THROUGH UNITED
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	37.53	45.87	83.40	9.20	92.60	40,557,048
1997	254	39.03	45.87	84.90	9.99	94.90	41,564,098
1998	274	40.59	45.87	86.46	10.79	97.25	45,267,083
1999	294	42.22	45.87	88.09	11.59	99.68	62,766,069
2000	324	43.90	45.87	89.77	12.77	102.54	78,599,050
2001	341	45.66	45.87	91.53	13.41	104.94	80,440,330
2002	358	47.49	45.87	93.36	14.10	107.46	82,364,582
2003	375	49.39	45.87	95.26	14.78	110.04	84,344,832
2004	395	51.36	45.87	97.23	15.54	112.77	86,441,575
2005	415	53.42	45.87	99.29	16.34	115.63	88,628,013
2006	435	55.55	45.87	100.00	17.14	117.14	89,786,277
2007	455	57.78	45.87	100.00	17.94	117.94	90,397,944
2008	479	60.09	45.87	100.00	18.85	118.85	91,096,992
2009	502	62.49	45.87	100.00	19.76	119.76	91,796,040
2010	526	64.99	45.87	100.00	20.71	120.71	92,524,215
2011	551	67.59	45.87	100.00	21.70	121.70	93,281,517
2012	578	70.29	45.87	100.00	22.76	122.76	94,097,073
2013	605	73.10	45.87	100.00	23.83	123.83	94,912,629
2014	634	76.03	45.87	100.00	24.97	124.97	95,786,439
2015	659	79.07	45.87	100.00	25.96	125.96	96,551,897
2016	686	82.23	45.87	100.00	27.00	127.00	97,347,972
2017	713	85.52	45.87	100.00	28.08	128.08	98,175,891
2018	742	88.94	45.87	100.00	29.21	129.21	99,036,927
2019	771	92.50	45.87	100.00	30.37	130.37	99,932,404
2020	802	96.20	45.87	100.00	31.59	131.59	100,863,700
							567,998,723

1/93NPV @ DISCOUNT RATE OF 8.99%

Note:
1. Transportation rate for 1996 is 83.4 C/MBTU, 45% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
100% OF SUPPLY THROUGH UNITED
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	14.20	64.70	78.90	6.78	85.68	37,526,088
1997	254	14.77	64.70	79.47	7.36	86.83	38,032,451
1998	274	15.36	64.70	80.06	7.95	88.01	40,964,666
1999	294	15.98	64.70	80.67	8.54	89.21	56,177,627
2000	324	16.61	64.70	81.31	9.41	90.72	69,537,134
2001	341	17.28	64.70	81.98	9.88	91.86	70,411,383
2002	358	17.97	64.70	82.67	10.39	93.06	71,327,471
2003	375	18.69	64.70	83.39	10.89	94.28	72,264,749
2004	395	19.44	64.70	84.13	11.45	95.59	73,266,989
2005	415	20.21	64.70	84.91	12.04	96.95	74,313,612
2006	435	21.02	64.70	85.72	12.63	98.35	75,384,071
2007	455	21.86	64.70	86.56	13.22	99.78	76,479,321
2008	479	22.74	64.70	87.44	13.89	101.32	77,664,7[illegible]
2009	502	23.65	64.70	88.35	14.56	102.91	78,876,969
2010	526	24.59	64.70	89.29	15.26	104.55	80,138,548
2011	551	25.58	64.70	90.27	15.99	106.26	81,450,589
2012	578	26.60	64.70	91.30	16.77	108.07	82,835,716
2013	605	27.66	64.70	92.36	17.56	109.92	84,252,210
2014	634	28.77	64.70	93.47	18.40	111.86	85,744,251
2015	659	29.92	64.70	94.62	19.13	113.75	87,190,381
2016	686	31.12	64.70	95.82	19.90	115.71	88,694,355
2017	713	32.36	64.70	97.06	20.69	117.75	90,258,489
2018	742	33.66	64.70	98.36	21.52	119.88	91,885,188
2019	771	35.00	64.70	99.70	22.38	122.08	93,576,954
2020	802	36.40	64.70	100.00	23.28	123.28	94,491,674

1/93NPV @ DISCOUNT RATE OF 8.99% 499,498,670

Note:
1. Transportation rate for 1996 is 78.9 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calcul[illegible] based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/[illegible]3 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW VOLUME CONSUMPTION
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	35.69	43.62	79.30	6.53	85.83	37,022,914
1997	254	37.11	43.62	80.73	7.10	87.83	37,846,792
1998	274	38.60	43.62	82.21	7.67	89.88	41,120,783
1999	294	40.14	43.62	83.76	8.24	91.99	56,889,473
2000	324	41.75	43.62	85.36	9.07	94.43	70,992,456
2001	341	43.42	43.62	87.03	9.53	96.56	72,553,869
2002	358	45.15	43.62	88.77	10.02	98.78	74,183,027
2003	375	46.96	43.62	90.57	10.50	101.08	75,865,430
2004	395	48.84	43.62	92.45	11.04	103.50	77,636,322
2005	415	50.79	43.62	94.41	11.61	106.02	79,481,361
2006	435	52.82	43.62	95.00	12.18	107.18	80,284,436
2007	455	54.94	43.62	95.00	12.74	107.74	80,632,121
2008	479	57.13	43.62	95.00	13.39	108.39	81,029,474
2009	502	59.42	43.62	95.00	14.04	109.04	81,426,828
2010	526	61.79	43.62	95.00	14.72	109.72	81,840,738
2011	551	64.27	43.62	95.00	15.42	110.42	82,271,204
2012	578	66.84	43.62	95.00	16.17	111.17	82,734,784
2013	605	69.51	43.62	95.00	16.93	111.93	83,198,363
2014	634	72.29	43.62	95.00	17.74	112.74	83,695,055
2015	659	75.18	43.62	95.00	18.45	113.45	84,130,157
2016	686	78.19	43.62	95.00	19.19	114.19	84,582,663
2017	713	81.32	43.62	95.00	19.95	114.95	85,053,270
2018	742	84.57	43.62	95.00	20.75	115.75	85,542,701
2019	771	87.95	43.62	95.00	21.58	116.58	86,051,709
2020	802	91.47	43.62	95.00	22.45	117.45	86,581,077

1/93NPV @ DISCOUNT RATE OF 8.99% 507,468,734

Note:

1. Transportation rate for 1996 is 79.3 C/MBTU, 45% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW VOLUME CONSUMPTION
FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.10	53.90	77.00	10.89	87.89	37,541,856
1997	254	23.10	53.90	77.00	11.84	88.84	37,872,984
1998	274	23.10	53.90	77.00	12.78	89.78	40,598,411
1999	294	24.02	53.90	77.92	13.73	91.65	55,982,849
2000	324	24.98	53.90	78.88	15.12	94.00	69,736,906
2001	341	25.98	53.90	79.88	15.89	95.77	70,972,043
2002	358	27.02	53.90	80.92	16.70	97.62	72,265,415
2003	375	28.10	53.90	82.00	17.51	99.51	73,590,655
2004	395	29.23	53.90	82.00	18.41	100.41	74,142,535
2005	415	30.40	53.90	82.00	19.35	101.35	74,722,009
2006	435	31.61	53.90	82.00	20.30	102.30	75,301,483
2007	455	32.88	53.90	82.00	21.24	103.24	75,880,957
2008	479	34.19	53.90	82.00	22.32	104.32	76,543,213
2009	502	35.56	53.90	82.00	23.40	105.40	77,205,469
2010	526	36.98	53.90	82.00	24.53	106.53	77,895,319
2011	551	38.46	53.90	82.00	25.70	107.70	78,612,763
2012	578	40.00	53.90	82.00	26.96	108.96	79,385,395
2013	605	41.60	53.90	82.00	28.22	110.22	80,158,027
2014	634	43.27	53.90	82.00	29.57	111.57	80,985,847
2015	659	45.00	53.90	82.00	30.75	112.75	81,711,017
2016	686	46.80	53.90	82.00	31.98	113.98	82,465,194
2017	713	48.67	53.90	82.00	33.26	115.26	83,249,538
2018	742	50.61	53.90	82.00	34.59	116.59	84,065,256
2019	771	52.64	53.90	82.00	35.97	117.98	84,913,603
2020	802	54.75	53.90	82.00	37.41	119.41	85,795,884

1/93NPV @ DISCOUNT RATE OF 8.99%.	492,080,341
UPFRONT METER COST(1/93)	1,622,032
TOTAL	493,702,372

Note:
1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 30% will be escalated at 4% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW VOLUME CONSUMPTION
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	24.75	57.75	82.50	8.47	90.97	39,102,888
1997	254	25.74	57.75	83.49	9.21	92.70	39,794,052
1998	274	26.77	57.75	84.52	9.94	94.46	43,040,906
1999	294	27.84	57.75	85.59	10.68	96.27	59,273,903
2000	324	28.95	57.75	86.70	11.76	98.46	73,669,848
2001	341	30.11	57.75	87.00	12.36	99.36	74,261,586
2002	358	31.32	57.75	87.00	12.99	99.99	74,647,902
2003	375	32.57	57.75	87.00	13.62	100.62	75,034,218
2004	395	33.87	57.75	87.00	14.32	101.32	75,463,458
2005	415	35.23	57.75	87.00	15.05	102.05	75,914,160
2006	435	36.64	57.75	87.00	15.79	102.79	76,364,862
2007	455	38.10	57.75	87.00	16.52	103.52	76,815,564
2008	479	39.63	57.75	87.00	17.36	104.36	77,330,652
2009	502	41.21	57.75	87.00	18.20	105.20	77,845,740
2010	526	42.86	57.75	87.00	19.08	106.08	78,382,290
2011	551	44.57	57.75	87.00	19.99	106.99	78,940,302
2012	578	46.36	57.75	87.00	20.97	107.97	79,541,238
2013	605	48.21	57.75	87.00	21.95	108.95	80,142,174
2014	634	50.14	57.75	87.00	23.00	110.00	80,786,034
2015	659	52.14	57.75	87.00	23.91	110.91	81,350,055
2016	686	54.23	57.75	87.00	24.87	111.87	81,936,638
2017	713	56.40	57.75	87.00	25.87	112.87	82,546,683
2018	742	58.66	57.75	87.00	26.90	113.90	83,181,130
2019	771	61.00	57.75	87.00	27.98	114.98	83,840,956
2020	802	63.44	57.75	87.00	29.10	116.10	84,527,174

1/93NPV @ DISCOUNT RATE OF 8.99% 504,185,426

Note:
1. Transportation rate for 1996 is 82.5 C/MBTU, 30% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW VOLUME CONSUMPTION
United – 26 inch

Year	Natural Gas Cost C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Tranpsortation Cost $
1996	234	23.52	54.88	78.40	8.47	86.87	37,307,088
1997	254	24.46	54.88	79.34	9.21	88.55	37,976,702
1998	274	25.44	54.88	80.32	9.94	90.26	41,085,845
1999	294	26.46	54.88	81.34	10.68	92.01	56,595,422
2000	324	27.52	54.88	82.40	11.76	94.16	70,367,056
2001	341	28.62	54.88	83.50	12.36	95.85	71,575,522
2002	358	29.76	54.88	84.64	12.99	97.63	72,839,194
2003	375	30.95	54.88	85.83	13.62	99.45	74,137,961
2004	395	32.19	54.88	87.00	14.32	101.32	75,463,458
2005	415	33.48	54.88	87.00	15.05	102.05	75,914,160
2006	435	34.82	54.88	87.00	15.79	102.79	76,364,862
2007	455	36.21	54.88	87.00	16.52	103.52	76,815,564
2008	479	37.66	54.88	87.00	17.36	104.36	77,330,652
2009	502	39.16	54.88	87.00	18.20	105.20	77,845,740
2010	526	40.73	54.88	87.00	19.08	106.08	78,382,290
2011	551	42.36	54.88	87.00	19.99	106.99	78,940,302
2012	578	44.05	54.88	87.00	20.97	107.97	79,541,238
2013	605	45.81	54.88	87.00	21.95	108.95	80,142,174
2014	634	47.65	54.88	87.00	23.00	110.00	80,786,034
2015	659	49.55	54.88	87.00	23.91	110.91	81,350,055
2016	686	51.54	54.88	87.00	24.87	111.87	81,936,638
2017	713	53.60	54.88	87.00	25.87	112.87	82,546,683
2018	742	55.74	54.88	87.00	26.90	113.90	83,181,130
2019	771	57.97	54.88	87.00	27.98	114.98	83,840,956
2020	802	60.29	54.88	87.00	29.10	116.10	84,527,174
1/93NPV @ DISCOUNT RATE OF 8.99%							495,089,595

Note:
1. Tranportation rate for 1996 is 78.4 C/MBTU, 30% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

RATE CAPS ANALYSIS

LOW VOLUME CONSUMPTION

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25-YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$495,089,595
UNITED – 30 IN	$504,185,426
FGT – 30 IN	$493,702,372
ANR – 30 IN	$507,468,734

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW ESCALATION RATE
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Copressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	35.69	43.62	79.30	6.53	85.83	37,595,292
1997	254	36.40	43.62	80.01	7.10	87.11	38,156,239
1998	274	37.13	43.62	80.74	7.67	88.41	41,150,283
1999	294	37.87	43.62	81.48	8.24	89.72	56,496,185
2000	324	38.63	43.62	82.24	9.07	91.31	69,991,868
2001	341	39.40	43.62	83.01	9.53	92.55	70,935,837
2002	358	40.19	43.62	83.80	10.02	93.82	71,912,345
2003	375	40.99	43.62	84.61	10.50	95.11	72,900,932
2004	395	41.81	43.62	85.43	11.04	96.47	73,943,232
2005	415	42.65	43.62	86.26	11.61	97.87	75,018,795
2006	435	43.50	43.62	87.11	12.18	99.29	76,107,177
2007	455	44.37	43.62	87.98	12.74	100.73	77,208,635
2008	479	45.26	43.62	88.87	13.39	102.26	78,385,516
2009	502	46.16	43.62	89.78	14.04	103.82	79,576,001
2010	526	47.09	43.62	90.70	14.72	105.42	80,801,057
2011	551	48.03	43.62	91.64	15.42	107.06	82,060,962
2012	578	48.99	43.62	92.60	16.17	108.78	83,376,695
2013	605	49.97	43.62	93.58	16.93	110.51	84,707,153
2014	634	50.97	43.62	94.58	17.74	112.32	86,094,021
2015	659	51.99	43.62	95.00	18.45	113.45	86,958,321
2016	686	53.03	43.62	95.00	19.19	114.19	87,523,954
2017	713	54.09	43.62	95.00	19.95	114.95	88,112,212
2018	742	55.17	43.62	95.00	20.75	115.75	88,724,001
2019	771	56.27	43.62	95.00	21.58	116.58	89,360,261
2020	802	57.40	43.62	95.00	22.45	117.45	90,021,971

1/93NPV @ DISCOUNT RATE OF 8.99% 501,011,940

Note:
1. Transportation rate for 1996 is 79.3 C/MBTU, 45% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW ESCALATION RATE
FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.10	53.90	77.00	10.89	87.89	38,495,820
1997	254	23.10	53.90	77.00	11.84	88.84	38,909,730
1998	274	23.10	53.90	77.00	12.78	89.78	41,788,101
1999	294	23.56	53.90	77.46	13.73	91.19	57,420,454
2000	324	24.03	53.90	77.93	15.12	93.05	71,325,308
2001	341	24.51	53.90	78.41	15.89	94.30	72,280,111
2002	358	25.00	53.90	78.90	16.70	95.60	73,276,774
2003	375	25.50	53.90	79.40	17.51	96.91	74,280,953
2004	395	26.01	53.90	79.91	18.41	98.32	75,361,783
2005	415	26.53	53.90	80.43	19.35	99.78	76,484,926
2006	435	27.07	53.90	80.97	20.30	101.26	77,616,044
2007	455	27.61	53.90	81.51	21.24	102.75	78,755,298
2008	479	28.16	53.90	82.00	22.32	104.32	79,961,28[illegible]
2009	502	28.72	53.90	82.00	23.40	105.40	80,789,10[illegible]
2010	526	29.30	53.90	82.00	24.53	106.53	81,651,413
2011	551	29.88	53.90	82.00	25.70	107.70	82,548,218
2012	578	30.48	53.90	82.00	26.96	108.96	83,514,008
2013	605	31.09	53.90	82.00	28.22	110.22	84,479,798
2014	634	31.71	53.90	82.00	29.57	111.57	85,514,573
2015	659	32.35	53.90	82.00	30.75	112.75	86,421,035
2016	686	32.99	53.90	82.00	31.98	113.98	87,363,757
2017	713	33.65	53.90	82.00	33.26	115.26	88,344,187
2018	742	34.33	53.90	82.00	34.59	116.59	89,363,835
2019	771	35.01	53.90	82.00	35.97	117.97	90,424,268
2020	802	35.71	53.90	82.00	37.41	119.41	91,527,119

1/93NPV @ DISCOUNT RATE OF 8.99%	508,382,640
UPFRONT METER COST(1/93)	1,622,032
TOTAL	510,004,672

Note:
1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 30% will be escalated at 2% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW ESCALATION RATE
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	24.75	57.75	82.50	8.47	90.97	39,844,860
1997	254	25.25	57.75	83.00	9.21	92.20	40,383,600
1998	274	25.75	57.75	83.50	9.94	93.44	43,491,601
1999	294	26.26	57.75	84.01	10.68	94.69	59,626,229
2000	324	26.79	57.75	84.54	11.76	96.30	73,814,100
2001	341	27.33	57.75	85.08	12.36	97.43	74,680,861
2002	358	27.87	57.75	85.62	12.99	98.61	75,582,664
2003	375	28.43	57.75	86.18	13.62	99.79	76,492,845
2004	395	29.00	57.75	86.75	14.32	101.06	77,465,226
2005	415	29.58	57.75	87.00	15.05	102.05	78,221,325
2006	435	30.17	57.75	87.00	15.79	102.79	78,784,703
2007	455	30.77	57.75	87.00	16.52	103.52	79,348,080
2008	479	31.39	57.75	87.00	17.36	104.36	79,991,940
2009	502	32.02	57.75	87.00	18.20	105.20	80,635,800
2010	526	32.66	57.75	87.00	19.08	106.08	81,306,488
2011	551	33.31	57.75	87.00	19.99	106.99	82,004,003
2012	578	33.98	57.75	87.00	20.97	107.97	82,755,173
2013	605	34.66	57.75	87.00	21.95	108.95	83,506,343
2014	634	35.35	57.75	87.00	23.00	110.00	84,311,168
2015	659	36.06	57.75	87.00	23.91	110.91	85,016,194
2016	686	36.78	57.75	87.00	24.87	111.87	85,749,422
2017	713	37.51	57.75	87.00	25.87	112.87	86,511,979
2018	742	38.26	57.75	87.00	26.90	113.90	87,305,038
2019	771	39.03	57.75	87.00	27.98	114.98	88,129,820
2020	802	39.81	57.75	87.00	29.10	116.10	88,987,592

1/93NPV @ DISCOUNT RATE OF 8.99% 516,571,885

Note:
1. Transportation rate for 1996 is 82.5 C/MBTU, 30% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
LOW ESCALATION RATE
United – 26 inch

Year	Natual Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.52	54.88	78.40	8.47	86.87	38,049,060
1997	254	23.99	54.88	78.87	9.21	88.08	38,577,025
1998	274	24.47	54.88	79.35	9.94	89.29	41,560,127
1999	294	24.96	54.88	79.84	10.68	90.51	56,997,051
2000	324	25.46	54.88	80.34	11.76	92.10	70,593,734
2001	341	25.97	54.88	80.85	12.36	93.20	71,440,085
2002	358	26.49	54.88	81.37	12.99	94.35	72,321,069
2003	375	27.02	54.88	81.90	13.62	95.51	73,210,015
2004	395	27.56	54.88	82.44	14.32	96.75	74,160,737
2005	415	28.11	54.88	82.99	15.05	98.04	75,146,569
2006	435	28.67	54.88	83.55	15.79	99.34	76,140,851
2007	455	29.24	54.88	84.12	16.52	100.64	77,143,752
2008	479	29.83	54.88	84.71	17.36	102.07	78,235,925
2009	502	30.43	54.88	85.31	18.20	103.51	79,337,064
2010	526	31.03	54.88	85.91	19.08	104.99	80,474,176
2011	551	31.65	54.88	86.53	19.99	106.52	81,647,445
2012	578	32.29	54.88	87.00	20.97	107.97	82,755,173
2013	605	32.93	54.88	87.00	21.95	108.95	83,506,343
2014	634	33.59	54.88	87.00	23.00	110.00	84,311,168
2015	659	34.26	54.88	87.00	23.91	110.91	85,016,194
2016	686	34.95	54.88	87.00	24.87	111.87	85,749,422
2017	713	35.65	54.88	87.00	25.87	112.87	86,511,979
2018	742	36.36	54.88	87.00	26.90	113.90	87,305,038
2019	771	37.09	54.88	87.00	27.98	114.98	88,129,820
2020	802	37.83	54.88	87.00	29.10	116.10	88,987,592
							501,201,644

1/93NPV @ DISCOUNT RATE OF 8.99%

Note:
1. Transportation rate for 1996 is 78.4 C/MBTU, 30% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

RATE CAPS ANALYSIS

LOW ESCALATION RATE

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25-YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$501,201,644
UNITED – 30 IN	$516,571,885
FGT – 30 IN	$510,004,672
ANR – 30 IN	$501,011,940

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
HIGH ESCALATION RATE
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	35.69	43.62	79.30	6.53	85.83	37,595,292
1997	254	37.11	43.62	80.73	7.10	87.83	38,468,839
1998	274	38.60	43.62	82.21	7.67	89.88	41,834,598
1999	294	40.14	43.62	83.76	8.24	91.99	57,926,589
2000	324	41.75	43.62	85.36	9.07	94.43	72,383,203
2001	341	43.42	43.62	87.03	9.53	96.56	74,014,971
2002	358	45.15	43.62	88.77	10.02	98.78	75,718,633
2003	375	46.96	43.62	90.57	10.50	101.08	77,475,540
2004	395	48.84	43.62	92.45	11.04	103.50	79,329,214
2005	415	50.79	43.62	94.41	11.61	106.02	81,261,174
2006	435	52.82	43.62	95.00	12.18	107.18	82,151,171
2007	455	54.94	43.62	95.00	12.74	107.74	82,585,776
2008	479	57.13	43.62	95.00	13.39	108.39	83,082,468
2009	502	59.42	43.62	95.00	14.04	109.04	83,579,160
2010	526	61.79	43.62	95.00	14.72	109.72	84,096,548
2011	551	64.27	43.62	95.00	15.42	110.42	84,634,631
2012	578	66.84	43.62	95.00	16.17	111.17	85,214,105
2013	605	69.51	43.62	95.00	16.93	111.93	85,793,579
2014	634	72.29	43.62	95.00	17.74	112.74	86,414,444
2015	659	75.18	43.62	95.00	18.45	113.45	86,958,321
2016	686	78.19	43.62	95.00	19.19	114.19	87,523,954
2017	713	81.32	43.62	95.00	19.95	114.95	88,112,212
2018	742	84.57	43.62	95.00	20.75	115.75	88,724,001
2019	771	87.95	43.62	95.00	21.58	116.58	89,360,261
2020	802	91.47	43.62	95.00	22.45	117.45	90,021,971
1/93NPV @ DISCOUNT RATE OF 8.99%							519,522,333

Note:
1. Transportation rate for 1996 is 79.3 C/MBTU, 45% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
HIGH ESCALATION RATE
FGT – 30 inch

Year	Natural Gas Cost C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.10	53.90	77.00	10.89	87.89	38,495,820
1997	254	23.10	53.90	77.00	11.84	88.84	38,909,730
1998	274	23.10	53.90	77.00	12.78	89.78	41,788,101
1999	294	24.49	53.90	78.39	13.73	92.11	58,002,297
2000	324	25.96	53.90	79.86	15.12	94.98	72,798,460
2001	341	27.51	53.90	81.41	15.89	97.30	74,578,510
2002	358	29.16	53.90	82.00	16.70	98.70	75,649,718
2003	375	30.91	53.90	82.00	17.51	99.51	76,270,583
2004	395	32.77	53.90	82.00	18.41	100.41	76,960,433
2005	415	34.73	53.90	82.00	19.35	101.35	77,684,775
2006	435	36.82	53.90	82.00	20.30	102.30	78,409,118
2007	455	39.03	53.90	82.00	21.24	103.24	79,133,460
2008	479	41.37	53.90	82.00	22.32	104.32	79,961,280
2009	502	43.85	53.90	82.00	23.40	105.40	80,789,100
2010	526	46.48	53.90	82.00	24.53	106.53	81,651,413
2011	551	49.27	53.90	82.00	25.70	107.70	82,548,218
2012	578	52.23	53.90	82.00	26.96	108.96	83,514,008
2013	605	55.36	53.90	82.00	28.22	110.22	84,479,798
2014	634	58.68	53.90	82.00	29.57	111.57	85,514,573
2015	659	62.20	53.90	82.00	30.75	112.75	86,421,035
2016	686	65.94	53.90	82.00	31.98	113.98	87,363,757
2017	713	69.89	53.90	82.00	33.26	115.26	88,344,187
2018	742	74.08	53.90	82.00	34.59	116.59	89,363,835
2019	771	78.53	53.90	82.00	35.97	117.97	90,424,268
2020	802	83.24	53.90	82.00	37.41	119.41	91,527,119

1/93NPV @ DISCOUNT RATE OF 8.99%	513,577,650
UPFRONT METER COST(1/93)	1,622,032
TOTAL	515,199,682

Note:

1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 30% will be escalated at 6% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
HIGH ESCALATION RATE
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	24.75	57.75	82.50	8.47	90.97	39,844,860
1997	254	26.24	57.75	83.99	9.21	93.19	40,817,220
1998	274	27.81	57.75	85.56	9.94	95.50	44,450,056
1999	294	29.48	57.75	87.00	10.68	97.68	61,505,948
2000	324	31.25	57.75	87.00	11.76	98.76	75,699,540
2001	341	33.12	57.75	87.00	12.36	99.36	76,155,608
2002	358	35.11	57.75	87.00	12.99	99.99	76,638,503
2003	375	37.21	57.75	87.00	13.62	100.62	77,121,398
2004	395	39.45	57.75	87.00	14.32	101.32	77,657,948
2005	415	41.81	57.75	87.00	15.05	102.05	78,221,325
2006	435	44.32	57.75	87.00	15.79	102.79	78,784,703
2007	455	46.98	57.75	87.00	16.52	103.52	79,348,080
2008	479	49.80	57.75	87.00	17.36	104.36	79,991,940
2009	502	52.79	57.75	87.00	18.20	105.20	80,635,800
2010	526	55.96	57.75	87.00	19.08	106.08	81,306,488
2011	551	59.31	57.75	87.00	19.99	106.99	82,004,003
2012	578	62.87	57.75	87.00	20.97	107.97	82,755,173
2013	605	66.65	57.75	87.00	21.95	108.95	83,506,343
2014	634	70.64	57.75	87.00	23.00	110.00	84,311,168
2015	659	74.88	57.75	87.00	23.91	110.91	85,016,194
2016	686	79.38	57.75	87.00	24.87	111.87	85,749,422
2017	713	84.14	57.75	87.00	25.87	112.87	86,511,979
2018	742	89.19	57.75	87.00	26.90	113.90	87,305,038
2019	771	94.54	57.75	87.00	27.98	114.98	88,129,820
2020	802	100.21	57.75	87.00	29.10	116.10	88,987,592

1/93NPV @ DISCOUNT RATE OF 8.99% 520,839,920

Note:
1. Transportation rate for 1996 is 82.5 C/MBTU, 30% will be escalated at 6%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS
HIGH ESCALATION RATE
United – 26 inch

Year	Natural Gas Cost C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.52	54.88	78.40	8.47	86.87	38,049,060
1997	254	24.93	54.88	79.81	9.21	89.02	38,989,096
1998	274	26.43	54.88	81.31	9.94	91.25	42,470,950
1999	294	28.01	54.88	82.89	10.68	93.57	58,919,578
2000	324	29.69	54.88	84.57	11.76	96.33	73,839,596
2001	341	31.48	54.88	86.36	12.36	98.71	75,661,265
2002	358	33.36	54.88	87.00	12.99	99.99	76,638,503
2003	375	35.37	54.88	87.00	13.62	100.62	77,121,398
2004	395	37.49	54.88	87.00	14.32	101.32	77,657,948
2005	415	39.74	54.88	87.00	15.05	102.05	78,221,325
2006	435	42.12	54.88	87.00	15.79	102.79	78,784,703
2007	455	44.65	54.88	87.00	16.52	103.52	79,348,080
2008	479	47.33	54.88	87.00	17.36	104.36	79,991,940
2009	502	50.17	54.88	87.00	18.20	105.20	80,635,800
2010	526	53.18	54.88	87.00	19.08	106.08	81,306,488
2011	551	56.37	54.88	87.00	19.99	106.99	82,004,003
2012	578	59.75	54.88	87.00	20.97	107.97	82,755,173
2013	605	63.33	54.88	87.00	21.95	108.95	83,506,343
2014	634	67.13	54.88	87.00	23.00	110.00	84,311,168
2015	659	71.16	54.88	87.00	23.91	110.91	85,016,194
2016	686	75.43	54.88	87.00	24.87	111.87	85,749,422
2017	713	79.96	54.88	87.00	25.87	112.87	86,511,979
2018	742	84.76	54.88	87.00	26.90	113.90	87,305,038
2019	771	89.84	54.88	87.00	27.98	114.98	88,129,820
2020	802	95.23	54.88	87.00	29.10	116.10	88,987,592
1/93NPV @ DISCOUNT RATE OF 8.99%							514,620,169

Note:
1. Transportation rate for 1996 is 78.4 C/MBTU, 30% will be escalated at 6%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

RATE CAPS ANALYSIS

HIGH ESCALATION RATE

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25-YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$514,620,169
UNITED – 30 IN	$520,839,920
FGT – 30 IN	$515,199,682
ANR – 30 IN	$519,522,333

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS

ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	35.69	43.62	79.30	6.53	85.83	37,595,292
1997	254	37.11	43.62	80.73	7.10	87.83	38,468,839
1998	274	38.60	43.62	82.21	7.67	89.88	41,834,598
1999	294	40.14	43.62	33.76	8.24	91.99	57,926,589
2000	324	41.75	43.62	85.36	9.07	94.43	72,383,203
2001	341	43.42	43.62	87.03	9.53	96.56	74,014,971
2002	358	45.15	43.62	88.77	10.02	98.78	75,718,633
2003	375	46.96	43.62	90.57	10.50	101.08	77,475,540
2004	395	48.84	43.62	92.45	11.04	103.50	79,329,214
2005	415	50.79	43.62	94.41	11.61	106.02	81,261,174
2006	435	52.82	43.62	95.00	12.18	107.18	82,151,171
2007	455	54.94	43.62	95.00	12.74	107.74	82,585,776
2008	479	57.13	43.62	95.00	13.39	108.39	83,082,468
2009	502	59.42	43.62	95.00	14.04	109.04	83,579,160
2010	526	61.79	43.62	95.00	14.72	109.72	84,096,548
2011	551	64.27	43.62	95.00	15.42	110.42	84,634,631
2012	578	66.84	43.62	95.00	16.17	111.17	85,214,105
2013	605	69.51	43.62	95.00	16.93	111.93	85,793,579
2014	634	72.29	43.62	95.00	17.74	112.74	86,414,444
2015	659	75.18	43.62	95.00	18.45	113.45	86,958,321
2016	686	78.19	43.62	95.00	19.19	114.19	87,523,954
2017	713	81.32	43.62	95.00	19.95	114.95	88,112,212
2018	742	84.57	43.62	95.00	20.75	115.75	88,724,001
2019	771	87.95	43.62	95.00	21.58	116.58	89,360,261
2020	802	91.47	43.62	95.00	22.45	117.45	90,021,971

1/93NPV @ DISCOUNT RATE OF 8.99% 519,522,333

Note:

1. Transportation rate for 1996 is 79.3 C/MBTU, 45% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS

FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	23.10	53.90	77.00	10.89	87.89	38,495,820
1997	254	23.10	53.90	77.00	11.84	88.84	38,909,730
1998	274	23.10	53.90	77.00	12.78	89.78	41,788,101
1999	294	24.02	53.90	77.92	13.73	91.65	57,711,375
2000	324	24.98	53.90	78.88	15.12	94.00	72,054,802
2001	341	25.98	53.90	79.88	15.89	95.77	73,407,213
2002	358	27.02	53.90	80.92	16.70	97.62	74,824,759
2003	375	28.10	53.90	82.00	17.51	99.51	76,274,171
2004	395	29.23	53.90	82.00	18.41	100.41	76,964,021
2005	415	30.40	53.90	82.00	19.35	101.35	77,688,364
2006	435	31.61	53.90	82.00	20.30	102.30	78,412,706
2007	455	32.88	53.90	82.00	21.24	103.24	79,137,049
2008	479	34.19	53.90	82.00	22.32	104.32	79,964,869
2009	502	35.56	53.90	82.00	23.40	105.40	80,792,689
2010	526	36.98	53.90	82.00	24.53	106.53	81,655,001
2011	551	38.46	53.90	82.00	25.70	107.70	82,551,806
2012	578	40.00	53.90	82.00	26.96	108.96	83,517,596
2013	605	41.60	53.90	82.00	28.22	110.22	84,483,386
2014	634	43.27	53.90	82.00	29.57	111.57	85,518,161
2015	659	45.00	53.90	82.00	30.75	112.75	86,424,624
2016	686	46.80	53.90	82.00	31.98	113.98	87,367,346
2017	713	48.67	53.90	82.00	33.26	115.26	88,347,776
2018	742	50.61	53.90	82.00	34.59	116.59	89,367,423
2019	771	52.64	53.90	82.00	35.97	117.98	90,427,857
2020	802	54.75	53.90	82.00	37.41	119.41	91,530,707

1/93NPV @ DISCOUNT RATE OF 8.99%	512,169,672
UPFRONT METER COST(1/93)	1,622,032
TOTAL	513,791,704

Note:

1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 30% will be escalated at 4% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS

United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	24.75	57.75	82.50	8.47	90.97	39,844,860
1997	254	25.74	57.75	83.49	9.21	92.70	40,600,410
1998	274	26.77	57.75	84.52	9.94	94.46	43,965,221
1999	294	27.84	57.75	85.59	10.68	96.27	60,618,312
2000	324	28.95	57.75	86.70	11.76	98.46	75,472,656
2001	341	30.11	57.75	87.00	12.36	99.36	76,155,608
2002	358	31.32	57.75	87.00	12.99	99.99	76,638,503
2003	375	32.57	57.75	87.00	13.62	100.62	77,121,398
2004	395	33.87	57.75	87.00	14.32	101.32	77,657,948
2005	415	35.23	57.75	87.00	15.05	102.05	78,221,325
2006	435	36.64	57.75	87.00	15.79	102.79	78,784,703
2007	455	38.10	57.75	87.00	16.52	103.52	79,348,080
2008	479	39.63	57.75	87.00	17.36	104.36	79,991,940
2009	502	41.21	57.75	87.00	18.20	105.20	80,635,800
2010	526	42.86	57.75	87.00	19.08	106.08	81,306,488
2011	551	44.57	57.75	87.00	19.99	106.99	82,004,003
2012	578	46.36	57.75	87.00	20.97	107.97	82,755,173
2013	605	48.21	57.75	87.00	21.95	108.95	83,506,343
2014	634	50.14	57.75	87.00	23.00	110.00	84,311,168
2015	659	52.14	57.75	87.00	23.91	110.91	85,016,194
2016	686	54.23	57.75	87.00	24.87	111.87	85,749,422
2017	713	56.40	57.75	87.00	25.87	112.87	86,511,979
2018	742	58.66	57.75	87.00	26.90	113.90	87,305,038
2019	771	61.00	57.75	87.00	27.98	114.98	88,129,820
2020	802	63.44	57.75	87.00	29.10	116.10	88,987,592

1/93NPV @ DISCOUNT RATE OF 8.99% 519,810,461

Note:

1. Transportation rate for 1996 is 82.5 C/MBTU, 30% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON RATE CAPS

United – 26 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	23.52	54.88	78.40	8.47	86.87	38,049,060
1997	254	24.46	54.88	79.34	9.21	88.55	38,783,060
1998	274	25.44	54.88	80.32	9.94	90.26	42,011,160
1999	294	26.46	54.88	81.34	10.68	92.01	57,939,831
2000	324	27.52	54.88	82.40	11.76	94.16	72,169,864
2001	341	28.62	54.88	83.50	12.36	95.85	73,469,543
2002	358	29.76	54.88	84.64	12.99	97.63	74,829,795
2003	375	30.95	54.88	85.83	13.62	99.45	76,225,141
2004	395	32.19	54.88	87.00	14.32	101.32	77,657,948
2005	415	33.48	54.88	87.00	15.05	102.05	78,221,325
2006	435	34.82	54.88	87.00	15.79	102.79	78,784,703
2007	455	36.21	54.88	87.00	16.52	103.52	79,348,080
2008	479	37.66	54.88	87.00	17.36	104.36	79,991,940
2009	502	39.16	54.88	87.00	18.20	105.20	80,635,800
2010	526	40.73	54.88	87.00	19.08	106.08	81,306,488
2011	551	42.36	54.88	87.00	19.99	106.99	82,004,003
2012	578	44.05	54.88	87.00	20.97	107.97	82,755,173
2013	605	45.81	54.88	87.00	21.95	108.95	83,506,343
2014	634	47.65	54.88	87.00	23.00	110.00	84,311,168
2015	659	49.55	54.88	87.00	23.91	110.91	85,016,194
2016	686	51.54	54.88	87.00	24.87	111.87	85,749,422
2017	713	53.60	54.88	87.00	25.87	112.87	86,511,979
2018	742	55.74	54.88	87.00	26.90	113.90	87,305,038
2019	771	57.97	54.88	87.00	27.98	114.98	88,129,820
2020	802	60.29	54.88	87.00	29.10	116.10	88,987,592
1/93NPV @ DISCOUNT RATE OF 8.99%							510,714,631

Note:
1. Transportation rate for 1996 is 78.4 C/MBTU, 30% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

RATE CAPS ANALYSIS

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25-YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$510,714,631
UNITED – 30 IN	$519,810,461
FGT – 30 IN	$513,791,704
ANR – 30 IN	$519,522,333

SOURCE: SYSTEM PLANNING

EXPECTED ASSUMPTIONS		
	26-INCH	30-INCH
UNITED		
1996	75.4¢/MMbtu	79.5¢/MMbtu
	esc. 18% & 4%/year	esc. 18% @ 4%/year
	max of 87¢/MMbtu	max of 87¢/MMbtu
	Compressor Fuel 3.5%	Compressor Fuel 3.1%
FGT		
1996	77¢/MMbtu fixed 1997 & 1998	
	then esc. 18% @4%/year	
	Max. of 82¢/MMbtu	
	Reduce fixed component to 51¢/MMbtu 2011 through 2020	
	Compressor Fuel 4.0%	
	+$2.1 million up front meter cost in 1996	
ANR		
1996	74.8¢/MMbtu - based on 50% of supply through United and 50% through Gateway	
	Esc. 18% @ 4%/year	
	Max. of 95¢/MMbtu	
	Compressor Fuel 1.9%	

1992 SPOT MARKET NATURAL GAS PRICES ¢/MMBTU			
Source: Natural Gas Week			
	S. Texas FGT/Mustang Island	S. Louisiana United/Erath	East Transco/Homesville
1/92	106	165	138
2/92	110	114	112
3/92	118	117	121
4/92	143	138	149
5/92	165	149	174
6/92	154	155	159
7/92	168	173	179
8/92	196	194	194
9/92	216	258	239
10/9	248	261	264
Ten Month Average	162.1	172.2	173.0

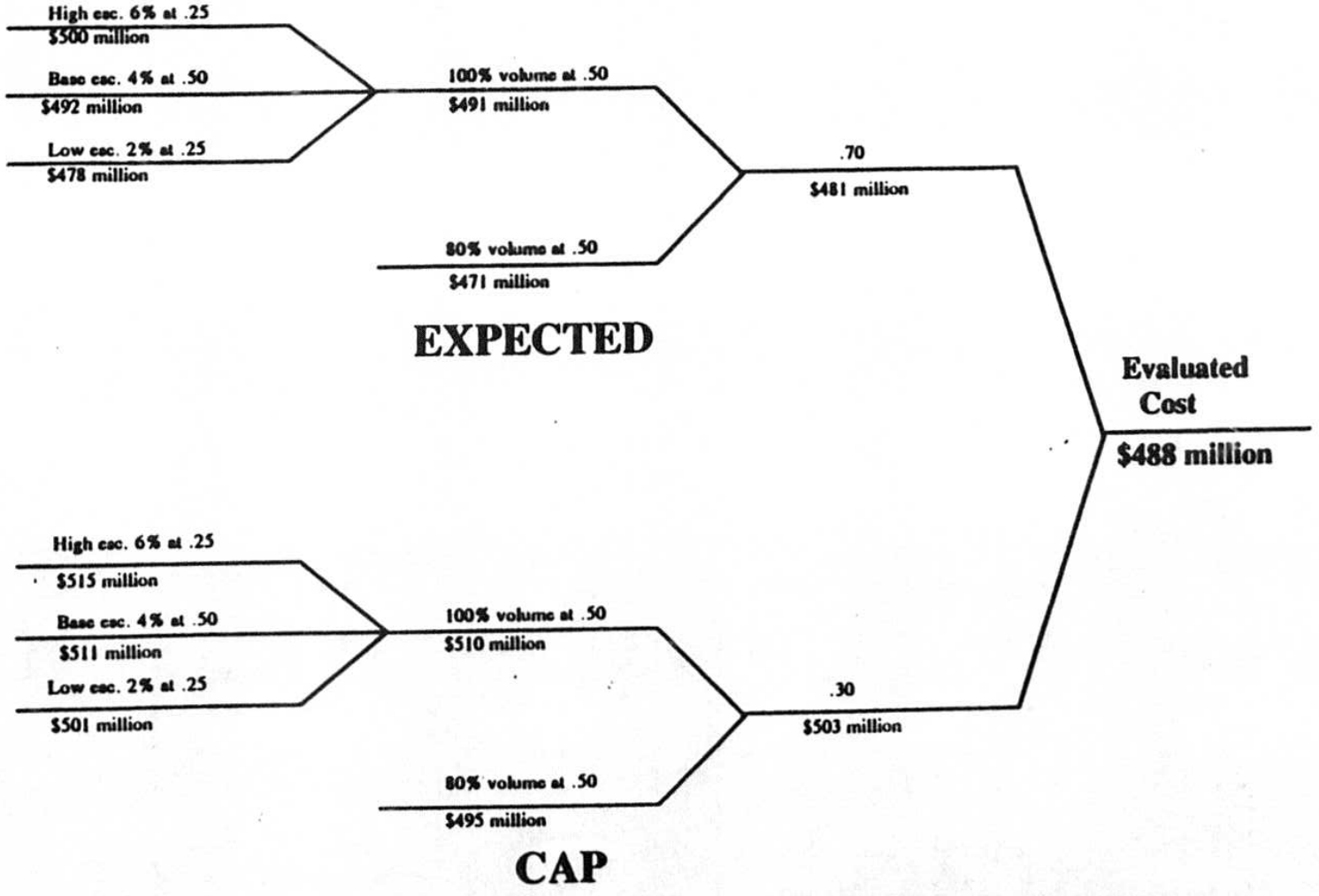
UNITED		ANR (50% THROUGH UNITED)		FGT	
Texas	26%	Texas	19%	Texas	19%
Louisiana	44%	Louisiana	31%	Louisiana	35%
East	30%	East	50%	East	46%
Wtd.Avg. Price	169.8	Wtd.Avg. Price	170.7	Wtd.Avg. Price	170.6

Florida Power Corporation
Final SO2 Allowance Allocations

PLANT	NAME PLATE (MWe)	Basic SO2 (Tons)	DET. ED. Special Allow. (Tons)	FLORIDA Growth Allowance (Tons)	12.7 % Racheting (Tons)	Bonus SO2 (Tons)	Total SO2 (Tons)
AVP 2	46	1,026			(130)		896
ANC 1	556	9,166	1,401	1,180	(1,490)	2,712	12,969
ANC 2	556	9,616	1,527	1,286	(1,576)	2,051	12,904
BAR 1	127	2,780		21	(355)	351	2,797
BAR 2	127	2,609		165	(352)	528	2,950
BAR 3	239	5,970		234	(787)		5,417
CR 1	441	13,687		515	(1,802)		12,400
CR 2	524	16,143		192	(2,072)		14,263
CR 4	739	26,098		937	(3,429)		23,606
CR 5	739	28,391		473	(3,661)		25,203
HIG 1	46	340		142	(61)		421
HIG 2	46	353		190	(69)		474
HIG 3	46	303		193	(63)	530	964
TUR 2	29	43		50	(12)	456	537
TUR 3	79	604		218	(104)		717
TUR 4	82	474		224	(89)		609
SR 1	34	133		157	(37)		254
SR 2	37	164		125	(37)		252
SR 3	75	357		384	(94)		647
DEB 7	104	805			(102)		703
DEB 8	104	805			(102)		703
DEB 9	104	805			(102)		703
DEB 10	104	805			(102)		703
IC 7	104	805			(102)		703
IC 8	104	805			(102)		703
IC 9	104	805			(102)		703
IC 10	104	805			(102)		703
Totals	5,400	124,697	2,928	6,686	(17,036)	6,629	123,903

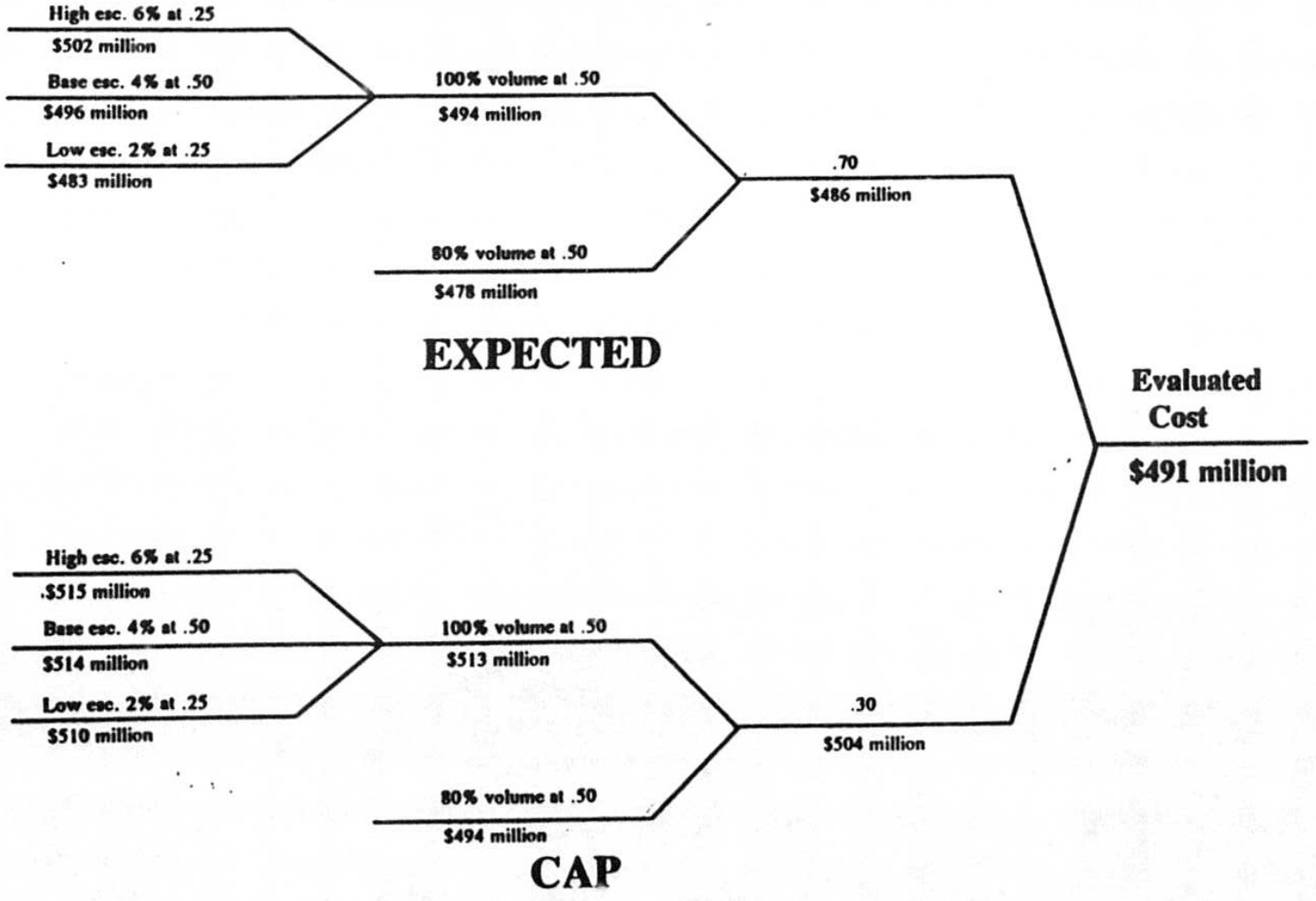
United Decision Analysis

Present Worth in 1993$



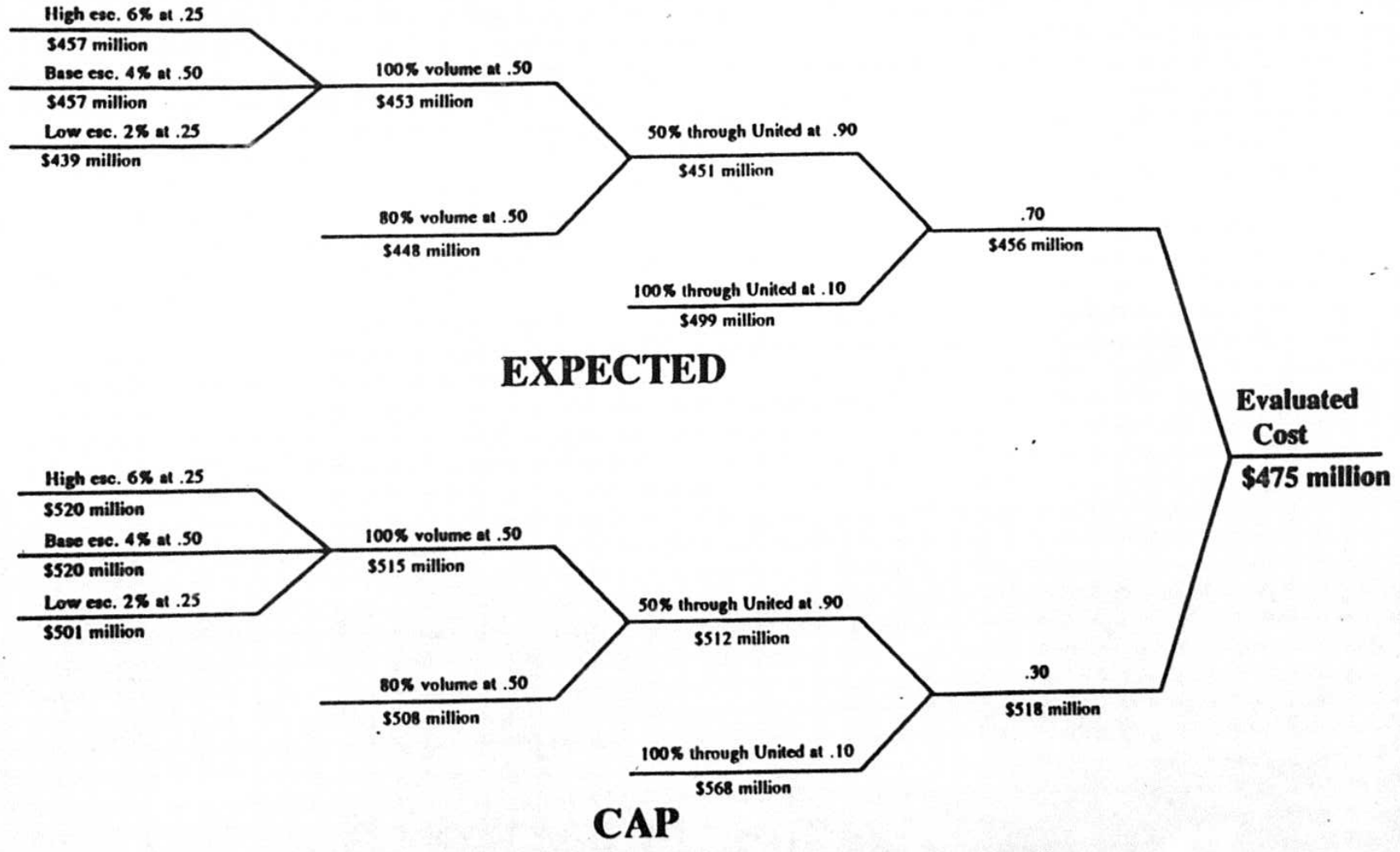
FGT Decision Analysis

Present Worth in 1993$



ANR Decision Analysis

Present Worth in 1993$



SPOT PRICES ON INTERSTATE PIPELINE SYSTEMS

Delivered-to-Pipeline ($/MMBtu)
October 5, 1992

Pipeline	This Week	Weekly Change	Sep Bid Week	Oct Bid Week	1991 Avg.	Oct 1991	Nov 1991	Dec 1991	Jan 1992	Feb 1992	Mar 1992	Apr 1992	May 1992	Jun 1992	Jul 1992	Aug 1992	1992
ANR Pipeline Co.																	
Southeast: Patterson, La.	2.63	.00	1.93	2.63	1.50	1.68	1.61	1.61	1.25	1.17	1.30	1.45	1.65	1.61	1.73	1.58	2.42
Westcam 167, offshore La.	2.52	.00	1.84	2.52	1.40	1.57	1.76	1.76	1.26	1.04	1.19	1.44	1.57	1.45	1.60	1.60	2.36
Southwest: Laverne Station, Okla.	2.56	.00	1.89	2.56	1.43	1.63	1.77	1.77	1.32	1.13	1.19	1.43	1.50	1.53	1.68	1.61	2.35
Arkla Energy Resources																	
Arizona: Wilburton, Okla.	2.56	-.02	1.91	2.58	1.34	1.59	1.66	1.66	1.16	1.04	1.14	1.40	1.49	1.50	1.49	1.32	2.29
CNG Transmission Co.																	
Cornwell, W.Va.	2.94	.00	2.42	2.94	1.75	1.86	1.98	1.98	1.92	1.69	1.70	1.83	1.97	2.06	1.94	2.14	2.60
Lebanon, Ohio	2.82	.00	2.30	2.82	1.73	1.67	1.67	1.67	1.35	1.44	1.48	1.61	1.64	1.90	1.76	2.04	2.56
Colorado Interstate Gas Co.																	
Kanda, Wyo.	2.20	.00	1.67	2.18	1.11	1.40	1.43	1.43	1.23	0.94	1.06	1.12	1.22	1.29	1.26	1.57	1.76
Columbia Gas Transmission Corp.																	
Maumee, Ohio	2.81	.00	2.25	2.81	1.73	1.69	1.89	1.89	1.43	1.51	1.46	1.75	1.67	1.75	1.72	2.01	2.66
Broad Run, W.Va.	2.73	.00	2.13	2.73	1.71	1.89	2.25	2.25	1.63	1.69	1.67	1.73	1.59	1.85	1.74	1.96	2.34
Columbia Gulf Transmission Co.																	
Leach, Ky.	2.72	-.04	2.11	2.76	1.56	1.84	2.03	2.03	—	1.18	1.60	1.58	1.72	1.63	1.64	2.08	2.29
Egan, La.	2.60	-.04	1.98	2.64	1.43	1.79	1.89	1.89	1.23	1.20	1.25	1.54	1.55	1.63	1.66	1.95	2.23
Erath, La.	2.58	-.05	1.97	2.63	1.44	1.80	1.90	1.90	1.47	1.22	1.28	1.49	1.56	1.56	1.82	1.94	2.60
Rayne, La.	2.61	-.01	1.99	2.66	1.47	1.83	1.93	1.93	1.23	1.25	1.38	1.47	1.62	1.57	1.73	1.97	2.44
Texaco Henry Plant, La.	2.56	-.06	1.95	2.62	1.41	1.65	1.91	1.91	—	1.17	1.27	1.41	1.55	1.61	1.72	1.93	2.07
El Paso Natural Gas Co.																	
Anadarko: Washita County, Okla.	2.29	-.15	1.89	2.44	1.35	1.58	1.71	1.71	1.23	1.14	1.10	1.33	1.43	1.45	1.50	1.58	2.14
Permian: Waha, Texas	2.33	-.14	1.92	2.47	1.43	1.63	1.85	1.85	1.29	1.18	1.20	1.41	1.50	1.51	1.59	1.91	2.21
San Juan: Ignacio, Colo.	2.30	-.21	1.91	2.46	1.26	1.28	1.70	1.70	1.25	1.13	1.20	1.37	1.45	1.51	1.59	1.62	2.16
Florida Gas Transmission Co.																	
Mustang Island (Tivoli)	2.48	-.11	1.93	2.50	1.38	1.70	1.76	1.76	1.06	1.10	1.18	1.43	1.65	1.54	1.66	1.96	2.16
Vermilion Parish, La.	2.50	-.07	1.99	2.54	1.46	1.77	1.81	1.81	1.08	1.15	1.24	1.44	1.70	1.69	1.73	1.98	2.26
St. Helena Parish, La.	2.48	-.13	2.00	2.55	1.50	1.77	1.83	1.85	1.51	1.13	1.22	1.48	1.76	1.62	1.77	2.01	2.32
Iroquois Gas Transmission System																	
Canajoharie, N.Y.	2.56	.00	2.25	2.56	—	—	2.65	2.65	2.58	1.86	1.97	1.90	1.47	1.47	1.70	1.93	
Wright, N.Y.	2.45	.00	2.31	2.45	—	—	—	2.68	—	—	1.95	2.02	1.96	1.55	1.74	2.35	
Kern River Gas Transmission Co.																	
Opal, Wyo.	2.11	—	1.68	2.14	—	—	—	—	—	1.15	1.17	1.28	1.56	1.26	1.59	1.68	
Whittier Ridge, Calif. (Kern Cty.-SoCal Jct.)	2.78	—	2.33	2.83	—	—	—	—	—	—	1.65	1.69	1.91	1.67	1.98	2.19	2.34
Natural Gas Pipeline Co. of America																	
Lake Arthur, La.	2.62	-.06	1.93	2.66	1.49	1.84	1.66	1.66	1.22	1.18	1.28	1.51	1.55	1.59	1.77	1.94	2.[illegible]
Fergus, Okla.	2.51	-.02	1.86	2.53	1.37	1.64	1.77	1.77	1.27	1.04	1.19	1.24	1.42	1.54	1.60	1.57	
Agua Dulce, Texas	2.58	-.04	1.94	2.61	1.48	1.64	1.60	1.60	1.25	1.11	1.28	1.48	1.62	1.64	1.73	1.90	2.[illegible]
Wharton County, Texas	2.42	-.17	1.91	2.60	1.36	1.64	1.60	1.60	1.23	1.10	1.30	1.47	1.56	1.64	1.69	1.66	2.33
Northern Natural Gas Co.																	
Custer County, Okla.	2.55	.00	1.87	2.46	1.37	1.62	1.77	1.77	1.54	0.99	1.08	1.30	1.40	1.43	1.53	1.60	2.17
Keystone (Kermit, Texas)	2.53	.00	1.85	2.48	1.35	1.68	1.77	1.77	1.70	1.13	1.22	1.42	1.45	1.47	1.60	1.79	2.15
Northwest Pipeline Corp.																	
Ignacio, Colo.	2.05	—	1.61	2.05	1.13	—	1.38	1.35	1.16	0.94	0.99	0.99	1.24	1.27	1.23	1.55	1.61
Sumas, Wash.	1.21	—	0.96	1.21	1.22	—	1.40	1.34	1.34	1.22	1.02	1.01	1.07	1.03	0.66	1.04	0.96
Green River, Wyo.	2.08	—	1.60	2.08	1.16	1.34	1.43	1.34	1.28	0.94	0.99	0.98	1.16	1.30	1.30	1.58	1.58
Panhandle Eastern Pipe Line Co.																	
Lakin, Kan.	2.40	-.15	1.93	2.55	1.29	1.66	1.71	1.59	1.18	1.11	1.28	1.44	1.49	1.49	1.62	1.66	2.16
Dewey County, Okla.	2.39	-.16	1.93	2.55	1.29	1.66	1.71	1.59	1.18	1.11	1.28	1.44	1.49	1.49	1.62	1.66	2.39
Southern Natural Gas Co.																	
Main Pass 46, offshore La.	2.40	-.10	1.95	2.49	1.37	1.64	1.66	1.67	1.51	1.09	1.30	1.52	1.63	1.58	1.65	1.92	2.23
St. Mary Parish, La.	2.40	-.12	1.94	2.48	1.40	1.79	1.86	1.66	1.30	1.16	1.31	1.52	1.63	1.56	1.70	1.90	2.18
Tennessee Gas Pipeline Co.																	
Egan, La.	2.52	-.07	1.90	2.59	1.46	1.76	1.67	1.71	1.14	1.13	1.32	1.50	1.51	1.64	1.71	1.90	2.40
Texas Eastern Transmission Corp.																	
Zone A: Calhoun County, Texas	2.54	-.03	1.93	2.57	1.41	1.72	1.80	1.67	1.24	1.15	1.31	1.50	1.60	1.60	1.79	2.04	2.22
Zone A: South Louisiana	2.54	-.04	1.94	2.58	—	—	—	—	—	1.26	1.53	1.56	1.64	1.75	2.05	2.21	
Zone B: Kosciusko, Miss.	2.65	-.04	1.96	2.67	1.52	1.73	1.92	1.52	1.30	1.19	1.16	1.39	1.52	1.63	1.73	1.93	2.28
Texas Gas Transmission Corp.																	
Louisa, La.	2.53	-.10	1.92	2.62	1.46	1.75	1.87	1.69	1.27	1.21	1.28	1.49	1.52	1.58	1.75	1.92	2.40
Texaco Henry Plant, La.	2.51	-.11	1.91	2.62	1.20	1.86	1.84	1.75	1.38	1.26	1.33	1.42	1.59	1.52	1.74	1.92	2.12
Transcontinental Gas Pipe Line Corp.																	
Station #30 (Wharton County, Texas-Zone 1)	2.50	.00	1.88	2.54	1.35	1.74	1.71	1.68	1.10	1.06	1.15	1.43	1.56	1.48	1.77	1.93	2.17
Station #45 (Texas-La. border-Zone 2)	2.52	-.04	1.91	2.56	1.20	1.73	1.76	1.69	1.12	1.15	1.19	1.44	1.60	1.54	1.60	1.96	2.27
Stations #50, 62, 65 (South La.-Zone 3)	2.55	-.06	1.92	2.62	1.43	1.77	1.82	1.71	1.08	1.14	1.19	1.46	1.65	1.51	1.83	1.93	2.29
Holmesville, Miss.	2.64	-.06	1.95	2.69	1.44	1.73	1.83	1.77	1.38	1.12	1.21	1.49	1.74	1.59	1.79	1.94	2.29
Transwestern Pipeline Co.																	
Anadarko: Sherman County, Texas	2.40	-.09	1.92	2.46	1.37	1.60	1.75	1.76	—	1.02	1.08	1.20	1.49	1.52	1.57	1.85	1.92
Permian: Ward County, Texas	2.31	-.19	1.95	2.46	1.46	1.67	1.65	1.65	1.48	1.10	1.17	1.33	1.49	1.49	1.61	1.69	2.07
Trunkline Gas Co.																	
Patterson, La.	2.51	-.12	1.93	2.60	1.57	1.72	1.65	1.65	1.16	1.11	1.27	1.45	1.64	1.54	1.73	1.95	2.42
Bee County, Texas	2.50	-.13	1.91	2.63	1.49	1.63	1.75	1.64	1.25	1.22	1.26	1.39	1.65	1.61	1.69	1.91	2.43
United Gas Pipe Line Co.																	
Erath, La.	2.61	-.06	1.94	2.66	1.41	1.71	1.75	1.65	1.65	1.14	1.17	1.38	1.49	1.55	1.73	1.94	2.58
Terrebonne Parish, La.	2.57	-.01	1.94	2.58	1.38	1.67	1.75	1.74	1.26	1.18	1.29	1.52	1.49	1.56	1.65	2.15	2.40
Williams Natural Gas Co.																	
Mamboo, Kan./Okla.	2.45	.00	1.81	2.44	1.29	1.55	1.66	1.63	1.00	1.15	1.18	1.32	1.56	1.46	1.53	1.60	2.
Weld County, Colo.	2.49	-.01	1.83	2.50	1.39	1.58	1.65	1.62	0.95	1.13	1.19	1.29	1.40	1.42	1.46	1.51	2.

NOTES: (1) "Delivered-To-Pipeline" is the average price paid for spot contracts with durations of 31 days or less, delivered into an interstate pipeline system at a specific interconnection. Prices include processing, gathering and transportation fees. Reported average prices, which are volume-weighted, reflect deals done the week before publication, regardless of the time of delivery. (2) A dash (—) means there are insufficient price quotes for a meaningful average. (3) Prices on Transcontinental Gas Pipe Line Corp. reflect posting point prices. (4) R = Revised. (5) Bid Week. These averages, updated the first issue of each month, reflect prices collected during the entire nomination period.

EXPECTED ASSUMPTIONS		
	26-INCH	30-INCH
UNITED		
1996	75.4¢/MMbtu	79.5¢/MMbtu
	esc. 18% & 4%/year	esc. 18% @ 4%/year
	max of 87¢/MMbtu	max of 87¢/MMbtu
	Compressor Fuel 3.5%	Compressor Fuel 3.1%
FGT		
1996	77¢/MMbtu fixed 1997 & 1998	
	then esc. 18% @4%/year	
	Max. of 82¢/MMbtu	
	Reduce fixed component to 51¢/MMbtu 2011 through 2020	
	Compressor Fuel 4.0%	
	+$2.1 million up front meter cost in 1996	
ANR		
1996	74.8¢/MMbtu - based on 50% of supply through United and 50% through Gateway	
	Esc. 18% @ 4%/year	
	Max. of 95¢/MMbtu	
	Compressor Fuel 1.9%	

1992 SPOT MARKET NATURAL GAS PRICES ¢/MMBTU			
Source: Natural Gas Week			
	S. Texas FGT/Mustang Island	S. Louisiana United/Erath	East Transco/Homesville
1/92	106	165	138
2/92	110	114	112
3/92	118	117	121
4/92	143	138	149
5/92	165	149	174
6/92	154	155	159
7/92	168	173	179
8/92	196	194	194
9/92	216	258	239
10/9	248	261	264
Ten Month Average	162.1	172.2	173.0

UNITED		ANR (50% THROUGH UNITED)		FGT	
Texas	26%	Texas	19%	Texas	19%
Louisiana	44%	Louisiana	31%	Louisiana	35%
East	30%	East	50%	East	46%
Wtd.Avg. Price	169.8	Wtd.Avg. Price	170.7	Wtd.Avg. Price	170.6

ANR Sensitivity: 100% of supply through United	
Expected	1996 - ANR
	Total 78.9 ¢/MMbtu
	Esc. 18% @ 4%/year
	Max. of 100 ¢/MMbtu
	Compressor Fuel 2.8%
Rate Caps	1996 ANR
	Total 83.4 ¢/MMbtu
	Esc. 45% @ 4%/year
	Max. of 100 ¢/MMbtu
	Compressor Fuel 3.8%

ANR Sensitivity: 100% of supply through United	
Expected	1996 - ANR
	Total 78.9 ¢/MMbtu
	Esc. 18% @ 4%/year
	Max. of 100 ¢/MMbtu
	Compressor Fuel 2.8%
Rate Caps	1996 ANR
	Total 83.4 ¢/MMbtu
	Esc. 45% @ 4%/year
	Max. of 100 ¢/MMbtu
	Compressor Fuel 3.8%

RATE CAP ASSUMPTIONS		
	26-INCH	30-INCH
UNITED		
1996	78.4/MMbtu	82.5/MMbtu
	esc. 30% & 4%/year	esc. 30% @ 4%/year
	max of 87¢/MMbtu	max of 87¢/MMbtu
	Compressor Fuel 3.5%	Compressor Fuel 3.5%
FGT		
1996	77¢/MMbtu fixed 1997 & 1998	
	then esc. 30% @4%/year	
	Max. of 82¢/MMbtu	
	Compressor Fuel 4.5%	
	+$2.1 million up front meter cost in 1996	
ANR		
1996	79.3¢/MMbtu - based on 50% of supply through United and 50% through Gateway	
	Esc. 45% @ 4%/year	
	Max. of 95¢/MMbtu	
	Compressor Fuel 2.7%	

RATE CAP ASSUMPTIONS		
	26-INCH	30-INCH
UNITED		
1996	78.4/MMbtu	82.5/MMbtu
	esc. 30% & 4%/year	esc. 30% @ 4%/year
	max of 87¢/MMbtu	max of 87¢/MMbtu
	Compressor Fuel 3.5%	Compressor Fuel 3.5%
FGT		
1996	77¢/MMbtu fixed 1997 & 1998	
	then esc. 30% @4%/year	
	Max. of 82¢/MMbtu	
	Compressor Fuel 4.5%	
	+$2.1 million up front meter cost in 1996	
ANR		
1996	79.3¢/MMbtu - based on 50% of supply through United and 50% through Gateway	
	Esc. 45% @ 4%/year	
	Max. of 95¢/MMbtu	
	Compressor Fuel 2.7%	

expected and, therefore, the caps provided in each proposal would be the applicable rate charged. The headings on each page have the same meaning as discussed in the Expected Rate Analysis.

The Rate Cap Analysis assumes that a higher percent of cost is escalated (from the initial Cap) than in the expected case. ANR and FGT both provided ceilings for this at 45% of total rate and 30%, respectively. United did not provide a ceiling on the portion to be escalated; therefore, 30% was assumed. For ANR, the United 50% upstream portion was assumed to escalate up to the jurisdictional rate of about 20¢/MMbtus and Gateway was estimated at 6¢/MMbtus for rate cap analysis purposes. The 20¢/MMbtus is the same cap United proposed into the Suncoast Pipeline. ANR has agreed to provide FPC protection against the cost impact of upstream rates higher than this level if the ANR SunShine rates are also at rate cap levels.

United and ANR both put ceilings on the compressor fuel amount at 3.5% and 1.5%, respectively. Fuel for the 50% upstream transportation component of ANR's cost was assumed to be at the tariff rate of 2.3%. FGT only estimated fuel to be 4%. No ceiling on compressor fuel was provided. For the rate cap analysis fuel was assumed to be 4.5% for FGT.

None of the proposals had a rate cap for the full 25-year period (they were all for 20 years) but for analysis purposes the caps were assumed to remain in effect throughout the 25 years analyzed.

Results

Page 1 of 5 lists the Net Present Value of each proposal based on the rate caps proposed. This rate cap case shows United's 26-inch case to have the lowest transport cost (including adjustments for compressor fuel) of the proposals. United's 26-inch case rate cap cost is about $9 million below ANR's and about $3 million below FGT's proposal. A graph of the adjusted total ¢/MMbtus is presented at the end of this section.

proposal left open a wider choice of options (0 to 100% through United, Transabama, Gateway or Chevron Pascagoula pipelines) the assumption was made that 50% of supply would come through United and 50% through Gateway. This assumption levelizes the natural gas supply cost between United, ANR and FGT (all are within about 1¢ of each other) so that the focus of the evaluation can be on the proposed transport costs. It was also assumed that transport cost for the 50% supply through United and 50% of supply through Gateway to ANR's SunShine project would be at about the same rates that United proposed as part of their Suncoast project. (United also owns the Gateway pipeline.) Due to United's current low throughput (about 50% of capacity on average) their need to discount prices to move volume is well known in the industry. This posture is not expected to change in the near future. The transportation rate was broken into Escalated ¢/MMbtus and Fixed ¢/MMbtus in order to estimate rates in future years. The escalated portion was estimated to be about 18% of total transport rates for all three of the competitors. This is an approximate value based on United's proposal and review of estimated variable cost of the other pipelines from various sources. Escalation was assumed to be 4% per year. Sensitivity cases at 2% and 6% were also done.

Total ¢/MMbtus is the sum of the escalated and unescalated portions. The column labeled Compressor Fuel Cost ¢/MMbtus presents the cost impact of differences in compressor fuel (required to be provided by the shipper) between the proposals. Adjusted Total ¢/MMbtus is the total of the Total ¢/MMbtus and Compressor Fuel Cost ¢/MMbtus. Total Transportation Cost is the transportation dollars spent each year assuming the volumes contracted for are used 100% of the time. A sensitivity analysis at an 80% usage rate was also computed.

All proposals were reviewed over a 25-year period beginning in 1996 and ending in 2020. A 1/93 Net Present Value (NPV) was calculated for this period at a discount rate of 8.99%. Although the proposals themselves have slightly different start and stop dates (see proposals) the analysis of all of them on a common time scale simplifies the comparison of each without undue distortion of the results.

Results

Page 1 of 5 lists the Net Present Value of each proposals' Transport Cost. The expected case shows ANR to be the most attractive proposal by about $35 million compared to United and about $39 million compared to FGT. A graph of the expected adjusted total ¢/MMbtus is presented at the end of this section.

Rate Caps Analysis

This section presents the potential pipeline transportation costs assuming the rate caps presented in each proposal are charged in each year of the agreements. This scenario would occur if pipeline construction costs or other costs are higher than

Expected Rate Analysis

This section presents the expected pipeline transportation cost for each alternative based on the rates expected to be charged with the design and throughput assumptions made by each pipeline company.

The options evaluated as follows:

1. United 26-inch
2. United 30-inch
3. FGT 30-inch (Option A)
4. ANR 30-inch (Option 1)

United presented two options, a 26-inch and a 30-inch case, both assuming the same overall throughput. The 30-inch case results in higher initial rates but has the ability to provide for future lower cost expansions than the 26-inch case. Both options are evaluated in this section.

FGT also presented two options, A & B. Option B provides for access only to supply sources from FGT's Mobile Bay facilities. Option B would unduly restrict FPC's supply access options and was therefore not considered further.

ANR presented four options. Option 1 was based on the volumes which FPC requested. Options 2 - 4 are based on additional volumes that FPC has previously discussed with ANR. Although these added volumes would lower overall rates, the potential increases in natural gas requirements are too uncertain for consideration at this point. Therefore, only Option 1: 120,000 MMbtus/day for Anclote and 45,000 MMbtus/day for Polk 1 and 45,000 MMbtus/day for Polk 2, was evaluated.

Methodology

Each proposals' expected transport cost to FPC was estimated based on the initial rates and compressor fuel costs and estimated cost increases over time. Each proposals' expected cost is presented in a one page year-by-year analysis and the net present value (NPV) of each is computed. The second column of each analysis page lists the current fuel cost forecast for natural gas as Natural Gas Forecast ¢/MMbtus. Natural gas spot market cost in the different supply regions was tabulated over the period 1/92 through 10/92 (see Appendix). The mix for each pipeline was calculated based on the supply access they provided. Since ANR

The results of this comparison are obviously close. However, the proposed rates to be charged will reflect levelization of the cost of service with a deferral adjustment to compensate for the under collection of equity during the first three years of the project (1996 - 1999). When this deferral component is added to the base rate the so called "rate after deferral" becomes $00.5249 per MCF for SunShine and $00.1482 per MCF for SITCO. Simply put, the deferral component provides for a 14.05% equity return, through out the life of the project, when applied to the sum of the under collected revenues (less tax impact) that are incurred during the first three project years. Detailed deferral rate calculation back-up has not yet been received from ANR, however, the ANR results as shown in its summary schedules and the described methodology used to calculate same appear reasonable.

See Exhibit 5 for the ANR analysis summaries on SITCO and SunShine. See Exhibit 6 for complete check model output applicable to these validation tests for SITCO and SunShine. Specific Schedules 1 through 4 include (1) Cost of Service; (2) Rate Base and Return; (3) Deferred Income Taxes, and (4) Income Taxes for Cost of Service are included separately for SITCO and SunShine.

No additional cases that incorporate the previously discussed potential capital cost adjustments or, more importantly, the potential increase in estimated A&G and O&M expenses for both SITCO and SunShine, have, as yet, been run. However, it should be noted that the costs of service and, in turn, the rates for both SITCO and SunShine may increase some 10% (or alternatively, the rates might 'cap out') if the operating expense is understated to the extent discussed above.

This concludes the initial report. As to additional matters to be addressed in the final report, they include: (1) alternate cost of service and rate analyses incorporating the above referenced increased operating expenses; (2) the test of an alternate system design and cost estimate based on a 26" main line system, and (3) a maximum expansion case for the proposed 30"/24" system. If you have any questions regarding this initial technical and economic analysis or the proposed additional items to be incorporated in the final report, please advise.

Very truly yours,

John J. Hibbs

Enclosures

XC: Mr. Dale Williams

This first pass, grass roots estimate was certainly not intended to be the last word, but it should give rise to the question of the adequacy of the ANR estimate of $3.3 million to cover both O&M and A&G expenses for both SITCO and SunShine. Given the rather significant impact that the O&M and A&G can have on the cost of service, it is recommended that a detailed line item estimate that gives weight to the SunShine operating plans (*e.g.*, lease versus ownership, amount of administrative support to be supplied by others, the amount of contract work anticipated, etc.) be developed, agreed to among the parties, and then incorporated in relevant certificate application filings.

Compressor Fuel

Compressor fuel, *per se*, does not appear within the ANR financials as an operating expense since it is proposed to extract that expense in kind. However, as noted in the Facility Design portion of this report, compressor fuel consumption was estimated to total some 4.2 MMCFD at the full buildup, nominal throughput level of 504.5 MMCFD. This is 0.8% and well below the proposed 1.5% cap.

COST OF SERVICE AND RATE ANALYSIS

An independent financial model was used to validate the twenty five year average cost of service and twenty five year average 100% load factor "rate" (i.e., the total cost of service divided by the total contract volume) for both SunShine and SITCO. The debt/equity ratio, return on debt, return on equity, and federal and state tax rates were held constant. Specific values used included a 75% - 25% debt - equity ratio; 14.25% return on equity; 10% interest on debt; 34% FIT rate, and a 5.5% state tax rate.

Capital costs recognized in the analyses (by the year 1999 and expressed in 1994 dollars) included $463.7 million for SunShine and $173.7 million for SITCO. Note that these values are slightly different from those included in the separate capital cost estimates also furnished by ANR (*i.e.*, $464.4 million for SunShine and $177.3 million for SITCO). Also note that this validation analysis accepted the previously discussed O&M expense estimates which were based on unit costs of $3000 per mile of pipe and $54 per horsepower.

A comparison of the results of this check model audit with the ANR analysis is set forth below.

	ANR ANALYSES	CHECK MODEL
SUNSHINE		
Avg. Year Cost of Service	$65.4 million	$65.5 million
Cost of Service per MCF	$00.4727	$00.4732
SITCO		
Avg. Year Cost of Service	$24.2 million	$24.3 million
Cost of Service per MCF	$00.1369	$00.1374

O&M estimate of $2.2 million is obtained. Accepting this amount for O&M expense, then only $1.1 million ($3.3 - $2.2) would remain to cover all A&G expenses.

More importantly, SITCO and SunShine are not expansions of an existing pipeline with an existing infrastructure. A headquarters administrative and field support staff must be put in place unless such support is to be furnished by ANR. This gives further rise to the question of operating cost estimate adequacy.

First Pass Grass Roots Estimate

In order to obtain a better fix on this question, a "first pass" grass roots O&M and A&G cost estimate was prepared. Again, bear in mind that this was done without the benefit of knowing the proposed operating philosophy for SunShine.

Specifically, an estimate was prepared assuming (1) the establishment of an independent headquarters office with a small administrative and support staff to cover administration, accounting, gas control, and other limited support services; (2) the establishment of three district offices complete with staffs to satisfy technical and skilled job requirements in the field; (3) full automation of compressor stations and measuring stations; (4) the leasing of offices, warehouses, vehicles and equipment, and (5) the use of contract labor for unskilled services. A summary of that estimate is set forth below.

LOCATION OR COST CENTER	EMPLOYEES	SALARIES (LOADED) ($ million)	EQUIP. EXPENSES, & OTHER ($ million)	TOTAL ($ million)
Admin & Support	057	04.4	01.3	05.7
Field - O&M	057	04.2	01.1	05.3
Field - Contract Services			01.0	01.0
Supplies & Parts			00.5	00.5
TOTAL	114	08.6	03.9	12.5

The following table illustrates the allocation of this $12.5 million of operating expense between SITCO and SunShine on the basis of pipeline mileage and compares the results with the current ANR allocation.

PIPELINE	ANR ESTIMATE ($ million)	GRASS ROOTS ESTIMATE ($ million)	DIFFERENCE ($ million)
SITCO	01.0	03.5	02.5
SunShine	02.3	09.0	06.7
TOTAL	03.3	12.5	09.2

These potential differences of $2.5 million and $6.7 million for SITCO and SunShine, represent some 10% of their respective estimated annual costs of service.

Other Capitalized Costs

Although not particularly significant, ANR did not make allowance for the capitalization of select operating costs such as offices, warehouses, vehicles, spare parts, and tools, if such items are to be purchased and not rented or leased.

Project Loading

As previously noted, ANR employed loading factors of 8% for contingencies, 2.5% for overheads, and 8.64% for AFUDC. Given the size and timing of the project these percentages appear reasonable and, in fact, were utilized in the estimation of alternative facility costs.

Capital Cost Summary

In summary, while the capital cost estimate of $595 million for the 700 miles of line pipe might be overstated by some $15 million and the estimated compression cost of $32 million understated by some $4 million, it is my opinion that the overall capital cost projection of $642 million for this 30" Option I or Base Case is indeed very reasonable.

OPERATING COST ESTIMATES

ANR Estimate

No detailed operating cost estimates were included in the material furnished by ANR. However, in the ANR cost of service and rate derivation analysis for both SunShine and SITCO (and select ANR summary data included for reference at Exhibit 5), there is the notation that O&M and A&G expenses were estimated on the basis $3000 per mile of pipeline and $54 per horsepower. These are the same unit cost values that were utilized in the original SunCoast and SITCO estimates. The use of these unit costs result in a total annual O&M/A&G projection of $2.3 million for SunShine and $1.0 million for SITCO commencing upon completion of the project in 1999.

Absent knowledge of the intended SunShine operating philosophy (*e.g.*, extent of automation; lease versus ownership of offices, warehouses, shops, vehicles; employees versus contract labor; the amount of operating and administrative support to be provided by ANR), it is difficult to accurately estimate the annual operating expense for this project. However, the $3.3 million total appears low.

First, $1500 to $2000 per mile of pipeline and $50 per horsepower are unit costs frequently used within the pipeline industry to estimate O&M expenses (exclusive of A&G) for system expansion projects. Using the low side pipeline estimate of $1500 per mile and $50 per horsepower, escalating same to 1994 dollars and then applying these unit costs to the SITCO and SunShine pipeline mileage and station horsepower, an

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	832.997	1127.106	1.347	505.309	8000.000	106.703	1.728
98.000	828.248	1120.526	1.347	505.266	8000.000	106.682	1.728
99.000	823.840	1114.594	1.347	504.952	8000.000	106.683	1.728
100.000	819.828	1109.425	1.347	504.311	8000.000	106.709	1.728
101.000	816.295	1105.184	1.348	503.259	8000.000	106.768	1.728
102.000	813.406	1102.255	1.349	501.558	8000.000	106.879	1.728
103.000	811.572	1101.766	1.351	498.364	8000.000	107.106	1.728
104.000	811.727	1105.870	1.356	492.480	8000.000	107.551	1.728
105.000	814.367	1115.703	1.363	483.521	8000.000	108.262	1.728
106.000	823.464	1143.264	1.381	463.642	8000.000	109.953	1.728
107.000	836.361	1175.938	1.399	446.476	8000.000	111.562	1.728
108.000	851.212	1204.050	1.408	426.292	7763.238	112.328	1.677
109.000	891.304	1202.427	1.343	362.578	5641.301	106.343	1.219
110.000	907.177	1202.302	1.320	388.439	5664.800	104.142	1.224
111.000	907.658	1202.649	1.320	423.269	6165.864	104.117	1.332
112.000	900.689	1203.042	1.330	452.639	6793.458	105.125	1.467
113.000	890.054	1203.362	1.346	476.579	7472.960	106.647	1.614
114.000	877.960	1200.336	1.361	490.231	7994.701	108.041	1.727
115.000	870.541	1187.577	1.358	493.720	7999.999	107.757	1.728
116.000	862.642	1172.279	1.353	499.679	8000.000	107.266	1.728
117.000	855.403	1160.228	1.350	502.485	8000.000	107.021	1.728
118.000	849.041	1150.449	1.349	503.816	8000.000	106.892	1.728
119.000	843.256	1141.877	1.348	504.577	8000.000	106.807	1.728
120.000	837.876	1134.087	1.347	505.022	8000.000	106.748	1.728

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	832.826	1126.924	1.347	505.224	8000.000	106.708	1.728
122.000	828.090	1120.353	1.347	505.192	8000.000	106.687	1.728
123.000	823.693	1114.431	1.347	504.889	8000.000	106.687	1.728
124.000	819.692	1109.271	1.347	504.256	8000.000	106.713	1.728
125.000	816.168	1105.038	1.348	503.212	8000.000	106.771	1.728
126.000	813.287	1102.116	1.349	501.517	8000.000	106.881	1.728
127.000	811.468	1101.655	1.351	498.313	8000.000	107.110	1.728
128.000	811.622	1105.731	1.356	492.467	8000.000	107.552	1.728
129.000	814.057	1114.775	1.363	484.232	8000.000	108.204	1.728
130.000	823.148	1142.752	1.381	463.722	8000.000	109.944	1.728
131.000	836.121	1175.587	1.399	446.483	8000.000	111.560	1.728
132.000	849.310	1204.977	1.412	435.175	8000.000	112.716	1.728
133.000	891.295	1202.178	1.343	363.162	5650.143	106.323	1.220
134.000	906.883	1202.291	1.321	388.325	5669.856	104.181	1.225
135.000	907.305	1202.647	1.320	423.236	6174.189	104.167	1.334
136.000	900.382	1203.042	1.331	452.612	6801.555	105.167	1.469
137.000	889.714	1203.361	1.347	476.695	7484.833	106.694	1.617
138.000	877.710	1200.171	1.361	490.004	7995.162	108.059	1.727
139.000	870.304	1187.284	1.358	493.665	7999.999	107.760	1.728
140.000	862.390	1171.940	1.353	499.658	7999.999	107.267	1.728
141.000	855.176	1159.948	1.350	502.429	8000.000	107.024	1.728
142.000	848.835	1150.202	1.349	503.755	8000.000	106.895	1.728
143.000	843.068	1141.652	1.348	504.519	8000.000	106.810	1.728
144.000	837.695	1133.869	1.348	504.972	8000.000	106.751	1.728

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	832.658	1126.719	1.347	505.180	8000.000	106.710	1.728
146.000	827.933	1120.159	1.347	505.154	8000.000	106.688	1.728
147.000	823.544	1114.244	1.347	504.857	8000.000	106.688	1.728
148.000	819.550	1109.090	1.347	504.231	8000.000	106.714	1.728
149.000	816.032	1104.860	1.348	503.194	8000.000	106.772	1.728
150.000	813.153	1101.932	1.349	501.512	8000.000	106.881	1.728
151.000	811.299	1101.362	1.351	498.401	8000.000	107.102	1.728
152.000	811.435	1105.419	1.356	492.539	8000.000	107.545	1.728
153.000	813.973	1114.893	1.363	483.880	8000.000	108.231	1.728
154.000	822.967	1142.240	1.381	464.033	8000.000	109.916	1.728
155.000	835.835	1174.916	1.399	446.770	8000.000	111.531	1.728
156.000	849.025	1204.411	1.411	435.329	8000.000	112.699	1.728
157.000	889.843	1202.481	1.346	363.782	5693.878	106.554	1.230
158.000	906.062	1202.309	1.322	388.628	5694.113	104.296	1.230
159.000	906.638	1202.651	1.321	423.395	6193.635	104.259	1.338
160.000	899.763	1203.044	1.332	452.732	6820.438	105.254	1.473
161.000	889.151	1203.363	1.348	476.632	7500.679	106.774	1.620
162.000	877.383	1200.083	1.362	489.520	7995.508	108.097	1.727
163.000	870.063	1187.178	1.358	493.341	7999.999	107.783	1.728
164.000	862.180	1171.807	1.353	499.428	8000.000	107.283	1.728
165.000	854.985	1159.800	1.350	502.253	8000.000	107.036	1.728
166.000	848.659	1150.050	1.349	503.616	8000.000	106.905	1.728
167.000	842.905	1141.501	1.348	504.405	8000.000	106.818	1.728
168.000	837.551	1133.732	1.348	504.874	8000.000	106.757	1.728

/*----------END OF SEVENTH DAY----------*/

EXHIBIT 38

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 3 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	841.314	1137.566	1.346	507.018	8000.000	106.620	1.728
1.000	836.004	1130.246	1.346	506.917	8000.000	106.601	1.728
2.000	831.036	1123.519	1.346	506.635	8000.000	106.597	1.728
3.000	826.428	1117.441	1.346	506.123	8000.000	106.611	1.728
4.000	822.237	1112.132	1.346	505.314	8000.000	106.649	1.728
5.000	818.543	1107.765	1.347	504.112	8000.000	106.717	1.728
6.000	815.522	1104.756	1.348	502.250	8000.000	106.839	1.728
7.000	813.659	1104.456	1.351	498.706	8000.000	107.092	1.728
8.000	813.860	1108.823	1.356	492.531	8000.000	107.558	1.728
9.000	816.722	1119.672	1.364	482.383	8000.000	108.349	1.728
10.000	826.895	1150.191	1.384	461.072	8000.000	110.194	1.728
11.000	840.029	1182.947	1.401	444.541	8000.000	111.764	1.728
12.000	864.427	1203.498	1.386	376.917	6471.720	110.270	1.398
13.000	902.011	1202.240	1.328	356.582	5310.779	104.833	1.147
14.000	915.333	1202.265	1.309	387.635	5461.564	103.023	1.180
15.000	914.635	1202.640	1.310	423.214	5986.361	103.162	1.293
16.000	907.127	1203.039	1.321	452.669	6615.793	104.235	1.429
17.000	896.175	1203.361	1.337	476.589	7291.887	105.788	1.575
18.000	882.075	1201.777	1.357	495.406	7981.854	107.608	1.724
19.000	873.714	1189.769	1.356	496.885	7999.995	107.532	1.728
20.000	865.515	1174.723	1.351	501.951	8000.000	107.111	1.728
21.000	857.998	1162.579	1.349	504.360	8000.000	106.897	1.728
22.000	851.418	1152.729	1.348	505.364	8000.000	106.791	1.728
23.000	845.445	1144.070	1.347	505.872	8000.000	106.724	1.728
24.000	839.898	1136.186	1.347	506.116	8000.000	106.679	1.728

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	834.698	1128.923	1.346	506.156	8000.000	106.650	1.728
26.000	829.826	1122.252	1.346	505.991	8000.000	106.637	1.728
27.000	825.305	1116.230	1.346	505.577	8000.000	106.645	1.728
28.000	821.191	1110.973	1.347	504.852	8000.000	106.677	1.728
29.000	817.565	1106.652	1.347	503.726	8000.000	106.741	1.728
30.000	814.595	1103.656	1.349	501.954	8000.000	106.856	1.728
31.000	812.700	1103.149	1.351	498.657	8000.000	107.090	1.728
32.000	812.859	1107.382	1.356	492.588	8000.000	107.549	1.728
33.000	815.646	1117.900	1.364	482.951	8000.000	108.314	1.728
34.000	825.319	1146.929	1.383	462.348	8000.000	110.074	1.728
35.000	838.302	1179.571	1.400	445.534	8000.000	111.661	1.728
36.000	853.001	1207.651	1.409	426.238	7781.519	112.443	1.681
37.000	897.186	1202.390	1.335	359.388	5460.996	105.520	1.180
38.000	911.625	1202.280	1.314	387.846	5551.315	103.530	1.199
39.000	911.402	1202.643	1.315	423.216	6068.909	103.604	1.311
40.000	904.121	1203.041	1.325	452.654	6698.506	104.649	1.447
41.000	893.306	1203.361	1.341	476.583	7376.503	106.190	1.593
42.000	880.055	1201.170	1.359	492.924	7991.591	107.830	1.726
43.000	872.212	1188.757	1.357	495.348	7999.998	107.641	1.728
44.000	864.163	1173.592	1.352	500.852	8000.000	107.186	1.728
45.000	856.773	1161.474	1.350	503.467	8000.000	106.956	1.728
46.000	850.296	1151.657	1.348	504.627	8000.000	106.839	1.728
47.000	844.412	1143.037	1.348	505.257	8000.000	106.764	1.728
48.000	838.944	1135.198	1.347	505.596	8000.000	106.712	1.728

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	833.815	1127.981	1.347	505.714	8000.000	106.677	1.728
50.000	829.007	1121.357	1.347	505.612	8000.000	106.661	1.728
51.000	824.544	1115.382	1.347	505.251	8000.000	106.664	1.728
52.000	820.483	1110.170	1.347	504.570	8000.000	106.694	1.728
53.000	816.905	1105.890	1.348	503.483	8000.000	106.755	1.728
54.000	813.977	1102.927	1.349	501.749	8000.000	106.868	1.728
55.000	812.110	1102.419	1.351	498.513	8000.000	107.098	1.728
56.000	812.265	1106.584	1.356	492.537	8000.000	107.550	1.728
57.000	814.986	1116.796	1.364	483.201	8000.000	108.291	1.728
58.000	824.369	1145.033	1.382	463.031	8000.000	110.010	1.728
59.000	837.292	1177.662	1.400	446.043	8000.000	111.608	1.728
60.000	851.956	1205.854	1.408	426.865	7787.877	112.409	1.682
61.000	893.997	1202.479	1.339	362.024	5572.987	105.973	1.204
62.000	909.250	1202.296	1.317	388.286	5613.643	103.856	1.213
63.000	909.415	1202.647	1.317	423.280	6120.774	103.876	1.322
64.000	902.313	1203.042	1.328	452.662	6748.671	104.900	1.458
65.000	891.597	1203.362	1.344	476.586	7427.185	106.429	1.604
66.000	878.956	1200.733	1.360	491.510	7993.252	107.941	1.727
67.000	871.336	1188.137	1.357	494.496	7999.998	107.701	1.728
68.000	863.368	1172.905	1.353	500.236	8000.000	107.227	1.728
69.000	856.054	1160.816	1.350	502.956	8000.000	106.990	1.728
70.000	849.638	1151.021	1.349	504.205	8000.000	106.866	1.728
71.000	843.806	1142.427	1.348	504.903	8000.000	106.786	1.728
72.000	838.384	1134.614	1.347	505.296	8000.000	106.730	1.728

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	833.296	1127.426	1.347	505.458	8000.000	106.693	1.728
74.000	828.526	1120.830	1.347	505.393	8000.000	106.674	1.728
75.000	824.098	1114.883	1.347	505.062	8000.000	106.676	1.728
76.000	820.068	1109.698	1.347	504.407	8000.000	106.703	1.728
77.000	816.519	1105.443	1.348	503.341	8000.000	106.763	1.728
78.000	813.615	1102.501	1.349	501.628	8000.000	106.875	1.728
79.000	811.767	1102.002	1.351	498.422	8000.000	107.103	1.728
80.000	811.923	1106.128	1.356	492.502	8000.000	107.550	1.728
81.000	814.591	1116.097	1.364	483.408	8000.000	108.272	1.728
82.000	823.794	1143.907	1.382	463.421	8000.000	109.974	1.728
83.000	836.700	1176.564	1.399	446.320	8000.000	111.578	1.728
84.000	851.455	1204.731	1.408	426.650	7776.257	112.364	1.680
85.000	892.274	1202.455	1.342	362.520	5618.947	106.211	1.214
86.000	907.928	1202.301	1.319	388.402	5646.525	104.038	1.220
87.000	908.293	1202.648	1.319	423.279	6149.620	104.030	1.328
88.000	901.278	1203.042	1.329	452.652	6777.265	105.043	1.464
89.000	890.614	1203.362	1.345	476.584	7456.374	106.568	1.611
90.000	878.321	1200.480	1.361	490.695	7994.188	108.005	1.727
91.000	870.830	1187.780	1.358	494.003	7999.998	107.737	1.728
92.000	862.907	1172.509	1.353	499.880	8000.000	107.252	1.728
93.000	855.640	1160.441	1.350	502.657	8000.000	107.010	1.728
94.000	849.258	1150.657	1.349	503.958	8000.000	106.883	1.728
95.000	843.456	1142.076	1.348	504.696	8000.000	106.800	1.728
96.000	838.060	1134.278	1.347	505.122	8000.000	106.742	1.728

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	990.476	1172.918	1.182	584.757	5000.000	90.250	1.080
98.000	988.688	1170.406	1.181	585.825	5000.000	90.208	1.080
99.000	986.927	1167.953	1.181	586.820	5000.000	90.169	1.080
100.000	985.213	1165.582	1.180	587.745	5000.000	90.132	1.080
101.000	983.565	1163.317	1.180	588.595	5000.000	90.099	1.080
102.000	982.001	1161.183	1.180	589.361	5000.000	90.069	1.080
103.000	980.543	1159.213	1.180	590.020	5000.000	90.042	1.080
104.000	979.229	1157.469	1.179	590.519	5000.000	90.022	1.080
105.000	978.130	1156.072	1.179	590.746	5000.000	90.011	1.080
106.000	977.362	1155.211	1.179	590.549	5000.000	90.016	1.080
107.000	977.169	1155.305	1.180	589.529	5000.000	90.050	1.080
108.000	977.803	1156.688	1.180	587.614	5000.000	90.117	1.080
109.000	979.482	1159.743	1.181	584.461	5000.000	90.231	1.080
110.000	983.134	1166.107	1.183	578.597	5000.000	90.446	1.080
111.000	988.004	1173.629	1.185	573.831	5000.000	90.629	1.080
112.000	992.492	1179.721	1.186	571.952	5000.000	90.709	1.080
113.000	995.770	1183.598	1.186	572.233	5000.000	90.707	1.080
114.000	997.610	1185.282	1.185	573.799	5000.000	90.656	1.080
115.000	998.138	1185.189	1.185	575.907	5000.000	90.582	1.080
116.000	997.769	1184.101	1.184	577.766	5000.000	90.515	1.080
117.000	996.811	1182.365	1.184	579.446	5000.000	90.452	1.080
118.000	995.455	1180.197	1.183	580.997	5000.000	90.394	1.080
119.000	993.860	1177.798	1.182	582.393	5000.000	90.341	1.080
120.000	992.140	1175.297	1.182	583.649	5000.000	90.292	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	990.368	1172.775	1.182	584.798	5000.000	90.248	1.080
122.000	988.591	1170.277	1.181	585.862	5000.000	90.206	1.080
123.000	986.839	1167.835	1.181	586.854	5000.000	90.167	1.080
124.000	985.134	1165.476	1.180	587.776	5000.000	90.131	1.080
125.000	983.493	1163.221	1.180	588.624	5000.000	90.098	1.080
126.000	981.935	1161.095	1.180	589.388	5000.000	90.068	1.080
127.000	980.483	1159.133	1.180	590.045	5000.000	90.041	1.080
128.000	979.174	1157.395	1.179	590.541	5000.000	90.021	1.080
129.000	978.080	1156.005	1.179	590.768	5000.000	90.010	1.080
130.000	977.310	1155.135	1.179	590.587	5000.000	90.014	1.080
131.000	977.106	1155.212	1.180	589.584	5000.000	90.048	1.080
132.000	977.733	1156.586	1.180	587.667	5000.000	90.115	1.080
133.000	979.353	1159.513	1.181	584.683	5000.000	90.223	1.080
134.000	982.967	1165.856	1.183	578.740	5000.000	90.440	1.080
135.000	987.839	1173.391	1.185	573.938	5000.000	90.625	1.080
136.000	992.339	1179.510	1.186	572.028	5000.000	90.706	1.080
137.000	995.628	1183.402	1.186	572.302	5000.000	90.705	1.080
138.000	997.475	1185.094	1.185	573.869	5000.000	90.653	1.080
139.000	998.010	1185.012	1.185	575.970	5000.000	90.579	1.080
140.000	997.650	1183.938	1.184	577.821	5000.000	90.512	1.080
141.000	996.699	1182.211	1.183	579.498	5000.000	90.450	1.080
142.000	995.350	1180.054	1.183	581.047	5000.000	90.392	1.080
143.000	993.762	1177.664	1.182	582.438	5000.000	90.339	1.080
144.000	992.049	1175.173	1.182	583.693	5000.000	90.291	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	990.283	1172.659	1.182	584.838	5000.000	90.246	1.080
146.000	988.512	1170.169	1.181	585.898	5000.000	90.205	1.080
147.000	986.766	1167.736	1.181	586.887	5000.000	90.166	1.080
148.000	985.065	1165.383	1.180	587.807	5000.000	90.130	1.080
149.000	983.429	1163.134	1.180	588.654	5000.000	90.097	1.080
150.000	981.875	1161.014	1.180	589.416	5000.000	90.066	1.080
151.000	980.427	1159.056	1.180	590.072	5000.000	90.040	1.080
152.000	979.119	1157.319	1.179	590.571	5000.000	90.020	1.080
153.000	978.024	1155.927	1.179	590.802	5000.000	90.009	1.080
154.000	977.256	1155.061	1.179	590.715	5000.000	90.013	1.080
155.000	977.054	1155.140	1.180	589.613	5000.000	90.047	1.080
156.000	977.675	1156.502	1.180	587.713	5000.000	90.114	1.080
157.000	979.309	1159.466	1.181	584.668	5000.000	90.223	1.080
158.000	982.884	1165.707	1.183	578.884	5000.000	90.435	1.080
159.000	987.698	1173.158	1.185	574.121	5000.000	90.618	1.080
160.000	992.165	1179.241	1.186	572.194	5000.000	90.699	1.080
161.000	995.428	1183.105	1.186	572.456	5000.000	90.698	1.080
162.000	997.270	1184.799	1.185	574.001	5000.000	90.648	1.080
163.000	997.814	1184.740	1.185	576.067	5000.000	90.575	1.080
164.000	997.473	1183.699	1.184	577.891	5000.000	90.509	1.080
165.000	996.543	1182.004	1.183	579.553	5000.000	90.448	1.080
166.000	995.213	1179.873	1.183	581.092	5000.000	90.390	1.080
167.000	993.642	1177.505	1.182	582.478	5000.000	90.337	1.080
168.000	991.943	1175.033	1.182	583.727	5000.000	90.289	1.080

/*----------END OF SEVENTH DAY----------->

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 1 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	994.458	1178.376	1.182	582.822	5000.000	90.328	1.080
1.000	992.435	1175.522	1.182	584.043	5000.000	90.280	1.080
2.000	990.442	1172.741	1.181	585.169	5000.000	90.235	1.080
3.000	988.504	1170.054	1.181	586.216	5000.000	90.194	1.080
4.000	986.637	1167.482	1.181	587.187	5000.000	90.155	1.080
5.000	984.856	1165.042	1.180	588.079	5000.000	90.120	1.080
6.000	983.176	1162.754	1.180	588.882	5000.000	90.088	1.080
7.000	981.616	1160.651	1.180	589.573	5000.000	90.060	1.080
8.000	980.217	1158.797	1.180	590.090	5000.000	90.039	1.080
9.000	979.052	1157.319	1.179	590.322	5000.000	90.028	1.080
10.000	978.244	1156.419	1.179	590.093	5000.000	90.034	1.080
11.000	978.068	1156.575	1.180	588.951	5000.000	90.072	1.080
12.000	978.765	1158.074	1.181	586.919	5000.000	90.144	1.080
13.000	980.769	1161.804	1.182	582.921	5000.000	90.288	1.080
14.000	985.041	1169.163	1.184	576.385	5000.000	90.530	1.080
15.000	990.289	1177.107	1.186	571.787	5000.000	90.709	1.080
16.000	994.931	1183.299	1.187	570.190	5000.000	90.780	1.080
17.000	998.233	1187.129	1.186	570.691	5000.000	90.770	1.080
18.000	1000.035	1188.709	1.186	572.411	5000.000	90.713	1.080
19.000	1000.439	1188.366	1.185	574.786	5000.000	90.628	1.080
20.000	999.857	1186.923	1.184	576.913	5000.000	90.551	1.080
21.000	998.680	1184.865	1.184	578.750	5000.000	90.482	1.080
22.000	997.117	1182.412	1.183	580.396	5000.000	90.420	1.080
23.000	995.339	1179.766	1.183	581.856	5000.000	90.364	1.080
24.000	993.460	1177.055	1.182	583.164	5000.000	90.313	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	991.551	1174.350	1.182	584.355	5000.000	90.266	1.080
26.000	989.655	1171.695	1.181	585.454	5000.000	90.223	1.080
27.000	987.799	1169.117	1.181	586.478	5000.000	90.183	1.080
28.000	986.003	1166.638	1.181	587.429	5000.000	90.145	1.080
29.000	984.284	1164.278	1.180	588.304	5000.000	90.111	1.080
30.000	982.656	1162.061	1.180	589.091	5000.000	90.080	1.080
31.000	981.143	1160.017	1.180	589.769	5000.000	90.052	1.080
32.000	979.780	1158.209	1.180	590.282	5000.000	90.031	1.080
33.000	978.642	1156.762	1.179	590.517	5000.000	90.020	1.080
34.000	977.848	1155.875	1.179	590.302	5000.000	90.026	1.080
35.000	977.663	1156.001	1.180	589.217	5000.000	90.062	1.080
36.000	978.326	1157.437	1.180	587.248	5000.000	90.131	1.080
37.000	980.109	1160.714	1.182	583.809	5000.000	90.255	1.080
38.000	984.090	1167.651	1.184	577.449	5000.000	90.489	1.080
39.000	989.183	1175.437	1.185	572.735	5000.000	90.671	1.080
40.000	993.766	1181.599	1.186	571.004	5000.000	90.747	1.080
41.000	997.065	1185.459	1.186	571.408	5000.000	90.741	1.080
42.000	998.889	1187.091	1.186	573.061	5000.000	90.686	1.080
43.000	999.349	1186.860	1.185	575.319	5000.000	90.606	1.080
44.000	998.867	1185.583	1.184	577.319	5000.000	90.533	1.080
45.000	997.795	1183.681	1.184	579.080	5000.000	90.468	1.080
46.000	996.330	1181.363	1.183	580.681	5000.000	90.408	1.080
47.000	994.639	1178.835	1.183	582.110	5000.000	90.353	1.080
48.000	992.835	1176.223	1.182	583.393	5000.000	90.303	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	990.991	1173.605	1.182	584.564	5000.000	90.258	1.080
50.000	989.152	1171.024	1.181	585.647	5000.000	90.215	1.080
51.000	987.345	1168.511	1.181	586.655	5000.000	90.176	1.080
52.000	985.592	1166.089	1.181	587.593	5000.000	90.139	1.080
53.000	983.910	1163.779	1.180	588.455	5000.000	90.105	1.080
54.000	982.316	1161.604	1.180	589.231	5000.000	90.074	1.080
55.000	980.831	1159.599	1.180	589.899	5000.000	90.047	1.080
56.000	979.493	1157.824	1.179	590.405	5000.000	90.026	1.080
57.000	978.375	1156.403	1.179	590.636	5000.000	90.016	1.080
58.000	977.595	1155.529	1.179	590.430	5000.000	90.021	1.080
59.000	977.407	1155.640	1.180	589.377	5000.000	90.056	1.080
60.000	978.055	1157.049	1.180	587.438	5000.000	90.124	1.080
61.000	979.792	1160.228	1.181	584.121	5000.000	90.243	1.080
62.000	983.611	1166.875	1.184	578.029	5000.000	90.467	1.080
63.000	988.580	1174.507	1.185	573.312	5000.000	90.649	1.080
64.000	993.108	1180.625	1.186	571.505	5000.000	90.727	1.080
65.000	996.392	1184.489	1.186	571.844	5000.000	90.723	1.080
66.000	998.222	1186.146	1.186	573.450	5000.000	90.670	1.080
67.000	998.716	1185.985	1.185	575.628	5000.000	90.593	1.080
68.000	998.293	1184.807	1.184	577.553	5000.000	90.524	1.080
69.000	997.281	1182.993	1.184	579.273	5000.000	90.460	1.080
70.000	995.873	1180.754	1.183	580.847	5000.000	90.401	1.080
71.000	994.232	1178.292	1.183	582.258	5000.000	90.347	1.080
72.000	992.471	1175.739	1.182	583.527	5000.000	90.298	1.080

/*----------END OF THIRD DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	990.665	1173.170	1.182	584.687	5000.000	90.253	1.080
74.000	988.858	1170.633	1.181	585.760	5000.000	90.211	1.080
75.000	987.080	1168.157	1.181	586.760	5000.000	90.171	1.080
76.000	985.352	1165.768	1.180	587.689	5000.000	90.135	1.080
77.000	983.691	1163.486	1.180	588.544	5000.000	90.101	1.080
78.000	982.116	1161.338	1.180	589.313	5000.000	90.071	1.080
79.000	980.649	1159.355	1.180	589.976	5000.000	90.044	1.080
80.000	979.325	1157.599	1.179	590.477	5000.000	90.024	1.080
81.000	978.220	1156.193	1.179	590.706	5000.000	90.013	1.080
82.000	977.447	1155.327	1.179	590.505	5000.000	90.018	1.080
83.000	977.256	1155.427	1.180	589.473	5000.000	90.052	1.080
84.000	977.895	1156.819	1.180	587.549	5000.000	90.120	1.080
85.000	979.596	1159.922	1.181	584.334	5000.000	90.235	1.080
86.000	983.311	1166.391	1.183	578.387	5000.000	90.454	1.080
87.000	988.216	1173.951	1.185	573.642	5000.000	90.636	1.080
88.000	992.718	1180.052	1.186	571.790	5000.000	90.715	1.080
89.000	995.997	1183.923	1.186	572.092	5000.000	90.713	1.080
90.000	997.833	1185.597	1.185	573.672	5000.000	90.661	1.080
91.000	998.348	1185.479	1.185	575.805	5000.000	90.586	1.080
92.000	997.959	1184.357	1.184	577.688	5000.000	90.518	1.080
93.000	996.982	1182.593	1.184	579.383	5000.000	90.455	1.080
94.000	995.607	1180.400	1.183	580.943	5000.000	90.396	1.080
95.000	993.995	1177.978	1.182	582.344	5000.000	90.343	1.080
96.000	992.260	1175.458	1.182	583.605	5000.000	90.294	1.080

/*----------END OF FOURTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	893.554	1165.472	1.299	581.811	8000.000	102.141	1.728
146.000	893.288	1164.573	1.299	582.866	8000.000	102.081	1.728
147.000	893.022	1163.677	1.298	583.918	8000.000	102.022	1.728
148.000	892.759	1162.799	1.298	584.949	8000.000	101.965	1.728
149.000	892.505	1161.950	1.297	585.950	8000.000	101.909	1.728
150.000	892.260	1161.138	1.297	586.908	8000.000	101.856	1.728
151.000	892.028	1160.373	1.296	587.811	8000.000	101.806	1.728
152.000	891.814	1159.667	1.296	588.645	8000.000	101.760	1.728
153.000	891.624	1159.046	1.295	589.379	8000.000	101.720	1.728
154.000	891.471	1158.549	1.295	589.964	8000.000	101.688	1.728
155.000	891.378	1158.253	1.295	590.308	8000.000	101.669	1.728
156.000	891.383	1158.287	1.295	590.256	8000.000	101.672	1.728
157.000	891.518	1158.747	1.295	589.694	8000.000	101.703	1.728
158.000	891.856	1159.894	1.296	588.305	8000.000	101.779	1.728
159.000	892.459	1161.921	1.297	585.886	8000.000	101.913	1.728
160.000	893.164	1164.281	1.299	583.109	8000.000	102.068	1.728
161.000	893.778	1166.339	1.300	580.715	8000.000	102.203	1.728
162.000	894.206	1167.770	1.301	579.067	8000.000	102.296	1.728
163.000	894.428	1168.503	1.301	578.235	7999.999	102.343	1.728
164.000	894.475	1168.643	1.302	578.088	8000.000	102.352	1.728
165.000	894.401	1168.376	1.301	578.407	8000.000	102.334	1.728
166.000	894.246	1167.837	1.301	579.042	8000.000	102.297	1.728
167.000	894.037	1167.119	1.301	579.884	8000.000	102.250	1.728
168.000	893.797	1166.295	1.300	580.847	8000.000	102.195	1.728

/*----------END OF SEVENTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	893.586	1165.578	1.299	581.688	8000.000	102.147	1.728
98.000	893.317	1164.668	1.299	582.754	8000.000	102.088	1.728
99.000	893.048	1163.764	1.298	583.815	8000.000	102.028	1.728
100.000	892.783	1162.879	1.298	584.856	8000.000	101.970	1.728
101.000	892.527	1162.023	1.297	585.864	8000.000	101.914	1.728
102.000	892.280	1161.205	1.297	586.829	8000.000	101.860	1.728
103.000	892.047	1160.435	1.296	587.739	8000.000	101.810	1.728
104.000	891.831	1159.725	1.296	588.577	8000.000	101.764	1.728
105.000	891.640	1159.100	1.295	589.315	8000.000	101.723	1.728
106.000	891.487	1158.602	1.295	589.902	8000.000	101.691	1.728
107.000	891.394	1158.308	1.295	590.243	8000.000	101.672	1.728
108.000	891.401	1158.347	1.295	590.184	8000.000	101.676	1.728
109.000	891.539	1158.817	1.295	589.610	8000.000	101.707	1.728
110.000	891.886	1159.995	1.296	588.184	8000.000	101.786	1.728
111.000	892.499	1162.055	1.297	585.726	8000.000	101.922	1.728
112.000	893.211	1164.440	1.299	582.923	8000.000	102.079	1.728
113.000	893.829	1166.511	1.300	580.514	8000.000	102.214	1.728
114.000	894.257	1167.946	1.301	578.862	8000.000	102.308	1.728
115.000	894.479	1168.676	1.302	578.034	7999.999	102.355	1.728
116.000	894.522	1168.805	1.302	577.899	8000.000	102.363	1.728
117.000	894.444	1168.524	1.301	578.236	8000.000	102.343	1.728
118.000	894.285	1167.971	1.301	578.887	8000.000	102.306	1.728
119.000	894.073	1167.239	1.301	579.744	8000.000	102.257	1.728
120.000	893.829	1166.404	1.300	580.721	8000.000	102.202	1.728

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	893.568	1165.518	1.299	581.758	8000.000	102.144	1.728
122.000	893.301	1164.615	1.299	582.817	8000.000	102.084	1.728
123.000	893.033	1163.716	1.298	583.872	8000.000	102.025	1.728
124.000	892.770	1162.836	1.298	584.907	8000.000	101.967	1.728
125.000	892.515	1161.984	1.297	585.910	8000.000	101.911	1.728
126.000	892.269	1161.170	1.297	586.871	8000.000	101.858	1.728
127.000	892.037	1160.402	1.296	587.776	8000.000	101.808	1.728
128.000	891.822	1159.696	1.296	588.612	8000.000	101.762	1.728
129.000	891.632	1159.073	1.295	589.346	8000.000	101.721	1.728
130.000	891.479	1158.577	1.295	589.932	8000.000	101.689	1.728
131.000	891.386	1158.280	1.295	590.276	8000.000	101.671	1.728
132.000	891.392	1158.314	1.295	590.224	8000.000	101.673	1.728
133.000	891.526	1158.775	1.295	589.661	8000.000	101.704	1.728
134.000	891.864	1159.921	1.296	588.273	8000.000	101.781	1.728
135.000	892.474	1161.974	1.297	585.822	8000.000	101.917	1.728
136.000	893.187	1164.359	1.299	583.017	8000.000	102.073	1.728
137.000	893.806	1166.435	1.300	580.602	8000.000	102.209	1.728
138.000	894.236	1167.874	1.301	578.946	8000.000	102.303	1.728
139.000	894.459	1168.607	1.301	578.114	7999.999	102.350	1.728
140.000	894.503	1168.741	1.302	577.974	7999.999	102.358	1.728
141.000	894.427	1168.464	1.301	578.306	8000.000	102.339	1.728
142.000	894.269	1167.914	1.301	578.952	8000.000	102.302	1.728
143.000	894.057	1167.186	1.301	579.805	8000.000	102.254	1.728
144.000	893.814	1166.355	1.300	580.778	8000.000	102.199	1.728

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	893.670	1165.862	1.300	581.356	8000.000	102.166	1.728
50.000	893.392	1164.923	1.299	582.456	8000.000	102.104	1.728
51.000	893.116	1163.993	1.298	583.548	8000.000	102.043	1.728
52.000	892.845	1163.085	1.298	584.614	8000.000	101.983	1.728
53.000	892.583	1162.209	1.297	585.645	8000.000	101.926	1.728
54.000	892.331	1161.374	1.297	586.630	8000.000	101.871	1.728
55.000	892.094	1160.589	1.296	587.556	8000.000	101.820	1.728
56.000	891.874	1159.866	1.296	588.410	8000.000	101.773	1.728
57.000	891.680	1159.230	1.295	589.161	8000.000	101.732	1.728
58.000	891.524	1158.723	1.295	589.758	8000.000	101.699	1.728
59.000	891.430	1158.426	1.295	590 103	8000.000	101.680	1.728
60.000	891.438	1158.468	1.295	590.040	8000.000	101.684	1.728
61.000	891.579	1158.950	1.295	589.451	8000.000	101.716	1.728
62.000	891.942	1160.183	1.296	587.959	8000.000	101.798	1.728
63.000	892.576	1162.314	1.297	585.420	8000.000	101.939	1.728
64.000	893.299	1164.739	1.299	582.570	8000.000	102.098	1.728
65.000	893.922	1166.828	1.300	580.143	8000.000	102.235	1.728
66.000	894.351	1168.265	1.301	578.491	8000.000	102.329	1.728
67.000	894.569	1168.986	1.302	577.674	8000.000	102.375	1.728
68.000	894.606	1169.094	1.302	577.565	8000.000	102.382	1.728
69.000	894.521	1168.787	1.302	577.931	8000.000	102.361	1.728
70.000	894.354	1168.204	1.301	578.615	8000.000	102.322	1.728
71.000	894.134	1167.446	1.301	579.503	8000.000	102.271	1.728
72.000	893.883	1166.588	1.300	580.506	8000.000	102.214	1.728

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	893.617	1165.682	1.300	581.567	8000.000	102.154	1.728
74.000	893.344	1164.762	1.299	582.645	8000.000	102.094	1.728
75.000	893.073	1163.848	1.298	583.717	8000.000	102.034	1.728
76.000	892.806	1162.954	1.298	584.768	8000.000	101.975	1.728
77.000	892.547	1162.091	1.297	585.784	8000.000	101.918	1.728
78.000	892.299	1161.267	1.297	586.756	8000.000	101.864	1.728
79.000	892.064	1160.491	1.296	587.671	8000.000	101.814	1.728
80.000	891.847	1159.776	1.296	588.516	8000.000	101.767	1.728
81.000	891.655	1159.147	1.295	589.259	8000.000	101.726	1.728
82.000	891.501	1158.646	1.295	589.849	8000.000	101.694	1.728
83.000	891.408	1158.351	1.295	590.192	8000.000	101.675	1.728
84.000	891.415	1158.391	1.295	590.132	8000.000	101.678	1.728
85.000	891.554	1158.866	1.295	589.552	8000.000	101.710	1.728
86.000	891.907	1160.064	1.296	588.101	8000.000	101.790	1.728
87.000	892.527	1162.151	1.297	585.614	8000.000	101.928	1.728
88.000	893.243	1164.550	1.299	582.793	8000.000	102.086	1.728
89.000	893.863	1166.627	1.300	580.378	8000.000	102.222	1.728
90.000	894.291	1168.062	1.301	578.727	8000.000	102.316	1.728
91.000	894.511	1168.789	1.302	577.903	7999.999	102.362	1.728
92.000	894.553	1168.910	1.302	577.777	8000.000	102.370	1.728
93.000	894.472	1168.620	1.302	578.125	8000.000	102.350	1.728
94.000	894.310	1168.056	1.301	578.788	8000.000	102.312	1.728
95.000	894.095	1167.314	1.301	579.656	8000.000	102.262	1.728
96.000	893.848	1166.471	1.300	580.643	8000.000	102.207	1.728

/*----------END OF FOURTH DAY----------->

(BASE * 125%)

SUNSHINE SYSTEM; GATEWAY COMPRESSOR STATION REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	894.210	1167.698	1.301	579.216	8000.000	102.287	1.728
1.000	893.908	1166.665	1.300	580.421	8000.000	102.219	1.728
2.000	893.604	1165.636	1.300	581.624	8000.000	102.151	1.728
3.000	893.306	1164.629	1.299	582.803	8000.000	102.085	1.728
4.000	893.016	1163.655	1.298	583.945	8000.000	102.021	1.728
5.000	892.737	1162.722	1.298	585.042	8000.000	101.960	1.728
6.000	892.471	1161.838	1.297	586.083	8000.000	101.902	1.728
7.000	892.221	1161.010	1.296	587.059	8000.000	101.848	1.728
8.000	891.991	1160.251	1.296	587.955	8000.000	101.798	1.728
9.000	891.788	1159.585	1.296	588.740	8000.000	101.755	1.728
10.000	891.626	1159.057	1.295	589.362	8000.000	101.721	1.728
11.000	891.530	1158.753	1.295	589.714	8000.000	101.701	1.728
12.000	891.542	1158.807	1.295	589.636	8000.000	101.706	1.728
13.000	891.698	1159.344	1.295	588.981	8000.000	101.742	1.728
14.000	892.114	1160.760	1.296	587.270	8000.000	101.836	1.728
15.000	892.805	1163.086	1.298	584.505	8000.000	101.990	1.728
16.000	893.562	1165.630	1.299	581.524	8000.000	102.157	1.728
17.000	894.197	1167.768	1.301	579.047	8000.000	102.298	1.728
18.000	894.627	1169.212	1.302	577.391	8000.000	102.392	1.728
19.000	894.838	1169.911	1.302	576.602	8000.000	102.437	1.728
20.000	894.858	1169.958	1.302	576.565	8000.000	102.439	1.728
21.000	894.749	1169.568	1.302	577.026	8000.000	102.412	1.728
22.000	894.558	1168.901	1.302	577.808	8000.000	102.368	1.728
23.000	894.316	1168.065	1.301	578.785	8000.000	102.312	1.728
24.000	894.045	1167.137	1.301	579.867	8000.000	102.250	1.728

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	893.761	1166.171	1.300	580.996	8000.000	102.187	1.728
26.000	893.475	1165.199	1.299	582.133	8000.000	102.122	1.728
27.000	893.190	1164.241	1.299	583.257	8000.000	102.059	1.728
28.000	892.912	1163.308	1.298	584.352	8000.000	101.998	1.728
29.000	892.644	1162.411	1.297	585.407	8000.000	101.939	1.728
30.000	892.387	1161.557	1.297	586.413	8000.000	101.883	1.728
31.000	892.144	1160.756	1.296	587.359	8000.000	101.831	1.728
32.000	891.921	1160.019	1.296	588.229	8000.000	101.783	1.728
33.000	891.723	1159.370	1.295	588.995	8000.000	101.741	1.728
34.000	891.564	1158.854	1.295	589.603	8000.000	101.707	1.728
35.000	891.469	1158.553	1.295	589.951	8000.000	101.688	1.728
36.000	891.478	1158.599	1.295	589.885	8000.000	101.692	1.728
37.000	891.622	1159.092	1.295	589.283	8000.000	101.725	1.728
38.000	891.999	1160.373	1.296	587.732	8000.000	101.811	1.728
39.000	892.654	1162.579	1.298	585.106	8000.000	101.956	1.728
40.000	893.393	1165.056	1.299	582.198	8000.000	102.119	1.728
41.000	894.022	1167.169	1.301	579.746	8000.000	102.258	1.728
42.000	894.452	1168.612	1.302	578.088	8000.000	102.352	1.728
43.000	894.668	1169.326	1.302	577.280	8000.000	102.398	1.728
44.000	894.699	1169.411	1.302	577.198	8000.000	102.403	1.728
45.000	894.605	1169.074	1.302	577.599	8000.000	102.380	1.728
46.000	894.429	1168.460	1.301	578.319	8000.000	102.339	1.728
47.000	894.201	1167.673	1.301	579.239	8000.000	102.286	1.728
48.000	893.943	1166.790	1.300	580.271	8000.000	102.228	1.728

/*----------END OF SECOND DAY----------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
49.000	809.915	860.097	1188.388	1183.003
50.000	805.715	926.109	1189.044	1184.217
51.000	801.593	985.383	1188.989	1184.151
52.000	797.588	1034.375	1188.881	1184.047
53.000	793.737	1062.496	1188.795	1183.957
54.000	790.078	1074.529	1188.799	1183.961
55.000	786.657	1079.107	1188.800	1183.962
56.000	783.552	1080.699	1188.801	1183.963
57.000	780.917	1081.271	1188.801	1183.963
58.000	779.010	1081.488	1188.443	1183.401
59.000	778.359	1079.076	1166.035	1148.838
60.000	779.635	998.338	1160.659	1141.409
61.000	783.285	927.787	1160.704	1141.455
62.000	791.502	892.431	1160.741	1141.492
63.000	803.428	872.510	1160.234	1140.621
64.000	814.706	859.455	1030.836	924.595
65.000	822.783	837.233	907.395	753.900
66.000	827.142	806.486	799.007	615.199
67.000	828.200	771.004	699.988	476.152
68.000	826.992	733.314	842.652	801.262
69.000	824.504	698.006	988.917	960.470
70.000	821.185	673.662	1082.741	1058.547
71.000	817.372	661.984	1149.625	1127.926
72.000	813.317	767.458	1161.618	1142.683

/*----------------END OF THIRD DAY----------------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
73.000	809.180	860.081	1188.275	1182.825
74.000	805.052	926.062	1189.049	1184.222
75.000	800.992	985.282	1188.989	1184.151
76.000	797.042	1034.246	1188.882	1184.048
77.000	793.239	1062.449	1188.795	1183.957
78.000	789.623	1074.510	1188.799	1183.961
79.000	786.240	1079.101	1188.800	1183.963
80.000	783.167	1080.699	1188.801	1183.963
81.000	780.560	1081.271	1188.801	1183.963
82.000	778.672	1081.487	1188.357	1183.264
83.000	778.016	1078.847	1166.138	1149.012
84.000	779.269	998.492	1160.658	1141.407
85.000	782.862	927.837	1160.704	1141.455
86.000	790.839	892.457	1160.741	1141.492
87.000	802.578	872.516	1160.266	1140.674
88.000	813.790	859.447	1031.170	925.191
89.000	821.868	837.252	907.312	753.784
90.000	826.251	806.522	798.979	615.153
91.000	827.360	771.036	699.892	475.876
92.000	826.235	733.335	841.909	799.768
93.000	823.830	698.071	988.708	960.239
94.000	820.588	673.716	1082.616	1058.415
95.000	816.841	663.542	1149.070	1127.463
96.000	812.843	767.431	1161.977	1143.254

/*----------------END OF FOURTH DAY----------------->

(BASE * 125%)

EXHIBIT 38

SUNSHINE SYSTEM; DELIVERY POINT REPORT

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
0.000	817.771	771.783	1161.879	1143.022
1.000	813.158	862.191	1188.584	1183.290
2.000	808.624	927.743	1189.038	1184.208
3.000	804.212	986.891	1188.989	1184.151
4.000	799.958	1035.739	1188.876	1184.042
5.000	795.889	1063.146	1188.796	1183.959
6.000	792.040	1074.786	1188.799	1183.961
7.000	788.454	1079.191	1188.800	1183.963
8.000	785.209	1080.728	1188.801	1183.963
9.000	782.468	1081.282	1188.801	1183.963
10.000	780.493	1081.493	1188.592	1183.635
11.000	779.860	1079.472	1165.859	1148.540
12.000	781.250	998.077	1160.660	1141.412
13.000	785.361	927.704	1160.704	1141.455
14.000	794.706	892.387	1160.741	1141.492
15.000	807.424	872.499	1160.352	1140.820
16.000	818.977	859.473	1030.198	923.458
17.000	827.044	837.215	907.426	753.952
18.000	831.289	806.449	798.998	615.194
19.000	832.133	770.969	699.914	476.079
20.000	830.549	733.284	841.683	799.061
21.000	827.660	697.948	988.678	960.224
22.000	823.980	673.600	1082.546	1058.346
23.000	819.857	661.098	1149.789	1128.021
24.000	815.538	767.620	1161.384	1142.313

/*----------END OF FIRST DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
25.000	811.174	860.169	1188.439	1183.083
26.000	806.850	926.244	1189.043	1184.215
27.000	802.620	985.593	1188.989	1184.151
28.000	798.522	1034.622	1188.880	1184.046
29.000	794.588	1062.616	1188.795	1183.957
30.000	790.856	1074.577	1188.799	1183.961
31.000	787.371	1079.122	1188.800	1183.962
32.000	784.210	1080.701	1188.801	1183.963
33.000	781.528	1081.272	1188.801	1183.963
34.000	779.589	1081.489	1188.471	1183.445
35.000	778.941	1079.151	1166.005	1148.787
36.000	780.254	998.301	1160.659	1141.409
37.000	783.984	927.777	1160.704	1141.455
38.000	792.550	892.425	1160.741	1141.492
39.000	804.825	872.510	1160.244	1140.637
40.000	816.249	859.460	1030.743	924.429
41.000	824.345	837.232	907.418	753.932
42.000	828.671	806.481	799.019	615.218
43.000	829.649	771.000	699.969	476.149
44.000	828.299	733.312	842.022	799.786
45.000	825.664	697.983	988.787	960.336
46.000	822.213	673.632	1082.634	1058.437
47.000	818.287	661.347	1149.766	1128.019
48.000	814.135	767.553	1161.452	1142.421

/*----------END OF SECOND DAY---------->

pipe cost. Therefore, it is concluded that the overall ANR estimate of cost for line pipe, while slightly conservative, is certainly reasonable.

Compression

ANR has identified the need for 8000 horsepower on SITCO at the Gateway Station plus 8000 HP and 5000 HP each at SunShine Stations 3 and 6, respectively. The cost of this horsepower was estimated at $12.3 million for SITCO and $20.0 million for SunShine. ANR prepared these estimates by employing a unit cost amount of $1538 per HP, which, in turn, was previously used by ANR in its SunCoast estimate.

On a 1994 dollar, fully loaded basis, the $1538/HP is, in my opinion, right on target for turbine horsepower. However, ANR has proposed the installation of reciprocating horsepower at SunShine's Station 6. While the design audit does not indicate the need for (more expensive) reciprocating compression at this location, should such compression, in fact, be installed, then the cost for this 5000 HP is, in my opinion, somewhat low.

I estimate the current direct cost of reciprocating compression for this sized station at $2000 per HP or $2400 per HP on a fully loaded, 1994 dollar basis. Using this amount for comparison purposes, a potential capital cost estimate difference (underage) of some $4 million was generated.

Metering and Communications

ANR estimated the project metering and communications costs as follows:

	METERS	COMMUNICATIONS
SITCO	$4.0 million	$0.6 million
SunShine	$7.4 million	$1.6 million

No cost estimate details were available to support these estimated capital expenditures for metering and communications, however, both projections appear reasonable.

As to metering and associated regulation, the projected 18 M&R stations would average some $600,000 per installation based on the ANR estimate. While the main line custody transfer meters at Pascagoula and Okaloosa may approach $2 million each, many of the delivery stations will be measuring low volumes, particularly on SITCO, at a station cost well under $500,000 each. Thus, the total of $11.4 million for measurement is not out of line.

As to the cost of system communications, the projected $2.2 million should be adequate to cover both SITCO and SunShine communications and SCADA (including compressor station automation) requirements assuming that the back bone communications network will be either leased land line based or satellite based.

24" Main Line

ANR has proposed 24" for the main line south of the 20" Anclote lateral tee. This 71 miles of 24" between the Anclote take-off and the 16" SEC Hardee lateral take-off is estimated to cost approximately $56 million or $789,000 per mile.

As with the 30", while certain line item details of ANR's estimate appear slightly high or slightly low, the overall estimate of $789 million per mile appears reasonable. For comparison purposes, PCS estimated a unit cost of $792 million per mile for the 24" pipe in its SunCoast analysis.

Lateral Lines

In addition to the 30" and 24" main line, there are 63 miles of 20", 14 miles of 16", 21 miles of 10", 7 miles of 8", and 21 miles of 4" lateral lines proposed for SITCO and SunShine. ANR has estimated the capital cost of these laterals at $20.0 million for SITCO and $52.5 million for SunShine. ANR utilized the following unit amounts in its capital cost estimate:

- 20" - $635,000 per mile;
- 16" - $591,000 per mile;
- 10" - $438,000 per mile;
- 08" - $419,000 per mile;
- 04" - $378,000 per mile.

On a per mile basis, the cost estimates for the 20", 16", and 10" laterals seem reasonable. As with the previously discussed 30" and 24" main line cost estimates, there may be room to quibble with individual cost estimate components, but the total cost per mile estimates are within reason.

On the other hand, the costs of the 8" and 4" laterals, estimated to average $419,000 per mile and $378,000 per mile, respectively, seem very high. While the proposed rights of way for these laterals have not been viewed, I find it difficult to believe that these small diameter lines will cost this much per mile unless there are extremely difficult R/W or other installation conditions to be dealt with.

However, even if the costs per mile of these small diameter lateral lines are significantly overstated, the overall pipe cost will not be materially affected due to the dampening effect of the main line costs. See following Line Pipe Cost Summary.

Line Pipe Cost Summary

To test the sensitivity of the pipe costs, select modifications to the main line and lateral cost estimates were made, reflecting, what I considered to be more reasonable assumptions for lay costs, material costs, R/W costs, etc. These hypothetical adjustments totaled $5.9 million for the main line and $8.9 million for the laterals. This total of $14.8 million represents only 2.5% of the total $595.4 million ANR estimate for

CAPITAL COST ESTIMATES

General

The ANR capital cost estimates for both SunShine and SITCO were prepared using unit cost data originally developed for the SunCoast project. ANR did, however, adjust the pipeline cost estimates to reflect a reduction in anticipated wetlands construction (requiring the use of concrete coated pipe) from 50% of total length to 20% of total length. This revision by ANR is consistent with the July 1992 projection of Mr. Paul Macy of Pipeline Construction Services, who prepared an independent SunCoast capital cost estimate for Mr. E. J. Burgin. This independent analysis was addressed in my original August 1992 report on SunCoast.

The following additional design and cost estimate assumptions and conditions should also be noted:

- All cost estimate data are expressed in 1994 dollars and are fully loaded unless otherwise indicated;

- ANR loading factors included 8% for contingency, 2.5% for overheads, and 8.64% for AFUDC. Referenced adjustments reflect these same loading conditions;

- The general pipeline design and associated cost estimates for the large diameter pipe assumed a 1200 PSIG MAOP and the use of X-65, DSAW line pipe at a base price of some $700 per ton, and

- The main line routes for SITCO and SunShine were assumed to generally track the formerly proposed SITCO and SunCoast routes, where applicable.

30" Main Line

ANR estimated the capital cost of the 148 miles of main 30" SITCO pipeline between its origination point at Pascagoula and the terminus at Okaloosa at $140.3 million and the capital cost of the 345 miles of main 30" SunShine pipeline from Okaloosa to the 20" Anclote lateral take-off at $327.1 million. ANR utilized a unit cost of $948,000 per mile to develop this estimate.

While there may be certain minor infirmities within the ANR cost estimate breakdown (*e.g.*, rights of way acquisition and damage cost and pipeline lay cost appear somewhat high), the total overall estimate of $948,000 per mile appears reasonable. This opinion, of course, is based on the previously noted 20% wetlands construction assumption. For a comparison of several recently prepared cost estimates for 30" pipe applicable to the U. S. southeast gulf coast region, see Exhibit 4.

The Transient Flow Pipeline Simulation Model

In order to audit the design of the combined SITCO and SunShine system, a transient flow model, using Stoner's Drem Pipeline Simulator ("DPS") was created. Transient analysis was necessary due to the widely varying hourly flow conditions projected for this system. For example, the total system hourly load varies from a low of 15 MMCF per hour to a high of 33 MMCF per hour. Hourly flows at certain individual delivery points are estimated to vary as much as 500% within a 24 hour period.

Design Audit Results

First, a seven day - twenty four hour per day base case was developed for the ANR referenced 30" Option I for the year 1999. Set forth at Exhibit 3 (Base Case) are the results of this analysis. You will note, given the proposed facilities and the projected hourly load pattern, that the minimum pressure encountered during the seven day simulation was 554 PSIG and that minimum pressure occurred at the SEC Hardee delivery point. Allowing for a 10 PSIG drop through the M&R station, the delivery pressure would be 544 PSIG, which is safely above the contract minimum of 450 PSIG.

Note that fuel consumption for this Base Case is estimated at 4.2 MMCFD or 0.8% of nominal throughput.

Secondly, an alternate case was developed to test the maximum capability of the proposed facilities. For this purpose, the power generation loads on the southern end of the system (Anclote, FPC Power Park and SEC Hardee) were ramped up until the lowest observed pressure dropped below the 450 PSIG minimum. Set forth at Exhibit 3A (Base Case X 103%) are the results of a scenario that approximates this maximum throughput condition. You will note that when the hourly Anclote, Power Park and Hardee loads were increased some 3%, the minimum observed pressure dropped to 472 PSIG. Again, allowing for a ten pound drop through the M&R station, the delivery pressure dropped to 462 PSIG, only 12 PSIG above minimum. Stated differently, this scenario demonstrates that the proposed facilities will operate within some 3% of their maximum design capability at the proposed hourly load conditions.

You will also note that the estimated fuel consumption for this scenario increased to approximately 4.5 MMCFD or 0.9% of nominal throughput.

Design Conclusions

The short answer is that the proposed system design is adequate to meet relevant load and pressure conditions. In fact, the design appears to be very close to optimal.

• a cost of service and rate derivation validation for both SunShine and SITCO utilizing a financial check model independent of any recommended adjustments to the capital or operating cost estimates.

MAJOR FINDINGS

• As a general observation, no major flaws in design, capital cost estimates, cost of service or rates for either SunShine or SITCO were observed.

• Facility designs for SunShine and SITCO are appropriate. In fact, the design is close to optimal.

• The capital cost estimates of $464 million for SunShine and $177 million for SITCO are reasonable.

• The combined annual operating cost estimate for SunShine and SITCO, $3.3 million, may be understated by some $9 million, or 10% of the total cost of service.

• Basic cost of service and rate derivation analyses by ANR were generally validated.

FACILITY DESIGN

Input Conditions

The basic design parameters and conditions defined by ANR are incorporated within Exhibits 1 and 2 and were utilized as direct input to this audit model. These input data include pipe segment lengths and diameters, horsepower amounts and locations, hourly loads by delivery point, and select design criteria.

While ANR did not provide (1) an estimate of yard piping pressure drops at each of the compressor stations; (2) an estimate of meter station pressure drops, or (3) an estimate of compressor efficiency, it was assumed for the purpose of this design audit that there would be a 5 PSIG loss into and a 5 PSIG loss out of each compressor station; a 10 PSIG drop through each meter station, and an overall compressor efficiency of 78%. Also note that compressor fuel was calculated utilizing a 9000 BTU per brake horsepower hour heat rate.

Further, the Stoner model incorporates the Benedict-Webb-Rubin-Starling equation for compression calculations and the Colebrook-White equation for flow and pressure drop calculations.

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JOHN J. HIBBS, President

(713) 893-9784

An Energy Services Company

November 30, 1992

Florida Power Corp.
P.O. Box 14042
St. Petersburg, Florida 33733

ATTN: Mr. Stephen Watsey, Vice President

RE: **SunShine Pipeline Project - Initial Report**

Dear Mr. Watsey:

Pursuant to your requests of November 9 and 17, 1992, our Consulting Services Agreement dated August 1, 1992, and my November 17, 1992 proposal regarding a technical and economic analysis for the above captioned project, there is set forth below the initial or preliminary report.

STUDY OBJECTIVES

The study objectives were to evaluate, from both technical and economic perspectives, the newly proposed ANR projects, SunShine Pipeline Company ("SunShine") and SunShine Interstate Transmission Company ("SITCO").

The specific case to be tested was the so called 30" Option I or Base Case for the year 1999 with an associated nominal throughput of 504.5 MMCFD. For SunShine the proposed facilities include 503 miles of various diameter pipelines and 13,000 horsepower at an estimated cost of $464 million. For SITCO, the proposed facilities include 197 miles of various diameter pipelines and 8000 horsepower at an estimated cost of $177 million. See Exhibit 1 for basic system configuration and cost estimate summaries provided by ANR.

Specific project deliverables to be provided in this preliminary report were:

- a design audit and opinion on the proposed facilities for both SunShine and SITCO utilizing a transient flow pipeline simulation model;

- a review of and opinion on the capital cost and operating cost estimates for both SunShine and SITCO independent of any recommended design modifications, and

disproportionately (as a function of the cost of debt and the debt/equity ratio) as the total plant cost varies.

FGT SUMMARY

As a result of performing a cursory review of the proposed FGT Phase III system expansion as set forth at its Application at FERC Docket No. CP 92-182-001, it appears that:

- the estimated cost of compression is likely understated by $36.0 million;

- the estimated cost of laying the 403 miles of 36" line pipe may be understated by $26.6 million, and

- the AFUDC will likely run 7% to 8%, not 3.7% .

The aggregate capital amount, in 1994 dollars, associated with all three of these items as well associated increases in overheads and contingency (and described above as Case II), is some $104.5 million. When added to FGT's currently estimated gross plant figure of $873.2 million (which includes the Transco Mobile Bay pipeline investment), the potential gross plant investment increases to $977.7 million.

Assuming FGT's financial structure remains the same as set forth in its Application Exhibits L and P (except for debt which was adjusted to 10% to make same consistent with the SunCoast debt cost assumption for comparison purposes) and applying same to the $977.7 million of adjusted gross plant, the resulting initial reservation demand charge would be expected to increase to 85¢ per MMBTU. Alternatively, if the reservation demand charge is fixed at the 75¢ level as set forth in the Application, then the return on equity would be expected to drop to 9.9%.

-- END --

See Exhibit 10, Schedules 0 throug 4 for complete check model output applicable to this validation test.

Having validated the FGT results, additional cases incorporating the potential capital cost adjustments previously discussed were then run to test the impact on the rate reservation charge, or alternatively, the return on equity. It should be noted that in all cases it was assumed that the project variable costs and, in turn, the commodity charge would not vary.

The first alternative, Case I, incorporated the potential increase in horsepower cost and the projected increase in AFUDC. Also included was an increase in the assumed cost of debt from 9% to 10% (making same consistent with the SunCoast debt cost assumption). The second alternative , Case II, was identical to the first alternative case except that the potential 36" pipeline lay cost increase was added to gross plant.

These two cases were then run on the check model to determine (1) the potential impact on the reservation rate assuming no change in return on equity and, alternatively (2) the potential impact on the return on equity assuming a fixed cost of service and rate reservation charge. The results of these analyses are set forth in the tables below.

PROJECTED COST OF SERVICE AND RATES HOLDING RETURN ON EQUITY AT 14.25%

	COST OF SERVICE (Years 1 - 16)	RESERVATION DEMAND CHARGE (Years 1 - 16)
CASE I	$164,551,000	$00.8234/MMBTU
CASE II	$169,092,000	$00.8468/MMBTU

PROJECTED RETURN ON EQUITY HOLDING COST OF SERVICE AT $151.0 MILLION AND RESERVATION CHARGE AT $0.7534

	RETURN ON EQUITY (Years 1 - 16)
CASE I	10.9%
CASE II	09.9%

As shown above, if the potential capital cost increase applicable to the cost of horsepower and AFUDC are recognized along with an increase in the debt cost to 10% (i.e., Case I), then the reservation demand charge for years 1 - 16 should increase from the FGT estimated 75¢ per MMBTU to approximately 82¢ per MMBTU or, alternatively, the resultant return on equity should decrease from the target 14.25% to approximately 10.9%.

If the potentially understated 36" lay cost is also recognized (Case II), then the reservation demand charge should increase to 85¢ per MMBTU or, alternatively, the return on equity will drop to 9.9%.

See Exhibit 10, Schedules 5 through 7 for the cost of service and rate analyses work sheets applicable to these Cases I and II tests.

In summary, it should first be noted that no major discrepancies in the FGT cost of service calculations or rate derivations were observed. Secondly, any change in capital cost assumptions has an approximately equal impact on both the estimated cost of service and the reservation demand charge, assuming the same through-put volumes or billing units and the same underlying project financial structure. However, if the cost of service and the reservation rate are "frozen" and the return on equity becomes the variable, then the return on equity will vary inversely and

CAPITAL COST ITEM	CASE I ADJUSTMENT FOR HP & AFUDC ($000)	CASE II ADJUSTMENT FOR 36" LAY, HP & AFUDC ($000)
FGT Base Cost Estimate	712,901.4	712,901.4
Direct Cost Adjustments		
Horsepower	036,014.1	036,014.1
36" Lay Cost		026,634.9
Adjusted Base Cost	748,915.5	775,550.4
Contingency (@ .09049)	067,769.4	070,179.6
Filing Fee	000,034.5	000,034.5
Adjusted Direct Cost	816,719.4	845,764.5
Overheads (@ .03669)	029,965.4	031,031.1
AFUDC (@ .075)	061,254.0	063,432.3
Total Adjusted Loaded Cost	90[illegible]938.8	940,227.9
FGT Loaded Cost	835,700.0	835,700.0
POTENTIAL COST INCREASE	072,238.8	104,527.9

OPERATING COST ESTIMATE

There is limited operations and maintenance cost information in FGT's Application. Page 6 of Exhibit P (and enclosed herewith as Exhibit 9) illustrates annual estimated O&M expenses by FERC Account Number. The total O&M expense is estimated at $18,180,000 of which $7.7 million is applicable to Account 858, transportation and compression expense by others, and $2.9 million represents administrative and general expense. The balance of these estimated annual O&M expenses is $7.5 million.

Utilizing gas transmission "rule of thumb" O&M estimates of $1500 per mile of transmission line and $50 per horsepower, escalating same to 1994 dollars and then applying these unit values to the 780 miles of pipeline and 88,500 horsepower, results in an annual total in excess of $6 million. Thus, the above referenced $7.5 million seems reasonable.

COST OF SERVICE AND RATE ANALYSIS

First, an independent financial model was used to validate the cost of service and rates projected by FGT and set forth in its Application Exhibits L and P. A comparison of the results of this check model, using the same input parameters, with the Exhibit L and P projections is set forth below.

	FGT APPLICATION	CHECK MODEL
ANNUAL COST OF SERVICE		
Years 1 - 15	$150,968,000	$150,976,000
Years 16 - 25	$089,992,000	$089,890,000
RATES (FTS-2)		
Years 1 - 15		
Demand Reservation Charge	$00.7534/ MMBTU	$00.7534/MMBTU
Commodity Charge	$00.0325/ MMBTU	$00.0325/MMBTU
Years 16 - 25		
Demand Reservation Charge	$00.4393/ MMBTU	$00.4387/MMBTU
Commodity Charge	$00.0325/ MMBTU	$00.0325/MMBTU

Without question, 30" lay costs can certainly exceed 36" lay costs. For example, the unit cost to lay 30" concrete coated pipe in wetlands might exceed the unit lay cost for 36" constructed on dry land by 50% or more. However, there is nothing in the FGT Application Exhibit K that would explain why the 403 miles of 36" lay cost should average less than the comparable cost for the 288 miles of 30". Therefore if it is assumed that the rights of way conditions for both the 36" pipe and 30" pipe are generally similar (i.e., approximately 25% of the rights of way will be in wetlands and thus concrete coated pipe will be required), then I would expect the 36" lay cost to average approximately $70 per foot or $370,000 per mile in 1994 dollars, some 15% more than the 30" lay cost.

If this $370,000 per mile lay cost is applied to the 403 miles, then the total direct cost, less contingency, of the 36" will increase from $347.4 million or $861,000 per mile to $374.0 million or $927,700 per mile. This is a potential direct capital cost increase of $26.6 million.

Horsepower

FGT has requested authorization for the addition of 89,570 horsepower and the removal of 1070 horsepower at a total of twelve compressor stations for an estimated total direct cost (excluding contingency) of $99,068,800 in 1994 dollars.

Following is a summary of the horsepower requirements by type and cost as set forth in Exhibits G and K.

TYPE	AMOUNT	DIRECT COST	COST PER HP
Centrifugal	60,570	$55,062,400	$0909
Reciprocating	29,000	$44,006,400	$1517

It is my opinion that both the reciprocating and turbine driven centrifugal horsepower costs are understated. More realistic estimates for both turbine driven centrifugal compression and reciprocating compression are $1200 and $1800 per horsepower, respectively, in 1992 dollars. Escalated to 1994 dollars, at 4% year, these same values become $1298 and $1947 per horsepower. Further, when these adjusted unit capital costs are applied to the quantities of horsepower shown above, the estimated total direct capital cost for horsepower increases from $99,068,800 to $135,082,900, excluding contingencies. This is a potential capital cost estimate increase of $36,014,100.

AFUDC

FGT projects project loading of approximately 17.2% covering contingencies, AFUDC, overheads and filing fees. The AFUDC is estimated at 3.67% of the direct capital cost including contingency (at 9.05%) and the FERC filing fee. Absent a project monthly or quarterly cash flow schedule, AFUDC is difficult to accurately forecast. However, the estimated 3.67% appears understated.

Given the anticipated return on this project and assuming that the project expenditure schedule for major capital items (including engineering and environment expense, progress payments for long lead time equipment and materials as well as charges for project construction and other material and equipment payments) spans up to one and a half years, the AFUDC would more likely be in the 7 to 8% range.

Summary - Potential Capital Cost Adjustments

Set forth below are two capital cost adjustment summaries. The first column, Case I, illustrates the potential capital cost impact when adjusting for the above described horsepower cost and AFUDC. The second column, Case II, incorporates the additional impact of increasing the 36" lay cost estimate.

and some 88,500 horsepower additions to that portion of its system located in the states of Louisiana, Mississippi, Alabama, and Florida. FGT states that the proposed facility additions are required to satisfy its new incremental load of 523 to 541 MMCFD. The total capital cost of these facilities (per FGT Application Exhibit K) is estimated at $835,700,000 on a fully loaded basis and expressed in 1994 dollars. The FGT Exhibit K is enclosed herewith for reference as Exhibit 8.

FGT's Application Exhibit K (capital cost estimate), Exhibit L (financing) and Exhibit P (rates) were reviewed. The facility design, as set forth at Exhibit G, was not reviewed. Following is a summary of the findings of this analysis.

CAPITAL COST ESTIMATE

The predominant focus of this cursory facility cost review was the 403 miles of 36" pipeline, the 288 miles of 30" pipeline and the 89,570 horsepower (gross), which together, represent some 95% of the total project cost. Note that this cursory review was simply that - a quick review of an existing estimate looking for potentially major facility cost flaws. The objective was not to reestimate the cost of the entire project on a line item basis. Should FPC subsequently decide to evaluate this FGT project on a more detailed basis, then a review of the subject Environmental Report, an on-site inspection of existing and proposed pipeline rights of way and a detailed analysis of the basic design criteria would be in order. Also note that unless otherwise stated, the following costs are stated in 1994 dollars assuming a 4% escalation factor.

288 Miles of 30"

Key components of the 30" pipeline cost estimate were reviewed. Note that for the purpose of testing the pipeline material and construction costs, it was assumed that approximately one fourth of the rights of way would be wetlands situated requiring the installation of concrete coated pipe.

While one might quibble with specific components of the FGT pipeline cost estimate, the overall capital cost for this 288 miles of 30" pipeline appears within reason. FGT estimates the direct cost, without contingency, at $236,050,870 or $820,000 per mile. When the contingency, overheads and AFUDC are added, the loaded cost increases to some $960,000 per mile. This value is very close to ANR's current SunCoast 30" estimate of $1,000,000 per mile on a fully loaded basis.

Further, the FGT estimated cost on a per mile basis is almost identical to the cost projected by Mr. Paul E. Macy of Pipeline Construction Services, Inc. ("PCS"), an independent consultant retained by Mr. E. J. Burgin to perform a detailed, independent review of the SunCoast capital cost estimate. PCS estimates the SunCoast 30" segment, when fully loaded, at approximately $880,000 per mile in 1992 dollars or $950,000 in 1994 dollars.

Without the benefit of additional input that might be derived from a more exhaustive, in depth review of the FGT Application, a review of the Environmental Report and an on-site R/W evaluation, I believe that the FGT cost estimate for 288 miles of 30" is reasonable.

403 Miles of 36"

FGT estimated, on a direct cost basis, the 403 miles of 36" at $347,402,200 or $861,600 per mile. This is only some 5% greater than the corresponding cost of 30" line pipe on a per mile basis. Assuming the same general rights of way conditions for the 36" as was projected for the 30", I would have expected the 36" cost to average, on a per mile basis, 10 to 20% more than the comparable 30" cost. The 36" material and lay cost estimates were then reviewed and while the 36" material cost estimate was approximately 17% greater than the corresponding 30" material cost estimate ($369,000 versus $315,000 per mile), the lay cost for the 36" was estimated to be only $304,000 per mile. This is less than the $324,000 per mile estimated lay cost for the 30".

COST OF SERVICE AND RATE ANALYSIS

First, an independent financial model was used to validate the twenty year average cost of service and twenty year average 100% load factor "rate" (i.e., the annual cost of service divided by 365 times the daily contract volume) for both SunCoast and Sitco. The debt/equity ratio, return on debt, and return on equity were held constant. A comparison of the results of this check model effort with the UGPL analyses is set forth below.

	UGPL ANALYSES	CHECK MODEL
SUNCOAST		
Avg. Year Cost of Service	$142.0 million	$142.7 million
Avg. Rate at 100% Load Factor	$00.5755/MMBTU	$00.5783/MMBTU
SITCO		
Avg. Year Cost of Service	$10.7 million	$10.8 million
Avg. Rate at 100% Load Factor	$00.0435/MMBTU	$00.0437/MMBTU

The results of this comparison are obviously close.

Note that while the so called "rate after deferral" for SunCoast and Sitco ($0.6091 and $0.0460, respectively) were not specifically checked, the methodology used to calculate same appeared reasonable.

See Exhibits 5 and 6 for the UGPL analyses on SunCoast and Sitco, respectively. See Exhibits 7 and 7A for complete check model output applicable to these validation tests for SunCoast and Sitco, respectively. Specific Exhibit 7 and 7A Schedules include (1) Cost of Service; (2) Rate Base and Return; (3) Deferred Income Taxes, and (4) Income Taxes for Cost of Service.

No additional case that incorporated the previously discussed potential downward capital adjustment of $33 million with the potential increase in estimated A&G and O&M expense was run. However, given the opposite directions of these two potential adjustments, little change in the average cost of service or rate would be anticipated.

SUNCOAST & SITCO SUMMARY

As a result of performing a facility design audit, reviewing capital cost estimates prepared by ANR and UGPL, and performing a financial audit of the cost of service and rate derivation analyses, it appears that:

- the facility design of SunCoast and Sitco are acceptable, if somewhat conservative, however, there are several refinements or adjustments to the UGPL model that should be considered before running any final design;

- the capital cost estimate for Sitco, $73 million, is reasonable but the estimate for SunCoast, $931 million, may be overstated by some $33 million (assuming 20% wetlands construction);

- the O&M and A&G cost estimate for SunCoast, $7.1 million, is likely understated by several million dollars and a detailed line item estimate for this operating expense should be prepared, and

- the cost of service and rate derivation analyses for SunCoast and Sitco as prepared by UGPL are generally accurate.

FLORIDA GAS TRANSMISSION - PHASE III

The proposed Florida Gas Transmission ("FGT") Phase III System Expansion, as set forth at FERC Docket No. CP 92-182-001, consists of some 780 miles of various sized pipeline additions

First, $1500 to $2000 per mile of pipeline and $50 per horsepower are unit costs frequently used within the pipeline industry to estimate O&M expenses (exclusive of A&G). Using the low side pipeline estimate of $1500 per mile and $50 per horsepower, escalating same to 1994 dollars and then applying these unit costs to the SunCoast pipeline mileage and station horsepower, an O&M estimate of $6.1 million is obtained. Accepting this amount for O&M expense, then only $1 million ($7.1 - $6.1) would remain to cover all A&G expenses.

Further, SunCoast is not an expansion of an existing pipeline with an existing infrastructure. A headquarters administrative and support staff must be put in place unless such support is to be furnished by one of the equity participants. This gives further rise to the question of A&G estimate adequacy.

In order to obtain a better fix on this question, a "first pass" grass roots O&M and A&G cost estimate was prepared. Again, bear in mind that this was done without the benefit of knowing the proposed operating philosophy for SunCoast.

Specifically, an estimate was prepared assuming (1) the establishment of an independent headquarters office with a small administrative and support staff to cover administration, accounting, gas control, and other limited support services; (2) the establishment of three district offices complete with staffs to satisfy technical and skilled job requirements in the field; (3) full automation of compressor stations and measuring stations; (4) the leasing of offices, warehouses, vehicles and equipment, and (5) the use of contract labor for unskilled services. A summary of that estimate is set forth below.

LOCATION OR COST CENTER	EMPLOYEES	SALARIES (LOADED) ($ million)	EQUIP, EXPENSES, & OTHER ($ million)	TOTAL ($ million)
Admin & Support	063	05.0	01.5	06.5
Field - O&M	058	04.2	01.3	05.5
Field - Contract Services			01.5	01.5
Supplies			00.5	00.5
TOTAL	121	09.2	04.8	14.0

This first pass estimate was certainly not intended to be the last word, but it should give rise to the question of the adequacy of the SunCoast estimate at $7.1 million to cover both O&M and A&G expenses. Given the rather significant impact that the O&M and A&G can have on the cost of service, it is recommended that a detailed line item estimate that gives weight to the SunCoast operating plans (e.g., lease versus ownership, amount of administrative support to be supplied by others, the amount of contract work anticipated, etc.) be developed and incorporated in relevant certificate application filings.

Sitco

UGPL has estimated the annual O&M and A&G expense at $0.7 million by 1999. See Exhibit 6. This estimate was prepared using the same unit cost values as were used for SunCoast. Therefore this Sitco estimate is theoretically subject to several of the same potential shortcomings as SunCoast. There is, however, one significant difference - - UGPL, as I understand it, would operate the Sitco facilities and no new administrative office and staff and perhaps no new district office(s) would be required. Thus, it is likely that the existing UGPL infrastructure could support the Sitco operations more economically than could a new "free standing" or self supporting organization.

The conclusion is that the Sitco O&M and A&G estimate is likely somewhat low , but not by a significant amount. More importantly, even if the Sitco estimate was in error by a substantial margin, the overall impact on the combined Sitco and SunCoast costs of service and rates would not be significant.

As to other project capital costs, PCS and ANR vary little, if at all. ANR estimated the compression cost at $136.9 million. PCS estimated $138.2 million. PCS made no change to ANR's estimate for the cost of metering and communications and little change to the project loading factors. Although not overly significant, neither ANR or PCS made allowance for the capitalization of select O&M costs such as offices, warehouses, vehicles, spare parts, and tools, assuming such items are to be purchased and not rented or leased.

In summary, PCS estimated the capital cost of Case V at $878.5 million fully loaded and in 1994 dollars. This is $33.4 million or 3.7% less than the comparable ANR estimate of $911.9 million.

Both the ANR and PCS detailed estimates have been reviewed. Further, this matter has also been discussed with E. J. Burgin (who, incidentally, believes that the wetlands construction factor may be as low as 8% to 10% based on his prior FGT experience). However, not having conducted an on-site rights of way evaluation or prepared a detailed independent cost estimate, it is difficult to opine on the exact accuracy of these estimates. However, the PCS estimate of $878.5 million appears more realistic.

Although PCS did not provide an estimate for the "Base Case with 30" Alternative," ANR Case V-R, one can take the PCS - ANR Case V differential of $33.4 million and apply that amount to the ANR Case V-R estimate of $931.3 million to get an approximate revised cost of $897.9 million. While this "accepts" ANR's net case cost differential between Cases V and V-R of $19.4 million, it provides a reasonable estimate of the cost of Case V-R after recognizing PCS's findings.

Sitco

The capital cost estimate for Sitco, $73.0 million in 1994 dollars and fully loaded, was prepared by UGPL (Case I-R) and reviewed by ANR. This estimate included $58.9 million for 62 miles of 1200 PSIG MAOP line pipe and $14.1 million for 10,000 horsepower. See Exhibit 4.

The estimated pipeline cost averages $949,000 per mile. This is less than ANR's estimate of $1,000,000 per mile for comparable 30" and, in fact, is very close to the PCS estimate of $936,000.

As to horsepower, UGPL estimated the compression cost at a low of $1250 per horsepower to a high of $1750 per horsepower, dependent upon individual station conditions. The weighted average was $1415 per horsepower. As noted under SunCoast above, there has been no allowance for possible capitalization of spare parts, tools, etc.

Both the estimated pipeline and compression costs appear reasonable.

OPERATING COST ESTIMATE

SunCoast

There was no detailed operating cost estimate included in the material furnished by ANR and UGPL. However, in the cost of service and rate derivation analysis furnished by UGPL (and included for reference at Exhibit 5), there was the notation that O&M and A&G expenses were estimated on the basis $3000 per mile of pipeline and $54 per horsepower. The use of these unit costs resulted in a total annual O&M/A&G projection of $7.1 million commencing upon completion of the project in 1999.

Absent knowledge of the intended SunCoast operating philosophy (e.g., extent of automation; lease versus ownership of offices, warehouses, shops, vehicles; employees versus contract labor; the amount of operating and administrative support to be provided by ANR or UGPL), it is difficult to accurately estimate the annual operating expense for this project. However, the $7.1 million noted above appears low.

• Flowing gas temperature should be decreased from 85°F to approximately 80°F assuming the installation of station out gas coolers where out gas temperatures would otherwise exceed 120°F.

• The allowance for a15 PSIG drop through the M&R stations seems excessive. A 5 to 10 PSIG drop would be more reasonable.

• A pressure drop of 5 to 10 PSIG through the piping at each of the proposed compressor stations should be recognized.

• Compressor fuel should be recognized unless the compressors are to be electrically driven. This fuel consumption is estimated to be approximately 15 MMCFD assuming gas turbine drivers.

• The sum of the hourly delivery or ramping schedules needs to be reconciled with the aggregate 24 hour volume for the system. The sum of the current hourly delivery volumes exceeds the stated 710 MMCF daily total by some 15 MMCF.

• If the SunCoast design objective is to provide for no standby or spare horsepower, then the need for Station 7 should be reevaluated.

With the possible exception of the issue or question of spare horsepower, all of these items are relatively minor and it is my general opinion that even if these suggested adjustments were incorporated into the final project design, said design would not be significantly different from the preliminary UGPL design that was the subject of this audit.

CAPITAL COST ESTIMATE

SunCoast

ANR has estimated the cost of the SunCoast Base Case with 30" Alternative system (Case V-R) at $931.3 million fully loaded and in 1994 dollars. This particular case evolved from ANR's Case V which incorporated 1200 PSIG MAOP 24" line pipe south of the FPC Power Park lateral in lieu of the 944 PSIG MAOP 30" included in Case V-R. Case V was estimated by ANR at $911.9 million. The increased cost of Case V-R over Case V, $19.4 million, is attributable to the higher cost of the 30" line pipe south of the Power Park lateral. However, this increase was partially offset by the reduction in required horsepower from 89,000 to 84,000. See Exhibit 3 for ANR capital cost estimate data.

Fundamental to the ANR cost estimates for these cases, is the assumption that 50% of the pipeline will be located in swamps or other wetlands thus requiring the installation of concrete coated pipe.

Pipeline Construction Services, Inc. ("PCS") was retained by E. J. Burgin, President of SunCoast, to perform an independent audit of the ANR Case V capital cost estimate. After a detailed field reconnaissance of the entire proposed pipeline rights of way and discussions with Ecology and Environment, SunCoast's environmental contractor, PCS prepared an independent cost estimate for this Case V on a detailed, line item basis.

It is significant to note that while PCS increased the estimated length of this system from 856 miles to 892 miles, there was a decrease in the overall estimated project cost. This is principally attributable to a reduction in the anticipated amount of wetlands construction. PCS, after its on-site investigation, estimated that only 20% of the line pipe would require concrete coating. The difference in material and lay costs attributable to varying the concrete coated pipe from 50% to 20% is significant. For example PCS estimated the average cost of 30" at $936,000 per mile while ANR projected $1,000,000. Most of this variance was applicable to the 50% versus 20% issue on wetlands construction.

The basic input parameters as identified by UGPL as noted above and enclosed at Exhibit 1 were utilized as direct input to this audit model. Further, the Stoner model utilized the Benedict-Webb-Rubin-Starling equation for compression calculations and the Colebrook-White equation for flow and pressure drop calculations.

Although information about the Sitco Gateway and Miss-Al compressor stations and the Sitco 62 mile pipeline do not discretely appear as part of the model input or output data, these facilities were taken into account. These proposed facilities proved adequate to deliver the required input volumes at the required pressures at the SunCoast Walnut Hill station without exceeding (1) the Sitco MAOP of 1200 PSIG, (2) the proposed 8000 HP at Miss-Al assuming a suction pressure of 760 PSIG, and (3) the proposed 2000 HP at Gateway assuming a suction pressure of 900 PSIG.

Two basic six-day, twenty four hour per day transient flow simulations were run. The first run, consistent with the UGPL design, ignored compressor fuel (some 15 MMCFD). The second run accounted for compressor fuel. Further, an additional run was made testing hourly delivery capability without utilizing the horsepower at Compressor Station 7.

Design Audit Results

Specific results of these Stoner "Pipeline Simulator" runs are set forth at Exhibit 2, Figures 1.1 through 1.6 and Tables 2 through 10, and are briefly described below.

- Fig. 1.1: Select System Pressure and Volume Trends. Includes Fuel.
- Fig. 1.2: Select System Pressure and Volume Trends. Excludes Fuel.
- Fig. 1.3: Pressure Trends by Delivery Point. Includes Fuel.
- Fig. 1.4: Pressure Trends by Delivery Point. Excludes Fuel.
- Fig. 1.5: Select System Pressure and Volume Trends without Station 7. Includes Fuel.
- Fig. 1.6: Pressure Trends by Delivery Point without Station 7. Includes Fuel.

- Table 02: Delivery Point Pressure Report. Includes Fuel.
- Table 03: Compressor Station 1 Report. Includes Fuel.
- Table 04: Compressor Station 2 Report. Includes Fuel.
- Table 05: Compressor Station 3 Report. Includes Fuel.
- Table 06: Compressor Station 4 Report. Includes Fuel.
- Table 07: Compressor Station 5 Report. Includes Fuel.
- Table 08: Compressor Station 6 Report. Includes Fuel.
- Table 09: Compressor Station 7 Report. Includes Fuel.
- Table 10: Delivery Point Pressure Report without Station 7. Includes Fuel.

On Figure 1.2 you will note that the lowest observed pressure during the six day simulation is at Fort Lauderdale and that this minimum pressure is just under 500 PSIG. This is consistent with the UGPL model output which indicated a minimum observed pressure at Fort Lauderdale of 490 PSIG. Even when compressor fuel is added, the minimum Fort Lauderdale pressure drops only to 481 PSIG. See Figure 1.1 and Table 2. This, of course, is well above the minimum requirement of 415 PSIG (which provides for a 15 PSIG drop through the M&R station).

Figures 1.5 and 1.6 and Table 10 illustrate the results of deleting the 3000 horsepower at Station 7. The minimum pressure at Fort Lauderdale drops to 440 PSIG but, of course, it is still slightly in excess of the minimum required pressure.

Design Conclusions

The short answer is that the system design is adequate to meet the relevant load and pressure conditions. There are, however, several minor adjustments or refinements to the UGPL model that should be considered in any final design. They are set forth below.

- Compressor efficiency should be increased from 75% to 80%, even assuming the use of turbine drivers and centrifugal compressors.

FLORIDA GAS TRANSMISSION - PHASE III

- The estimated capital cost of compression is very likely low by some $36 million.

- The estimated capital cost of the 403 miles of 36" line pipe is likely understated by some $27 million.

- AFUDC, estimated at 3.7%, is likely to run 7.5%.

- The aggregate impact of adjusting for the potential increase in horsepower cost, 36" pipeline cost and AFUDC is estimated at $104 million, after project loading.

- FGT's estimated cost of service and proposed rates were validated; however, adjusting for the potential $104 million underage, results in a potential rate increase of approximately 10¢ per MMBTU or, alternatively, a decrease in the return on equity from 14.25% to 9.9% assuming the rate and return on debt are held constant.

SUNCOAST PIPELINE COMPANY
SUNCOAST INTERSTATE TRANSMISSION COMPANY

The SunCoast and Sitco project review was performed on what has been referred to as the "Base Case with 30" Alternative." For Sitco, this case included a 1200 MAOP 30" pipeline from the originating Gateway and Miss-Al compressor stations to its termination point at Walnut Hill, Florida. For SunCoast, this case assumed the installation of 1200 PSIG MAOP 30" line pipe from Walnut Hill to the FPC Power Park lateral and 944 PSIG MAOP 30" line pipe from Power Park to Fort Lauderdale. This case is also referenced as Case I-R by UGPL and Case V-R by ANR. Further, this case was the basis for the capital cost and rate projections presented to the prospective SunCoast customers and suppliers at the Tarpon Springs, Florida meeting held July 6 and 7,1992. The design test year chosen was 1999, the first full year of operation at 710 MMCFD.

The proposed SunCoast facilities, as estimated by ANR and UGPL, consist of approximately 856 miles of pipeline and 84,000 horsepower with an estimated capital cost of $931 million in 1994 dollars and on a fully loaded basis (per ANR's Case V-R estimate). Sitco, as proposed, consists of 62 miles of pipeline and 10,000 horsepower at an estimated capital cost of $73 million in 1994 dollars and on a fully loaded basis (per UGPL's Case I-R estimate).

FACILITY DESIGN

Input Conditions

The specific 1999 design conditions and assumptions as furnished by UGPL (and designated as Case I-R) are enclosed at Exhibit 1. Included in this exhibit are a listing of the constants utilized, a system schematic showing horsepower amounts and locations, pipe segment lengths and minimum observed pressures occurring during UGPL's transient flow analysis, and hourly volumes, including flexibility by delivery point.

The Transient Pipeline Simulation Model

In order to audit the design of the combined Sitco and SunCoast systems, a transient flow model, using Stoner's "Pipeline Simulator," was created. Transient analysis was necessary due to the widely varying hourly flow conditions projected for this system. For example, the total system hourly load varies from a low of 10 MMCF per hour to a high of 54 MMCF per hour. Hourly flows at certain individual delivery points are estimated to vary as much as 700%.

STUDY OBJECTIVES

The original study objectives were to evaluate from technical and economic perspectives both the proposed SunCoast Pipeline Company project and the proposed Florida Gas Transmission ("FGT") Phase III expansion project. These analyses were to be general in nature. Further, the SunCoast evaluation was to be limited to the so called "Base Case with 30" Alternative." This case is also referred to as Case I-R by United Gas Pipe Line ("UGPL") and Case V-R by American Natural Resources ("ANR"). Further, the SunCoast analysis was also to include the corresponding SunCoast Interstate Transmission Company ("Sitco") Case.

Specific work product by project to be addressed is set forth below.

SUNCOAST & SITCO

- Using a pipeline simulation model, perform a design audit of and provide an opinion on the proposed SunCoast and Sitco project facilities for the above referenced Base Case.

- Review and provide an opinion on the capital cost and operating cost estimates for the proposed SunCoast and Sitco projects for the above referenced Base Case.

- Using a financial model, check the proposed cost of service and rate calculations for the proposed SunCoast and Sitco projects for the above referenced Base Case and perform alternate cost of service and rate calculations, if applicable.

FLORIDA GAS TRANSMISSION - PHASE III

- Review and provide an opinion on the capital cost and operating cost estimates as set forth in the FGT Application Exhibits K and P.

- Using a financial model, check the proposed cost of service and rate calculations as set forth in the FGT Application Exhibits L and P and perform alternate cost of service and rate calculations, if applicable.

MAJOR FINDINGS

SUNCOAST & SITCO

- As a general matter, no major flaws in design, cost estimates, cost of service or rates were observed.

- Facility design for SunCoast is certainly acceptable, if somewhat conservative.

- Capital cost estimate of $73 million for Sitco is reasonable.

- Assuming approximately 20% wetlands construction, the estimated capital cost of $931 million for SunCoast may be overstated by some $33 million.

- Operating cost estimate for SunCoast, $7.1 million, is likely understated by several million dollars. A detailed O&M and A&G cost estimate should be prepared to obtain a more accurate fix on this potential operating expense.

- Basic cost of service and rate derivation analyses were generally validated. The cost of service and rate impact of the aforementioned overage and underage, when combined, is insignificant.

FLORIDA POWER CORPORATION

SUNCOAST PIPELINE COMPANY PROJECT
&
FLORIDA GAS TRANSMISSION PHASE III PROJECT

TECHNICAL & ECONOMIC ANALYSIS

August 1992

JOHN J. HIBBS & ASSOCIATES, INC.
13131 CHAMPIONS DR. • SUITE 206 • HOUSTON, TEXAS 77069
P. O. BOX 680304 • HOUSTON, TEXAS 77268
(713) 893-9784

fully executed copy to the undersigned, and retain one fully executed copy for your records.

Very truly yours,
FLORIDA GAS TRANSMISSION COMPANY

William V. Allison
William V. Allison
President and Chief Executive Officer

AGREED AND ACCEPTED TO
this 7 day of August, 1992

FLORIDA POWER & LIGHT COMPANY

By: C. O. Woody
C. O. Woody
Senior Vice President, Power Generation

TOTAL P.02

TOTAL P.02

(i) FPL shall identify its supplier to FGT at the receipt point where capacity is unavailable and shall provide FGT an opportunity to work with FPL and such supplier in an attempt to facilitate receipt of such supplies, without any increase in cost to FPL, from the supplier at other receipt points where capacity is available.

(ii) If reasonable, good faith efforts by FPL and FGT under (i) above fail to result in an accommodation acceptable to FPL in its sole judgment, then FPL shall have the option to request that FGT build or expand receipt point capacity to accommodate FPL's choice of receipt points. In such event, FGT shall agree to construct or to cause to be constructed additional receipt point capacity, having a total construction cost not to exceed in the aggregate $5 million, without requiring a contribution in aid of construction from FPL for the incremental costs of such facilities. Furthermore, FGT shall agree to construct additional receipt point capacity upon FPL's request upon FPL's agreement to reimburse, or to cause its designee to reimburse, FGT for the actual construction costs of receipt point capacity in excess of such $5 million.

If the foregoing correctly reflects our agreement, please so signify by executing in the appropriate space herein, return one

to accommodate FPL's request and similar requests by other shippers to the maximum extent practicable. Similarly, FGT will use all reasonable efforts to facilitate and accommodate trades of constrained receipt point capacity among FPL, other Phase III shippers and existing shippers.

3. To facilitate aggregation and pooling of supplies to serve FPL and other firm shippers, in its Order No. 636 compliance filing in Docket No. RS92-16-000, FGT shall file tariff revisions which facilitate pooling of supplies at the in-line transfer point at FGT's Compressor Station No. 11 by ensuring that firm market area shippers will be economically indifferent (i.e., no in-line transfer fee shall be assessed) as to whether supplies are received at specific firm receipt points or at the in-line transfer point and that supplies transported in the supply area and pooled at the in-line transfer point for delivery to a firm market area shipper receive the priority of the firm downstream shipper for scheduling regardless of whether the receipt points nominated by the supplier in the supply area are the same as the primary receipt points listed in the firm downstream shipper's service agreement, provided that primary Shippers at such receipt points always retain priority at those receipt points.

4. In the event that FPL in good faith nominates receipt point capacity in any production zone which does not exceed in the aggregate its pro rata quantity for such zone as listed above, and such receipt point capacity is not available, then the parties agree as follows:

capacity to the design of the Phase III Facilities such that under the proportional access methodology proposed by FGT in Docket No. CP92-182, FPL's pro rata share of supply area mainline capacity based on its Maximum Daily Transportation Quantity ("MDTQ") of 200,000 MMBtu per day under the FTS-2 Agreement shall not be less than the following:

FGT Production Zone	FPL Pro Rata Quantity
Station 0 - 7	38,910 MMBtu per day
Station 7 - 8	70,180 MMBtu per day
Station 8 - 11	90,910 MMBtu per day

FGT anticipates that the capital costs to add such incremental mainline capacity will not exceed $40 million; however, notwithstanding the actual capital costs incurred, FPL's initial Base Rate Cap under the FTS-2 Service Agreement shall not exceed $0.786 per MMBtu.

2. Within each FGT production zone, FPL may nominate capacity at receipt points totaling its pro rata quantity for such production zone, as set forth above, plus fuel. FPL will not be required to nominate proportionally at any specific receipt points within a production zone, i.e., FPL will not be required to nominate any specific percentage of its Station 8-11 pro rata quantity at receipt points on the proposed Mobile Bay or Southern Natural capacity. In the event that FPL desires to nominate aggregate receipt point capacity within a specific production zone which exceeds its pro rata quantity of supply area mainline capacity in such zone, FGT will use all reasonable efforts to act as a clearing house to facilitate trades of supply area mainline capacity among Phase III and existing firm transportation shippers in an effort

shall pay Transporter the rates established under Transporter's Rate Schedule FTS-2 as filed with and approved by the FERC.

B. Subparagraph (u) of Article 10.2 of the FTS-2 Agreement is hereby deleted.

C. Section I.C. of the Precedent Agreement is hereby amended and superseded in its entirety by the following provision:

C. Firm Transportation Rates

Subject to Article 3.1 of the FTS-2 Agreement, as amended, beginning on the Initial Delivery date(s), FPL shall pay FGT for all quantities transported under the FTS-2 Agreement at the rates and under the terms and conditions established by its FTS-2 Rate Schedule on file at FERC and in effect, or such other FGT rate schedule as approved by the FERC, for firm transportation service rendered by FGT on FGT's Phase III Facilities.

III. ACCESS TO SUPPLY AREA AND RECEIPT POINT CAPACITY

A. The Precedent Agreement is hereby amended to add the following provisions relating to Supply Area and Receipt Point Capacity as Article V of the Precedent Agreement:

V. SUPPLY AREA AND RECEIPT POINT CAPACITY

1. No later than August 31, 1992, FGT shall revise its request for authorizations to construct the Phase III Facilities, through either a further amendment to its certificate application or a settlement filed with the FERC in Docket No. CP92-182, to add additional mainline supply area

escalated pursuant to this subsection (ii) and the MDTQ effective for the billing month and (b) any dollar credit for the billing month for interruptible revenue shared by Shipper under this Agreement pursuant to Transporter's capacity relinquishment program or any other similar mechanism, by (2) the MDTQ effective for the billing month.

If at any time during the primary 20-year term of this Agreement, the effective rate that Transporter is authorized by the FERC to charge Shipper exceeds the Final Rate Cap then Transporter shall discount such authorized FERC rate down to the Final Rate Cap; provided, however, that in the event Shipper permanently or temporarily relinquishes capacity under this Agreement, the rate applicable to the majority of Phase III volumes flowed by Transporter during the applicable billing month, excepting those volumes flowed for Shipper ("Applicable Rate") shall apply to all relinquished capacity, i.e., to the extent the capacity under this Agreement is relinquished to another Shipper (Acquiring Shipper) at less than the Applicable Rate, Shipper shall pay Transporter the difference between the amount paid by the Acquiring Shipper and the Applicable Rate, and to the extent the amount paid by the Acquiring Shipper for such relinquished capacity exceeds the Applicable Rate, the difference between the amount paid and the Applicable Rate shall be credited to Shipper. Once temporarily relinquished capacity is transferred back to Shipper, Transporter shall again discount the FERC rate down to the Final Rate Cap.

Unless otherwise mutually agreed by the parties, after the primary 20-year term of this Agreement, Shipper

Transporter's merchant service under orders in FERC Docket No. RS92-16-000 or similar proceedings, or any separately stated surcharge related to recovery of the restructuring costs of any upstream provider of transportation or sales services to Transporter.

(ii) Beginning with the first anniversary of Initial Delivery Date "A", as defined in Article I.A.(2) of the Precedent Agreement, and annually thereafter ("Escalation Date") the Base Rate Cap shall be escalated in accordance with the following formula; provided that in no event shall the Base Rate Cap as it may be escalated pursuant to this subsection (ii) exceed $0.87 per MMBtu. On each Escalation Date, the Base Rate Cap to be effective for the subsequent twelve-month period shall be determined as the sum of (a) seventy percent (70%) of the Base Rate Cap ("Prior Base Rate Cap") which was effective for the twelve-month period immediately preceding the Escalation Date ("Prior Rate Period") and (b) thirty percent (30%) of the Prior Base Rate Cap escalated (but not decreased) through use of the GNP Implicit Price Deflator ("GNP Deflator") (or any substitute index that the parties mutually agree to in writing) determined by multiplying thirty percent (30%) of the Prior Rate Cap by a fraction, the numerator of which is the GNP Deflator for the last calendar quarter immediately preceding the Escalation Date and the denominator of which is the GNP Deflator for the calendar quarter immediately preceding the first month of the Prior Rate Period.

For any billing month, the Final Rate Cap shall be determined by dividing (1) the sum of (a) the product of the Base Rate Cap as

II. RATE CAP

A. Article 3.1 of the FTS-2 Agreement is hereby amended as follows:

> During the primary 20-year term of this Agreement, Shipper shall pay Transporter, for all services rendered hereunder, the lower of (1) the rates established under Transporter's Rate Schedule FTS-2 as filed with and approved by the FERC and as said Rate Schedule may hereafter be legally amended or superseded, or (2) the Final Rate Cap as determined below:
>
> (i) The Base Rate Cap shall be $0.786 per MMBtu. The Base Rate Cap is stated in nominal dollars, and shall exclude all applicable surcharges and fuel. A separately stated fuel percentage shall not exceed 3.5 percent of the quantities received by Transporter at Shipper's receipt points (exclusive of fuel reimbursement). The Base Rate Cap assumes the levelized rate methodology which FGT filed for approval in the amendment to its certificate application in Docket No. CP92-182-001 on April 15, 1992. For purposes of this Agreement, a "levelized rate" shall mean a rate designed by adjusting the annual depreciation expense such that it results in a levelized annual cost of service. The type of surcharges contemplated under the FTS-2 Rate Schedule are GRI and ACA, and their current level as of August 1, 1992, is $0.017 per MMBtu. Transporter shall not include in Rate Schedule FTS-2 and shall not collect under this Agreement any surcharge associated with the recovery of take-or-pay costs or gas purchase reformation costs, FERC Account No. 191 costs, ("restructuring costs") or any other similar surcharge associated with the restructuring of

at the plant locations and pressures determined under the FTS-2 Agreement in accordance with Article I.A.1. herein, provided that if FGT's failure to deliver is due to events of FGT's force majeure, as defined in FGT's FTS-2 Rate Schedule, FPL shall have the right to terminate or reduce the MDTQ only in the event such force majeure continues for more than 185 days or any 365 day period.

2. In addition to the foregoing, FPL shall have the right to terminate this Agreement and the FTS-2 Agreement if FGT has not received and accepted a certificate of public convenience and necessity for the Phase III Facilities from the FERC by December 31, 1993.

3. In addition to the foregoing, FPL shall have the right to terminate this Agreement and the FTS-2 Agreement in the event Phase III Facilities are not in service to deliver the entire Final MDTQ under the FTS-2 Agreement within twenty-seven (27) months after FGT's receipt and acceptance of a certificate of public convenience and necessity from the FERC authorizing the construction of the Phase III Facilities.

B. Article 10.2(h) of the FTS-2 Agreement is hereby amended as follows:

In the event that all requisite approvals necessary to effectuate the proposed service hereunder are not granted in satisfactory form on or before December 31, 1993, then at such time either party shall have the right to terminate this Agreement upon forty-five (45) days written notice.

maintained ongoing discussions concerning the competitiveness of the Base Rate Cap under such agreements and the assurances FPL needs from FGT to facilitate its purchase of economical supply. As a result of such discussions, the parties desire to amend the FTS-2 Agreement and the Precedent Agreement in the respects set forth below.

Subject to the terms and conditions set forth below, it is mutually agreed and understood that this Agreement, together with the Precedent Agreement and FTS-2 Agreement executed by the parties on December 12, 1991, as heretofore amended, will preserve FPL's position in FGT's firm transportation service queue for capacity made available under FGT's Phase III Expansion Project on an equal basis with all other firm customers submitting executed FTS-2 Service Agreements on or before December 12, 1991.

I. **TERMINATION BY FPL**

A. Section III of the Precedent Agreement is hereby amended and superseded in its entirety by the following provisions:

> FGT agrees that FPL shall have the right to terminate the Precedent Agreement and FTS-2 Agreement, as amended, without costs or penalty, by written notice to be provided to FGT within forty-five (45) days (unless another time period is stated below) of the occurrence of any of the following events:
>
> 1. After commencement of service under the FTS-2 Agreement, FPL shall have the right to terminate or to reduce the MDTQ under the FTS-2 Agreement if FGT does not provide FPL with its designated quantities

Florida Gas Transmission Company

William V. Allison
President and Chief
Executive Officer

P. O. Box 1188
Houston, Texas 77251-1188
(713) 853-6159

August 7, 1992

Mr. C. Ronald Rostorfer
Director of Fuel Management
Florida Power & Light Company
P. O. Box 029100
Miami, Florida 33102-9100

RE: Amendments to the Precedent Agreement and FTS-2 Service Agreement for Firm Transportation Service, as amended on April 9, 1992 ("FTS-2 Agreement") between Florida Gas Transmission Company ("FGT") and Florida Power & Light Company ("FPL") dated December 12, 1991.

Dear Mr. Rostorfer:

On December 12, 1991, FGT and FPL entered into the above-referenced Precedent Agreement and FTS-2 Agreement regarding a firm transportation service to be provided to FPL by FGT under FGT's proposed Phase III Expansion Project. The Precedent Agreement and FTS-2 Agreement contained, inter alia, specific termination rights by FPL in the event the Base Rate Cap offered by FGT to FPL is not acceptable to FPL in its sole discretion; in the event that FPL is unable, in its sole judgment, to secure sufficient economical and reliable long-term gas supply for delivery under the FTS-2 Agreement prior to July 1, 1992; and in the event that FGT does not receive and accept a certificate of public convenience and necessity for the Phase III Expansion Project from the FERC by June 1, 1993. Subsequent to the execution by the parties of the Precedent Agreement and FTS-2 Agreement, FPL and FGT have

currently allocated. In the event less than $23.5 million of rehabilitation costs are allocated to the existing cost-of-service, then the Initial Base Rate Cap and any subsequent Rate Cap used in the calculation of a Final Rate Cap shall be adjusted upward by $.0006 per every $1 million (or portion thereof) less than the $23.5 million currently allocated to the Phase III cost-of-service.

Shipper agrees that it shall not avail itself of any other Rate Cap that may be made available to it by the Commission.

immediately preceding the Anniversary Date and the denominator of which is the GDP Implicit Price Deflator for the calendar quarter immediately Preceding the first month of the eighth year of service.

The initial Base Rate Cap and all Final Rate Caps to be calculated hereunder are stated in nominal dollars and are 100 percent load factor rates, exclusive of all applicable surcharges and fuel. The Initial Base Rate Cap assumes the levelized rate methodology which Transporter filed for approval in the Offer of Settlement and Stipulation and Agreement of the parties in Docket No. CP92-182, et al., on August 25, 1992 ("Settlement").

The Initial Base Rate Cap and any subsequent Rate Cap used in the calculation of a Final Rate Cap hereunder shall be adjusted for the impact of changes in State and Federal income tax rates by adding or subtracting from the applicable Rate Cap the difference between the applicable Commission approved rate and such rate as adjusted to include changes in State and/or Federal income tax rates utilizing the cost of service underlying such rate. In the event of changes in State and/or Federal income tax rates prior to the effectiveness of initial FTS-2, the Rate Cap adjustment shall be determined by adding or subtracting the difference between the initial rates and the initial rates as recalculated to include the State and Federal income tax rates as included in the April 15, 1992 filing in Docket No. CP92-182-001.

Rate Cap adjustments shall be implemented on the date of effectiveness of tariff sheets filed by Transporter incorporating changes in State and/or Federal income tax rates.

The Initial Base Rate Cap is based on $23.5 million of pipeline rehabilitation costs allocated to the existing cost-of-service. In the event more than $23.5 million of rehabilitation costs are allocated to the existing cost-of-service, then the Initial Base Rate Cap and any subsequent Rate Cap used in the calculation of a Final Rate Cap shall be adjusted downward by $.0006 per every $1 million (or portion thereof) allocated to the existing cost-of-service over and above the $23.5 million

superseded, or (2) the Final Rate Cap as determined below:

(i) For the first two years of service, the Rate Cap shall be $0.80 per MMBtu.

(ii) Commencing on the third year of service and extending for a period of one year, the Rate Cap shall be $0.82 per MMBtu.

(iii) Commencing on the fourth year of service and extending for a period of one year, the Rate Cap shall be $0.84 per MMBtu.

(iv) Commencing on the fifth year of service and extending to the end of the eighth year of service, the Rate Cap shall be $0.86 per MMBtu.

(v) Commencing on the ninth year of service and extending to the end of the twentieth year of service, the Rate Cap shall be calculated as follows:

On each Anniversary (Anniversary Date), the Final Rate Cap to be effective for the subsequent twelve-month period shall be determined as the sum of (a) seventy percent (70%) of the Rate Cap which was effective for the eighth year of service (Base Rate Cap) and (b) thirty percent (30%) of the Base Rate Cap escalated (but not decreased) through use of the GDP Implicit Price Deflator (or any substitute index that the parties mutually agree to in writing) determined by multiplying thirty percent (30%) of the Base Rate Cap by a fraction, the numerator of which is the GDP Implicit Price Deflator for the last calendar quarter

RATE CAP 3

Rate Cap 3 has been elected by the following Phase III Shippers:

1. Aluminum Company of America
2. Ark Energy
3. Atmore, City of
4. Central Florida Gas Co.
5. Citrus Marketing, Inc.
6. Citrus World, Inc.
7. City Gas Company of Florida, Inc.
8. Clearwater Gas System
9. Coca-Cola Foods, Inc.
10. Consolidated Minerals, Inc.
11. Destec Energy, Inc.
12. El Dorado Energy Co.
13. Florida Gas Utility
14. Florida Municipal Power Agency
15. Florida Public Utilities Co.
16. Ft. Pierce Utilities Authority
17. Lake Apopka Natural Gas District
18. Lakeland, City of
19. Okaloosa County Natural Gas District
20. Orlando Utilities Commission
21. Panda-Kathleen, L.P.
22. Reedy Creek Improvement District
23. Rinker Materials Corp.
24. St. Joe Natural Gas Co., Inc.
25. Tallahassee, City of
26. The Feldspar Corporation
27. U.S. Agri-Chemicals Corp.
28. West Florida Natural Gas Co.

Pursuant to the terms of this Settlement, FGT and the above-listed Phase III Shippers will amend Article 3.1 of their Service Agreements to provide for the following:

> During the first twenty (20) years of service under this Agreement, Shipper shall pay Transporter the lower of (1) the rates established under Transporter's Rate Schedule FTS-2, as filed with and approved by the FERC and as said Rate Schedule may hereafter be legally amended or

the Settlement are expressly agreed to be not severable.

13. Article XIII incorporates, by reference, each Exhibit attached to the Settlement.

forth in Section 3(b) of Article III; the provisions regarding allocation of certain avoided pipeline rehabilitation costs to the cost-of-service underlying FGT's existing services as set forth in Section 3(a) of Article III; the provisions regarding the establishment of an incremental Phase III cost-of-service as set forth in Section 2 of Article III; and the provisions relating to FGT's agreement to restate the standard delivery pressure on its system from 100 psig to 250 psig. Peoples also agrees that it will not contest or propose alternatives to the cost allocation methodologies set forth in Section 3 of Article III during the Effective Period of the Settlement and FGT agrees that it will not file to seek rolled-in rate treatment of the Phase III Facilities during the Effective Period of the Settlement. Peoples also supports the methodology for the allocation of receipt point capacity set forth in Article VII, Section 2, of the Settlement.

11. Article XI provides that the Settlement shall not become effective unless and until the Commission has issued an order approving all the terms and conditions thereof without modification or conditions, and such order becomes final and no longer subject to appeal, although FGT may waive the latter condition. Article XI also provides that except as otherwise provided therein, the Settlement will continue in effect through the Effective Period as defined in Article II.

12. Article XII sets forth standard reservations that the Settlement is privileged and of no effect unless approved in its entirety without modifications, and that the various provisions of

receipt point selection by the Phase III Shippers. Article VII also addresses allocation of the incremental mainline capacity created by the Phase III Expansion and tariff revisions which FGT agrees to file with its Order No. 636 compliance filing in Docket No. RS92-16-000 to facilitate pooling of supplies at the in-line transfer point at FGT's Compressor Station No. 11.

8. Article VIII addresses the terms and conditions of service under new Rate Schedule FTS-2 and reflects FGT's agreement to conform the pro forma tariff sheets at Volume I, Exhibit P, of the Settlement to the Commission's implementation of FGT's Order No. 636 compliance filing.

9. Article IX sets forth Florida Power & Light Company's ("FPL") agreement as a Signatory Party to the provisions of the Settlement with the exception of Articles II and VI, which relate to the negotiated allocation of risk among FGT and the other Signatory Parties and the rate cap provisions. The resolution of these latter issues with respect to FPL are the subject of the amendment to FPL's FTS-2 Service Agreement and Precedent Agreement attached at Volume I, Exhibit I, of the Settlement.

10. Article X sets forth the agreement of Peoples Gas System, Inc. ("Peoples") to the Settlement as a Signatory Party that is not a Phase III Shipper. Peoples agrees to withdraw its protests to FGT's certificate application in this docket, as amended, effective with Commission approval of this Article X of the Settlement, in consideration for the Signatory Parties' support for the cost allocation methodology for allocating O&M and A&G expenses set

Article III further provides that Commission approval of the Settlement shall approve the cost allocation methodologies set forth in Sections 3(a), (b), and (c) for the purpose of establishing Initial Rates, and provides for the Signatory Parties' support for the same for the Effective Period of the Settlement, subject to the exceptions set forth in Articles II and III.

Finally, Article III provides that FGT will file a Section 4 general rate proceeding no later than eighteen (18) months after the in-service date of the Phase III Facilities.

4. Article IV provides for FGT's voluntary acceptance of the at-risk condition set forth therein during the Effective Period of the Settlement. After the Effective Period, FGT may elect to file with the Commission to prove that good cause exists for removal of the at-risk condition, but FGT would bear the burden of proof in such proceeding and the condition could be removed only on a prospective basis after an order of the Commission.

5. Article V provides for FGT's agreement to seek to roll-in the costs and revenues of a "Phase IV" expansion(s), as defined in, and under the terms and conditions stated in, Article V.

6. Article VI sets forth the agreement among FGT and the Phase III Shippers listed in TAB 4 of the Stipulation and Agreement with respect to amendments of their existing FTS-2 Service Agreements to incorporate the rate caps elected by such Shippers.

7. Article VII sets forth a Supply Area Capacity Allocation Methodology which addresses receipt point selection by FGT's existing sales customer with remaining conversion rights and

service under the terms and conditions set forth in Article V of the Settlement; and (iii) FGT's agreement to provide certain Signatory Parties with Rate Caps over the first twenty (20) years of service under Rate Schedule FTS-2. Article II further provides for circumstances under which the Signatory Parties' agreement to support certain of the Article III rate terms and conditions may terminate prior to the end of the Effective Period of the Settlement. Article II also provides FGT and each Signatory Party with a right of withdrawal from the Settlement if the Commission modifies the Settlement in a manner unacceptable to a party in the exercise of its good faith judgment.

3. Article III sets forth the rate terms, conditions, and methodology underlying the Initial Rates for service through the Phase III Facilities under Rate Schedule FTS-2, which the Signatory Parties have agreed to support for the Effective Period of the Settlement, subject to the exceptions set forth in Articles II and III of the Settlement. Article III provides that Initial Rates under Rate Schedule FTS-2 will be incremental, two-part rates consisting of a reservation charge and a commodity rate. The Initial Rates will be designed using a two-tiered levelized rate methodology by adjusting the annual depreciation expense such that it results in a levelized annual cost-of-service. A 25-year depreciation life is utilized in designing the FTS-2 rates under this approach. Article III also provides that the FTS-2 rates will be designed using the straight-fixed variable method of classifying and allocating costs, and with a return on equity of 14.0 percent.

include the cost of such arrangement in the Phase III cost-of-service; and grant any necessary waivers to effectuate the transaction pursuant to the terms of the Settlement. Finally Article I would provide for pre-approval of certain assignments of all or a portion of several of the FTS-2 Service Agreements included in the April 15, 1992 amendment to FGT's certificate application in this docket, and permit FGT to build certain of the Phase III Facilities pursuant to its blanket certificate authorization, if needed, to provide interruptible service prior to the in-service date of the entirety of the Phase III Facilities.

2. Article II sets forth the negotiated allocation of risk among FGT as the project sponsor and certain of the Signatory Parties as the beneficiaries of the project. In consideration of the Signatory Parties agreement to support the rate terms, conditions, and methodology for designing rates for the Phase III Expansion, as set forth in Article III of the Settlement, for a period ending five (5) years after the in-service date of the Phase III Expansion ("Effective Period of the Settlement"), and their agreement to forego any pre-existing termination rights under their FTS-2 Service Agreements, except as related to receipt of regulatory approval on or before December 31, 1993, FGT agrees to provide certain rate protections to the Signatory Parties. Such rate protections include (i) FGT's acceptance of the "at-risk condition" set forth in Article IV of the Settlement; (ii) FGT's agreement to seek regulatory approval to roll-in subsequent defined expansions of the Phase III Facilities into the Phase III cost-of-

to embark upon financing related activities and the option to commence other preconstruction activities, such as ordering of pipe, compression and other materials, that may be essential for FGT to meet the time sensitive demand of the electric generation market in Florida, which dictates an in-service date for the Phase III Expansion occur no later than fourth quarter of 1994.

PROVISIONS OF THE STIPULATION AND AGREEMENT[1]

1. Article I provides that the Commission's order approving the Settlement will constitute a preliminary determination that, on the basis on all non-environmental issues in this proceeding, a certificate authorizing the construction of the Phase III Facilities, as described in the Settlement, is in the public convenience and necessity. Such preliminary determination would also authorize FGT's interest in the Mobile Bay Facilities of Transcontinental Pipe Line Company ("Transco"), as expanded pursuant to the authorizations requested jointly by Transco and FGT in Docket No. CP92-415-000, once such authorizations are granted by the Commission, to be included in the Phase III cost-of-service. The preliminary determination would permit FGT to treat as an extension of its system a proposed firm transportation arrangement between FGT, on behalf of the Phase III Shippers, and Southern Natural Gas Company ("Southern") for 100,000 MMBtu per day; to

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[1]This explanatory statement does not alter in any manner the terms of the Stipulation and Agreement. To the extent there may be any inconsistencies between this explanatory statement and the terms of the Stipulation and Agreement, the terms of the Stipulation and Agreement shall govern.

capacity.

On April 15, 1992, FGT filed to amend its application to downsize the facilities to reflect the actual level of subscriptions.

On May 12, 1992, Peoples filed its protest to certain aspects of the April 15 amended application. Among other arguments, Peoples raised issues regarding receipt point and supply area allocation and the appropriate allocation of costs and expenses between the existing system and the Phase III Facilities.

Accordingly, FGT and the Signatory Parties negotiated this Settlement to resolve the issues raised by Peoples and other Phase III customers. It is the intent of the Signatory Parties and FGT that by resolving issues through this Settlement pertaining to rate design, cost allocation, supply area capacity, allocation of receipt point capacity, and terms and conditions of firm transportation service under proposed FTS-2 Rate Schedule to be rendered through FGT's proposed pipeline expansion, the Commission will issue an order approving the Settlement which will constitute a preliminary determination on non-environmental issues. A Commission order resolving non-environmental issues will provide both FGT and its Phase III customers with certainty on important issues. Prompt resolution of such issues will demonstrate to FGT's Phase III customers the significant progress and certainty of the Phase III Expansion necessary in order to aid certain customers in the financing and development of their individual electric generation projects. In addition, such resolution will allow FGT

On December 12, 1991, FGT obtained executed service agreements from 30 customers representing demand for 541,117 MMBtu per day of Firm Winter Capacity and 522,573 MMBtu per day of Firm Summer Capacity.

On December 11, 1991, the Commission identified certain deficiencies in the November 15 application, including the need for FGT and Transcontinental Gas Pipe Line Corporation ("Transco") to file for authorization to expand the Mobile Bay Pipeline Company ("Mobile Bay") to be used in connection with Phase III. On March 16, 1992, FGT and Transco filed a joint application in Docket No. CP92-415-000, to expand the Mobile Bay pipeline. FGT also requested that the Mobile Bay and Phase III proceeding be consolidated. Such request has not been granted.

As promised in the November 15 application, FGT filed to amend its application in order to reflect the actual level of customer commitments received on December 12. However, prior to making such filing, FGT needed to remove a cloud placed on the Phase III application by a complaint filed on October 8, 1991, by Peoples Gas System, Inc. ("Peoples"). The unresolved complaint, inasmuch as it indicated the potential for Peoples to obtain Phase III capacity, prevented FGT from finalizing project size.

On February 13, 1992, the Commission held a technical conference to discuss the issues raised by Peoples. As a result of the technical conference, Peoples stated its intention to withdraw its complaint, thus allowing FGT to move forward in redesigning its facilities with the knowledge that Peoples did not desire Phase III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Florida Gas Transmission Company	)	Docket Nos. CP92-182-000, 001, and 002

EXPLANATORY STATEMENT

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure, on August 21, 1992, Florida Gas Transmission Company ("FGT") and certain parties that have agreed to join in this Offer of Settlement ("Signatory Parties"), have submitted for the approval of the Commission an Offer of Settlement and Stipulation and Agreement which provides for resolution of all non-environmental issues raised by the captioned proceeding.

INTRODUCTION AND PROCEDURAL HISTORY

A series of procedural milestones have led to this Offer of Settlement.

On November 15, 1991, FGT filed a certificate application for a major system expansion ("Phase III Expansion") in this docket. At the time of its application, FGT had yet to receive executed firm service agreements for the expansion project, but was involved in extensive negotiations with customers regarding the project. The November 15 application reflected a capacity design of 825,000 MMBtu per day, which reflected FGT's assessment of the market demand. Once FGT obtained firm commitments for capacity, it pledged to amend its application to increase or downsize the designed capacity.

FLORIDA GAS TRANSMISSION COMPANY
PHASE III EXPANSION

OFFER OF SETTLEMENT

Docket Nos. CP92-182, et. al.

005-107-C

If the terms of this letter are in accordance with your understanding, please sign in the space provided below.

Very truly yours,

FLORIDA GAS TRANSMISSION COMPANY

By: William V. Allison TCB
William V. Allison
President

FLORIDA POWER CORPORATION

By: _____
Stephen Watsey
Vice President

thereafter, FPC agrees to keep confidential the terms and conditions set forth in this letter of intent, subsequent proposals, and any other information pertaining to the contemplated service that may be provided during negotiations. Keeping such information "confidential" shall mean the following:

(i) terms and conditions contained in the written proposals shall be disclosed only to (a) those employees of FPC who need to know such information for the purpose of FPC's evaluation of FGT's written proposal(s) (and FPC agrees to require such employees to abide by the terms of this agreement); and (b) those attorneys or other representatives engaged by FPC who need to know such information for the purpose of FPC's evaluation of FGT's written proposal(s) (and FPC agrees to require such attorneys and other representatives to abide by the terms of this agreement).

(ii) terms and conditions contained in such written proposals may not be directly or indirectly disclosed by FPC or its representatives to any other person or entity, except that information relating to production zone receipt point and supply area capacity may be discussed or disclosed to potential gas sellers.

In the event FPC is required to disclose details of the proposals to the Florida Public Service Commission or the Federal Energy Regulatory Commission in the course of proceedings before either commission, FPC shall take reasonable steps to protect the confidentiality of the terms and conditions contained in the proposals.

4. THIS LETTER OF INTENT SHALL BE GOVERNED AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS.

August 1993	-	FGT files with FERC for construction authorization
February 1995	-	FGT receives construction authorization
March 1997	-	In-service date for Anclote facilities
August 1998	-	In-service date for Polk Co. 1 facilities
August 1999	-	In-service date for Polk Co. 2 facilities

9. Requisite Authorization. FGT's obligation to provide firm transportation service to FPC and to construct the facilities necessary to provide such service is subject to i) receipt and acceptance of all regulatory authorizations from the FERC in Docket Nos. CP92-182-000, et al. and CP92-415-000 necessary to construct and operate FGT's proposed Phase III Expansion; ii) receipt and acceptance by FGT of all necessary approvals and authorization from the FERC to provide firm transportation service to FPC and to construct the facilities necessary to provide such service; and iii) all other approvals required to construct such facilities including all necessary authorizations from federal, state, local and/or municipal agencies or other governmental authorities.

B. MISCELLANEOUS

1. This letter of intent shall terminate and be of no further force and effect upon the earlier of (i) the date upon which FGT and FPC enter into definitive agreements, (ii) January 18, 1993 unless extended by mutual agreement or iii) upon written notice by either party to terminate. This letter of intent and proposal contained herein will expire, unless executed by FPC, at 5 p.m. Central Time on November 16, 1992 and may be withdrawn by FGT at any time prior to execution by FPC.

2. Exclusive Negotiations. During the term of this letter of intent FPC shall not negotiate or enter into any other agreements for the natural gas service contemplated by this proposal.

3. Confidential Treatment of Negotiations. During the term of this letter of intent and for a period of two years

to serve Polk Co. 1 and 210,000 MMBtu per day upon the in-service date of facilities necessary to serve Polk Co. 2.

5. Rate Cap. FPC shall be provided rate protection through a rate cap mechanism. The applicable rate cap is dependent upon FPC's selection of the supply area option set forth in 2 above.

Option A Rate Cap:

During the first twenty years of service, FPC shall pay the lower of the rate established under Rate Schedule FTS-2 or the Rate Cap. For the first three years of service, the Rate Cap shall be $0.77 per MMBtu. Commencing in the fourth year and annually thereafter, the Rate Cap shall be escalated, provided that in no event shall the Rate Cap exceed $0.82 per MMBtu, at a rate equal to thirty percent of the percentage change in the GDP Deflator from the calendar quarter immediately preceding the escalation date and the GDP Deflator for the quarter occurring one year prior.

The Rate Cap shall be adjusted to reflect changes in state or federal income tax rates.

Option B Rate Cap:

Same as Option A Rate Cap except for the first three years, the Rate Cap shall be $0.73 per MMBtu and the Rate Cap shall not exceed $0.78 per MMBtu.

6. Fuel. Fuel reimbursement is estimated to be four percent.

7. Facility Reimbursement. FPC shall reimburse FGT for the cost of constructing any metering, gas regulating and appurtenant facilities. Such reimbursement shall include tax gross-up. FGT's preliminary estimate of such cost is $2.1 million.

8. Anticipated Project Schedule. To provide FPC with service by the anticipated in-service dates, FGT envisions the following project schedule:

November 17, 1992	-	FGT and FPC execute this Letter of Intent
January 18, 1993	-	FGT and FPC execute binding definitive agreements

Supply Zone	Maximum Receipt Point Quantity* MMBTu/day	Percent
Zone 1	40,000	19
Zone 2	113,000	54
Zone 3	210,000	100

*The receipt point quantities are exclusive of the required fuel reimbursement.

Zone 1 extends from the origin of FGT's system in south Texas to Compressor Station 7 in Louisiana.

Zone 2 extends from Compressor Station 7 to Compressor Station 8 in Louisiana.

Zone 3 extends from Compressor Station 8 to Compressor Station 11 and includes direct access (i.e., no separate transportation or gathering fee) to Chevron's proposed natural gas processing plant located in the vicinity of Pascagoula, Mississippi and the natural gas processing plants owned by Shell, Amoco, Mobil and Exxon which are connected to the Mobile Bay Pipeline in the vicinity of Mobile, Alabama (together referred to as "FGT's Mobile Bay Facilities").

Option B: FPC shall receive all natural gas supplies from FGT's Mobile Bay Facilities.

3. Term of Service. Service shall commence on the in-service date of the facilities necessary to provide service to FPC's Anclote generating facility and shall continue until August 31, 2019. FPC shall have the right to extend the term for additional ten year increments by providing FGT with written notice two years prior to the expiration of the primary or subsequent ten year term.

4. Rate Schedule and Service Agreement. The terms and conditions of service will be governed by FGT's proposed FTS-2 Rate Schedule pending approval in FGT's certificate application in Docket No. CP92-182 and the specific provisions of a definitive FTS-2 Service Agreement. Demand charges for firm service will be assessed upon the in-service date of each increment of capacity, i.e., demand charges assessed on 120,000 MMBtu per day upon the in-service date of the facilities necessary to deliver gas to the Anclote Plant, then on an MDTQ of 165,000 MMBtu upon the in-service date of the facilities needed

Florida Gas Transmission Company

William V. Allison
President and Chief
Executive Officer

P. O. Box 1188
Houston, Texas 77251-1188
(713) 853-6159

October 28, 1991

Mr. Stephen Watsey
Vice President
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

RE: Florida Gas Transmission Company ("FGT") proposal to provide Florida Power Corporation ("FPC") firm natural gas transportation service on facilities to be constructed by FGT.

Dear Mr. Watsey:

In response to your letter dated October 13, 1992 FGT extends for your consideration the following proposal to provide FPC firm natural gas transportation service on facilities to be constructed by FGT. This letter of intent, when executed below, evidences the desire of the parties to enter into good faith negotiations leading to the execution of the definitive agreements necessary to provide FPC with the contemplated natural gas services. The general parameters of the terms and conditions of the proposed service are set forth in Section A below and are subject to the preparation and execution of definitive agreements on or before January 18, 1993.

A. TERMS OF PROPOSED SERVICE

1. Quantity. FGT shall provide FPC with a total Maximum Daily Transportation Quantity (MDTQ) of 210,000 MMBtu per day on its expanded facilities in the following increments:

Delivery Point	MDTQ MMBtu/day	Anticipated In-Service Date
1. Anclote	120,000	March 1997
2. Polk Co. 1	45,000	August 1998
3. Polk Co. 2	45,000	August 1999

2. Supply Area Capacity. FPC shall have the right to select the following supply area capacity design options to be incorporated in the definitive agreements.

Option A: FPC shall be provided proportional access, on a phased in basis, to supply sources along FGT's system in the following manner:

FGT PROPOSAL AND SUPPORTING DATA

SUNCOAST FUEL REQUIREMENTS

Year	SunCoast (MMBTU/D)	SunCoast 26" Main Line Volumes (MCF/D)	SunCoast 26" Main Line % of MDQ	SunCoast 30" Main Line Volumes (MCF/D)	SunCoast 30" Main Line % of MDQ
1996	194,000	1.44	0.74%	1.44	0.74%
1997	194,000	1.44	0.74%	1.44	0.74%
1998	239,000	2.09	0.87%	1.84	0.77%
1999	374,000	6.85	1.83%	4.64	1.24%

NOTE: The SunCoast fuel consumption is based upon 10cf/B-HpHr.

- Storage

  Storage on the United system will allow FPC to minimize overall commodity cost by managing gas purchased to take advantage of seasonal prices while also maintaining supply integrity. Storage also provides for the daily and weekly cycling which meets the load profile of FPC.

  To be negotiated

- Fuel Oil Supplies

  United in concert with Koch Industries can arrange for fuel oil backup in the event of unforeseen circumstances at terms to be negotiated.

6. Rate Caps & Escalation

$/MMBTU

- Initial year rate caps will be:

  - Initial year cumulative rate cap - 26" Configuration $ 0.784

  - Initial year cumulative rate cap - 30" Configuration 0.825

- Rates will be escalated to reflect actual increases in variable operating costs (O&M, G&A, and taxes) for SunCoast Intrastate and SunCoast Interstate which are currently estimated to be 18% of total rates.

- For the contract term the UGPL rates will escalate at the lesser of 4% or the percentage change in the GNP deflator each year not to exceed United's maximum lawful rates.

- During the first 20 years of the contract, in no event shall the base rate, as escalated above, exceed $0.87 per MMBTU.

7. Fuel

- Rates shown above are exclusive of fuel, lost and unaccounted for gas and other charges.

- Fuel rates would be actual fuel used by UGPL and SunCoast pipelines prorata for FPC's volume, not to exceed maximum percentage allowed in respective gas tariffs in each company.

- A cumulative fuel cap of 3.5% of total volume would be provided to FPC.

8. Value Added Services

Aggregation Service

- United Gas Services Company (UGS) would act as agent for FPC in arranging for supplies and other related services including nomination, transportation imbalance control disposition, reconcile volumetric disputes, perform all contract administration and consolidate all customer billings. UGS's services would be optional to FPC, but would be at an initial fee of: $0.01/MMBTU

5. Rates for firm transportation assuming the initial supply mix as shown above in Item 4

A. 26" Configuration

		$/MMBTU
• SunCoast Intrastate		0.607
• SunCoast Interstate		0.055
• UGPL will provide FPC with a capital lease for capacity through Gateway/Pascagoula	$.033 x 30% =	0.010
• UGPL system rates from Louisiana and Texas to SunCoast	$.116 x 70% =	0.082
Total Average Rate		0.754

B. 30" Configuration

• SunCoast Intrastate		0.648
• SunCoast Interstate		0.055
• UGPL will provide FPC with a capital lease for capacity through Gateway/Pascagoula	$.033 x 30% =	0.010
• UGPL system rates from Louisiana and Texas to SunCoast	$.116 x 70% =	0.082
Total Average Rate		0.795

C. Adjustments to Initial Rates

- All rates quoted above are based upon currently projected volumes as shown in Item 1 above.
- Initial rates will be adjusted to reflect actual construction cost and initial volume commitments from customers.
- On SunCoast Intrastate, based on initial assumptions as reflected in (1) above, with an additional 25,000 MMBTU/D of firm contract demand, the illustrative rate set forth above would be reduced by $.045.

Schedule A

Term Sheet

1. Volume Commitments

   - Total initial volume of 194,00 MMBTU/D with build-up to 374,000 MMBTU/D by 1999.

   - FPC minimum initial commitment of 120,000 MMBTU/D at Anclote with an additional commitment of 45,000 MMBTU/D in 1998 for Polk 1 and 45,000 MMBTU/D in 1999 for Polk 2. FPC would also agree to give SunCoast a first right of refusal on any additional natural gas volume requirements.

2. Term

   - 25 years

3. Pipeline Size

   - The optimum case given the volume commitment reflected above would suggest the construction of a 26" pipeline. From the initial volumes of 194,000 MMBTU/D, the 26" pipeline can be economically expanded to over 500,000 MMBTU/D without adversely affecting the rates.

   - The 30" pipeline option shall be considered.

4. Supply Access

   - UGPL will commit to FPC that firm capacity will be available on UGPL's system that would allow for the following initial supply mix:

	Volume %
Gateway or Pascagoula	30%
Louisiana	44%
Texas	26%
	100%

If this letter accurately reflects the understandings of the parties, please execute one copy below and return it to the undersigned's attention as soon as possible.

Very truly yours,

Koch Industries, Inc.

C. C. McCampbell
Vice President

Agreed and accepted this ___ day of
October, 1992.
Florida Power Corporation

By_____
Stephen Watsey
Vice President

Agreed and accepted this 28th day of
October, 1992
United Gas Pipe Line Company

By_____
M. John Baker, Jr.
President

(2) United and its affiliates will perform firm transportation service for the benefit of SunCoast Pipeline customers. Such arrangements will include firm transportation agreements and may also include capacity leases or sales of undivided interests in the necessary facilities. Such firm transportation service will have a firm contract demand of not less than 194,000 MMBTU/D with build up to 374,000 MMBTU/D. by 1999. and shall be subject to the conditions. including but not limited to receipt points and rates. set forth in the attached Schedule A.

(3) The FT rates charged by United to FPC set forth in (2) above may change annually, in accordance with the attached Schedule A. subject to the $0.87 cap set forth therein. Any increase above the $0.87 cap will be shared by United and SunCoast Pipeline in proportion to the price relationship of those rates that existed when the $0.87 cap was reached.

(4) The FT rates are exclusive of fuel but United agrees to assess FPC a fuel charge equal to actual fuel used but no more than 1.6% of the total volumes delivered. This 1.6% limitation on the fuel charge shall be effective only so long as the total MDQ for all SunCoast Pipeline shippers does not in the aggregate exceed 374,000 MMBTU/D. This 1.6% limitation will increase to a 1.9% limitation if a 30" mainline facility is constructed. If the total aggregate MDQ for all SunCoast Pipeline customers exceeds 374,000 MMBTU/D. then the fuel charge applicable to the MDQ in excess of the 374,000 MMBTU/D shall equal the actual fuel utilized for such incremental MDQ.

(5) Neither (a) the negotiations among UGPL. Koch and FPC. or any of them. that have resulted in the execution of this letter agreement. (b) the execution hereof nor (c) the subsequent negotiations among such parties. or any of them. with respect to the subject matter hereof shall be construed or asserted by UGPL or Koch as an interference with the September 25. 1992 stock purchase agreement between Koch and UGPL. nor actionable as such by either UGPL or Koch against any other party hereto.

(6) Because of the sensitive nature of the subject matter hereof. the parties each agree to keep this letter agreement confidential. and to disclose its contents only to their respective agents. employees. counsel. directors. stockholders and sources of financing on a "need to know" basis.

(7) This letter agreement may be executed in two or more counterparts. each of which when so executed shall be an original. but all counterparts together shall constitute one and the same instrument. It shall not be necessary for any counterpart to bear the signature of all parties hereto.

October 28, 1992

Mr. M. John Baker, Jr.
President
United Gas Pipe Line Company
600 Travis
Houston, Texas 77251

Mr. Stephen Watsey
Vice President
Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33733

Gentlemen:

The purpose of this letter is to set forth the agreement by and among Florida Power Corporation (FPC), Koch Industries, Inc. (Koch) and United Gas Pipe Line Company (United) with respect to (i) construction of pipeline and other facilities necessary to provide firm transportation to the proposed SunCoast Pipeline interconnect at Whistler Junction and (ii) certain related transportation services to be provided by United such that gas will be transported on a firm basis to the aforesaid interconnect. This letter is expressly conditioned on Koch not having purchased all of the outstanding stock of United on or before November 12, 1992.

The parties' agree and understand as follows:

(1) Koch and FPC, or their affiliates, will form a partnership or partnerships to construct, own and operate the SunCoast Pipeline by separate agreements subject to approval of Koch's and FPC's boards of directors. The partnership agreements will, among other things, finance or arrange for the financing of the "SunCoast Pipeline" (as defined below). In addition, the partnership or partnerships so formed shall also grant to United, or its affiliates, designees or assigns, an option to acquire up to one-half of Koch's interest in such partnership or partnerships at the then existing cost of the project and subject to such other terms mutually agreeable to United and the partnership or partnerships. The term, "SunCoast Pipeline" refers to proposed intrastate and interstate natural gas pipeline facilities extending easterly and southerly from Whistler Junction to a terminus with FPC facilities in Florida. "SunCoast Interstate" refers to the interstate natural gas pipeline facilities of SunCoast Pipeline.

UNITED PROPOSAL AND SUPPORTING DATA

EXHIBIT "B"

ATTACHED TO
PRECEDENT AGREEMENT
DATED _____, 1992
BETWEEN

FLORIDA POWER CORPORATION
AND
ANR Southern PIPELINE COMPANY

ANR Southern PIPELINE COMPANY:

Points of Receipts:

Point of Delivery:

EXHIBIT "A"

ATTACHED TO
PRECEDENT AGREEMENT
DATED _____, 1992
FLORIDA POWER CORPORATION
AND
ANR Southern PIPELINE COMPANY

[Attach ANR Southern Service Agreement]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed in multiple originals by their duly authorized officers as of the date first written above.

ATTEST

By: _____
Name: _____
Title: _____
[SEAL]

ANR Southern PIPELINE COMPANY

By: _____
Name: _____
Title: _____

FLORIDA POWER CORPORATION

ATTEST:

By: _____
Name: _____
Title: _____
[SEAL]

By: _____
Name: _____
Title: _____

pursuant to the Hinshaw Exemption. In the event that ANR Southern should, for any reason, lose, become ineligible or otherwise fail to qualify for the Hinshaw Exemption, then ANR Southern and Shipper nevertheless agree to (i) remain bound by the terms and conditions of this Agreement, and (ii) negotiate in good faith any revisions to this Agreement made necessary by ANR Southern's change in regulatory status.

19. Confidentiality. Except as provided hereinbelow, neither ANR Southern nor Shipper, nor their respective Affiliates, directors, officers, and employees, advisors and representatives shall disclose to any third party the terms and conditions of this Agreement, including the information and agreements set forth on the Exhibit, without the other Party's written consent to such disclosure. This provision shall not apply to such disclosures that, in the opinion of ANR Southern's or Shipper's counsel, as the case may be, are required by state or federal laws, rules or regulations (in which case, the Party making such disclosure shall advise the other Party prior to disclosure and, if requested by the other Party, shall use every effort to maintain the confidentiality of this Agreement, including, without limitation, seeking a protective order). The disclosure of any information pertaining to this Agreement within ANR Southern's or Shipper's internal organization (including Affiliates) and within the organization of any third party to which disclosure is authorized by ANR Southern or Shipper shall be limited to such personnel whose duties require their review or counsel with respect to this Agreement and the Party making such disclosure shall instruct such personnel to maintain the confidentiality of this Agreement.

20. Regulatory Status. The Parties hereby acknowledge that this Agreement contemplates, in all respects, that the Florida Facilities will be constructed, operated and regulated as an intrastate pipeline exempt from the regulatory jurisdiction of FERC

15. Survival. All of the terms and provisions of this Agreement shall survive the execution by the Parties of a Service Agreement, except those terms and provisions hereof that are inconsistent with the terms and provisions of such Service Agreement.

16. Governing Law. THE CONSTRUCTION, INTERPRETATION, AND ENFORCEMENT OF THIS AGREEMENT SHALL BE GOVERNED BY THE LAWS OF THE STATE OF FLORIDA, EXCLUDING ANY CONFLICT OF LAW RULE WHICH WOULD REFER ANY MATTER TO THE LAWS OF A JURISDICTION OTHER THAN THE STATE OF FLORIDA.

17. Counterpart Execution. This Agreement may be executed by the Parties in any number of counterparts, each of which shall be deemed an original instrument, but all of which shall constitute but one and the same agreement.

18. Partial Invalidity. Except as otherwise expressly stated herein, in the event any provision contained in this Agreement shall for any reason be held invalid, illegal or unenforceable by a court or regulatory agency of competent jurisdiction by reason of a statutory change or enactment, such invalidity, illegality or unenforceability shall not affect the remaining provisions of this Agreement.

or to such other place within the United States of America as either Party may designate as to itself by written notice to the other. All notices given by personal delivery or mail shall be effective on the date of actual receipt at the appropriate address. Notice given by telex or telecopier shall be effective upon actual receipt if received during recipient's normal business hours or at the beginning of the next business day after receipt if received after the recipient's normal business hours.

13. Limitation of Liability. Shipper agrees that any liability relating to and any and all claims against ANR Southern shall be limited to the assets of ANR Southern, and, subject to applicable law, Shipper waives its rights to proceed against any of ANR Southern's Affiliates. Execution of this Agreement does not bind any Affiliate of ANR Southern or require any Affiliate to undertake any obligation in connection with this Agreement. Shipper and ANR Southern agree that neither party shall be liable to the other for incidental, consequential or indirect damages under this Agreement, whether arising in contract, tort or otherwise.

14. No Third Party Rights or Obligations. This Agreement shall not create any rights in third parties, and no provision hereof shall be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than ANR Southern and Shipper.

beneficially owns, holds or controls fifty percent (50%) or more of the interest of such first mentioned entity. The term "control" means the possession, either directly or indirectly, of the power to direct or cause the direction of the management policies of an entity, whether through ownership of stock, as general partner, by contract or credit arrangement or otherwise.

11. Modification or Waiver. No modification or waiver of the terms and provisions of this Agreement shall be made except by the execution by the Parties of a written amendment to this Agreement.

12. Notices. All notices, requests, demands, instructions and other communications required or permitted to be given hereunder shall be in writing and shall be delivered personally or mailed by certified mail, postage prepaid and return receipt requested or by telex or telecopier, as follows:

If to ANR Southern:

ANR Southern Pipeline Company
Coastal Tower
Nine Greenway Plaza
Houston, Texas 77046
Attention: Mr. E. J. Burgin
Telephone No. (713) 877-3388
Facsimile No. (713) 877-3714

If to Shipper:

Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733
Attention: Mr. Stephen Watsey, C.P.M.
Telephone No. (813) 866-4382
Facsimile No. (813) 866-4941

Agreement have not been fulfilled or waived by the required date, as may be modified by Section 5.c. or Section 5.d., as applicable, then ANR Southern or Shipper, as the case may be, may terminate this Agreement pursuant to Section 5.d.

10. Assignment. This Agreement shall be binding upon ANR Southern, Shipper and their successors and assigns; provided, however, neither Party shall assign this Agreement or any rights or obligations hereunder without first obtaining the written consent of the other Party (which consent shall not be unreasonably withheld or delayed) and any regulatory authorizations reasonably deemed necessary by ANR Southern, unless such assignment is to an Affiliate of such Party desiring to make assignment; provided, however, any assignment by Shipper to an Affiliate of Shipper shall not relieve Shipper of any obligations, liabilities and responsibilities under this Agreement. Nothing contained herein shall prevent either Party from pledging, mortgaging or assigning its rights as security for its indebtedness and either Party may assign to the pledgee or mortgagee (or to a trustee for a holder of such indebtedness) any monies due or to become due under any Service Agreements. For purposes of this Agreement, the term "Affiliate" shall mean when used with respect to an entity, any other entity (i) which directly or indirectly (through one or more intermediaries) controls, or is controlled by, or is under common control with, such first mentioned person or entity or (ii) which

Agreement have not been fulfilled or waived by the required date as may be modified by Section 5.c., then Shipper may terminate this Agreement by giving written notice to ANR Southern not later than five (5) business days after the nonoccurrence of such condition by the required date, and this Agreement shall terminate upon the expiration of sixty (60) days from the receipt of such notice, unless within such period such condition has been fulfilled or has been waived by Shipper in writing.

b. In the event that the conditions set forth in Section 5.a.(i), Section 5.a.(iii) of this Agreement have not been fulfilled or waived by the required date, then ANR Southern may terminate this Agreement by giving written notice to Shipper not later than five (5) business days after the non-occurrence of any such condition by the required date, and this Agreement shall terminate upon the expiration of sixty (60) days from the receipt of such notice, unless within such period such condition has been fulfilled or has been waived by ANR Southern in writing.

c. In the event that the conditions set forth in Section 5.a. (ii) or Section 5.b. (iii) of this

capacity, then ANR Southern's transportation charge to Shipper for firm service rendered pursuant to this Agreement during the period such interruptible transportation capacity was not made available to Shipper shall be equal to the lowest weighted average transportation rate including rates for interruptible service paid by such similarly situated shipper multiplied by Shipper's MDQ as provided in this Agreement.

In the event that ANR Southern enters into a precedent agreement or service agreement to provide comparable interruptible transportation service to similarly situated shippers for ultimate consumption of natural gas within the State of Florida, at rates more favorable than the rates offered to Shipper by ANR Southern pursuant to the preceding paragraph, such rates shall be offered to Shipper with respect to the volumes and term of service set forth in such precedent agreement or service agreement, as applicable, with such similarly situated shipper. Shipper shall not be entitled to such rate unless Shipper transports the natural gas for its ultimate consumption within the State of Florida.

9. Termination. This Agreement shall become effective when executed by both ANR Southern and Shipper, and shall remain in effect unless and until terminated as hereinafter provided.

a. In the event that the condition set forth in Section 5.b.(i) or Section 5.D. (ii) of this

maintenance of the Additional Facilities and the use thereof for the purpose of providing Shipper with the Additional FT Service.

8. Interruptible Transportation Service. Concurrent with the execution of a Service Agreement for the FT Service, ANR Southern and shipper shall execute and deliver an interruptible transportation service agreement for up to 210,000 MMBtu per day in a form mutually agreed upon by the Parties. The interruptible transportation service agreement between ANR Southern and Shipper shall provide that at any time interruptible transportation service is available on the Florida Facilities, Shipper shall be entitled to, and ANR Southern shall offer, a proportionate share of the interruptible transportation capacity available as expressed by a fraction, the numerator of which is Shipper's MDQ as provided in its Service Agreement and the denominator of which is the aggregate firm MDQs for all FT Service over the Florida Facilities. Shipper shall advise ANR Southern whether or not it intends to receive all or any portion of such interruptible transportation service offered. If, and only if, ANR Southern fails to offer such interruptible capacity to Shipper as provided in this Section 8, and such interruptible capacity is used to provide interruptible transportation service to similarly situated shippers through the Florida Facilities for ultimate consumption of gas within the State of Florida, and Shipper does not have actual or constructive knowledge of the availability of interruptible transportation

Facilities (which shall be owned by Shipper but operated and maintained by ANR Southern or its nominee pursuant to a mutually acceptable operation and maintenance agreement) or (ii) agree to pay the otherwise applicable rate plus the incremental rate designed to recover all costs associated with the Additional Facilities. If Shipper exercises such election so that Additional Facilities are constructed, ANR Southern shall negotiate with Shipper in good faith for formal agreements with respect to FT Service over such Additional Facilities and the incremental rate for such FT Service, or the operation and maintenance of such Additional Facilities and the incremental rate and for such FT Service, as the case may be; provided, however, in the event the Parties are unable to agree upon the terms of service applicable to the construction of the Additional Facilities by ANR Southern, Shipper shall have the right to proceed under the provisions of the clause (i) of the first sentence of this Section 7.d.

e. ANR Southern and Shipper agree to cooperate with and assist one another for the purpose of obtaining any governmental and regulatory authorizations and approvals for the construction, operation and

practicable, ANR Southern shall determine the cost of expanding the Florida Facilities in order to provide capacity (the "Additional Facilities") for the Additional FT Service and the rates applicable to Service over the Additional Facilities and provide such information to Shipper together with ANR Southern's decision as to whether or not ANR Southern will construct and operate the Additional Facilities and provide the Additional FT Service.

c. If ANR Southern is willing to construct and operate the Additional Facilities and provide to Shipper the Additional FT Service, Shipper shall have sixty (60) days from the date of its receipt of notification of such fact by ANR Southern to commence negotiations for a formal agreement with respect to such Additional FT Service.

d. If ANR Southern is not willing to construct and operate the Additional Facilities and provide the Additional FT Service to Shipper, or if the Parties are unable to agree upon the terms and provisions of a service agreement with respect to such Additional FT Service, Shipper may elect, within sixty (60) days of receipt of notification, (i) to pay the cost of constructing the Additional

Service provided for in Section I. above (the "Additional FT Service") for an additional supply or supplies of natural gas to fuel Shipper's future gas requirements, Shipper shall, with respect to MDQ's of Additional FT Service up to an aggregate MDQ of 300,000 MMBtus (inclusive of the MDQ's of FT Service provided for under Sections 1. and 6.c. hereof) and Shipper may, with respect to any MDQ's of Additional FT Service in excess of an aggregate MDQ of 300,000 MMBtus, tender a written offer to ANR Southern to provide such Additional FT Service (including the amount of Additional FT Service required and supporting information in reasonable detail). If ANR Southern accepts such offer, ANR Southern shall provide such Additional FT Service pursuant to its then effective tariff, rate schedule or Service Agreement, as applicable. ANR Southern shall notify Shipper as to whether or not it accepts such offer to provide the Additional FT Service described in Shipper's offer within thirty (30) days after receipt of such offer.

b. If ANR Southern determines that the Florida Facilities do not have the capacity to provide the Additional FT Service for which Shipper has offered to contract with ANR Southern, as promptly as

(iii) If ANR Southern determines that contracting with Shipper to provide FT Service for the offered Replacement Gas Supply will provide economic benefits to ANR Southern, which are reasonably sufficient to ANR Southern in its sole discretion, the Parties shall negotiate in good faith with respect to a service agreement for the FT Service.

(iv) Shipper shall be obligated to continue to offer to contract with ANR Southern to provide FT Service pursuant to Section 6.c. (i) above until the Parties have entered into service agreements covering MDQ's of gas at least equal to the applicable Replacement Gas Supply, after which the obligations of the Parties under this Section 6.c. shall be deemed fully satisfied.

7. Expansion of the Florida Facilities. ANR Southern and Shipper agree as follows with respect to the future expansion of the Florida Facilities:

a. In the event that Shipper shall require firm transportation service in addition to the FT

preceding sentences of this Section 6.c. shall hereinafter be referred to as the "Replacement Gas Supply". Each offer by Shipper shall be made in writing and shall describe in reasonable detail the location of the proposed electric power generation unit or units, the MDQ of FT Service required and any other informa-tion pertinent to the nature and extent of such service.

(ii) Within thirty (30) days after receipt by ANR Southern of any offer by Shipper to contract for FT Service for all or a portion of the Replacement Gas Supply, ANR Southern shall determine, in the exercise of its good faith judgement, whether providing Shipper FT Service for the MDQ of Replacement Gas Supply over the term offered by Shipper will provide economic benefits to ANR Southern, which are reasonably sufficient to ANR Southern in the exercise of its good faith judgment, and shall so notify Shipper.

described in the second sentence of Section 4. hereof, the following provisions shall apply:

(i) In the event Shipper is unable to obtain the regulatory or environmental authorizations necessary to proceed with the construction of Shipper's first and second power generation units at its Polk County, Florida Powerpark, Shipper shall offer to ANR Southern the right to contract for FT Service at the rate then applicable under Section 2 hereof for the natural gas supply for all of the gas fired electric power generation units to be constructed by Shipper in Shipper's service area up to an aggregate MDQ of 90,000 MMBtus. In the event Shipper obtains the necessary regulatory and environmental authorizations for one but not both of such first and second power generation units, Shipper shall offer to ANR Southern the right to contract for FT Service at the rate then applicable under Section 2 hereof for an aggregate MDQ of up to 45,000 MMBtus. As applicable, the MDQ's of 90,000 MMBtus or 45,000 MMBtus described in the immediately

applicable to Shipper contained in the abstract. The rights of Shipper under this Section 6.a.(iv) shall become effective, if and only to the extent that, such other precedent agreement or service agreement provides for comparable service to similarly situated shippers. In the event that the Third Party Service does not commence, for whatever reason, the rate, terms and conditions of this Precedent Agreement and the Service Agreement originally agreed to by the Parties shall apply to the FT Service.

b. Upon the execution of this Agreement by the Parties, Shipper agrees that Shipper shall affirmatively support all governmental and regulatory authorizations and approvals sought by ANR Southern under the Florida Statutes for the construction and operation of the Florida Facilities, and shall take all actions consistent with Shipper's interests to assist ANR Southern in securing such governmental and regulatory authorizations.

c. Upon the execution of this Agreement by the Parties, ANR Southern and Shipper agree that under the circumstances

by notice to ANR Southern within thirty (30) days of receipt of ANR Southern's notice of such terms, to require that this Agreement and the Service Agreement be amended to include the initial rate and all material terms and conditions of service applicable to Shipper in the respective contract related to the Third Party Service. Such amendment shall continue to be effective for a term coextensive with such Third Party Service. Except as specifically amended pursuant to this Section, the terms and conditions of this Precedent Agreement and the Service Agreement shall remain in effect, and in the event that the term of such amendment expires prior to the term of the FT Service pursuant to this Precedent Agreement and the Service Agreement, after the expiration of such amendment, all of the terms and provisions of this Precedent Agreement and the Service Agreement shall be effective for the remaining term of the FT Service. Shipper shall not be entitled to select less than the initial rate and all of the material terms and conditions of service

Facilities to third parties as set forth in ANR Southern's applicable gas tariff; and

(iv) In the event that ANR Southern enters into a precedent agreement or service agreement to provide comparable service to similarly situated shippers for ultimate consumption of natural gas within the State of Florida through the Florida Facilities prior to the initial in service date of the Florida Facilities, on terms more favorable (in the reasonable judgment of ANR Southern to be exercised in good faith) than the initial rates and material terms and conditions of service applicable to Shipper provided for in this Agreement and the Service Agreement (the "Third Party Service"), ANR Southern shall promptly so notify Shipper, including in such notice an abstract of the initial rates and material terms and conditions of service applicable to Shipper related to the Third Party Service; provided, however, this provision shall in no way require ANR Southern to breach any confidentiality provision in any other precedent agreement. Shipper shall have the right, exercisable

the construction and operation of the Florida Facilities;

(ii) With respect to the Florida Facilities, ANR Southern shall make applications for all necessary authorizations and approvals to construct and operate the Florida Facilities, including, without limitation, all authorizations and approvals required under the Florida Statutes and shall prosecute such applications with all reasonable diligence;

(iii) ANR Southern shall exert commercially reasonable efforts to obtain all necessary authorizations and approvals required under the Florida Statutes for a tariff (consistent in all material respects with Exhibit C, if applicable), rate schedule and rate that authorizes ANR Southern to provide to Shipper the FT Service at the rates set out in Section 2 above, or such other mutually acceptable rates, and providing for the assignment of firm capacity held by Shipper on the Florida

raising such Objection, or until such time as the Party raising such Objection waives its reserved Objection. After the Regulatory Extension Period, if a reserved Objection has not been fulfilled or waived by the Party raising such Objection, such Party may elect to terminate this Agreement by giving written notice to the other Party. In the event that a Party chooses not to waive its reserved Objections and elects to terminate this Agreement, this Agreement shall terminate five (5) business days after such other Party receives the notice, unless the reserved Objection has been fulfilled or has been waived by the Party raising the Objection in writing during such five (5) day period. In no event shall the extension of time provided in Section 5.d. result in the dates specified in Section 5.a.(ii) and Section 5.b.(iii) being later than April 15, 1995, and the extension of time provided in Section 5.d. is subject, in all respects, to the rights of ANR Southern to require that Shipper make an election as provided for in Section 5.c.

6. Covenants of the Forties.

a. Upon the execution of this Agreement by the Parties, ANR Southern agrees that:

(i) ANR Southern shall exert commercially reasonable efforts to obtain financing for

material terms and conditions of the Regulatory Authorizations, or such unacceptable risks associated with any Third-party Challenge that may have a material adverse effect on either Party (collectively, the "Objections"), in writing, as soon as practicable but in no event later than fifteen (IS) days after receipt by ANR Southern of the Regulatory Authorizations or notice of any Third-Party Challenge, as the case may be; provided that in all events Shipper shall have at least three (3) business days from the date it receives a copy of such Regulatory Authorizations or notice of Third-Party Challenges to advise ANR Southern of any Objections thereto.

Each Party shall waive its rights under Section 5.a.(ii) and Section 5.b.(iii), as applicable, save and except for any reserved Objections; provided, however, no waiver shall be required until all Regulatory Authorizations have been issued by FPSC or the time for Third-Party Challenge has expired.

If ANR Southern has not accepted the Regulatory Authorizations, or ANR Southern has accepted the Regulatory Authorizations and there are reserved Objections, prior to the dates set forth in Section 5.a.(ii) and Section 5.b.(iii), the dates specified in Section 5.a.(ii) and 5.b.(iii) shall be extended for a period of thirty (30) days, or such longer period as the Parties may agree in writing (the "Regulatory Extension Period"), to resolve any reserved Objection to the satisfaction of the Party

(iii). ANR Southern agrees to provide Shipper a true copy of each and every Regulatory Authorization received by it with full particulars as to the date of its issuance and any material procedural dates with respect thereto, as promptly as practicable after its receipt by ANR Southern, but in no event later than three (3) business days thereafter. The Parties acknowledge and agree that the Regulatory Authorizations, as issued by the applicable regulatory authorities, may not be acceptable to ANR Southern and Shipper, or either ANR Southern or Shipper, or may be judicially challenged by third parties by rehearing petition before the FPSC, or by court appeal ("Third-Party Challenge"). ANR Southern further agrees to provide Shipper with notice of all such Third Party Challenges, if any, including such particulars as the date of filing and any material procedural dates with respect thereto as promptly as practicable after receipt of such notice by ANR Southern, but in no event less than three (3) business days thereafter.

If the Regulatory Authorizations contain material terms or conditions unacceptable to the Parties, or are subject to unacceptable risks associated with a Third Party Challenge that may have a material adverse effect on either Party, each Party shall advise the other Party of any objections to such

Southern's Board of Directors vote is scheduled to be taken. At least fifteen (IS) days prior to the scheduled vote of ANR Southern's Board of Directors, Shipper shall be required to exercise, in writing, its right to terminate this Agreement or waive its right to terminate this Agreement with respect to any Outstanding Conditions. In the event that Shipper chooses not to waive its Outstanding Conditions and elects to terminate this Agreement, this Agreement shall terminate five (5) business days after ANR Southern receives the notice, unless the Outstanding Conditions have been satisfied or have been waived by Shipper in writing during such five (5) day period.

d. With respect to the dates in the Conditions Precedent set forth in Section 5.a.(ii) and Section 5.b.(iii), the Parties contemplate that ANR Southern shall have been issued and accepted all of the regulatory and environmental authorizations and approvals required from the FPSC to construct, own and operate the Florida Facilities and offer the transportation service consistent with the terms of this Agreement (the "Regulatory Authorizations"), and the Parties further contemplate that the Regulatory Authorizations shall have become final and no longer subject to appeal as of the dates set forth in Section 5.a.(ii) and Section 5.b.

(iii) On or before August 31, 1994, ANR Southern shall have been issued and shall have accepted all regulatory authorizations and approvals required under the Florida Statues to construct, own and operate the Florida Facilities and offer the transportation service consistent with the terms of this Agreement, except those authorizations and approvals normally obtained after the FPSC authorizations and approvals have been issued and accepted, and all such authorizations and approvals shall have become final and subject to no further appeal.

c. If any of the Conditions Precedent in Section 5.b., as may be extended by Section 5.d., have not been fulfilled or waived by Shipper (the "Outstanding Conditions") thirty (30) days before the date upon which ANR Southern's Board of Directors is scheduled to vote on either (i) construction of the Florida Facilities, or (ii) acceptance of the term sheet with respect to financing construction of the Florida Facilities, ANR Southern's Board of Directors shall provide Shipper written notice at such time stating the date that ANR

financing of the construction of the Florida Facilities in such amount and on such terms and conditions as are acceptable to ANR Southern.

b. The obligation of Shipper to accept and pay for the FT Service in accordance with the terms of this Agreement and the Service Agreement is subject to the fulfillment, or waiver by Shipper, of the following conditions:

(i) On or before December 31, 1992, Shipper shall have executed Precedent Agreements satisfactory to Shipper for firm transportation upstream of the Florida Facilities required for the delivery of Shipper's Anclote Gas Supply to the receipt point specified in Exhibit B hereto; and

(ii) On or before March 1, 1993 ANR Southern shall have filed an application for authority to construct and operate the Florida Facilities in accordance with the Florida Statutes; and

agreements having a maximum daily quantity, in the aggregate, equal to at least 219,000 NMBtus;

(ii) On or before August 31, 1994, ANR Southern shall have been issued and shall have accepted all regulatory authorizations and approvals required under the Florida Statutes and all other necessary regulatory authorizations and approvals from federal, state, local and/or municipal agencies to construct, own and operate the Florida Facilities and offer the transportation service consistent with the terms of this Agreement, and all such authorizations and approvals shall have become final and subject to no further appeal; and

(iii) On or before May 1, 1995, the ANR Southern Board of Directors shall have voted to construct the Florida Facilities in accordance with applicable voting procedures, and ANR Southern shall have accepted a term sheet with respect to, and obtained a commitment for, the

or both of Shipper's proposed first and second power generation units at Shipper's Polk County, Florida Powerpark by the earlier of August 31, 1994 or fifteen (15) days prior to the scheduled vote of ANR Southern's Board of Directors on either (i) construction of the Florida Facilities or (ii) acceptance of the term sheet with respect to financing construction of the Florida Facilities, Shipper shall not be liable for the payment of reservation charges for FT Service for either or both of such increments of service, as the case may be, and ANR Southern and Shipper shall have the respective obligations set forth in Section 6.c. hereof.

5. Conditions Precedent.

a. The obligation of ANR Southern to provide FT Service to Shipper in accordance with the terms of this Agreement and the Service Agreement is subject to the fulfillment, or waiver by ANR Southern, of each of the following conditions:

(i) On or before December 31, 1992, ANR Southern shall have received executed precedent agreements in which shippers agree, on the initial in-service date of the Florida Facilities, to pay for firm transportation service through the Florida Facilities under service

Notwithstanding the foregoing, Shipper shall have the right to intervene and protest any such rate filing by ANR Southern with respect to changes in ANR Southern's maximum rates, terms and conditions of service or any other provision in its currently effective gas tariff.

3. Terms of Service. Subject to the terms and conditions of this Agreement and to such terms and conditions as may be or become applicable to ANR Southern's transportation service pursuant to the Florida Statutes, ANR Southern agrees to provide the FT Service on the terms and conditions substantially similar to those set forth in the Service Agreement and the Pro Forma tariff attached hereto as Exhibit C.

4. Execution of Service Agreement. Concurrently with the fulfillment or waiver of all of the Conditions Precedent set forth below in Section 5, ANR Southern and Shipper shall execute and deliver the Service Agreement, to be effective as of the dates described in Section I above. Shipper shall become liable for payment of reservation charges with respect to each increment of service under the Service Agreement on the dates described in Section 1 above, except that with respect to the increments of service described in Sections 1b. and 1.c. above, in the event Shipper is unable to obtain the regulatory or environmental authorizations necessary to proceed with the construction of either

TIME HRS	SUCT PSIG	DISC PSIG.	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	960.011	1145.260	1.190	557.770	5000.000	91.144	1.080
98.000	955.940	1144.208	1.194	546.946	5000.000	91.551	1.080
99.000	955.104	1148.039	1.199	534.082	5000.000	92.067	1.080
100.000	958.352	1159.397	1.207	515.742	5000.000	92.862	1.080
101.000	969.722	1186.063	1.220	487.705	5000.000	94.213	1.080
102.000	1001.873	1204.010	1.199	382.597	3478.070	91.995	0.751
103.000	1057.232	1202.452	1.136	325.375	2084.514	85.325	0.450
104.000	1102.481	1201.984	1.089	310.943	1326.282	80.243	0.286
105.000	1137.523	1201.741	1.056	307.475	827.322	76.490	0.179
106.000	1146.940	1201.440	1.050	306.649	728.976	75.744	0.157
107.000	1146.125	1201.507	1.050	317.083	780.179	75.951	0.169
108.000	1134.726	1201.747	1.058	360.357	1012.537	76.800	0.219
109.000	1115.612	1202.252	1.077	411.293	1512.744	78.879	0.327
110.000	1095.777	1202.806	1.096	451.049	2078.422	81.083	0.449
111.000	1079.573	1203.272	1.113	476.975	2570.247	82.917	0.555
112.000	1067.015	1203.562	1.126	497.203	2982.377	84.359	0.644
113.000	1046.098	1203.902	1.149	545.725	3834.803	86.793	0.828
114.000	1021.084	1204.712	1.177	579.492	4824.959	89.815	1.042
115.000	1009.958	1198.717	1.184	578.169	4999.933	90.534	1.080
116.000	1003.853	1190.101	1.183	581.739	5000.000	90.391	1.080
117.000	994.920	1179.531	1.183	581.052	5000.000	90.391	1.080
118.000	984.820	1168.549	1.184	577.409	5000.000	90.492	1.080
119.000	975.203	1158.739	1.186	572.026	5000.000	90.659	1.080
120.000	966.676	1150.566	1.187	565.735	5000.000	90.865	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	959.922	1145.187	1.190	557.673	5000.000	91.147	1.080
122.000	955.847	1144.129	1.194	546.854	5000.000	91.554	1.080
123.000	955.001	1147.943	1.199	534.007	5000.000	92.070	1.080
124.000	958.230	1159.227	1.207	515.797	5000.000	92.860	1.080
125.000	969.563	1185.869	1.220	487.705	5000.000	94.213	1.080
126.000	1002.077	1203.544	1.198	387.069	3533.646	91.932	0.763
127.000	1056.754	1202.459	1.136	325.903	2095.999	85.381	0.453
128.000	1102.072	1201.987	1.089	311.014	1332.540	80.288	0.288
129.000	1138.338	1201.771	1.055	307.585	817.003	76.406	0.176
130.000	1147.110	1201.454	1.050	306.921	731.871	75.763	0.158
131.000	1146.083	1201.511	1.050	317.340	781.305	75.954	0.169
132.000	1134.690	1201.748	1.058	360.395	1013.406	76.804	0.219
133.000	1115.620	1202.252	1.077	411.246	1512.640	78.878	0.327
134.000	1095.796	1202.805	1.096	450.984	2077.887	81.081	0.449
135.000	1079.622	1203.272	1.113	476.932	2568.235	82.915	0.555
136.000	1066.910	1203.561	1.126	497.656	2987.560	84.371	0.645
137.000	1045.772	1203.911	1.149	546.370	3848.391	86.832	0.831
138.000	1020.821	1204.731	1.178	579.797	4835.821	89.849	1.045
139.000	1009.825	1198.712	1.184	577.728	5000.000	90.549	1.080
140.000	1003.782	1190.062	1.183	581.601	5000.000	90.396	1.080
141.000	994.803	1179.442	1.183	580.900	5000.000	90.396	1.080
142.000	984.682	1168.429	1.184	577.272	5000.000	90.497	1.080
143.000	975.054	1158.599	1.186	571.908	5000.000	90.662	1.080
144.000	966.477	1150.340	1.187	565.689	5000.000	90.866	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	959.712	1144.949	1.190	557.619	5000.000	91.149	1.080
146.000	955.621	1143.869	1.194	546.810	5000.000	91.555	1.080
147.000	954.784	1147.704	1.199	533.934	5000.000	92.072	1.080
148.000	957.926	1158.849	1.207	515.772	5000.000	92.859	1.080
149.000	969.287	1185.502	1.220	487.726	5000.000	94.210	1.080
150.000	999.706	1204.787	1.202	381.840	3494.624	92.329	0.755
151.000	1056.269	1202.450	1.136	325.067	2097.105	85.433	0.453
152.000	1101.582	1201.984	1.090	310.907	1338.754	80.339	0.289
153.000	1137.161	1201.749	1.056	307.467	832.195	76.528	0.180
154.000	1146.873	1201.439	1.050	306.567	727.667	75.734	0.157
155.000	1146.233	1201.502	1.050	316.632	778.481	75.947	0.168
156.000	1134.797	1201.744	1.058	360.357	1010.940	76.792	0.218
157.000	1115.613	1202.252	1.077	411.407	1512.700	78.879	0.327
158.000	1095.730	1202.807	1.096	451.199	2079.865	81.089	0.449
159.000	1079.541	1203.274	1.113	477.088	2570.742	82.924	0.555
160.000	1067.040	1203.564	1.126	497.007	2980.437	84.357	0.644
161.000	1046.003	1203.904	1.149	545.994	3839.284	86.804	0.829
162.000	1020.939	1204.740	1.177	579.803	4832.539	89.836	1.044
163.000	1009.851	1198.736	1.184	577.753	5000.000	90.548	1.080
164.000	1003.788	1190.071	1.183	581.596	5000.000	90.396	1.080
165.000	994.792	1179.436	1.183	580.876	5000.000	90.397	1.080
166.000	984.652	1168.407	1.184	577.233	5000.000	90.498	1.080
167.000	975.008	1158.560	1.185	571.857	5000.000	90.664	1.080
168.000	966.464	1150.369	1.187	565.563	5000.000	90.870	1.080

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3B

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 5 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	968.074	1151.711	1.187	567.326	5000.000	90.810	1.080
1.000	961.532	1146.608	1.190	559.188	5000.000	91.094	1.080
2.000	957.630	1145.773	1.194	548.300	5000.000	91.502	1.080
3.000	956.931	1149.787	1.198	535.355	5000.000	92.020	1.080
4.000	960.421	1161.717	1.206	516.283	5000.000	92.844	1.080
5.000	972.248	1189.152	1.220	487.842	5000.000	94.214	1.080
6.000	1008.964	1203.885	1.190	384.635	3405.155	91.135	0.736
7.000	1063.758	1202.357	1.129	323.155	1967.562	84.572	0.425
8.000	1108.454	1201.969	1.083	310.619	1240.052	79.594	0.268
9.000	1141.807	1201.679	1.052	307.051	768.145	76.039	0.166
10.000	1147.379	1201.464	1.050	307.215	736.691	75.797	0.159
11.000	1146.241	1201.505	1.050	316.743	779.380	75.951	0.168
12.000	1134.789	1201.744	1.058	360.288	1011.010	76.793	0.218
13.000	1115.571	1202.251	1.077	411.339	1513.333	78.883	0.327
14.000	1095.729	1202.807	1.096	451.129	2079.629	81.089	0.449
15.000	1079.550	1203.274	1.113	477.038	2570.528	82.922	0.555
16.000	1067.038	1203.563	1.126	497.056	2980.878	84.357	0.644
17.000	1046.097	1203.902	1.149	545.799	3835.189	86.793	0.828
18.000	1021.111	1204.659	1.177	579.250	4820.825	89.807	1.041
19.000	1009.961	1198.699	1.184	578.233	4999.912	90.531	1.080
20.000	1003.999	1190.158	1.183	582.086	5000.000	90.379	1.080
21.000	995.386	1179.832	1.183	581.832	5000.000	90.365	1.080
22.000	985.496	1169.050	1.184	578.344	5000.000	90.461	1.080
23.000	976.039	1159.413	1.185	573.021	5000.000	90.625	1.080
24.000	967.630	1151.369	1.187	566.756	5000.000	90.830	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	960.964	1146.096	1.190	558.681	5000.000	91.112	1.080
26.000	956.942	1145.101	1.194	547.842	5000.000	91.518	1.080
27.000	956.147	1148.994	1.199	534.923	5000.000	92.036	1.080
28.000	959.481	1160.578	1.206	516.242	5000.000	92.843	1.080
29.000	971.028	1187.534	1.220	488.039	5000.000	94.200	1.080
30.000	1004.231	1204.779	1.197	373.283	3319.536	91.772	0.717
31.000	1060.690	1202.376	1.132	323.071	2015.034	84.922	0.435
32.000	1105.603	1201.972	1.086	310.682	1280.734	79.902	0.277
33.000	1139.522	1201.702	1.064	307.218	799.371	76.279	0.173
34.000	1147.076	1201.448	1.050	306.897	731.576	75.760	0.158
35.000	1146.184	1201.505	1.050	316.864	779.495	75.950	0.168
36.000	1134.767	1201.745	1.058	360.312	1011.561	76.796	0.219
37.000	1115.594	1202.251	1.077	411.316	1512.923	78.881	0.327
38.000	1095.748	1202.806	1.096	451.097	2079.155	81.087	0.449
39.000	1079.560	1203.273	1.113	477.015	2570.374	82.920	0.555
40.000	1067.028	1203.562	1.126	497.116	2981.510	84.358	0.644
41.000	1046.099	1203.902	1.149	545.770	3834.939	86.793	0.828
42.000	1021.118	1204.661	1.177	579.247	4820.654	89.806	1.041
43.000	1009.960	1198.702	1.184	578.219	4999.913	90.532	1.080
44.000	1003.927	1190.125	1.183	581.929	5000.000	90.384	1.080
45.000	995.173	1179.691	1.183	581.484	5000.000	90.377	1.080
46.000	985.180	1168.813	1.184	577.916	5000.000	90.475	1.080
47.000	975.647	1159.094	1.185	572.559	5000.000	90.641	1.080
48.000	967.181	1150.989	1.187	566.282	5000.000	90.846	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	960.474	1145.667	1.190	558.211	5000.000	91.128	1.080
50.000	956.422	1144.634	1.194	547.387	5000.000	91.535	1.080
51.000	955.604	1148.493	1.199	534.494	5000.000	92.052	1.080
52.000	958.892	1159.966	1.207	515.966	5000.000	92.854	1.080
53.000	970.346	1186.758	1.220	487.878	5000.000	94.206	1.080
54.000	1002.818	1204.503	1.198	377.530	3396.166	91.921	0.734
55.000	1058.889	1202.414	1.134	324.181	2050.372	85.132	0.443
56.000	1103.971	1201.978	1.088	310.806	1304.415	80.080	0.282
57.000	1138.389	1201.718	1.055	307.326	815.028	76.398	0.176
58.000	1146.969	1201.442	1.050	306.708	729.405	75.746	0.158
59.000	1146.170	1201.505	1.050	316.891	779.492	75.949	0.168
60.000	1134.759	1201.745	1.058	360.324	1011.735	76.796	0.219
61.000	1115.602	1202.251	1.077	411.318	1512.829	78.880	0.327
62.000	1095.757	1202.806	1.096	451.096	2078.954	81.086	0.449
63.000	1079.563	1203.273	1.113	477.012	2570.324	82.920	0.555
64.000	1067.026	1203.562	1.126	497.133	2981.678	84.358	0.644
65.000	1046.096	1203.902	1.149	545.768	3835.043	86.793	0.828
66.000	1021.114	1204.666	1.177	579.268	4821.064	89.807	1.041
67.000	1009.957	1198.701	1.184	578.210	4999.915	90.532	1.080
68.000	1003.882	1190.103	1.183	581.834	5000.000	90.388	1.080
69.000	995.037	1179.600	1.183	581.267	5000.000	90.384	1.080
70.000	984.985	1168.667	1.184	577.654	5000.000	90.484	1.080
71.000	975.409	1158.903	1.185	572.278	5000.000	90.650	1.080
72.000	966.913	1150.765	1.187	565.991	5000.000	90.856	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	960.186	1145.419	1.190	557.922	5000.000	91.139	1.080
74.000	956.119	1144.367	1.194	547.109	5000.000	91.545	1.080
75.000	955.288	1148.206	1.199	534.235	5000.000	92.061	1.080
76.000	958.546	1159.598	1.207	515.830	5000.000	92.859	1.080
77.000	969.948	1186.312	1.220	487.773	5000.000	94.210	1.080
78.000	1002.148	1204.236	1.199	380.447	3445.220	91.980	0.744
79.000	1057.833	1202.441	1.135	324.956	2072.134	85.255	0.448
80.000	1103.023	1201.982	1.089	310.890	1318.302	80.183	0.285
81.000	1137.840	1201.733	1.055	307.418	822.804	76.456	0.178
82.000	1146.948	1201.441	1.050	306.668	729.086	75.744	0.157
83.000	1146.149	1201.506	1.050	316.981	779.811	75.950	0.168
84.000	1134.744	1201.746	1.058	360.339	1012.116	76.798	0.219
85.000	1115.609	1202.252	1.077	411.307	1512.763	78.880	0.327
86.000	1095.768	1202.806	1.096	451.075	2078.695	81.084	0.449
87.000	1079.568	1203.272	1.113	476.995	2570.267	82.918	0.555
88.000	1067.020	1203.562	1.126	497.170	2982.065	84.359	0.644
89.000	1046.096	1203.902	1.149	545.746	3834.948	86.793	0.828
90.000	1021.104	1204.683	1.177	579.350	4822.489	89.810	1.042
91.000	1009.957	1198.708	1.184	578.192	4999.922	90.533	1.080
92.000	1003.860	1190.097	1.183	581.775	5000.000	90.390	1.080
93.000	994.961	1179.554	1.183	581.133	5000.000	90.388	1.080
94.000	984.878	1168.590	1.184	577.499	5000.000	90.489	1.080
95.000	975.277	1158.797	1.185	572.117	5000.000	90.656	1.080
96.000	966.758	1150.630	1.187	565.837	5000.000	90.861	1.080

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	954.338	1148.162	1.200	531.366	5000.000	92.177	1.080
98.000	947.430	1140.826	1.201	528.430	5000.000	92.279	1.080
99.000	941.666	1135.218	1.202	524.674	5000.000	92.422	1.080
100.000	937.249	1131.630	1.204	520.028	5000.000	92.609	1.080
101.000	934.768	1131.342	1.207	513.196	5000.000	92.902	1.080
102.000	935.116	1136.004	1.212	503.119	5000.000	93.363	1.080
103.000	943.626	1158.539	1.224	476.960	5000.000	94.672	1.080
104.000	958.573	1189.771	1.238	453.188	5000.000	96.019	1.080
105.000	996.151	1203.642	1.205	357.355	3401.645	92.675	0.735
106.000	1047.776	1202.170	1.145	312.988	2149.546	86.387	0.464
107.000	1089.667	1201.906	1.102	309.939	1505.481	81.639	0.325
108.000	1120.314	1201.914	1.072	333.185	1154.411	78.326	0.249
109.000	1125.270	1201.995	1.067	374.895	1214.927	77.820	0.262
110.000	1110.753	1202.398	1.081	417.837	1631.981	79.415	0.353
111.000	1094.012	1202.860	1.098	451.577	2120.384	81.279	0.458
112.000	1079.566	1203.271	1.113	475.848	2563.769	82.920	0.554
113.000	1065.589	1203.555	1.128	502.792	3049.724	84.521	0.659
114.000	1045.359	1204.000	1.150	541.109	3826.118	86.887	0.826
115.000	1020.078	1204.452	1.178	566.051	4737.805	89.904	1.023
116.000	1002.188	1198.346	1.193	553.190	4999.937	91.439	1.080
117.000	990.468	1187.629	1.196	543.780	5000.000	91.776	1.080
118.000	980.095	1176.730	1.198	539.134	5000.000	91.933	1.080
119.000	970.649	1166.298	1.199	536.184	5000.000	92.026	1.080
120.000	962.016	1156.665	1.199	533.731	5000.000	92.101	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	954.191	1148.025	1.200	531.257	5000.000	92.181	1.080
122.000	947.286	1140.689	1.201	528.331	5000.000	92.283	1.080
123.000	941.526	1135.082	1.202	524.584	5000.000	92.425	1.080
124.000	937.114	1131.498	1.204	519.945	5000.000	92.612	1.080
125.000	934.630	1131.195	1.207	513.142	5000.000	92.904	1.080
126.000	935.031	1136.022	1.212	502.834	5000.000	93.376	1.080
127.000	943.485	1158.299	1.224	477.102	5000.000	94.664	1.080
128.000	958.373	1189.450	1.237	453.314	5000.000	96.011	1.080
129.000	994.965	1204.062	1.207	344.452	3251.677	92.843	0.702
130.000	1047.456	1202.153	1.146	311.974	2147.621	86.423	0.464
131.000	1089.291	1201.904	1.102	309.972	1511.111	81.681	0.326
132.000	1119.980	1201.920	1.072	333.324	1159.804	78.362	0.251
133.000	1125.610	1201.970	1.067	374.706	1208.196	77.782	0.261
134.000	1110.795	1202.397	1.081	417.799	1631.178	79.411	0.352
135.000	1094.046	1202.866	1.098	451.615	2119.001	81.279	0.458
136.000	1079.570	1203.271	1.113	475.895	2563.939	82.920	0.554
137.000	1065.458	1203.556	1.128	503.195	3055.317	84.536	0.660
138.000	1045.091	1204.005	1.150	541.525	3836.357	86.919	0.829
139.000	1019.497	1204.469	1.179	566.839	4761.767	89.975	1.029
140.000	1001.911	1198.136	1.193	552.855	4999.961	91.451	1.080
141.000	990.230	1187.417	1.196	543.573	5000.000	91.784	1.080
142.000	979.878	1176.524	1.198	538.979	5000.000	91.939	1.080
143.000	970.446	1166.099	1.199	536.059	5000.000	92.030	1.080
144.000	961.810	1156.451	1.199	533.630	5000.000	92.105	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	953.990	1147.809	1.200	531.178	5000.000	92.184	1.080
146.000	947.089	1140.471	1.201	528.269	5000.000	92.285	1.080
147.000	941.333	1134.865	1.202	524.531	5000.000	92.427	1.080
148.000	936.917	1131.263	1.204	519.924	5000.000	92.612	1.080
149.000	934.430	1130.955	1.207	513.122	5000.000	92.904	1.080
150.000	934.671	1135.282	1.211	503.514	5000.000	93.343	1.080
151.000	943.025	1157.646	1.224	477.222	5000.000	94.655	1.080
152.000	957.986	1188.958	1.237	453.298	5000.000	96.010	1.080
153.000	995.067	1203.294	1.206	357.593	3419.133	92.769	0.739
154.000	1046.418	1202.182	1.147	313.319	2172.407	86.544	0.469
155.000	1088.506	1201.909	1.103	309.736	1521.277	81.767	0.329
156.000	1119.399	1201.916	1.073	333.005	1167.750	78.424	0.252
157.000	1125.032	1201.997	1.068	374.881	1218.692	77.846	0.263
158.000	1110.695	1202.399	1.081	417.922	1633.145	79.421	0.353
159.000	1093.973	1202.868	1.098	451.773	2120.978	81.287	0.458
160.000	1079.527	1203.273	1.113	475.894	2564.770	82.925	0.554
161.000	1065.552	1203.556	1.128	502.876	3051.127	84.526	0.659
162.000	1045.229	1203.999	1.150	541.263	3830.640	86.902	0.827
163.000	1019.528	1204.464	1.179	566.746	4759.944	89.971	1.028
164.000	1001.866	1198.115	1.193	552.764	4999.960	91.455	1.080
165.000	990.155	1187.369	1.196	543.464	5000.000	91.788	1.080
166.000	979.786	1176.454	1.198	538.870	5000.000	91.943	1.080
167.000	970.344	1166.014	1.199	535.956	5000.000	92.034	1.080
168.000	961.717	1156.375	1.199	533.532	5000.000	92.109	1.080

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3B

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 4 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	964.638	1159.009	1.198	535.972	5000.000	92.017	1.080
1.000	956.815	1150.456	1.199	533.281	5000.000	92.105	1.080
2.000	949.890	1143.176	1.200	530.147	5000.000	92.215	1.080
3.000	944.092	1137.598	1.202	526.207	5000.000	92.364	1.080
4.000	939.631	1134.019	1.204	521.392	5000.000	92.557	1.080
5.000	937.150	1133.846	1.207	514.262	5000.000	92.862	1.080
6.000	937.807	1139.490	1.212	502.761	5000.000	93.388	1.080
7.000	947.062	1163.427	1.225	475.771	5000.000	94.744	1.080
8.000	962.296	1194.961	1.238	452.363	5000.000	96.079	1.080
9.000	1007.688	1202.517	1.191	333.738	2971.548	91.141	0.642
10.000	1056.982	1202.079	1.135	310.227	1990.025	85.320	0.430
11.000	1097.895	1201.891	1.093	309 546	1385.418	80.735	0.299
12.000	1127.442	1201.883	1.065	332 794	1047.072	77.567	0.226
13.000	1126.632	1201.968	1.066	375.017	1191.641	77.674	0.257
14.000	1110.952	1202.393	1.081	417.952	1628.287	79.393	0.352
15.000	1094.026	1202.864	1.098	451.721	2119.977	81.280	0.458
16.000	1079.553	1203.272	1.113	475.870	2564.117	82.922	0.554
17.000	1065.595	1203.555	1.128	502.774	3049.444	84.521	0.659
18.000	1045.594	1204.015	1.149	541.203	3820.825	86.861	0.825
19.000	1021.512	1204.475	1.177	566.019	4696.480	89.735	1.014
20.000	1003.542	1199.192	1.192	555.296	4999.803	91.362	1.080
21.000	991.968	1188.787	1.195	545.531	5000.000	91.711	1.080
22.000	981.688	1178.064	1.197	540.718	5000.000	91.874	1.080
23.000	972.282	1167.741	1.198	537.620	5000.000	91.972	1.080
24.000	963.658	1158.172	1.199	535.033	5000.000	92.052	1.080

/*----------END OF FIRST DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	955.817	1149.562	1.200	532.436	5000.000	92.137	1.080
26.000	948.882	1142.230	1.201	529.399	5000.000	92.243	1.080
27.000	943.080	1136.612	1.202	525.552	5000.000	92.388	1.080
28.000	938.621	1133.003	1.204	520.820	5000.000	92.578	1.080
29.000	936.116	1132.741	1.207	513.847	5000.000	92.877	1.080
30.000	936.429	1137.358	1.211	503.758	5000.000	93.337	1.080
31.000	945.279	1160.863	1.225	476.435	5000.000	94.704	1.080
32.000	960.464	1192.438	1.238	452.712	5000.000	96.052	1.080
33.000	1002.935	1202.397	1.196	344.083	3142.590	91.712	0.679
34.000	1052.477	1202.132	1.140	311.995	2070.174	85.841	0.447
35.000	1093.906	1201.900	1.097	309.772	1443.579	81.172	0.312
36.000	1124.323	1201.913	1.068	333.079	1094.594	77.900	0.236
37.000	1126.191	1201.962	1.066	374.933	1198.671	77.720	0.259
38.000	1110.897	1202.394	1.081	417.906	1629.275	79.399	0.352
39.000	1094.025	1202.863	1.098	451.671	2120.016	81.279	0.458
40.000	1079.559	1203.272	1.113	475.862	2563.975	82.921	0.554
41.000	1065.593	1203.555	1.128	502.778	3049.498	84.521	0.659
42.000	1045.514	1204.010	1.150	541.165	3822.572	86.870	0.826
43.000	1020.888	1204.462	1.177	566.000	4714.139	89.808	1.018
44.000	1002.927	1198.804	1.192	554.341	4999.846	91.397	1.080
45.000	991.269	1188.251	1.196	544.703	5000.000	91.742	1.080
46.000	980.943	1177.442	1.197	539.972	5000.000	91.902	1.080
47.000	971.515	1167.065	1.198	536.944	5000.000	91.997	1.080
48.000	962.887	1157.464	1.199	534.420	5000.000	92.076	1.080

/*----------END OF SECOND DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	955.052	1148.839	1.200	531.880	5000.000	92.158	1.080
50.000	948.130	1141.504	1.201	528.897	5000.000	92.262	1.080
51.000	942.347	1135.890	1.202	525.097	5000.000	92.406	1.080
52.000	937.908	1132.289	1.204	520.412	5000.000	92.594	1.080
53.000	935.416	1132.013	1.207	513.510	5000.000	92.890	1.080
54.000	935.731	1136.606	1.211	503.494	5000.000	93.347	1.080
55.000	944.399	1159.625	1.224	476.711	5000.000	94.687	1.080
56.000	959.468	1191.038	1.238	452.953	5000.000	96.035	1.080
57.000	999.773	1202.740	1.200	351.082	3268.570	92.137	0.706
58.000	1049.985	1202.154	1.143	312.684	2113.112	86.130	0.456
59.000	1091.677	1201.904	1.100	309.036	1475.945	81.418	0.319
60.000	1122.240	1201.914	1.070	333.097	1125.554	78.121	0.243
61.000	1125.510	1201.982	1.067	374.952	1210.632	77.794	0.262
62.000	1110.786	1202.397	1.081	417.881	1631.367	79.411	0.352
63.000	1094.008	1202.863	1.098	451.652	2120.351	81.281	0.458
64.000	1079.557	1203.272	1.113	475.860	2564.012	82.922	0.554
65.000	1065.590	1203.555	1.128	502.785	3049.628	84.521	0.659
66.000	1045.430	1204.005	1.150	541.145	3824.543	86.880	0.826
67.000	1020.467	1204.455	1.178	565.999	4726.198	89.858	1.021
68.000	1002.542	1198.561	1.193	553.742	4999.879	91.419	1.080
69.000	990.845	1187.923	1.196	544.212	5000.000	91.760	1.080
70.000	980.495	1177.065	1.197	539.531	5000.000	91.918	1.080
71.000	971.058	1166.659	1.198	536.546	5000.000	92.012	1.080
72.000	962.428	1157.042	1.199	534.060	5000.000	92.089	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	954.599	1148.411	1.200	531.553	5000.000	92.170	1.080
74.000	947.687	1141.076	1.201	528.599	5000.000	92.273	1.080
75.000	941.916	1135.466	1.202	524.828	5000.000	92.416	1.080
76.000	937.491	1131.871	1.204	520.170	5000.000	92.603	1.080
77.000	935.004	1131.587	1.207	513.312	5000.000	92.898	1.080
78.000	935.334	1136.204	1.211	503.284	5000.000	93.356	1.080
79.000	943.904	1158.933	1.224	476.862	5000.000	94.677	1.080
80.000	958.897	1190.230	1.238	453.101	5000.000	96.025	1.080
81.000	997.503	1203.284	1.203	355.040	3351.339	92.471	0.724
82.000	1048.577	1202.164	1.144	312.886	2136.337	86.294	0.461
83.000	1090.399	1201.905	1.101	309.885	1494.627	81.559	0.323
84.000	1121.023	1201.914	1.071	333.137	1143.737	78.251	0.247
85.000	1125.331	1201.990	1.067	374.919	1213.795	77.814	0.262
86.000	1110.760	1202.398	1.082	417.857	1631.856	79.414	0.352
87.000	1094.009	1202.861	1.098	451.617	2120.390	81.280	0.458
88.000	1079.561	1203.272	1.113	475.855	2563.912	82.921	0.554
89.000	1065.588	1203.555	1.128	502.791	3049.722	84.521	0.659
90.000	1045.384	1204.002	1.150	541.124	3825.587	86.885	0.826
91.000	1020.222	1204.453	1.178	566.019	4733.399	89.887	1.022
92.000	1002.319	1198.423	1.193	553.396	4999.907	91.432	1.080
93.000	990.605	1187.735	1.196	543.937	5000.000	91.770	1.080
94.000	980.240	1176.851	1.198	539.279	5000.000	91.928	1.080
95.000	970.797	1166.428	1.198	536.316	5000.000	92.021	1.080
96.000	962.165	1156.800	1.199	533.851	5000.000	92.097	1.080

/*----------END OF FOURTH DAY----------->

Florida Power
CORPORATION

INTEROFFICE CORRESPONDENCE

System Planning Department | B3L | 231-4220
OFFICE | MAC | TELEPHONE

SUBJECT: **Anclote Gas Conversion and Pipeline Project**

TO: **D. D. Williams** DATE: **October 5, 1992**

Based on the conclusion of the memo to you dated September 14, 1992, a new alternative was formulated to maximize the net benefit to Florida Power Corporation. The new alternative is described as follows:

> Provide 120,000 MCF/day of gas initially with the high sulfur No. 6 oil as the secondary fuel at Anclote. In order to avoid the fuel switching at CR 1 & 2 in year 2000, the gas volume is increased to 165,000 MCF/day at Anclote and the secondary fuel is switched to low sulfur No. 6 oil in 2000. An additional 45,000 MCF/day each for Polk County Units 1 & 2. The demand charges for the pipeline is based on a 24 inch pipeline amortized for 25 years.

This alternative was analyzed based on the same base assumptions used in the September 14, 1992 memo. The result of the economic analysis is shown in the attached table. Because the secondary fuel at Anclote is high sulfur, the total fuel savings has increased significantly. The cumulative fuel savings is about $30 million as compared to $13 million in Alternative 1 in the September 14 memo. This fuel savings has resulted in a present worth net benefit of $30 million for FPC over the study period.

If consuming the high sulfur No. 6 oil as the secondary fuel is feasible at Anclote, this alternative is the most economical. It would provide the maximum benefit to FPC's customers.

If you have any questions, please let me know.

J. J. Tang
Senior Generation Planning Engineer

c: R. D. Niekum

JJT:92-SEP-ANCLOTE-10/bhl

Attachment

Economic Impact For Anclote Gas Conversion And
Gas Pipeline Project

120,000 M/D in 1996, HS Oil As Secondary Fuel @ Anclote Before 2000
Additional 45,000 M/D For Anclote In 2000 And 45,000 M/D For Each CC

Year	Savings/(Cost)
1992	$0
1993	$0
1994	$0
1995	$0
1996	$1,021,051
1997	($1,683)
1998	$1,017,526
1999	$5,031,706
2000	$13,534,130
2001	$14,384,577
2002	$12,632,561
2003	$14,659,827
2004	$9,301,390
92NPV	$29,685,806
PWRR Gas Conversion	($20,309,702)
PWRR Fuel Switching At CR 1&2	$19,673,166
Net Benefit /(cost)*	$29,049,270

* Net Benefit/(Cost) = Net Fuel Savings/(cost) +
PWRR Gas Conversion + PWRR Fuel Switching

Fuel Savings/(cost) For Natural Gas cost Sensitivities

Year	+20%	Base	-20%
1992	$0	$0	$0
1993	$0	$0	$0
1994	$0	$0	$0
1995	$0	$0	$0
1996	($16,943,738)	$1,021,051	$19,976,736
1997	($19,040,824)	($1,683)	$21,650,391
1998	($20,452,865)	$1,017,526	$24,800,371
1999	($18,051,574)	$5,031,706	$30,500,893
2000	($19,317,651)	$13,534,130	$44,771,956
2001	($21,459,170)	$14,384,577	$50,289,742
2002	($25,722,159)	$12,632,561	$50,221,382
2003	($26,973,784)	$14,659,827	$55,182,930
2004	($25,289,044)	$9,301,390	$47,241,151
92NPV	($90,889,293)	$29,685,806	$154,790,085
Probability	0.25	0.50	0.25
Expected Fuel Savings/(Cost) =			$30,818,101

Florida Power
CORPORATION

INTEROFFICE CORRESPONDENCE

System Planning Department (OFFICE) | B3L (MAC) | 231-4220 (TELEPHONE)

SUBJECT: Anclote Gas Conversion and Pipeline Project

TO: D. D. Williams

DATE: September 14, 1992

The purpose of this memo is to update you regarding the economic evaluation of converting Anclote to gas, and the gas pipeline project based on the latest assumptions.

Generation Planning used the August 1992 Business Plan Forecast in the current base case. The study period goes out to 2004. Other key assumptions are listed as follows:

1. The Polk County combined cycle unit 3 has been postponed to November 2003. The Polk county combine cycle unit 4 is not included in the study.

2. The Anclote Plant gas conversion cost is approximately $17 million (in 1992 $) for both units. It is a 100% gas conversion. Due to potential environmental concerns, the secondary fuel is low sulfur No. 6 oil.

3. Anclote will be on gas on January 1, 1996.

4. The base scenario is Anclote Plant on low sulfur oil and the Polk County combined cycle units on Florida Gas Transmission gas.

5. Seasonal variation of gas pricing structure is captured in the study.

Many alternatives were considered for the economic evaluation of the Anclote gas conversion and the pipeline project. Based on the Anclote Plant gas consumption, two alternatives emerged as the most reasonable scenarios for the study after the preliminary screening. The two alternatives are:

1. 120,000 MCF/day initially for Anclote, and an additional 45,000 MCF/day each for Polk County Units 1 & 2. The ultimate contract amount for this alternative is 210,000 MCF/day. The 120,000 MCF/day of gas supply represents the minimum requirement for anchoring the gas pipeline. The fixed charges for the pipeline is based on a 24 inch pipeline amortized for 25 years. Attachment I shows the gas price forecast which includes the fixed and variable components.

2. 168,000 MCF/day initially for Anclote, and an additional 45,000 MCF/day each for Polk County Units 1 & 2. The ultimate contract amount for this alternative is 258,000 MCF/day. The 168,000 MCF/day of gas supply is approximately the maximum amount Anclote Plant can consume. The fixed charges for the pipeline are calculated based on a 30 inch pipeline amortized for 25 years. Attachment II shows the gas price forecast which includes the fixed and variable components.

Basically, the study evaluated the economic impact of the gas pipeline and its gas supply during the study period vs. the total revenue required for the Anclote gas conversion. Attachment III shows the table of the economic impact for Alternatives 1 and 2. For a capital project of gas conversion at Anclote in 1996, the present-worthed cumulative revenue requirement is approximately $20.3 million. The study shows that the total present worth fuel savings for Alternative 1 over the study period is about $12.7 million. The net cost is about $7.6 million. Unless future fuel savings beyond the year 2004 are considered, Alternative 1 is not cost-effective.

The study indicates that Alternative 2 ends up with a present worth additional fuel cost of about $13 million for the gas conversion and pipeline during the study period. The study also shows that the total SO_2 emission of Alternative 2 is under the allowance limit even without fuel switching at CR 1 & 2. Without fuel switching at CR 1 & 2, Alternative 2 could provide a total present worth fuel benefit of about $8.4 million. The cumulative present worth revenue requirements for the avoided capital project of fuel switching at CR 1 is about $19.7 million. There is a net benefit of $7.7 million. In this respect, Alternative 2 is considered cost-effective.

It is clearly indicated in the course of the study that Anclote gas conversion is not as cost-effective as it once was during the inception of the gas pipeline project evaluation process. However, it is cost effective when FPC uses the Anclote gas conversion to help meet its SO_2 emission limit without fuel switching at CR 1 & 2 in the year 2000. Compared to the alternative of using FGT gas for the Polk County combined cycle units, the Anclote gas conversion and the gas pipeline project can be beneficial in the long run both economically and strategically. It would be in FPC's best interest to secure a minimum gas supply for Anclote initially and to have the capability to expand later. This expansion should be staged for the Polk County units and provide an alternative to meet the SO_2 emission limit in the year 2000.

If you have any questions or require additional information, please let me know.

J. J. Tang
Senior Generation Planning Engineer

c: R. D. Niekum
L. B. Tittle

JJT:92-SEP-ANCGAS-10/bhl

Attachments

ATTACHMENT I

FUEL & SPECIAL PROJECTS
United/Suncoast Pipeline 24" Line/25 Year Contract
Anclote & Polk County Plants

	Available [1] Volume 10^6BTUs	Price ¢/10^6BTUs Variable[3]	Fixed
1996 (June)	120,000/day	242	76
1997	120,000/day	263	76
1998 (Aug)	165,000/day	284	76
1999 (Aug)	210,000/day[2]	305	76
2000	210,000/day	336	76
2001	210,000/day	353	76
2002	210,000/day	371	76
2003	210,000/day	389	76
2004	210,000/day	409	76
2005	210,000/day	430	76
2006	210,000/day	451	76
2007	210,000/day	472	76
2008	210,000/day	496	76
2009	210,000/day	520	76
2010	210,000/day	545	76
2011	210,000/day	571	76
2012	210,000/day	599	76
2013	210,000/day	627	76
2014	210,000/day	657	76

(1) 1,000 BTU/CF
(2) Option for 45,000/day each for Polk 3 & 4.
(3) Add ten cents in Winter (October-March) and subtract ten cents in Summer (April-September) due to seasonal price patterns.

DDW 8/31/92

ATTACHMENT II

FUEL & SPECIAL PROJECTS
United/Suncoast Pipeline 30" Line/25 Year Contract
Anclote & Polk County Plants

	Available [1] Volume 10^6BTUs	Price ¢/10^6BTUs Variable	Fixed
1996 (June)	168,000/day	242	73
1997	168,000/day	263	73
1998 (Aug)	213,000/day	284	73
1999 (Aug)	258,000/day[2]	305	73
2000	258,000/day	336	73
2001	258,000/day	353	73
2002	258,000/day	371	73
2003	258,000/day	389	73
2004	258,000/day	409	73
2005	258,000/day	430	73
2006	258,000/day	451	73
2007	258,000/day	472	73
2008	258,000/day	496	73
2009	258,000/day	520	73
2010	258,000/day	545	73
2011	258,000/day	571	73
2012	258,000/day	599	73
2013	258,000/day	627	73
2014	258,000/day	657	73

(1) 1,000 BTU/CF
(2) Option for 45,000/day each for Polk 3 & 4.
(3) Add ten cents in Winter (October-March) and subtract ten cents in Summer (April-September) due to seasonal price patterns.

DDW 9/14/92

Attachment III

Economic Impact For Anclote Gas Conversion And Gas Pipeline Project

Alternative 1 - 120,000 M/D in 1996, Additional 90,000 M/D For CCs
Alternative 2 - 168,000 M/D in 1996, Additional 90,000 M/D For CCs

Year	Alt 1 Fuel Savings/(Cost)	Alt 2 Fuel Savings/(Cost)	Alt 2 w/o Fuel Switching CR1&2 Savings/(Cost)
1992	$0	$0	$0
1993	$0	$0	$0
1994	$0	$0	$0
1995	$0	$0	$0
1996	($4,877,004)	($10,362,751)	($10,362,751)
1997	($5,298,458)	($11,579,909)	($11,579,909)
1998	($5,458,824)	($10,860,776)	($10,860,776)
1999	$977,041	($6,678,806)	($6,678,806)
2000	$11,671,886	$4,921,580	$14,924,930
2001	$12,488,366	$5,441,311	$15,890,060
2002	$9,455,450	$3,302,126	$14,452,064
2003	$10,709,489	$5,373,905	$16,010,432
2004	$11,056,471	$9,988,128	$21,939,858
92NPV	$12,737,570	($12,905,984)	$8,368,624
PWRR Gas Conversion	($20,309,702)	($20,309,702)	($20,309,702)
PWRR Fuel Switching At CR 1&2			$19,673,166
Net Benefit /(cost)*	($7,572,132)	($33,215,686)	$7,732,088

* Net Benefit/(Cost) = Net Fuel Savings/(cost) + PWRR Gas Conversion + PWRR Fuel Switching

Customers Impact Analysis For Anclote Gas Conversion In 1996

Year	(1) Annual Fuel Bnft	(2) Cumulative PW* Fuel Bnft	(3) Annual Rev Req**	(4) Cumulative PW Rev Req	(1)-(3) Annual Net Benefit	(2)-(4) Cum PW Net Benefit	(2)/(4) Cumulative Benf/Cost
1993							
1994							
1995							
1996	1,021,051	704,281	2,921,166	2,014,906	(1,900,115)	(1,310,625)	0.35
1997	(1,683)	703,223	2,921,166	3,851,145	(2,922,849)	(3,147,922)	0.18
1998	1,017,526	1,286,122	2,921,166	5,524,561	(1,903,640)	(4,238,439)	0.23
1999	5,031,706	3,912,986	2,921,166	7,049,592	2,110,540	(3,136,606)	0.56
2000	13,534,130	10,352,118	2,921,166	8,439,394	10,612,964	1,912,723	1.23
2001	14,384,577	16,589,016	2,921,166	9,705,960	11,463,411	6,883,056	1.71
2002	12,632,561	21,580,591	2,921,166	10,860,217	9,711,395	10,720,374	1.99
2003	14,659,827	26,859,567	2,921,166	11,912,123	11,738,661	14,947,444	2.25
2004	9,301,390	29,911,980	2,921,166	12,870,755	6,380,224	17,041,225	2.32

* Present worth to 1/1993 @ discount rate of 9.73%.
** Based on conversion cost of $16,610,000 in 1992 and fixed charge rate of 15.11%.

Hibbs' Study

JOHN J. HIBBS & ASSOCIATES, INC.
13131 Champions Drive • Suite 206 • Houston, Texas 77069
P. O. Box 680304 • Houston, Texas 77268-0304

JOHN J. HIBBS, President

(713) 893-9784

An Energy Services Company

December 2, 1992

Mr. James T. Pollard,
Director, Information Services
Florida Power Corp.
P.O. Box 14042
St. Petersburg, FL 33711

Re: SunShine / SITCO Project
Pipeline Competition and Equity Participation Issues

Dear Jim:

Pursuant to our discussion yesterday, I have given the above captioned matters some thought and have set forth below some points that Florida Power might consider when weighing its options with regard to competing gas transportation services and potential project equity participation.

Merits of Competitive Pipeline Services

As a general matter, having two or more pipelines in a service area will:

- foster competition in terms of rates and services;
- provide for supply or producer diversification, and
- provide alternative shipping opportunities.

In the instant case, the construction of SITCO and SunShine, and the resulting competition with Florida Gas Transmission should provide FPC with the long term benefits of superior gas transportation services at costs less than would be incurred if FGT continued as Florida's sole gas pipeline supplier. Without a doubt, an additional Florida pipeline will promote a competitive atmosphere and should result in future lower rates, more responsive services, and more diversified supply opportunities.

As to what can happen when there is no competition and the pipeline supplier enjoys a captive market, let me site a recent, real time example. An LDC client requested that its pipeline supplier provide it with an incremental firm transport service. In the meantime an independent facility analysis was performed which indicated that virtually no additional facilities would be required to actually render the very modest requested service addition. However, the pipeline, after taking months to respond to the request,

advised the LDC that some ten miles of large diameter, main line looping would be necessary to effect the service (as a result of the pipeline employing an ultra conservative pipeline design formula no longer in general industry use) and, adding insult to injury, proposed that the LDC make a capital contribution in aid of construction that was based on a unit cost for the pipeline facilities that was double the general industry standard in that geographic location. Needless to say, the plans for that particular project were aborted. The point of relating this incident is simply to demonstrate that there is little incentive for a pipeline to operate efficiently when it is not in a competitive market environment. In fact, even where pipelines in this monopolistic situation are not intentionally "gold plating" the design and cost estimates, you will find, at the minimum, a natural tendency to error on the conservative side. This is simply the "nature of the beast."

Generally speaking, while the establishment of dual pipeline service may come at some initial cost premium since an existing pipeline can typically expand its system at a cost less than that associated with the construction of a new system, I don't see this as an issue (at least not a significant one) in this case. Based on the FGT Phase III filing, the proposed FGT initial rate for new incremental service was indeed marginally higher than the comparable rates estimated for SITCO and SunShine. Assuming that any further expansion on FGT for FPC service would result in a somewhat similar rate, then, it appears to me that the advantages that the two pipeline system would bring to south Florida, can be achieved for little or no initial premium. More importantly, even if such an initial cost premium was required, FPC (or its electric rate payers) should seriously consider absorbing such an initial differential, if not overly burdensome or a perceived prudency issue, in order to enjoy the long term competitive benefits that the alternative system will generate. How much of a premium should FPC be willing to pay? That is a very subjective matter and the question can only be answered by FPC itself.

Merits of FPC Taking an Equity Position

By taking an equity position (even a very minor percentage) in the proposed SunShine project, FPC, or its designated affiliate or subsidiary, can control, or at least influence:

- the project's management philosophy;
- O&M expenditures;
- major capital expenditures;
- the development of capital and O&M budgets, and
- rate design and cost allocation methodology.

While the exact rights of a minority interest venture partner such as FPC would have to be negotiated with Coastal or ANR and incorporated in the formal partnership or joint venture agreement, FPC is obviously in an excellent bargaining position given the fact

that it is the keystone shipper. Simply put, without FPC, the Sun will not Shine! This should put FPC in a position of extracting a position in the venture virtually equal to Coastal. For example, FPC should be able to persuade Coastal that every significant project decision must require unanimous approval. On the other hand, FPC must keep its demands within reason or Coastal might opt to abort the project, and this would not be in FPC's best interest, unless United is standing by with an equally attractive proposal or FPC stands ready to enter the gas pipeline business itself.

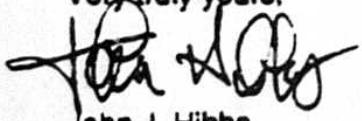
While it is also true that such an equity position comes at a price, the benefits of being able to control one's gas supply and transportation "destiny" in my opinion, far outweigh the investment. Further, the equity investment should earn a modest, 14.25% return in the process. While there may be other investment opportunities for FPC that exceed this rate of return on equity, I doubt that there are many, if any, opportunities that couple a reasonable return with the collateral long term benefits described above.

Should FPC opt to take an equity position in the SunShine project, then its interests would be like a two edged sword in that its position as a shipper will not always be in phase with its position as an equity participant. This should not be a major issue, however, since the potential equity percentage is relatively small and FPC's principal interest in the project should lie as a shipper.

In summary, it is my opinion that it would be to FPC's significant long term gas transportation rate and service advantages to support SunShine or some other equally attractive alternative Florida pipeline system, and take a small equity position in said system, even at the initial expense of a rate differential premium and a lost capital investment opportunity that might have generated a higher equity return.

I hope you find this opinion responsive to your request. If you need anything further from me regarding this matter, please advise.

Very truly yours,



John J. Hibbs

FLORIDA POWER CORPORATION

SITCO & SUNSHINE PIPELINE PROJECT

TECHNICAL & ECONOMIC ANALYSIS

December 1992

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- 2 **ANR Design Criteria**
- 3 **Design Audit Results and Diagrams - Base Case**
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STUDY OBJECTIVES

The study objectives were to evaluate, from both technical and economic perspectives, the newly proposed ANR projects, SunShine Pipeline Company ("SunShine") and SunShine Interstate Transmission Company ("SITCO").

The specific case to be tested was the so called 30" Option I or Base Case for the year 1999 with an associated nominal throughput of 504.5 MMCFD. For SunShine the proposed facilities include 503 miles of various diameter pipelines and 13,000 horsepower at an estimated cost of $464 million. For SITCO, the proposed facilities include 197 miles of various diameter pipelines and 8000 horsepower at an estimated cost of $177 million. See Exhibit 1 for basic system configuration and cost estimate summaries provided by ANR.

Specific project deliverables to be provided in this preliminary report were:

- a design audit and opinion on the proposed facilities for both SunShine and SITCO utilizing a transient flow pipeline simulation model;

- a review of and opinion on the capital cost and operating cost estimates for both SunShine and SITCO, and

- a cost of service and rate derivation validation for both SunShine and SITCO utilizing a financial check model.

MAJOR FINDINGS

- As a general observation, no major flaws in design, capital cost estimates, cost of service or rates for either SunShine or SITCO were observed.

- Facility designs for SunShine and SITCO are appropriate. In fact, the design of the proposed 30" Base Case system is close to optimal.

- With the addition of 20,000 horsepower, the proposed 30" system can support an increase of 75 MMCFD in power generation load on the southern end of the system.

- An alternative 26" system with 41,000 horsepower was evaluated. The overall cost of service for this alternative system was estimated to be slightly greater than the proposed 30" system and it would not provide for expansion without pipeline looping.

- The capital cost estimates of $464 million for SunShine and $177 million for SITCO are reasonable.

- The initial report stated that the original combined annual operating cost estimate for SunShine and SITCO, $3.3 million, may be understated by as much as $9 million, or 10% of the total cost of service. However, more recent projections, which reflect substantial ANR technical and staff support, indicate operating expenses may be in the $4.1 to $7.5 million range or some $1 to $4 million more than the original ANR estimate. Such operating cost variations could

result in initial rates being some 1¢ to 3¢ greater than the combined rate originally projected by ANR.

• The original cost of service and rate derivation analyses by ANR were generally validated.

FACILITY DESIGN

Input Conditions

The basic design parameters and conditions defined by ANR are incorporated within Exhibits 1 and 2 and were utilized as direct input to this audit model. These input data include pipe segment lengths and diameters, horsepower amounts and locations, hourly loads by delivery point, and select design criteria.

While ANR did not provide (1) an estimate of yard piping pressure drops at each of the compressor stations; (2) an estimate of meter station pressure drops, or (3) an estimate of compressor efficiency, it was assumed for the purpose of this design audit that there would be a 5 PSIG loss into and a 5 PSIG loss out of each compressor station; a 10 PSIG drop through each meter station, and an overall compressor efficiency of 78%. Also note that compressor fuel was calculated utilizing a 9000 BTU per brake horsepower hour heat rate.

Further, the Stoner model incorporates the Benedict-Webb-Rubin-Starling equation for compression calculations and the Colebrook-White equation for flow and pressure drop calculations.

The Transient Flow Pipeline Simulation Model

In order to audit the design of the combined SITCO and SunShine system, a transient flow model, using Stoner's Drem Pipeline Simulator ("DPS") was created. Transient analysis was necessary due to the widely varying hourly flow conditions projected for this system. For example, the total system hourly load varies from a low of 15 MMCF per hour to a high of 33 MMCF per hour. Hourly flows at certain individual delivery points are estimated to vary as much as 500% within a 24 hour period.

Design Audit Results - Base Case

First, a seven day - twenty four hour per day base case was developed for the ANR referenced 30" Option I for the year 1999. Set forth at Exhibit 3 (Base Case) are the results of this analysis. You will note, given the proposed facilities and the projected hourly load pattern, that the minimum pressure encountered during the seven day simulation was 554 PSIG and that minimum pressure occurred at the SEC Hardee delivery point. Allowing for a 10 PSIG drop through the M&R station, the delivery pressure would be 544 PSIG, which is safely above the contract minimum of 450 PSIG.

Note that fuel consumption for this Base Case is estimated at 4.2 MMCFD or 0.8% of nominal throughput.

Secondly, an alternate case was developed to test the maximum capability of the proposed facilities. For this purpose, the power generation loads on the southern end of

the system (Anclote, FPC Power Park and SEC Hardee) were ramped up until the lowest observed pressure dropped below the 450 PSIG minimum. Set forth at Exhibit 3A (Base Case X 103%) are the results of a scenario that approximates this maximum throughput condition. You will note that when the hourly Anclote, Power Park and Hardee loads were increased some 3%, the minimum observed pressure dropped to 472 PSIG. Again, allowing for a ten pound drop through the M&R station, the delivery pressure dropped to 462 PSIG, only 12 PSIG above minimum. Stated differently, this scenario demonstrates that the proposed facilities will operate within some 3% of their maximum design capability at the proposed hourly load conditions. You will also note that the estimated fuel consumption for this scenario increased to approximately 4.5 MMCFD or 0.9% of nominal throughput.

30" System Fully Powered

To assess the maximum capability of the proposed 30" system (without pipeline looping), the southern end power generation loads at Anclote, FPC Power Park and SEC Hardee were ramped up in a manner identical to that in the "Base Case X 103%" scenario described above. In the instant case, however, the three power generation loads were increased while horsepower was added at the proposed compressor station locations until the system reached its peak capacity. This maximum load condition occurred at the 125% level. More specifically, with 20,000 additional horsepower (5000 HP at Station 1; 5000 HP at Station 4; 5000 HP at Station 5, and 5000 HP at Station 7), the three southern power generation loads can be increased approximately 25%, assuming no change in hourly load profiles, without violating either the system's MAOP of 1200 PSIG or the minimum contract delivery pressure of 450 PSIG.

In terms of nominal contract volumes, this 25% increase equals a total of 75 MMCFD. Fuel consumption for this fully powered scenario increased to approximately 8.5 MMCFD. See Exhibit 3B for detailed design data and graphics.

Alternative 26" Case

An alternative mainline system, utilizing 26" line pipe in lieu of 30", was tested. This alternate system required a total of 41,000 HP to flow the 1999 contract level volumes at the prescribed hourly load patterns. Horsepower by station included 8000 HP at Gateway; 8000 HP at Station 1; 5000 HP at Station 2; 5000 HP at Station 3; 5000 at Station 4; 5000 HP at Station 5, and 5000 HP at Station 6.

A cursory economic analysis comparing the capital and operating costs of the 30" and 26" systems was performed and a summary is set forth below.

	30" with 21000 HP	26" with 41000 HP	DIFFERENCE
TOTAL CAPITAL COST	$641.7 million	$624.2 million	- $17.5 million
TOTAL ANNUAL O&M and A&G*	$003.3 million	$004.4 million	+$01.1 million
TOTAL ANNUAL FUEL @ $2/MCF	$003.1 million	$006.4 million	+$03.3 million

* Utilizing the ANR estimate of $3000 per mile and $54 per HP.

While a 26" system may cost some $17.5 million less than the proposed 30" base case system, it is estimated that the increased annual operating expenses (including fuel at

an assumed value of $2.00 per MCF) associated with the alternative 26" pipeline, some $4.4 million, would more than offset the annual cost of service savings, some $2.5 million, attributable to the lesser capital cost of this smaller system.

It is equally important to note that a 26" system would provide no "cheap" future expansion capability in that the 26" system with 41,000 HP would be virtually "powered out" and that any increase in future throughput would necessitate more costly pipeline looping.

Therefore the proposed 30" system is the more attractive alternative from both cost of service and future growth perspectives. See Exhibit 3C for design analysis details of this 26" alternative case.

Design Conclusions

The short answer is that the proposed system design is adequate to meet relevant load and pressure conditions. In fact, the design appears to be very close to optimal.

CAPITAL COST ESTIMATES

General

The ANR capital cost estimates for both SunShine and SITCO were prepared using unit cost data originally developed for the SunCoast project. ANR did, however, adjust the pipeline cost estimates to reflect a reduction in anticipated wetlands construction (requiring the use of concrete coated pipe) from 50% of total length to 20% of total length. This revision by ANR is consistent with the July 1992 projection of Mr. Paul Macy of Pipeline Construction Services, who prepared an independent SunCoast capital cost estimate for Mr. E. J. Burgin. This independent analysis was addressed in my original August 1992 report on SunCoast.

The following additional design and cost estimate assumptions and conditions should also be noted:

- All cost estimate data are expressed in 1994 dollars and are fully loaded unless otherwise indicated;

- ANR loading factors included 8% for contingency, 2.5% for overheads, and 8.64% for AFUDC. Referenced adjustments reflect these same loading conditions;

- The general pipeline design and associated cost estimates for the large diameter pipe assumed a 1200 PSIG MAOP and the use of X-65, DSAW line pipe at a base price of some $700 per ton, and

- The main line routes for SITCO and SunShine were assumed to generally track the formerly proposed SITCO and SunCoast routes, where applicable.

30" Main Line

ANR estimated the capital cost of the 148 miles of main 30" SITCO pipeline between its

origination point at Pascagoula and the terminus at Okaloosa at $140.3 million and the capital cost of the 345 miles of main 30" SunShine pipeline from Okaloosa to the 20" Anclote lateral take-off at $327.1 million. ANR utilized a unit cost of $948,000 per mile to develop this estimate.

While there may be certain minor infirmities within the ANR cost estimate breakdown (*e.g.*, rights of way acquisition and damage cost and pipeline lay cost appear somewhat high), the total overall estimate of $948,000 per mile appears reasonable. This opinion, of course, is based on the previously noted 20% wetlands construction assumption. For a comparison of several recently prepared cost estimates for 30" pipe applicable to the U. S. southeast gulf coast region, see Exhibit 4.

24" Main Line

ANR has proposed 24" for the main line south of the 20" Anclote lateral tee. This 71 miles of 24" between the Anclote take-off and the 16" SEC Hardee lateral take-off is estimated to cost approximately $56 million or $789,000 per mile.

As with the 30", while certain line item details of ANR's estimate appear slightly high or slightly low, the overall estimate of $0.789 million per mile appears reasonable. For comparison purposes, PCS estimated a unit cost of $0.792 million per mile for the 24" pipe in its SunCoast analysis.

Lateral Lines

In addition to the 30" and 24" main line, there are 63 miles of 20", 14 miles of 16", 21 miles of 10", 7 miles of 8", and 21 miles of 4" lateral lines proposed for SITCO and SunShine. ANR has estimated the capital cost of these laterals at $20.0 million for SITCO and $52.5 million for SunShine. ANR utilized the following unit amounts in its capital cost estimate:

- 20" - $635,000 per mile;
- 16" - $591,000 per mile;
- 10" - $438,000 per mile;
- 08" - $419,000 per mile;
- 04" - $378,000 per mile.

On a per mile basis, the cost estimates for the 20", 16", and 10" laterals seem reasonable. As with the previously discussed 30" and 24" main line cost estimates, there may be room to quibble with individual cost estimate components, but the total cost per mile estimates are within reason.

On the other hand, the costs of the 8" and 4" laterals, estimated to average $419,000 per mile and $378,000 per mile, respectively, seem very high. While the proposed rights of way for these laterals have not been viewed, I find it difficult to believe that these small diameter lines will cost this much per mile unless there are extremely difficult R/W or other installation conditions to be dealt with.

However, even if the costs per mile of these small diameter lateral lines are significantly overstated, the overall pipe cost will not be materially affected due to the dampening effect of the main line costs. See following Line Pipe Cost Summary.

Line Pipe Cost Summary

To test the sensitivity of the pipe costs, select modifications to the main line and lateral cost estimates were made, reflecting, what I considered to be more reasonable assumptions for lay costs, material costs, R/W costs, etc. These hypothetical adjustments totaled $5.9 million for the main line and $8.9 million for the laterals. This total of $14.8 million represents only 2.5% of the total $595.4 million ANR estimate for pipe cost. Therefore, it is concluded that the overall ANR estimate of cost for line pipe, while slightly conservative, is certainly reasonable.

Compression

ANR has identified the need for 8000 horsepower on SITCO at the Gateway Station plus 8000 HP and 5000 HP each at SunShine Stations 3 and 6, respectively. The cost of this horsepower was estimated at $12.3 million for SITCO and $20.0 million for SunShine. ANR prepared these estimates by employing a unit cost amount of $1538 per HP, which, in turn, was previously used by ANR in its SunCoast estimate.

On a 1994 dollar, fully loaded basis, the $1538/HP is, in my opinion, right on target for turbine horsepower. However, ANR has proposed the installation of reciprocating horsepower at SunShine's Station 6. While the design audit does not indicate the need for (more expensive) reciprocating compression at this location, should such compression, in fact, be installed, then the cost for this 5000 HP is, in my opinion, somewhat low.

I estimate the current direct cost of reciprocating compression for this sized station at $2000 per HP or $2400 per HP on a fully loaded, 1994 dollar basis. Using this amount for comparison purposes, a potential capital cost estimate difference (underage) of some $4 million was generated.

Metering and Communications

ANR estimated the project metering and communications costs as follows:

	METERS	COMMUNICATIONS
SITCO	$4.0 million	$0.6 million
SunShine	$7.4 million	$1.6 million

No cost estimate details were available to support these estimated capital expenditures for metering and communications, however, both projections appear reasonable.

As to metering and associated regulation, the projected 18 M&R stations would average some $600,000 per installation based on the ANR estimate. While the main line custody transfer meters at Pascagoula and Okaloosa may approach $2 million each, many of the delivery stations will be measuring low volumes, particularly on SITCO, at a station cost well under $500,000 each. Thus, the total of $11.4 million for measurement is not out of line.

As to the cost of system communications, the projected $2.2 million should be adequate to cover both SITCO and SunShine communications and SCADA (including compressor

station automation) requirements assuming that the back bone communications network will be either leased land line based or satellite based.

Other Capitalized Costs

Although not particularly significant, ANR did not make allowance for the capitalization of select operating costs such as offices, warehouses, vehicles, spare parts, and tools, if such items are to be purchased and not rented or leased.

Project Loading

As previously noted, ANR employed loading factors of 8% for contingencies, 2.5% for overheads, and 8.64% for AFUDC. Given the size and timing of the project these percentages appear reasonable and, in fact, were utilized in the estimation of alternative facility costs.

Capital Cost Summary

In summary, while the capital cost estimate of $595 million for the 700 miles of line pipe might be overstated by some $15 million and the estimated compression cost of $32 million understated by some $4 million, it is my opinion that the overall capital cost projection of $642 million for this 30" Option I or Base Case is indeed very reasonable.

OPERATING COST ESTIMATES

Initial ANR Estimate

No detailed operating cost estimates were included in the material furnished by ANR. However, in the ANR cost of service and rate derivation analysis for both SunShine and SITCO (and select ANR summary data included for reference at Exhibit 5), there is the notation that O&M and A&G expenses were estimated on the basis $3000 per mile of pipeline and $54 per horsepower. These are the same unit cost values that were utilized in the original SunCoast and SITCO estimates prepared by UGPL. The use of these unit costs result in a total annual O&M/A&G projection of $2.3 million for SunShine and $1.0 million for SITCO commencing upon completion of the project in 1999.

Absent detailed knowledge of the intended SunShine operating philosophy (*e.g.*, extent of automation; lease versus ownership of offices, warehouses, shops, vehicles; employees versus contract labor; the amount of operating and administrative support to be provided by ANR), it is difficult to accurately estimate the annual operating expense for this project. However, the $3.3 million total appears low.

First, $1500 to $2000 per mile of pipeline and $50 per horsepower are unit costs frequently used within the pipeline industry to estimate O&M expenses (exclusive of A&G) for system expansion projects. Using the low side pipeline estimate of $1500 per mile and $50 per horsepower, escalating same to 1994 dollars and then applying these unit costs to the SITCO and SunShine pipeline mileage and station horsepower, an O&M estimate of $2.2 million is obtained. Accepting this amount for O&M expense, then only $1.1 million ($3.3 - $2.2) would remain to cover all A&G expenses.

More importantly, SITCO and SunShine are not expansions of an existing pipeline with an existing infrastructure. A headquarters administrative and field support staff must be put in place unless such support is to be furnished by ANR. This gives further rise to the question of operating cost estimate adequacy.

First Pass Grass Roots Estimate

In order to obtain a better fix on this question, a "first pass" grass roots O&M and A&G cost estimate was prepared. Again, bear in mind that this was done without the benefit of knowing the proposed operating philosophy for SunShine.

Specifically, an estimate was prepared assuming (1) the establishment of an independent headquarters office with a small administrative and support staff to cover administration, accounting, gas control, and other support services; (2) the establishment of three district offices complete with staffs to satisfy technical and skilled job requirements in the field; (3) full automation of compressor stations and measuring stations; (4) the leasing of offices, warehouses, vehicles and equipment, and (5) the use of contract labor for unskilled services. A summary of that estimate is set forth below.

LOCATION OR COST CENTER	EMPLOYEES	SALARIES (LOADED) ($ million)	EQUIP, EXPENSES, & OTHER ($ million)	TOTAL ($ million)
Admin & Support	057	04.4	01.3	05.7
Field - O&M	057	04.2	01.1	05.3
Field - Contract Services			01.0	01.0
Supplies & Parts			00.5	00.5
TOTAL	114	08.6	03.9	12.5

The following table illustrates the allocation of this $12.5 million of operating expense between SITCO and SunShine on the basis of pipeline mileage and compares the results with the current ANR allocation.

PIPELINE	ANR ESTIMATE ($ million)	GRASS ROOTS ESTIMATE ($ million)	DIFFERENCE ($ million)
SITCO	01.0	03.5	02.5
SunShine	02.3	09.0	06.7
TOTAL	03.3	12.5	09.2

These potential differences of $2.5 million and $6.7 million for SITCO and SunShine, represent some 10% of their respective estimated annual costs of service.

While this original first pass, grass roots, stand alone estimate was certainly not intended to be the last word, but it did give rise to the question of the adequacy of the ANR estimate of $3.3 million to cover both O&M and A&G expenses for both SITCO and SunShine. Given the rather significant impact that the O&M and A&G can have on the cost of service, it was recommended in the initial report that a detailed line item estimate that gives weight to the SunShine operating plans (*e.g.*, lease versus ownership, amount of administrative support to be supplied by others, the amount of contract work anticipated, etc.) be developed and agreed to among the parties.

Alternative Operating Cost Estimates

Subsequent to the preparation of the initial report, discussions were held, at the request of FPC, with Messrs. E. J. Burgin, President of SunShine, and A. Bradley of Coastal. These conversations, in turn, led to the development of separate, alternative estimates by E. J. Burgin and ANR as well as a modified Hibbs and Associates estimate that reflected substantial ANR technical and administrative staff support as proposed by ANR. A comparison of these several estimates is set forth below.

ORIGINAL ANR (UGPL) ESTIMATE	$03.3 MILLION
ORIGINAL HIBBS & ASSOCIATES ESTIMATE [1]	$12.5 MILLION
E.J. BURGIN 12/2/92 ESTIMATE	$04.1 MILLION
ANR 12/2/92 ESTIMATE	$05.3 MILLION
HIBBS & ASSOCIATES 12/2/92 ESTIMATE [2]	$07.5 MILLION

[1] Operated as a stand alone, independent organization.
[2] Operated with technical and administrative staff support by ANR.

As noted in the Hibbs and Associates letter dated December 3, 1992 to Mr. S. Watsey (and enclosed herewith as Exhibit 7), this matter of estimated operating expenses is not yet fully resolved, however, the potential variance is considerably smaller. See "Alternative Cases" within the "Cost of Service and Rate Analysis" section of this report for a description of the potential impacts on rates that the various levels of operating expense create.

Compressor Fuel

Compressor fuel, *per se*, does not appear within the ANR financials as an operating expense since it is proposed to extract that expense in kind. However, as noted in the Facility Design portion of this report, compressor fuel consumption was estimated to total some 4.2 MMCFD at the full buildup, nominal throughput level of 504.5 MMCFD. This is 0.8% and well below the proposed 1.5% cap.

COST OF SERVICE AND RATE ANALYSIS

Initial Validation

An independent financial model was used to validate the twenty five year average cost of service and twenty five year average 100% load factor "rate" (i.e., the total cost of service divided by the total contract volume) for both SunShine and SITCO. The debt/equity ratio, return on debt, return on equity, and federal and state tax rates were held constant. Specific values used included a 75% - 25% debt - equity ratio; 14.25% return on equity; 10% interest on debt; 34% FIT rate, and a 5.5% state tax rate.

Capital costs incorporated in the ANR analyses (by the year 1999 and expressed in 1994 dollars) included $463.7 million for SunShine and $173.7 million for SITCO. Note that these values are slightly different from those included in the separate capital cost estimates also furnished by ANR (*i.e.*, $464.4 million for SunShine and $177.3 million for SITCO). Also note that this initial validation analysis accepted the previously discussed O&M expense estimates which were based on unit costs of $3000 per mile of pipe and $54 per horsepower.

A comparison of the results of this check model audit with the ANR analysis is set forth below.

	ANR ANALYSES	CHECK MODEL
SUNSHINE		
Avg. Year Cost of Service	$65.4 million	$65.5 million
Cost of Service per MCF	$00.4727	$00.4732
SITCO		
Avg. Year Cost of Service	$24.2 million	$24.3 million
Cost of Service per MCF	$00.1369	$00.1374

The results of this comparison are obviously close. However, the proposed rates to be charged will reflect levelization of the cost of service with a deferral adjustment to compensate for the under collection of equity during the first three years of the project (1996 - 1999). When this deferral component is added to the base rate the so called "rate after deferral" becomes $0.5249 per MCF for SunShine and $0.1482 per MCF for SITCO. Simply put, the deferral component provides for a 14.25% equity return, through out the life of the project, when applied to the sum of the under collected revenues (less tax impact) that are incurred during the first three project years. While the ANR deferral calculations were not specifically checked, the described methodology used to calculate same and the results appear reasonable.

It should be noted, however, that the cost associated with rate levelization and income deferral is not inexpensive. At the proposed volumetric levels, the system shippers will be paying an average of 6.4¢ per MCF more than the average cost of service per MCF of the transported gas or a total of $231 million over the twenty five year project life for this rate levelization feature.

See Exhibit 5 for the ANR financial estimate summaries on SITCO and SunShine. See Exhibit 6 for complete check model output applicable to these validation tests for SITCO and SunShine. Specific Schedules 1 through 4 include (1) Cost of Service; (2) Rate Base and Return; (3) Deferred Income Taxes, and (4) Income Taxes for Cost of Service are included separately for SITCO and SunShine.

Alternative Cases

Three additional cases that incorporate the aforementioned minor capital cost adjustments and the potential increase in estimated A&G and O&M expenses for both SITCO and SunShine, have been run. These cases, Alternate Case I, II, and III, include O&M and A&G expenses of $12.5 million, $7.5 million and $5.0 million (which is approximately the average of the E.J. Burgin and ANR estimates), respectively. A summary of the potential incremental rate impact associated with these higher estimated operating expenses is set forth below.

CASE	SITCO	SUNSHINE	TOTAL
ALTERNATE I (O&M at $12.5 million)	$0.014	$0.047	$0.061*
ALTERNATE II (O&M at $7.5 million)	$0.007	$0.021	$0.028
ALTERNATE III (O&M at $5.0 million)	$0.003	$0.009	$0.012

* Ignoring initial rate cap.

For detailed cost of service information concerning these three alternate cases, see Exhibit 8.

- - END - -

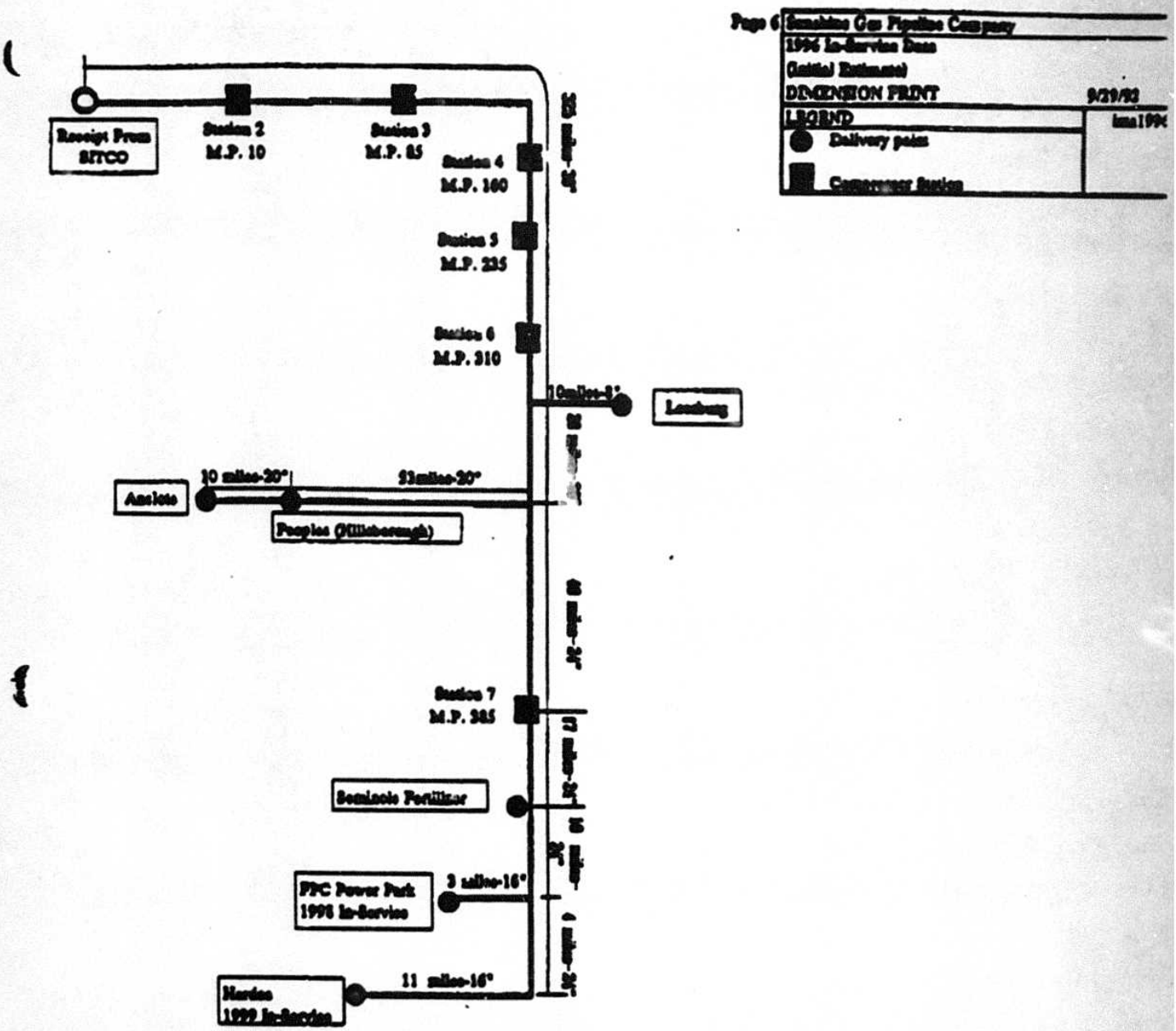
EXHIBIT 1

SUNSHINE GAS PIPELINE COMPANY
COST BACKUP - 30" OPTION
1996-Inservice Date

FACILITIES	1996	1998	1999	TOTAL
Pipeline:				
30in.(0.948 $MM/Mi.)	345 Mi.	0 Mi.	0 Mi.	345 Mi.
24in.(0.789 $MM/Mi.)	57 Mi.	10 Mi.	4 Mi.	71 Mi.
20in.(0.635 $MM/Mi.)	63 Mi.	0 Mi.	0 Mi.	63 Mi.
16in.(0.591 $MM/Mi.)	0 Mi.	3 Mi.	11 Mi.	14 Mi.
8in.(0.419 $MM/Mi.)	10 Mi.	0 Mi.	0 Mi.	10 Mi.
Total	475 Mi.	13 Mi.	15 Mi.	503 Mi.
Compression	0 HP	0 HP	13,000 HP 2 New Stations	13,000 HP 2 Stations
Meter Stations	7	1 SBC Power Pack	1 SBC Hardee	9

TOTAL INVESTMENT ($1994 Million)

Pipeline	$416.2	$9.7	$9.6	$435.5
Compression	$0.0	$0.0	$20.0	$20.0
Meters	$5.2	$1.1	$1.1	$7.4
Communication	$1.6	$0.0	$0.0	$1.6
Total	$423.0	$10.8	$30.7	$464.4



PIPELINE MILEAGE SUMMARY

SIZE	8"	10"	12"	16"	20"	24"	30"	36"	TOTAL
1996	10	0	0	0	63	57	345	0	475
1998	10	0	0	3	63	67	345	0	488
1999	10	0	0	14	63	71	345	0	503

COMPRESSOR STATION SUMMARY

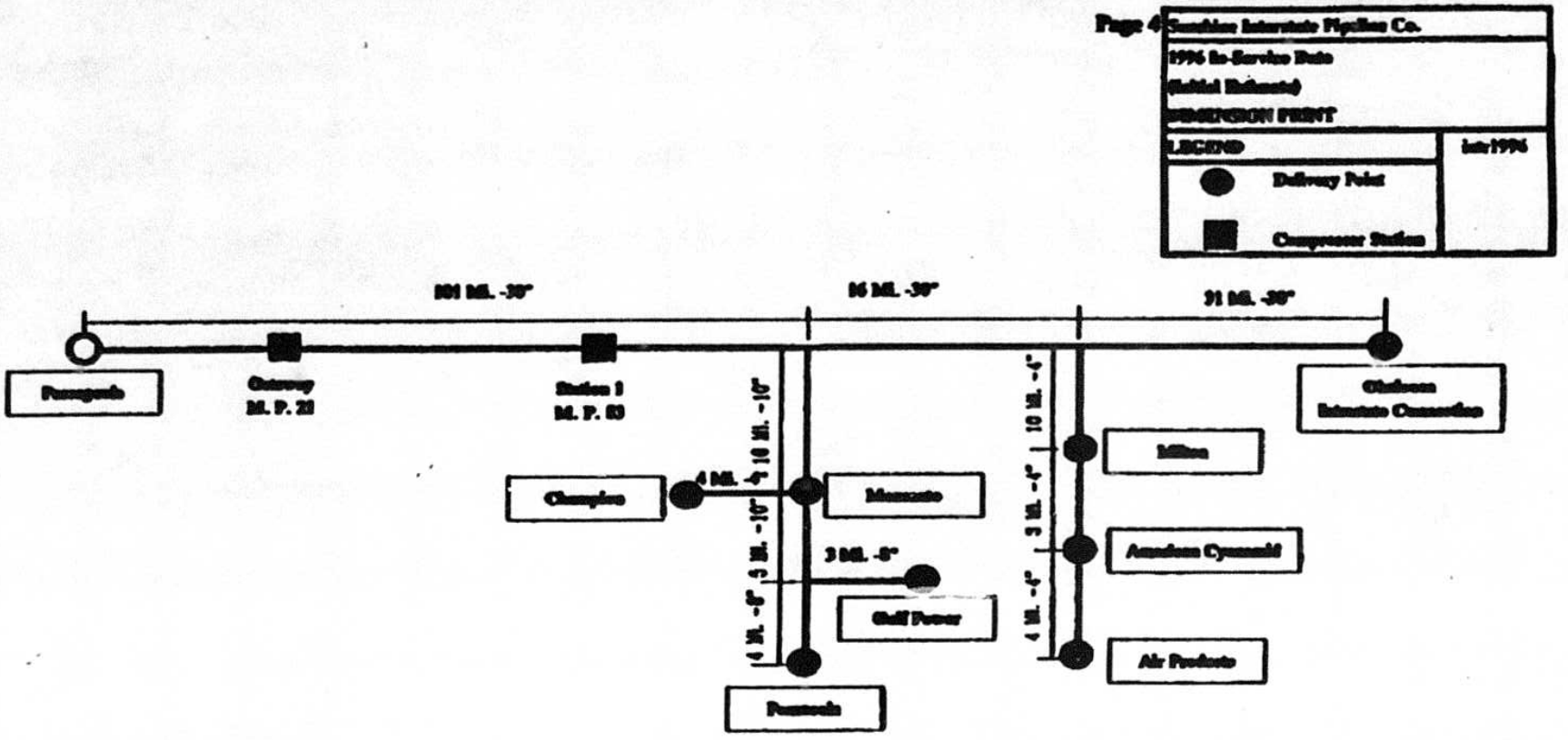
HP	Station 2 Turbine	Station 3 Turbine	Station 4 Turbine	Station 5 Recip.	Station 6 Recip.	Station 7 Recip.	Incremental Total	GRAND TOTAL
Yr 1996	0	0	0	0	0	0	0	0
Yr 1998	0	0	0	0	0	0	0	0
Yr 1999	0	8,000	0	0	5,000	0	13,000	13,000

SUNSHINE INTERSTATE GAS PIPELINE COMPANY
COST BACKUP - 30" OPTION
1996 In-Service Date

FACILITIES	1996	1998	1999	TOTAL
Pipeline:				
30in.(0.948 $MM/Mi.)	148 Mi.	0 Mi.	0 Mi.	148 Mi.
24in.(0.789 $MM/Mi.)	0 Mi.	0 Mi.	0 Mi.	0 Mi.
20in.(0.635 $MM/Mi.)	0 Mi.	0 Mi.	0 Mi.	0 Mi.
16in.(0.591 $MM/Mi.)	0 Mi.	0 Mi.	0 Mi.	0 Mi.
10in.(0.438 $MM/Mi.)	21 Mi.	0 Mi.	0 Mi.	21 Mi.
8in.(0.419 $MM/Mi.)	7 Mi.	0 Mi.	0 Mi.	7 Mi.
4in.(0.378 $MM/Mi.)	21 Mi.	0 Mi.	0 Mi.	21 Mi.
Total	197 Mi.	0 Mi.	0 Mi.	197 Mi.
Compression	2,000 HP 1 Station	2,000 HP	4,000 HP	8,000 HP 1Station
Meter Stations	9	0	0	9

TOTAL INVESTMENT ($1994 Million)

Pipeline	$160.4	$0.0	$0.0	$160.4
Compression	$3.1	$3.1	$6.2	$12.3
Meters	$4.0	$0.0	$0.0	$4.0
Communication	$0.6	$0.0	$0.0	$0.6
Total	$168.0	$3.1	$6.2	$177.3



PIPELINE MILEAGE SUMMARY

SIZE	4"	6"	8"	10"	12"	16"	20"	24"	30"	Total
1996	21	0	7	21	0	0	0	0	148	197

COMPRESSOR STATION SUMMARY

Station HP	Gateway Turbine	Sta. 1 Turbine	Incremental Total	GRAND TOTAL
Yr. 1996	2000	0	2000	2000
Yr. 1998	2000	0	2000	4000
Yr. 1999	4000	0	4000	8000

EXHIBIT 1

EXHIBIT 2

SUNSHINE PIPELINE COMPANY
DESIGN CRITERIA

Temperature Base	520	°R
Flow Temperature	545	°R
Pressure Base	14.73	Psi
Roughness	700	μinch
Minimum Pressure	450	Psig
MAOP	1200	Psig
Pressure @ Pascagoula	965	Psig
Specific Gravity	0.6	
BTU Content	1000	BTU

Pipeline Nominal Diameter	ID	
36"	35.08	Inch
30"	29.23	Inch
24"	23.38	Inch
20"	19.486	Inch
16"	15.5	Inch
12"	12.25	Inch
10"	10.25	Inch
8"	8.125	Inch
4"	4.25	Inch

SUNSHINE INTRASTATE PIPELINE COMPANY
HOURLY TRANSIENT VOLUME)MMcf/d)
BASE CASE - 1996 IN-SERVICE DATE

	FPC Power Park	SEC Hardee	Peoples (Hillsborough)	Anciote	Peoples	Seminole Fertilizer	City of Leesburg	Total
Ave. Flow	90	90	50	120	15	24	10	399
Hr. 1	43	43	50	80	15	24	10	265
Hr. 2	86	86	50	160	15	24	10	432
Hr. 3	86	86	50	160	15	24	10	432
Hr. 4	86	86	50	160	15	24	10	432
Hr. 5	86	86	50	160	15	24	10	432
Hr. 6	86	86	50	160	15	24	10	432
Hr. 7	216	216	50	160	15	24	10	691
Hr. 8	216	216	50	160	15	24	10	691
Hr. 9	216	216	50	160	15	24	10	691
Hr. 10	216	216	50	160	15	24	10	691
Hr. 11	86	86	50	160	15	24	10	432
Hr. 12	86	86	50	160	15	24	10	432
Hr. 13	86	86	50	160	15	24	10	432
Hr. 14	86	86	50	80	15	24	10	352
Hr. 15	86	86	50	80	15	24	10	352
Hr. 16	43	43	50	80	15	24	10	265
Hr. 17	43	43	50	80	15	24	10	265
Hr. 18	43	43	50	80	15	24	10	265
Hr. 19	43	43	50	80	15	24	10	265
Hr. 20	43	43	50	80	15	24	10	265
Hr. 21	43	43	50	80	15	24	10	265
Hr. 22	43	43	50	80	15	24	10	265
Hr. 23	43	43	50	80	15	24	10	265
Hr. 24	43	43	50	80	15	24	10	265

EXHIBIT 2

SUNSHINE INTERSTATE PIPELINE COMPANY
HOURLY TRANSIENT VOLUME (MMcf/d)
BASE CASE - 1996 IN-SERVICE DATE

	Okaloosa & Panama	Pensacola & Gulf Breeze	Champion Paper	Gulf Power	Monsanto	Air Products	American Cyanamid	City of Milton	Total
Ave. Flow	12	31	5	40	6	7	4	0.5	105.5
Hr. 1	12	31	5	40	6	7	4	0.5	105.5
Hr. 2	12	31	5	40	6	7	4	0.5	105.5
Hr. 3	12	31	5	40	6	7	4	0.5	105.5
Hr. 4	12	31	5	40	6	7	4	0.5	105.5
Hr. 5	12	31	5	40	6	7	4	0.5	105.5
Hr. 6	12	31	5	40	6	7	4	0.5	105.5
Hr. 7	12	31	5	40	6	7	4	0.5	105.5
Hr. 8	12	31	5	40	6	7	4	0.5	105.5
Hr. 9	12	31	5	40	6	7	4	0.5	105.5
Hr. 10	12	31	5	40	6	7	4	0.5	105.5
Hr. 11	12	31	5	40	6	7	4	0.5	105.5
Hr. 12	12	31	5	40	6	7	4	0.5	105.5
Hr. 13	12	31	5	40	6	7	4	0.5	105.5
Hr. 14	12	31	5	40	6	7	4	0.5	105.5
Hr. 15	12	31	5	40	6	7	4	0.5	105.5
Hr. 16	12	31	5	40	6	7	4	0.5	105.5
Hr. 17	12	31	5	40	6	7	4	0.5	105.5
Hr. 18	12	31	5	40	6	7	4	0.5	105.5
Hr. 19	12	31	5	40	6	7	4	0.5	105.5
Hr. 20	12	31	5	40	6	7	4	0.5	105.5
Hr. 21	12	31	5	40	6	7	4	0.5	105.5
Hr. 22	12	31	5	40	6	7	4	0.5	105.5
Hr. 23	12	31	5	40	6	7	4	0.5	105.5
Hr. 24	12	31	5	40	6	7	4	0.5	105.5

EXHIBIT 2

SUNSHINE INTERSTATE AND INTRASTATE PIPELINE COMPANY
MARKET REQUIREMENTS (MMcf/d)
Base 30" System - 1996 In-Service Date

Line #	MARKET (Column 1)	1996 (Col. 2)	1997 (Col. 3)	1998 (Col. 4)	1999 (Col. 5)
1	**INTERSTATE**				
2	Okaloosa				
3	Okaloosa County Gas District	10	10	10	10
4	Panama City (through Okaloosa)	2	2	2	2
5	Okaloosa Subtotal	12	12	12	12
6	Pensacola Lateral				
7	Champion Paper	5	5	5	5
8	Energy Services of Pensacola	5	5	5	5
9	City of Gulf Breeze	1	1	1	1
10	Gulf Power	40	40	40	40
11	Monsanto	6	6	6	6
12	City of Pensacola	25	25	25	25
13	Pensacola Subtotal	82	82	82	82
14	Milton Lateral				
15	Air Products	7	7	7	7
16	American Cyanamid	4	4	4	4
17	City of Milton	0.5	0.5	0.5	0.5
18	Milton Subtotal	11.5	11.5	11.5	11.5
19	Interstate Total	105.5	105.5	105.5	105.5
20	**INTRASTATE**				
21	FPC Power Park	0	0	45	90
22	FPC Anclote	120	120	120	120
23	Peoples (Hillsborough)	50	50	50	50
24	SEC Hardee	0	0	0	90
25	Seminole Fertilizer	24	24	24	24
26	Peoples	15	15	15	15
27	City of Leesburg	10	10	10	10
28	Intrastate Total	219	219	264	399
29	Grand Total	324.5	324.5	369.5	504.5

EXHIBIT 3

FIGURE 1

FIG 1–SUNSHINE PIPELINE SYSTEM; BASE 30 IN DESIGN(INCLUDES COMP'R FUEL)

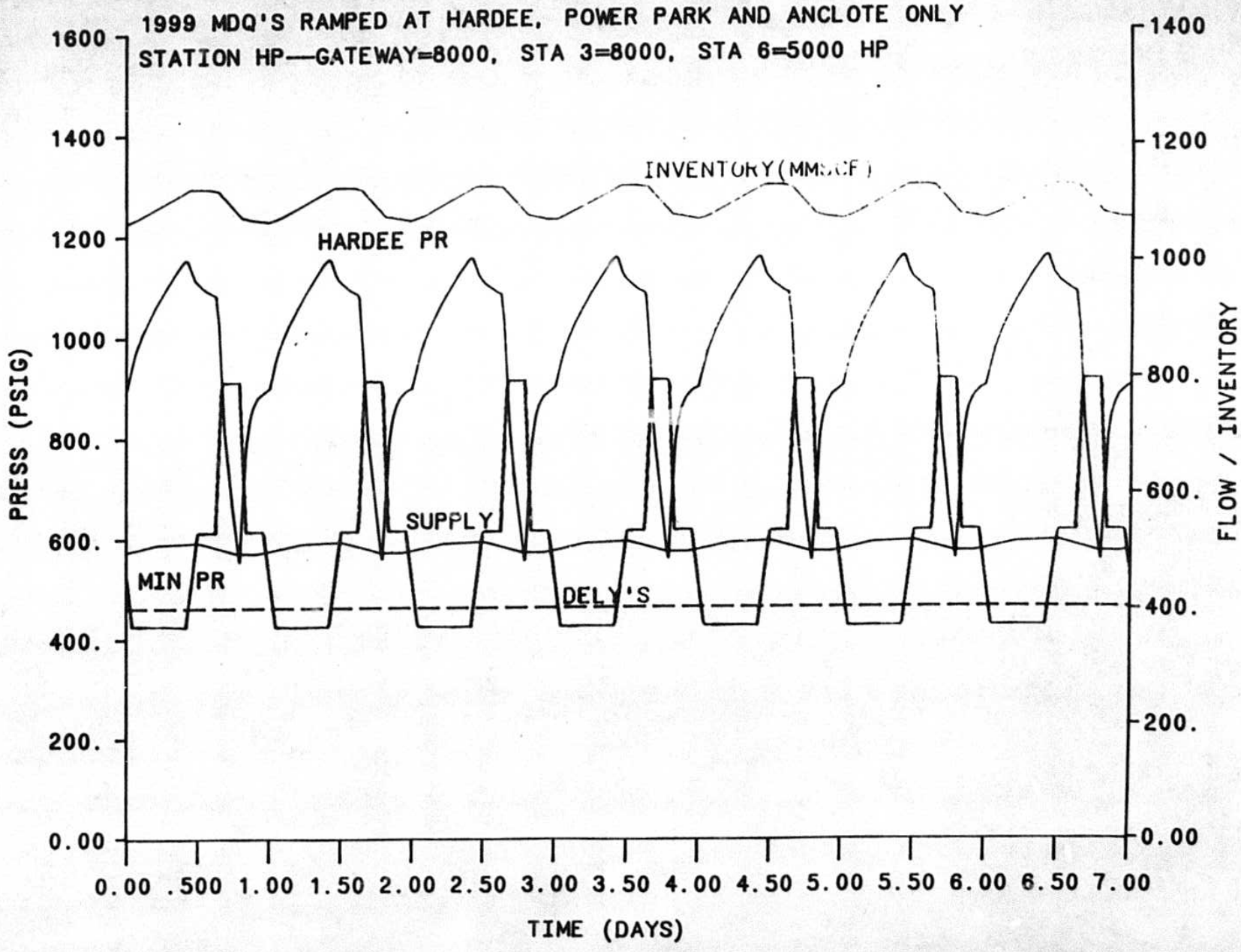


EXHIBIT 3

TABLE 1(BASE CASE)

SUNSHINE SYSTEM; GATEWAY COMPRESSOR STATION REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	912.483	1204.015	1.314	500.599	7176.794	103.598	1.550
1.000	911.837	1204.061	1.315	503.632	7240.920	103.691	1.564
2.000	911.192	1204.113	1.316	506.603	7304.518	103.784	1.578
3.000	910.644	1204.159	1.317	509.097	7358.361	103.864	1.589
4.000	910.201	1204.197	1.318	511.099	7401.839	103.929	1.599
5.000	909.848	1204.227	1.318	512.690	7436.497	103.980	1.606
6.000	909.571	1204.251	1.319	513.934	7463.719	104.021	1.612
7.000	909.359	1204.269	1.319	514.878	7484.454	104.052	1.617
8.000	909.207	1204.283	1.319	515.554	7499.345	104.074	1.620
9.000	909.108	1204.292	1.319	515.990	7509.018	104.088	1.622
10.000	909.055	1204.298	1.320	516.215	7514.065	104.096	1.623
11.000	909.045	1204.301	1.320	516.249	7514.918	104.098	1.623
12.000	909.111	1204.302	1.319	515.917	7508.077	104.089	1.622
13.000	909.435	1204.290	1.319	514.365	7475.122	104.043	1.615
14.000	910.075	1204.254	1.318	511.376	7411.026	103.951	1.601
15.000	910.920	1204.194	1.317	507.470	7327.152	103.829	1.583
16.000	911.785	1204.126	1.316	503.485	7241.812	103.704	1.564
17.000	912.526	1204.063	1.314	500.074	7169.058	103.596	1.549
18.000	913.083	1204.013	1.314	497.504	7114.397	103.515	1.537
19.000	913.457	1203.977	1.313	495.784	7077.844	103.460	1.529
20.000	913.645	1203.955	1.313	494.944	7059.775	103.432	1.525
21.000	913.643	1203.947	1.313	495.006	7060.573	103.432	1.525
22.000	913.442	1203.955	1.313	496.005	7080.952	103.460	1.530
23.000	913.055	1203.977	1.314	497.878	7119.791	103.515	1.538
24.000	912.513	1204.013	1.314	500.460	7173.863	103.593	1.550

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	911.868	1204.059	1.315	503.483	7237.778	103.686	1.563
26.000	911.220	1204.110	1.316	506.472	7301.697	103.780	1.577
27.000	910.667	1204.157	1.317	508.993	7356.101	103.861	1.589
28.000	910.220	1204.195	1.318	511.014	7399.983	103.926	1.598
29.000	909.864	1204.225	1.318	512.622	7435.010	103.978	1.606
30.000	909.583	1204.250	1.319	513.879	7462.512	104.019	1.612
31.000	909.369	1204.268	1.319	514.833	7483.463	104.050	1.617
32.000	909.215	1204.282	1.319	515.518	7498.558	104.073	1.620
33.000	909.114	1204.292	1.319	515.962	7508.399	104.088	1.622
34.000	909.061	1204.298	1.320	516.192	7513.548	104.095	1.623
35.000	909.050	1204.300	1.320	516.230	7514.515	104.097	1.623
36.000	909.117	1204.301	1.320	515.891	7507.499	104.088	1.622
37.000	909.436	1204.290	1.319	514.363	7475.074	104.043	1.615
38.000	910.072	1204.253	1.318	511.394	7411.386	103.952	1.601
39.000	910.912	1204.195	1.317	507.511	7328.040	103.830	1.583
40.000	911.773	1204.127	1.316	503.542	7243.010	103.705	1.565
41.000	912.512	1204.064	1.314	500.140	7170.421	103.598	1.549
42.000	913.068	1204.014	1.314	497.574	7115.854	103.517	1.537
43.000	913.441	1203.978	1.313	495.862	7079.480	103.462	1.529
44.000	913.632	1203.956	1.313	495.008	7061.121	103.434	1.525
45.000	913.629	1203.948	1.313	495.073	7061.971	103.434	1.525
46.000	913.428	1203.956	1.313	496.071	7082.335	103.462	1.530
47.000	913.041	1203.978	1.314	497.943	7121.144	103.517	1.538
48.000	912.499	1204.014	1.314	500.521	7175.145	103.595	1.550

/*----------END OF SECOND DAY----------->

EXHIBIT 3

TABLE 1(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	911.856	1204.060	1.315	503.541	7239.000	103.688	1.564
50.000	911.209	1204.111	1.316	506.522	7302.779	103.782	1.577
51.000	910.659	1204.158	1.317	509.031	7356.938	103.862	1.589
52.000	910.214	1204.196	1.318	511.044	7400.635	103.927	1.599
53.000	909.859	1204.226	1.318	512.643	7435.486	103.979	1.606
54.000	909.579	1204.250	1.319	513.896	7462.892	104.019	1.612
55.000	909.366	1204.268	1.319	514.846	7483.751	104.050	1.617
56.000	909.213	1204.282	1.319	515.528	7498.774	104.073	1.620
57.000	909.112	1204.292	1.319	515.969	7508.553	104.088	1.622
58.000	909.059	1204.298	1.320	516.196	7513.650	104.096	1.623
59.000	909.049	1204.300	1.320	516.234	7514.584	104.097	1.623
60.000	909.114	1204.302	1.319	515.904	7507.775	104.088	1.622
61.000	909.437	1204.290	1.319	514.356	7474.919	104.043	1.615
62.000	910.076	1204.253	1.318	511.373	7410.955	103.951	1.601
63.000	910.920	1204.194	1.317	507.474	7327.242	103.829	1.583
64.000	911.783	1204.126	1.316	503.496	7242.044	103.704	1.564
65.000	912.522	1204.063	1.314	500.091	7169.389	103.597	1.549
66.000	913.079	1204.013	1.314	497.522	7114.776	103.515	1.537
67.000	913.453	1203.977	1.313	495.805	7078.273	103.461	1.529
68.000	913.641	1203.956	1.313	494.965	7060.219	103.433	1.525
69.000	913.638	1203.948	1.313	495.027	7061.003	103.433	1.525
70.000	913.438	1203.955	1.313	496 026	7081.394	103.461	1.530
71.000	913.051	1203.977	1.314	497 898	7120.217	103.516	1.538
72.000	912.508	1204.013	1.314	500.480	7174.270	103.594	1.550

/*----------END OF THIRD DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	911.864	1204.059	1.315	503.501	7238.153	103.687	1.564
74.000	911.217	1204.111	1.316	506.488	7302.046	103.781	1.577
75.000	910.664	1204.157	1.317	509.005	7356.359	103.861	1.589
76.000	910.218	1204.195	1.318	511.025	7400.202	103.926	1.599
77.000	909.862	1204.225	1.318	512.629	7435.175	103.978	1.606
78.000	909.581	1204.250	1.319	513.887	7462.683	104.019	1.612
79.000	909.368	1204.268	1.319	514.839	7483.608	104.050	1.617
80.000	909.214	1204.282	1.319	515.523	7498.669	104.073	1.620
81.000	909.113	1204.292	1.319	515.966	7508.492	104.088	1.622
82.000	909.060	1204.298	1.320	516.196	7513.644	104.096	1.623
83.000	909.049	1204.300	1.320	516.234	7514.583	104.097	1.623
84.000	909.115	1204.301	1.319	515.897	7507.619	104.088	1.622
85.000	909.433	1204.290	1.319	514.373	7475.288	104.043	1.615
86.000	910.069	1204.254	1.318	511.406	7411.662	103.952	1.601
87.000	910.909	1204.195	1.317	507.525	7328.330	103.831	1.583
88.000	911.770	1204.127	1.316	503.556	7243.325	103.706	1.565
89.000	912.508	1204.064	1.314	500.156	7170.768	103.599	1.549
90.000	913.065	1204.014	1.314	497.591	7116.203	103.517	1.537
91.000	913.438	1203.979	1.313	495.879	7079.816	103.463	1.529
92.000	913.628	1203.957	1.313	495.024	7061.458	103.435	1.525
93.000	913.625	1203.949	1.313	495.088	7062.291	103.434	1.526
94.000	913.425	1203.956	1.313	496.086	7082.649	103.463	1.530
95.000	913.038	1203.978	1.314	497.957	7121.434	103.518	1.538
96.000	912.497	1204.014	1.315	500.535	7175.430	103.596	1.550

/*----------END OF FOURTH DAY----------*/

EXHIBIT 3

TABLE 1(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	911.853	1204.060	1.315	503.553	7239.251	103.688	1.564
98.000	911.207	1204.112	1.316	506.531	7302.974	103.782	1.578
99.000	910.657	1204.158	1.317	509.038	7357.092	103.862	1.589
100.000	910.212	1204.196	1.318	511.050	7400.754	103.927	1.599
101.000	909.857	1204.226	1.318	512.650	7435.625	103.979	1.606
102.000	909.578	1204.250	1.319	513.901	7462.992	104.019	1.612
103.000	909.366	1204.268	1.319	514.850	7483.834	104.051	1.617
104.000	909.212	1204.282	1.319	515.531	7498.853	104.073	1.620
105.000	909.112	1204.292	1.320	515.972	7508.617	104.088	1.622
106.000	909.059	1204.298	1.320	516.200	7513.730	104.096	1.623
107.000	909.048	1204.301	1.320	516.237	7514.659	104.097	1.623
108.000	909.113	1204.301	1.320	515.905	7507.801	104.088	1.622
109.000	909.435	1204.290	1.319	514.363	7475.077	104.043	1.615
110.000	910.074	1204.254	1.318	511.383	7411.175	103.951	1.601
111.000	910.916	1204.195	1.317	507.492	7327.632	103.830	1.583
112.000	911.778	1204.126	1.316	503.517	7242.506	103.705	1.564
113.000	912.517	1204.064	1.314	500.115	7169.902	103.597	1.549
114.000	913.074	1204.014	1.314	497.549	7115.334	103.516	1.537
115.000	913.447	1203.978	1.313	495.830	7078.817	103.462	1.529
116.000	913.636	1203.956	1.313	494.990	7060.734	103.434	1.525
117.000	913.633	1203.948	1.313	495.052	7061.514	103.433	1.525
118.000	913.433	1203.955	1.313	496.049	7081.858	103.461	1.530
119.000	913.046	1203.978	1.314	497.920	7120.681	103.517	1.538
120.000	912.504	1204.013	1.314	500.501	7174.720	103.595	1.550

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	911.860	1204.060	1.315	503.522	7238.606	103.687	1.564
122.000	911.213	1204.111	1.316	506.505	7302.410	103.781	1.577
123.000	910.661	1204.157	1.317	509.018	7356.652	103.862	1.589
124.000	910.216	1204.195	1.318	511.035	7400.441	103.927	1.599
125.000	909.860	1204.226	1.318	512.638	7435.367	103.978	1.606
126.000	909.580	1204.250	1.319	513.894	7462.836	104.019	1.612
127.000	909.367	1204.268	1.319	514.844	7483.716	104.050	1.617
128.000	909.213	1204.282	1.319	515.529	7498.793	104.073	1.620
129.000	909.112	1204.292	1.319	515.970	7508.590	104.088	1.622
131.000	909.048	1204.301	1.320	516.238	7514.676	104.097	1.623
132.000	909.114	1204.301	1.319	515.903	7507.742	104.088	1.622
133.000	909.432	1204.290	1.319	514.382	7475.479	104.043	1.615
134.000	910.067	1204.254	1.318	511.417	7411.897	103.952	1.601
135.000	910.906	1204.195	1.317	507.538	7328.598	103.831	1.583
136.000	911.767	1204.127	1.316	503.569	7243.594	103.706	1.565
137.000	912.505	1204.065	1.314	500.171	7171.077	103.599	1.549
138.000	913.062	1204.015	1.314	497.603	7116.467	103.518	1.537
139.000	913.435	1203.979	1.313	495.892	7080.091	103.463	1.529
140.000	913.626	1203.957	1.313	495.036	7061.717	103.435	1.525
141.000	913.622	1203.949	1.313	495.103	7062.594	103.435	1.526
142.000	913.423	1203.956	1.313	496.099	7082.909	103.463	1.530
143.000	913.036	1203.978	1.314	497.969	7121.688	103.518	1.538
144.000	912.494	1204.014	1.314	500.546	7175.673	103.596	1.550

/*----------END OF SIXTH DAY----------->

TABLE 1(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	911.851	1204.060	1.315	503.564	7239.488	103.689	1.564
146.000	911.205	1204.112	1.316	506.541	7303.180	103.782	1.578
147.000	910.655	1204.158	1.317	509.046	7357.248	103.862	1.589
148.000	910.211	1204.196	1.318	511.056	7400.900	103.927	1.599
149.000	909.856	1204.226	1.318	512.654	7435.712	103.979	1.606
150.000	909.577	1204.250	1.319	513.905	7463.095	104.020	1.612
151.000	909.365	1204.269	1.319	514.854	7483.922	104.051	1.617
152.000	909.211	1204.283	1.319	515.535	7498.944	104.073	1.620
153.000	909.111	1204.292	1.320	515.976	7508.706	104.088	1.622
154.000	909.058	1204.298	1.320	516.203	7513.809	104.096	1.623
155.000	909.047	1204.301	1.320	516.241	7514.745	104.098	1.623
156.000	909.113	1204.301	1.320	515.908	7507.865	104.089	1.622
157.000	909.434	1204.290	1.319	514.372	7475.274	104.043	1.615
158.000	910.071	1204.254	1.318	511.399	7411.505	103.952	1.601
159.000	910.911	1204.195	1.317	507.514	7328.097	103.830	1.583
160.000	911.773	1204.127	1.316	503.544	7243.062	103.705	1.565
161.000	912.511	1204.064	1.314	500.144	7170.522	103.598	1.549
162.000	913.067	1204.014	1.314	497.579	7115.970	103.517	1.537
163.000	913.442	1203.978	1.313	495.859	7079.414	103.462	1.529
164.000	913.630	1203.956	1.313	495.016	7061.291	103.434	1.525
165.000	913.628	1203.949	1.313	495.076	7062.040	103.434	1.525
166.000	913.428	1203.956	1.313	496.073	7082.380	103.462	1.530
167.000	913.041	1203.978	1.314	497.943	7121.158	103.517	1.538
168.000	912.499	1204.014	1.314	500.522	7175.167	103.595	1.550

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3

TABLE 2 (BASE CASE)

SUNSHINE SYSTEM; COMPRESSOR STATION # 3 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	841.029	1202.802	1.423	423.652	7981.031	113.726	1.724
1.000	836.800	1200.921	1.428	420.178	7999.978	114.163	1.728
2.000	833.919	1198.536	1.430	418.271	8000.000	114.346	1.728
3.000	831.643	1196.467	1.431	416.953	8000.000	114.473	1.728
4.000	829.886	1195.045	1.432	415.761	8000.000	114.589	1.728
5.000	828.626	1194.398	1.434	414.539	8000.000	114.713	1.728
6.000	827.831	1194.508	1.435	413.258	8000.000	114.847	1.728
7.000	827.458	1195.300	1.437	411.934	8000.000	114.989	1.728
8.000	827.459	1196.682	1.439	410.589	8000.000	115.136	1.728
9.000	827.786	1198.567	1.440	409.239	8000.000	115.287	1.728
10.000	828.405	1200.947	1.442	407.846	8000.000	115.446	1.728
11.000	831.925	1202.643	1.438	393.174	7644.799	115.077	1.651
12.000	840.583	1202.660	1.423	381.539	7196.095	113.767	1.554
13.000	850.746	1202.442	1.406	370.432	6730.962	112.222	1.454
14.000	859.473	1202.302	1.392	366.558	6447.538	110.920	1.393
15.000	865.481	1202.256	1.383	368.441	6335.748	110.039	1.369
16.000	868.969	1202.276	1.377	372.700	6325.229	109.536	1.366
17.000	870.779	1202.314	1.374	377.025	6355.313	109.279	1.373
18.000	871.180	1202.349	1.374	381.860	6427.533	109.226	1.388
19.000	869.917	1202.394	1.376	388.067	6564.323	109.413	1.418
20.000	866.794	1202.461	1.381	395.619	6772.965	109.875	1.463
21.000	861.902	1202.545	1.389	403.923	7045.005	110.598	1.522
22.000	855.554	1202.644	1.399	412.062	7360.326	111.543	1.590
23.000	848.453	1202.745	1.410	418.806	7679.945	112.607	1.659
24.000	841.358	1202.782	1.422	423.374	7966.021	113.674	1.721

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	836.953	1201.022	1.427	420.304	7999.967	114.150	1.728
26.000	834.038	1198.642	1.430	418.342	8000.000	114.340	1.728
27.000	831.741	1196.563	1.431	417.002	8000.000	114.468	1.728
28.000	829.966	1195.127	1.432	415.798	8000.000	114.586	1.728
29.000	828.691	1194.464	1.434	414.569	8000.000	114.710	1.728
30.000	827.883	1194.560	1.435	413.284	8000.000	114.844	1.728
31.000	827.500	1195.338	1.437	411.957	8000.000	114.986	1.728
32.000	827.491	1196.709	1.438	410.609	8000.000	115.134	1.728
33.000	827.810	1198.584	1.440	409.257	8000.000	115.285	1.728
34.000	828.425	1200.970	1.442	407.853	8000.000	115.445	1.728
35.000	831.710	1202.832	1.438	397.031	7731.458	115.134	1.670
36.000	840.549	1202.645	1.423	381.670	7199.371	113.771	1.555
37.000	850.632	1202.444	1.407	370.648	6737.811	112.240	1.455
38.000	859.328	1202.305	1.392	366.750	6454.470	110.942	1.394
39.000	865.328	1202.259	1.383	368.580	6341.812	110.062	1.370
40.000	868.833	1202.278	1.377	372.793	6330.107	109.556	1.367
41.000	870.649	1202.315	1.375	377.096	6359.671	109.298	1.374
42.000	871.054	1202.350	1.374	381.923	6431.704	109.244	1.389
43.000	869.783	1202.396	1.376	388.149	6569.065	109.434	1.419
44.000	866.682	1202.462	1.381	395.672	6776.723	109.891	1.464
45.000	861.786	1202.546	1.389	403.977	7049.018	110.616	1.523
46.000	855.440	1202.645	1.399	412.110	7364.274	111.560	1.591
47.000	848.347	1202.746	1.411	418.838	7683.463	112.623	1.660
48.000	841.236	1202.806	1.422	423.544	7973.114	113.695	1.722

/*----------END OF SECOND DAY----------->

EXHIBIT 3

TABLE 2(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	836.900	1201.005	1.427	420.243	7999.976	114.157	1.728
50.000	834.000	1198.623	1.430	418.304	8000.000	114.343	1.728
51.000	831.712	1196.547	1.431	416.974	8000.000	114.471	1.728
52.000	829.944	1195.116	1.432	415.777	8000.000	114.588	1.728
53.000	828.674	1194.457	1.434	414.552	8000.000	114.712	1.728
54.000	827.872	1194.558	1.435	413.269	8000.000	114.846	1.728
55.000	827.492	1195.340	1.437	411.945	8000.000	114.988	1.728
56.000	827.487	1196.715	1.439	410.598	8000.000	115.135	1.728
57.000	827.809	1198.593	1.440	409.247	8000.000	115.286	1.728
58.000	828.424	1200.969	1.442	407.852	8000.000	115.445	1.728
59.000	831.908	1202.681	1.438	393.666	7655.849	115.084	1.654
60.000	840.590	1202.658	1.423	381.579	7196.673	113.766	1.555
61.000	850.727	1202.442	1.406	370.498	6732.635	112.225	1.454
62.000	859.441	1202.303	1.392	366.622	6449.452	110.925	1.393
63.000	865.442	1202.257	1.383	368.492	6337.571	110.045	1.369
64.000	868.929	1202.277	1.377	372.739	6326.855	109.542	1.367
65.000	870.739	1202.314	1.375	377.054	6356.770	109.285	1.373
66.000	871.140	1202.349	1.374	381.885	6428.944	109.231	1.389
67.000	869.879	1202.395	1.376	388.088	6565.653	109.419	1.418
68.000	866.756	1202.461	1.381	395.638	6774.268	109.881	1.463
69.000	861.865	1202.545	1.389	403.940	7046.282	110.604	1.522
70.000	855.518	1202.644	1.399	412.079	7361.613	111.548	1.590
71.000	848.418	1202.745	1.411	418.821	7681.220	112.613	1.659
72.000	841.324	1202.783	1.422	423.389	7967.304	113.680	1.721

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	836.935	1201.011	1.427	420.289	7999.968	114.152	1.728
74.000	834.024	1198.629	1.430	418.334	8000.000	114.340	1.728
75.000	831.729	1196.550	1.431	416.997	8000.000	114.468	1.728
76.000	829.956	1195.114	1.432	415.795	8000.000	114.586	1.728
77.000	828.681	1194.452	1.434	414.567	8000.000	114.710	1.728
78.000	827.875	1194.547	1.435	413.284	8000.000	114.844	1.728
79.000	827.492	1195.327	1.437	411.958	8000.000	114.986	1.728
80.000	827.484	1196.698	1.438	410.610	8000.000	115.134	1.728
81.000	827.803	1198.573	1.440	409.259	8000.000	115.285	1.728
82.000	828.419	1200.959	1.442	407.855	8000.000	115.445	1.728
83.000	831.663	1202.848	1.439	397.167	7735.677	115.143	1.671
84.000	840.521	1202.645	1.423	381.696	7200.568	113.775	1.555
85.000	850.603	1202.444	1.407	370.671	6738.926	112.244	1.456
86.000	859.298	1202.305	1.392	366.773	6455.582	110.946	1.394
87.000	865.298	1202.259	1.383	368.601	6342.911	110.066	1.370
88.000	868.802	1202.278	1.378	372.811	6331.154	109.560	1.368
89.000	870.621	1202.315	1.375	377.108	6360.564	109.302	1.374
90.000	871.028	1202.350	1.374	381.932	6432.495	109.248	1.389
91.000	869.758	1202.396	1.376	388.157	6569.822	109.437	1.419
92.000	866.658	1202.462	1.381	395.678	6777.489	109.895	1.464
93.000	861.761	1202.546	1.389	403.985	7049.817	110.619	1.523
94.000	855.416	1202.645	1.399	412.119	7365.085	111.563	1.591
95.000	848.324	1202.746	1.411	418.846	7684.292	112.627	1.660
96.000	841.224	1202.797	1.422	423.494	7972.356	113.696	1.722

/*----------END OF FOURTH DAY----------->

EXHIBIT 3

TABLE 2(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	836.889	1200.994	1.428	420.237	7999.975	114.157	1.728
98.000	833.991	1198.613	1.430	418.300	8000.000	114.344	1.728
99.000	831.704	1196.536	1.431	416.973	8000.000	114.471	1.728
100.000	829.937	1195.104	1.432	415.777	8000.000	114.588	1.728
101.000	828.667	1194.446	1.434	414.552	8000.000	114.712	1.728
102.000	827.865	1194.546	1.435	413.271	8000.000	114.846	1.728
103.000	827.486	1195.328	1.437	411.947	8000.000	114.988	1.728
104.000	827.481	1196.703	1.438	410.600	8000.000	115.135	1.728
105.000	827.802	1198.580	1.440	409.250	8000.000	115.286	1.728
106.000	828.418	1200.959	1.442	407.854	8000.000	115.445	1.728
107.000	831.873	1202.695	1.438	394.129	7666.370	115.092	1.656
108.000	840.562	1202.656	1.423	381.622	7198.191	113.770	1.555
109.000	850.685	1202.443	1.406	370.555	6734.730	112.232	1.455
110.000	859.392	1202.304	1.392	366.675	6451.583	110.932	1.394
111.000	865.390	1202.258	1.383	368.535	6339.556	110.052	1.369
112.000	868.880	1202.277	1.377	372.772	6328.609	109.549	1.367
113.000	870.691	1202.315	1.375	377.080	6358.376	109.292	1.373
114.000	871.094	1202.349	1.374	381.908	6430.465	109.238	1.389
115.000	869.835	1202.395	1.376	388.106	6567.062	109.425	1.419
116.000	866.714	1202.462	1.381	395.656	6775.641	109.887	1.464
117.000	861.825	1202.546	1.389	403.957	7047.637	110.610	1.522
118.000	855.479	1202.644	1.399	412.094	7362.940	111.554	1.590
119.000	848.380	1202.745	1.411	418.836	7682.526	112.618	1.660
120.000	841.287	1202.784	1.422	423.408	7968.746	113.685	1.721

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	836.916	1201.000	1.428	420.272	7999.970	114.154	1.728
122.000	834.009	1198.616	1.430	418.324	8000.000	114.341	1.728
123.000	831.716	1196.537	1.431	416.991	8000.000	114.469	1.728
124.000	829.945	1195.101	1.432	415.792	8000.000	114.586	1.728
125.000	828.672	1194.439	1.434	414.566	8000.000	114.711	1.728
126.000	827.866	1194.536	1.435	413.283	8000.000	114.844	1.728
127.000	827.484	1195.315	1.437	411.958	8000.000	114.986	1.728
128.000	827.477	1196.687	1.438	410.611	8000.000	115.134	1.728
129.000	827.797	1198.562	1.440	409.259	8000.000	115.285	1.728
130.000	828.413	1200.948	1.442	407.857	8000.000	115.445	1.728
131.000	831.621	1202.863	1.439	397.285	7739.392	115.151	1.672
132.000	840.496	1202.646	1.423	381.718	7201.632	113.779	1.556
133.000	850.578	1202.444	1.407	370.688	6739.853	112.248	1.456
134.000	859.273	1202.306	1.393	366.790	6456.494	110.950	1.395
135.000	865.272	1202.259	1.383	368.619	6343.853	110.070	1.370
136.000	868.777	1202.278	1.378	372.826	6332.018	109.564	1.368
137.000	870.596	1202.316	1.375	377.120	6361.367	109.306	1.374
138.000	871.006	1202.350	1.374	381.940	6433.176	109.251	1.390
139.000	869.738	1202.396	1.376	388.164	6570.452	109.440	1.419
140.000	866.637	1202.462	1.381	395.682	6778.110	109.897	1.464
141.000	861.738	1202.546	1.389	403.993	7050.558	110.622	1.523
142.000	855.395	1202.645	1.399	412.128	7365.835	111.566	1.591
143.000	848.303	1202.746	1.411	418.856	7685.075	112.630	1.660
144.000	841.215	1202.787	1.422	423.436	7971.341	113.697	1.722

/*----------END OF SIXTH DAY----------->

TABLE 2(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	836.880	1200.985	1.428	420.232	7999.973	114.158	1.728
146.000	833.982	1198.602	1.430	418.299	8000.000	114.344	1.728
147.000	831.696	1196.525	1.431	416.972	8000.000	114.471	1.728
148.000	829.929	1195.093	1.432	415.778	8000.000	114.588	1.728
149.000	828.661	1194.434	1.434	414.554	8000.000	114.712	1.728
150.000	827.858	1194.533	1.435	413.273	8000.000	114.845	1.728
151.000	827.479	1195.316	1.437	411.949	8000.000	114.987	1.728
152.000	827.474	1196.689	1.438	410.603	8000.000	115.135	1.728
153.000	827.795	1198.567	1.440	409.253	8000.000	115.286	1.728
154.000	828.411	1200.947	1.442	407.856	8000.000	115.445	1.728
155.000	831.824	1202.713	1.438	394.702	7679.555	115.102	1.659
156.000	840.525	1202.655	1.423	381.677	7200.204	113.775	1.555
157.000	850.633	1202.444	1.407	370.622	6737.254	112.239	1.455
158.000	859.333	1202.305	1.392	366.734	6454.038	110.941	1.394
159.000	865.331	1202.258	1.383	368.581	6341.781	110.061	1.370
160.000	868.822	1202.278	1.377	372.805	6330.562	109.557	1.367
161.000	870.637	1202.315	1.375	377.108	6360.168	109.300	1.374
162.000	871.042	1202.350	1.374	381.932	6432.160	109.246	1.389
163.000	869.787	1202.395	1.376	388.123	6568.542	109.432	1.419
164.000	866.672	1202.462	1.381	395.671	6776.985	109.893	1.464
165.000	861.786	1202.546	1.389	403.970	7048.885	110.616	1.523
166.000	855.441	1202.645	1.399	412.108	7364.210	111.559	1.591
167.000	848.345	1202.746	1.411	418.845	7683.681	112.624	1.660
168.000	841.234	1202.800	1.422	423.526	7972.792	113.695	1.722

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3

TABLE 3(BASE CASE)

SUNSHINE SYSTEM; COMPRESSOR STATION # 6 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	849.296	1057.365	1.241	440.992	5000.000	96.345	1.080
1.000	851.205	1065.746	1.248	429.691	5000.000	97.045	1.080
2.000	857.920	1083.762	1.259	413.186	5000.000	98.152	1.080
3.000	866.810	1103.769	1.269	399.594	5000.000	99.144	1.080
4.000	876.047	1122.947	1.277	389.061	5000.000	99.971	1.080
5.000	885.187	1141.135	1.284	380.510	5000.000	100.682	1.080
6.000	894.115	1158.402	1.291	373.367	5000.000	101.307	1.080
7.000	902.813	1174.842	1.296	367.306	5000.000	101.861	1.080
8.000	911.294	1190.544	1.301	362.110	5000.000	102.355	1.080
9.000	920.104	1205.119	1.305	354.387	4936.084	102.676	1.066
10.000	949.160	1202.061	1.262	295.888	3578.052	98.487	0.773
11.000	969.061	1201.330	1.236	294.565	3227.509	95.859	0.697
12.000	971.809	1201.385	1.233	335.615	3625.687	95.525	0.783
13.000	961.824	1201.830	1.246	378.054	4299.715	96.847	0.929
14.000	948.802	1202.223	1.263	401.823	4872.891	98.571	1.053
15.000	940.424	1198.789	1.271	401.313	4999.861	99.308	1.080
16.000	934.330	1188.240	1.268	405.025	5000.000	99.012	1.080
17.000	923.137	1161.880	1.255	423.204	5000.000	97.718	1.080
18.000	907.559	1130.671	1.242	442.587	5000.000	96.450	1.080
19.000	890.077	1100.055	1.232	458.837	5000.000	95.458	1.080
20.000	872.240	1072.018	1.225	470.551	5000.000	94.764	1.080
21.000	859.353	1057.701	1.227	466.509	5000.000	94.938	1.080
22.000	853.490	1055.467	1.233	455.539	5000.000	95.518	1.080
23.000	850.669	1055.827	1.237	447.501	5000.000	95.966	1.080
24.000	849.349	1057.333	1.241	441.188	5000.000	96.333	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	851.194	1065.606	1.248	429.928	5000.000	97.031	1.080
26.000	857.845	1083.510	1.259	413.454	5000.000	98.133	1.080
27.000	866.716	1103.513	1.269	399.804	5000.000	99.129	1.080
28.000	875.952	1122.706	1.277	389.232	5000.000	99.958	1.080
29.000	885.096	1140.911	1.284	380.652	5000.000	100.671	1.080
30.000	894.028	1158.194	1.291	373.488	5000.000	101.297	1.080
31.000	902.731	1174.649	1.296	367.410	5000.000	101.852	1.080
32.000	911.216	1190.364	1.301	362.200	5000.000	102.347	1.080
33.000	922.463	1202.752	1.299	339.431	4639.395	102.101	1.002
34.000	948.870	1201.990	1.263	294.992	3571.350	98.516	0.771
35.000	968.644	1201.346	1.237	295.041	3239.495	95.913	0.700
36.000	971.483	1201.390	1.233	335.710	3632.891	95.567	0.785
37.000	961.651	1201.829	1.246	377.851	4301.302	96.869	0.929
38.000	948.668	1202.234	1.263	401.795	4875.952	98.590	1.053
39.000	940.368	1198.738	1.271	401.274	4999.772	99.310	1.080
40.000	934.240	1188.081	1.268	405.084	5000.000	99.007	1.080
41.000	923.038	1161.706	1.255	423.275	5000.000	97.713	1.080
42.000	907.452	1130.494	1.242	442.660	5000.000	96.445	1.080
43.000	889.967	1099.865	1.232	458.906	5000.000	95.450	1.080
44.000	872.114	1071.800	1.225	470.679	5000.000	94.756	1.080
45.000	859.310	1057.706	1.227	466.378	5000.000	94.945	1.080
46.000	853.517	1055.579	1.233	455.376	5000.000	95.528	1.080
47.000	850.721	1055.951	1.237	447.383	5000.000	95.973	1.080
48.000	849.392	1057.407	1.241	441.151	5000.000	96.336	1.080

/*----------END OF SECOND DAY----------->

EXHIBIT 3

TABLE 3(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	851.222	1065.647	1.248	429.915	5000.000	97.031	1.080
50.000	857.898	1083.624	1.259	413.371	5000.000	98.139	1.080
51.000	866.777	1103.634	1.269	399.738	5000.000	99.134	1.080
52.000	876.013	1122.821	1.277	389.178	5000.000	99.962	1.080
53.000	885.154	1141.020	1.284	380.606	5000.000	100.674	1.080
54.000	894.084	1158.299	1.291	373.448	5000.000	101.300	1.080
55.000	902.785	1174.748	1.296	367.375	5000.000	101.855	1.080
56.000	911.268	1190.458	1.302	362.170	5000.000	102.350	1.080
57.000	920.343	1204.802	1.304	352.803	4903.841	102.609	1.059
58.000	949.038	1202.058	1.263	295.989	3581.337	98.502	0.774
59.000	968.929	1201.334	1.236	294.727	3231.445	95.876	0.698
60.000	971.702	1201.387	1.233	335.669	3628.300	95.539	0.784
61.000	961.753	1201.830	1.246	378.032	4301.029	96.856	0.929
62.000	948.751	1202.219	1.263	401.784	4873.545	98.577	1.053
63.000	940.394	1198.772	1.271	401.281	4999.862	99.310	1.080
64.000	934.294	1188.185	1.268	405.038	5000.000	99.011	1.080
65.000	923.101	1161.828	1.255	423.214	5000.000	97.718	1.080
66.000	907.526	1130.624	1.242	442.597	5000.000	96.449	1.080
67.000	890.045	1100.012	1.232	458.846	5000.000	95.458	1.080
68.000	872.209	1071.972	1.225	470.566	5000.000	94.763	1.080
69.000	859.325	1057.664	1.227	466.512	5000.000	94.938	1.080
70.000	853.467	1055.438	1.233	455.540	5000.000	95.518	1.080
71.000	850.649	1055.799	1.237	447.504	5000.000	95.966	1.080
72.000	849.328	1057.303	1.241	441.196	5000.000	96.333	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	851.174	1065.576	1.248	429.934	5000.000	97.030	1.080
74.000	857.829	1083.490	1.259	413.451	5000.000	98.133	1.080
75.000	866.701	1103.495	1.269	399.803	5000.000	99.129	1.080
76.000	875.938	1122.687	1.277	389.230	5000.000	99.958	1.080
77.000	885.081	1140.892	1.284	380.651	5000.000	100.671	1.080
78.000	894.014	1158.176	1.291	373.487	5000.000	101.297	1.080
79.000	902.716	1174.630	1.296	367.408	5000.000	101.852	1.080
80.000	911.201	1190.345	1.301	362.199	5000.000	102.347	1.080
81.000	922.436	1202.745	1.299	339.508	4640.937	102.103	1.002
82.000	948.837	1201.987	1.263	294.955	3571.398	98.520	0.771
83.000	968.621	1201.345	1.237	295.028	3239.726	95.916	0.700
84.000	971.457	1201.390	1.233	335.725	3633.515	95.570	0.785
85.000	961.619	1201.829	1.246	377.880	4302.305	96.873	0.929
86.000	948.637	1202.234	1.263	401.811	4876.847	98.594	1.053
87.000	940.352	1198.729	1.271	401.257	4999.777	99.312	1.080
88.000	934.234	1188.090	1.268	405.058	5000.000	99.009	1.080
89.000	923.028	1161.688	1.255	423.283	5000.000	97.712	1.080
90.000	907.438	1130.468	1.242	442.672	5000.000	96.444	1.080
91.000	889.951	1099.838	1.232	458.918	5000.000	95.450	1.080
92.000	872.093	1071.770	1.225	470.692	5000.000	94.756	1.080
93.000	859.291	1057.672	1.227	466.401	5000.000	94.944	1.080
94.000	853.491	1055.533	1.233	455.404	5000.000	95.526	1.080
95.000	850.693	1055.905	1.237	447.405	5000.000	95.972	1.080
96.000	849.368	1057.375	1.241	441.155	5000.000	96.335	1.080

/*----------END OF FOURTH DAY----------->

TABLE 3(BASE CASE)--CONT

EXHIBIT 3

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	851.205	1065.627	1.248	429.913	5000.000	97.032	1.080
98.000	857.876	1083.588	1.259	413.386	5000.000	98.138	1.080
99.000	866.754	1103.596	1.269	399.750	5000.000	99.133	1.080
100.000	875.989	1122.784	1.277	389.186	5000.000	99.961	1.080
101.000	885.130	1140.984	1.284	380.614	5000.000	100.674	1.080
102.000	894.061	1158.263	1.291	373.454	5000.000	101.300	1.080
103.000	902.761	1174.713	1.296	367.380	5000.000	101.854	1.080
104.000	911.245	1190.424	1.302	362.174	5000.000	102.349	1.080
105.000	920.603	1204.514	1.304	351.061	4869.393	102.543	1.052
106.000	948.961	1202.061	1.263	296.100	3584.048	98.513	0.774
107.000	968.827	1201.337	1.236	294.868	3234.642	95.889	0.699
108.000	971.614	1201.388	1.233	335.716	3630.483	95.550	0.784
109.000	961.695	1201.831	1.246	378.009	4302.039	96.864	0.929
110.000	948.708	1202.216	1.263	401.754	4874.143	98.582	1.053
111.000	940.368	1198.758	1.271	401.254	4999.862	99.312	1.080
112.000	934.262	1188.132	1.268	405.055	5000.000	99.009	1.080
113.000	923.069	1161.780	1.255	423.226	5000.000	97.717	1.080
114.000	907.495	1130.579	1.242	442.607	5000.000	96.449	1.080
115.000	890.016	1099.972	1.232	458.856	5000.000	95.457	1.080
116.000	872.179	1071.926	1.225	470.583	5000.000	94.762	1.080
117.000	859.298	1057.629	1.227	466.514	5000.000	94.938	1.080
118.000	853.447	1055.413	1.233	455.538	5000.000	95.518	1.080
119.000	850.631	1055.776	1.237	447.505	5000.000	95.966	1.080
120.000	849.309	1057.275	1.241	441.204	5000.000	96.332	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	851.155	1065.548	1.248	429.941	5000.000	97.030	1.080
122.000	857.815	1083.475	1.259	413.446	5000.000	98.134	1.080
123.000	866.689	1103.481	1.269	399.799	5000.000	99.129	1.080
124.000	875.926	1122.673	1.277	389.228	5000.000	99.958	1.080
125.000	885.069	1140.878	1.284	380.648	5000.000	100.671	1.080
126.000	894.001	1158.161	1.291	373.484	5000.000	101.297	1.080
127.000	902.704	1174.615	1.296	367.406	5000.000	101.852	1.080
128.000	911.189	1190.329	1.301	362.197	5000.000	102.347	1.080
129.000	922.403	1202.747	1.299	339.634	4643.433	102.108	1.003
130.000	948.810	1201.984	1.263	294.905	3571.160	98.523	0.771
131.000	968.608	1201.344	1.237	295.002	3239.659	95.918	0.700
132.000	971.439	1201.389	1.233	335.737	3633.968	95.573	0.785
133.000	961.590	1201.830	1.246	377.915	4303.288	96.877	0.930
134.000	948.609	1202.234	1.263	401.828	4877.704	98.597	1.054
135.000	940.337	1198.722	1.271	401.240	4999.784	99.313	1.080
136.000	934.232	1188.107	1.268	405.029	5000.000	99.011	1.080
137.000	923.020	1161.670	1.255	423.293	5000.000	97.712	1.080
138.000	907.425	1130.442	1.242	442.688	5000.000	96.443	1.080
139.000	889.936	1099.811	1.232	458.933	5000.000	95.449	1.080
140.000	872.071	1071.735	1.225	470.711	5000.000	94.755	1.080
141.000	859.271	1057.634	1.227	466.429	5000.000	94.942	1.080
142.000	853.462	1055.482	1.233	455.436	5000.000	95.524	1.080
143.000	850.662	1055.853	1.237	447.430	5000.000	95.971	1.080
144.000	849.342	1057.340	1.241	441.160	5000.000	96.335	1.080

/*----------END OF SIXTH DAY----------->

TABLE 6(BASE CASE)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	851.186	1065.605	1.248	429.911	5000.000	97.032	1.080
146.000	857.852	1083.547	1.259	413.404	5000.000	98.137	1.080
147.000	866.727	1103.552	1.269	399.764	5000.000	99.132	1.080
148.000	875.962	1122.741	1.277	389.197	5000.000	99.960	1.080
149.000	885.103	1140.942	1.284	380.622	5000.000	100.673	1.080
150.000	894.034	1158.222	1.291	373.461	5000.000	101.299	1.080
151.000	902.735	1174.673	1.296	367.386	5000.000	101.854	1.080
152.000	911.219	1190.385	1.302	362.179	5000.000	102.349	1.080
153.000	920.889	1204.194	1.303	349.137	4831.338	102.470	1.044
154.000	948.884	1202.052	1.263	296.037	3584.531	98.522	0.774
155.000	968.720	1201.340	1.237	294.988	3237.687	95.903	0.699
156.000	971.522	1201.389	1.233	335.752	3632.628	95.562	0.785
157.000	961.635	1201.830	1.246	377.973	4302.956	96.871	0.929
158.000	948.663	1202.215	1.263	401.735	4874.973	98.588	1.053
159.000	940.342	1198.744	1.271	401.224	4999.863	99.314	1.080
160.000	934.228	1188.072	1.268	405.077	5000.000	99.008	1.080
161.000	923.037	1161.739	1.255	423.229	5000.000	97.717	1.080
162.000	907.469	1130.546	1.242	442.608	5000.000	96.449	1.080
163.000	889.993	1099.945	1.232	458.856	5000.000	95.458	1.080
164.000	872.148	1071.872	1.225	470.618	5000.000	94.760	1.080
165.000	859.275	1057.609	1.227	466.496	5000.000	94.939	1.080
166.000	853.445	1055.427	1.233	455.502	5000.000	95.520	1.080
167.000	850.636	1055.796	1.237	447.479	5000.000	95.968	1.080
168.000	849.307	1057.267	1.241	441.213	5000.000	96.332	1.080

/*----------END OF SEVENTH DAY----------*/

EXHIBIT 3

TABLE 4(BASE CASE)

SUNSHINE SYSTEM; DELIVERY POINT REPORT

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
0.000	699.878	836.189	914.115	898.046
1.000	697.062	890.439	954.502	949.351
2.000	694.117	923.111	992.614	988.187
3.000	691.474	952.383	1021.036	1016.840
4.000	689.273	979.370	1045.893	1041.855
5.000	687.491	1004.129	1068.481	1064.569
6.000	686.077	1026.943	1089.345	1085.541
7.000	684.984	1048.115	1108.804	1105.094
8.000	684.179	1067.906	1127.084	1123.458
9.000	683.632	1086.520	1144.349	1140.799
10.000	683.314	1100.364	1155.641	1152.209
11.000	683.203	1105.453	1134.589	1123.353
12.000	683.420	1050.354	1116.106	1103.528
13.000	684.628	1004.622	1105.572	1092.754
14.000	687.190	984.226	1098.135	1085.118
15.000	690.789	973.576	1092.408	1078.844
16.000	694.698	964.535	973.121	902.797
17.000	698.234	943.733	850.600	748.034
18.000	701.035	907.987	765.034	645.172
19.000	703.013	865.602	691.977	554.404
20.000	704.144	821.944	790.945	761.217
21.000	704.408	785.909	868.334	849.368
22.000	703.772	767.310	895.615	878.344
23.000	702.268	762.805	907.317	890.659
24.000	700.009	832.611	914.347	898.503

/*----------END OF FIRST DAY----------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
25.000	697.206	889.206	953.946	948.481
26.000	694.253	922.483	992.220	987.797
27.000	691.589	951.932	1020.683	1016.486
28.000	689.366	978.998	1045.574	1041.534
29.000	687.567	1003.805	1068.192	1064.279
30.000	686.138	1026.653	1089.083	1085.278
31.000	685.035	1047.853	1108.565	1104.854
32.000	684.220	1067.667	1126.865	1123.238
33.000	683.664	1086.267	1144.093	1140.548
34.000	683.340	1100.175	1155.115	1151.480
35.000	683.225	1104.437	1134.890	1123.908
36.000	683.445	1051.019	1116.149	1103.571
37.000	684.638	1004.836	1105.602	1092.784
38.000	687.179	984.325	1098.164	1085.148
39.000	690.756	973.607	1090.634	1076.029
40.000	694.648	964.458	972.259	901.461
41.000	698.174	943.567	850.101	747.445
42.000	700.969	907.767	764.634	644.690
43.000	702.940	865.368	694.185	559.346
44.000	704.081	821.681	794.391	768.281
45.000	704.343	785.757	869.161	850.255
46.000	703.708	767.342	896.034	878.782
47.000	702.205	761.787	907.588	890.940
48.000	699.948	833.473	914.008	897.846

/*----------END OF SECOND DAY----------->

EXHIBIT 3

TABLE 4(BASE CASE)

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
49.000	697.148	889.513	954.377	949.189
50.000	694.201	922.665	992.431	988.007
51.000	691.546	952.102	1020.848	1016.651
52.000	689.333	979.157	1045.720	1041.681
53.000	687.541	1003.952	1068.327	1064.414
54.000	686.118	1026.790	1089.208	1085.403
55.000	685.019	1047.980	1108.682	1104.972
56.000	684.208	1067.786	1126.976	1123.349
57.000	683.656	1086.409	1144.245	1140.696
58.000	683.335	1100.283	1155.492	1152.017
59.000	683.220	1105.220	1134.629	1123.448
60.000	683.435	1050.468	1116.104	1103.527
61.000	684.640	1004.653	1105.571	1092.753
62.000	687.196	984.239	1098.137	1085.121
63.000	690.788	973.579	1092.034	1078.252
64.000	694.689	964.506	973.077	902.804
65.000	698.220	943.676	850.522	747.945
66.000	701.018	907.924	764.954	645.075
67.000	702.995	865.539	691.766	554.082
68.000	704.124	821.880	791.030	761.412
69.000	704.388	785.845	868.329	849.365
70.000	703.752	767.256	895.590	878.318
71.000	702.248	762.648	907.286	890.628
72.000	699.989	832.661	914.263	898.388

/*----------END OF THIRD DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
73.000	697.187	889.194	953.953	948.514
74.000	694.236	922.461	992.205	987.781
75.000	691.575	951.911	1020.665	1016.468
76.000	689.355	978.978	1045.555	1041.515
77.000	687.558	1003.785	1068.173	1064.260
78.000	686.131	1026.633	1089.063	1085.258
79.000	685.028	1047.832	1108.546	1104.835
80.000	684.214	1067.646	1126.846	1123.219
81.000	683.659	1086.246	1144.074	1140.528
82.000	683.336	1100.172	1155.149	1151.528
83.000	683.221	1104.507	1134.850	1123.843
84.000	683.440	1050.935	1116.139	1103.561
85.000	684.629	1004.807	1105.595	1092.778
86.000	687.168	984.311	1098.159	1085.143
87.000	690.742	973.599	1090.762	1076.235
88.000	694.633	964.463	971.956	900.920
89.000	698.158	943.566	849.994	747.316
90.000	700.953	907.745	764.559	644.600
91.000	702.925	865.336	693.586	558.187
92.000	704.066	821.638	793.921	767.395
93.000	704.328	785.723	869.014	850.100
94.000	703.693	767.287	895.939	878.684
95.000	702.191	762.021	907.514	890.863
96.000	699.935	833.278	914.085	898.006

/*----------END OF FOURTH DAY---------->

EXHIBIT 3

TABLE 4 (BASE CASE)

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
97.000	697.136	889.433	954.278	949.028
98.000	694.190	922.613	992.375	987.951
99.000	691.537	952.052	1020.800	1016.603
100.000	689.325	979.109	1045.676	1041.636
101.000	687.535	1003.907	1068.285	1064.372
102.000	686.113	1026.746	1089.167	1085.363
103.000	685.015	1047.938	1108.643	1104.933
104.000	684.204	1067.746	1126.938	1123.311
105.000	683.652	1086.365	1144.202	1140.653
106.000	683.331	1100.225	1155.355	1151.839
107.000	683.217	1105.000	1134.672	1123.545
108.000	683.433	1050.580	1116.105	1103.527
109.000	684.634	1004.685	1105.572	1092.754
110.000	687.186	984.253	1098.140	1085.123
111.000	690.772	973.583	1091.671	1077.675
112.000	694.669	964.479	973.032	902.808
113.000	698.197	943.622	850.447	747.858
114.000	700.993	907.865	764.877	644.982
115.000	702.970	865.479	691.507	553.679
116.000	704.100	821.817	791.164	761.710
117.000	704.365	785.782	868.340	849.379
118.000	703.729	767.207	895.574	878.303
119.000	702.226	762.458	907.263	890.604
120.000	699.968	832.740	914.167	898.251

/*----------END OF FIFTH DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
121.000	697.167	889.193	953.974	948.569
122.000	694.218	922.445	992.197	987.773
123.000	691.560	951.895	1020.652	1016.455
124.000	689.343	978.962	1045.541	1041.500
125.000	687.548	1003.769	1068.159	1064.245
126.000	686.123	1026.617	1089.048	1085.243
127.000	685.021	1047.816	1108.530	1104.819
128.000	684.208	1067.630	1126.830	1123.203
129.000	683.654	1086.230	1144.058	1140.513
130.000	683.331	1100.174	1155.198	1151.596
131.000	683.217	1104.603	1134.802	1123.764
132.000	683.435	1050.833	1116.128	1103.550
133.000	684.620	1004.773	1105.588	1092.770
134.000	687.157	984.295	1098.154	1085.138
135.000	690.730	973.590	1090.936	1076.514
136.000	694.620	964.471	971.593	900.263
137.000	698.145	943.570	849.874	747.170
138.000	700.940	907.725	764.476	644.501
139.000	702.912	865.304	692.844	556.747
140.000	704.053	821.590	793.443	766.513
141.000	704.314	785.685	868.847	849.924
142.000	703.680	767.225	895.831	878.572
143.000	702.179	762.283	907.430	890.777
144.000	699.923	833.052	914.172	898.185

/*----------END OF SIXTH DAY---------->

TABLE 4(BASE CASE)

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
145.000	697.125	889.340	954.162	948.843
146.000	694.181	922.553	992.310	987.886
147.000	691.530	951.995	1020.746	1016.549
148.000	689.319	979.055	1045.625	1041.586
149.000	687.530	1003.855	1068.237	1064.324
150.000	686.109	1026.696	1089.121	1085.316
151.000	685.011	1047.890	1108.598	1104.888
152.000	684.200	1067.699	1126.894	1123.267
153.000	683.648	1086.316	1144.153	1140.604
154.000	683.327	1100.187	1155.232	1151.670
155.000	683.213	1104.767	1134.733	1123.666
156.000	683.430	1050.715	1116.111	1103.533
157.000	684.626	1004.726	1105.576	1092.758
158.000	687.172	984.272	1098.145	1085.128
159.000	690.752	973.590	1091.265	1077.030
160.000	694.644	964.449	973.149	903.107
161.000	698.169	943.566	850.427	747.837
162.000	700.964	907.815	764.838	644.934
163.000	702.942	865.432	691.489	553.651
164.000	704.074	821.762	791.924	763.278
165.000	704.340	785.719	868.555	849.612
166.000	703.705	767.189	895.671	878.405
167.000	702.203	761.821	907.318	890.602
168.000	699.947	833.157	913.899	897.802

/*----------END OF SEVENTH DAY----------->

FIGURE 2

FIG 2-SUNSHINE PIPELINE SYSTEM; BASE 30 IN DESIGN(INCLUDES COMP'R FUEL)

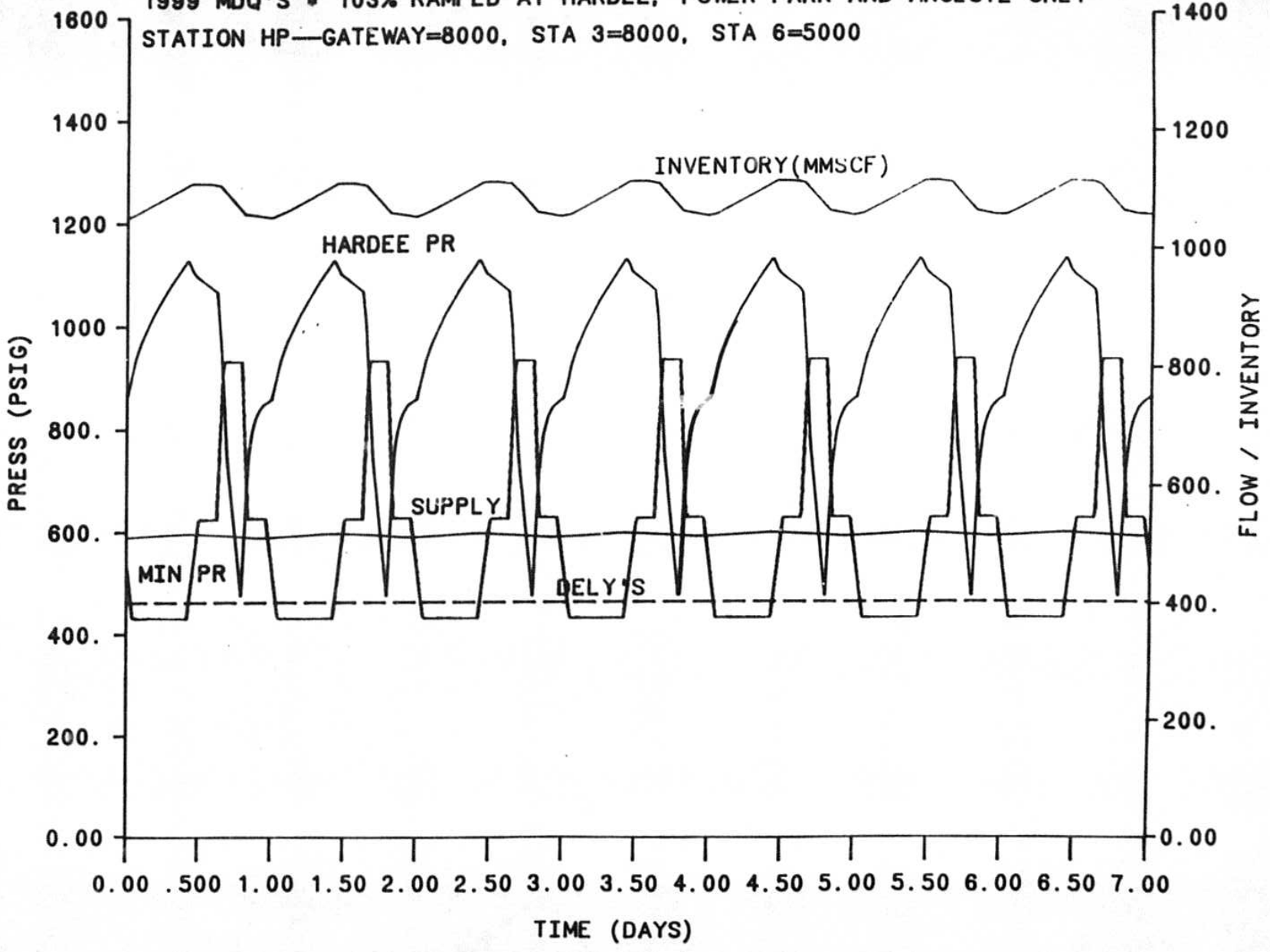


EXHIBIT 3A

TABLE 5(BASE * 103%)

SUNSHINE SYSTEM; GATEWAY COMPRESSOR STATION REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	909.785	1204.235	1.319	512.954	7442.483	103.990	1.608
1.000	909.564	1204.252	1.319	513.957	7464.312	104.022	1.612
2.000	909.354	1204.268	1.319	514.907	7485.032	104.052	1.617
3.000	909.156	1204.284	1.319	515.802	7504.594	104.081	1.621
4.000	908.971	1204.299	1.320	516.632	7522.785	104.108	1.625
5.000	908.805	1204.312	1.320	517.378	7539.159	104.132	1.629
6.000	908.662	1204.324	1.320	518.014	7553.182	104.153	1.632
7.000	908.548	1204.334	1.320	518.520	7564.378	104.170	1.634
8.000	908.466	1204.342	1.320	518.881	7572.413	104.182	1.636
9.000	908.417	1204.347	1.320	519.091	7577.128	104.189	1.637
10.000	908.401	1204.349	1.321	519.156	7578.649	104.191	1.637
11.000	908.416	1204.349	1.321	519.078	7577.019	104.189	1.637
12.000	908.461	1204.347	1.320	518.870	7572.512	104.183	1.636
13.000	908.532	1204.342	1.320	518.543	7565.406	104.173	1.634
14.000	908.627	1204.336	1.320	518.110	7555.950	104.159	1.632
15.000	908.745	1204.328	1.320	517.574	7544.288	104.142	1.630
16.000	908.934	1204.319	1.320	516.689	7525.227	104.115	1.626
17.000	909.233	1204.300	1.319	515.315	7495.436	104.072	1.619
18.000	909.579	1204.274	1.319	513.745	7461.263	104.022	1.612
19.000	909.908	1204.247	1.318	512.256	7428.825	103.974	1.605
20.000	910.163	1204.224	1.318	511.119	7403.931	103.936	1.599
21.000	910.290	1204.208	1.318	510.577	7391.806	103.917	1.597
22.000	910.252	1204.204	1.318	510.794	7396.019	103.922	1.598
23.000	910.068	1204.214	1.318	511.663	7414.500	103.949	1.602
24.000	909.838	1204.231	1.318	512.7[illegible]5	7437.290	103.982	1.607

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	909.612	1204.248	1.319	513.740	7459.583	104.015	1.611
26.000	909.398	1204.265	1.319	514.712	7480.755	104.046	1.616
27.000	909.196	1204.281	1.319	515.622	7500.644	104.075	1.620
28.000	909.008	1204.296	1.320	516.468	7519.179	104.103	1.624
29.000	908.838	1204.310	1.320	517.231	7535.924	104.127	1.628
30.000	908.691	1204.322	1.320	517.885	7550.328	104.149	1.631
31.000	908.573	1204.332	1.320	518.408	7561.907	104.166	1.633
32.000	908.487	1204.340	1.320	518.786	7570.309	104.179	1.635
33.000	908.434	1204.345	1.321	519.014	7575.407	104.186	1.636
34.000	908.415	1204.348	1.321	519.092	7577.229	104.189	1.637
35.000	908.427	1204.348	1.321	519.029	7575.922	104.188	1.636
36.000	908.469	1204.346	1.321	518.833	7571.691	104.182	1.636
37.000	908.538	1204.342	1.320	518.519	7564.870	104.172	1.634
38.000	908.630	1204.336	1.320	518.096	7555.645	104.158	1.632
39.000	908.745	1204.328	1.320	517.575	7544.276	104.142	1.630
40.000	908.922	1204.319	1.320	516.747	7526.440	104.116	1.626
41.000	909.209	1204.301	1.319	515.426	7497.824	104.075	1.620
42.000	909.547	1204.276	1.319	513.889	7464.385	104.026	1.612
43.000	909.872	1204.250	1.318	512.422	7432.414	103.979	1.605
44.000	910.125	1204.226	1.318	511.295	7407.720	103.942	1.600
45.000	910.250	1204.211	1.318	510.760	7395.756	103.923	1.598
46.000	910.212	1204.207	1.318	510.977	7399.974	103.928	1.598
47.000	910.032	1204.217	1.318	511.826	7418.063	103.954	1.602
48.000	909.808	1204.233	1.318	512.849	7440.223	103.986	1.607

/*----------END OF SECOND DAY----------->

EXHIBIT 3A

TABLE 5(BASE * 103%)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	909.588	1204.250	1.319	513.849	7461.960	104.018	1.612
50.000	909.378	1204.267	1.319	514.799	7482.675	104.049	1.616
51.000	909.179	1204.282	1.319	515.697	7502.292	104.078	1.621
52.000	908.993	1204.297	1.320	516.532	7520.589	104.105	1.625
53.000	908.825	1204.311	1.320	517.288	7537.172	104.129	1.628
54.000	908.680	1204.323	1.320	517.935	7551.455	104.150	1.631
55.000	908.563	1204.333	1.320	518.455	7562.937	104.167	1.634
56.000	908.477	1204.341	1.320	518.830	7571.268	104.180	1.635
57.000	908.425	1204.346	1.321	519.055	7576.317	104.188	1.637
58.000	908.406	1204.349	1.321	519.133	7578.118	104.191	1.637
59.000	908.419	1204.349	1.320	519.067	7576.766	104.189	1.637
60.000	908.461	1204.347	1.320	518.872	7572.553	104.183	1.636
61.000	908.530	1204.343	1.320	518.556	7565.682	104.173	1.634
62.000	908.622	1204.337	1.320	518.134	7556.481	104.160	1.632
63.000	908.735	1204.329	1.320	517.621	7545.276	104.143	1.630
64.000	908.904	1204.320	1.320	516.832	7528.281	104.119	1.626
65.000	909.183	1204.303	1.319	515.547	7500.438	104.079	1.620
66.000	909.516	1204.278	1.319	514.035	7467.549	104.031	1.613
67.000	909.837	1204.252	1.319	512.581	7435.857	103.984	1.606
68.000	910.089	1204.229	1.318	511.457	7411.237	103.947	1.601
69.000	910.214	1204.214	1.318	510.925	7399.315	103.928	1.598
70.000	910.177	1204.210	1.318	511.136	7403.419	103.933	1.599
71.000	910.001	1204.219	1.318	511.965	7421.082	103.958	1.603
72.000	909.783	1204.235	1.318	512.962	7442.670	103.990	1.608

/*----------END OF THIRD DAY----------

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	909.568	1204.252	1.319	513.938	7463.900	104.021	1.612
74.000	909.362	1204.268	1.319	514.871	7484.249	104.051	1.617
75.000	909.166	1204.283	1.319	515.757	7503.606	104.080	1.621
76.000	908.982	1204.298	1.320	516.583	7521.705	104.106	1.625
77.000	908.815	1204.311	1.320	517.331	7538.146	104.131	1.628
78.000	908.671	1204.323	1.320	517.974	7552.307	104.152	1.631
79.000	908.555	1204.333	1.320	518.490	7563.718	104.169	1.634
80.000	908.470	1204.341	1.320	518.862	7571.988	104.181	1.636
81.000	908.418	1204.346	1.321	519.086	7577.003	104.189	1.637
82.000	908.400	1204.349	1.321	519.161	7578.738	104.191	1.637
83.000	908.413	1204.349	1.321	519.095	7577.377	104.190	1.637
84.000	908.455	1204.347	1.320	518.898	7573.133	104.184	1.636
85.000	908.524	1204.343	1.320	518.582	7566.256	104.174	1.634
86.000	908.616	1204.337	1.320	518.160	7557.045	104.160	1.632
87.000	908.729	1204.329	1.320	517.648	7545.867	104.144	1.630
88.000	908.894	1204.321	1.320	516.882	7529.347	104.121	1.626
89.000	909.165	1204.304	1.319	515.630	7502.230	104.081	1.621
90.000	909.493	1204.280	1.319	514.136	7469.730	104.034	1.614
91.000	909.813	1204.254	1.319	512.689	7438.210	103.988	1.607
92.000	910.063	1204.231	1.318	511.576	7413.808	103.951	1.601
93.000	910.190	1204.216	1.318	511.034	7401.680	103.932	1.599
94.000	910.154	1204.212	1.318	511.243	7405.720	103.936	1.600
95.000	909.981	1204.221	1.318	512.059	7423.125	103.961	1.603
96.000	909.767	1204.237	1.319	513.036	7444.299	103.992	1.608

/*----------END OF FOURTH DAY----------

TABLE 5(BASE * 103%)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	909.555	1204.253	1.319	513.997	7465.209	104.023	1.613
98.000	909.351	1204.269	1.319	514.921	7485.337	104.053	1.617
99.000	909.156	1204.284	1.319	515.798	7504.514	104.081	1.621
100.000	908.974	1204.299	1.320	516.621	7522.524	104.107	1.625
101.000	908.808	1204.312	1.320	517.365	7538.866	104.132	1.628
102.000	908.664	1204.324	1.320	518.005	7552.989	104.153	1.632
103.000	908.548	1204.334	1.320	518.519	7564.350	104.170	1.634
104.000	908.464	1204.341	1.320	518.890	7572.582	104.182	1.636
105.000	908.412	1204.347	1.321	519.113	7577.596	104.190	1.637
106.000	908.394	1204.349	1.321	519.188	7579.327	104.192	1.637
107.000	908.407	1204.350	1.321	519.121	7577.934	104.190	1.637
108.000	908.449	1204.348	1.320	518.924	7573.702	104.185	1.636
109.000	908.518	1204.343	1.320	518.607	7566.807	104.175	1.635
110.000	908.611	1204.337	1.320	518.184	7557.584	104.161	1.633
111.000	908.723	1204.330	1.320	517.675	7546.445	104.145	1.630
112.000	908.882	1204.321	1.320	516.936	7530.516	104.122	1.627
113.000	909.150	1204.305	1.319	515.702	7503.790	104.084	1.621
114.000	909.474	1204.281	1.319	514.223	7471.634	104.037	1.614
115.000	909.792	1204.256	1.319	512.788	7440.328	103.991	1.607
116.000	910.041	1204.233	1.318	511.678	7416.016	103.954	1.602
117.000	910.168	1204.217	1.318	511.137	7403.895	103.935	1.599
118.000	910.132	1204.213	1.318	511.343	7407.885	103.940	1.600
119.000	909.961	1204.223	1.318	512.147	7425.049	103.964	1.604
120.000	909.751	1204.238	1.319	513.108	7445.871	103.995	1.608

/*----------END OF FIFTH DAY----------

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	909.542	1204.254	1.319	514.056	7466.485	104.025	1.613
122.000	909.340	1204.270	1.319	514.969	7486.382	104.054	1.617
123.000	909.147	1204.285	1.319	515.838	7505.395	104.082	1.621
124.000	908.966	1204.299	1.320	516.655	7523.280	104.109	1.625
125.000	908.801	1204.312	1.320	517.395	7539.548	104.133	1.629
126.000	908.658	1204.324	1.320	518.034	7553.630	104.154	1.632
127.000	908.542	1204.334	1.320	518.546	7564.946	104.170	1.634
128.000	908.458	1204.342	1.320	518.915	7573.147	104.183	1.636
129.000	908.407	1204.347	1.321	519.137	7578.122	104.190	1.637
130.000	908.389	1204.350	1.321	519.211	7579.829	104.193	1.637
131.000	908.402	1204.350	1.321	519.144	7578.443	104.191	1.637
132.000	908.444	1204.348	1.320	518.946	7574.181	104.185	1.636
133.000	908.513	1204.344	1.320	518.629	7567.281	104.175	1.635
134.000	908.606	1204.338	1.320	518.206	7558.050	104.162	1.633
135.000	908.718	1204.330	1.320	517.698	7546.968	104.146	1.630
136.000	908.873	1204.322	1.320	516.976	7531.378	104.123	1.627
137.000	909.135	1204.306	1.320	515.771	7505.307	104.086	1.621
138.000	909.456	1204.283	1.319	514.307	7473.451	104.039	1.614
139.000	909.772	1204.257	1.319	512.881	7442.361	103.994	1.608
140.000	910.020	1204.234	1.318	511.773	7418.060	103.957	1.602
141.000	910.147	1204.219	1.318	511.232	7405.951	103.938	1.600
142.000	910.112	1204.215	1.318	511.434	7409.880	103.943	1.601
143.000	909.943	1204.224	1.318	512.227	7426.783	103.967	1.604
144.000	909.736	1204.239	1.319	513.172	7447.259	103.997	1.609

/*----------END OF SIXTH DAY----------

TABLE 5(BASE * 103%)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	909.530	1204.255	1.319	514.107	7467.604	104.027	1.613
146.000	909.331	1204.271	1.319	515.011	7487.309	104.056	1.617
147.000	909.140	1204.286	1.319	515.874	7506.167	104.083	1.621
148.000	908.960	1204.300	1.320	516.683	7523.915	104.110	1.625
149.000	908.795	1204.313	1.320	517.420	7540.091	104.133	1.629
150.000	908.653	1204.325	1.320	518.056	7554.096	104.154	1.632
151.000	908.538	1204.335	1.320	518.566	7565.384	104.171	1.634
152.000	908.454	1204.342	1.321	518.933	7573.554	104.183	1.636
153.000	908.403	1204.348	1.321	519.153	7578.479	104.191	1.637
154.000	908.385	1204.350	1.321	519.227	7580.188	104.194	1.637
155.000	908.398	1204.350	1.321	519.159	7578.788	104.192	1.637
156.000	908.441	1204.348	1.321	518.960	7574.496	104.186	1.636
157.000	908.510	1204.344	1.320	518.643	7567.589	104.176	1.635
158.000	908.603	1204.338	1.320	518.221	7558.391	104.162	1.633
159.000	908.715	1204.330	1.320	517.713	7547.275	104.146	1.630
160.000	908.868	1204.322	1.320	517.000	7531.892	104.124	1.627
161.000	909.126	1204.306	1.320	515.808	7506.097	104.087	1.621
162.000	909.446	1204.283	1.319	514.353	7474.431	104.041	1.615
163.000	909.761	1204.258	1.319	512.930	7443.408	103.995	1.608
164.000	910.009	1204.235	1.318	511.824	7419.152	103.959	1.603
165.000	910.135	1204.220	1.318	511.284	7407.072	103.940	1.600
166.000	910.101	1204.216	1.318	511.485	7410.954	103.944	1.601
167.000	909.934	1204.225	1.318	512.270	7427.722	103.968	1.604
168.000	909.728	1204.240	1.319	513.208	7448.051	103.998	1.609

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3A

TABLE 6(BASE * 103%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 3 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	828.965	1194.638	1.433	414.801	8000.000	114.686	1.728
1.000	827.261	1191.576	1.433	415.322	8000.000	114.620	1.728
2.000	825.686	1188.841	1.432	415.710	8000.000	114.569	1.728
3.000	824.298	1186.629	1.432	415.856	8000.000	114.545	1.728
4.000	823.175	1185.138	1.432	415.675	8000.000	114.557	1.728
5.000	822.374	1184.446	1.433	415.172	8000.000	114.607	1.728
6.000	821.912	1184.519	1.433	414.410	8000.000	114.686	1.728
7.000	821.780	1185.271	1.435	413.465	8000.000	114.787	1.728
8.000	821.955	1186.609	1.436	412.397	8000.000	114.904	1.728
9.000	822.406	1188.444	1.437	411.253	8000.000	115.032	1.728
10.000	823.101	1190.697	1.439	410.067	8000.000	115.167	1.728
11.000	824.009	1193.301	1.440	408.860	8000.000	115.306	1.728
12.000	825.102	1196.207	1.442	407.640	8000.000	115.448	1.728
13.000	826.368	1199.406	1.443	406.401	8000.000	115.594	1.728
14.000	827.691	1202.421	1.445	405.430	8000.000	115.712	1.728
15.000	831.964	1202.678	1.438	397.154	7724.615	115.082	1.669
16.000	835.922	1202.625	1.431	394.254	7560.662	114.473	1.633
17.000	839.063	1202.590	1.426	393.661	7464.695	113.994	1.612
18.000	841.093	1202.571	1.422	395.129	7437.972	113.687	1.607
19.000	841.503	1202.577	1.422	399.055	7500.946	113.627	1.620
20.000	839.967	1202.619	1.424	405.110	7657.514	113.864	1.654
21.000	836.482	1202.686	1.430	412.465	7895.214	114.400	1.705
22.000	833.124	1201.422	1.434	414.214	7999.741	114.774	1.728
23.000	831.138	1198.443	1.434	414.243	8000.000	114.760	1.728
24.000	829.314	1195.219	1.434	414.741	8000.000	114.695	1.728

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	827.587	1192.126	1.433	415.257	8000.000	114.629	1.728
26.000	825.985	1189.337	1.432	415.659	8000.000	114.576	1.728
27.000	824.564	1187.051	1.432	415.830	8000.000	114.549	1.728
28.000	823.405	1185.480	1.432	415.675	8000.000	114.559	1.728
29.000	822.566	1184.712	1.433	415.192	8000.000	114.605	1.728
30.000	822.069	1184.716	1.433	414.446	8000.000	114.683	1.728
31.000	821.904	1185.409	1.435	413.511	8000.000	114.783	1.728
32.000	822.050	1186.697	1.436	412.450	8000.000	114.899	1.728
33.000	822.474	1188.489	1.437	411.310	8000.000	115.026	1.728
34.000	823.147	1190.706	1.439	410.125	8000.000	115.161	1.728
35.000	824.035	1193.279	1.440	408.919	8000.000	115.299	1.728
36.000	825.110	1196.153	1.442	407.704	8000.000	115.441	1.728
37.000	826.348	1199.276	1.443	406.496	8000.000	115.584	1.728
38.000	827.644	1202.239	1.445	405.536	8000.000	115.700	1.728
39.000	831.598	1202.701	1.439	397.387	7739.463	115.139	1.672
40.000	835.559	1202.631	1.432	394.616	7577.467	114.529	1.637
41.000	838.694	1202.594	1.426	393.953	7480.165	114.051	1.616
42.000	840.722	1202.575	1.423	395.378	7452.633	113.743	1.610
43.000	841.134	1202.580	1.422	399.268	7514.949	113.683	1.623
44.000	839.604	1202.621	1.425	405.293	7670.986	113.919	1.657
45.000	836.123	1202.688	1.431	412.633	7908.561	114.455	1.708
46.000	832.926	1201.310	1.435	414.039	7999.812	114.792	1.728
47.000	830.985	1198.306	1.434	414.154	8000.000	114.768	1.728
48.000	829.184	1195.074	1.434	414.693	8000.000	114.699	1.728

/*----------END OF SECOND DAY----------->

TABLE 6(BASE * 103%)--CONT

EXHIBIT 3A

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	827.472	1191.978	1.433	415.234	8000.000	114.630	1.728
50.000	825.881	1189.189	1.432	415.652	8000.000	114.576	1.728
51.000	824.468	1186.903	1.432	415.835	8000.000	114.548	1.728
52.000	823.315	1185.333	1.432	415.688	8000.000	114.557	1.728
53.000	822.481	1184.566	1.433	415.212	8000.000	114.603	1.728
54.000	821.987	1184.570	1.433	414.470	8000.000	114.680	1.728
55.000	821.825	1185.264	1.435	413.538	8000.000	114.780	1.728
56.000	821.972	1186.552	1.436	412.478	8000.000	114.896	1.728
57.000	822.398	1188.345	1.437	411.340	8000.000	115.022	1.728
58.000	823.072	1190.563	1.439	410.156	8000.000	115.157	1.728
59.000	823.962	1193.137	1.440	408.950	8000.000	115.295	1.728
60.000	825.037	1196.007	1.442	407.739	8000.000	115.437	1.728
61.000	826.269	1199.102	1.443	406.549	8000.000	115.577	1.728
62.000	827.558	1202.046	1.445	405.595	8000.000	115.692	1.728
63.000	831.470	1202.534	1.439	397.473	7741.744	115.141	1.672
64.000	835.204	1202.637	1.432	394.908	7592.730	114.584	1.640
65.000	838.350	1202.598	1.427	394.183	7493.817	114.103	1.619
66.000	840.388	1202.578	1.424	395.561	7465.071	113.794	1.613
67.000	840.815	1202.583	1.423	399.416	7526.389	113.731	1.626
68.000	839.300	1202.623	1.425	405.409	7681.591	113.964	1.659
69.000	835.827	1202.690	1.431	412.743	7919.040	114.500	1.711
70.000	832.767	1201.219	1.435	413.895	7999.841	114.807	1.728
71.000	830.862	1198.201	1.434	414.076	8000.000	114.776	1.728
72.000	829.081	1194.966	1.434	414.647	8000.000	114.703	1.728

/*----------END OF THIRD DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	827.382	1191.870	1.433	415.209	8000.000	114.633	1.728
74.000	825.801	1189.082	1.432	415.640	8000.000	114.577	1.728
75.000	824.396	1186.798	1.432	415.832	8000.000	114.548	1.728
76.000	823.248	1185.230	1.432	415.692	8000.000	114.556	1.728
77.000	822.419	1184.465	1.433	415.221	8000.000	114.602	1.728
78.000	821.928	1184.471	1.433	414.482	8000.000	114.678	1.728
79.000	821.769	1185.166	1.435	413.553	8000.000	114.778	1.728
80.000	821.918	1186.455	1.436	412.495	8000.000	114.893	1.728
81.000	822.346	1188.248	1.437	411.358	8000.000	115.020	1.728
82.000	823.021	1190.467	1.439	410.175	8000.000	115.154	1.728
83.000	823.912	1193.042	1.440	408.970	8000.000	115.293	1.728
84.000	824.987	1195.907	1.442	407.764	8000.000	115.434	1.728
85.000	826.215	1198.984	1.443	406.585	8000.000	115.573	1.728
86.000	827.499	1201.913	1.445	405.637	8000.000	115.687	1.728
87.000	831.083	1202.643	1.439	398.055	7765.534	115.212	1.677
88.000	834.960	1202.640	1.433	395.121	7603.449	114.621	1.642
89.000	838.113	1202.601	1.427	394.337	7503.102	114.139	1.621
90.000	840.159	1202.580	1.424	395.687	7473.614	113.829	1.614
91.000	840.598	1202.583	1.423	399.512	7534.057	113.764	1.627
92.000	839.073	1202.625	1.426	405.525	7690.015	114.000	1.661
93.000	835.632	1202.691	1.432	412.819	7925.990	114.530	1.712
94.000	832.659	1201.159	1.435	413.798	7999.875	114.817	1.728
95.000	830.778	1198.126	1.434	414.026	8000.000	114.781	1.728
96.000	829.008	1194.884	1.434	414.622	8000.000	114.706	1.728

/*----------END OF FOURTH DAY----------*/

TABLE 6(BASE * 103%)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	827.317	1191.783	1.433	415.199	8000.000	114.633	1.728
98.000	825.741	1188.991	1.432	415.641	8000.000	114.576	1.728
99.000	824.339	1186.705	1.432	415.841	8000.000	114.546	1.728
100.000	823.193	1185.134	1.432	415.706	8000.000	114.554	1.728
101.000	822.365	1184.367	1.433	415.237	8000.000	114.599	1.728
102.000	821.875	1184.373	1.433	414.502	8000.000	114.676	1.728
103.000	821.717	1185.068	1.435	413.573	8000.000	114.775	1.728
104.000	821.867	1186.357	1.436	412.517	8000.000	114.891	1.728
105.000	822.296	1188.150	1.437	411.380	8000.000	115.017	1.728
106.000	822.971	1190.369	1.439	410.198	8000.000	115.151	1.728
107.000	823.862	1192.944	1.440	408.993	8000.000	115.290	1.728
108.000	824.938	1195.810	1.442	407.786	8000.000	115.431	1.728
109.000	826.164	1198.876	1.443	406.615	8000.000	115.569	1.728
110.000	827.445	1201.797	1.444	405.670	8000.000	115.683	1.728
111.000	831.047	1202.510	1.439	397.572	7754.571	115.202	1.675
112.000	834.746	1202.645	1.433	395.296	7612.652	114.654	1.644
113.000	837.906	1202.603	1.428	394.472	7511.276	114.171	1.623
114.000	839.962	1202.582	1.424	395.788	7480.828	113.859	1.616
115.000	840.391	1202.587	1.424	399.636	7542.045	113.796	1.629
116.000	838.875	1202.627	1.426	405.620	7697.280	114.030	1.663
117.000	835.437	1202.692	1.432	412.908	7933.208	114.559	1.714
118.000	832.555	1201.094	1.435	413.711	7999.890	114.826	1.728
119.000	830.696	1198.049	1.434	413.982	8000.000	114.785	1.728
120.000	828.937	1194.802	1.434	414.599	8000.000	114.708	1.728

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	827.254	1191.699	1.433	415.189	8000.000	114.634	1.728
122.000	825.683	1188.906	1.432	415.640	8000.000	114.576	1.728
123.000	824.285	1186.619	1.432	415.846	8000.000	114.545	1.728
124.000	823.142	1185.048	1.432	415.716	8000.000	114.553	1.728
125.000	822.316	1184.281	1.433	415.251	8000.000	114.598	1.728
126.000	821.828	1184.287	1.433	414.517	8000.000	114.674	1.728
127.000	821.671	1184.982	1.434	413.590	8000.000	114.773	1.728
128.000	821.822	1186.271	1.436	412.535	8000.000	114.889	1.728
129.000	822.251	1188.065	1.437	411.399	8000.000	115.015	1.728
130.000	822.927	1190.284	1.439	410.217	8000.000	115.149	1.728
131.000	823.819	1192.859	1.440	409.012	8000.000	115.288	1.728
132.000	824.895	1195.723	1.442	407.807	8000.000	115.428	1.728
133.000	826.118	1198.776	1.443	406.644	8000.000	115.566	1.728
134.000	827.395	1201.686	1.444	405.704	8000.000	115.679	1.728
135.000	830.758	1202.575	1.440	398.111	7774.157	115.253	1.679
136.000	834.540	1202.648	1.434	395.481	7621.831	114.686	1.646
137.000	837.705	1202.605	1.428	394.606	7519.244	114.201	1.624
138.000	839.768	1202.583	1.425	395.895	7488.083	113.888	1.618
139.000	840.205	1202.589	1.424	399.723	7548.765	113.824	1.631
140.000	838.696	1202.628	1.426	405.694	7703.648	114.057	1.664
141.000	835.266	1202.694	1.432	412.973	7939.288	114.586	1.715
142.000	832.464	1201.041	1.435	413.629	7999.904	114.834	1.728
143.000	830.625	1197.987	1.434	413.938	8000.000	114.790	1.728
144.000	828.877	1194.738	1.434	414.573	8000.000	114.710	1.728

/*----------END OF SIXTH DAY----------->

TABLE 6(BASE * 103%)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	827.202	1191.636	1.433	415.174	8000.000	114.635	1.728
146.000	825.636	1188.844	1.432	415.634	8000.000	114.576	1.728
147.000	824.243	1186.558	1.432	415.845	8000.000	114.545	1.728
148.000	823.104	1184.988	1.432	415.718	8000.000	114.552	1.728
149.000	822.280	1184.222	1.433	415.256	8000.000	114.597	1.728
150.000	821.794	1184.229	1.433	414.524	8000.000	114.673	1.728
151.000	821.639	1184.925	1.434	413.599	8000.000	114.772	1.728
152.000	821.791	1186.215	1.436	412.544	8000.000	114.887	1.728
153.000	822.221	1188.010	1.437	411.409	8000.000	115.014	1.728
154.000	822.899	1190.230	1.439	410.227	8000.000	115.148	1.728
155.000	823.791	1192.806	1.440	409.023	8000.000	115.286	1.728
156.000	824.868	1195.671	1.442	407.818	8000.000	115.427	1.728
157.000	826.091	1198.723	1.443	406.656	8000.000	115.564	1.728
158.000	827.368	1201.629	1.444	405.718	8000.000	115.677	1.728
159.000	830.604	1202.611	1.440	398.404	7784.762	115.281	1.682
160.000	834.431	1202.649	1.434	395.577	7626.669	114.702	1.647
161.000	837.597	1202.607	1.428	394.680	7523.557	114.218	1.625
162.000	839.662	1202.584	1.425	395.956	7492.074	113.904	1.618
163.000	840.102	1202.589	1.424	399.775	7552.522	113.839	1.631
164.000	838.597	1202.629	1.427	405.738	7707.222	114.072	1.665
165.000	835.170	1202.694	1.432	413.011	7942.708	114.600	1.716
166.000	832.413	1201.010	1.435	413.585	7999.911	114.839	1.728
167.000	830.585	1197.952	1.435	413.914	8000.000	114.792	1.728
168.000	828.844	1194.702	1.434	414.559	8000.000	114.711	1.728

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3A

TABLE 7(BASE * 103 %)

SUNSHINE SYSTEM; COMPRESSOR STATION # 6 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	832.899	1032.969	1.236	448.212	5000.000	95.863	1.080
1.000	834.681	1041.294	1.243	436.034	5000.000	96.592	1.080
2.000	841.047	1058.731	1.254	418.811	5000.000	97.710	1.080
3.000	849.631	1078.348	1.265	404.429	5000.000	98.729	1.080
4.000	858.615	1097.187	1.273	393.320	5000.000	99.576	1.080
5.000	867.554	1115.054	1.280	384.387	5000.000	100.300	1.080
6.000	876.328	1132.013	1.287	377.003	5000.000	100.930	1.080
7.000	884.909	1148.155	1.293	370.800	5000.000	101.484	1.080
8.000	893.302	1163.572	1.298	365.530	5000.000	101.974	1.080
9.000	901.520	1178.345	1.302	361.014	5000.000	102.410	1.080
10.000	909.578	1192.545	1.306	357.123	5000.000	102.799	1.080
11.000	917.182	1203.293	1.307	354.658	4973.093	102.881	1.074
12.000	924.939	1201.821	1.295	360.580	4866.404	101.682	1.051
13.000	923.662	1197.119	1.291	374.145	4999.981	101.362	1.080
14.000	922.617	1189.359	1.285	382.257	5000.000	100.692	1.080
15.000	920.973	1182.054	1.279	389.091	5000.000	100.147	1.080
16.000	917.679	1170.117	1.271	399.730	5000.000	99.327	1.080
17.000	907.996	1142.735	1.254	422.563	5000.000	97.701	1.080
18.000	893.033	1110.731	1.240	445.255	5000.000	96.239	1.080
19.000	875.634	1079.491	1.229	463.694	5000.000	95.143	1.080
20.000	857.516	1050.647	1.221	477.099	5000.000	94.375	1.080
21.000	844.109	1035.078	1.222	474.382	5000.000	94.473	1.080
22.000	837.878	1031.925	1.228	463.870	5000.000	95.007	1.080
23.000	834.837	1031.778	1.232	455.868	5000.000	95.435	1.080
24.000	833.184	1032.759	1.235	449.399	5000.000	95.795	1.080

/*----------END OF FIRST DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	834.498	1040.223	1.242	437.673	5000.000	96.492	1.080
26.000	840.684	1057.518	1.253	420.137	5000.000	97.621	1.080
27.000	849.222	1077.176	1.264	405.471	5000.000	98.653	1.080
28.000	858.203	1096.091	1.273	394.162	5000.000	99.511	1.080
29.000	867.152	1114.036	1.280	385.079	5000.000	100.244	1.080
30.000	875.939	1131.067	1.286	377.581	5000.000	100.881	1.080
31.000	884.533	1147.274	1.292	371.286	5000.000	101.441	1.080
32.000	892.938	1162.748	1.297	365.942	5000.000	101.937	1.080
33.000	901.166	1177.571	1.302	361.367	5000.000	102.377	1.080
34.000	909.231	1191.811	1.306	357.428	5000.000	102.770	1.080
35.000	916.904	1202.499	1.307	354.507	4964.374	102.836	1.072
36.000	923.816	1201.780	1.296	361.051	4896.203	101.828	1.058
37.000	923.165	1196.692	1.293	373.847	4999.884	101.384	1.080
38.000	922.214	1188.938	1.285	382.109	5000.000	100.702	1.080
39.000	920.610	1181.629	1.279	389.019	5000.000	100.151	1.080
40.000	917.328	1169.632	1.271	399.767	5000.000	99.323	1.080
41.000	907.669	1142.285	1.254	422.613	5000.000	97.697	1.080
42.000	892.727	1110.308	1.240	445.319	5000.000	96.234	1.080
43.000	875.345	1079.095	1.229	463.764	5000.000	95.138	1.080
44.000	857.239	1050.275	1.221	477.168	5000.000	94.371	1.080
45.000	843.851	1034.717	1.222	474.470	5000.000	94.468	1.080
46.000	837.620	1031.555	1.227	463.972	5000.000	95.000	1.080
47.000	834.582	1031.415	1.232	455.959	5000.000	95.429	1.080
48.000	832.936	1032.418	1.235	449.455	5000.000	95.791	1.080

/*----------END OF SECOND DAY----------*/

EXHIBIT 3A

TABLE 7(BASE * 103 %)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	834.255	1039.895	1.242	437.711	5000.000	96.489	1.080
50.000	840.432	1057.163	1.253	420.194	5000.000	97.616	1.080
51.000	848.967	1076.818	1.264	405.516	5000.000	98.649	1.080
52.000	857.949	1095.736	1.272	394.197	5000.000	99.508	1.080
53.000	866.900	1113.684	1.280	385.108	5000.000	100.241	1.080
54.000	875.689	1130.719	1.286	377.606	5000.000	100.878	1.080
55.000	884.287	1146.929	1.292	371.309	5000.000	101.438	1.080
56.000	892.694	1162.406	1.297	365.963	5000.000	101.934	1.080
57.000	900.926	1177.233	1.302	361.386	5000.000	102.374	1.080
58.000	908.994	1191.474	1.306	357.449	5000.000	102.767	1.080
59.000	916.646	1202.152	1.307	354.643	4966.288	102.835	1.073
60.000	923.191	1201.746	1.297	361.100	4909.738	101.908	1.061
61.000	922.834	1196.478	1.292	373.566	4999.900	101.406	1.080
62.000	921.943	1188.711	1.285	381.939	5000.000	100.715	1.080
63.000	920.366	1181.389	1.279	388.908	5000.000	100.159	1.080
64.000	917.092	1169.339	1.271	399.747	5000.000	99.324	1.080
65.000	907.454	1142.015	1.254	422.602	5000.000	97.697	1.080
66.000	892.531	1110.055	1.240	445.328	5000.000	96.233	1.080
67.000	875.164	1078.859	1.229	463.783	5000.000	95.136	1.080
68.000	857.064	1050.048	1.221	477.197	5000.000	94.370	1.080
69.000	843.701	1034.513	1.222	474.510	5000.000	94.465	1.080
70.000	837.465	1031.332	1.227	464.034	5000.000	94.997	1.080
71.000	834.426	1031.192	1.232	456.013	5000.000	95.425	1.080
72.000	832.787	1032.222	1.235	449.470	5000.000	95.790	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	834.114	1039.718	1.242	437.710	5000.000	96.488	1.080
74.000	840.277	1056.945	1.253	420.231	5000.000	97.614	1.080
75.000	848.806	1076.594	1.264	405.543	5000.000	98.647	1.080
76.000	857.787	1095.513	1.272	394.216	5000.000	99.506	1.080
77.000	866.738	1113.462	1.280	385.123	5000.000	100.239	1.080
78.000	875.529	1130.497	1.286	377.618	5000.000	100.877	1.080
79.000	884.127	1146.709	1.292	371.319	5000.000	101.437	1.080
80.000	892.537	1162.188	1.297	365.972	5000.000	101.933	1.080
81.000	900.770	1177.016	1.302	361.395	5000.000	102.373	1.080
82.000	908.840	1191.255	1.306	357.461	5000.000	102.765	1.080
83.000	916.207	1202.145	1.307	356.385	5000.000	102.895	1.080
84.000	922.521	1201.958	1.298	363.385	4958.177	102.022	1.071
85.000	922.601	1196.353	1.292	373.335	4999.888	101.424	1.080
86.000	921.760	1188.576	1.285	381.801	5000.000	100.725	1.080
87.000	920.203	1181.239	1.279	388.819	5000.000	100.165	1.080
88.000	916.923	1169.119	1.271	399.747	5000.000	99.323	1.080
89.000	907.304	1141.828	1.254	422.594	5000.000	97.697	1.080
90.000	892.396	1109.883	1.240	445.332	5000.000	96.232	1.080
91.000	875.043	1078.705	1.229	463.784	5000.000	95.136	1.080
92.000	856.989	1049.985	1.221	477.108	5000.000	94.372	1.080
93.000	843.533	1034.246	1.222	474.638	5000.000	94.458	1.080
94.000	837.283	1031.048	1.227	464.156	5000.000	94.989	1.080
95.000	834.242	1030.913	1.232	456.114	5000.000	95.419	1.080
96.000	832.586	1031.909	1.235	449.593	5000.000	95.782	1.080

/*----------END OF FOURTH DAY----------->

EXHIBIT 3A

TABLE 7(BASE * 103 %)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	833.897	1039.382	1.242	437.823	5000.000	96.481	1.080
98.000	840.081	1056.675	1.253	420.259	5000.000	97.611	1.080
99.000	848.621	1076.336	1.264	405.568	5000.000	98.644	1.080
100.000	857.606	1095.259	1.272	394.240	5000.000	99.503	1.080
101.000	866.560	1113.211	1.280	385.144	5000.000	100.237	1.080
102.000	875.353	1130.250	1.286	377.638	5000.000	100.874	1.080
103.000	883.955	1146.464	1.292	371.338	5000.000	101.435	1.080
104.000	892.366	1161.946	1.297	365.989	5000.000	101.930	1.080
105.000	900.602	1176.777	1.302	361.411	5000.000	102.371	1.080
106.000	908.675	1191.024	1.306	357.471	5000.000	102.763	1.080
107.000	916.062	1201.976	1.307	356.353	5000.000	102.897	1.080
108.000	922.301	1201.822	1.298	362.232	4945.400	102.036	1.068
109.000	922.401	1196.180	1.292	373.222	4999.937	101.433	1.080
110.000	921.585	1188.387	1.285	381.743	5000.000	100.729	1.080
111.000	920.039	1181.057	1.279	388.773	5000.000	100.168	1.080
112.000	916.842	1169.136	1.271	399.555	5000.000	99.336	1.080
113.000	907.190	1141.631	1.254	422.656	5000.000	97.691	1.080
114.000	892.250	1109.633	1.240	445.438	5000.000	96.225	1.080
115.000	874.879	1078.423	1.229	463.906	5000.000	95.126	1.080
116.000	856.825	1049.750	1.221	477.177	5000.000	94.368	1.080
117.000	843.372	1034.015	1.222	474.708	5000.000	94.454	1.080
118.000	837.125	1030.819	1.227	464.223	5000.000	94.985	1.080
119.000	834.086	1030.689	1.232	456.173	5000.000	95.415	1.080
120.000	832.431	1031.690	1.235	449.640	5000.000	95.779	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	833.742	1039.165	1.242	437.860	5000.000	96.478	1.080
122.000	839.926	1056.458	1.253	420.289	5000.000	97.608	1.080
123.000	848.466	1076.121	1.264	405.593	5000.000	98.642	1.080
124.000	857.453	1095.045	1.272	394.261	5000.000	99.501	1.080
125.000	866.409	1112.999	1.280	385.162	5000.000	100.235	1.080
126.000	875.204	1130.040	1.286	377.653	5000.000	100.872	1.080
127.000	883.807	1146.257	1.292	371.352	5000.000	101.433	1.080
128.000	892.221	1161.740	1.297	366.002	5000.000	101.929	1.080
129.000	900.458	1176.574	1.302	361.423	5000.000	102.369	1.080
130.000	908.533	1190.822	1.306	357.482	5000.000	102.762	1.080
131.000	915.921	1201.776	1.307	356.366	5000.000	102.895	1.080
132.000	921.919	1201.826	1.299	362.435	4956.452	102.088	1.071
133.000	922.205	1196.048	1.292	373.062	4999.960	101.446	1.080
134.000	921.424	1188.244	1.285	381.651	5000.000	100.736	1.080
135.000	919.892	1180.910	1.279	388.710	5000.000	100.172	1.080
136.000	916.706	1168.983	1.271	399.519	5000.000	99.338	1.080
137.000	907.067	1141.478	1.254	422.647	5000.000	97.691	1.080
138.000	892.137	1109.486	1.240	445.444	5000.000	96.224	1.080
139.000	874.774	1078.283	1.229	463.920	5000.000	95.124	1.080
140.000	856.726	1049.619	1.221	477.195	5000.000	94.367	1.080
141.000	843.278	1033.887	1.222	474.731	5000.000	94.452	1.080
142.000	837.035	1030.695	1.227	464.248	5000.000	94.984	1.080
143.000	833.998	1030.568	1.232	456.196	5000.000	95.414	1.080
144.000	832.343	1031.569	1.235	449.658	5000.000	95.777	1.080

/*----------END OF SIXTH DAY----------->

TABLE 7(BASE * 103 %)--CONT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	833.652	1039.044	1.242	437.873	5000.000	96.477	1.080
146.000	839.837	1056.339	1.253	420.297	5000.000	97.607	1.080
147.000	848.377	1076.002	1.264	405.598	5000.000	98.641	1.080
148.000	857.364	1094.926	1.272	394.264	5000.000	99.500	1.080
149.000	866.320	1112.881	1.280	385.165	5000.000	100.234	1.080
150.000	875.116	1129.922	1.286	377.656	5000.000	100.872	1.080
151.000	883.720	1146.139	1.292	371.354	5000.000	101.432	1.080
152.000	892.134	1161.623	1.297	366.004	5000.000	101.928	1.080
153.000	900.373	1176.457	1.302	361.425	5000.000	102.368	1.080
154.000	908.449	1190.706	1.306	357.485	5000.000	102.761	1.080
155.000	915.838	1201.661	1.307	356.369	5000.000	102.895	1.080
156.000	921.680	1201.847	1.299	362.960	4969.097	102.122	1.073
157.000	922.096	1195.953	1.292	373.001	4999.986	101.450	1.080
158.000	921.331	1188.143	1.285	381.622	5000.000	100.738	1.080
159.000	919.806	1180.808	1.279	388.693	5000.000	100.173	1.080
160.000	916.624	1168.880	1.271	399.513	5000.000	99.338	1.080
161.000	906.992	1141.380	1.254	422.649	5000.000	97.691	1.080
162.000	892.068	1109.394	1.240	445.452	5000.000	96.223	1.080
163.000	874.709	1078.197	1.229	463.932	5000.000	95.124	1.080
164.000	856.665	1049.536	1.221	477.210	5000.000	94.366	1.080
165.000	843.221	1033.812	1.222	474.743	5000.000	94.452	1.080
166.000	836.982	1030.622	1.227	464.262	5000.000	94.983	1.080
167.000	833.946	1030.496	1.232	456.210	5000.000	95.413	1.080
168.000	832.291	1031.500	1.235	449.667	5000.000	95.777	1.080

/*----------END OF SEVENTH DAY----------

EXHIBIT 3A

TABLE 8(BASE * 103%)

SUNSHINE SYSTEM; DELIVERY POINT REPORT

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
0.000	686.945	801.873	880.347	863.964
1.000	685.921	854.780	921.497	915.798
2.000	684.927	887.704	961.298	956.444
3.000	683.981	917.352	990.414	985.831
4.000	683.096	944.712	1015.556	1011.153
5.000	682.289	969.747	1038.229	1033.969
6.000	681.584	992.727	1059.069	1054.930
7.000	681.007	1013.976	1078.442	1074.407
8.000	680.574	1033.780	1096.599	1092.656
9.000	680.295	1052.370	1113.729	1109.868
10.000	680.171	1069.931	1129.787	1125.912
11.000	680.198	1085.197	1117.231	1104.847
12.000	680.364	1035.946	1105.100	1091.470
13.000	680.659	991.257	1097.131	1083.403
14.000	681.071	968.603	1087.574	1073.753
16.000	682.398	938.824	947.531	871.771
17.000	683.656	914.174	814.003	699.631
18.000	685.188	875.248	719.216	581.924
19.000	686.726	829.882	637.306	474.168
20.000	688.002	783.211	746.505	716.185
21.000	688.756	743.675	827.948	806.665
22.000	688.801	721.566	857.777	838.521
23.000	688.162	713.717	870.614	852.109
24.000	687.189	789.351	877.630	859.787

/*----------END OF FIRST DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
25.000	686.151	849.511	919.881	914.073
26.000	685.138	884.644	959.582	954.723
27.000	684.174	915.160	988.780	984.186
28.000	683.272	942.937	1014.069	1009.656
29.000	682.448	968.221	1036.890	1032.621
30.000	681.726	991.375	1057.860	1053.712
31.000	681.131	1012.760	1077.342	1073.300
32.000	680.680	1032.674	1095.591	1091.642
33.000	680.384	1051.355	1112.799	1108.933
34.000	680.244	1068.992	1128.737	1124.774
35.000	680.254	1083.913	1116.537	1104.262
36.000	680.407	1035.681	1104.645	1090.992
37.000	680.690	990.931	1096.775	1083.044
38.000	681.090	968.185	1087.169	1073.344
39.000	681.596	952.404	1075.721	1060.833
40.000	682.357	938.281	947.144	871.374
41.000	683.561	913.588	813.379	698.906
42.000	685.053	874.662	718.540	581.086
43.000	686.566	829.304	636.836	473.599
44.000	687.827	782.636	745.401	714.438
45.000	688.572	743.133	827.288	805.977
46.000	688.615	720.999	857.217	837.943
47.000	687.988	713.591	870.106	851.588
48.000	687.041	788.586	877.363	859.636

/*----------END OF SECOND DAY---------->

EXHIBIT 3A

TABLE 8(BASE * 103%)--CONT

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
49.000	686.029	848.971	919.356	913.448
50.000	685.038	884.173	959.143	954.283
51.000	684.091	914.708	988.366	983.770
52.000	683.201	942.499	1013.668	1009.253
53.000	682.386	967.795	1036.499	1032.228
54.000	681.670	990.960	1057.476	1053.327
55.000	681.080	1012.354	1076.965	1072.921
56.000	680.632	1032.275	1095.219	1091.269
57.000	680.339	1050.963	1112.433	1108.566
58.000	680.200	1068.606	1128.242	1124.218
59.000	680.213	1083.239	1116.265	1104.068
60.000	680.367	1035.649	1104.464	1090.800
61.000	680.651	990.821	1096.630	1082.898
62.000	681.050	968.005	1086.984	1073.157
63.000	681.551	952.177	1074.977	1059.772
64.000	682.280	937.990	946.958	871.282
65.000	683.450	913.256	813.044	698.518
66.000	684.913	874.326	718.165	580.621
67.000	686.409	828.967	636.705	473.461
68.000	687.662	782.287	744.720	712.992
69.000	688.404	742.838	826.831	805.497
70.000	688.451	720.676	856.856	837.570
71.000	687.840	713.919	869.789	851.262
72.000	686.917	787.908	877.380	859.834

/*----------END OF THIRD DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
73.000	685.929	848.600	918.955	912.896
74.000	684.957	883.879	958.857	953.996
75.000	684.024	914.425	988.104	983.507
76.000	683.144	942.224	1013.415	1008.999
77.000	682.337	967.527	1036.251	1031.980
78.000	681.627	990.697	1057.233	1053.083
79.000	681.041	1012.096	1076.725	1072.681
80.000	680.597	1032.022	1094.983	1091.032
81.000	680.306	1050.714	1112.200	1108.331
82.000	680.170	1068.359	1127.814	1123.701
83.000	680.184	1082.564	1116.170	1104.089
84.000	680.339	1035.788	1104.348	1090.682
85.000	680.623	990.811	1096.555	1082.822
86.000	681.023	967.928	1086.885	1073.057
87.000	681.523	952.056	1074.074	1058.401
88.000	682.236	937.800	946.911	871.397
89.000	683.375	913.027	812.817	698.257
90.000	684.816	874.095	717.913	580.306
91.000	686.301	828.732	635.805	471.894
92.000	687.544	782.128	742.255	708.005
93.000	688.292	742.492	826.211	804.845
94.000	688.342	720.267	856.376	837.074
95.000	687.741	712.427	869.374	850.835
96.000	686.834	788.031	876.516	858.665

/*----------END OF FOURTH DAY---------->

TABLE 8(BASE * 103%)--CONT

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
97.000	685.861	848.332	918.801	912.946
98.000	684.901	883.538	958.578	953.714
99.000	683.977	914.100	987.815	983.217
100.000	683.104	941.912	1013.132	1008.714
101.000	682.301	967.224	1035.973	1031.700
102.000	681.595	990.402	1056.960	1052.808
103.000	681.010	1011.807	1076.457	1072.411
104.000	680.568	1031.739	1094.719	1090.767
105.000	680.278	1050.436	1111.940	1108.071
106.000	680.142	1068.088	1127.865	1123.888
107.000	680.157	1082.971	1115.668	1103.369
108.000	680.312	1035.083	1104.151	1090.476
109.000	680.597	990.516	1096.416	1082.683
110.000	680.997	967.687	1086.709	1072.880
111.000	681.495	951.824	1075.097	1060.149
112.000	682.188	937.686	944.335	866.737
113.000	683.307	912.911	811.911	697.140
114.000	684.732	873.843	717.233	579.468
115.000	686.204	828.425	635.934	472.671
116.000	687.442	781.784	741.798	707.508
117.000	688.188	742.137	825.831	804.453
118.000	688.239	719.904	856.039	836.727
119.000	687.646	712.078	869.064	850.517
120.000	686.755	787.704	876.230	858.377

/*----------END OF FIFTH DAY---------->

TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
121.000	685.797	848.029	918.533	912.674
122.000	684.848	883.254	958.322	953.456
123.000	683.932	913.827	987.568	982.968
124.000	683.065	941.648	1012.891	1008.472
125.000	682.267	966.968	1035.738	1031.463
126.000	681.564	990.152	1056.729	1052.577
127.000	680.982	1011.563	1076.230	1072.184
128.000	680.541	1031.499	1094.496	1090.543
129.000	680.252	1050.200	1111.720	1107.850
130.000	680.117	1067.856	1127.643	1123.663
131.000	680.132	1082.733	1115.446	1103.145
132.000	680.288	1034.923	1104.016	1090.335
133.000	680.574	990.406	1096.322	1082.587
134.000	680.974	967.557	1086.589	1072.759
135.000	681.471	951.673	1074.941	1059.981
136.000	682.150	937.518	944.119	866.475
137.000	683.245	912.729	811.700	696.893
138.000	684.651	873.653	717.008	579.188
139.000	686.112	828.232	635.694	472.349
140.000	687.346	781.591	741.601	707.296
141.000	688.092	741.943	825.653	804.269
142.000	688.144	719.709	855.870	836.554
143.000	687.560	711.862	868.903	850.352
144.000	686.683	787.553	876.066	858.204

/*----------END OF SIXTH DAY---------->

TABLE 8(BASE * 103%)--CONT

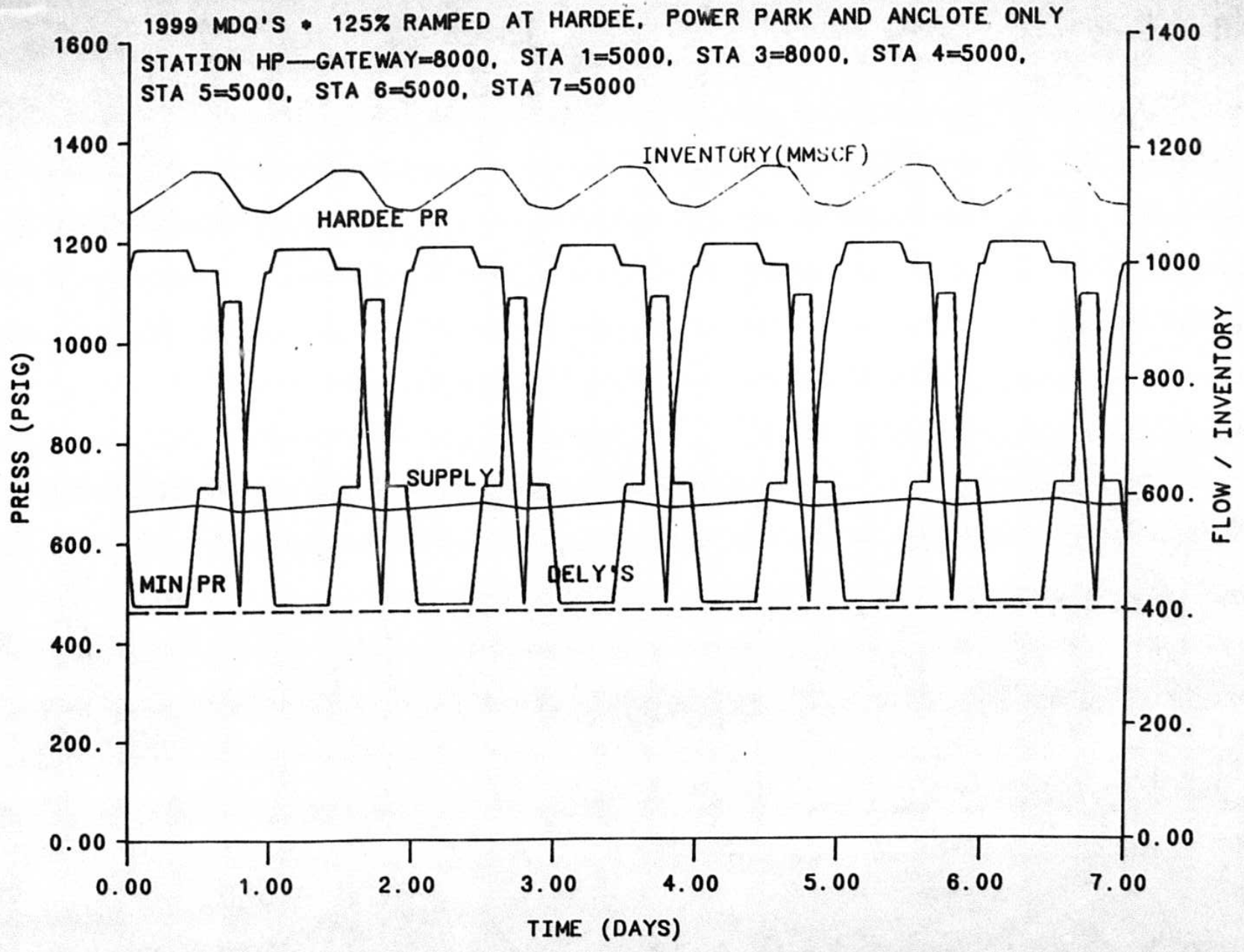
TIME HRS	PENSACOLA PSIG	ANCLOTE PSIG	PWR PARK PSIG	HARDEE PSIG
145.000	685.739	847.874	918.399	912.545
146.000	684.801	883.103	958.187	953.320
147.000	683.894	913.681	987.435	982.834
148.000	683.032	941.505	1012.760	1008.340
149.000	682.239	966.827	1035.608	1031.333
150.000	681.539	990.014	1056.601	1052.448
151.000	680.959	1011.426	1076.103	1072.056
152.000	680.521	1031.364	1094.370	1090.416
153.000	680.233	1050.067	1111.595	1107.724
154.000	680.100	1067.723	1127.525	1123.547
155.000	680.116	1082.615	1115.310	1103.001
156.000	680.272	1034.756	1103.878	1090.194
157.000	680.558	990.292	1096.229	1082.493
158.000	680.959	967.444	1086.490	1072.659
159.000	681.456	951.554	1074.860	1059.913
160.000	682.129	937.394	944.025	866.397
161.000	683.211	912.602	811.573	696.746
162.000	684.608	873.527	716.867	579.014
163.000	686.063	828.108	635.559	472.172
164.000	687.294	781.467	741.532	707.264
165.000	688.039	741.824	825.548	804.160
166.000	688.092	719.591	855.770	836.451
167.000	687.513	711.787	868.808	850.254
168.000	686.644	787.444	875.994	858.141

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3B

FIGURE 3

FIG 3-SUNSHINE PIPELINE SYSTEM; BASE 30 IN DESIGN(INCLUDES COMP'R FUEL)



SUNSHINE PIPELINE SYSTEM (1200# MAOP) BASE DESIGN LOADS AT 125% OF 1999 MDQ'S AT HARDEE, POWER PARK AND ANCLOTE) ALL OTHER LOADS AT 100 % OF 1999 MDQ'S

LOCATION FROM	LOCATION TO	NOMINAL OD	LENGTH	NOTES
Pascagoula	Gateway	30"	21 miles	
Gateway	Sta. #1	30"	62 miles	
Sta. #1	Okaloosa	30"	65 miles	
Main 30"	Monsanto	10"	16 miles	Pensacola lateral
Monsanto	Champion	4"	4 miles	" "
Monsanto	Gulf Power	10"	5 miles	" "
10"	Gulf Power	8"	3 miles	" "
Gulf Power	Pensacola	8"	4 miles	" "
30"	Milton	4"	10 miles	Milton lateral
Milton	Cyanamid	4"	3 miles	" "
Cyanamid	Air Products	4"	4 miles	" "
Okaloosa	Sta. #2	30"	10 miles	
Sta. #2	Sta. #3	30"	75 miles	
Sta. #3	Sta. #4	30"	75 miles	
Sta. #4	Sta. #5	30"	75 miles	
Sta. #5	Sta. #6	30"	75 miles	
Sta. #6	Anclote lat.	30"	20 miles	
Anclote lat.	Sta. #7	24"	40 miles	
30"	Hillsborough	20"	53 miles	Anclote lateral
Hillsborough	Anclote	20"	10 miles	" "
Sta. #7	Seminole	24"	17 miles	
Seminole	Power Park lat.	24"	10 miles	
24"	Power Park	16"	3 miles	Power Park lateral
Power Park lat.	Hardee lat.	24"	4 miles	
24"	Hardee	16"	11 miles	Hardee lateral

STATION	INSTALLED HP	SPECIFIC FUEL RATIO
Gateway	8000	9000 BTU/HP-HR
Sta. #1	5000	" " " "
Sta. #2	None	" " " "
Sta. #3	8000	" " " "
Sta. #4	5000	" " " "
Sta. #5	5000	" " " "
Sta. #6	5000	" " " "
Sta. #7	5000	" " " "
	41000	

Note: *System design allows for maximum of 10 psi suction and discharge piping pressure losses (total for station).*

Compressor suction temperature 70°F
Average pipeline flowing temperature 85°F
Compressor efficiencies:
Mechanical - 98%
Compression - 80%

SCHEDULE 2
PAGE 2 OF 2

SUNSHINE
RATE BASE AND RETURN

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	GROSS PLANT	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700
2	PREV DEP'N LESS: AVG. ACC. DEPR.	57,095	74,047	93,900	116,912	142,737	171,034	201,991	235,765	272,548	312,557	356,085	403,408
3	NET PLANT	$406,605	$389,653	$369,792	$346,788	$320,963	$292,666	$261,709	$227,935	$191,152	$151,143	$107,615	$60,292
4	PLUS: WORKING CAPITAL	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288
5													
6	LESS: AVG. DEFERRED TAXES	129,721	134,459	127,209	118,011	109,383	99,052	87,751	75,421	61,996	47,307	31,496	14,220
7	RATE BASE	$277,172	$255,482	$242,871	$229,265	$211,868	$193,902	$174,246	$152,802	$129,452	$104,044	$76,407	$46,360
8	RATE OF RETURN	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%
9	RETURN ON RATE BASE	$30,655	$28,256	$26,862	$25,346	$23,433	$21,446	$19,272	$16,900	$14,317	$11,507	$8,451	$5,127
10	PRETAX RATE OF RETURN	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
11	PRETAX RETURN	$36,032	$33,213	$31,573	$29,674	$27,543	$25,207	$22,652	$19,864	$16,829	$13,526	$9,933	$6,027
12	INTEREST EXPENSE	20,782	19,161	18,215	17,120	15,890	14,543	13,068	11,460	9,709	7,803	5,731	3,477
13	ROE & RELATED INCOME TAXES	$15,244	$14,051	$13,358	$12,555	$11,653	$10,665	$9,584	$8,404	$7,120	$5,722	$4,202	$2,550

EXHIBIT 6

SCHEDULE 3
PAGE 1 OF 2

SUNBIRD
DEFERRED INCOME TAXES

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	DEFERRED AMOUNT - BEG.	$0	$20,114	$37,611	$91,005	$127,402	$162,935	$193,517	$220,048	$246,400	$270,125	$292,950	$311,904	$329,521
2	TAX DEPRECIATION 1/	$20,424	$30,806	$35,349	$34,529	$35,048	$31,541	$29,716	$29,403	$29,147	$29,039	$29,039	$29,039	$29,039
3	LESS:													
4	BOOK DEPRECIATION EXPENSE	320	1,350	2,914	(1,926)	(500)	909	2,458	3,969	5,589	7,333	9,468	11,775	14,259
5	NET OF TAX LESS BOOK DEPR.	$20,104	$37,456	$33,335	$36,455	$35,548	$30,553	$27,258	$25,434	$23,558	$21,706	$19,571	$17,266	$14,780
6	PLUS:													
7	DEPR. OF EQUITY AFUDC 2/	10	40	59	(57)	(15)	29	73	118	167	219	282	351	425
8	TOTAL	$20,114	$37,496	$33,394	$36,398	$35,533	$30,582	$27,331	$25,552	$23,725	$21,925	$19,853	$17,617	$15,205
9	DEFERRED AMOUNT - END	$20,114	$57,611	$91,005	$127,402	$162,935	$193,517	$220,048	$246,400	$270,125	$292,050	$311,904	$329,521	$344,726
10	DEFERRED AMOUNT	$20,114	$57,611	$91,005	$127,402	$162,935	$193,517	$220,048	$246,400	$270,125	$292,050	$311,904	$329,521	$344,726
11	ACCUM DEFERRED TAXES	$7,569	$21,679	$34,245	$47,942	$61,312	$72,820	$83,[illegible]	$92,720	$101,648	$109,898	$117,369	$123,999	$129,721
12	1/ TAX PLANT = GROSS PLANT	$420,000	$420,000	$420,000	$430,000	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700
13	LESS: AFUDC	12,313	12,313	12,582	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
14	TAX DEPRECIABLE PLANT	$408,487	$408,487	$408,218 8931	$416,432 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714	$450,132 8931 32714
15	15 YEAR MACRS TAX DEPRECIATION	5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
16	TAX DEPRECIATION	$20,424	$30,806	$35,349	$34,529	$35,048	$31,541	$29,716	$29,403	$29,147	$29,039	$29,039	$29,039	$29,039
17	2/ EQUITY AFUDC	$12,313	$12,313	$12,582	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568
18	BOOK DEPRECIATION RATE	0.08%	0.32%	0.67%	-0.42%	-0.11%	0.21%	0.53%	0.86%	1.20%	1.54%	2.04%	2.54%	3.07%
	BOOK DEPRECIATION RATE AFUDC	0.081%	0.325%	0.669%	-0.420%	-0.111%	0.214%	0.538%	0.870%	1.231%	1.614%	2.078%	2.587%	3.132%
19	DEPR. OF EQUITY AFUDC	$10	$40	$59	($57)	($15)	$29	$73	$118	$167	$219	$282	$351	$425

EXHIBIT 6

SUBCOAST
COST OF SERVICE

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
1	O&M/A&G EXPENSE	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,192
2	DEPRECIATION EXPENSE	16,953	19,861	23,004	25,825	28,297	30,957	33,774	36,775	40,017	43,528	47,323	51,430	$10,194
3	INTEREST EXPENSE	20,788	19,161	18,215	17,120	15,890	14,543	13,060	11,460	9,709	7,802	5,731	3,477	$20,990
4	OTHER TAXES	7,931	7,700	7,493	7,287	7,089	6,902	6,725	6,562	6,422	6,317	6,292	6,571	$7,816
5	ROE	9,867	9,695	8,646	8,126	7,543	6,903	6,203	5,440	4,609	3,704	2,720	1,650	$9,963
6	FED. & ST. INCOME TAXES	6,261	5,847	5,632	5,370	5,062	4,724	4,352	3,946	3,502	3,025	2,494	1,922	$6,341
7	TOTAL COST OF SERVICE	$64,100	$63,573	$65,291	$66,028	$66,181	$66,328	$66,423	$66,483	$66,559	$66,671	$66,859	$67,350	$65,495
8	VOLUMES @ 100% LF	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	
9	VOL. RATE @ 100 % LF	$0.4401	$0.4333	$0.4483	$0.4534	$0.4544	$0.4554	$0.4561	$0.4565	$0.4570	$0.4578	$0.4591	$0.4625	

EXHIBIT 6

SUNSHINE
RATE BASE AND RETURN

SCHEDULE 2
PAGE 1 OF 2

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	GROSS PLANT	$420,000	$420,000	$430,000	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700
	PREV DEP'N	0												
2	LESS: AVG. ACC. DEPR.	0	320	1,670	3,684	1,758	1,258	2,846	4,704	8,673	14,262	21,595	31,053	42,836
3	NET PLANT	$420,000	$420,680	$428,330	$460,016	$461,942	$462,442	$461,454	$458,996	$455,027	$449,438	$442,105	$432,647	$420,864
4	PLUS: WORKING CAPITAL	$175	$175	$175	$288	$288	$288	$288	$288	$288	$288	$288	$288	$288
5														
6	LESS: AVG. DEFERRED TAXES	0	7,569	21,679	34,245	47,942	61,312	72,820	83,105	92,720	101,648	109,898	117,369	123,999
7	RATE BASE	$420,975	$413,006	$406,826	$426,059	$414,288	$401,418	$388,922	$376,179	$362,595	$348,078	$332,495	$315,556	$297,153
8	RATE OF RETURN	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%
9	RETURN ON RATE BASE	$46,560	$45,687	$44,995	$47,122	$45,820	$44,397	$43,015	$41,605	$40,103	$38,497	$36,774	$34,900	$32,865
10	PRETAX RATE OF RETURN	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
11	PRETAX RETURN	$54,727	$53,701	$52,887	$55,388	$53,858	$52,184	$50,569	$48,903	$47,137	$45,258	$43,224	$41,022	$38,630
12	INTEREST EXPENSE	31,573	30,981	30,512	31,954	31,072	30,106	29,169	28,213	27,195	26,106	24,937	23,667	22,296
13	ROE & RELATED INCOME TAXES	$23,154	$22,720	$22,375	$23,433	$22,786	$22,078	$21,391	$20,690	$19,943	$19,144	$18,287	$17,356	$16,342

EXHIBIT 6

SUNSHINE GAS PIPELINE COMPANY - 25 YE
COST OF SERVICE

30" OPTION

NE O.	DESCRIPTION	2017	2018	2019	2020	25 YEAR AVERAGE
	(col. 1)	(col.23)	(col.24)	(col.25)	(col.26)	(col.22)
	COST OF SERVICE					
1	Operation and maintenance	$2,300	$2,300	$2,300	$2,300	$2,192
2	Depreciation	40,803	44,383	48,252	52,440	18,548
	Taxes:					
3	Income federal & State	3,218	2,719	2,175	1,583	6,286
4	Other	6,245	6,063	5,887	5,715	7,720
5	Return @ 11.06 %	12,861	9,964	6,812	3,386	30,682
6	Total	$65,427	$65,429	$65,426	$65,424	$65,428
	RATE DERIVATION	2017	2018	2019	2020	TOTAL
	Cost of Service	$65,427	$65,429	$65,426	$65,424	$65,428
	NDQ	399	399	399	399	379
	Volume - MMcf/d - 100% L.F.	145,635	145,635	145,635	145,635	138,408
	Base Rate Per Mcf (Year 2000)	$0.4493	$0.4493	$0.4492	$0.4492	$0.4493
	Revenue Collection on Base Rate	$65,427	$65,429	$65,426	$65,424	$62,181
	REVENUES SHORTAGE					
	LESS INCOME TAXES					
	DEFERRED COLLECTION OF EQUITY RETURN					
	CUMULATIVE DEFERRED RETURN					
	AVERAGE CUMULATIVE DEFERRED RETURN					

EXHIBIT 5

SUNSHINE GAS
COST OF SERVICE

SCHEDULE 1
PAGE 1 OF 2

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$1,400	$1,400	$1,400	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300
2	DEPRECIATION EXPENSE	320	1,356	2,014	(1,926)	(500)	980	2,450	3,965	5,500	7,333	9,460	11,973	14,255
3	INTEREST EXPENSE	31,273	30,901	30,512	31,954	31,072	30,106	29,169	28,213	27,195	26,106	24,927	23,667	22,266
4	OTHER TAXES	6,100	6,094	6,245	6,022	6,015	6,002	6,001	6,004	6,005	6,560	6,622	6,603	6,163
5	ROE	16,007	16,706	16,483	15,160	16,749	16,290	13,846	13,252	12,900	12,382	11,837	11,236	10,579
6	FED. & ST. INCOME TAXES	9,051	8,966	8,777	9,120	8,892	8,642	8,106	7,154	7,092	7,611	7,314	6,992	6,641
7	TOTAL COST OF SERVICE	$65,431	$65,431	$65,431	$65,671	$65,428	$65,229	$62,072	$64,933	$64,780	$64,650	$64,560	$64,369	$64,222
8	VOLUMES @ 100% LF	70,035	70,035	96,360	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
9	VOL. RATE @ 100 % LF	$0.0186	$0.0186	$0.0790	$0.4496	$0.4453	$0.4479	$0.4468	$0.4459	$0.4449	$0.4439	$0.4429	$0.4420	$0.4410

EXHIBIT 6

SUNSHINE GAS PIPELINE COMPANY - 25 YEARS
COST OF SERVICE
30th OPTION

UTILITY RETURN ON EQUITY 14.25%

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LINE NO.	DESCRIPTION	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12)
	COST OF SERVICE											
1	Operation and maintenance	$1,400	$1,400	$1,400	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300
2	Depreciation	319	1,350	2,014	(1,964)	(510)	1,008	2,507	4,047	5,699	7,477	9,654
	Taxes:											
3	Income Federal & State	9,048	8,896	8,773	9,116	8,895	8,669	8,447	8,219	7,976	7,712	7,432
4	Other	8,181	8,095	8,246	8,856	8,894	8,904	8,904	8,904	8,904	8,904	8,645
5	Return @ 11.06 %	46,560	45,687	44,995	47,121	45,849	44,547	43,270	41,958	40,549	39,034	37,397
6	Total	$65,428	$65,428	$65,428	$65,429	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427	$65,428
	RATE DERIVATION	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
7	Cost of Service	$65,428	$65,428	$65,428	$65,429	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427	$65,428
8	MDQ	219	219	264	399	399	399	399	399	399	399	399
9	Volume - MMcf/d - 100% L.F.	79,935	79,935	96,360	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
10	Base Rate Per Mcf (Year 2000)	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493
11	Revenue Collection on Base Rate	$35,912	$35,912	$43,291	$65,428	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427	$65,428
12	REVENUES SHORTAGE	$29,516	$29,516	$22,137	$0	$0						
13	LESS INCOME TAXES	$11,107	$11,107	$8,330	$0	$0						
14	DEFERRED COLLECTION OF EQUITY RETURN	$18,409	$18,409	$13,807	$0	$0						
15	CUMULATIVE DEFERRED RETURN	$18,409	$36,819	$50,626	$50,626	$50,626						
16	AVERAGE CUMULATIVE DEFERRED RETURN	$9,205	$27,614	$43,722	$50,626	$50,626	$50,626					

EXHIBIT 5

12-Oct-92

SUNSHINE GAS PIPELINE COMPANY - 25 YE
COST OF SERVICE

30" OPTION

LINE NO.	DESCRIPTION	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)	(col.22)
	COST OF SERVICE										
1	Operation and maintenance	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300	$2,300
2	Depreciation	12,005	14,540	17,285	20,251	23,456	26,332	28,853	31,565	34,437	37,496
	Taxes:										
3	Income Federal & State	7,125	6,792	6,424	6,023	5,585	5,195	4,857	4,490	4,098	3,676
4	Other	8,393	8,148	7,911	7,681	7,457	7,240	7,029	6,824	6,625	6,432
5	Return @ 11.06 %	35,605	33,647	31,508	29,175	26,630	24,361	22,389	20,249	17,968	15,523
6	Total	$65,428	$65,427	$65,428	$65,430	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427
	RATE DERIVATION	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
7	Cost of Service	$65,428	$65,427	$65,428	$65,430	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427
8	MDQ	399	399	399	399	399	399	399	399	399	399
9	Volume - MMcf/d - 100% L.F.	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
10	Base Rate Per Mcf (Year 2000)	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493	$0.4493
11	Revenue Collection on Base Rate	$65,428	$65,427	$65,428	$65,430	$65,428	$65,428	$65,428	$65,428	$65,428	$65,427
12	REVENUES SHORTAGE										
13	LESS INCOME TAXES										
14	DEFERRED COLLECTION OF EQUITY RETURN										
15	CUMULATIVE DEFERRED RETURN										

EXHIBIT 5

SUNSHINE INTERSTATE GAS PIPELINE -
COST OF SERVICE

30" OPTION

NE O.	DESCRIPTION	2017	2018	2019	2020	25 YEAR AVERAGE
	(col. 1)	(col.23)	(col.24)	(col.25)	(col.26)	(col.22)
	COST OF SERVICE					
1	Operation and maintenance	$1,000	$1,000	$1,000	$1,000	$968
2	Depreciation	15,535	16,873	18,320	19,887	7,072
	Taxes:					
3	Income Federal & State	1,225	1,034	828	603	2,420
4	Other	1,566	1,521	1,476	1,433	1,945
5	Return @ 11.06 %	4,895	3,793	2,597	1,298	11,817
6	Total	$24,221	$24,221	$24,221	$24,221	$24,222
	RATE DERIVATION	2017	2018	2019	2020	TOTAL
7	Cost of Service	$24,221	$24,221	$24,221	$24,221	$24,222
8	MDQ	505	505	505	505	485
9	Volume - MMcf/d - 100% L.F.	184,143	184,143	184,143	184,143	176,916
0	Base Rate Per Mcf (Year 2000)	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315
1	Revenue Collection on Base Rate	$24,221	$24,221	$24,221	$24,221	$23,271
2	REVENUES SHORTAGE					
3	LESS INCOME TAXES					
4	DEFERRED COLLECTION OF EQUITY RETURN					
5	CUMULATIVE DEFERRED RETURN					
6	AVERAGE CUMULATIVE DEFERRED RETURN					

EXHIBIT 5

SUNSHINE GAS PIPELINE COMPANY

SUMMARY OF RESULTS -- SUNSHINE GAS PIPELINE COMPANY - 25 YEARS

BASE ASSUMPTIONS

TARGET DEBT/CAPITAL RATIO	75% / 25%
DEBT MATURITY	25 YEARS
EFFECTIVE TAX RATE	37.63%

SCENARIO RESULTS

RATE @ 100% L. F.

BASE RATE	$0.4493
DEFERRED EQUITY RATE	0.0756
TOTAL RATE	$0.5249

RATES OF RETURN	DEBT	EQUITY	OVERALL
DURING CONSTRUCTION	10.00%	14.25%	11.06%
AT COMPLETION	10.00%	14.25%	11.06%

PROJECT COST ($MILLIONS)	1996	1998	1999	TOTAL
CAPITAL COST (1996 COST)	$382.5	$8.4	$30.6	$421.5
DEBT AFUDC	25.9	0.6	2.1	28.6
EQUITY AFUDC	12.3	0.3	1.0	13.6
TOTAL	$420.8	$9.2	$33.7	$463.7
LONG TERM DEBT	$315.6	$6.9	$25.3	$347.8
PARTNERS EQUITY	105.2	2.3	8.4	115.9
TOTAL	$420.8	$9.2	$33.7	$463.7

	1996	1998	1999
VOLUMES - MDQ - MMBTU/D	219	399	399
PIPELINE CAPACITY - ANNUAL	79,935	145,635	145,635
O & M	$1,400	$2,300	$2,300

EXHIBIT 5

SUNSHINE INTERSTATE GAS PIPELINE - 25 YEARS
COST OF SERVICE

UTILITY RETURN ON EQUITY 14.25%

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30th OPTION

LINE NO.	DESCRIPTION	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12)
	COST OF SERVICE											
1	Operation and maintenance	$700	$700	$800	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
2	Depreciation	(694)	(363)	(185)	(596)	(12)	577	1,157	1,754	2,399	3,095	3,912
	Taxes:											
3	Income Federal & State	3,587	3,537	3,488	3,502	3,415	3,328	3,242	3,154	3,058	2,956	2,845
4	Other	2,094	2,102	2,146	2,226	2,233	2,233	2,233	2,233	2,233	2,233	2,168
5	Return @ 11.06 %	18,535	18,246	17,972	18,089	17,586	17,084	16,590	16,080	15,531	14,939	14,297
6	Total	$24,222	$24,222	$24,221	$24,221	$24,222	$24,222	$24,222	$24,221	$24,221	$24,223	$24,222
	RATE DERIVATION	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
7	Cost of Service	$24,222	$24,222	$24,221	$24,221	$24,222	$24,222	$24,222	$24,221	$24,221	$24,223	$24,222
8	MDQ	324.5	324.5	369.5	504.5	504.5	504.5	504.5	505	505	505	505
9	Volume - MMcf/d - 100% L.F.	118,443	118,443	134,868	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
10	Base Rate Per Mcf (Year 2000)	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315
11	Revenue Collection on Base Rate	$15,580	$15,580	$17,740	$24,222	$24,222	$24,222	$24,222	$24,221	$24,221	$24,223	$24,222
12	REVENUES SHORTAGE	$8,642	$8,642	$6,482	$0	$0						
13	LESS INCOME TAXES	$3,252	$3,252	$2,439	$0	$0						
14	DEFERRED COLLECTION OF EQUITY RETURN	$5,390	$5,390	$4,043	$0	$0						
15	CUMULATIVE DEFERRED RETURN	$5,390	$10,780	$14,823	$14,823	$14,823						
16	AVERAGE CUMULATIVE DEFERRED RETURN	$2,695	$8,085	$12,801	$14,823	$14,823	$14,823					

EXHIBIT 5

12-Oct-92

SUNSHINE INTERSTATE GAS PIPELINE -
COST OF SERVICE

30th OPTION

LINE NO.	DESCRIPTION	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
	(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)	(col.22)
	COST OF SERVICE										
1	Operation and maintenance	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
2	Depreciation	4,794	5,748	6,779	7,895	9,102	10,174	11,098	12,095	13,157	14,298
	Taxes:										
3	Income Federal & State	2,725	2,594	2,451	2,297	2,126	1,978	1,849	1,710	1,561	1,400
4	Other	2,105	2,044	1,984	1,926	1,870	1,816	1,763	1,712	1,662	1,613
5	Return @ 11.06 %	13,598	12,836	12,007	11,105	10,123	9,256	8,512	7,707	6,842	5,909
6	Total	$24,222	$24,222	$24,221	$24,223	$24,221	$24,224	$24,222	$24,224	$24,222	$24,220
	RATE DERIVATION	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
7	Cost of Service	$24,222	$24,222	$24,221	$24,223	$24,221	$24,224	$24,222	$24,224	$24,222	$24,220
8	MDQ	505	505	505	505	505	505	505	505	505	505
9	Volume - MMcf/d - 100% L.F.	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
10	Base Rate Per Mcf (Year 2000)	$0.1315	$0.1315	$0.1315	$0.1315	$0.1315	$0.1316	$0.1315	$0.1316	$0.1315	$0.1315
11	Revenue Collection on Base Rate	$24,222	$24,222	$24,221	$24,223	$24,221	$24,224	$24,222	$24,224	$24,222	$24,220
12	REVENUES SHORTAGE										
13	LESS INCOME TAXES										
14	DEFERRED COLLECTION OF EQUITY RETURN										
15	CUMULATIVE DEFERRED RETURN										

EXHIBIT 5

EXHIBIT 5

Sunshine Gas Pipeline Company
Sunshine Interstate Gas Pipeline
Base Case

CONFIDENTIAL

The following are the assumptions employed in the Sunshine Gas and Sunshine Interstate Gas Pipeline Company Studies:

(1) 25-year levelized rate.

(2) 25-year variable depreciation is used to levelize cost of service, the rate is levelized through the operation of a deferral calculation.

(3) 25-year amortization of original long-term debt. However, additional new debt issued each year to maintain Debt/Equity ratio.

(4) 75% / 25% - Debt / Equity ratio, initially and throughout the project.

(5) No inflation on O & M, estimated at $3,000/mile of pipeline and $54/horsepower annually.

(6) Ad Valorem initially calculated on gross plant and later, after facility build up, on net plant: • 1.93% Sunshine • 1.25% Sunshine Interstate

(7) 14.25% return on equity - 10.00% interest on debt.

(8) Federal taxes calculated at 34%, state taxes at 5.5%, for both Sunshine and Sunshine Interstate.

(9) Tax depreciation taken at IRS mandated percentages, deferred tax based on the difference between tax and book depreciation.

(10) Income taxes are the responsibility of the Partners and are not normally reflected in the financial statements of partnerships. However, FERC requires jurisdictional partnerships to record an allowance for income taxes on the partnership records (calculated as if the partnership were a corporation). The Florida Public Service Commission is expected to impose the same requirement. Consequently, this allowance reflects income taxes payable by the Partners.

(11) Capital cost in 1994 dollars.

(12) Rates based on maximum daily quantity at 100% throughput utilization of capacity.

(13) Day one rate base.

October 13, 1992

SUNSHINE INTERSTATE GAS PIPELINE

SUMMARY OF RESULTS -- SUNSHINE INTERSTATE GAS PIPELINE - 25 YEARS

BASE ASSUMPTIONS

TARGET DEBT/CAPITAL RATIO	75% / 25%
DEBT MATURITY	25 YEARS
EFFECTIVE TAX RATE	37.63%

RATES OF RETURN	DEBT	EQUITY	OVERALL
DURING CONSTRUCTION	10.00%	14.25%	11.06%
AT COMPLETION	10.00%	14.25%	11.06%

PROJECT COST ($MILLIONS)	1996	1998	1999	TOTAL
CAPITAL COST (1994 COST)	$152.3	$5.6	$0.0	$157.9
DEBT AFUDC	10.3	0.4	0.0	10.7
EQUITY AFUDC	4.9	0.2	0.0	5.1
TOTAL	$167.5	$6.2	$0.0	$173.7
LONG TERM DEBT	$125.6	$4.7	$0.0	$130.3
PARTNERS EQUITY	41.9	1.6	0.0	43.4
TOTAL	$167.5	$6.2	$0.0	$173.7

	1996	1998	1999
VOLUMES - MDQ - MMBTU/D	325	504.5	504.5
PIPELINE CAPACITY - ANNUAL	118,443	184,143	184,143
O & M	$700	$1,000	$1,000

SCENARIO RESULTS

RATE @ 100% L. F.

BASE RATE	$0.1315
DEFERRED EQUITY RATE	0.0167
TOTAL RATE	$0.1482

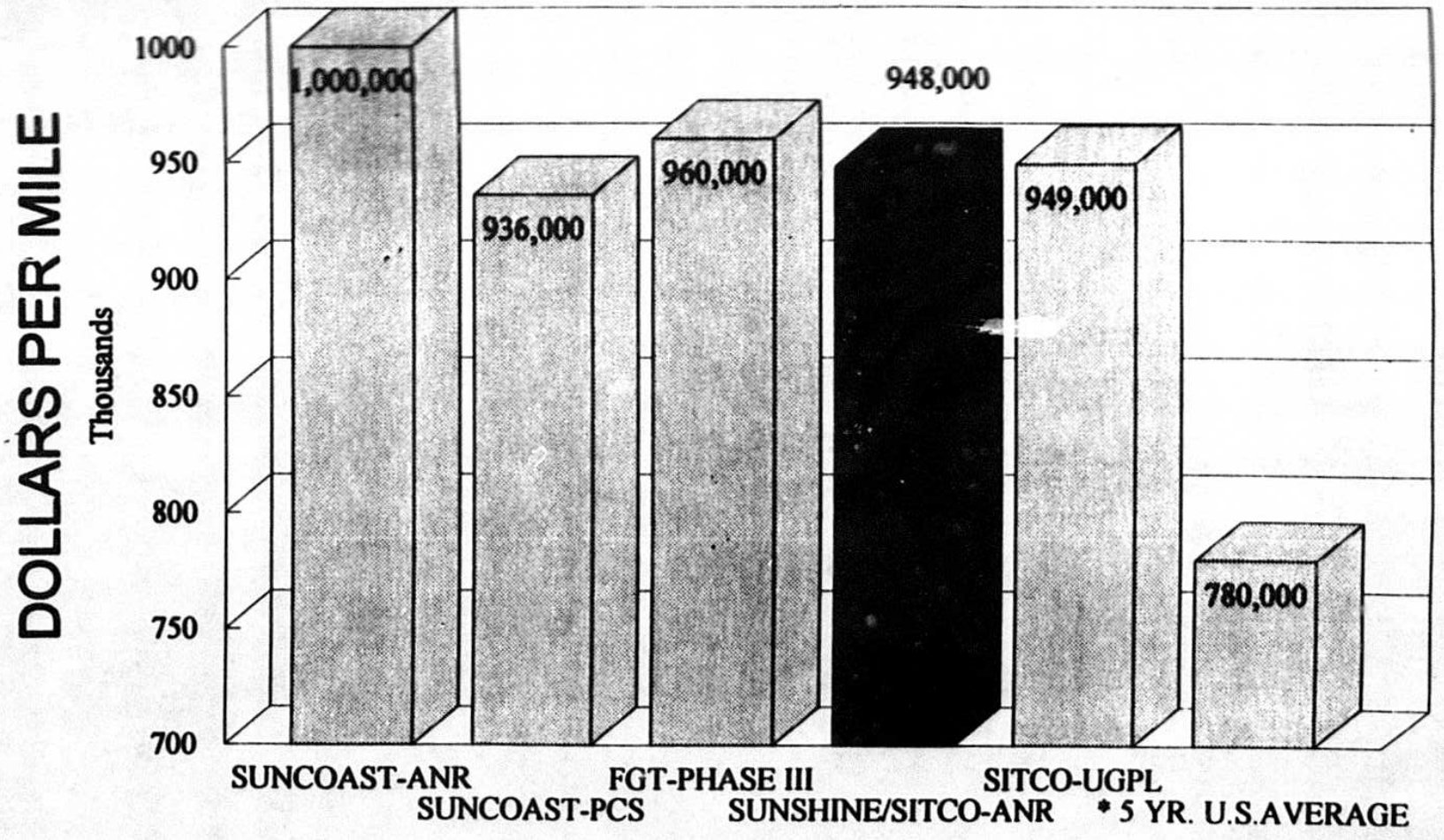
EXHIBIT 5

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	891.376	1108.870	1.240	444.846	5000.000	96.267	1.080
146.000	899.427	1126.995	1.249	430.632	5000.000	97.164	1.080
147.000	910.622	1148.617	1.257	418.566	5000.000	97.989	1.080
148.000	922.792	1170.416	1.264	409.171	5000.000	98.679	1.080
149.000	935.294	1191.877	1.270	401.597	5000.000	99.269	1.080
150.000	960.260	1201.798	1.248	357.060	4062.448	96.995	0.878
151.000	1001.302	1202.528	1.198	328.512	3038.569	91.946	0.656
152.000	1045.516	1202.063	1.148	302.901	2112.780	86.641	0.456
153.000	1083.719	1201.645	1.107	286.410	1466.682	82.276	0.317
154.000	1102.702	1201.357	1.088	276.943	1172.206	80.172	0.253
155.000	1107.104	1201.184	1.084	284.294	1144.431	79.684	0.247
156.000	1093.849	1201.251	1.097	317.260	1469.232	81.140	0.317
157.000	1069.340	1201.535	1.122	354.298	2053.388	83.897	0.444
158.000	1044.967	1201.878	1.148	379.591	2657.402	86.719	0.574
159.000	1025.150	1202.162	1.170	396.147	3173.384	89.071	0.685
160.000	1003.945	1202.114	1.195	422.980	3849.386	91.619	0.832
161.000	967.683	1196.554	1.233	459.213	4968.262	95.555	1.073
162.000	947.292	1169.238	1.231	464.913	4999.978	95.319	1.080
163.000	930.055	1142.064	1.224	475.908	5000.000	94.679	1.080
164.000	912.049	1116.145	1.220	483.091	5000.000	94.253	1.080
165.000	898.309	1101.040	1.222	478.528	5000.000	94.441	1.080
166.000	892.410	1098.100	1.227	468.946	5000.000	94.920	1.080
167.000	889.983	1098.691	1.231	461.375	5000.000	95.321	1.080
168.000	888.970	1100.606	1.234	454.942	5000.000	95.675	1.080

/*----------END OF SEVENTH DAY----------->

COMPARISON OF 30" PIPELINE COST ESTIMATES (1994 $)



* From Oil & Gas Journal for years 1987 - 1991 and escalated to 1994 dollars.

EXHIBIT 4

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	892.061	1109.350	1.240	445.586	5000.000	96.226	1.080
50.000	900.431	1127.704	1.248	431.641	5000.000	97.104	1.080
51.000	911.939	1149.583	1.256	419.758	5000.000	97.915	1.080
52.000	924.403	1171.643	1.263	410.487	5000.000	98.593	1.080
53.000	937.171	1193.361	1.269	402.987	5000.000	99.175	1.080
54.000	964.833	1201.717	1.242	359.239	4008.921	96.409	0.866
55.000	1006.564	1202.499	1.192	327.323	2937.110	91.302	0.634
56.000	1051.335	1202.048	1.141	302.121	2020.685	85.967	0.436
57.000	1086.825	1201.591	1.104	285.873	1422.051	81.929	0.307
58.000	1103.704	1201.342	1.087	276.713	1158.434	80.062	0.250
59.000	1107.379	1201.181	1.084	284.237	1140.561	79.654	0.246
60.000	1093.901	1201.250	1.097	317.201	1468.251	81.134	0.317
61.000	1069.388	1201.534	1.122	354.202	2052.148	83.891	0.443
62.000	1045.015	1201.877	1.148	379.530	2656.142	86.713	0.574
63.000	1025.188	1202.160	1.170	396.124	3172.463	89.067	0.685
64.000	1003.957	1202.114	1.195	422.994	3848.933	91.617	0.831
65.000	967.699	1196.525	1.233	459.295	4967.781	95.550	1.073
66.000	947.277	1169.204	1.231	464.942	4999.978	95.318	1.080
67.000	930.028	1141.985	1.224	475.979	5000.000	94.673	1.080
68.000	912.068	1116.177	1.220	483.067	5000.000	94.254	1.080
69.000	898.313	1101.064	1.222	478.486	5000.000	94.443	1.080
70.000	892.483	1098.201	1.227	468.925	5000.000	94.922	1.080
71.000	890.192	1098.888	1.231	461.513	5000.000	95.314	1.080
72.000	889.349	1100.865	1.234	455.381	5000.000	95.652	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	891.873	1109.204	1.240	445.405	5000.000	96.236	1.080
74.000	900.155	1127.549	1.249	431.289	5000.000	97.125	1.080
75.000	911.565	1149.355	1.257	419.341	5000.000	97.941	1.080
76.000	923.928	1171.326	1.264	410.028	5000.000	98.623	1.080
77.000	936.602	1192.955	1.269	402.501	5000.000	99.208	1.080
78.000	962.426	1202.876	1.246	365.566	4158.083	96.845	0.898
79.000	1004.936	1202.500	1.194	327.591	2966.680	91.499	0.641
80.000	1049.534	1202.051	1.143	302.248	2047.711	86.174	0.442
81.000	1086.408	1201.596	1.105	285.894	1427.529	81.975	0.308
82.000	1103.555	1201.345	1.087	276.687	1160.198	80.078	0.251
83.000	1107.487	1201.178	1.083	284.004	1138.199	79.642	0.246
84.000	1094.006	1201.248	1.097	317.138	1466.003	81.122	0.317
85.000	1069.362	1201.534	1.122	354.352	2052.989	83.894	0.443
86.000	1044.949	1201.878	1.148	379.628	2657.804	86.720	0.574
87.000	1025.137	1202.163	1.170	396.135	3173.486	89.073	0.686
88.000	1004.136	1202.113	1.194	422.675	3842.047	91.595	0.830
89.000	967.578	1196.774	1.233	459.067	4974.205	95.591	1.074
90.000	947.315	1169.291	1.231	464.869	4999.983	95.322	1.080
91.000	930.084	1142.100	1.224	475.907	5000.000	94.679	1.080
92.000	912.102	1116.230	1.220	483.044	5000.000	94.255	1.080
93.000	898.291	1100.996	1.222	478.575	5000.000	94.438	1.080
94.000	892.393	1098.041	1.227	469.022	5000.000	94.916	1.080
95.000	890.046	1098.687	1.231	461.546	5000.000	95.311	1.080
96.000	889.133	1100.625	1.234	455.313	5000.000	95.655	1.080

/*----------END OF FOURTH DAY----------->

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	891.578	1108.908	1.240	445.253	5000.000	96.244	1.080
98.000	899.783	1127.204	1.249	431.055	5000.000	97.138	1.080
99.000	911.114	1148.946	1.257	419.057	5000.000	97.958	1.080
100.000	923.401	1170.852	1.264	409.709	5000.000	98.644	1.080
101.000	936.007	1192.415	1.270	402.160	5000.000	99.231	1.080
102.000	960.851	1202.958	1.248	365.834	4193.219	97.054	0.906
103.000	1003.214	1202.509	1.196	328.041	3000.374	91.709	0.648
104.000	1047.683	1202.056	1.145	302.537	2077.250	86.388	0.449
105.000	1085.415	1201.613	1.106	286.091	1441.916	82.086	0.311
106.000	1103.219	1201.350	1.088	276.770	1164.837	80.115	0.252
107.000	1107.401	1201.179	1.084	284.005	1139.303	79.651	0.246
108.000	1093.995	1201.249	1.097	317.154	1466.143	81.123	0.317
109.000	1069.344	1201.534	1.122	354.393	2053.458	83.896	0.444
110.000	1044.928	1201.879	1.148	379.656	2658.367	86.723	0.574
111.000	1025.120	1202.164	1.170	396.144	3173.886	89.075	0.686
112.000	1004.223	1202.112	1.194	422.536	3838.450	91.584	0.829
113.000	967.328	1196.974	1.234	458.867	4982.833	95.643	1.076
114.000	947.278	1169.255	1.231	464.845	4999.990	95.323	1.080
115.000	930.064	1142.051	1.224	475.943	5000.000	94.676	1.080
116.000	912.053	1116.160	1.220	483.073	5000.000	94.254	1.080
117.000	898.308	1101.025	1.222	478.560	5000.000	94.439	1.080
118.000	892.395	1098.052	1.227	469.009	5000.000	94.917	1.080
119.000	890.012	1098.671	1.231	461.492	5000.000	95.314	1.080
120.000	889.084	1100.654	1.234	455.133	5000.000	95.665	1.080

/*----------END OF FIFTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	891.496	1108.940	1.240	445.001	5000.000	96.259	1.080
122.000	899.603	1127.108	1.249	430.828	5000.000	97.152	1.080
123.000	910.850	1148.774	1.257	418.789	5000.000	97.975	1.080
124.000	923.069	1170.618	1.264	409.412	5000.000	98.663	1.080
125.000	935.616	1192.123	1.270	401.846	5000.000	99.252	1.080
126.000	960.951	1202.166	1.247	364.531	4162.777	96.960	0.899
127.000	1002.226	1202.516	1.197	328.514	3022.695	91.832	0.653
128.000	1046.490	1202.062	1.147	302.874	2098.039	86.528	0.453
129.000	1084.751	1201.630	1.106	286.325	1452.308	82.160	0.314
130.000	1102.938	1201.354	1.088	276.940	1169.188	80.146	0.253
131.000	1107.154	1201.184	1.084	284.304	1143.778	79.678	0.247
132.000	1093.854	1201.251	1.097	317.260	1469.132	81.139	0.317
133.000	1069.345	1201.534	1.122	354.285	2053.260	83.896	0.444
134.000	1044.972	1201.878	1.148	379.584	2657.292	86.718	0.574
135.000	1025.154	1202.161	1.170	396.146	3173.313	89.071	0.685
136.000	1004.041	1202.113	1.194	422.862	3845.374	91.606	0.831
137.000	967.531	1196.645	1.233	459.171	4973.574	95.583	1.074
138.000	947.238	1169.153	1.231	464.944	4999.982	95.317	1.080
139.000	930.013	1141.941	1.224	476.027	5000.000	94.670	1.080
140.000	912.020	1116.100	1.220	483.108	5000.000	94.252	1.080
141.000	898.285	1101.010	1.222	478.528	5000.000	94.441	1.080
142.000	892.397	1098.080	1.227	468.954	5000.000	94.920	1.080
143.000	889.996	1098.690	1.231	461.413	5000.000	95.319	1.080
144.000	889.022	1100.632	1.234	455.021	5000.000	95.671	1.080

/*----------END OF SIXTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	928.456	1156.690	1.242	443.786	5000.000	96.461	1.080
146.000	924.584	1154.073	1.244	439.648	5000.000	96.696	1.080
147.000	922.276	1153.981	1.247	434.656	5000.000	96.995	1.080
148.000	921.491	1156.020	1.251	429.466	5000.000	97.318	1.080
149.000	921.939	1159.581	1.254	424.508	5000.000	97.639	1.080
150.000	923.463	1164.591	1.257	419.585	5000.000	97.969	1.080
151.000	928.645	1177.647	1.264	409.744	5000.000	98.662	1.080
152.000	938.446	1198.742	1.273	397.717	5000.000	99.568	1.080
153.000	978.784	1202.836	1.226	332.575	3478.997	94.760	0.752
154.000	1027.845	1202.085	1.167	296.563	2330.477	88.708	0.503
155.000	1072.270	1201.691	1.119	282.529	1600.504	83.552	0.346
156.000	1094.034	1201.350	1.097	292.724	1356.421	81.120	0.293
157.000	1087.685	1201.367	1.103	320.563	1578.888	81.828	0.341
158.000	1069.323	1201.581	1.122	349.707	2028.757	83.902	0.438
159.000	1049.060	1201.847	1.144	372.792	2534.227	86.241	0.547
160.000	1030.241	1202.065	1.164	391.435	3032.672	88.459	0.655
161.000	1007.716	1202.181	1.190	418.743	3729.854	91.167	0.806
162.000	981.462	1202.578	1.222	442.105	4564.565	94.441	0.986
163.000	963.510	1199.580	1.241	446.853	4998.244	96.394	1.080
164.000	956.434	1190.252	1.241	447.542	5000.000	96.337	1.080
165.000	950.763	1181.038	1.239	451.097	5000.000	96.109	1.080
166.000	944.860	1173.085	1.238	451.910	5000.000	96.042	1.080
167.000	938.791	1166.472	1.239	449.895	5000.000	96.138	1.080
168.000	933.143	1160.936	1.240	446.894	5000.000	96.294	1.080

/*----------END OF SEVENTH DAY----------

EXHIBIT 3C

SUNSHINE SYSTEM; COMPRESSOR STATION # 6 ALTERNATE DESIGN REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	889.825	1102.177	1.235	453.974	5000.000	95.733	1.080
1.000	893.603	1112.288	1.241	443.747	5000.000	96.340	1.080
2.000	902.602	1131.213	1.249	430.376	5000.000	97.192	1.080
3.000	914.484	1153.321	1.257	419.028	5000.000	97.973	1.080
4.000	927.213	1175.522	1.264	410.143	5000.000	98.628	1.080
5.000	940.186	1197.352	1.269	402.915	5000.000	99.192	1.080
6.000	972.056	1203.032	1.234	357.628	3877.474	95.633	0.838
7.000	1016.271	1202.410	1.181	322.265	2727.134	90.121	0.589
8.000	1061.074	1201.972	1.131	298.759	1854.890	84.844	0.401
9.000	1091.559	1201.530	1.099	283.915	1349.002	81.402	0.291
10.000	1105.696	1201.313	1.085	275.548	1128.199	79.844	0.244
11.000	1108.379	1201.164	1.083	283.364	1123.915	79.544	0.243
12.000	1094.387	1201.242	1.096	316.812	1458.697	81.080	0.315
13.000	1069.561	1201.531	1.122	354.197	2048.562	83.871	0.443
14.000	1045.074	1201.876	1.148	379.533	2654.706	86.706	0.573
15.000	1025.225	1202.162	1.170	396.064	3171.087	89.062	0.685
16.000	1004.255	1202.112	1.194	422.541	3838.145	91.580	0.829
17.000	967.622	1196.833	1.233	459.075	4974.381	95.591	1.075
18.000	947.346	1169.337	1.231	464.854	4999.983	95.323	1.080
19.000	930.112	1142.140	1.224	475.895	5000.000	94.680	1.080
20.000	912.134	1116.277	1.220	483.030	5000.000	94.256	1.080
21.000	898.321	1101.032	1.222	478.577	5000.000	94.438	1.080
22.000	892.424	1098.071	1.227	469.046	5000.000	94.915	1.080
23.000	890.169	1098.774	1.230	461.687	5000.000	95.304	1.080
24.000	889.486	1100.879	1.234	455.696	5000.000	95.634	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	892.248	1109.401	1.239	445.933	5000.000	96.206	1.080
26.000	900.791	1127.945	1.248	432.020	5000.000	97.082	1.080
27.000	912.459	1149.958	1.256	420.234	5000.000	97.885	1.080
28.000	925.061	1172.137	1.263	411.035	5000.000	98.557	1.080
29.000	937.953	1193.971	1.269	403.581	5000.000	99.135	1.080
30.000	966.181	1202.224	1.241	362.890	4042.594	96.295	0.873
31.000	1008.743	1202.485	1.189	326.774	2893.945	91.035	0.625
32.000	1053.795	1202.041	1.139	301.733	1981.020	85.682	0.428
33.000	1088.007	1201.574	1.103	285.638	1404.830	81.797	0.303
34.000	1104.138	1201.337	1.087	276.531	1152.101	80.015	0.249
35.000	1107.676	1201.175	1.083	283.912	1135.315	79.621	0.245
36.000	1094.052	1201.247	1.097	317.087	1465.018	81.117	0.316
37.000	1069.384	1201.533	1.122	354.322	2052.436	83.891	0.443
38.000	1044.964	1201.878	1.148	379.611	2657.402	86.719	0.574
39.000	1025.149	1202.163	1.170	396.123	3173.146	89.072	0.685
40.000	1004.243	1202.112	1.194	422.525	3837.731	91.581	0.829
41.000	967.241	1197.033	1.234	458.806	4985.659	95.660	1.077
42.000	947.262	1169.238	1.231	464.839	4999.993	95.323	1.080
43.000	930.054	1142.031	1.224	475.956	5000.000	94.675	1.080
44.000	912.041	1116.141	1.220	483.078	5000.000	94.254	1.080
45.000	898.298	1101.010	1.222	478.564	5000.000	94.439	1.080
46.000	892.398	1098.041	1.227	469.038	5000.000	94.915	1.080
47.000	890.111	1098.724	1.231	461.640	5000.000	95.307	1.080
48.000	889.388	1100.862	1.234	455.483	5000.000	95.646	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	930.739	1158.526	1.241	445.715	5000.000	96.355	1.080
50.000	927.280	1156.356	1.243	441.703	5000.000	96.582	1.080
51.000	925.279	1156.616	1.246	436.753	5000.000	96.876	1.080
52.000	924.717	1158.929	1.249	431.549	5000.000	97.198	1.080
53.000	925.322	1162.702	1.253	426.543	5000.000	97.520	1.080
54.000	927.030	1168.116	1.256	421.316	5000.000	97.868	1.080
55.000	932.663	1182.060	1.263	410.968	5000.000	98.592	1.080
56.000	942.847	1203.821	1.273	398.682	5000.000	99.514	1.080
57.000	990.539	1202.709	1.211	327.132	3214.465	93.286	0.694
58.000	1039.227	1202.019	1.154	294.340	2144.206	87.365	0.463
59.000	1081.895	1201.620	1.109	281.668	1466.664	82.473	0.317
60.000	1097.258	1201.314	1.094	292.579	1311.528	80.765	0.283
61.000	1088.614	1201.354	1.102	320.503	1564.441	81.725	0.338
62.000	1069.634	1201.577	1.122	349.649	2023.218	83.866	0.437
63.000	1049.138	1201.844	1.144	372.744	2532.481	86.232	0.547
64.000	1030.237	1202.064	1.164	391.417	3032.568	88.459	0.655
65.000	1007.714	1202.181	1.190	418.718	3729.451	91.167	0.806
66.000	981.459	1202.578	1.222	442.109	4564.556	94.441	0.986
67.000	963.545	1199.566	1.241	446.832	4996.879	96.390	1.079
68.000	956.432	1190.249	1.241	447.543	5000.000	96.337	1.080
69.000	950.802	1181.050	1.238	451.163	5000.000	96.105	1.080
70.000	945.281	1173.334	1.238	452.433	5000.000	96.014	1.080
71.000	939.770	1167.156	1.238	450.918	5000.000	96.082	1.080
72.000	934.629	1162.080	1.240	448.250	5000.000	96.219	1.080

/*----------END OF THIRD DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	930.020	1157.973	1.241	445.062	5000.000	96.391	1.080
74.000	926.402	1155.631	1.244	441.001	5000.000	96.621	1.080
75.000	924.287	1155.764	1.247	436.026	5000.000	96.917	1.080
76.000	923.642	1157.979	1.250	430.819	5000.000	97.240	1.080
77.000	924.189	1161.676	1.253	425.827	5000.000	97.562	1.080
78.000	925.872	1167.067	1.256	420.600	5000.000	97.911	1.080
79.000	931.310	1180.574	1.264	410.551	5000.000	98.615	1.080
80.000	941.379	1202.162	1.273	398.307	5000.000	99.535	1.080
81.000	986.953	1202.588	1.215	329.115	3296.825	93.719	0.712
82.000	1035.646	1202.029	1.158	294.743	2199.347	87.784	0.475
83.000	1079.276	1201.652	1.112	281.696	1501.664	82.765	0.324
84.000	1096.551	1201.323	1.094	292.446	1320.695	80.843	0.285
85.000	1088.454	1201.356	1.102	320.495	1566.628	81.742	0.338
86.000	1069.559	1201.578	1.122	349.722	2024.605	83.875	0.437
87.000	1049.097	1201.845	1.144	372.815	2533.502	86.236	0.547
88.000	1030.252	1202.066	1.164	391.349	3031.739	88.458	0.655
89.000	1007.777	1202.177	1.190	418.692	3727.782	91.159	0.805
90.000	981.468	1202.579	1.222	442.107	4564.325	94.440	0.986
91.000	963.520	1199.589	1.241	446.831	4997.899	96.394	1.080
92.000	956.448	1190.266	1.241	447.549	5000.000	96.336	1.080
93.000	950.804	1181.061	1.238	451.150	5000.000	96.106	1.080
94.000	945.179	1173.270	1.238	452.312	5000.000	96.020	1.080
95.000	939.483	1166.945	1.238	450.638	5000.000	96.097	1.080
96.000	934.158	1161.700	1.240	447.852	5000.000	96.241	1.080

/*----------END OF FOURTH DAY----------*/

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	929.401	1157.445	1.242	444.591	5000.000	96.417	1.080
98.000	925.670	1154.982	1.244	440.493	5000.000	96.649	1.080
99.000	923.470	1155.020	1.247	435.503	5000.000	96.947	1.080
100.000	922.764	1157.161	1.250	430.298	5000.000	97.270	1.080
101.000	923.267	1160.801	1.253	425.316	5000.000	97.591	1.080
102.000	924.875	1166.015	1.257	420.223	5000.000	97.932	1.080
103.000	930.157	1179.229	1.264	410.319	5000.000	98.627	1.080
104.000	940.107	1200.619	1.273	398.130	5000.000	99.543	1.080
105.000	983.556	1202.554	1.219	330.721	3372.694	94.137	0.729
106.000	1032.288	1202.049	1.162	295.474	2254.743	88.180	0.487
107.000	1076.369	1201.670	1.115	281.957	1542.034	83.091	0.333
108.000	1095.664	1201.334	1.095	292.478	1332.989	80.940	0.288
109.000	1088.196	1201.359	1.103	320.514	1570.591	81.771	0.339
110.000	1069.469	1201.579	1.122	349.746	2026.222	83.885	0.438
111.000	1049.069	1201.846	1.144	372.837	2534.136	86.239	0.547
112.000	1030.259	1202.067	1.164	391.321	3031.298	88.457	0.655
113.000	1007.783	1202.173	1.190	418.765	3727.924	91.158	0.805
114.000	981.401	1202.581	1.222	442.176	4566.564	94.448	0.986
115.000	963.503	1199.575	1.241	446.782	4997.528	96.396	1.080
116.000	956.429	1190.252	1.241	447.533	5000.000	96.338	1.080
117.000	950.792	1181.055	1.239	451.133	5000.000	96.107	1.080
118.000	945.060	1173.203	1.238	452.157	5000.000	96.029	1.080
119.000	939.206	1166.757	1.239	450.339	5000.000	96.114	1.080
120.000	933.745	1161.392	1.240	447.457	5000.000	96.263	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	928.880	1157.034	1.242	444.138	5000.000	96.442	1.080
122.000	925.070	1154.487	1.244	440.014	5000.000	96.676	1.080
123.000	922.808	1154.450	1.247	435.024	5000.000	96.974	1.080
124.000	922.056	1156.530	1.250	429.828	5000.000	97.297	1.080
125.000	922.527	1160.124	1.254	424.860	5000.000	97.618	1.080
126.000	924.122	1165.336	1.257	419.754	5000.000	97.960	1.080
127.000	929.383	1178.467	1.264	409.955	5000.000	98.650	1.080
128.000	939.229	1199.640	1.273	397.896	5000.000	99.557	1.080
129.000	981.440	1202.350	1.222	330.865	3410.930	94.379	0.737
130.000	1029.894	1202.064	1.165	296.001	2295.326	88.464	0.496
131.000	1074.068	1201.680	1.117	282.371	1575.437	83.350	0.340
132.000	1094.769	1201.345	1.096	292.701	1346.227	81.039	0.291
133.000	1087.893	1201.364	1.103	320.556	1575.651	81.805	0.340
134.000	1069.390	1201.580	1.122	349.701	2027.595	83.894	0.438
135.000	1049.083	1201.846	1.144	372.787	2533.774	86.238	0.547
136.000	1030.248	1202.066	1.164	391.396	3032.075	88.458	0.655
137.000	1007.740	1202.178	1.190	418.760	3728.893	91.163	0.805
138.000	981.425	1202.579	1.222	442.162	4565.790	94.445	0.986
139.000	963.494	1199.580	1.241	446.757	4997.568	96.398	1.080
140.000	956.421	1190.239	1.241	447.538	5000.000	96.337	1.080
141.000	950.766	1181.029	1.239	451.119	5000.000	96.108	1.080
142.000	944.941	1173.126	1.238	452.024	5000.000	96.036	1.080
143.000	938.968	1166.590	1.239	450.090	5000.000	96.127	1.080
144.000	933.403	1161.132	1.240	447.139	5000.000	96.280	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	936.712	1175.654	1.251	429.361	5000.000	97.380	1.080
146.000	931.496	1169.947	1.252	427.703	5000.000	97.467	1.080
147.000	926.855	1165.016	1.253	425.986	5000.000	97.561	1.080
148.000	922.872	1161.026	1.254	424.116	5000.000	97.667	1.080
149.000	919.580	1158.005	1.255	422.117	5000.000	97.786	1.080
150.000	916.955	1155.888	1.257	420.059	5000.000	97.912	1.080
151.000	915.044	1154.842	1.258	417.774	5000.000	98.058	1.080
152.000	914.259	1155.785	1.260	414.668	5000.000	98.265	1.080
153.000	915.842	1161.883	1.264	408.406	5000.000	98.706	1.080
154.000	923.654	1180.959	1.274	395.440	5000.000	99.679	1.080
155.000	939.574	1204.768	1.278	370.295	4725.440	100.030	1.021
156.000	991.176	1202.366	1.210	307.965	3010.940	93.170	0.650
157.000	1029.183	1201.763	1.165	304.418	2371.885	88.529	0.512
158.000	1050.722	1201.734	1.142	323.767	2174.854	86.024	0.470
159.000	1057.053	1201.785	1.135	346.834	2222.310	85.310	0.480
160.000	1047.761	1201.885	1.145	367.683	2524.300	86.393	0.545
161.000	1032.468	1202.033	1.162	387.674	2959.430	88.193	0.639
162.000	1012.518	1202.218	1.185	411.053	3560.134	90.589	0.769
163.000	990.748	1202.506	1.211	430.953	4234.012	93.271	0.915
164.000	973.585	1202.822	1.232	440.480	4743.439	95.450	1.025
165.000	962.008	1201.346	1.245	440.415	4997.135	96.770	1.079
166.000	954.766	1195.141	1.248	435.505	4999.999	97.060	1.080
167.000	948.054	1188.196	1.249	432.728	5000.000	97.209	1.080
168.000	941.805	1181.400	1.250	430.685	5000.000	97.315	1.080

/*----------END OF SEVENTH DAY----------->

SUNSHINE SYSTEM; COMPRESSOR STATION # 5 ALTERNATE DESIGN REPORT

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	935.185	1162.249	1.239	449.231	5000.000	96.164	1.080
1.000	931.378	1159.040	1.241	446.257	5000.000	96.325	1.080
2.000	928.503	1157.603	1.243	442.261	5000.000	96.553	1.080
3.000	926.992	1158.463	1.246	437.353	5000.000	96.845	1.080
4.000	926.811	1161.232	1.249	432.202	5000.000	97.165	1.080
5.000	927.707	1165.350	1.252	427.239	5000.000	97.484	1.080
6.000	929.953	1171.927	1.256	421.255	5000.000	97.883	1.080
7.000	936.532	1187.598	1.264	410.198	5000.000	98.660	1.080
8.000	956.870	1203.074	1.253	364.829	4246.327	97.570	0.917
9.000	1005.211	1202.500	1.193	317.134	2864.770	91.460	0.619
10.000	1053.263	1201.924	1.139	290.338	1912.090	85.730	0.413
11.000	1091.062	1201.487	1.100	279.520	1334.385	81.450	0.288
12.000	1100.508	1201.267	1.090	291.713	1263.320	80.407	0.273
13.000	1089.739	1201.338	1.101	320.190	1545.468	81.599	0.334
14.000	1070.030	1201.570	1.121	349.556	2015.516	83.821	0.435
15.000	1049.235	1201.841	1.143	372.715	2530.170	86.220	0.547
16.000	1030.325	1202.065	1.164	391.252	3029.507	88.449	0.654
17.000	1007.851	1202.175	1.190	418.610	3725.358	91.150	0.805
18.000	981.519	1202.578	1.222	442.076	4562.753	94.433	0.986
19.000	963.539	1199.604	1.241	446.836	4997.784	96.393	1.080
20.000	956.459	1190.282	1.241	447.545	5000.000	96.337	1.080
21.000	950.822	1181.080	1.238	451.155	5000.000	96.106	1.080
22.000	945.452	1173.426	1.238	452.661	5000.000	96.001	1.080
23.000	940.424	1167.561	1.238	451.700	5000.000	96.039	1.080
24.000	935.814	1162.917	1.239	449.472	5000.000	96.152	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	931.657	1159.240	1.240	446.538	5000.000	96.309	1.080
26.000	928.394	1157.270	1.243	442.604	5000.000	96.532	1.080
27.000	926.545	1157.704	1.246	437.678	5000.000	96.824	1.080
28.000	926.096	1160.156	1.249	432.472	5000.000	97.145	1.080
29.000	926.784	1164.035	1.252	427.448	5000.000	97.467	1.080
30.000	928.581	1169.631	1.256	422.097	5000.000	97.822	1.080
31.000	934.377	1183.880	1.263	411.577	5000.000	98.556	1.080
32.000	944.736	1205.961	1.272	399.145	5000.000	99.487	1.080
33.000	995.477	1202.715	1.205	324.400	3099.760	92.674	0.670
34.000	1044.103	1201.994	1.149	293.410	2065.363	86.794	0.446
35.000	1085.900	1201.583	1.105	281.046	1410.142	82.025	0.305
36.000	1098.604	1201.296	1.092	292.316	1291.955	80.617	0.279
37.000	1089.039	1201.348	1.102	320.462	1557.484	81.677	0.336
38.000	1069.743	1201.575	1.122	349.702	2021.337	83.854	0.437
39.000	1049.113	1201.844	1.144	372.804	2533.109	86.234	0.547
40.000	1030.250	1202.067	1.164	391.304	3031.277	88.458	0.655
41.000	1007.761	1202.172	1.190	418.798	3728.578	91.160	0.805
42.000	981.360	1202.582	1.222	442.203	4567.807	94.453	0.987
43.000	963.487	1199.567	1.241	446.761	4997.536	96.397	1.080
44.000	956.423	1190.244	1.241	447.534	5000.000	96.338	1.080
45.000	950.804	1181.056	1.239	451.159	5000.000	96.106	1.080
46.000	945.362	1173.368	1.238	452.558	5000.000	96.007	1.080
47.000	940.062	1167.324	1.238	451.291	5000.000	96.062	1.080
48.000	935.150	1162.437	1.239	448.808	5000.000	96.189	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	941.525	1179.938	1.249	432.516	5000.000	97.198	1.080
50.000	936.374	1174.482	1.250	430.580	5000.000	97.302	1.080
51.000	931.717	1169.683	1.252	428.609	5000.000	97.410	1.080
52.000	927.669	1165.745	1.253	426.511	5000.000	97.530	1.080
53.000	924.279	1162.720	1.254	424.310	5000.000	97.660	1.080
54.000	921.537	1160.562	1.255	422.069	5000.000	97.797	1.080
55.000	919.523	1159.514	1.257	419.564	5000.000	97.955	1.080
56.000	918.674	1160.517	1.259	416.222	5000.000	98.176	1.080
57.000	920.897	1168.544	1.265	408.273	5000.000	98.735	1.080
58.000	929.626	1189.318	1.275	394.717	5000.000	99.757	1.080
59.000	960.123	1202.379	1.249	335.305	3834.113	97.072	0.828
60.000	1008.564	1202.089	1.189	300.381	2659.338	91.017	0.574
61.000	1044.805	1201.706	1.148	302.432	2119.180	86.697	0.458
62.000	1064.635	1201.692	1.127	323.071	1950.652	84.431	0.421
63.000	1063.155	1201.695	1.129	346.600	2116.397	84.608	0.457
64.000	1049.880	1201.855	1.143	367.666	2485.118	86.146	0.537
65.000	1033.225	1202.022	1.161	387.682	2944.346	88.103	0.636
66.000	1012.806	1202.213	1.184	411.056	3553.785	90.554	0.768
67.000	990.900	1202.507	1.210	430.929	4228.934	93.258	0.913
68.000	973.674	1202.822	1.232	440.487	4741.050	95.441	1.024
69.000	963.290	1201.985	1.244	442.098	4996.885	96.672	1.079
70.000	957.476	1196.959	1.246	438.282	4999.998	96.898	1.080
71.000	951.436	1190.823	1.248	435.582	5000.000	97.043	1.080
72.000	945.494	1184.531	1.249	433.356	5000.000	97.160	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	939.882	1178.502	1.250	431.394	5000.000	97.263	1.080
74.000	934.698	1172.946	1.251	429.556	5000.000	97.360	1.080
75.000	930.041	1168.091	1.252	427.676	5000.000	97.463	1.080
76.000	926.011	1164.128	1.253	425.659	5000.000	97.579	1.080
77.000	922.653	1161.101	1.254	423.529	5000.000	97.705	1.080
78.000	919.951	1158.956	1.256	421.351	5000.000	97.838	1.080
79.000	917.976	1157.916	1.257	418.920	5000.000	97.992	1.080
80.000	917.149	1158.896	1.259	415.663	5000.000	98.208	1.080
81.000	919.007	1165.963	1.264	408.454	5000.000	98.715	1.080
82.000	927.549	1186.486	1.275	394.854	5000.000	99.738	1.080
83.000	953.848	1202.650	1.267	335.569	3931.325	97.897	0.849
84.000	1003.016	1202.154	1.196	302.047	2761.370	91.695	0.596
85.000	1039.842	1201.718	1.154	302.816	2196.838	87.274	0.475
86.000	1060.567	1201.720	1.131	323.308	2016.272	84.895	0.436
87.000	1061.607	1201.706	1.130	346.664	2142.891	84.785	0.463
88.000	1049.325	1201.863	1.143	367.685	2495.418	86.210	0.539
89.000	1033.049	1202.025	1.161	387.628	2947.466	88.124	0.637
90.000	1012.758	1202.214	1.184	411.039	3554.666	90.560	0.768
91.000	990.857	1202.504	1.210	430.917	4230.957	93.257	0.914
92.000	973.702	1202.821	1.232	440.460	4740.132	95.438	1.024
93.000	963.075	1201.851	1.244	441.765	4995.840	96.686	1.079
94.000	956.683	1196.451	1.247	437.425	4999.997	96.948	1.080
95.000	950.376	1190.021	1.248	434.651	5000.000	97.097	1.080
96.000	944.306	1183.536	1.249	432.471	5000.000	97.211	1.080

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	938.636	1177.388	1.250	430.582	5000.000	97.310	1.080
98.000	933.430	1171.761	1.251	428.817	5000.000	97.403	1.080
99.000	928.773	1166.866	1.252	427.004	5000.000	97.502	1.080
100.000	924.757	1162.886	1.254	425.045	5000.000	97.614	1.080
101.000	921.420	1159.856	1.255	422.969	5000.000	97.737	1.080
102.000	918.745	1157.718	1.256	420.839	5000.000	97.867	1.080
103.000	916.791	1156.664	1.258	418.472	5000.000	98.018	1.080
104.000	915.971	1157.610	1.260	415.284	5000.000	98.230	1.080
105.000	917.624	1164.081	1.264	408.581	5000.000	98.700	1.080
106.000	925.882	1184.087	1.275	395.147	5000.000	99.709	1.080
107.000	948.139	1203.216	1.265	347.115	4206.387	98.712	0.909
108.000	998.059	1202.210	1.202	304.123	2860.368	92.306	0.618
109.000	1035.395	1201.734	1.158	303.367	2268.558	87.796	0.490
110.000	1056.476	1201.726	1.136	323.479	2081.786	85.362	0.450
111.000	1059.884	1201.737	1.132	346.730	2172.887	84.983	0.469
112.000	1048.728	1201.871	1.144	367.700	2506.440	86.280	0.541
113.000	1032.846	1202.028	1.162	387.608	2951.239	88.148	0.638
114.000	1012.663	1202.214	1.185	411.089	3556.970	90.571	0.768
115.000	990.789	1202.507	1.211	430.990	4232.544	93.269	0.914
116.000	973.600	1202.830	1.232	440.534	4744.005	95.447	1.025
117.000	962.699	1201.667	1.244	441.267	4995.921	96.715	1.079
118.000	955.905	1195.928	1.247	436.631	4999.997	96.994	1.080
119.000	949.412	1189.271	1.249	433.839	5000.000	97.144	1.080
120.000	943.261	1182.650	1.250	431.714	5000.000	97.255	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	937.556	1176.419	1.251	429.890	5000.000	97.350	1.080
122.000	932.343	1170.745	1.252	428.185	5000.000	97.439	1.080
123.000	927.694	1165.829	1.253	426.426	5000.000	97.535	1.080
124.000	923.696	1161.842	1.254	424.517	5000.000	97.644	1.080
125.000	920.384	1158.817	1.255	422.485	5000.000	97.765	1.080
126.000	917.737	1156.690	1.256	420.396	5000.000	97.893	1.080
127.000	915.815	1155.661	1.258	418.060	5000.000	98.041	1.080
128.000	915.022	1156.614	1.260	414.919	5000.000	98.251	1.080
129.000	916.560	1162.694	1.264	408.590	5000.000	98.696	1.080
130.000	924.627	1182.357	1.274	395.271	5000.000	99.695	1.080
131.000	944.086	1203.517	1.271	357.318	4434.505	99.290	0.958
132.000	994.230	1202.260	1.206	306.079	2942.155	92.782	0.636
133.000	1031.885	1201.750	1.162	303.979	2326.880	88.210	0.503
134.000	1053.222	1201.730	1.139	323.642	2134.242	85.736	0.461
135.000	1058.724	1201.755	1.133	346.699	2192.653	85.117	0.474
136.000	1048.271	1201.879	1.145	367.687	2514.825	86.333	0.543
137.000	1032.664	1202.030	1.162	387.653	2955.135	88.169	0.638
138.000	1012.591	1202.216	1.185	411.076	3558.417	90.580	0.769
139.000	990.765	1202.508	1.211	431.023	4232.826	93.274	0.914
140.000	973.580	1202.824	1.232	440.506	4743.857	95.451	1.025
141.000	962.306	1201.498	1.245	440.795	4997.023	96.748	1.079
142.000	955.264	1195.485	1.248	435.999	4999.999	97.031	1.080
143.000	948.646	1188.664	1.249	433.214	5000.000	97.181	1.080
144.000	942.439	1181.944	1.250	431.134	5000.000	97.289	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	923.722	1167.763	1.260	415.115	5000.000	98.270	1.080
146.000	919.736	1162.767	1.260	414.849	5000.000	98.273	1.080
147.000	916.063	1158.202	1.260	414.546	5000.000	98.279	1.080
148.000	912.683	1154.057	1.260	414.175	5000.000	98.292	1.080
149.000	909.593	1150.344	1.261	413.716	5000.000	98.311	1.080
150.000	906.801	1147.074	1.261	413.168	5000.000	98.338	1.080
151.000	904.312	1144.246	1.261	412.539	5000.000	98.372	1.080
152.000	902.150	1141.918	1.262	411.789	5000.000	98.415	1.080
153.000	900.408	1140.292	1.262	410.795	5000.000	98.478	1.080
154.000	899.468	1140.253	1.263	408.950	5000.000	98.603	1.080
155.000	900.004	1143.029	1.266	405.745	5000.000	98.831	1.080
156.000	904.627	1155.302	1.273	396.460	5000.000	99.526	1.080
157.000	915.093	1177.701	1.282	384.489	5000.000	100.488	1.080
158.000	926.955	1198.897	1.289	377.410	5000.000	101.109	1.080
159.000	951.621	1202.406	1.260	348.575	4173.304	98.200	0.901
160.000	969.904	1202.108	1.236	352.566	3857.627	95.832	0.833
161.000	977.605	1202.098	1.226	366.685	3856.897	94.864	0.833
162.000	976.419	1202.155	1.228	384.614	4070.966	95.023	0.879
163.000	966.829	1202.254	1.240	404.473	4496.675	96.247	0.971
164.000	951.986	1201.532	1.258	418.302	4985.309	98.082	1.077
165.000	943.847	1193.422	1.260	415.785	4999.998	98.301	1.080
166.000	937.372	1185.235	1.260	415.462	5000.000	98.298	1.080
167.000	931.919	1178.352	1.260	415.174	5000.000	98.297	1.080
168.000	927.152	1172.313	1.260	414.954	5000.000	98.294	1.080

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3C

SUNSHINE SYSTEM; COMPRESSOR STATION # 4 ALTERNATE DESIGN REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	949.058	1187.095	1.247	436.724	5000.000	96.964	1.080
1.000	943.843	1181.715	1.248	434.521	5000.000	97.081	1.080
2.000	938.890	1176.629	1.249	432.389	5000.000	97.197	1.080
3.000	934.371	1172.123	1.251	430.221	5000.000	97.317	1.080
4.000	930.417	1168.412	1.252	427.946	5000.000	97.448	1.080
5.000	927.086	1165.554	1.253	425.592	5000.000	97.587	1.080
6.000	924.380	1163.528	1.255	423.207	5000.000	97.732	1.080
7.000	922.448	1162.738	1.256	420.456	5000.000	97.907	1.080
8.000	921.808	1164.298	1.259	416.655	5000.000	98.159	1.080
9.000	925.520	1175.801	1.266	406.409	5000.000	98.885	1.080
10.000	935.492	1198.656	1.277	392.474	5000.000	99.950	1.080
11.000	978.965	1202.682	1.225	322.858	3371.767	94.721	0.728
12.000	1026.971	1201.906	1.168	293.577	2319.408	88.796	0.501
13.000	1061.430	1201.651	1.130	300.208	1858.766	84.782	0.402
14.000	1075.486	1201.550	1.116	322.004	1774.644	83.198	0.383
15.000	1066.804	1201.643	1.125	346.397	2052.991	84.190	0.443
16.000	1051.146	1201.837	1.141	367.591	2461.262	85.998	0.532
17.000	1033.743	1202.015	1.161	387.557	2933.150	88.042	0.634
18.000	1013.061	1202.210	1.184	410.985	3547.619	90.523	0.766
19.000	991.010	1202.502	1.210	430.889	4227.015	93.239	0.913
20.000	973.789	1202.820	1.232	440.447	4737.893	95.427	1.023
21.000	963.588	1202.069	1.244	442.487	4995.515	96.642	1.079
22.000	959.512	1198.151	1.245	440.674	4999.997	96.759	1.080
23.000	954.491	1193.042	1.246	438.439	5000.000	96.878	1.080
24.000	949.018	1187.397	1.247	436.128	5000.000	97.000	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	943.619	1181.765	1.248	433.956	5000.000	97.116	1.080
26.000	938.516	1176.445	1.250	431.897	5000.000	97.226	1.080
27.000	933.866	1171.720	1.251	429.811	5000.000	97.341	1.080
28.000	929.795	1167.815	1.252	427.608	5000.000	97.467	1.080
29.000	926.367	1164.797	1.253	425.314	5000.000	97.602	1.080
30.000	923.577	1162.628	1.255	422.987	5000.000	97.744	1.080
31.000	921.517	1161.577	1.257	420.388	5000.000	97.908	1.080
32.000	920.635	1162.598	1.259	416.943	5000.000	98.135	1.080
33.000	923.181	1171.547	1.265	408.219	5000.000	98.747	1.080
34.000	932.261	1192.955	1.275	394.467	5000.000	99.786	1.080
35.000	968.429	1201.932	1.238	328.081	3604.354	95.961	0.779
36.000	1016.150	1202.006	1.180	297.454	2515.456	90.094	0.543
37.000	1051.719	1201.684	1.141	301.548	2010.107	85.896	0.434
38.000	1070.048	1201.643	1.121	322.672	1863.617	83.816	0.403
39.000	1064.826	1201.673	1.127	346.600	2087.852	84.417	0.451
40.000	1050.426	1201.847	1.142	367.697	2475.117	86.082	0.535
41.000	1033.446	1202.019	1.161	387.622	2939.378	88.077	0.635
42.000	1012.874	1202.211	1.184	411.124	3552.653	90.545	0.767
43.000	990.859	1202.506	1.210	431.026	4231.059	93.261	0.914
44.000	973.632	1202.829	1.232	440.538	4743.263	95.443	1.025
45.000	963.498	1202.027	1.244	442.370	4995.600	96.649	1.079
46.000	958.413	1197.522	1.246	439.356	4999.997	96.836	1.080
47.000	952.793	1191.817	1.247	436.836	5000.000	96.970	1.080
48.000	947.049	1185.799	1.248	434.570	5000.000	97.090	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	930.356	1174.517	1.258	417.990	5000.000	98.101	1.080
50.000	925.907	1169.207	1.259	417.285	5000.000	98.131	1.080
51.000	921.831	1164.333	1.259	416.650	5000.000	98.159	1.080
52.000	918.087	1159.890	1.259	416.014	5000.000	98.187	1.080
53.000	914.668	1155.892	1.260	415.337	5000.000	98.220	1.080
54.000	911.574	1152.347	1.260	414.605	5000.000	98.258	1.080
55.000	908.806	1149.260	1.260	413.817	5000.000	98.302	1.080
56.000	906.391	1146.699	1.261	412.921	5000.000	98.354	1.080
57.000	904.441	1144.914	1.262	411.751	5000.000	98.427	1.080
58.000	903.439	1145.021	1.263	409.556	5000.000	98.576	1.080
59.000	904.215	1148.711	1.266	405.438	5000.000	98.870	1.080
60.000	910.649	1165.139	1.275	393.687	5000.000	99.758	1.080
61.000	922.162	1189.036	1.285	381.882	5000.000	100.726	1.080
62.000	943.484	1203.019	1.271	349.948	4356.783	99.319	0.941
63.000	973.073	1202.131	1.232	337.517	3633.859	95.426	0.785
64.000	989.327	1202.000	1.212	348.766	3445.901	93.387	0.744
65.000	995.364	1202.055	1.205	365.403	3493.069	92.652	0.755
66.000	993.011	1202.140	1.208	384.173	3721.601	92.954	0.804
67.000	982.578	1202.262	1.220	404.398	4145.999	94.265	0.896
68.000	966.186	1202.439	1.241	421.981	4708.583	96.354	1.017
69.000	951.911	1198.943	1.256	423.327	4999.131	97.824	1.080
70.000	944.206	1191.092	1.257	420.100	5000.000	98.012	1.080
71.000	938.025	1184.101	1.258	418.526	5000.000	98.094	1.080
72.000	932.726	1177.839	1.259	417.593	5000.000	98.136	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	928.015	1172.155	1.259	416.942	5000.000	98.163	1.080
74.000	923.732	1166.954	1.259	416.402	5000.000	98.183	1.080
75.000	919.800	1162.187	1.259	415.890	5000.000	98.202	1.080
76.000	916.186	1157.848	1.260	415.351	5000.000	98.225	1.080
77.000	912.884	1153.950	1.260	414.754	5000.000	98.253	1.080
78.000	909.897	1150.502	1.260	414.088	5000.000	98.287	1.080
79.000	907.228	1147.506	1.261	413.357	5000.000	98.327	1.080
80.000	904.904	1145.029	1.261	412.514	5000.000	98.376	1.080
81.000	903.022	1143.284	1.262	411.421	5000.000	98.444	1.080
82.000	902.031	1143.324	1.263	409.351	5000.000	98.585	1.080
83.000	902.674	1146.532	1.266	405.701	5000.000	98.845	1.080
84.000	908.521	1161.719	1.274	394.569	5000.000	99.683	1.080
85.000	919.763	1185.277	1.284	382.637	5000.000	100.655	1.080
86.000	932.964	1205.752	1.288	372.054	4910.075	101.014	1.061
87.000	966.123	1202.299	1.241	340.891	3802.876	96.326	0.821
88.000	983.078	1202.029	1.219	349.762	3573.984	94.166	0.772
89.000	989.611	1202.067	1.212	365.730	3608.781	93.363	0.780
90.000	987.624	1202.143	1.214	384.259	3833.437	93.621	0.828
91.000	977.479	1202.254	1.227	404.333	4258.104	94.899	0.920
92.000	961.194	1202.438	1.247	421.952	4825.812	96.992	1.042
93.000	949.143	1197.232	1.257	420.475	4999.892	98.006	1.080
94.000	941.913	1189.195	1.258	418.432	5000.000	98.115	1.080
95.000	935.985	1182.216	1.259	417.350	5000.000	98.165	1.080
96.000	930.864	1176.014	1.259	416.679	5000.000	98.191	1.080

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	926.295	1170.406	1.259	416.192	5000.000	98.207	1.080
98.000	922.131	1165.284	1.260	415.768	5000.000	98.220	1.080
99.000	918.302	1160.595	1.260	415.344	5000.000	98.234	1.080
100.000	914.781	1156.331	1.260	414.875	5000.000	98.252	1.080
101.000	911.563	1152.505	1.260	414.334	5000.000	98.277	1.080
102.000	908.654	1149.126	1.261	413.717	5000.000	98.308	1.080
103.000	906.055	1146.196	1.261	413.028	5000.000	98.345	1.080
104.000	903.795	1143.775	1.261	412.224	5000.000	98.392	1.080
105.000	901.964	1142.065	1.262	411.181	5000.000	98.457	1.080
106.000	900.980	1142.048	1.263	409.213	5000.000	98.590	1.080
107.000	901.558	1145.026	1.266	405.782	5000.000	98.835	1.080
108.000	906.848	1158.910	1.274	395.449	5000.000	99.610	1.080
109.000	917.784	1182.062	1.283	383.422	5000.000	100.584	1.080
110.000	929.829	1203.367	1.290	376.596	5000.000	101.189	1.080
111.000	960.101	1202.314	1.248	343.890	3952.004	97.097	0.854
112.000	977.610	1202.058	1.226	350.830	3689.629	94.854	0.797
113.000	984.619	1202.079	1.218	366.091	3710.929	93.984	0.802
114.000	982.966	1202.148	1.220	384.386	3931.389	94.201	0.849
115.000	973.001	1202.259	1.232	404.455	4358.221	95.466	0.941
116.000	956.880	1202.425	1.253	421.962	4928.800	97.541	1.065
117.000	946.867	1195.648	1.259	418.372	4999.966	98.138	1.080
118.000	939.976	1187.529	1.259	417.128	5000.000	98.195	1.080
119.000	934.256	1180.584	1.259	416.405	5000.000	98.223	1.080
120.000	929.289	1174.451	1.260	415.936	5000.000	98.235	1.080

/*----------END OF FIFTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	924.838	1168.914	1.260	415.576	5000.000	98.243	1.080
122.000	920.775	1163.862	1.260	415.244	5000.000	98.250	1.080
123.000	917.036	1159.243	1.260	414.889	5000.000	98.260	1.080
124.000	913.594	1155.046	1.260	414.476	5000.000	98.275	1.080
125.000	910.449	1151.284	1.260	413.982	5000.000	98.297	1.080
126.000	907.606	1147.967	1.261	413.404	5000.000	98.325	1.080
127.000	905.070	1145.095	1.261	412.749	5000.000	98.360	1.080
128.000	902.867	1142.730	1.261	411.974	5000.000	98.405	1.080
129.000	901.086	1141.064	1.262	410.963	5000.000	98.468	1.080
130.000	900.121	1141.024	1.263	409.069	5000.000	98.597	1.080
131.000	900.681	1143.910	1.266	405.746	5000.000	98.834	1.080
132.000	905.592	1156.850	1.273	396.048	5000.000	99.561	1.080
133.000	916.263	1179.598	1.283	384.024	5000.000	100.530	1.080
134.000	928.205	1200.839	1.289	377.057	5000.000	101.144	1.080
135.000	955.912	1201.917	1.253	346.712	4062.331	97.598	0.878
136.000	973.393	1202.076	1.231	351.653	3779.710	95.387	0.816
137.000	980.766	1202.088	1.222	366.376	3790.423	94.466	0.819
138.000	979.353	1202.151	1.224	384.502	4008.066	94.654	0.866
139.000	969.534	1202.264	1.237	404.535	4436.077	95.908	0.958
140.000	954.008	1202.028	1.256	419.930	4965.528	97.872	1.073
141.000	945.161	1194.399	1.260	416.898	4999.987	98.231	1.080
142.000	938.505	1186.236	1.260	416.183	5000.000	98.254	1.080
143.000	932.936	1179.324	1.260	415.708	5000.000	98.265	1.080
144.000	928.083	1173.244	1.260	415.381	5000.000	98.268	1.080

/*----------END OF SIXTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	902.573	1146.206	1.266	406.001	5000.000	98.822	1.080
146.000	900.504	1143.202	1.265	406.476	5000.000	98.780	1.080
147.000	898.484	1140.360	1.265	406.807	5000.000	98.749	1.080
148.000	896.526	1137.667	1.265	407.033	5000.000	98.725	1.080
149.000	894.641	1135.123	1.265	407.177	5000.000	98.708	1.080
150.000	892.843	1132.737	1.264	407.251	5000.000	98.696	1.080
151.000	891.143	1130.519	1.264	407.265	5000.000	98.688	1.080
152.000	889.554	1128.480	1.264	407.223	5000.000	98.685	1.080
153.000	888.092	1126.644	1.264	407.123	5000.000	98.686	1.080
154.000	886.788	1125.074	1.264	406.927	5000.000	98.695	1.080
155.000	885.736	1123.968	1.265	406.519	5000.000	98.720	1.080
156.000	885.136	1123.744	1.265	405.654	5000.000	98.779	1.080
157.000	885.583	1125.665	1.267	403.583	5000.000	98.929	1.080
158.000	887.456	1130.039	1.269	400.638	5000.000	99.149	1.080
159.000	890.856	1137.171	1.272	396.627	5000.000	99.458	1.080
160.000	896.808	1148.813	1.276	391.093	5000.000	99.899	1.080
161.000	903.062	1158.914	1.279	388.474	5000.000	100.125	1.080
162.000	907.972	1165.091	1.279	388.876	5000.000	100.113	1.080
163.000	910.814	1166.815	1.277	391.669	5000.000	99.910	1.080
164.000	911.197	1164.125	1.273	396.176	5000.000	99.570	1.080
165.000	909.739	1159.421	1.270	400.221	5000.000	99.265	1.080
166.000	907.861	1155.350	1.268	402.611	5000.000	99.085	1.080
167.000	905.864	1151.717	1.267	404.149	5000.000	98.967	1.080
168.000	903.833	1148.392	1.266	405.173	5000.000	98.885	1.080

/*----------END OF SEVENTH DAY----------->

SUNSHINE SYSTEM; COMPRESSOR STATION # 3 ALTERNATE DESIGN REPORT

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	939.684	1184.298	1.256	421.586	5000.000	97.896	1.080
1.000	934.453	1178.420	1.257	420.188	5000.000	97.969	1.080
2.000	929.733	1172.990	1.258	419.126	5000.000	98.022	1.080
3.000	925.419	1167.986	1.258	418.215	5000.000	98.067	1.080
4.000	921.466	1163.415	1.259	417.354	5000.000	98.110	1.080
5.000	917.859	1159.293	1.259	416.491	5000.000	98.154	1.080
6.000	914.595	1155.629	1.259	415.602	5000.000	98.202	1.080
7.000	911.676	1152.434	1.260	414.676	5000.000	98.254	1.080
8.000	909.136	1149.800	1.261	413.642	5000.000	98.315	1.080
9.000	907.145	1148.129	1.261	412.210	5000.000	98.406	1.080
10.000	906.307	1148.730	1.263	409.580	5000.000	98.585	1.080
11.000	908.128	1155.322	1.268	403.152	5000.000	99.049	1.080
12.000	916.691	1175.847	1.278	389.830	5000.000	100.077	1.080
13.000	929.273	1201.017	1.288	378.606	5000.000	101.021	1.080
14.000	967.007	1202.224	1.240	330.624	3670.951	96.201	0.793
15.000	994.115	1201.940	1.206	330.627	3181.237	92.783	0.687
16.000	1008.168	1201.933	1.189	346.517	3077.217	91.073	0.665
17.000	1012.695	1202.028	1.184	364.601	3153.030	90.540	0.681
18.000	1009.335	1202.129	1.188	383.832	3387.609	90.959	0.732
19.000	998.272	1202.252	1.201	404.154	3804.231	92.318	0.822
20.000	981.380	1202.440	1.222	421.862	4355.585	94.434	0.941
21.000	962.372	1202.619	1.246	433.559	4933.580	96.860	1.066
22.000	951.478	1196.851	1.254	425.828	5000.000	97.663	1.080
23.000	944.436	1189.897	1.256	422.440	5000.000	97.858	1.080
24.000	938.537	1183.462	1.257	420.567	5000.000	97.960	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	933.368	1177.547	1.257	419.353	5000.000	98.021	1.080
26.000	928.705	1172.100	1.258	418.431	5000.000	98.065	1.080
27.000	924.442	1167.090	1.258	417.634	5000.000	98.102	1.080
28.000	920.533	1162.514	1.259	416.871	5000.000	98.139	1.080
29.000	916.963	1158.387	1.259	416.090	5000.000	98.178	1.080
30.000	913.731	1154.720	1.260	415.271	5000.000	98.221	1.080
31.000	910.836	1151.516	1.260	414.409	5000.000	98.269	1.080
32.000	908.307	1148.849	1.261	413.446	5000.000	98.325	1.080
33.000	906.261	1146.996	1.261	412.190	5000.000	98.404	1.080
34.000	905.232	1147.165	1.263	409.841	5000.000	98.563	1.080
35.000	906.145	1151.369	1.266	405.214	5000.000	98.893	1.080
36.000	913.391	1169.621	1.276	392.441	5000.000	99.864	1.080
37.000	925.338	1194.114	1.286	380.753	5000.000	100.830	1.080
38.000	955.246	1201.436	1.254	336.475	3944.781	97.616	0.852
39.000	982.361	1202.039	1.220	334.200	3427.725	94.250	0.740
40.000	997.645	1201.969	1.202	347.759	3281.333	92.359	0.709
41.000	1003.006	1202.043	1.196	365.068	3342.096	91.715	0.722
42.000	1000.215	1202.135	1.199	384.047	3573.355	92.069	0.772
43.000	989.479	1202.258	1.212	404.364	3995.300	93.404	0.863
44.000	972.848	1202.431	1.233	421.960	4554.073	95.502	0.984
45.000	956.017	1200.933	1.252	427.800	4989.961	97.500	1.078
46.000	947.372	1193.615	1.256	422.559	4999.993	97.861	1.080
47.000	940.818	1186.638	1.257	420.210	5000.000	97.992	1.080
48.000	935.266	1180.303	1.258	418.882	5000.000	98.060	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	908.576	1153.341	1.265	407.033	5000.000	98.772	1.080
50.000	905.949	1149.691	1.265	407.388	5000.000	98.737	1.080
51.000	903.451	1146.304	1.265	407.599	5000.000	98.712	1.080
52.000	901.075	1143.139	1.264	407.717	5000.000	98.695	1.080
53.000	898.822	1140.179	1.264	407.765	5000.000	98.683	1.080
54.000	896.698	1137.422	1.264	407.757	5000.000	98.675	1.080
55.000	894.707	1134.871	1.264	407.699	5000.000	98.671	1.080
56.000	892.857	1132.533	1.264	407.597	5000.000	98.671	1.080
57.000	891.160	1130.428	1.264	407.441	5000.000	98.676	1.080
58.000	889.654	1128.635	1.264	407.183	5000.000	98.688	1.080
59.000	888.445	1127.383	1.265	406.686	5000.000	98.718	1.080
60.000	887.829	1127.334	1.265	405.518	5000.000	98.799	1.080
61.000	888.499	1129.834	1.267	403.012	5000.000	98.981	1.080
62.000	890.742	1135.075	1.270	399.517	5000.000	99.244	1.080
63.000	896.200	1147.055	1.275	392.452	5000.000	99.793	1.080
64.000	903.798	1160.995	1.280	386.941	5000.000	100.248	1.080
65.000	910.749	1171.432	1.282	385.225	5000.000	100.410	1.080
66.000	915.917	1177.358	1.281	386.434	5000.000	100.335	1.080
67.000	918.806	1178.663	1.278	389.827	5000.000	100.082	1.080
68.000	919.181	1175.601	1.275	394.751	5000.000	99.708	1.080
69.000	917.227	1169.339	1.271	400.032	5000.000	99.308	1.080
70.000	914.386	1163.401	1.268	403.297	5000.000	99.061	1.080
71.000	911.611	1158.621	1.267	405.029	5000.000	98.926	1.080
72.000	908.964	1154.503	1.266	406.037	5000.000	98.844	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	906.435	1150.801	1.265	406.659	5000.000	98.790	1.080
74.000	904.011	1147.386	1.265	407.056	5000.000	98.753	1.080
75.000	901.686	1144.196	1.265	407.311	5000.000	98.726	1.080
76.000	899.461	1141.201	1.264	407.468	5000.000	98.706	1.080
77.000	897.340	1138.390	1.264	407.550	5000.000	98.692	1.080
78.000	895.332	1135.766	1.264	407.573	5000.000	98.683	1.080
79.000	893.446	1133.334	1.264	407.541	5000.000	98.678	1.080
80.000	891.690	1131.103	1.264	407.460	5000.000	98.676	1.080
81.000	890.077	1129.094	1.264	407.325	5000.000	98.680	1.080
82.000	888.641	1127.378	1.264	407.092	5000.000	98.690	1.080
83.000	887.487	1126.174	1.265	406.628	5000.000	98.719	1.080
84.000	886.868	1126.045	1.265	405.579	5000.000	98.791	1.080
85.000	887.465	1128.362	1.267	403.205	5000.000	98.963	1.080
86.000	889.535	1133.127	1.269	400.074	5000.000	99.198	1.080
87.000	894.218	1143.511	1.274	393.802	5000.000	99.683	1.080
88.000	901.396	1156.900	1.279	388.221	5000.000	100.138	1.080
89.000	908.164	1167.285	1.281	386.218	5000.000	100.322	1.080
90.000	913.270	1173.312	1.280	387.180	5000.000	100.266	1.080
91.000	916.166	1174.780	1.278	390.386	5000.000	100.030	1.080
92.000	916.529	1171.804	1.274	395.198	5000.000	99.664	1.080
93.000	914.681	1165.910	1.270	400.179	5000.000	99.288	1.080
94.000	912.164	1160.648	1.268	403.082	5000.000	99.068	1.080
95.000	909.662	1156.281	1.267	404.728	5000.000	98.940	1.080
96.000	907.229	1152.440	1.266	405.740	5000.000	98.858	1.080

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	904.874	1148.947	1.266	406.388	5000.000	98.803	1.080
98.000	902.595	1145.700	1.265	406.817	5000.000	98.764	1.080
99.000	900.394	1142.652	1.265	407.103	5000.000	98.735	1.080
100.000	898.278	1139.779	1.265	407.289	5000.000	98.714	1.080
101.000	896.253	1137.076	1.264	407.398	5000.000	98.698	1.080
102.000	894.330	1134.548	1.264	407.441	5000.000	98.688	1.080
103.000	892.519	1132.202	1.264	407.429	5000.000	98.682	1.080
104.000	890.830	1130.048	1.264	407.364	5000.000	98.680	1.080
105.000	889.277	1128.107	1.264	407.243	5000.000	98.682	1.080
106.000	887.893	1126.447	1.264	407.028	5000.000	98.692	1.080
107.000	886.777	1125.277	1.265	406.590	5000.000	98.719	1.080
108.000	886.159	1125.093	1.265	405.624	5000.000	98.785	1.080
109.000	886.684	1127.230	1.267	403.381	5000.000	98.947	1.080
110.000	888.665	1131.819	1.269	400.332	5000.000	99.176	1.080
111.000	892.755	1140.728	1.273	395.058	5000.000	99.583	1.080
112.000	899.447	1153.475	1.278	389.416	5000.000	100.038	1.080
113.000	906.016	1163.772	1.280	387.147	5000.000	100.240	1.080
114.000	911.048	1169.872	1.280	387.875	5000.000	100.203	1.080
115.000	913.914	1171.430	1.277	390.920	5000.000	99.979	1.080
116.000	914.296	1168.583	1.274	395.614	5000.000	99.625	1.080
117.000	912.565	1163.106	1.270	400.234	5000.000	99.276	1.080
118.000	910.322	1158.373	1.268	402.890	5000.000	99.074	1.080
119.000	908.039	1154.330	1.267	404.482	5000.000	98.951	1.080
120.000	905.780	1150.715	1.266	405.496	5000.000	98.870	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	903.567	1147.391	1.266	406.167	5000.000	98.814	1.080
122.000	901.408	1144.283	1.265	406.622	5000.000	98.773	1.080
123.000	899.311	1141.352	1.265	406.934	5000.000	98.743	1.080
124.000	897.284	1138.581	1.265	407.143	5000.000	98.720	1.080
125.000	895.339	1135.969	1.264	407.271	5000.000	98.704	1.080
126.000	893.487	1133.522	1.264	407.333	5000.000	98.692	1.080
127.000	891.739	1131.249	1.264	407.335	5000.000	98.685	1.080
128.000	890.107	1129.161	1.264	407.283	5000.000	98.683	1.080
129.000	888.606	1127.280	1.264	407.174	5000.000	98.685	1.080
130.000	887.267	1125.670	1.264	406.971	5000.000	98.694	1.080
131.000	886.187	1124.535	1.265	406.550	5000.000	98.719	1.080
132.000	885.581	1124.332	1.265	405.638	5000.000	98.782	1.080
133.000	886.062	1126.345	1.267	403.494	5000.000	98.937	1.080
134.000	887.982	1130.813	1.269	400.505	5000.000	99.161	1.080
135.000	891.548	1138.441	1.272	396.091	5000.000	99.501	1.080
136.000	897.923	1150.834	1.277	390.308	5000.000	99.963	1.080
137.000	904.345	1161.061	1.279	387.844	5000.000	100.179	1.080
138.000	909.321	1167.212	1.279	388.403	5000.000	100.155	1.080
139.000	912.163	1168.833	1.277	391.327	5000.000	99.940	1.080
140.000	912.550	1166.076	1.273	395.924	5000.000	99.595	1.080
141.000	910.968	1161.020	1.270	400.231	5000.000	99.270	1.080
142.000	908.931	1156.664	1.268	402.733	5000.000	99.080	1.080
143.000	906.810	1152.853	1.267	404.294	5000.000	98.960	1.080
144.000	904.680	1149.402	1.266	405.313	5000.000	98.879	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	857.874	1159.913	1.346	508.082	8000.000	106.627	1.728
146.000	857.235	1158.793	1.346	508.430	8000.000	106.598	1.728
147.000	856.532	1157.611	1.346	508.737	8000.000	106.573	1.728
148.000	855.797	1156.406	1.345	509.014	8000.000	106.549	1.728
149.000	855.051	1155.202	1.345	509.265	8000.000	106.527	1.728
150.000	854.308	1154.017	1.345	509.496	8000.000	106.507	1.728
151.000	853.580	1152.867	1.345	509.706	8000.000	106.489	1.728
152.000	852.877	1151.765	1.345	509.897	8000.000	106.471	1.728
153.000	852.206	1150.719	1.344	510.068	8000.000	106.456	1.728
154.000	851.573	1149.743	1.344	510.217	8000.000	106.442	1.728
155.000	850.991	1148.856	1.344	510.337	8000.000	106.431	1.728
156.000	850.481	1148.103	1.344	510.404	8000.000	106.423	1.728
157.000	850.096	1147.597	1.344	510.361	8000.000	106.424	1.728
158.000	849.954	1147.567	1.344	510.102	8000.000	106.442	1.728
159.000	850.164	1148.182	1.345	509.606	8000.000	106.479	1.728
160.000	850.865	1149.713	1.345	508.760	8000.000	106.543	1.728
161.000	852.179	1152.284	1.346	507.631	8000.000	106.631	1.728
162.000	853.881	1155.310	1.347	506.641	8000.000	106.711	1.728
163.000	855.618	1158.131	1.348	506.041	7999.999	106.763	1.728
164.000	857.064	1160.223	1.348	505.928	8000.000	106.779	1.728
165.000	857.976	1161.264	1.348	506.271	8000.000	106.758	1.728
166.000	858.336	1161.408	1.347	506.805	8000.000	106.721	1.728
167.000	858.292	1161.002	1.347	507.321	8000.000	106.683	1.728
168.000	857.975	1160.260	1.346	507.773	8000.000	106.649	1.728

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3C

SUNSHINE SYSTEM; COMPRESSOR STATION # 2 ALTERNATE DESIGN REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	916.025	1162.698	1.265	407.545	5000.000	98.765	1.080
1.000	912.736	1158.122	1.265	407.995	5000.000	98.720	1.080
2.000	909.682	1154.009	1.264	408.208	5000.000	98.694	1.080
3.000	906.822	1150.234	1.264	408.294	5000.000	98.677	1.080
4.000	904.136	1146.738	1.264	408.303	5000.000	98.665	1.080
5.000	901.615	1143.490	1.264	408.257	5000.000	98.659	1.080
6.000	899.257	1140.483	1.264	408.169	5000.000	98.656	1.080
7.000	897.062	1137.711	1.264	408.043	5000.000	98.656	1.080
8.000	895.034	1135.180	1.264	407.882	5000.000	98.660	1.080
9.000	893.185	1132.912	1.264	407.669	5000.000	98.668	1.080
10.000	891.562	1131.020	1.264	407.332	5000.000	98.685	1.080
11.000	890.301	1129.790	1.265	406.695	5000.000	98.725	1.080
12.000	889.861	1130.268	1.266	405.069	5000.000	98.839	1.080
13.000	890.923	1133.583	1.268	402.117	5000.000	99.055	1.080
14.000	894.455	1142.191	1.273	396.163	5000.000	99.507	1.080
15.000	902.445	1158.794	1.280	387.506	5000.000	100.199	1.080
16.000	911.206	1173.777	1.284	382.896	5000.000	100.598	1.080
17.000	918.609	1184.111	1.284	382.192	5000.000	100.684	1.080
18.000	923.939	1189.666	1.283	384.157	5000.000	100.548	1.080
19.000	926.878	1190.601	1.280	388.071	5000.000	100.252	1.080
20.000	927.204	1187.134	1.276	393.366	5000.000	99.845	1.080
21.000	925.136	1180.343	1.272	399.090	5000.000	99.409	1.080
22.000	921.443	1172.297	1.268	403.759	5000.000	99.055	1.080
23.000	917.770	1166.059	1.266	405.909	5000.000	98.887	1.080
24.000	914.426	1161.002	1.265	406.963	5000.000	98.800	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	911.338	1156.618	1.265	407.517	5000.000	98.749	1.080
26.000	908.448	1152.662	1.265	407.816	5000.000	98.716	1.080
27.000	905.726	1149.019	1.264	407.972	5000.000	98.695	1.080
28.000	903.156	1145.634	1.264	408.039	5000.000	98.680	1.080
29.000	900.732	1142.482	1.264	408.042	5000.000	98.671	1.080
30.000	898.456	1139.554	1.264	407.995	5000.000	98.665	1.080
31.000	896.331	1136.850	1.264	407.904	5000.000	98.663	1.080
32.000	894.360	1134.374	1.264	407.772	5000.000	98.665	1.080
33.000	892.556	1132.145	1.264	407.591	5000.000	98.671	1.080
34.000	890.956	1130.250	1.264	407.304	5000.000	98.685	1.080
35.000	889.675	1128.931	1.265	406.765	5000.000	98.718	1.080
36.000	889.056	1128.973	1.266	405.451	5000.000	98.809	1.080
37.000	889.826	1131.733	1.268	402.755	5000.000	99.005	1.080
38.000	892.362	1137.788	1.271	398.624	5000.000	99.316	1.080
39.000	898.976	1152.153	1.277	390.393	5000.000	99.961	1.080
40.000	907.104	1166.625	1.281	385.214	5000.000	100.397	1.080
41.000	914.253	1177.031	1.283	383.929	5000.000	100.527	1.080
42.000	919.487	1182.798	1.282	385.460	5000.000	100.427	1.080
43.000	922.391	1183.936	1.279	389.079	5000.000	100.155	1.080
44.000	922.741	1180.693	1.275	394.170	5000.000	99.768	1.080
45.000	920.687	1174.100	1.271	399.694	5000.000	99.347	1.080
46.000	917.452	1167.248	1.268	403.526	5000.000	99.056	1.080
47.000	914.294	1161.855	1.267	405.422	5000.000	98.908	1.080
48.000	911.347	1157.338	1.266	406.443	5000.000	98.825	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	860.960	1164.631	1.347	507.454	8000.000	106.687	1.728
50.000	860.048	1163.073	1.347	507.884	8000.000	106.652	1.728
51.000	859.093	1161.499	1.346	508.249	8000.000	106.621	1.728
52.000	858.129	1159.945	1.346	508.568	8000.000	106.593	1.728
53.000	857.177	1158.431	1.346	508.856	8000.000	106.567	1.728
54.000	856.252	1156.971	1.345	509.115	8000.000	106.544	1.728
55.000	855.362	1155.578	1.345	509.352	8000.000	106.523	1.728
56.000	854.514	1154.258	1.345	509.566	8000.000	106.503	1.728
57.000	853.714	1153.019	1.345	509.758	8000.000	106.485	1.728
58.000	852.967	1151.870	1.345	509.926	8000.000	106.470	1.728
59.000	852.283	1150.832	1.344	510.059	8000.000	106.457	1.728
60.000	851.689	1149.960	1.344	510.131	8000.000	106.449	1.728
61.000	851.256	1149.407	1.344	510.056	8000.000	106.452	1.728
62.000	851.116	1149.423	1.345	509.735	8000.000	106.474	1.728
63.000	851.432	1150.309	1.345	509.052	8000.000	106.525	1.728
64.000	852.490	1152.594	1.346	507.817	8000.000	106.619	1.728
65.000	854.245	1155.940	1.347	506.458	8000.000	106.726	1.728
66.000	856.321	1159.535	1.348	505.410	8000.000	106.813	1.728
67.000	858.327	1162.716	1.349	504.840	8000.000	106.864	1.728
68.000	859.953	1165.025	1.349	504.779	8000.000	106.877	1.728
69.000	860.966	1166.156	1.348	505.199	8000.000	106.851	1.728
70.000	861.293	1166.130	1.348	505.912	8000.000	106.801	1.728
71.000	861.095	1165.380	1.348	506.616	8000.000	106.749	1.728
72.000	860.572	1164.257	1.347	507.203	8000.000	106.703	1.728

/*----------END OF THIRD DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	859.860	1162.946	1.347	507.680	8000.000	106.665	1.728
74.000	859.045	1161.546	1.346	508.079	8000.000	106.633	1.728
75.000	858.180	1160.113	1.346	508.422	8000.000	106.604	1.728
76.000	857.298	1158.685	1.346	508.726	8000.000	106.577	1.728
77.000	856.420	1157.282	1.345	509.000	8000.000	106.553	1.728
78.000	855.561	1155.922	1.345	509.250	8000.000	106.531	1.728
79.000	854.729	1154.615	1.345	509.477	8000.000	106.511	1.728
80.000	853.933	1153.374	1.345	509.683	8000.000	106.492	1.728
81.000	853.179	1152.204	1.345	509.867	8000.000	106.475	1.728
82.000	852.473	1151.117	1.344	510.028	8000.000	106.460	1.728
83.000	851.826	1150.133	1.344	510.157	8000.000	106.448	1.728
84.000	851.261	1149.302	1.344	510.228	8000.000	106.440	1.728
85.000	850.844	1148.764	1.344	510.165	8000.000	106.442	1.728
86.000	850.704	1148.765	1.344	509.865	8000.000	106.463	1.728
87.000	850.967	1149.517	1.345	509.274	8000.000	106.507	1.728
88.000	851.899	1151.548	1.346	508.155	8000.000	106.592	1.728
89.000	853.515	1154.660	1.347	506.855	8000.000	106.694	1.728
90.000	855.478	1158.086	1.348	505.817	8000.000	106.779	1.728
91.000	857.407	1161.168	1.348	505.232	8000.000	106.831	1.728
92.000	858.977	1163.409	1.348	505.157	8000.000	106.844	1.728
93.000	859.962	1164.515	1.348	505.555	8000.000	106.820	1.728
94.000	860.296	1164.534	1.348	506.217	8000.000	106.774	1.728
95.000	860.146	1163.896	1.347	506.858	8000.000	106.726	1.728
96.000	859.694	1162.904	1.347	507.397	8000.000	106.685	1.728

/*----------END OF FOURTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	859.056	1161.718	1.346	507.843	8000.000	106.650	1.728
98.000	858.312	1160.431	1.346	508.221	8000.000	106.619	1.728
99.000	857.514	1159.102	1.346	508.549	8000.000	106.591	1.728
100.000	856.692	1157.764	1.346	508.842	8000.000	106.566	1.728
101.000	855.867	1156.442	1.345	509.107	8000.000	106.543	1.728
102.000	855.055	1155.153	1.345	509.348	8000.000	106.521	1.728
103.000	854.266	1153.911	1.345	509.569	8000.000	106.502	1.728
104.000	853.508	1152.725	1.345	509.769	8000.000	106.484	1.728
105.000	852.787	1151.606	1.345	509.948	8000.000	106.467	1.728
106.000	852.111	1150.563	1.344	510.105	8000.000	106.453	1.728
107.000	851.489	1149.618	1.344	510.230	8000.000	106.441	1.728
108.000	850.946	1148.817	1.344	510.300	8000.000	106.433	1.728
109.000	850.541	1148.288	1.344	510.246	8000.000	106.435	1.728
110.000	850.397	1148.272	1.344	509.965	8000.000	106.454	1.728
111.000	850.633	1148.957	1.345	509.419	8000.000	106.495	1.728
112.000	851.460	1150.764	1.346	508.418	8000.000	106.571	1.728
113.000	852.948	1153.650	1.347	507.184	8000.000	106.667	1.728
114.000	854.802	1156.913	1.347	506.163	8000.000	106.750	1.728
115.000	856.651	1159.885	1.348	505.573	8000.000	106.802	1.728
116.000	858.174	1162.072	1.348	505.479	7999.999	106.817	1.728
117.000	859.122	1163.137	1.348	505.860	8000.000	106.794	1.728
118.000	859.463	1163.203	1.347	506.471	8000.000	106.751	1.728
119.000	859.357	1162.661	1.347	507.058	8000.000	106.708	1.728
120.000	858.961	1161.775	1.347	507.558	8000.000	106.670	1.728

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	858.384	1160.692	1.346	507.979	8000.000	106.636	1.728
122.000	857.700	1159.500	1.346	508.339	8000.000	106.607	1.728
123.000	856.956	1158.255	1.346	508.656	8000.000	106.581	1.728
124.000	856.184	1156.993	1.346	508.939	8000.000	106.556	1.728
125.000	855.404	1155.738	1.345	509.197	8000.000	106.534	1.728
126.000	854.631	1154.508	1.345	509.431	8000.000	106.513	1.728
127.000	853.877	1153.319	1.345	509.646	8000.000	106.494	1.728
128.000	853.150	1152.180	1.345	509.841	8000.000	106.477	1.728
129.000	852.457	1151.103	1.344	510.016	8000.000	106.461	1.728
130.000	851.806	1150.098	1.344	510.168	8000.000	106.447	1.728
131.000	851.207	1149.186	1.344	510.290	8000.000	106.435	1.728
132.000	850.682	1148.412	1.344	510.359	8000.000	106.427	1.728
133.000	850.289	1147.897	1.344	510.311	8000.000	106.429	1.728
134.000	850.146	1147.873	1.344	510.042	8000.000	106.448	1.728
135.000	850.362	1148.505	1.345	509.535	8000.000	106.485	1.728
136.000	851.105	1150.134	1.345	508.626	8000.000	106.554	1.728
137.000	852.497	1152.853	1.346	507.440	8000.000	106.647	1.728
138.000	854.271	1155.995	1.347	506.430	8000.000	106.728	1.728
139.000	856.060	1158.885	1.348	505.835	8000.000	106.780	1.728
140.000	857.543	1161.024	1.348	505.730	8000.000	106.795	1.728
141.000	858.473	1162.078	1.348	506.091	8000.000	106.774	1.728
142.000	858.825	1162.188	1.347	506.659	8000.000	106.734	1.728
143.000	858.755	1161.723	1.347	507.207	8000.000	106.694	1.728
144.000	858.403	1160.919	1.347	507.679	8000.000	106.658	1.728

/*----------END OF SIXTH DAY----------->

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	851.189	1150.035	1.345	508.955	8000.000	106.530	1.728
146.000	851.112	1149.819	1.345	509.121	8000.000	106.518	1.728
147.000	851.019	1149.558	1.345	509.322	8000.000	106.503	1.728
148.000	850.915	1149.270	1.345	509.542	8000.000	106.487	1.728
149.000	850.807	1148.968	1.344	509.773	8000.000	106.470	1.728
150.000	850.696	1148.661	1.344	510.006	8000.000	106.453	1.728
151.000	850.585	1148.356	1.344	510.239	8000.000	106.436	1.728
152.000	850.477	1148.057	1.344	510.466	8000.000	106.419	1.728
153.000	850.373	1147.770	1.344	510.685	8000.000	106.403	1.728
154.000	850.273	1147.495	1.344	510.894	8000.000	106.387	1.728
155.000	850.179	1147.237	1.343	511.090	8000.000	106.373	1.728
156.000	850.093	1147.001	1.343	511.269	8000.000	106.360	1.728
157.000	850.019	1146.799	1.343	511.423	8000.000	106.348	1.728
158.000	849.965	1146.656	1.343	511.528	8000.000	106.341	1.728
159.000	849.949	1146.618	1.343	511.552	8000.000	106.339	1.728
160.000	849.986	1146.729	1.343	511.461	8000.000	106.346	1.728
161.000	850.099	1147.049	1.343	511.207	8000.000	106.364	1.728
162.000	850.292	1147.591	1.344	510.786	8000.000	106.395	1.728
163.000	850.535	1148.266	1.344	510.268	7999.999	106.433	1.728
164.000	850.782	1148.946	1.345	509.751	8000.000	106.471	1.728
165.000	850.985	1149.503	1.345	509.334	8000.000	106.502	1.728
166.000	851.116	1149.854	1.345	509.076	8000.000	106.522	1.728
167.000	851.172	1150.000	1.345	508.972	8000.000	106.529	1.728
168.000	851.169	1149.985	1.345	508.989	8000.000	106.528	1.728

/*----------END OF SEVENTH DAY----------

EXHIBIT 3C

SUNSHINE SYSTEM; COMPRESSOR STATION # 1 ALTERNATE DESIGN REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	864.295	1169.950	1.348	506.453	8000.000	106.776	1.728
1.000	863.226	1168.053	1.347	507.057	8000.000	106.727	1.728
2.000	862.078	1166.130	1.347	507.539	8000.000	106.687	1.728
3.000	860.912	1164.237	1.346	507.941	8000.000	106.652	1.728
4.000	859.763	1162.406	1.346	508.288	8000.000	106.621	1.728
5.000	858.649	1160.651	1.346	508.597	8000.000	106.593	1.728
6.000	857.584	1158.983	1.346	508.875	8000.000	106.568	1.728
7.000	856.571	1157.408	1.345	509.128	8000.000	106.545	1.728
8.000	855.617	1155.929	1.345	509.355	8000.000	106.524	1.728
9.000	854.723	1154.553	1.345	509.559	8000.000	106.505	1.728
10.000	853.895	1153.286	1.345	509.736	8000.000	106.488	1.728
11.000	853.145	1152.153	1.345	509.873	8000.000	106.474	1.728
12.000	852.507	1151.230	1.345	509.927	8000.000	106.467	1.728
13.000	852.078	1150.722	1.345	509.792	8000.000	106.475	1.728
14.000	852.007	1150.905	1.345	509.363	8000.000	106.505	1.728
15.000	852.619	1152.462	1.346	508.289	8000.000	106.586	1.728
16.000	854.187	1155.705	1.347	506.689	8000.000	106.709	1.728
17.000	856.420	1159.816	1.348	505.196	8000.000	106.829	1.728
18.000	858.860	1163.927	1.349	504.148	8000.000	106.918	1.728
19.000	861.121	1167.439	1.350	503.625	8000.000	106.967	1.728
20.000	862.903	1169.926	1.350	503.628	8000.000	106.976	1.728
21.000	864.011	1171.149	1.350	504.104	8000.000	106.946	1.728
22.000	864.353	1171.067	1.349	504.926	8000.000	106.888	1.728
23.000	864.037	1170.017	1.348	505.824	8000.000	106.821	1.728
24.000	863.316	1168.505	1.348	506.573	8000.000	106.763	1.728

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	862.379	1166.804	1.347	507.160	8000.000	106.716	1.728
26.000	861.342	1165.044	1.347	507.630	8000.000	106.676	1.728
27.000	860.270	1163.288	1.346	508.024	8000.000	106.643	1.728
28.000	859.200	1161.570	1.346	508.365	8000.000	106.613	1.728
29.000	858.153	1159.912	1.346	508.669	8000.000	106.586	1.728
30.000	857.143	1158.325	1.346	508.943	8000.000	106.561	1.728
31.000	856.177	1156.818	1.345	509.191	8000.000	106.538	1.728
32.000	855.263	1155.397	1.345	509.416	8000.000	106.518	1.728
33.000	854.403	1154.069	1.345	509.618	8000.000	106.499	1.728
34.000	853.602	1152.840	1.345	509.794	8000.000	106.482	1.728
35.000	852.872	1151.733	1.345	509.933	8000.000	106.469	1.728
36.000	852.239	1150.806	1.344	510.006	8000.000	106.460	1.728
37.000	851.784	1150.233	1.344	509.916	8000.000	106.465	1.728
38.000	851.647	1150.270	1.345	509.566	8000.000	106.489	1.728
39.000	852.044	1151.363	1.345	508.743	8000.000	106.550	1.728
40.000	853.296	1154.033	1.346	507.338	8000.000	106.658	1.728
41.000	855.246	1157.699	1.348	505.911	8000.000	106.771	1.728
42.000	857.471	1161.510	1.349	504.859	8000.000	106.859	1.728
43.000	859.582	1164.827	1.349	504.307	8000.000	106.910	1.728
44.000	861.274	1167.212	1.349	504.274	7999.999	106.920	1.728
45.000	862.315	1168.361	1.349	504.722	8000.000	106.893	1.728
46.000	862.641	1168.296	1.348	505.488	8000.000	106.838	1.728
47.000	862.385	1167.407	1.348	506.276	8000.000	106.780	1.728
48.000	861.771	1166.112	1.347	506.930	8000.000	106.729	1.728

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	851.690	1151.425	1.346	507.903	8000.000	106.609	1.728
50.000	851.573	1151.094	1.346	508.156	8000.000	106.590	1.728
51.000	851.439	1150.721	1.346	508.442	8000.000	106.569	1.728
52.000	851.298	1150.327	1.345	508.741	8000.000	106.546	1.728
53.000	851.155	1149.930	1.345	509.043	8000.000	106.524	1.728
54.000	851.014	1149.538	1.345	509.341	8000.000	106.502	1.728
55.000	850.876	1149.157	1.345	509.631	8000.000	106.480	1.728
56.000	850.744	1148.791	1.344	509.909	8000.000	106.460	1.728
57.000	850.617	1148.442	1.344	510.174	8000.000	106.440	1.728
58.000	850.498	1148.114	1.344	510.424	8000.000	106.422	1.728
59.000	850.387	1147.809	1.344	510.656	8000.000	106.405	1.728
60.000	850.286	1147.532	1.344	510.866	8000.000	106.389	1.728
61.000	850.200	1147.296	1.344	511.044	8000.000	106.376	1.728
62.000	850.140	1147.137	1.344	511.161	8000.000	106.368	1.728
63.000	850.126	1147.105	1.343	511.180	8000.000	106.366	1.728
64.000	850.185	1147.280	1.344	511.036	8000.000	106.377	1.728
65.000	850.348	1147.744	1.344	510.671	8000.000	106.404	1.728
66.000	850.601	1148.454	1.344	510.122	8000.000	106.444	1.728
67.000	850.898	1149.277	1.345	509.493	8000.000	106.491	1.728
68.000	851.184	1150.069	1.345	508.893	8000.000	106.535	1.728
69.000	851.416	1150.702	1.346	508.420	8000.000	106.570	1.728
70.000	851.559	1151.088	1.346	508.137	8000.000	106.591	1.728
71.000	851.609	1151.214	1.346	508.050	8000.000	106.598	1.728
72.000	851.585	1151.138	1.346	508.114	8000.000	106.593	1.728

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	851.512	1150.929	1.346	508.278	8000.000	106.581	1.728
74.000	851.409	1150.639	1.345	508.500	8000.000	106.564	1.728
75.000	851.289	1150.305	1.345	508.756	8000.000	106.545	1.728
76.000	851.162	1149.950	1.345	509.027	8000.000	106.525	1.728
77.000	851.031	1149.587	1.345	509.303	8000.000	106.505	1.728
78.000	850.901	1149.225	1.345	509.578	8000.000	106.484	1.728
79.000	850.773	1148.872	1.345	509.847	8000.000	106.464	1.728
80.000	850.649	1148.530	1.344	510.107	8000.000	106.445	1.728
81.000	850.531	1148.204	1.344	510.356	8000.000	106.427	1.728
82.000	850.418	1147.895	1.344	510.590	8000.000	106.410	1.728
83.000	850.313	1147.606	1.344	510.810	8000.000	106.394	1.728
84.000	850.218	1147.344	1.344	511.009	8000.000	106.379	1.728
85.000	850.136	1147.120	1.343	511.178	8000.000	106.366	1.728
86.000	850.078	1146.967	1.343	511.291	8000.000	106.358	1.728
87.000	850.063	1146.931	1.343	511.313	8000.000	106.356	1.728
88.000	850.113	1147.079	1.343	511.191	8000.000	106.365	1.728
89.000	850.258	1147.494	1.344	510.864	8000.000	106.389	1.728
90.000	850.492	1148.150	1.344	510.355	8000.000	106.427	1.728
91.000	850.772	1148.928	1.345	509.760	8000.000	106.471	1.728
92.000	851.047	1149.686	1.345	509.186	8000.000	106.513	1.728
93.000	851.271	1150.297	1.345	508.728	8000.000	106.547	1.728
94.000	851.410	1150.672	1.345	508.453	8000.000	106.568	1.728
95.000	851.461	1150.804	1.346	508.361	8000.000	106.574	1.728
96.000	851.444	1150.749	1.346	508.410	8000.000	106.571	1.728

/*----------END OF FOURTH DAY----------->

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	851.381	1150.567	1.345	508.552	8000.000	106.560	1.728
98.000	851.289	1150.307	1.345	508.752	8000.000	106.546	1.728
99.000	851.180	1150.003	1.345	508.985	8000.000	106.528	1.728
100.000	851.062	1149.675	1.345	509.235	8000.000	106.510	1.728
101.000	850.940	1149.337	1.345	509.493	8000.000	106.491	1.728
102.000	850.818	1148.997	1.345	509.751	8000.000	106.472	1.728
103.000	850.697	1148.663	1.344	510.005	8000.000	106.453	1.728
104.000	850.580	1148.339	1.344	510.252	8000.000	106.435	1.728
105.000	850.467	1148.028	1.344	510.489	8000.000	106.417	1.728
106.000	850.360	1147.734	1.344	510.713	8000.000	106.401	1.728
107.000	850.259	1147.457	1.344	510.923	8000.000	106.385	1.728
108.000	850.167	1147.205	1.344	511.114	8000.000	106.371	1.728
109.000	850.088	1146.990	1.343	511.277	8000.000	106.359	1.728
110.000	850.033	1146.840	1.343	511.388	8000.000	106.351	1.728
111.000	850.016	1146.803	1.343	511.412	8000.000	106.349	1.728
112.000	850.060	1146.932	1.343	511.305	8000.000	106.357	1.728
113.000	850.190	1147.305	1.344	511.010	8000.000	106.379	1.728
114.000	850.407	1147.913	1.344	510.538	8000.000	106.414	1.728
115.000	850.672	1148.648	1.344	509.975	8000.000	106.455	1.728
116.000	850.935	1149.374	1.345	509.424	7999.999	106.496	1.728
117.000	851.150	1149.961	1.345	508.985	8000.000	106.528	1.728
118.000	851.285	1150.325	1.345	508.717	8000.000	106.548	1.728
119.000	851.338	1150.462	1.345	508.621	8000.000	106.555	1.728
120.000	851.327	1150.423	1.345	508.657	8000.000	106.553	1.728

/*----------END OF FIFTH DAY----------*/

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	851.272	1150.264	1.345	508.781	8000.000	106.543	1.728
122.000	851.189	1150.030	1.345	508.962	8000.000	106.530	1.728
123.000	851.089	1149.750	1.345	509.176	8000.000	106.514	1.728
124.000	850.979	1149.445	1.345	509.410	8000.000	106.497	1.728
125.000	850.864	1149.127	1.345	509.652	8000.000	106.479	1.728
126.000	850.749	1148.806	1.344	509.896	8000.000	106.461	1.728
127.000	850.634	1148.489	1.344	510.138	8000.000	106.443	1.728
128.000	850.522	1148.179	1.344	510.373	8000.000	106.426	1.728
129.000	850.414	1147.881	1.344	510.600	8000.000	106.409	1.728
130.000	850.311	1147.598	1.344	510.816	8000.000	106.393	1.728
131.000	850.214	1147.332	1.344	511.018	8000.000	106.378	1.728
132.000	850.125	1147.090	1.343	511.202	8000.000	106.365	1.728
133.000	850.049	1146.882	1.343	511.359	8000.000	106.353	1.728
134.000	849.995	1146.736	1.343	511.467	8000.000	106.345	1.728
135.000	849.978	1146.698	1.343	511.491	8000.000	106.343	1.728
136.000	850.017	1146.813	1.343	511.397	8000.000	106.350	1.728
137.000	850.136	1147.154	1.344	511.127	8000.000	106.370	1.728
138.000	850.339	1147.725	1.344	510.683	8000.000	106.403	1.728
139.000	850.593	1148.428	1.344	510.144	8000.000	106.443	1.728
140.000	850.847	1149.130	1.345	509.611	8000.000	106.482	1.728
141.000	851.056	1149.701	1.345	509.183	8000.000	106.514	1.728
142.000	851.189	1150.058	1.345	508.920	8000.000	106.533	1.728
143.000	851.244	1150.200	1.345	508.820	8000.000	106.540	1.728
144.000	851.238	1150.175	1.345	508.844	8000.000	106.539	1.728

/*----------END OF SIXTH DAY----------*/

SUNSHINE PIPELINE SYSTEM (1200# MAOP) ALTERNATE DESIGN
ALL LOADS AT 100% OF 1999 MDO'S AT HARDEE, POWER PARK AND ANCLOTE

LOCATION FROM	LOCATION TO	NOMINAL OD	LENGTH	NOTES
Pascagoula	Gateway	26"	21 miles	
Gateway	Sta. #1	26"	62 miles	
Sta. #1	Okaloosa	26"	65 miles	
Main 30"	Monsanto	10"	16 miles	Pensacola lateral
Monsanto	Champion	4"	4 miles	" "
Monsanto	Gulf Power	10"	5 miles	" "
10"	Gulf Power	8"	3 miles	" "
Gulf Power	Pensacola	8"	4 miles	" "
30"	Milton	4"	10 miles	Milton lateral
Milton	Cyanamid	4"	3 miles	" "
Cyanamid	Air Products	4"	4 miles	" "
Okaloosa	Sta. #2	26"	10 miles	
Sta. #2	Sta. #3	26"	75 miles	
Sta. #3	Sta. #4	26"	75 miles	
Sta. #4	Sta. #5	26"	75 miles	
Sta. #5	Sta. #6	26"	75 miles	
Sta. #6	Anclote lat.	26"	20 miles	
Anclote lat.	Sta. #7	24"	40 miles	
30"	Hillsborough	20"	53 miles	Anclote lateral
Hillsborough	Anclote	20"	10 miles	" "
Sta. #7	Seminole	24"	17 miles	
Seminole	Power Park lat.	24"	10 miles	
24"	Power Park	16"	3 miles	Power Park lateral
Power Park lat.	Hardee lat.	24"	4 miles	
24"	Hardee	16"	11 miles	Hardee lateral

STATION	INSTALLED HP	SPECIFIC FUEL RATIO
Gateway	8000	9000 BTU/HP-HR
Sta. #1	8000	" " " "
Sta. #2	5000	" " " "
Sta. #3	5000	" " " "
Sta. #4	5000	" " " "
Sta. #5	5000	" " " "
Sta. #6	5000	" " " "
Sta. #7	None	" " " "
	41000	

Note: *System design allows for maximum of 10 psi suction and discharge piping pressure losses (total for station).*

Compressor suction temperature 70°F
Average pipeline flowing temperature 85°F
Compressor efficiencies:
Mechanical - 98%
Compression - 80%

SUNSHINE SYSTEM; GATEWAY COMPRESSOR STATION ALTERNATE DESIGN REPORT

EXHIBIT 3C

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	852.190	1152.824	1.347	506.840	8000.000	106.688	1.728
1.000	852.066	1152.470	1.347	507.113	8000.000	106.667	1.728
2.000	851.911	1152.034	1.346	507.446	8000.000	106.643	1.728
3.000	851.743	1151.562	1.346	507.805	8000.000	106.616	1.728
4.000	851.571	1151.081	1.346	508.171	8000.000	106.589	1.728
5.000	851.400	1150.607	1.345	508.531	8000.000	106.562	1.728
6.000	851.234	1150.147	1.345	508.880	8000.000	106.536	1.728
7.000	851.076	1149.707	1.345	509.215	8000.000	106.511	1.728
8.000	850.925	1149.289	1.345	509.531	8000.000	106.488	1.728
9.000	850.782	1148.897	1.345	509.830	8000.000	106.466	1.728
10.000	850.649	1148.530	1.344	510.108	8000.000	106.445	1.728
11.000	850.526	1148.191	1.344	510.365	8000.000	106.426	1.728
12.000	850.416	1147.887	1.344	510.596	8000.000	106.409	1.728
13.000	850.324	1147.637	1.344	510.784	8000.000	106.395	1.728
14.000	850.265	1147.482	1.344	510.897	8000.000	106.387	1.728
15.000	850.266	1147.495	1.344	510.879	8000.000	106.388	1.728
16.000	850.373	1147.807	1.344	510.627	8000.000	106.407	1.728
17.000	850.605	1148.464	1.344	510.114	8000.000	106.445	1.728
18.000	850.925	1149.359	1.345	509.425	8000.000	106.496	1.728
19.000	851.275	1150.331	1.345	508.685	8000.000	106.550	1.728
20.000	851.599	1151.229	1.346	508.008	8000.000	106.601	1.728
21.000	851.855	1151.931	1.346	507.484	8000.000	106.640	1.728
22.000	852.012	1152.355	1.346	507.173	8000.000	106.663	1.728
23.000	852.062	1152.479	1.347	507.090	8000.000	106.669	1.728
24.000	852.021	1152.354	1.346	507.194	8000.000	106.661	1.728

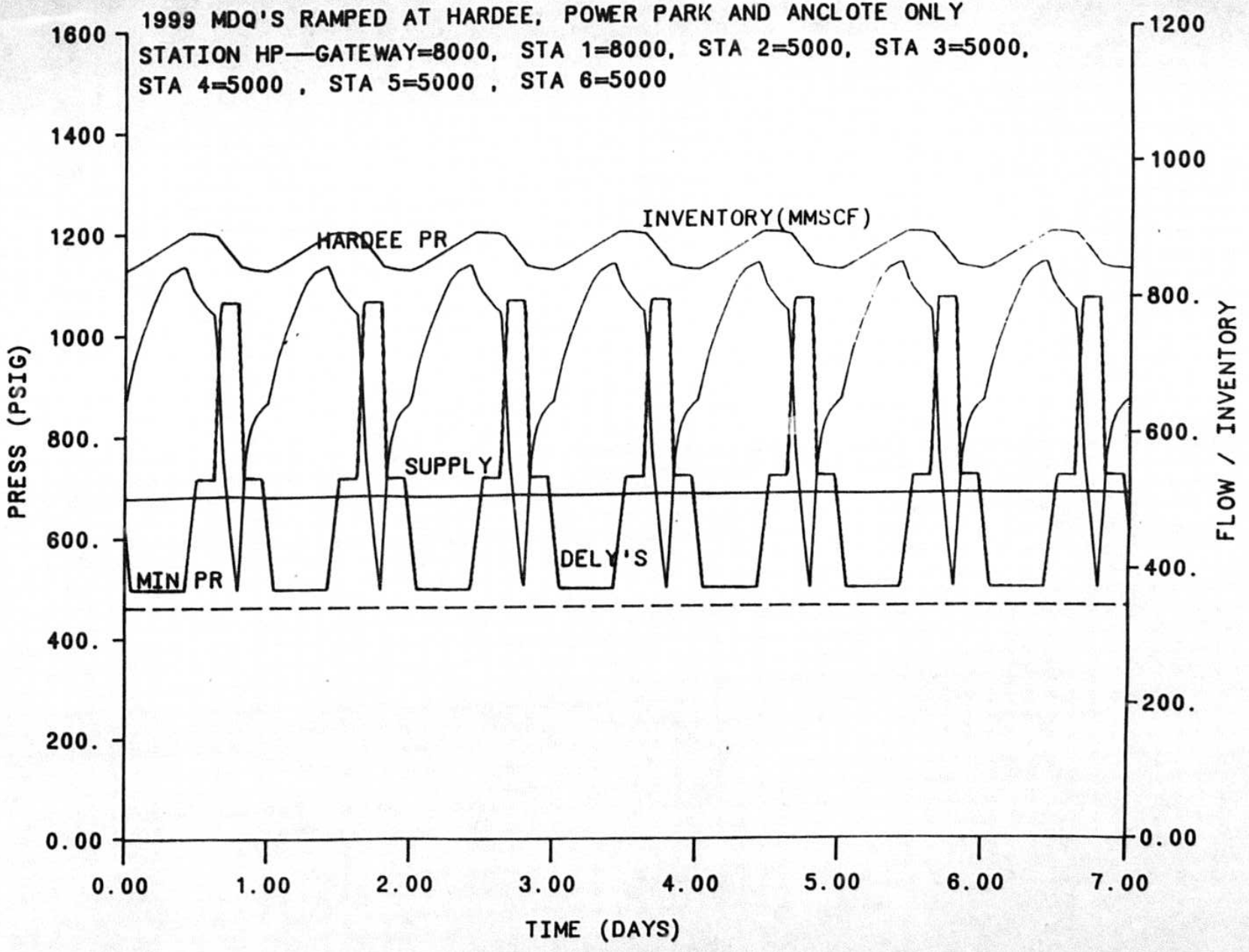
/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	851.920	1152.063	1.346	507.419	8000.000	106.645	1.728
26.000	851.784	1151.682	1.346	507.711	8000.000	106.623	1.728
27.000	851.632	1151.256	1.346	508.036	8000.000	106.599	1.728
28.000	851.474	1150.815	1.346	508.372	8000.000	106.574	1.728
29.000	851.315	1150.373	1.345	508.708	8000.000	106.549	1.728
30.000	851.160	1149.941	1.345	509.036	8000.000	106.524	1.728
31.000	851.009	1149.525	1.345	509.352	8000.000	106.501	1.728
32.000	850.866	1149.127	1.345	509.654	8000.000	106.479	1.728
33.000	850.729	1148.751	1.344	509.940	8000.000	106.458	1.728
34.000	850.601	1148.398	1.344	510.208	8000.000	106.438	1.728
35.000	850.482	1148.070	1.344	510.457	8000.000	106.419	1.728
36.000	850.374	1147.774	1.344	510.682	8000.000	106.403	1.728
37.000	850.283	1147.523	1.344	510.871	8000.000	106.389	1.728
38.000	850.220	1147.357	1.344	510.994	8000.000	106.380	1.728
39.000	850.207	1147.330	1.344	511.007	8000.000	106.379	1.728
40.000	850.281	1147.549	1.344	510.829	8000.000	106.392	1.728
41.000	850.470	1148.086	1.344	510.407	8000.000	106.423	1.728
42.000	850.750	1148.870	1.344	509.802	8000.000	106.468	1.728
43.000	851.069	1149.754	1.345	509.127	8000.000	106.518	1.728
44.000	851.371	1150.590	1.345	508.496	7999.999	106.564	1.728
45.000	851.611	1151.248	1.346	508.004	8000.000	106.601	1.728
46.000	851.760	1151.648	1.346	507.711	8000.000	106.623	1.728
47.000	851.808	1151.770	1.346	507.628	8000.000	106.629	1.728
48.000	851.776	1151.670	1.346	507.711	8000.000	106.623	1.728

/*----------END OF SECOND DAY----------->

FIGURE 4

FIG 4–SUNSHINE PIPELINE SYSTEM; ALT. 26 IN DESIGN(INCLUDES COMP'R FUEL)



TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	1006.025	1202.047	1.192	151.607	1333.755	91.277	0.288
98.000	1070.701	1200.210	1.119	131.272	746.278	83.574	0.161
99.000	1115.063	1200.192	1.075	131.788	477.344	78.706	0.103
100.000	1145.755	1200.068	1.050	131.589	301.513	75.529	0.065
101.000	1154.900	1200.008	1.050	131.848	310.867	75.701	0.067
102.000	1157.985	1200.010	1.050	131.829	315.419	75.792	0.068
103.000	1158.958	1200.012	1.050	131.830	317.409	75.830	0.069
104.000	1159.263	1200.012	1.050	131.829	317.898	75.840	0.069
105.000	1159.415	1200.012	1.050	131.827	318.027	75.842	0.069
106.000	1159.138	1199.992	1.050	133.817	324.705	75.877	0.070
107.000	1132.610	1200.443	1.059	216.426	636.526	77.106	0.137
108.000	1106.152	1200.795	1.084	239.775	971.587	79.752	0.210
109.000	1093.501	1200.829	1.097	239.678	1110.979	81.133	0.240
110.000	1085.260	1200.866	1.105	239.680	1203.417	82.044	0.260
111.000	1080.565	1200.881	1.110	239.740	1256.796	82.565	0.271
112.000	986.705	1196.612	1.210	427.040	4066.299	93.154	0.878
113.000	900.676	1119.690	1.239	446.623	4999.606	96.185	1.080
114.000	845.885	1042.708	1.229	462.234	5000.000	95.116	1.080
115.000	794.845	974.590	1.222	471.844	5000.000	94.437	1.080
116.000	776.253	968.276	1.243	433.237	5000.000	96.549	1.080
117.000	821.977	1068.569	1.295	364.718	5000.000	101.721	1.080
118.000	857.005	1146.109	1.332	329.715	5000.000	105.270	1.080
119.000	886.337	1200.391	1.349	292.527	4610.716	106.845	0.996
120.000	941.412	1201.363	1.272	237.573	2971.610	99.418	0.642

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	1005.955	1202.075	1.192	152.243	1344.017	91.293	0.290
122.000	1070.588	1200.216	1.119	131.201	746.490	83.587	0.161
123.000	1114.968	1200.192	1.075	131.787	477.931	78.717	0.103
124.000	1145.816	1200.067	1.050	131.567	302.460	75.545	0.065
125.000	1154.903	1200.008	1.050	131.847	310.902	75.701	0.067
126.000	1157.983	1200.010	1.050	131.829	315.432	75.792	0.068
127.000	1158.962	1200.012	1.050	131.829	317.392	75.830	0.069
128.000	1159.266	1200.012	1.050	131.828	317.898	75.840	0.069
129.000	1159.415	1200.012	1.050	131.827	318.025	75.842	0.069
130.000	1158.993	1199.984	1.050	134.671	327.533	75.891	0.071
131.000	1132.680	1200.424	1.059	215.662	639.494	77.174	0.138
132.000	1106.189	1200.794	1.084	239.745	971.041	79.748	0.210
133.000	1093.523	1200.829	1.097	239.676	1110.730	81.131	0.240
134.000	1085.278	1200.866	1.105	239.679	1203.218	82.042	0.260
135.000	1079.298	1200.773	1.111	244.996	1297.504	82.698	0.280
136.000	984.442	1197.719	1.214	430.095	4168.007	93.550	0.900
137.000	900.612	1119.880	1.240	446.137	5000.000	96.214	1.080
138.000	845.867	1042.776	1.229	462.037	5000.000	95.127	1.080
139.000	794.802	974.577	1.222	471.744	5000.000	94.442	1.080
140.000	776.205	968.336	1.243	433.042	5000.000	96.562	1.080
141.000	821.797	1068.262	1.295	364.817	5000.000	101.713	1.080
142.000	856.842	1145.842	1.332	329.763	5000.000	105.265	1.080
143.000	881.345	1204.027	1.360	307.420	5000.000	107.957	1.080
144.000	939.909	1201.655	1.274	240.664	3031.550	99.647	0.655

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	1005.821	1202.154	1.192	150.190	1317.512	91.306	0.285
146.000	1070.468	1200.192	1.120	131.497	749.183	83.597	0.162
147.000	1114.766	1200.192	1.076	131.792	479.070	78.737	0.103
148.000	1145.671	1200.076	1.050	131.629	298.740	75.480	0.065
149.000	1154.874	1200.007	1.050	131.846	310.767	75.699	0.067
150.000	1157.981	1200.010	1.050	131.830	315.391	75.792	0.068
151.000	1158.955	1200.012	1.050	131.830	317.430	75.831	0.069
152.000	1159.261	1200.012	1.050	131.830	317.900	75.840	0.069
153.000	1159.414	1200.012	1.050	131.827	318.027	75.842	0.069
154.000	1159.419	1200.009	1.050	132.156	319.199	75.850	0.069
155.000	1132.448	1200.498	1.059	218.034	629.100	76.950	0.136
156.000	1106.062	1200.797	1.085	239.838	972.866	79.762	0.210
157.000	1093.451	1200.828	1.097	239.681	1111.540	81.139	0.240
158.000	1085.222	1200.866	1.105	239.679	1203.847	82.048	0.260
159.000	1080.414	1200.876	1.110	240.280	1261.261	82.583	0.272
160.000	986.356	1196.917	1.210	429.089	4070.673	93.205	0.879
161.000	900.392	1119.497	1.239	446.330	5000.000	96.202	1.080
162.000	845.698	1042.501	1.229	462.171	5000.000	95.119	1.080
163.000	794.664	974.371	1.222	471.826	5000.000	94.438	1.080
164.000	776.098	968.177	1.243	433.089	5000.000	96.559	1.080
165.000	821.718	1068.131	1.295	364.851	5000.000	101.709	1.080
166.000	856.778	1145.731	1.332	329.786	5000.000	105.262	1.080
167.000	887.773	1198.730	1.345	287.550	4478.972	106.457	0.968
168.000	940.867	1201.405	1.273	237.231	2974.372	99.492	0.642

/*----------END OF SEVENTH DAY----------->

EXHIBIT 3B

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 7 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	942.082	1201.478	1.271	238.973	2979.574	99.342	0.644
1.000	1007.225	1202.114	1.191	150.584	1311.037	91.133	0.283
2.000	1072.051	1200.199	1.118	131.422	738.772	83.420	0.160
3.000	1116.538	1200.192	1.074	131.790	468.578	78.548	0.101
4.000	1146.490	1200.064	1.050	131.603	295.597	75.423	0.064
5.000	1155.093	1200.007	1.050	131.836	311.064	75.705	0.067
6.000	1158.047	1200.010	1.050	131.829	315.567	75.795	0.068
7.000	1158.972	1200.012	1.050	131.828	317.411	75.831	0.069
8.000	1159.269	1200.012	1.050	131.828	317.880	75.840	0.069
9.000	1159.418	1200.012	1.050	131.828	318.033	75.843	0.069
10.000	1159.346	1200.004	1.050	132.597	320.662	75.857	0.069
11.000	1132.549	1200.459	1.059	217.386	633.983	77.038	0.137
12.000	1106.102	1200.797	1.084	239.808	972.296	79.757	0.210
13.000	1093.474	1200.828	1.097	239.679	1111.270	81.136	0.240
14.000	1085.238	1200.866	1.105	239.680	1203.667	82.047	0.260
15.000	1080.558	1200.878	1.110	239.749	1256.894	82.566	0.272
16.000	986.675	1196.776	1.210	427.915	4064.078	93.163	0.878
17.000	900.579	1119.732	1.239	446.332	5000.000	96.202	1.080
18.000	845.858	1042.711	1.229	462.154	5000.000	95.120	1.080
19.000	794.825	974.578	1.222	471.813	5000.000	94.439	1.080
20.000	776.530	968.306	1.242	433.158	5000.000	96.529	1.080
21.000	822.005	1068.652	1.295	364.541	5000.000	101.730	1.080
22.000	857.035	1146.153	1.332	329.663	5000.000	105.273	1.080
23.000	881.588	1204.298	1.360	307.337	4998.059	107.952	1.080
24.000	940.530	1201.569	1.273	240.793	3025.539	99.560	0.654

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	1006.231	1202.096	1.192	150.958	1323.473	91.253	0.286
26.000	1071.029	1200.204	1.119	131.373	744.871	83.536	0.161
27.000	1115.503	1200.192	1.075	131.789	474.715	78.659	0.103
28.000	1145.933	1200.068	1.050	131.602	299.277	75.489	0.065
29.000	1154.949	1200.007	1.050	131.845	310.903	75.701	0.067
30.000	1158.005	1200.010	1.050	131.830	315.447	75.793	0.068
31.000	1158.953	1200.012	1.050	131.831	317.441	75.831	0.069
32.000	1159.262	1200.012	1.050	131.829	317.875	75.839	0.069
33.000	1159.415	1200.012	1.050	131.827	318.026	75.842	0.069
34.000	1159.269	1200.000	1.050	133.041	322.131	75.864	0.070
35.000	1132.574	1200.453	1.059	217.031	634.933	77.064	0.137
36.000	1106.122	1200.796	1.084	239.796	972.021	79.755	0.210
37.000	1093.485	1200.829	1.097	239.679	1111.158	81.135	0.240
38.000	1085.247	1200.866	1.105	239.679	1203.566	82.046	0.260
39.000	1080.558	1200.875	1.110	239.772	1256.989	82.566	0.272
40.000	986.678	1196.719	1.210	427.580	4065.419	93.161	0.878
41.000	900.614	1119.751	1.239	446.380	5000.000	96.200	1.080
42.000	845.880	1042.732	1.229	462.165	5000.000	95.120	1.080
43.000	794.845	974.602	1.222	471.817	5000.000	94.439	1.080
44.000	776.529	968.300	1.242	433.154	5000.000	96.529	1.080
45.000	822.061	1068.748	1.295	364.521	5000.000	101.733	1.080
46.000	857.071	1146.230	1.332	329.637	5000.000	105.276	1.080
47.000	881.924	1204.082	1.359	306.275	4971.255	107.880	1.074
48.000	940.467	1201.578	1.273	240.707	3025.356	99.569	0.654
49.000	1006.118	1202.086	1.192	151.066	1325.845	91.267	0.286

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
50.000	1070.838	1200.204	1.119	131.365	746.012	83.557	0.161
51.000	1115.253	1200.192	1.075	131.789	476.204	78.685	0.103
52.000	1145.793	1200.069	1.050	131.603	300.244	75.507	0.065
53.000	1154.916	1200.007	1.050	131.847	310.866	75.701	0.067
54.000	1157.993	1200.010	1.050	131.829	315.426	75.792	0.068
55.000	1158.954	1200.012	1.050	131.830	317.426	75.831	0.069
56.000	1159.262	1200.012	1.050	131.829	317.890	75.840	0.069
57.000	1159.415	1200.012	1.050	131.827	318.026	75.842	0.069
58.000	1159.252	1199.999	1.050	133.145	322.476	75.866	0.070
59.000	1132.575	1200.451	1.059	216.961	635.197	77.069	0.137
60.000	1106.125	1200.796	1.084	239.793	971.977	79.755	0.210
61.000	1093.486	1200.829	1.097	239.679	1111.146	81.135	0.240
62.000	1085.248	1200.866	1.105	239.680	1203.556	82.046	0.260
63.000	1080.558	1200.875	1.110	239.775	1257.005	82.566	0.272
64.000	986.659	1196.705	1.210	427.531	4066.341	93.163	0.878
65.000	900.614	1119.743	1.239	446.399	5000.000	96.199	1.080
66.000	845.877	1042.726	1.229	462.171	5000.000	95.120	1.080
67.000	794.842	974.597	1.222	471.818	5000.000	94.439	1.080
68.000	776.464	968.197	1.242	433.161	5000.000	96.527	1.080
69.000	822.125	1068.868	1.295	364.495	5000.000	101.737	1.080
70.000	857.116	1146.327	1.332	329.610	5000.000	105.279	1.080
71.000	882.838	1203.440	1.357	303.497	4899.399	107.679	1.058
72.000	940.506	1201.578	1.273	240.380	3020.649	99.563	0.652

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	1006.080	1202.064	1.192	151.322	1329.531	91.271	0.287
74.000	1070.738	1200.207	1.119	131.336	746.449	83.569	0.161
75.000	1115.123	1200.192	1.075	131.789	476.986	78.700	0.103
76.000	1145.765	1200.069	1.050	131.596	300.903	75.518	0.065
77.000	1154.905	1200.008	1.050	131.847	310.863	75.701	0.067
78.000	1157.988	1200.010	1.050	131.829	315.420	75.792	0.068
79.000	1158.956	1200.012	1.050	131.830	317.418	75.831	0.069
80.000	1159.262	1200.012	1.050	131.829	317.898	75.840	0.069
81.000	1159.415	1200.012	1.050	131.827	318.026	75.842	0.069
82.000	1159.198	1199.996	1.050	133.464	323.534	75.871	0.070
83.000	1132.591	1200.447	1.059	216.708	635.852	77.087	0.137
84.000	1106.137	1200.796	1.084	239.784	971.796	79.754	0.210
85.000	1093.493	1200.829	1.097	239.679	1111.071	81.134	0.240
86.000	1085.254	1200.866	1.105	239.679	1203.486	82.045	0.260
87.000	1080.560	1200.876	1.110	239.770	1256.968	82.566	0.272
88.000	986.669	1196.662	1.210	427.302	4066.756	93.160	0.878
89.000	900.642	1119.723	1.239	446.495	4999.853	96.193	1.080
90.000	845.881	1042.720	1.229	462.198	5000.000	95.118	1.080
91.000	794.844	974.596	1.222	471.828	5000.000	94.438	1.080
92.000	776.397	968.284	1.243	433.168	5000.000	96.539	1.080
93.000	822.058	1068.731	1.295	364.608	5000.000	101.729	1.080
94.000	857.066	1146.229	1.332	329.661	5000.000	105.275	1.080
95.000	884.662	1201.868	1.353	297.779	4749.116	107.246	1.026
96.000	941.408	1201.348	1.272	238.455	2982.932	99.418	0.644

/*----------END OF FOURTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
97.000	946.530	1131.174	1.192	551.125	5000.000	91.360	1.080
98.000	962.468	1164.801	1.207	514.904	5000.000	92.911	1.080
99.000	981.106	1198.954	1.219	490.554	5000.000	94.110	1.080
100.000	1030.506	1203.526	1.166	381.742	2965.139	88.534	0.641
101.000	1082.836	1202.462	1.109	335.501	1740.536	82.443	0.376
102.000	1127.225	1202.010	1.065	317.682	1000.988	77.594	0.216
103.000	1143.807	1201.600	1.050	310.555	749.299	75.829	0.162
104.000	1147.011	1201.496	1.050	308.381	741.018	75.809	0.160
105.000	1147.606	1201.489	1.050	307.513	742.453	75.838	0.160
106.000	1147.528	1201.486	1.050	307.372	743.776	75.851	0.161
107.000	1141.227	1201.626	1.052	339.493	873.525	76.224	0.189
108.000	1121.200	1202.073	1.071	401.037	1370.427	78.265	0.296
109.000	1097.847	1202.727	1.094	450.763	2031.641	80.850	0.439
110.000	1079.254	1203.279	1.113	479.439	2589.952	82.957	0.559
111.000	1066.872	1203.648	1.126	494.954	2974.783	84.381	0.643
112.000	1050.405	1203.588	1.144	539.400	3667.199	86.263	0.792
113.000	1013.927	1197.059	1.178	595.431	4983.936	89.889	1.077
114.000	996.978	1174.512	1.175	604.073	4999.991	89.617	1.080
115.000	982.781	1153.467	1.171	617.423	5000.000	89.158	1.080
116.000	967.156	1132.491	1.168	625.520	5000.000	88.871	1.080
117.000	953.862	1117.437	1.169	622.681	5000.000	88.924	1.080
118.000	945.625	1110.981	1.172	610.744	5000.000	89.273	1.080
119.000	940.652	1108.826	1.176	597.775	5000.000	89.678	1.080
120.000	939.963	1113.967	1.182	578.465	5000.000	90.333	1.080

/*----------END OF FIFTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
121.000	946.516	1131.202	1.192	551.008	5000.000	91.365	1.080
122.000	962.402	1164.716	1.207	514.924	5000.000	92.910	1.080
123.000	981.023	1198.864	1.219	490.532	5000.000	94.111	1.080
124.000	1030.206	1203.568	1.166	380.748	2962.742	88.572	0.640
125.000	1082.620	1202.464	1.109	335.475	1744.199	82.468	0.377
126.000	1126.707	1202.000	1.066	317.632	1008.174	77.648	0.218
127.000	1143.690	1201.603	1.050	310.533	750.835	75.841	0.162
128.000	1147.000	1201.494	1.050	308.370	740.795	75.808	0.160
129.000	1147.615	1201.489	1.050	307.513	742.352	75.837	0.160
130.000	1147.507	1201.486	1.050	307.457	744.212	75.853	0.161
131.000	1141.148	1201.627	1.052	339.600	874.643	76.229	0.189
132.000	1121.188	1202.073	1.071	401.002	1370.858	78.266	0.296
133.000	1097.874	1202.726	1.094	450.661	2030.807	80.847	0.439
134.000	1079.287	1203.278	1.113	479.377	2588.935	82.953	0.559
135.000	1066.892	1203.640	1.126	495.077	2974.574	84.381	0.643
136.000	1049.926	1203.603	1.144	540.701	3688.995	86.320	0.797
137.000	1013.662	1196.802	1.178	595.373	4985.041	89.894	1.077
138.000	996.858	1174.350	1.175	604.129	4999.991	89.615	1.080
139.000	982.822	1153.444	1.171	617.666	5000.000	89.151	1.080
140.000	967.140	1132.463	1.168	625.555	5000.000	88.870	1.080
141.000	953.814	1117.381	1.169	622.676	5000.000	88.924	1.080
142.000	945.543	1110.889	1.172	610.719	5000.000	89.273	1.080
143.000	940.527	1108.667	1.176	597.811	5000.000	89.676	1.080
144.000	939.783	1113.860	1.182	578.102	5000.000	90.345	1.080

/*----------END OF SIXTH DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
145.000	946.177	1130.699	1.192	551.220	5000.000	91.355	1.080
146.000	962.180	1164.523	1.207	514.697	5000.000	92.919	1.080
147.000	980.809	1198.642	1.219	490.422	5000.000	94.115	1.080
148.000	1030.004	1203.414	1.166	383.041	2984.364	88.583	0.645
149.000	1082.174	1202.463	1.110	335.680	1751.276	82.516	0.378
150.000	1127.127	1202.031	1.066	317.845	1002.867	77.605	0.217
151.000	1143.885	1201.599	1.050	310.576	748.266	75.821	0.162
152.000	1147.020	1201.497	1.050	308.392	741.164	75.810	0.160
153.000	1147.611	1201.489	1.050	307.514	742.424	75.838	0.160
154.000	1147.553	1201.487	1.050	307.216	743.138	75.849	0.161
155.000	1141.366	1201.634	1.052	339.352	869.054	76.195	0.188
156.000	1121.211	1202.073	1.071	401.165	1370.025	78.263	0.296
157.000	1097.780	1202.729	1.094	450.984	2033.686	80.857	0.439
158.000	1079.179	1203.282	1.113	479.572	2592.277	82.965	0.560
159.000	1066.842	1203.646	1.126	495.012	2975.442	84.387	0.643
160.000	1050.570	1203.578	1.144	539.272	3659.734	86.243	0.791
161.000	1013.778	1196.866	1.178	595.562	4984.710	89.887	1.077
162.000	996.879	1174.365	1.175	604.162	4999.991	89.614	1.080
163.000	982.826	1153.439	1.171	617.699	5000.000	89.150	1.080
164.000	967.138	1132.451	1.168	625.588	5000.000	88.869	1.080
165.000	953.804	1117.364	1.169	622.699	5000.000	88.923	1.080
166.000	945.524	1110.864	1.172	610.729	5000.000	89.273	1.080
167.000	940.520	1108.690	1.176	597.705	5000.000	89.680	1.080
168.000	939.801	1113.762	1.182	578.498	5000.000	90.332	1.080

/*----------END OF SEVENTH DAY----------*>

EXHIBIT 3B

(BASE * 125%)

SUNSHINE SYSTEM; COMPRESSOR STATION # 6 REPORT

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
0.000	940.688	1114.837	1.182	578.462	5000.000	90.335	1.080
1.000	947.458	1132.129	1.192	551.597	5000.000	91.344	1.080
2.000	963.699	1166.137	1.207	515.328	5000.000	92.895	1.080
3.000	982.535	1200.458	1.219	491.140	5000.000	94.085	1.080
4.000	1034.298	1203.317	1.161	379.579	2875.226	88.068	0.621
5.000	1086.517	1202.436	1.105	334.516	1677.030	82.032	0.362
6.000	1129.490	1201.951	1.063	317.018	966.483	77.350	0.209
7.000	1144.294	1201.583	1.050	310.373	742.607	75.781	0.160
8.000	1147.071	1201.497	1.050	308.343	741.345	75.813	0.160
9.000	1147.606	1201.489	1.050	307.493	742.565	75.839	0.160
10.000	1147.497	1201.488	1.050	307.254	743.236	75.849	0.161
11.000	1141.341	1201.629	1.052	339.324	870.668	76.207	0.188
12.000	1121.229	1202.072	1.071	401.073	1369.580	78.262	0.296
13.000	1097.817	1202.728	1.094	450.889	2032.559	80.853	0.439
14.000	1079.214	1203.281	1.113	479.516	2591.198	82.961	0.560
15.000	1066.860	1203.647	1.126	494.971	2974.877	84.384	0.643
16.000	1050.536	1203.581	1.144	539.217	3661.455	86.247	0.791
17.000	1013.861	1196.960	1.178	595.551	4984.452	89.887	1.077
18.000	996.930	1174.443	1.175	604.110	4999.991	89.616	1.080
19.000	982.731	1153.405	1.171	617.432	5000.000	89.158	1.080
20.000	967.129	1132.446	1.168	625.560	5000.000	88.869	1.080
21.000	953.858	1117.375	1.169	622.887	5000.000	88.918	1.080
22.000	945.756	1111.047	1.172	611.052	5000.000	89.263	1.080
23.000	940.905	1108.978	1.176	598.282	5000.000	89.662	1.080
24.000	940.384	1114.365	1.182	578.795	5000.000	90.322	1.080

/*----------END OF FIRST DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
25.000	946.934	1131.411	1.192	551.826	5000.000	91.334	1.080
26.000	963.012	1165.244	1.207	515.437	5000.000	92.889	1.080
27.000	981.751	1199.496	1.218	491.101	5000.000	94.085	1.080
28.000	1032.118	1203.439	1.164	381.693	2933.716	88.337	0.634
29.000	1084.451	1202.454	1.107	335.264	1713.499	82.263	0.370
30.000	1129.058	1202.011	1.064	317.588	974.825	77.399	0.211
31.000	1144.295	1201.587	1.050	310.518	743.218	75.783	0.161
32.000	1147.061	1201.498	1.050	308.384	741.458	75.813	0.160
33.000	1147.604	1201.489	1.050	307.510	742.561	75.839	0.160
34.000	1147.516	1201.487	1.050	307.299	743.424	75.850	0.161
35.000	1141.300	1201.628	1.052	339.382	871.761	76.214	0.188
36.000	1121.220	1202.073	1.071	401.055	1369.843	78.263	0.296
37.000	1097.829	1202.727	1.094	450.839	2032.176	80.852	0.439
38.000	1079.230	1203.280	1.113	479.487	2590.715	82.960	0.560
39.000	1066.866	1203.647	1.126	494.963	2974.777	84.383	0.643
40.000	1050.481	1203.584	1.144	539.297	3663.886	86.254	0.791
41.000	1013.881	1196.985	1.178	595.525	4984.265	89.887	1.077
42.000	996.943	1174.463	1.175	604.099	4999.991	89.616	1.080
43.000	982.743	1153.421	1.171	617.426	5000.000	89.158	1.080
44.000	967.136	1132.457	1.168	625.553	5000.000	88.869	1.080
45.000	953.841	1117.376	1.169	622.812	5000.000	88.920	1.080
46.000	945.687	1111.007	1.172	610.904	5000.000	89.268	1.080
47.000	940.778	1108.889	1.176	598.069	5000.000	89.668	1.080
48.000	940.209	1114.239	1.182	578.532	5000.000	90.331	1.080

/*----------END OF SECOND DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
49.000	946.704	1131.234	1.192	551.535	5000.000	91.344	1.080
50.000	962.719	1164.997	1.207	515.164	5000.000	92.900	1.080
51.000	981.405	1199.196	1.219	490.825	5000.000	94.097	1.080
52.000	1031.277	1203.474	1.165	382.177	2953.833	88.439	0.638
53.000	1083.585	1202.459	1.108	335.435	1728.097	82.359	0.373
54.000	1128.162	1202.013	1.065	317.668	987.710	77.494	0.213
55.000	1144.061	1201.593	1.050	310.545	746.138	75.805	0.161
56.000	1147.036	1201.497	1.050	308.389	741.297	75.811	0.160
57.000	1147.604	1201.489	1.050	307.513	742.516	75.839	0.160
58.000	1147.528	1201.487	1.050	307.309	743.469	75.850	0.161
59.000	1141.289	1201.628	1.052	339.403	872.039	76.215	0.188
60.000	1121.215	1202.073	1.071	401.059	1369.999	78.263	0.296
61.000	1097.830	1202.728	1.094	450.834	2032.160	80.852	0.439
62.000	1079.231	1203.280	1.113	479.482	2590.654	82.959	0.560
63.000	1066.866	1203.647	1.126	494.963	2974.809	84.383	0.643
64.000	1050.465	1203.584	1.144	539.325	3664.574	86.256	0.792
65.000	1013.884	1196.990	1.178	595.517	4984.207	89.887	1.077
66.000	996.945	1174.465	1.175	604.098	4999.991	89.616	1.080
67.000	982.745	1153.423	1.171	617.425	5000.000	89.158	1.080
68.000	967.134	1132.452	1.168	625.558	5000.000	88.869	1.080
69.000	953.832	1117.383	1.169	622.750	5000.000	88.922	1.080
70.000	945.648	1110.989	1.172	610.805	5000.000	89.271	1.080
71.000	940.708	1108.849	1.176	597.921	5000.000	89.673	1.080
72.000	940.122	1114.187	1.182	578.366	5000.000	90.337	1.080

/*----------END OF THIRD DAY----------->

TIME HRS	SUCT PSIG	DISC PSIG	CR NONE	FLOW MMSCFD	PWR HP	DISC T DEGF	FUEL MMSCFD
73.000	946.592	1131.175	1.192	551.325	5000.000	91.352	1.080
74.000	962.559	1164.867	1.207	515.008	5000.000	92.906	1.080
75.000	981.213	1199.036	1.219	490.661	5000.000	94.105	1.080
76.000	1030.786	1203.502	1.165	381.972	2961.559	88.499	0.640
77.000	1083.102	1202.461	1.109	335.483	1736.106	82.413	0.375
78.000	1127.593	1202.012	1.065	317.685	995.788	77.555	0.215
79.000	1143.897	1201.598	1.050	310.559	748.071	75.820	0.162
80.000	1147.020	1201.497	1.050	308.388	741.165	75.810	0.160
81.000	1147.605	1201.489	1.050	307.513	742.476	75.838	0.160
82.000	1147.529	1201.486	1.050	307.339	743.617	75.851	0.161
83.000	1141.260	1201.627	1.052	339.445	872.772	76.220	0.189
84.000	1121.208	1202.073	1.071	401.050	1370.204	78.264	0.296
85.000	1097.837	1202.727	1.094	450.800	2031.923	80.851	0.439
86.000	1079.242	1203.280	1.113	479.462	2590.335	82.958	0.560
87.000	1066.869	1203.647	1.126	494.959	2974.791	84.382	0.643
88.000	1050.432	1203.586	1.144	539.371	3666.033	86.260	0.792
89.000	1013.905	1197.020	1.178	595.480	4984.033	89.888	1.077
90.000	996.960	1174.486	1.175	604.087	4999.991	89.616	1.080
91.000	982.761	1153.442	1.171	617.424	5000.000	89.158	1.080
92.000	967.143	1132.469	1.168	625.541	5000.000	88.870	1.080
93.000	953.847	1117.413	1.169	622.704	5000.000	88.923	1.080
94.000	945.633	1110.984	1.172	610.761	5000.000	89.272	1.080
95.000	940.671	1108.834	1.176	597.830	5000.000	89.676	1.080
96.000	939.984	1113.992	1.182	578.458	5000.000	90.333	1.080

/*----------END OF FOURTH DAY----------->

EXPECTED RATES ANALYSIS

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25–YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$492,177,380
UNITED – 30 IN	$499,834,358
FGT – 30 IN	$495,771,864
ANR – 30 IN	$456,714,442

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES

United – 26 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Copressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.57	61.83	75.40	8.47	83.87	36,735,060
1997	254	14.11	61.83	75.94	9.21	85.15	37,294,771
1998	274	14.68	61.83	76.51	9.94	86.45	40,236,977
1999	294	15.27	61.83	77.09	10.68	87.77	55,268,551
2000	324	15.88	61.83	77.71	11.76	89.47	68,575,168
2001	341	16.51	61.83	78.34	12.36	90.70	69,518,034
2002	358	17.17	61.83	79.00	12.99	91.99	70,507,200
2003	375	17.86	61.83	79.69	13.62	93.30	71,516,616
2004	395	18.57	61.83	80.40	14.32	94.72	72,600,748
2005	415	19.32	61.83	81.15	15.05	96.20	73,733,612
2006	435	20.09	61.83	81.92	15.79	97.70	74,889,254
2007	455	20.89	61.83	82.72	16.52	99.24	76,0[illegible],587
2008	479	21.73	61.83	83.56	17.36	100.92	77,353,041
2009	502	22.60	61.83	84.43	18.20	102.63	78,663,118
2010	526	23.50	61.83	85.33	19.08	104.41	80,026,672
2011	551	24.44	61.83	86.27	19.99	106.26	81,444,768
2012	578	25.42	61.83	87.00	20.97	107.97	82,755,173
2013	605	26.44	61.83	87.00	21.95	108.95	83,506,343
2014	634	27.49	61.83	87.00	23.00	110.00	84,311,168
2015	659	28.59	61.83	87.00	23.91	110.91	85,016,194
2016	686	29.74	61.83	87.00	24.87	111.87	85,749,422
2017	713	30.93	61.83	87.00	25.87	112.87	86,511,979
2018	742	32.16	61.83	87.00	26.90	113.90	87,305,038
2019	771	33.45	61.83	87.00	27.98	114.98	88,129,820
2020	802	34.79	61.83	87.00	29.10	116.10	88,987,592
1/93NPV @ DISCOUNT RATE OF 8.99%							492,177,380

Note:
1. Transportation rate for 1996 is 75.4 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES

United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	14.31	65.19	79.50	7.50	87.00	38,106,876
1997	254	14.88	65.19	80.07	8.15	88.23	38,642,725
1998	274	15.48	65.19	80.67	8.80	89.47	41,644,601
1999	294	16.10	65.19	81.29	9.46	90.74	57,140,114
2000	324	16.74	65.19	81.93	10.42	92.35	70,783,727
2001	341	17.41	65.19	82.60	10.94	93.54	71,700,942
2002	358	18.11	65.19	83.30	11.50	94.80	72,662,449
2003	375	18.83	65.19	84.02	12.06	96.08	73,645,308
2004	395	19.58	65.19	84.77	12.68	97.45	74,697,896
2005	415	20.37	65.19	85.56	13.33	98.89	75,797,339
2006	435	21.18	65.19	86.37	13.98	100.35	76,920,801
2007	455	22.03	65.19	87.00	14.63	101.63	77,900,928
2008	479	22.91	65.19	87.00	15.38	102.38	78,471,204
2009	502	23.83	65.19	87.00	16.12	103.12	79,041,480
2010	526	24.78	65.19	87.00	16.90	103.90	79,635,518
2011	551	25.77	65.19	87.00	17.70	104.70	80,253,317
2012	578	26.80	65.19	87.00	18.57	105.57	80,918,639
2013	605	27.87	65.19	87.00	19.44	106.44	81,583,961
2014	634	28.99	65.19	87.00	20.37	107.37	82,296,806
2015	659	30.15	65.19	87.00	21.18	108.18	82,921,258
2016	686	31.35	65.19	87.00	22.03	109.03	83,570,688
2017	713	32.61	65.19	87.00	22.91	109.91	84,246,096
2018	742	33.91	65.19	87.00	23.83	110.83	84,948,519
2019	771	35.27	65.19	87.00	24.78	111.78	85,679,040
2020	802	36.68	65.19	87.00	25.77	112.77	86,438,782
1/93NPV @ DICOUNT RATE OF 8.99%							499,834,358

Note:

1. Transportation rate for 1996 is 79.5 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES

FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.86	63.14	77.00	9.68	86.68	37,965,840
1997	254	13.86	63.14	77.00	10.52	87.52	38,333,760
1998	274	13.86	63.14	77.00	11.36	88.36	41,127,162
1999	294	14.41	63.14	77.55	12.20	89.75	56,518,346
2000	324	14.99	63.14	78.13	13.44	91.57	70,189,153
2001	341	15.59	63.14	78.73	14.12	92.85	71,169,996
2002	358	16.21	63.14	79.35	14.84	94.19	72,199,885
2003	375	16.86	63.14	80.00	15.56	95.56	73,248,893
2004	395	17.54	63.14	80.68	16.36	97.04	74,379,107
2005	415	18.24	63.14	81.38	17.20	98.58	75,560,661
2006	435	18.97	63.14	82.00	18.04	100.04	76,680,660
2007	455	19.73	63.14	82.00	18.88	100.88	77,324,520
2008	479	20.52	63.14	82.00	19.84	101.84	78,060,360
2009	502	21.34	63.14	82.00	20.80	102.80	78,796,200
2010	526	22.19	63.14	82.00	21.80	103.80	79,562,700
2011	551	23.08	51.00	74.08	22.84	96.92	74,287,585
2012	578	24.00	51.00	75.00	23.96	98.96	75,853,634
2013	605	24.96	51.00	75.96	25.08	101.04	77,447,986
2014	634	25.96	51.00	76.96	26.28	103.24	79,133,092
2015	659	27.00	51.00	78.00	27.33	105.33	80,734,756
2016	686	28.08	51.00	79.08	28.42	107.50	82,400,486
2017	713	29.20	51.00	80.20	29.56	109.76	84,132,845
2018	742	30.37	51.00	81.37	30.74	112.11	85,934,499
2019	771	31.58	51.00	82.00	31.97	113.97	87,360,794
2020	802	32.85	51.00	82.00	33.25	115.25	88,341,105

1/93NPV @ DISCOUNT RATE OF 8.99%	494,149,832
UPFRONT METER COST(1/93)	1,622,032
TOTAL	495,771,864

Note:

1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 18% will be escalated at 4% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES

ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.46	61.34	74.80	4.60	79.40	34,776,324
1997	254	14.00	61.34	75.34	5.00	80.34	35,186,975
1998	274	14.56	61.34	75.90	5.40	81.29	37,838,601
1999	294	15.15	61.34	76.48	5.80	82.28	51,809,304
2000	324	15.75	61.34	77.09	6.38	83.47	63,980,503
2001	341	16.38	61.34	77.72	6.71	84.42	64,711,007
2002	358	17.04	61.34	78.37	7.05	85.42	65,475,392
2003	375	17.72	61.34	79.05	7.39	86.44	66,259,867
2004	395	18.43	61.34	79.76	7.77	87.53	67,094,362
2005	415	19.16	61.34	80.50	8.17	88.67	67,965,149
2006	435	19.93	61.34	81.27	8.57	89.84	68,858,534
2007	455	20.73	61.34	82.06	8.97	91.03	69,775,422
2008	479	21.56	61.34	82.89	9.42	92.32	70,760,442
2009	502	22.42	61.34	83.75	9.88	93.63	71,770,882
2010	526	23.32	61.34	84.65	10.36	95.01	72,822,323
2011	551	24.25	61.34	85.58	10.85	96.43	73,915,820
2012	578	25.22	61.34	86.55	11.38	97.93	75,067,039
2013	605	26.23	61.34	87.56	11.91	99.48	76,247,995
2014	634	27.28	61.34	88.61	12.48	101.09	77,489.006
2015	659	28.37	61.34	89.70	12.98	102.68	78,708.004
2016	686	29.50	61.34	90.84	13.50	104.34	79,975,763
2017	713	30.68	61.34	92.02	14.04	106.06	81,294,232
2018	742	31.91	61.34	93.24	14.60	107.85	82,665,439
2019	771	33.18	61.34	94.52	15.19	109.71	84,091,495
2020	802	34.51	61.34	95.00	15.79	110.79	84,924,350
1/93NPV @ DISCOUNT RATE OF 8.99% .							456,714,442

Note:

1. Transportation rate for 1996 is 74.8 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EXPECTED RATES ANALYSIS

HIGH ESCALATION RATE

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25-YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED - 26 IN	$500,331,452
UNITED - 30 IN	$504,155,328
FGT - 30 IN	$502,035,854
ANR - 30 IN	$456,714,442

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
HIGH ESCALATION RATE
United – 26 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	13.57	61.83	75.40	8.47	83.87	36,735,060
1997	254	14.39	61.83	76.21	9.21	85.42	37,413,662
1998	274	15.25	61.83	77.08	9.94	87.02	40,502,295
1999	294	16.16	61.83	77.99	10.68	88.67	55,833,905
2000	324	17.13	61.83	78.96	11.76	90.72	69,538,672
2001	341	18.16	61.83	79.99	12.36	92.35	70,782,747
2002	358	19.25	61.83	81.08	12.99	94.07	72,100,931
2003	375	20.41	61.83	82.24	13.62	95.85	73,469,232
2004	395	21.63	61.83	83.46	14.32	97.77	74,944,312
2005	415	22.93	61.83	84.76	15.05	99.81	76,502,532
2006	435	24.31	61.83	86.13	15.79	101.92	78,120,442
2007	455	25.76	61.83	87.00	16.52	103.52	79,348,080
2008	479	27.31	61.83	87.00	17.36	104.36	79,991,940
2009	502	28.95	61.83	87.00	18.20	105.20	80,635,800
2010	526	30.68	61.83	87.00	19.08	106.08	81,306,488
2011	551	32.53	61.83	87.00	19.99	106.99	82,004,003
2012	578	34.48	61.83	87.00	20.97	107.97	82,755,173
2013	605	36.55	61.83	87.00	21.95	108.95	83,506,343
2014	634	38.74	61.83	87.00	23.00	110.00	84,311,168
2015	659	41.06	61.83	87.00	23.91	110.91	85,016,194
2016	686	43.53	61.83	87.00	24.87	111.87	85,749,422
2017	713	46.14	61.83	87.00	25.87	112.87	86,511,979
2018	742	48.91	61.83	87.00	26.90	113.90	87,305,038
2019	771	51.84	61.83	87.00	27.98	114.98	88,129,820
2020	802	54.95	61.83	87.00	29.10	116.10	88,987,592

1/93NPV @ DISCOUNT RATE OF 8.99% 500,331,452

Note:
1. Transportation rate for 1996 is 75.4 C/MBTU, 18% will be escalated at 6%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
HIGH ESCALATION RATE
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	14.31	65.19	79.50	7.50	87.00	38,106,876
1997	254	15.17	65.19	80.36	8.15	88.51	38,768,081
1998	274	16.08	65.19	81.27	8.80	90.07	41,924,346
1999	294	17.04	65.19	82.23	9.46	91.69	57,736,210
2000	324	18.07	65.19	83.26	10.42	93.67	71,799,623
2001	341	19.15	65.19	84.34	10.94	95.28	73,034,426
2002	358	20.30	65.19	85.49	11.50	96.99	74,342,842
2003	375	21.52	65.19	86.71	12.06	98.77	75,704,100
2004	395	22.81	65.19	87.00	12.68	99.68	76,403,954
2005	415	24.18	65.19	87.00	13.33	100.33	76,902,945
2006	435	25.63	65.19	87.00	13.98	100.98	77,401,937
2007	455	27.16	65.19	87.00	14.63	101.63	77,900,928
2008	479	28.79	65.19	87.00	15.38	102.38	78,471,2[illegible]
2009	502	30.52	65.19	87.00	16.12	103.12	79,041,480
2010	526	32.35	65.19	87.00	16.90	103.90	79,635,518
2011	551	34.29	65.19	87.00	17.70	104.70	80,253,317
2012	578	36.35	65.19	87.00	18.57	105.57	80,918,639
2013	605	38.53	65.19	87.00	19.44	106.44	81,583,961
2014	634	40.85	65.19	87.00	20.37	107.37	82,296,806
2015	659	43.30	65.19	87.00	21.18	108.18	82,921,258
2016	686	45.89	65.19	87.00	22.03	109.03	83,570,688
2017	713	48.65	65.19	87.00	22.91	109.91	84,246,096
2018	742	51.57	65.19	87.00	23.83	110.83	84,948,519
2019	771	54.66	65.19	87.00	24.78	111.78	85,679,040
2020	802	57.94	65.19	87.00	25.77	112.77	86,438,782
1/93NPV @ DICOUNT RATE OF 8.99%							504,155,328

Note:
1. Transportation rate for 1996 is 79.5 C/MBTU, 18% will be escalated at 6%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
HIGH ESCALATION RATE
FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.86	63.14	77.00	9.68	86.68	37,965,840
1997	254	13.86	63.14	77.00	10.52	87.52	38,333,760
1998	274	13.86	63.14	77.00	11.36	88.36	41,127,162
1999	294	14.69	63.14	77.83	12.20	90.03	56,692,899
2000	324	15.57	63.14	78.71	13.44	92.15	70,635,348
2001	341	16.51	63.14	79.65	14.12	93.77	71,872,775
2002	358	17.50	63.14	80.64	14.84	95.48	73,183,834
2003	375	18.55	63.14	81.69	15.56	97.25	74,540,444
2004	395	19.66	63.14	82.00	16.36	98.36	75,392,940
2005	415	20.84	63.14	82.00	17.20	99.20	76,036,800
2006	435	22.09	63.14	82.00	18.04	100.04	76,680,660
2007	455	23.42	63.14	82.00	18.88	100.88	77,324,520
2008	479	24.82	63.14	82.00	19.84	101.84	78,060,360
2009	502	26.31	63.14	82.00	20.80	102.80	78,796,200
2010	526	27.89	63.14	82.00	21.80	103.80	79,562,700
2011	551	29.56	51.00	80.56	22.84	103.40	79,257,929
2012	578	31.34	51.00	82.00	23.96	105.96	81,218,340
2013	605	33.22	51.00	82.00	25.08	107.08	82,076,820
2014	634	35.21	51.00	82.00	26.28	108.28	82,996,620
2015	659	37.32	51.00	82.00	27.33	109.33	83,802,365
2016	686	39.56	51.00	82.00	28.42	110.42	84,640,339
2017	713	41.93	51.00	82.00	29.56	111.56	85,511,833
2018	742	44.45	51.00	82.00	30.74	112.74	86,418,186
2019	771	47.12	51.00	82.00	31.97	113.97	87,360,794
2020	802	49.95	51.00	82.00	33.25	115.25	88,341,105

1/93NPV @ DISCOUNT RATE OF 8.99%	500,413,823
UPFRONT METER COST(1/93)	1,622,032
TOTAL	502,035,854

Note:
1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 18% will be escalated at 6% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
HIGH ESCALATION RATE
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.46	61.34	74.80	4.60	79.40	34,776,324
1997	254	14.00	61.34	75.34	5.00	80.34	35,186,975
1998	274	14.56	61.34	75.90	5.40	81.29	37,838,601
1999	294	15.15	61.34	76.48	5.80	82.28	51,809,304
2000	324	15.75	61.34	77.09	6.38	83.47	63,980,503
2001	341	16.38	61.34	77.72	6.71	84.42	64,711,007
2002	358	17.04	61.34	78.37	7.05	85.42	65,475,392
2003	375	17.72	61.34	79.05	7.39	86.44	66,259,867
2004	395	18.43	61.34	79.76	7.77	87.53	67,094,362
2005	415	19.16	61.34	80.50	8.17	88.67	67,965,149
2006	435	19.93	61.34	81.27	8.57	89.84	68,858,534
2007	455	20.73	61.34	82.06	8.97	91.03	69,775,422
2008	479	21.56	61.34	82.89	9.42	92.32	70,760,442
2009	502	22.42	61.34	83.75	9.88	93.63	71,770,882
2010	526	23.32	61.34	84.65	10.36	95.01	72,822,323
2011	551	24.25	61.34	85.58	10.85	96.43	73,915,820
2012	578	25.22	61.34	86.55	11.38	97.93	75,067,039
2013	605	26.23	61.34	87.56	11.91	99.48	76,247,995
2014	634	27.28	61.34	88.61	12.48	101.09	77,489,006
2015	659	28.37	61.34	89.70	12.98	102.68	78,708,004
2016	686	29.50	61.34	90.84	13.50	104.34	79,975,763
2017	713	30.68	61.34	92.02	14.04	106.06	81,294,232
2018	742	31.91	61.34	93.24	14.60	107.85	82,665,439
2019	771	33.18	61.34	94.52	15.19	109.71	84,091,495
2020	802	34.51	61.34	95.00	15.79	110.79	84,924,350
							456,714,442

1/93NPV @ DISCOUNT RATE OF 8.99%

Note:
1. Transportation rate for 1996 is 74.8 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EXPECTED RATES ANALYSIS

LOW ESCALATION RATE

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25–YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$477,935,681
UNITED – 30 IN	$490,582,164
FGT – 30 IN	$483,457,235
ANR – 30 IN	$439,039,798

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW ESCALATION RATE
United – 26 inch

Year	Natural Gas Forecast C/MBTU	Transportation			Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
		Escalated C/MBTU	Fixed C/MBTU	Total C/MBTU			
1996	234	13.57	61.83	75.40	8.47	83.87	36,735,060
1997	254	13.84	61.83	75.67	9.21	84.88	37,175,881
1998	274	14.12	61.83	75.95	9.94	85.89	39,976,713
1999	294	14.40	61.83	76.23	10.68	86.91	54,724,529
2000	324	14.69	61.83	76.52	11.76	88.28	67,665,677
2001	341	14.98	61.83	76.81	12.36	89.17	68,346,954
2002	358	15.28	61.83	77.11	12.99	90.10	69,059,562
2003	375	15.59	61.83	77.42	13.62	91.03	69,776,765
2004	395	15.90	61.83	77.73	14.32	92.04	70,552,309
2005	415	16.22	61.83	78.05	15.05	93.10	71,359,461
2006	435	16.54	61.83	78.37	15.79	94.16	72,171,488
2007	455	16.88	61.83	78.70	16.52	95.22	72,988,48[illegible]
2008	479	17.21	61.83	79.04	17.36	96.40	73,891,0[illegible]
2009	502	17.56	61.83	79.38	18.20	97.58	74,798,772
2010	526	17.91	61.83	79.74	19.08	98.81	75,738,605
2011	551	18.27	61.83	80.09	19.99	100.08	76,710,649
2012	578	18.63	61.83	80.46	20.97	101.42	77,741,839
2013	605	19.00	61.83	80.83	21.95	102.78	78,778,629
2014	634	19.38	61.83	81.21	23.00	104.21	79,874,787
2015	659	19.77	61.83	81.60	23.91	105.51	80,876,973
2016	686	20.17	61.83	82.00	24.87	106.87	81,913,303
2017	713	20.57	61.83	82.40	25.87	108.26	82,985,024
2018	742	20.98	61.83	82.81	26.90	109.71	84,093,431
2019	771	21.40	61.83	83.23	27.98	111.21	85,239,867
2020	802	21.83	61.83	83.66	29.10	112.75	86,425,727

1/93NPV @ DISCOUNT RATE OF 8.99% 477,935,681

Note:
1. Transportation rate for 1996 is 75.4 C/MBTU, 18% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW ESCALATION RATE
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	14.31	65.19	79.50	7.50	87.00	38,106,876
1997	254	14.60	65.19	79.79	8.15	87.94	38,517,370
1998	274	14.89	65.19	80.08	8.80	88.88	41,370,185
1999	294	15.19	65.19	80.38	9.46	89.83	56,566,509
2000	324	15.49	65.19	80.68	10.42	91.10	69,824,781
2001	341	15.80	65.19	80.99	10.94	91.93	70,466,182
2002	358	16.12	65.19	81.31	11.50	92.81	71,136,094
2003	375	16.44	65.19	81.63	12.06	93.69	71,810,849
2004	395	16.77	65.19	81.96	12.68	94.64	72,538,069
2005	415	17.10	65.19	82.29	13.33	95.62	73,294,090
2006	435	17.44	65.19	82.63	13.98	96.61	74,055,252
2007	455	17.79	65.19	82.98	14.63	97.61	74,821,657
2008	479	18.15	65.19	83.34	15.38	98.71	75,664,695
2009	502	18.51	65.19	83.70	16.12	99.82	76,513,188
2010	526	18.88	65.19	84.07	16.90	100.97	77,391,007
2011	551	19.26	65.19	84.45	17.70	102.15	78,298,263
2012	578	19.64	65.19	84.83	18.57	103.40	79,258,831
2013	605	20.04	65.19	85.23	19.44	104.66	80,225,305
2014	634	20.44	65.19	85.63	20.37	106.00	81,245,324
2015	659	20.85	65.19	86.04	21.18	107.22	82,183,094
2016	686	21.26	65.19	86.45	22.03	108.48	83,152,108
2017	713	21.69	65.19	86.88	22.91	109.79	84,153,491
2018	742	22.12	65.19	87.00	23.83	110.83	84,948,519
2019	771	22.57	65.19	87.00	24.78	111.78	85,679,040
2020	802	23.02	65.19	87.00	25.77	112.77	86,438,782
1/93NPV @ DICOUNT RATE OF 8.99%							490,582,164

Note:
1. Transportation rate for 1996 is 79.5 C/MBTU, 18% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW ESCALATION RATE
FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Copressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.86	63.14	77.00	9.68	86.68	37,965,840
1997	254	13.86	63.14	77.00	10.52	87.52	38,333,760
1998	274	13.86	63.14	77.00	11.36	88.36	41,127,162
1999	294	14.14	63.14	77.28	12.20	89.48	56,343,793
2000	324	14.42	63.14	77.56	13.44	91.00	69,751,457
2001	341	14.71	63.14	77.85	14.12	91.97	70,493,735
2002	358	15.00	63.14	78.14	14.84	92.98	71,271,094
2003	375	15.30	63.14	78.44	15.56	94.00	72,052,962
2004	395	15.61	63.14	78.75	16.36	95.11	72,900,750
2005	415	15.92	63.14	79.06	17.20	96.26	73,783,890
2006	435	16.24	63.14	79.38	18.04	97.42	74,671,816
2007	455	16.56	63.14	79.70	18.88	98.58	75,564,623
2008	479	16.90	63.14	80.04	19.84	99.88	76,554,38
2009	502	17.23	63.14	80.37	20.80	101.17	77,549,233
2010	526	17.58	63.14	80.72	21.80	102.52	78,579,918
2011	551	17.93	51.00	68.93	22.84	91.77	70,341,236
2012	578	18.29	51.00	69.29	23.96	93.25	71,474,573
2013	605	18.65	51.00	69.65	25.08	94.73	72,613,408
2014	634	19.03	51.00	70.03	26.28	96.31	73,819,170
2015	659	19.41	51.00	70.41	27.33	97.74	74,916,596
2016	686	19.80	51.00	70.80	28.42	99.22	76,052,085
2017	713	20.19	51.00	71.19	29.56	100.75	77,227,043
2018	742	20.60	51.00	71.60	30.74	102.34	78,442,931
2019	771	21.01	51.00	72.01	31.97	103.98	79,701,263
2020	802	21.43	51.00	72.43	33.25	105.68	81,003,614

1/93NPV @ DISCOUNT RATE OF 8.99%	481,835,204
UPFRONT METER COST(1/93)	1,622,032
TOTAL	483,457,235

Note:
1. Transportation rate for 1996 – 1998 is 77.0 C/MBTU, 18% will be escalated at 2% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MBTU/day in 1996, 165,000 MBTU/day in 11/1998 and 210,000 MBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW ESCALATION RATE
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.46	61.34	74.80	4.60	79.40	34,776,324
1997	254	13.73	61.34	75.07	5.00	80.07	35,069,031
1998	274	14.01	61.34	75.34	5.40	80.74	37,580,408
1999	294	14.29	61.34	75.62	5.80	81.42	51,269,610
2000	324	14.57	61.34	75.91	6.38	82.29	63,078,249
2001	341	14.87	61.34	76.20	6.71	82.91	63,549,246
2002	358	15.16	61.34	76.50	7.05	83.55	64,039,274
2003	375	15.47	61.34	76.80	7.39	84.19	64,533,861
2004	395	15.78	61.34	77.11	7.77	84.88	65,062,223
2005	415	16.09	61.34	77.43	8.17	85.60	65,609,891
2006	435	16.41	61.34	77.75	8.57	86.32	66,162,395
2007	455	16.74	61.34	78.08	8.97	87.04	66,719,833
2008	479	17.08	61.34	78.41	9.42	87.84	67,325,993
2009	502	17.42	61.34	78.75	9.88	88.63	67,937,286
2010	526	17.77	61.34	79.10	10.36	89.46	68,568,378
2011	551	18.12	61.34	79.46	10.85	90.31	69,219,374
2012	578	18.48	61.34	79.82	11.38	91.20	69,904,943
2013	605	18.85	61.34	80.19	11.91	92.10	70,596,068
2014	634	19.23	61.34	80.57	12.48	93.05	71,321,988
2015	659	19.61	61.34	80.95	12.98	93.93	71,999,511
2016	686	20.01	61.34	81.34	13.50	94.84	72,698,239
2017	713	20.41	61.34	81.74	14.04	95.78	73,418,903
2018	742	20.82	61.34	82.15	14.60	96.75	74,162,259
2019	771	21.23	61.34	82.57	15.19	97.75	74,929,092
2020	802	21.66	61.34	82.99	15.79	98.79	75,720,217

1/93NPV @ DISCOUNT RATE OF 8.99% 439,039,798

Note:
1. Transportation rate for 1996 is 74.8 C/MBTU, 18% will be escalated at 2%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EXPECTED RATES ANALYSIS

LOW VOLUME CONSUMPTION

ECONOMIC EVALUATION OF GAS PIPELINE PROPOSALS
BASED ON 25–YEAR LIFE IN PRESENT VALUE

PROPOSAL	1/93 NPV
UNITED – 26 IN	$471,259,547
UNITED – 30 IN	$485,995,041
FGT – 30 IN	$477,914,680
ANR – 30 IN	$448,232,280

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW VOLUME CONSUMPTION
United – 26 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation cost $
1996	234	13.57	61.83	75.40	8.47	83.87	35,993,088
1997	254	14.11	61.83	75.94	9.21	85.15	36,488,413
1998	274	14.68	61.83	76.51	9.94	86.45	39,311,663
1999	294	15.27	61.83	77.09	10.68	87.77	53,553,878
2000	324	15.88	61.83	77.71	11.76	89.47	65,656,336
2001	341	16.51	61.83	78.34	12.36	90.70	66,593,837
2002	358	17.17	61.83	79.00	12.99	91.99	67,765,429
2003	375	17.86	61.83	79.69	13.62	93.30	68,656,805
2004	395	18.57	61.83	80.40	14.32	94.72	69,590,703
2005	415	19.32	61.83	81.15	15.05	96.20	70,546,505
2006	435	20.09	61.83	81.92	15.79	97.70	71,568,010
2007	455	20.89	61.83	82.72	16.52	99.24	72,634,667
2008	479	21.73	61.83	83.56	17.36	100.92	73,725,963
2009	502	22.60	61.83	84.43	18.20	102.63	74,842,882
2010	526	23.50	61.83	85.33	19.08	104.41	76,050,837
2011	551	24.44	61.83	86.27	19.99	106.26	77,286,506
2012	578	25.42	61.83	87.00	20.97	107.97	78,382,290
2013	605	26.44	61.83	87.00	21.95	108.95	78,940,302
2014	634	27.49	61.83	87.00	23.00	110.00	79,541,238
2015	659	28.59	61.83	87.00	23.91	110.91	80,142,174
2016	686	29.74	61.83	87.00	24.87	111.87	80,786,034
2017	713	30.93	61.83	87.00	25.87	112.87	81,350,055
2018	742	32.16	61.83	87.00	26.90	113.90	81,936,638
2019	771	33.45	61.83	87.00	27.98	114.98	82,546,683
2020	802	34.79	61.83	87.00	29.10	116.10	83,181,130
1/93NPV @ DISCOUNT RATE OF 8.99%							471,259,547

Note:
1. Tansportation rate for 1996 is 75.4 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW VOLUME CONSUMPTION
United – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Transportation Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	14.31	65.19	79.50	7.50	87.00	37,449,701
1997	254	14.88	65.19	80.07	8.15	88.23	37,928,522
1998	274	15.48	65.19	80.67	8.80	89.47	40,825,037
1999	294	16.10	65.19	81.29	9.46	90.74	55,949,351
2000	324	16.74	65.19	81.93	10.42	92.35	69,186,954
2001	341	17.41	65.19	82.60	10.94	93.54	70,023,380
2002	358	18.11	65.19	83.30	11.50	94.80	70,899,345
2003	375	18.83	65.19	84.02	12.06	96.08	71,796,663
2004	395	19.58	65.19	84.77	12.68	97.45	72,754,205
2005	415	20.37	65.19	85.56	13.33	98.89	73,753,850
2006	435	21.18	65.19	86.37	13.98	100.35	74,777,514
2007	455	22.03	65.19	87.00	14.63	101.63	75,657,842
2008	479	22.91	65.19	87.00	15.38	102.38	76,114,0€
2009	502	23.83	65.19	87.00	16.12	103.12	76,570,284
2010	526	24.78	65.19	87.00	16.90	103.90	77,045,514
2011	551	25.77	65.19	87.00	17.70	104.70	77,539,753
2012	578	26.80	65.19	87.00	18.57	105.57	78,072.011
2013	605	27.87	65.19	87.00	19.44	106.44	78,604.268
2014	634	28.99	65.19	87.00	20.37	107.37	79,174,544
2015	659	30.15	65.19	87.00	21.18	108.18	79,674,106
2016	686	31.35	65.19	87.00	22.03	109.03	80,193,650
2017	713	32.61	65.19	87.00	22.91	109.91	80,733,976
2018	742	33.91	65.19	87.00	23.83	110.83	81,295,915
2019	771	35.27	65.19	87.00	24.78	111.78	81,880,332
2020	802	36.68	65.19	87.00	25.77	112.77	82,488,125
							485,995,041

1/93NPV @ DICOUNT RATE OF 8.99%

Note:
1. Transportation rate for 1996 is 79.5 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW VOLUME CONSUMPTION
FGT – 30 inch

Year	Natural Gas Forecast C/MBTU	Transportation Escalated C/MBTU	Transportation Fixed C/MBTU	Total C/MBTU	Compressor Fuel Cost C/MBTU	Adjusted Total C/MBTU	Total Transportation Cost $
1996	234	13.86	63.14	77.00	9.68	86.68	37,117,872
1997	254	13.86	63.14	77.00	10.52	87.52	37,412,208
1998	274	13.86	63.14	77.00	11.36	88.36	40,069,660
1999	294	14.41	63.14	77.55	12.20	89.75	54,981,878
2000	324	14.99	63.14	78.13	13.44	91.57	68,128,801
2001	341	15.59	63.14	78.73	14.12	92.85	69,005,400
2002	358	16.21	63.14	79.35	14.84	94.19	69,924,913
2003	375	16.86	63.14	80.00	15.56	95.56	70,863,545
2004	395	17.54	63.14	80.68	16.36	97.04	71,871,119
2005	415	18.24	63.14	81.38	17.20	98.58	72,923,901
2006	435	18.97	63.14	82.00	18.04	100.04	73,915,128
2007	455	19.73	63.14	82.00	18.88	100.88	74,430,216
2008	479	20.52	63.14	82.00	19.84	101.84	75,018,888
2009	502	21.34	63.14	82.00	20.80	102.80	75,607,560
2010	526	22.19	63.14	82.00	21.80	103.80	76,220,760
2011	551	23.08	51.00	74.08	22.84	96.92	70,786,213
2012	578	24.00	51.00	75.00	23.96	98.96	72,180,566
2013	605	24.96	51.00	75.96	25.08	101.04	73,603,222
2014	634	25.96	51.00	76.96	26.28	103.24	75,104,368
2015	659	27.00	51.00	78.00	27.33	105.33	76,544,883
2016	686	28.08	51.00	79.08	28.42	107.50	78,043,018
2017	713	29.20	51.00	80.20	29.56	109.76	79,601,079
2018	742	30.37	51.00	81.37	30.74	112.11	81,221,462
2019	771	31.58	51.00	82.00	31.97	113.97	82,459,235
2020	802	32.85	51.00	82.00	33.25	115.25	83,243,484

1/93NPV @ DISCOUNT RATE OF 8.99%	476,292,649
UPFRONT METER COST(1/93)	1,622,032
TOTAL	477,914,680

Note:
1. Tranpsortation rate for 1996 – 1998 is 77.0 C/MBTU, 18% will be escalated at 4% beginning in 1999.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

EVALUATION OF GAS PIPELINE PROPOSAL BASED ON 'EXPECTED' RATES
LOW VOLUME CONSUMPTION
ANR – 30 inch

Year	Natural Gas Forecast C/MBTU	Fixed		Total Fixed C/MBTU	Incremental Variable C/MBTU	Adjusted Total C/MBTU	Total Demand $
		Escalated C/MBTU	Fixed C/MBTU				
1996	234	13.46	61.34	74.80	4.60	79.40	34,373,539
1997	254	14.00	61.34	75.34	5.00	80.34	34,749,238
1998	274	14.56	61.34	75.90	5.40	81.29	37,336,287
1999	294	15.15	61.34	76.48	5.80	82.28	51,079,481
2000	324	15.75	61.34	77.09	6.38	83.47	63,001,836
2001	341	16.38	61.34	77.72	6.71	84.42	63,682,824
2002	358	17.04	61.34	78.37	7.05	85.42	64,394,780
2003	375	17.72	61.34	79.05	7.39	86.44	65,126,826
2004	395	18.43	61.34	79.76	7.77	87.53	65,903,067
2005	415	19.16	61.34	80.50	8.17	88.67	66,712,688
2006	435	19.93	61.34	81.27	8.57	89.84	67,544,907
2007	455	20.73	61.34	82.06	8.97	91.03	68,400,628
2008	479	21.56	61.34	82.89	9.42	92.32	69,315,743
2009	502	22.42	61.34	83.75	9.88	93.63	70,256,278
2010	526	23.32	61.34	84.65	10.36	95.01	71,234,901
2011	551	24.25	61.34	85.58	10.85	96.43	72,252,669
2012	578	25.22	61.34	86.55	11.38	97.93	73,322,332
2013	605	26.23	61.34	87.56	11.91	99.48	74,421,733
2014	634	27.28	61.34	88.61	12.48	101.09	75,575,362
2015	659	28.37	61.34	89.70	12.98	102.68	76,717,815
2016	686	29.50	61.34	90.84	13.50	104.34	77,905,966
2017	713	30.68	61.34	92.02	14.04	106.06	79,141,642
2018	742	31.91	61.34	93.24	14.60	107.85	80,426,746
2019	771	33.18	61.34	94.52	15.19	109.71	81,763,255
2020	802	34.51	61.34	95.00	15.79	110.79	82,502,980
1/93NPV @ DISCOUNT RATE OF 8.99%.							448,232,280

Note:
1. Transportation rate for 1996 is 74.8 C/MBTU, 18% will be escalated at 4%.
2. Total transportation cost is calculated based on gas volume of 120,000 MMBTU/day in 1996, 165,000 MMBTU/day in 11/1998 and 210,000 MMBTU/day in 11/1999.

SOURCE: SYSTEM PLANNING

SUNSHINE
INCOME TAXES FOR COST OF SERVICE

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	RETURN ON RATE BASE	$46,560	$45,687	$44,995	$47,122	$45,826	$44,397	$43,015	$41,605	$40,103	$38,497	$36,774	$34,900	$32,965
2	LESS: INTEREST EXPENSE	31,573	30,901	30,512	31,954	31,072	30,106	29,169	28,213	27,195	26,106	24,927	23,667	22,286
3	PLUS: DEPR. OF EQUITY AFUDC	10	40	59	(57)	(15)	29	73	110	167	219	282	351	425
4	LESS: NORMALIZATION ADJ	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PRO F.T. - STORAGE LEASE PMT	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NET INCOME	$14,997	$14,746	$14,542	$15,111	$14,734	$14,319	$13,919	$13,510	$13,075	$12,611	$12,119	$11,585	$11,004
7	FEDERAL INCOME TAXES	8,020	8,476	8,359	8,686	8,469	8,231	8,000	7,766	7,516	7,249	6,966	6,659	6,325
8	STATE INCOME TAXES	431	424	418	434	423	412	400	388	376	362	348	333	316
9	TOTAL INCOME TAXES	$9,051	$8,900	$8,777	$9,120	$8,892	$8,642	$8,400	$8,154	$7,892	$7,611	$7,314	$6,992	$6,641
8	DEPR. OF EQUITY AFUDC	$10	$40	$59	($57)	($15)	$29	$73	$110	$167	$219	$282	$351	$425
9	FEDERAL INCOME TAXES	6	23	34	(33)	(9)	17	42	64	96	126	162	202	244
0	STATE INCOME TAXES	0	1	2	(2)	(0)	1	2	3	5	6	8	10	12
1	AFUDC RELATED INCOME TAXES	$6	$24	$36	($34)	($9)	$18	$44	$71	$101	$132	$170	$212	$257
2	INCOME RELATED INCOME TAXES	$9,045	$8,876	$8,741	$9,154	$8,901	$8,625	$8,356	$8,083	$7,791	$7,479	$7,144	$6,780	$6,385

EXHIBIT 6

SUNRIDE
DEFERRED INCOME TAXES

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	DEFERRED AMOUNT - BEG.	$344,726	$357,320	$338,052	$315,734	$290,680	$263,227	$233,194	$200,428	$164,751	$125,928	$83,699	$37,788
2	TAX DEPRECIATION 1/	$29,039	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	LESS:												
4	BOOK DEPRECIATION EXPENSE	16,953	19,861	23,004	25,825	28,297	30,957	33,174	36,775	40,017	43,528	47,323	51,430
5	NET OF TAX LESS BOOK DEPR.	$12,087	($19,861)	($23,004)	($25,825)	($28,297)	($30,957)	($33,174)	($36,775)	($40,017)	($43,528)	($47,323)	($51,430)
6	PLUS:												
7	DEPR. OF EQUITY AFUDC 2/	506	593	686	771	844	924	1,008	1,098	1,194	1,299	1,412	1,534
8	TOTAL	$12,593	($19,268)	($22,318)	($25,054)	($27,453)	($30,033)	($32,166)	($35,677)	($38,823)	($42,229)	($45,911)	($49,896)
9	DEFERRED AMOUNT - END	$357,320	$338,052	$315,734	$290,680	$263,227	$233,194	$200,428	$164,751	$125,928	$83,699	$37,788	($12,108)
10	DEFERRED AMOUNT	$357,320	$338,052	$315,734	$290,680	$263,227	$233,194	$200,428	$164,751	$125,928	$83,699	$37,788	($12,108)
11	ACCUM DEFERRED TAXES	$134,459	$127,209	$118,811	$109,383	$99,052	$87,751	$75,421	$61,996	$47,387	$31,436	$14,220	($4,556)
12	1/ TAX PLANT = GROSS PLANT	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700	$463,700
13	LESS: AFUDC	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568	13,568
14	TAX DEPRECIABLE PLANT	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132	$450,132
		8931	8931	8931	8931	8931	8931	8931	8931	8931	8931	8931	8931
		32714	32714	32714	32714	32714	32714	32714	32714	32714	32714	32714	32714
15	15 YEAR MACRS TAX DEPRECIATION	5.91%	5.91%	2.95%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	TAX DEPRECIATION	$29,039	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	2/ EQUITY AFUDC	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568	$13,568
18	BOOK DEPRECIATION RATE	3.65%	4.28%	4.96%	5.57%	6.10%	6.67%	7.28%	7.93%	8.62%	9.38%	10.20%	11.08%
	BOOK DEPRECIATION RATE AFUDC	3.729%	4.371%	5.056%	5.682%	6.221%	6.810%	7.429%	8.093%	8.800%	9.574%	10.407%	11.306%
19	DEPR. OF EQUITY AFUDC	$506	$593	$686	$771	$844	$924	$1,008	$1,098	$1,194	$1,299	$1,412	$1,534

EXHIBIT 6

SITCO
COST OF SERVICE

SCHEDULE 1
PAGE 1 OF 2

SE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$700	$700	$800	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
2	DEPRECIATION EXPENSE	(694)	(363)	(188)	(611)	(12)	587	1,178	1,786	2,443	3,152	3,984	4,882	5,854
3	INTEREST EXPENSE	12,569	12,373	12,187	12,267	11,926	11,585	11,250	10,904	10,531	10,128	9,682	9,217	8,698
4	OTHER TAXES	2,094	2,102	2,146	2,226	2,233	2,233	2,226	2,229	2,224	2,227	2,176	2,102	2,040
5	ROE	5,966	5,873	5,785	5,823	5,661	5,499	5,340	5,176	4,999	4,808	4,601	4,375	4,129
6	FED. & ST. INCOME TAXES	3,587	3,536	3,487	3,582	3,615	3,328	3,242	3,153	3,056	2,955	2,844	2,726	2,592
7	TOTAL COST OF SERVICE	$24,222	$24,221	$24,217	$24,286	$24,223	$24,233	$24,236	$24,249	$24,255	$24,271	$24,291	$24,300	$24,312
8	VOLUMES @ 100%	110,443	110,443	134,068	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
9	VOL. RATE @ 100 %	$0.2045	$0.2045	$0.1796	$0.1315	$0.1315	$0.1316	$0.1316	$0.1317	$0.1317	$0.1318	$0.1319	$0.1320	$0.1320

EXHIBIT 6

SUNSHINE
INCOME TAXES FOR COST OF SERVICE

SCHEDULE 4
PAGE 2 OF 2

LNE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	RETURN ON RATE BASE	$30,655	$28,256	$26,062	$25,246	$23,433	$21,446	$19,272	$16,900	$14,317	$11,507	$8,451	$5,127
2	LESS: INTEREST EXPENSE	20,788	19,161	18,215	17,120	15,890	14,543	13,068	11,460	9,709	7,803	5,731	3,477
3	PLUS: DEPR. OF EQUITY AFUDC	506	593	686	771	844	924	1,008	1,098	1,194	1,299	1,412	1,534
4	LESS: DECELERATION ADJ	0	0	0	0	0	0	0	0	0	0	0	0
5	FED I.T. - STORAGE LEASE PMT	0	0	0	0	0	0	0	0	0	0	0	0
6	NET INCOME	$10,373	$9,688	$9,332	$8,897	$8,387	$7,827	$7,211	$6,538	$5,803	$5,003	$4,132	$3,184
7	FEDERAL INCOME TAXES	5,963	5,569	5,364	5,114	4,821	4,499	4,145	3,758	3,335	2,876	2,375	1,830
8	STATE INCOME TAXES	298	278	268	256	241	225	207	188	167	144	119	92
9	TOTAL INCOME TAXES	$6,261	$5,847	$5,632	$5,370	$5,062	$4,724	$4,352	$3,946	$3,502	$3,020	$2,494	$1,922
8	DEPR. OF EQUITY AFUDC	$506	$593	$686	$771	$844	$924	$1,008	$1,098	$1,194	$1,299	$1,412	$1,534
9	FEDERAL INCOME TAXES	291	341	394	443	485	531	579	631	686	747	812	882
10	STATE INCOME TAXES	15	17	20	23	24	27	29	32	34	37	41	44
11	AFUDC RELATED INCOME TAXES	$305	$358	$414	$465	$509	$558	$608	$663	$721	$784	$852	$926
12	INCOME RELATED INCOME TAXES	$5,955	$5,489	$5,218	$4,905	$4,552	$4,166	$3,744					

EXHIBIT 6

SCHEDULE 2
PAGE 1 OF 2

SITCO
RATE BASE AND RETURN

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	GROSS PLANT	$167,500	$167,500	$170,600	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000
	PREV DEP'N	0												
2	LESS: ACC. DEPR.	0	(694)	(1,057)	(1,245)	(1,856)	(1,860)	(1,201)	(103)	1,683	4,126	7,278	11,262	15,144
3	NET PLANT	$167,500	$168,194	$171,657	$178,045	$178,656	$178,668	$178,081	$176,902	$175,117	$172,674	$169,522	$165,538	$160,656
4	PLUS: WORKING CAPITAL	$88	$88	$100	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
5														
6	LESS: AVG. DEFERRED TAXES	0	3,313	9,258	14,615	19,768	24,322	28,201	31,637	34,824	37,752	40,414	42,772	44,903
7	RATE BASE	$167,588	$164,969	$162,499	$163,555	$159,014	$154,472	$150,005	$145,391	$140,418	$135,046	$129,232	$122,890	$115,878
8	RATE OF RETURN	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%
9	RETURN ON RATE BASE	$18,535	$18,246	$17,972	$18,089	$17,587	$17,085	$16,591	$16,080	$15,530	$14,936	$14,293	$13,592	$12,817
10	PRETAX RATE OF RETURN	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
11	PRETAX RETURN	$21,706	$21,446	$21,125	$21,262	$20,672	$20,081	$19,501	$18,901	$18,254	$17,556	$16,800	$15,976	$15,077
12	INTEREST EXPENSE	12,569	12,373	12,187	12,267	11,926	11,585	11,250	10,904	10,531	10,128	9,692	9,217	8,698
13	DOE & RELATED INCOME TAXES	$9,217	$9,073	$8,937	$8,996	$8,746	$8,496	$8,250	$7,997	$7,723	$7,428	$7,108	$6,759	$6,379

EXHIBIT 6

SCHEDULE 1
PAGE 2 OF 2

SITCO
COST OF SERVICE

	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 YEAR AVG.
1	O&M/A&G EXPENSE	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$950
2	DEPRECIATION EXPENSE	6,903	8,040	9,269	10,301	11,302	12,317	13,399	14,560	15,826	17,102	18,656	20,253	$7,302
3	INTEREST EXPENSE	8,134	7,519	6,850	6,259	5,751	5,200	4,609	3,971	3,278	2,526	1,700	820	$7,990
4	OTHER TAXES	1,966	1,910	1,860	1,802	1,748	1,693	1,637	1,581	1,522	1,459	1,327	1,224	$1,922
5	ROE	3,861	3,569	3,252	2,971	2,730	2,468	2,188	1,885	1,556	1,199	811	389	$2,756
6	FED. & ST. INCOME TAXES	2,449	2,293	2,122	1,972	1,843	1,703	1,552	1,389	1,213	1,021	812	586	$2,415
7	TOTAL COST OF SERVICE	$24,312	$24,339	$24,354	$24,365	$24,372	$24,381	$24,385	$24,387	$24,391	$24,307	$24,364	$24,272	$24,382
8	VOLUMES @ 100%	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	176,916 ✓
9	VOL. RATE @ 100 %	$0.1320	$0.1322	$0.1323	$0.1323	$0.1324	$0.1324	$0.1324	$0.1324	$0.1325	$0.1324	$0.1323	$0.1318	$0.1378 ✓

EXHIBIT 6

SCHEDULE 3
PAGE 1 OF 2

SITCO
DEFERRED INCOME TAXES

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	DEFERRED AMOUNT - BEG.	$0	$8,804	$24,603	$38,839	$52,532	$64,633	$74,944	$84,073	$92,544	$100,325	$107,399	$113,667	$119,062
2	TAX DEPRECIATION 1/	$8,130	$15,447	$14,053	$13,099	$12,091	$10,881	$10,273	$10,206	$10,154	$10,125	$10,137	$10,137	$10,137
3	LESS:													
4	BOOK DEPRECIATION EXPENSE	(694)	(363)	(188)	(611)	(12)	587	1,178	1,786	2,443	3,152	3,984	4,862	5,824
5	NET OF TAX LESS BOOK DEPR.	$8,824	$15,810	$14,241	$13,710	$12,103	$10,294	$9,095	$8,420	$7,711	$6,983	$6,153	$5,255	$4,294
6	PLUS:													
7	DEPR. OF EQUITY AFUDC 2/	(20)	(11)	(5)	(17)	(1)	17	34	51	70	91	114	140	168
8	TOTAL	$8,804	$15,799	$14,236	$13,693	$12,102	$10,311	$9,129	$8,471	$7,781	$7,074	$6,267	$5,395	$4,462
9	DEFERRED AMOUNT - END	$8,804	$24,603	$38,839	$52,532	$64,633	$74,944	$84,073	$92,544	$100,325	$107,399	$113,667	$119,062	$123,514
10	DEFERRED AMOUNT	$8,804	$24,603	$38,839	$52,532	$64,633	$74,944	$84,073	$92,544	$100,325	$107,399	$113,667	$119,062	$123,514
11	ACCUM DEFERRED TAXES	$3,313	$9,258	$14,615	$19,768	$24,332	$28,201	$31,637	$34,824	$37,752	$40,414	$42,773	$44,832	$46,670
12	1/ TAX PLANT = GROSS PLANT	$167,500	$167,500	$167,500	$170,500	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000
13	LESS: AFUDC	4,901	4,901	4,901	8,001	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201
14	TAX DEPRECIABLE PLANT	$162,599	$162,599	$162,599	$162,599	$162,599	$161,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599
				3009	3009	3009	3009	3009	3009	3009	3009	3009	3009	3009
					6019	6019	6019	6019	6019	6019	6019	6019	6019	6019
15	15 YEAR MACRS TAX DEPRECIATION	5.000%	9.500%	8.550%	7.695%	6.926%	6.233%	5.905%	5.905%	5.905%	5.905%	5.905%	5.905%	5.905%
16	TAX DEPRECIATION	$8,130	$15,447	$14,053	$13,099	$12,091	$10,881	$10,273	$10,206	$10,154	$10,125	$10,137	$10,137	$10,137
17	2/ EQUITY AFUDC	$4,901	$4,901	$4,901	$8,001	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201
18	BOOK DEPRECIATION RATE	-0.41%	-0.22%	-0.11%	-0.35%	-0.01%	0.34%	0.68%	1.03%	1.41%	1.82%	2.29%	2.81%	3.37%
	BOOK DEPRECIATION RATE AFUD	-0.41%	-0.22%	-0.10%	-0.21%	-0.01%	0.12%	0.24%	0.36%	0.49%	0.64%	0.81%	0.99%	1.19%
19	DEPR. OF EQUITY AFUDC	($20)	($11)	($5)	($17)	($1)	$17	$34	$51	$70	$91	$114	$140	$168

EXHIBIT 6

SITCO
RATE BASE AND RETURN

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	GROSS PLANT PREV DEP'N	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000	$176,000
2	LESS: AVG. ACC. DEPR.	21,997	28,901	36,941	46,210	56,571	67,873	80,190	93,588	108,148	123,969	141,152	159,008
3	NET PLANT	$154,003	$147,099	$139,059	$130,590	$120,329	$108,927	$96,610	$83,212	$68,652	$52,031	$34,848	$16,992
4	PLUS: WORKING CAPITAL	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
5													
6	LESS: AVG. DEFERRED TAXES	46,478	47,770	48,646	47,265	43,680	39,717	35,282	30,385	25,064	19,282	13,001	6,183
7	RATE BASE	$108,449	$100,255	$91,338	$83,450	$76,674	$69,335	$61,453	$52,952	$43,713	$33,675	$22,772	$10,934
8	RATE OF RETURN	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%	11.06%
9	RETURN ON RATE BASE	$11,994	$11,088	$10,102	$9,230	$8,480	$7,668	$6,797	$5,856	$4,835	$3,724	$2,519	$1,209
10	PRETAX RATE OF RETURN	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
11	PRETAX RETURN	$14,098	$13,033	$11,874	$10,848	$9,960	$9,014	$7,989	$6,884	$5,683	$4,378	$2,960	$1,421
12	INTEREST EXPENSE	8,134	7,519	6,850	6,259	5,751	5,200	4,609	3,971	3,278	2,526	1,708	820
13	DOE & DELAYED INCOME TAXES	$5,965	$5,514	$5,024	$4,590	$4,217	$3,813	$3,380	$2,912	$2,404	$1,852	$1,252	$601

EXHIBIT 6

SITCO
INCOME TAXES FOR COST OF SERVICE

SCHEDULE 4
PAGE 1 OF 2

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	RETURN ON RATE BASE	$10,535	$10,246	$17,972	$10,009	$17,587	$17,085	$16,591	$16,080	$15,530	$14,9[illegible]	$14,293	$13,592	$12,827
2	LESS: INTEREST EXPENSE	12,569	12,373	12,187	12,267	11,926	11,585	11,250	10,904	10,531	10,128	9,692	9,217	8,698
3	PLUS: DEPR. OF EQUITY AFUDC	(20)	(11)	(5)	(17)	(1)	17	34	51	70	91	114	140	168
4	LESS: NORMALIZATION ADJ	0	0	0	0	0	0	0	0	0	0	0	0	0
5	FED I.T. - STORAGE LEASE PUT	0	0	0	0	0	0	0	0	0	0	0	0	0
6	NET INCOME	$5,946	$5,862	$5,780	$5,806	$5,660	$5,516	$5,374	$5,227	$5,069	$4,859	$4,715	$4,515	$4,297
7	FEDERAL INCOME TAXES	3,063	3,020	2,978	2,991	2,916	2,842	2,769	2,693	2,611	2,524	2,429	2,326	2,214
8	STATE INCOME TAXES	524	517	509	512	499	486	474	461	447	432	415	398	379
9	TOTAL INCOME TAXES	$3,587	$3,536	$3,487	$3,502	$3,415	$3,328	$3,242	$3,153	$3,058	$2,955	$2,844	$2,724	$2,593
8	DEPR. OF EQUITY AFUDC	($20)	($11)	($5)	($17)	($1)	$17	$34	$51	$70	$91	$114	$140	$168
9	FEDERAL INCOME TAXES	(10)	(6)	(3)	(9)	(0)	9	18	26	36	47	59	72	87
10	STATE INCOME TAXES	(2)	(1)	(0)	(1)	(0)	1	3	4	6	8	10	12	15
11	AFUDC RELATED INCOME TAXES	($13)	($7)	($3)	($10)	($1)	$10	$21	$31	$42	$55	$69	$84	$101
12	INCOME RELATED INCOME TAXES	$3,599	$3,543	$3,490	$3,513	$3,415	$3,318	$3,222	$3,123	$3,016	$2,900	$2,775	$2,639	$2,491

EXHIBIT 6

SCHEDULE 3
PAGE 2 OF 2

SITCO
DEFERRED INCOME TAXES

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	DEFERRED AMOUNT - BEG.	$123,514	$126,946	$129,273	$125,604	$116,077	$105,546	$93,761	$80,747	$66,605	$51,240	$34,551	$16,431
2	TAX DEPRECIATION 1/	$10,137	$10,137	$5,334	$536	$446	$178	$0	$0	$0	$0	$0	$0
3	LESS:												
4	BOOK DEPRECIATION EXPENSE	6,903	8,040	9,269	10,361	11,302	12,317	13,399	14,560	15,020	16,103	18,[illegible]	20,253
5	NET OF TAX LESS BOOK DEPR.	$3,234	$2,097	($3,935)	($9,825)	($10,856)	($12,139)	($13,399)	($14,560)	($15,020)	($16,103)	($18,[illegible])	($20,253)
6	PLUS:												
7	DEPR. OF EQUITY AFUDC 2/	198	231	266	298	325	354	385	418	455	494	536	582
8	TOTAL	$3,432	$2,328	($3,669)	($9,527)	($10,531)	($11,785)	($13,014)	($14,142)	($15,365)	($15,609)	($18,120)	($19,671)
9	DEFERRED AMOUNT - END	$126,946	$129,273	$125,604	$116,077	$105,546	$93,761	$80,747	$66,605	$51,240	$34,551	$16,431	($3,240)
10	DEFERRED AMOUNT	$126,946	$129,273	$125,604	$116,077	$105,546	$93,761	$80,747	$66,605	$51,240	$34,551	$16,431	($3,240)
11	ACCUM DEFERRED TAXES	$47,770	$48,646	$47,265	$43,680	$39,717	$35,282	$30,385	$25,064	$19,282	$13,001	$6,183	($1,219)
12	1/ TAX PLANT = GROSS PLANT	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800	$176,800
13	LESS: AFUDC	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201	14,201
14	TAX DEPRECIABLE PLANT	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599	$162,599
		3009	3009	3009	3009	3009	3009	3009	3009	3009	3009	3009	3009
		6019	6019	6019	6019	6019	6019	6019	6019	6019	6019	6019	6019
15	15 YEAR MACRS TAX DEPRECIATION	5.905%	5.905%	3.051%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
16	TAX DEPRECIATION	$10,137	$10,137	$5,334	$536	$446	$178	$0	$0	$0	$0	$0	$0
17	2/ EQUITY AFUDC	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201	$14,201
18	BOOK DEPRECIATION RATE	3.90%	4.63%	5.34%	5.97%	6.51%	7.09%	7.72%	8.39%	9.11%	9.90%	10.75%	11.66%
	BOOK DEPRECIATION RATE AFUD	1.39%	1.63%	1.87%	2.10%	2.29%	2.49%	2.71%	2.94%	3.20%	3.48%	3.77%	4.10%
19	DEPR. OF EQUITY AFUDC	$198	$231	$266	$298	$325	$354	$385	$418	$455	$494	$[illegible]	$582

EXHIBIT 6

EXHIBIT 7

JOHN J. HIBBS & ASSOCIATES, INC.
13131 Champions Drive • Suite 206 • Houston, Texas 77069
P. O. Box 680304 • Houston, Texas 77268-0304

JOHN J. HIBBS, President

(713) 893-9784

An Energy Services Company

December 3, 1992

Florida Power Corp.
P.O. Box 14042
St. Petersburg, Florida 33733

ATTN: Mr. Stephen Watsey, Vice President

RE: **SunShine Pipeline Project - Supplemental Operating Cost Review**

Dear Mr. Watsey:

I have discussed the issue of operating expenses (O&M and A&G) in some detail with Messrs. E.J. Burgin and A. Bradley over the past two days. As a result of this operating cost issue and our discussions, Mr. Burgin and ANR have each developed separate operating cost projections. These were provided to me late yesterday. Further, based on SunShine's proposed operating philosophy as described by Mr. Burgin, we have also prepared a preliminary alternative operating cost estimate which reflects substantive ANR administrative support in contrast with the original free standing organization approach.

A bottom line comparison of these several estimates is set forth below.

ORIGINAL ANR (UGPL) ESTIMATE	$03.3 MILLION
ORIGINAL HIBBS & ASSOCIATES ESTIMATE	$12.5 MILLION
E.J. BURGIN 12/2/92 ESTIMATE	$04.1 MILLION
ANR 12/2/92 ESTIMATE	$05.3 MILLION
HIBBS & ASSOCIATES 12/2/92 ESTIMATE	$07.5 MILLION

It is also interesting to note that O&M and A&G expenditures for recently completed interstate pipeline systems, Kern River and Iroquois, are running $22 million and $14 million, respectively. While these systems are not identical to SunShine and SITCO in size, structure and situation, there is enough similarity to provide a reasonably valid broad comparison.

As to the 12/2/92 estimates from Mr. Burgin and ANR, they have been cursorily reviewed and I believe that both are likely on the low side.

SITCO
INCOME TAXES FOR COST OF SERVICE

SCHEDULE 4
PAGE 2 OF 2

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	RETURN ON RATE BASE	$11,994	$11,088	$10,102	$9,230	$8,480	$7,668	$6,797	$5,856	$4,835	$3,724	$2,519	$1,209
2	LESS: INTEREST EXPENSE	8,134	7,519	6,850	6,259	5,751	5,200	4,609	3,971	3,278	2,526	1,708	820
3	PLUS: DEPR. OF EQUITY AFUDC	198	231	266	298	325	354	385	418	455	494	536	582
4	LESS: NORMALIZATION ADJ	0	0	0	0	0	0	0	0	0	0	0	0
5	PRO I.T. - STORAGE LEASE PMT	0	0	0	0	0	0	0	0	0	0	0	0
6	NET INCOME	$4,059	$3,800	$3,518	$3,269	$3,055	$2,822	$2,573	$2,303	$2,011	$1,692	$1,347	$971
7	FEDERAL INCOME TAXES	3,091	1,950	1,812	1,684	1,574	1,454	1,325	1,186	1,036	872	694	500
8	STATE INCOME TAXES	360	335	310	288	269	249	227	203	177	149	119	86
9	TOTAL INCOME TAXES	$2,449	$2,293	$2,122	$1,972	$1,843	$1,703	$1,552	$1,389	$1,213	$1,021	$812	$586
8	DEPR. OF EQUITY AFUDC	$198	$231	$266	$298	$325	$354	$385	$418	$455	$494	$536	$582
9	FEDERAL INCOME TAXES	102	119	137	154	167	182	198	215	234	254	276	300
10	STATE INCOME TAXES	17	20	23	26	29	31	34	37	40	44	47	51
11	AFUDC RELATED INCOME TAXES	$119	$139	$160	$180	$196	$214	$232	$252	$274	$298	$323	$351
12	INCOME RELATED INCOME TAXES	$2,329	$2,153	$1,962	$1,792	$1,647	$1,489	$1,320	$1,137	$939	$723	$489	$235

EXHIBIT 6

EXHIBIT 8

	Annual Capital Cost (1999-2020)	Annual O&M/A&G (1999-2020)	25 Yr. COS	25 Yr. Vol.	Annual Rate
Alternate Case I					
SITCO	$177,300	$3,500	$670,050	4,422,900	$0.1515
Sunshine	464,400	9,000	1,796,375	3,460,200	0.5192
Total	$641,700	$12,500	$2,466,425	7,883,100	$0.6707
Alternate Case II					
SITCO	$177,300	$2,250	$639,550	4,422,900	$0.1446
Sunshine	464,400	5,250	1,707,125	3,460,200	0.4934
Total	$641,700	$7,500	$2,346,675	7,883,100	$0.6380
Alternate Case III					
SITCO	$177,300	$1,500	$621,550	4,422,900	$0.1405
Sunshine	464,400	3,500	1,664,875	3,460,200	0.4811
Total	$641,700	$5,000	$2,286,425	7,883,100	$0.6216

Based on the operating approach for SunShine as described by Mr. Burgin, we have revised our estimate, as noted above, to reflect substantial ANR support (at a cost for same as projected by ANR), reduced salary levels and labor rates, and a reduction in field and administrative office staffing to "bare bones" levels and the end result is that our alternative cost estimate of some $7.5 million is still somewhat in excess of the Burgin and ANR projections.

While I personally believe that it will be a challenge to contain operating and A&G expenditures within the $7.5 million projection (and that assumes that ANR has accurately forecasted the cost of its administrative support), Mr. Burgin, on the other hand, is equally confident that he can operate the system for the $4.1 million. In fact, he has advised me that he would, if possible, take a turn key contract for said amount.

I have the greatest respect for Mr. Burgin's pipeline industry technical and administrative abilities and that, coupled with his Florida pipeline operations experience, may well result in actual SunShine operating and administrative expenses at the $4 to 5 million level that he predicts. If anyone can achieve this result, it will be E.J. Burgin. I am simply not yet persuaded that this result is very likely, particularly over the life of the project.

As noted above this supplemental cost analysis was performed on a very cursory basis and the subject can be addressed in greater detail in the final project report, if it is still a relevant issue at that time. Please advise if there are any questions regarding this matter.

Very truly yours,

John J. Hibbs

XC: J. Pollard
D. Williams

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE I

SCHEDULE I
PAGE 2 OF 2

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 Year Avg.
1	O&M/A&G EXPENSE	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
2	DEPRECIATION EXPENSE	14,970	13,651	23,039	25,364	28,340	31,304	33,925	35,830	40,077	43,594	47,334	51,508	$19,221
3	INTEREST EXPENSE	20,315	19,197	18,250	17,152	15,321	14,571	13,635	11,484	9,731	7,322	5,706	3,199	$21,321
4	OTHER TAXES	7,595	7,661	7,632	7,209	6,392	6,783	6,579	6,382	6,190	6,005	5,824	5,650	$7,765
5	ROE	3,645	3,112	4,662	6,112	7,557	6,317	6,216	5,651	4,619	3,713	2,728	1,956	$9,374
6	FED. & ST. INCOME TAXES	6,272	5,857	5,642	5,379	5,070	4,732	4,360	3,353	3,506	3,025	2,498	1,925	$6,350
7	TOTAL COST OF SERVICE	$70,359	$70,718	$72,026	$72,746	$72,960	$72,606	$73,975	$73,100	$73,135	$73,158	$73,191	$73,228	$71,855
8	VOLUMES @ 100% LF	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	138,408
9	VOL. RATE @ 100 % LF	$0.4966	$0.4856	$0.4946	$0.4995	$0.5004	$0.5013	$0.5018	$0.5019	$0.5021	$0.5023	$0.5026	$0.5029	$0.5152

EXHIBIT 8

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE I

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$5,500	$5,500	$5,500	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
2	DEPRECIATION EXPENSE	320	1,350	3,010	(1,929)	(501)	989	3,462	3,975	5,597	7,344	9,482	11,791	14,281
3	INTEREST EXPENSE	31,573	30,981	30,512	32,007	31,124	30,158	29,219	28,262	27,242	26,152	24,981	23,709	22,327
4	OTHER TAXES	8,100	8,094	8,245	8,869	8,929	8,916	8,915	8,918	8,918	8,922	8,654	8,334	8,143
5	ROE	14,987	14,706	14,483	15,133	14,774	14,315	13,869	13,415	12,931	12,413	11,858	11,254	10,598
6	FED. & ST. INCOME TAXES	9,051	8,500	8,777	9,135	8,907	8,657	8,415	8,168	7,905	7,624	7,327	7,004	6,653
7	TOTAL COST OF SERVICE	$69,531	$69,531	$69,531	$72,376	$72,234	$72,035	$71,880	$71,738	$71,594	$71,455	$71,302	$71,152	$71,000
8	VOLUMES @ 100% LF	79,935	79,935	96,360	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
9	VOL. RATE @ 100 % LF	$0.8698	$0.8698	$0.7216	$0.4963	$0.4960	$0.4946	$0.4936	$0.4926	$0.4916	$0.4906	$0.4896	$0.4886	$0.4875

SCHEDULE I
PAGE 2 OF 2

SITCO
COST OF SERVICE --ALTERNATE CASE I

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 YEAR AVG.
1	O&M/AAG EXPENSE	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,390
2	DEPRECIATION EXPENSE	6,923	8,064	9,296	10,391	11,334	12,352	13,437	14,602	15,866	17,232	18,710	20,311	$7,223
3	INTEREST EXPENSE	8,160	7,544	6,873	6,280	5,770	5,219	4,631	3,991	3,296	2,541	1,721	831	$8,021
4	OTHER TAXES	1,978	1,918	1,861	1,805	1,751	1,698	1,647	1,598	1,550	1,503	1,458	1,415	$1,939
5	ROE	3,873	3,581	3,263	2,981	2,739	2,477	2,198	1,895	1,565	1,206	817	394	$3,807
6	FED. & ST. INCOME TAXES	3,456	2,300	3,129	1,978	1,848	1,708	1,558	1,395	1,218	1,026	816	589	$2,422
7	TOTAL COST OF SERVICE	$26,891	$26,906	$26,921	$26,935	$26,963	$26,954	$26,971	$26,981	$26,996	$27,009	$27,023	$27,040	$26,802
8	VOLUMES @ 100%	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	176,916
9	VOL. RATE @ 100 %	$0.1460	$0.1461	$0.1462	$0.1463	$0.1463	$0.1464	$0.1465	$0.1465	$0.1466	$0.1467	$0.1468	$0.1468	$0.1515

EXHIBIT 8

SITCO
COST OF SERVICE --ALTERNATE CASE I

SCHEDULE 1
PAGE 1 OF 2

NE).	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$2,500	$2,500	$2,750	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500
2	DEPRECIATION EXPENSE	(694)	(363)	(188)	(613)	(12)	589	1,181	1,791	2,450	3,161	3,995	4,896	5,870
3	INTEREST EXPENSE	12,569	12,373	12,187	12,304	11,964	11,622	11,286	10,939	10,565	10,161	9,724	9,247	8,727
4	OTHER TAXES	2,094	2,102	2,146	2,232	2,239	2,240	2,232	2,235	2,230	2,224	2,167	2,102	2,039
5	ROE	5,966	5,873	5,785	5,840	5,679	5,517	5,357	5,192	5,015	4,823	4,615	4,389	4,142
6	FED. & ST. INCOME TAXES	3,507	3,536	3,487	3,513	3,425	3,338	3,252	3,163	3,060	2,965	2,853	2,732	2,600
7	TOTAL COST OF SERVICE	$26,032	$26,021	$26,167	$26,777	$26,795	$26,805	$26,809	$26,821	$26,828	$26,844	$26,854	$26,865	$26,878
8	VOLUMES @ 100%	118,443	118,443	134,060	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
9	VOL. RATE @ 100 %	$0.2197	$0.2197	$0.1940	$0.1454	$0.1455	$0.1456	$0.1456	$0.1457	$0.1457	$0.1458	$0.1458	$0.1459	$0.1460

EXHIBIT 8

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE II

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 Year Avg.
1	O&M/A&G EXPENSE	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,010
2	DEPRECIATION EXPENSE	16,970	19,091	23,039	25,864	28,340	31,004	33,025	36,030	40,077	43,594	47,394	51,500	$18,221
3	INTEREST EXPENSE	20,026	19,197	18,250	17,152	15,921	14,571	13,095	11,484	9,731	7,822	5,746	3,489	$21,021
4	OTHER TAXES	7,096	7,661	7,432	7,209	6,992	6,783	6,579	6,382	6,190	6,005	5,824	5,650	$7,765
5	ROE	9,805	9,112	8,662	8,142	7,557	6,917	6,216	5,451	4,619	3,713	2,728	1,656	$9,970
6	FED. & ST. INCOME TAXES	6,272	5,057	5,042	5,379	5,070	4,732	4,360	3,953	3,508	3,025	2,498	1,925	$6,350
7	TOTAL COST OF SERVICE	$67,109	$66,968	$68,274	$69,996	$69,130	$69,256	$69,325	$69,350	$69,375	$69,408	$69,441	$69,470	$68,285
8	VOLUMES @ 100% LF	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	138,409
9	VOL. RATE @ 100 % LF	$0.4608	$0.4598	$0.4688	$0.4738	$0.4747	$0.4755	$0.4760	$0.4762	$0.4764	$0.4766	$0.4768	$0.4771	$0.4934

EXHIBIT 8

SCHEDULE 1
PAGE 1 OF 2

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE II

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$3,250	$3,250	$3,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,250	$5,25(
2	DEPRECIATION EXPENSE	320	1,350	2,014	(1,929)	(501)	989	2,462	3,975	5,597	7,344	9,482	11,791	14,251
3	INTEREST EXPENSE	31,573	30,981	30,512	32,007	31,124	30,158	29,219	28,262	27,242	26,152	24,981	23,709	22.327
4	OTHER TAXES	8,100	8,094	8,245	8,069	8,029	8,016	8,015	8,010	8,010	8,022	8,054	8,394	8,143
5	ROE	14,987	14,706	14,483	15,193	14,774	14,315	13,869	13,415	12,931	12,413	11,858	11,254	10,590
6	FED. & ST. INCOME TAXES	9,051	8,900	8,777	9,135	8,907	8,657	8,415	8,168	7,905	7,624	7,327	7,004	6,653
7	TOTAL COST OF SERVICE	$67,281	$67,281	$67,281	$68,524	$68,484	$68,285	$68,130	$67,988	$67,844	$67,705	$67,552	$67,402	$67,250
8	VOLUMES @ 100% LF	79,935	79,935	96,360	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
9	VOL. RATE @ 100 % LF	$0.8417	$0.8417	$0.6982	$0.4705	$0.4702	$0.4689	$0.4678	$0.4668	$0.4658	$0.4649	$0.4638	$0.4628	$0.4618

EXHIBIT 8

SCHEDULE 1
PAGE 2 OF 2

SITCO
COST OF SERVICE --ALTERNATE CASE II

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 YEAR AVG.
1	O&M/A&G EXPENSE	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,170
2	DEPRECIATION EXPENSE	6,923	8,064	9,296	10,391	11,334	12,352	13,437	14,602	15,866	17,232	18,710	20,311	$7,222
3	INTEREST EXPENSE	8,160	7,540	6,873	6,280	5,770	5,219	4,631	3,991	3,296	2,541	1,721	831	$8,021
4	OTHER TAXES	1,978	1,918	1,861	1,805	1,751	1,698	1,647	1,598	1,550	1,503	1,458	1,415	$1,939
5	DOE	3,073	3,581	3,263	2,981	2,739	2,477	2,190	1,895	1,565	1,206	817	394	$3,007
6	FED. & ST. INCOME TAXES	2,456	2,300	2,109	1,978	1,868	1,706	1,558	1,395	1,118	1,026	816	589	$2,422
7	TOTAL COST OF SERVICE	$25,641	$25,656	$25,671	$25,685	$25,693	$25,704	$25,721	$25,731	$25,746	$25,759	$25,773	$25,790	$25,582
8	VOLUMES @ 100%	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	176,916
9	VOL. RATE @ 100 %	$0.1392	$0.1393	$0.1394	$0.1395	$0.1395	$0.1396	$0.1397	$0.1397	$0.1398	$0.1399	$0.1400	$0.1401	$0.1446

EXHIBIT 8

SITCO
COST OF SERVICE --ALTERNATE CASE II

SCHEDULE 1
PAGE 1 OF 2

NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$1,500	$1,500	$1,750	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250	$2,250
2	DEPRECIATION EXPENSE	(694)	(363)	(188)	(613)	(12)	589	1,181	1,791	2,450	3,161	3,995	4,896	5,870
3	INTEREST EXPENSE	12,569	12,373	12,187	12,304	11,964	11,622	11,286	10,939	10,565	10,161	9,724	9,247	8,727
4	OTHER TAXES	2,094	2,102	2,146	2,232	2,239	2,240	2,232	2,235	2,230	2,234	2,167	2,102	2,039
5	ROE	5,966	5,873	5,785	5,840	5,679	5,517	5,357	5,192	5,015	4,823	4,615	4,389	4,142
6	FED. & ST. INCOME TAXES	3,587	3,536	3,487	3,513	3,425	3,330	3,252	3,163	3,060	2,965	2,853	2,732	2,600
7	TOTAL COST OF SERVICE	$25,022	$25,021	$25,167	$25,527	$25,545	$25,555	$25,559	$25,571	$25,578	$25,594	$25,604	$25,615	$25,628
8	VOLUMES @ 100%	118,443	118,443	134,868	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
9	VOL. RATE @ 100 %	$0.2113	$0.2112	$0.1866	$0.1386	$0.1387	$0.1388	$0.1388	$0.1389	$0.1389	$0.1390	$0.1390	$0.1391	$0.1392

EXHIBIT 8

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE III

SCHEDULE I
PAGE 2 OF 2

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 Year Avg.
1	O&M/A&G EXPENSE	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,320
2	DEPRECIATION EXPENSE	16,970	19,891	23,039	25,864	28,340	31,004	33,825	36,820	40,077	42,594	47,394	51,505	$18,221
3	INTEREST EXPENSE	20,826	19,197	18,250	17,152	15,921	14,571	13,095	11,484	9,731	7,822	5,746	3,489	$11,021
4	OTHER TAXES	7,098	7,661	7,432	7,209	6,992	6,783	6,579	6,382	6,190	6,005	5,824	5,650	$1,735
5	ROR	9,805	9,112	8,662	8,142	7,557	6,917	6,216	5,451	4,619	3,713	2,726	1,656	$9,978
6	FED. & ST. INCOME TAXES	6,272	5,857	5,642	5,379	5,070	4,732	4,360	3,953	3,500	3,025	2,490	1,925	$6,350
7	TOTAL COST OF SERVICE	$65,359	$65,218	$66,524	$67,246	$67,380	$67,506	$67,575	$67,600	$67,625	$67,658	$67,691	$67,729	$66,595
8	VOLUMES @ 100% LF	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	128,488
9	VOL. RATE @ 100 % LF	$0.4488	$0.4478	$0.4568	$0.4617	$0.4627	$0.4635	$0.4640	$0.4642	$0.4643	$0.4646	$0.4648	$0.4651	$0.4811

EXHIBIT 8

SUNSHINE GAS
COST OF SERVICE--ALTERNATE CASE III

SCHEDULE I
PAGE 1 OF 2

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$2,000	$2,000	$2,000	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500
2	DEPRECIATION EXPENSE	320	1,350	2,014	(1,925)	(501)	989	2,462	3,975	5,597	7,344	9,452	11,791	14,271
3	INTEREST EXPENSE	31,573	30,981	30,512	32,067	31,124	30,158	29,219	28,262	27,242	26,152	24,981	23,709	22,327
4	OTHER TAXES	8,100	8,094	8,245	8,069	8,029	8,016	8,015	8,018	8,018	8,022	8,054	8,394	8,143
5	ROE	14,907	14,796	14,483	15,193	14,774	14,315	13,869	13,415	12,931	12,413	11,858	11,254	10,598
6	FED. & ST. INCOME TAXES	9,051	8,900	8,777	9,135	8,907	8,657	8,415	8,168	7,905	7,624	7,327	7,004	6,653
7	TOTAL COST OF SERVICE	$66,031	$66,031	$66,031	$66,774	$66,734	$66,535	$66,380	$66,238	$66,094	$65,955	$65,802	$65,652	$65,500
8	VOLUMES @ 100% LF	79,935	79,935	96,360	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635	145,635
9	VOL. RATE @ 100 % LF	$0.8261	$0.8261	$0.6853	$0.4585	$0.4582	$0.4569	$0.4558	$0.4548	$0.4538	$0.4529	$0.4518	$0.4508	$0.4498

EXHIBIT 8

SCHEDULE 1
PAGE 1 OF 2

SITCO
COST OF SERVICE --ALTERNATE CASE III

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$1,000	$1,000	$1,250	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
2	DEPRECIATION EXPENSE	(694)	(363)	(188)	(613)	(12)	589	1,181	1,791	2,450	3,161	3,995	4,896	5,870
3	INTEREST EXPENSE	13,569	12,373	12,187	13,304	11,964	11,622	11,286	10,939	10,565	10,161	9,724	9,247	8,727
4	OTHER TAXES	2,094	2,102	2,146	2,232	2,239	2,240	2,232	2,235	2,230	2,234	2,167	2,102	2,039
5	ROE	5,966	5,873	5,705	5,040	5,679	5,517	5,357	5,192	5,015	4,823	4,615	4,389	4,142
6	FED. & ST. INCOME TAXES	3,587	3,536	3,437	3,513	3,425	3,338	3,252	3,163	3,060	2,965	2,853	2,732	2,600
7	TOTAL COST OF SERVICE	$24,522	$24,521	$24,067	$24,777	$24,795	$24,805	$24,809	$24,821	$24,820	$24,844	$24,854	$24,865	$24,878
8	VOLUMES @ 100%	118,443	118,443	134,868	184,143	184,143	184,143	184,143	184,143	[illegible]	184,143	184,143	184,143	184,143
9	VOL. RATE @ 100 %	$0.2070	$0.2070	$0.1829	$0.1346	$0.1347	$0.1347	$0.1347	$0.1348	$0.1348	$0.1349	$0.1350	$0.1350	$0.1351

EXHIBIT 8

SITCO
COST OF SERVICE --ALTERNATE CASE I

SCHEDULE I
PAGE 1 OF 2

LINE NO.	PARTICULARS	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	O&M/A&G EXPENSE	$2,500	$2,500	$2,750	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500	$3,500
2	DEPRECIATION EXPENSE	(694)	(383)	(188)	(613)	(13)	589	1,181	1,791	2,450	3,161	3,995	4,896	5,870
3	INTEREST EXPENSE	12,569	12,373	12,187	12,304	11,964	11,622	11,286	10,939	10,565	10,161	9,724	9,247	8,727
4	OTHER TAXES	2,094	2,102	2,146	2,232	2,239	2,240	2,232	2,235	2,230	2,224	2,167	2,102	2,029
5	ROE	5,966	5,873	5,785	5,840	5,679	5,517	5,357	5,192	5,015	4,823	4,615	4,389	4,142
6	FED. & ST. INCOME TAXES	3,587	3,536	3,487	3,513	3,425	3,338	3,252	3,163	3,068	2,965	2,853	2,732	2,600
7	TOTAL COST OF SERVICE	$26,022	$26,021	$26,167	$26,777	$26,795	$26,805	$26,809	$26,821	$26,828	$26,844	$26,854	$26,865	$26,870
8	VOLUMES @ 100%	118,443	118,443	134,868	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143
9	VOL. RATE @ 100 %	$0.2197	$0.2197	$0.1940	$0.1454	$0.1455	$0.1456	$0.1456	$0.1457	$0.1457	$0.1458	$0.1458	$0.1459	$0.1460

EXHIBIT 8

SITCO
COST OF SERVICE --ALTERNATE CASE III

LINE NO.	PARTICULARS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	25 YEAR AVG.
1	O&M/A&G EXPENSE	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,450
2	DEPRECIATION EXPENSE	6,923	8,064	9,296	10,391	11,334	12,352	13,437	14,602	15,866	17,232	18,710	20,311	$7,223
3	INTEREST EXPENSE	8,160	7,544	6,873	6,280	5,770	5,219	4,631	3,991	3,296	2,541	1,721	831	$8,021
4	OTHER TAXES	1,978	1,918	1,861	1,805	1,751	1,698	1,647	1,598	1,550	1,503	1,458	1,415	$1,939
5	ROE	3,873	3,581	3,263	2,981	2,739	2,477	2,198	1,895	1,565	1,206	817	394	$3,807
6	FED. & ST. INCOME TAXES	2,456	2,300	2,129	1,978	1,848	1,708	1,558	1,395	1,218	1,026	816	589	$2,422
7	TOTAL COST OF SERVICE	$24,891	$24,906	$24,921	$24,935	$24,943	$24,954	$24,971	$24,981	$24,996	$25,009	$25,023	$25,040	$24,862
8	VOLUMES @ 100%	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	184,143	176,916
9	VOL. RATE @ 100 %	$0.1352	$0.1353	$0.1353	$0.1354	$0.1355	$0.1355	$0.1356	$0.1357	$0.1357	$0.1358	$0.1359	$0.1360	$0.1405

EXHIBIT 8

SUNSHINE GAS PIPELINE COMPANY

SUMMARY OF RESULTS -- SUNSHINE GAS PIPELINE COMPANY

BASE ASSUMPTIONS

TARGET DEBT/CAPITAL RATIO	75% / 25%
DEBT MATURITY	25 YEARS
EFFECTIVE TAX RATE	37.63%

RATES OF RETURN	DEBT	EQUITY	OVERALL
DURING CONSTRUCTION	9.140%	14.25%	10.42%
AT COMPLETION	9.140%	14.25%	10.42%

SCENARIO RESULTS

RATE B 100% L. F.

BASE RATE	$0.4138
DEFERRED RECOVERY RATE	0.1112
TOTAL RATE	$0.5250

PROJECT COST ($MILLIONS)	1995	1998	1999	TOTAL
CAPITAL COST (1996 COST)	$415.8	$121.6	$50.9	$588.3
DEBT AFUDC	14.3	4.2	1.7	20.2
EQUITY AFUDC	7.4	2.2	0.9	10.5
TOTAL	$437.5	$127.9	$53.5	$618.9
LONG TERM DEBT	$328.1	$95.9	$40.1	$464.2
PARTNERS EQUITY	109.4	32.0	13.4	154.7
TOTAL	$437.5	$127.9	$53.5	$618.9

	1995	1998	1999
VOLUMES - MDQ - MMDTH/D	250	424.5	549.5
PIPELINE CAPACITY - ANNUAL	91,068	154,943	200,568

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Exhibit ___ (PRC-9)
Docket No. 920807-GP

SUNSHINE GAS PIPELINE COMPANY

PRO FORMA STATEMENT OF INCOME

(000'S OMITTED)

LINE NO.	DESCRIPTION	1995	1996	1997	1998	ULTIMATE DEVELOPMENT 1999	2000	2001	2002	2003	2004	2005
	(Col. 1)	(Col.2)	(Col.3)	(Col.4)	(Col.5)	(Col.6)	(Col.7)	(Col.8)	(Col.9)	(Col.10)	(Col.11)	(Col.12
1	Operating Revenue	$47,813	$47,813	$47,813	$81,350	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304	$105,30
	Operating Expenses:											
2	Operation and Maintenance	3,500	3,500	3,500	5,200	6,800	6,800	6,800	6,800	6,800	6,800	6,80
3	Depreciation-MDQ Capacity Methodology	8,587	8,587	8,587	19,147	27,333	27,333	27,333	27,333	27,333	27,333	27,33
4	Regulatory Asset-Levelized Depreciation	6,526	8,715	11,984	(16,486)	(32,638)	(30,875)	(27,451)	(24,814)	(22,086)	(19,251)	(16,27
5	Regulatory Asset-Deferred Cost	8,977	2,381	(5,426)	(3,694)	776	927	1,092	1,300	1,549	1,840	2,17
6	Regulatory Asset-Deferred Recovery	(44,399)	(44,399)	(44,399)	(18,500)	0	0	0	0	0	0	
7	Other Taxes	9,192	9,192	9,192	12,852	14,625	13,713	12,858	12,056	11,304	10,599	9,93
8	Total Operating Expenses	($7,618)	($12,825)	($16,560)	($1,481)	$16,896	$18,698	$20,631	$22,675	$24,901	$27,322	$29,97
9	EBIT	$55,431	$59,838	$64,376	$82,830	$88,409	$86,686	$84,673	$82,629	$80,404	$77,982	$75,32
	Less:											
10	Interest Expense	29,991	29,991	29,991	38,192	40,675	39,382	37,971	36,431	34,750	32,916	30,91
11	Federal and State Inc Tax	9,669	11,342	13,069	16,815	17,928	17,755	17,573	17,400	17,213	17,810	16,78
12	Net Income	$15,771	$18,505	$21,314	$27,823	$29,806	$29,471	$29,129	$28,798	$28,441	$28,056	$27,63

SUNSHINE GAS PIPELINE COMPANY

PRO FORMA STATEMENT OF INCOME

($000'S OMITTED)

LINE NO.	DESCRIPTION	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	(Col. 1)	(Col.2)	(Col.3)	(Col.4)	(Col.5)	(Col.6)	(Col.7)	(Col.8)	(Col.9)	(Col.10)	(Col.11)
1	Operating Revenue	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304	$105,304
	Operating Expenses:										
2	Operation and Maintenance	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800	6,800
3	Depreciation-MDQ Capacity Methodology	27,333	27,333	27,333	27,333	27,333	27,333	27,333	27,333	27,333	27,333
4	Regulatory Asset-Levelized Depreciation	(13,111)	(9,736)	(6,138)	(2,288)	1,831	5,647	9,143	12,887	16,725	20,595
5	Regulatory Asset-Deferred Cost	2,589	3,078	3,655	4,339	5,160	6,129	7,277	8,647	10,270	12,203
6	Regulatory Asset-Deferred Recovery	0	0	0	0	0	0	0	0	0	0
7	Other Taxes	9,319	8,738	8,193	7,682	7,283	6,754	6,333	5,938	5,568	5,220
8	Total Operating Expenses	$32,930	$36,213	$39,843	$43,866	$48,327	$52,663	$56,886	$61,605	$66,696	$72,152
9	EBIT	$72,374	$69,091	$65,461	$61,438	$56,977	$52,641	$48,418	$43,699	$38,609	$33,152
	Less:										
10	Interest Expense	28,729	26,344	23,741	20,901	17,801	14,[illegible]	10,724	6,694	2,295	0
11	Federal and State Inc Tax	16,515	16,198	15,834	15,414	14,928	14,594	14,416	14,181	13,945	12,780
12	Net Income	$27,130	$26,549	$25,886	$25,123	$24,248	$23,638	$23,278	$22,824	$22,369	$20,372

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Exhibit ___ (PRC-9)
Docket No. 920807-GP

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SUNSHINE GAS PIPELINE COMPANY

PRO FORMA STATEMENT OF INCOME

(000'S OMITTED)

LINE NO.	DESCRIPTION	2016	2017	2018	2019
	(Col. 1)	(Col.2)	(Col.3)	(Col.4)	(Col.5)
1	Operating Revenue	$105,304	$105,304	$105,304	$105,304
	Operating Expenses:				
2	Operation and Maintenance	6,800	6,800	6,800	6,800
3	Depreciation-MDQ Capacity Methodology	27,333	27,333	27,333	27,333
4	Regulatory Asset-Levelized Depreciation	24,674	29,052	33,756	38,810
5	Regulatory Asset-Deferred Cost	14,492	17,216	20,453	24,289
6	Regulatory Asset-Deferred Recovery	0	0	0	0
7	Other Taxes	4,895	4,590	4,304	4,035
8	Total Operating Expenses	$78,194	$84,991	$92,646	$101,267
9	EBIT	$27,110	$20,313	$12,659	$4,037
	Less:				
10	Interest Expense	0	0	0	0
11	Federal and State Inc Tax	10,532	8,003	5,152	1,940
12	Net Income	$16,578	$12,310	$7,507	$2,097

Exhibit ___ (PRC-9)
Docket No. 920807-GP

SUNSHINE GAS
PIPELINE COMPANY
PRO FORMA BALANCE SHEET
(000'S OMITTED)

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col.10)	(Col.12)
	ASSETS AND OTHER DEBITS										
1	PLANT	$437,500	$437,500	$565,400	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900
2	LESS: ACC. DEPRECIATION	8,587	17,173	25,760	44,907	72,240	99,573	126,906	154,239	181,572	208,905
3	REG. ASSET-LEVELIZED DEPR.	6,526	15,242	27,226	18,748	(21,898)	(51,973)	(79,424)	(104,238)	(126,324)	(145,575)
4	NET PLANT	$422,387	$405,085	$512,414	$563,253	$568,558	$571,300	$571,418	$568,899	$563,652	$555,570
5	REG. ASSET - DEF. COST/RECOVERY	$44,399	$88,799	$133,198	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698
6	LESS: ACCUMULATED AMORTIZATION	8,977	11,357	5,933	2,240	3,016	3,943	5,035	6,334	7,884	9,724
7	NET	$35,423	$77,441	$127,265	$149,458	$148,682	$147,755	$146,663	$145,364	$143,816	$141,974
8	CURRENT ASSETS	438	438	438	650	850	850	850	850	850	850
9	TOTAL ASSETS AND OTHER DEBITS	$458,247	$482,964	$640,116	$713,361	$718,090	$719,905	$718,931	$715,113	$708,316	$698,394
	LIABILITIES AND OTHER CREDITS										
10	LONG-TERM DEBT	$328,125	$328,125	$424,050	$451,781	$438,254	$423,491	$407,379	$389,794	$370,602	$349,655
11	DEFERRED TAXES	15,831	40,617	65,594	87,781	106,145	122,824	137,347	150,283	161,636	171,538
12	EQUITY	114,291	114,221	150,472	173,799	173,691	173,590	174,206	175,036	176,079	177,201
13	TOTAL LIABILITIES AND OTHER CREDITS	$458,247	$482,964	$640,116	$713,361	$718,090	$719,905	$718,931	$715,113	$708,316	$698,394

SUNSHINE GAS
PIPELINE COMPANY
PRO FORMA BALANCE SHEET
(000'S OMITTED)

LINE NO.	DESCRIPTION	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)	(Col. 8)	(Col. 9)	(Col.10)	(Col.11)
	ASSETS AND OTHER DEBITS										
1	PLANT	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900
2	LESS: ACC. DEPRECIATION	236,238	263,571	290,984	318,237	345,570	372,903	400,236	427,569	454,902	482,235
3	REG. ASSET-LEVELIZED DEPR.	(161,847)	(174,958)	(184,694)	(190,832)	(193,120)	(191,289)	(185,642)	(176,499)	(163,612)	(146,887)
4	NET PLANT	$544,509	$530,287	$512,690	$491,495	$466,450	$437,286	$404,306	$367,830	$327,610	$283,552
5	REG. ASSET - DEF. COST/RECOVERY	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698	$151,698
6	LESS: ACCUMULATED AMORTIZATION	11,902	14,491	17,569	21,224	25,563	30,723	36,851	44,129	52,775	63,845
7	NET	$139,796	$137,207	$134,129	$130,474	$126,136	$120,975	$114,847	$107,570	$98,923	$88,653
8	CURRENT ASSETS	850	850	850	850	850	850	850	850	850	850
9	TOTAL ASSETS AND OTHER DEBITS	$685,155	$668,344	$647,669	$622,819	$593,436	$559,111	$520,003	$476,250	$427,383	$373,055
	LIABILITIES AND OTHER CREDITS										
10	LONG-TERM DEBT	$326,794	$301,844	$274,613	$244,893	$212,456	$177,055	$138,419	$96,251	$50,229	$0
11	DEFERRED TAXES	180,146	187,430	193,283	49,098	208,208	196,216	185,672	173,403	157,835	138,256
12	EQUITY	178,215	179,070	179,774	328,829	180,771	185,840	195,912	206,596	219,319	234,799
13	TOTAL LIABILITIES AND OTHER CREDITS	$685,155	$668,344	$647,669	$622,819	$593,436	$559,111	$520,003	$476,250	$427,383	$373,055

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Exhibit ___ (PRC-9)
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SUNSHINE GAS
PIPELINE COMPANY
PRO FORMA BALANCE SHEET
(000'S OMITTED)

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)
	ASSETS AND OTHER DEBITS					
1	PLANT	$618,900	$618,900	$618,900	$618,900	$618,900
2	LESS: ACC. DEPRECIATION	509,568	536,901	564,234	591,567	618,900
3	REG. ASSET-LEVELIZED DEPR.	(126,292)	(101,618)	(72,566)	(38,810)	0
4	NET PLANT	$235,624	$183,617	$127,232	$66,143	$0
5	REG. ASSET - DEF. COST/RECOVERY	$151,698	$151,698	$151,698	$151,698	$151,698
6	LESS: ACCUMULATED AMORTIZATION	75,248	89,741	106,957	127,409	151,698
7	NET	$76,450	$61,958	$44,742	$24,289	$0
8	CURRENT ASSETS	850	850	850	850	0
9	TOTAL ASSETS AND OTHER DEBITS	$312,924	$246,425	$172,824	$91,282	$0
	LIABILITIES AND OTHER CREDITS					
10	LONG-TERM DEBT	$0	$0	$0	$0	$0
11	DEFERRED TAXES	115,934	91,241	63,904	33,609	0
12	EQUITY	196,990	155,183	108,919	57,673	(0)
13	TOTAL LIABILITIES AND OTHER CREDITS	$312,924	$246,425	$172,824	$91,282	$0

SUNSHINE GAS PIPELINE COMPANY
COST OF SERVICE

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12)
	COST OF SERVICE											
1	Operation and maintenance	$3,500	$3,500	$3,500	$5,200	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800
2	Depreciation	15,113	17,302	20,571	2,661	(5,305)	(2,742)	(118)	2,519	5,247	8,082	11,061
	Taxes:											
3	Income Federal & State	9,560	9,205	8,674	10,666	11,384	11,124	10,844	10,552	10,238	9,899	9,527
4	Other	9,192	9,192	9,192	12,852	14,625	13,713	12,858	12,056	11,304	10,599	9,938
5	Return @ 10.42 %	45,633	43,798	41,060	51,616	55,493	54,102	52,613	51,070	49,408	47,618	45,672
6	Total	$82,998	$82,997	$82,997	$82,995	$82,997	$82,997	$82,997	$82,997	$82,997	$82,998	$82,998

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Exhibit ___ (PRC-9)
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SUNSHINE GAS PIPELINE COMPANY
COST OF SERVICE

LINE NO.	DESCRIPTION	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)	(col.22)
	COST OF SERVICE										
1	Operation and maintenance	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800	$6,800
2	Depreciation	14,222	17,595	21,195	25,045	29,164	32,988	36,476	40,220	44,058	47,928
	Taxes:										
3	Income Federal & State	9,120	8,671	8,179	7,641	7,054	6,511	6,015	5,474	4,913	4,345
4	Other	9,319	8,738	8,193	7,682	7,203	6,754	6,333	5,938	5,568	5,220
5	Return @ 10.42 %	43,537	41,194	38,630	35,830	32,777	29,952	27,374	24,566	21,658	18,705
6	Total	$82,998	$82,998	$82,997	$82,998	$82,998	$82,997	$82,998	$82,998	$82,997	$82,998

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Exhibit ___ (PRC-9)
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SUNSHINE GAS PIPELINE COMPANY
COST OF SERVICE

LINE NO.	DESCRIPTION	2016	2017	2018	2019
	(col. 1)	(col.23)	(col.24)	(col.25)	(col.26)
	COST OF SERVICE				
1	Operation and maintenance	$6,800	$6,800	$6,800	$6,800
2	Depreciation	52,007	56,385	61,089	66,143
	Taxes:				
3	Income Federal & State	3,737	3,079	2,363	1,588
4	Other	4,895	4,590	4,304	4,035
5	Return @ 10.42 %	15,558	12,144	8,442	4,431
6	Total	$82,997	$82,998	$82,998	$82,997

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SUNSHINE GAS PIPELINE COMPANY
RETURN AND INCOME TAXES

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12)
	RETURN											
1	Plant	$437,500	$437,500	$437,500	$565,400	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900
2	Reserve for depreciation	0	15,113	32,415	52,986	55,647	58,342	47,600	47,482	50,001	55,248	63,330
3	Net plant	$437,500	$422,387	$405,085	$512,414	$563,253	$560,558	$571,300	$571,418	$568,899	$563,652	$555,570
	Working capital											
4	Cash working capital	$438	$438	$438	$650	$850	$850	$850	$850	$850	$850	$850
5	Materials and supplies	0	0	0	0	0	0	0	0	0	0	0
6	Total working capital	$438	$438	$438	$650	$850	$850	$850	$850	$850	$850	$850
7	Less: Accumulated deferred taxes	$0	$2,501	$11,476	$17,704	$31,540	$50,196	$67,224	$82,157	$95,583	$107,518	$118,113
8	Rate base	$437,938	$420,323	$394,046	$495,360	$532,563	$519,212	$504,926	$490,111	$474,166	$456,984	$438,307
9	Return @ 10.42 %	$45,633	$43,798	$41,068	$51,616	$55,493	$54,102	$52,613	$51,070	$49,408	$47,618	$45,672
	INCOME TAXES											
10	Return	$45,633	$43,798	$41,060	$51,616	$55,493	$54,102	$52,613	$51,070	$49,408	$47,618	$45,672
11	Less: Interest	30,043	28,834	27,032	33,982	36,534	35,618	34,638	33,622	32,528	31,349	30,068
12	Plus: Equity AFUDC	255	293	348	45	(90)	(46)	(2)	43	89	137	187
13	Tax base	$15,845	$15,257	$14,376	$17,679	$18,869	$18,438	$17,973	$17,491	$16,969	$16,406	$15,791
14	Fed Taxes @ 34.0%	$8,163	$7,860	$7,406	$9,107	$9,720	$9,498	$9,259	$9,010	$8,742	$8,452	$8,135
15	State taxes @ 5.5%	1,397	1,345	1,268	1,559	1,664	1,626	1,585	1,542	1,496	1,447	1,392
16	Total income taxes	$9,560	$9,205	$8,674	$10,666	$11,384	$11,124	$10,844	$10,552	$10,238	$9,899	$9,527

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SUNSHINE GAS PIPELINE COMPANY
RETURN AND INCOME TAXES

DESCRIPTION	2006	2007	2008	2009	2010	2011	2012	2013	2014
(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)
RETURN									
Plant	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900	$618,900
Reserve for depreciation	74,391	88,613	106,208	127,403	152,448	181,612	214,592	251,068	291,288
Net plant	$544,509	$530,287	$512,692	$491,497	$466,452	$437,288	$404,308	$367,832	$327,612
Working capital									
Cash working capital	$850	$850	$850	$850	$850	$850	$850	$850	$850
Materials and supplies	0	0	0	0	0	0	0	0	0
Total working capital	$850	$850	$850	$850	$850	$850	$850	$850	$850
Less: Accumulated deferred taxes	$127,541	$135,799	$142,810	$148,489	$152,743	$150,693	$142,656	$132,924	$120,611
Rate base	$417,818	$395,338	$370,732	$343,858	$314,559	$287,445	$262,702	$235,758	$207,851
Return @ 10.42 %	$43,537	$41,194	$38,630	$35,830	$32,777	$29,952	$27,374	$24,566	$21,658
INCOME TAXES									
Return	$43,537	$41,194	$38,630	$35,830	$32,777	$29,952	$27,374	$24,566	$21,658
Less: Interest	28,662	27,120	25,432	23,589	21,579	19,719	18,021	16,173	14,259
Plus: Equity AFUDC	241	298	359	424	493	558	617	680	745
Tax base	$15,116	$14,372	$13,557	$12,665	$11,691	$10,791	$9,970	$9,073	$8,144
ed Taxes @ 34.0%	$7,787	$7,404	$6,984	$6,524	$6,023	$5,559	$5,136	$4,674	$4,195
tate taxes @ 5.5%	1,333	1,267	1,195	1,117	1,031	952	879	800	718
Total income taxes	$9,120	$8,671	$8,179	$7,641	$7,054	$6,511	$6,015	$5,474	$4,913

SUNSHINE GAS PIPELINE COMPANY
RETURN AND INCOME TAXES

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
	(col. 1)	(col.22)	(col.23)	(col.24)	(col.25)	(col.26)
	RETURN					
1	Plant	$618,900	$618,900	$618,900	$618,900	$618,900
2	Reserve for depreciation	335,346	383,274	435,281	491,666	552,755
3	Net plant	$283,554	$235,626	$183,619	$127,234	$66,145
	Working capital					
4	Cash working capital	$850	$850	$850	$850	$850
5	Materials and supplies	0	0	0	0	0
6	Total working capital	$850	$850	$850	$850	$850
7	Less: Accumulated deferred taxes	$104,896	$87,166	$67,927	$47,068	$24,469
8	Rate base	$179,508	$149,310	$116,542	$81,016	$42,526
9	Return @ 10.42 %	$18,705	$15,558	$12,144	$8,442	$4,431
	INCOME TAXES					
10	Return	$18,705	$15,558	$12,144	$8,442	$4,431
11	Less: Interest	12,314	10,243	7,995	5,558	2,917
12	Plus: Equity AFUDC	811	880	954	1,034	1,119
13	Tax base	$7,202	$6,195	$5,103	$3,918	$2,633
14	Fed Taxes @ 34.0%	$3,710	$3,191	$2,629	$2,018	$1,356
15	State taxes @ 5.5%	635	546	450	345	232
16	Total income taxes	$4,345	$3,737	$3,079	$2,363	$1,588

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Exhibit ___ (PRC-9)
Docket No. 920807-GP

SUNSHINE GAS
PIPELINE COMPANY
DERIVATION OF DEFERRED RECOVERY
($000'S)

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999
	(Col. 1)	(Col.2)	(Col.3)	(Col.4)	(Col.5)	(Col.6)
1	LEVELIZED FIXED COST OF SERVICE	$81,325	$81,325	$81,325	$81,325	$81,325
2	MDQ - MDTH/D	249.5	249.5	249.5	424.5	549.5
	BASE RESERVATION RATE					
3	PER DTH/D-(YEAR 1999)	$12.3332	$12.3332	$12.3332	$12.3332	$12.3332
	REVENUE COLLECTION ON BASE RATE					
4	(LINE 2 X LINE 3 X 12 MONTHS)	$36,926	$36,926	$36,926	$62,825	$81,325
5	DEFERRED RECOVERY (LINE 1 - LINE 4)	$44,399	$44,399	$44,399	$18,500	$0
6	LESS INC. TAXES ON DEFERRED RECOVERY	$9,560	$9,205	$8,674	$6,961	$0
7	AFTER-TAX DEFERRED RECOVERY(LINE5-LINE6)	$34,839	$35,194	$35,725	$11,538	$0
8	CUMULATIVE AFTER-TAX DEFERRED RECOVERY	$34,839	$70,034	$105,759	$117,298	$117,298
9	AVERAGE CUMULATIVE DEFERRED RECOVERY	$17,420	$52,437	$87,897	$111,529	$117,298
	DEVELOPMENT OF DEFERRED RECOVERY RETURN					
10	AFTER-TAX DEFERRED RECOVERY(LINE5-LINE6)	$34,839	$35,194	$35,725	$11,538	$0
11	EQUITY PORTION OF DEFERRED RECOVERY	$15,591	$14,964	$14,028	$11,538	$0
12	DEBT PORTION OF DEFERRED RECOVERY	$19,249	$20,231	$21,697	$0	$0
13	AFTER-TAX DEFERRED RECOVERY (LINE 10)	$34,839	$35,194	$35,725	$11,538	$0
	CUMULATIVE EQUITY PORTION OF					
14	DEFERRED RECOVERY	$15,591	$30,554	$44,582	$56,121	
	CUMULATIVE DEBT PORTION OF					
15	DEFERRED RECOVERY	$19,249	$39,480	$61,177	$61,177	
16	CUMULATIVE EQUITY PERCENTAGE	44.75%	43.63%	42.15%	47.84%	47.84%
17	CUMULATIVE DEBT PERCENTAGE	55.25%	56.37%	57.85%	52.16%	52.16%
18	CUMULATIVE OVERALL RETURN	11.43%	11.37%	11.29%	11.58%	11.58%

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Exhibit ___ (PRC-9)
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SUNSHINE GAS PIPELINE CO. - 25 YEARS
STANDARD COST OF SERVICE
ON DEFERRED RECOVERY

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12
	COST OF SERVICE											
1	Operation and maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Amortization	6,941	1,841	(4,194)	(2,856)	600	717	844	1,005	1,198	1,423	1,684
	Taxes:											
3	Income Federal & State	1,201	3,121	5,391	7,560	8,169	8,127	8,076	8,017	7,945	7,861	7,760
4	Other	0	0	0	0	0	0	0	0	0	0	0
5	Return	1,991	5,173	8,935	12,530	13,540	13,470	13,386	13,287	13,169	13,029	12,862
6	Total	$10,133	$10,135	$10,132	$17,234	$22,309	$22,314	$22,306	$22,309	$22,312	$22,313	$22,306

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2016

SUNSHINE GAS PIPELINE CO. - 25 YEARS
STANDARD COST OF SERVICE
ON DEFERRED RECOVERY

LINE NO.	DESCRIPTION	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)	(col.22)
	COST OF SERVICE										
1	Operation and maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Amortization	2,002	2,380	2,826	3,355	3,998	4,739	5,627	6,686	7,941	9,436
	Taxes:										
3	Income Federal & State	7,641	7,500	7,332	7,131	6,895	6,612	6,277	5,879	5,407	4,845
4	Other	0	0	0	0	0	0	0	0	0	0
5	Return	12,665	12,430	12,152	11,820	11,427	10,960	10,405	9,745	8,962	8,032
6	Total	$22,308	$22,310	$22,310	$22,306	$22,312	$22,311	$22,309	$22,310	$22,310	$22,313

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SUNSHINE GAS PIPELINE CO. - 25 YEARS
STANDARD COST OF SERVICE
ON DEFERRED RECOVERY

LINE NO.	DESCRIPTION	2016	2017	2018	2019	25 YEAR AVERAGE
	(col. 1)	(col.23)	(col.24)	(col.25)	(col.26)	
	COST OF SERVICE					
1	Operation and maintenance	$0	$0	$0	$0	$0
2	Amortization	11,206	13,312	15,815	18,781	4,692
	Taxes:					
3	Income Federal & State	4,179	3,387	2,445	1,328	6,003
4	Other	0	0	0	0	0
5	Return	6,926	5,613	4,053	2,200	9,951
6	Total	$22,311	$22,312	$22,313	$22,309	$20,646

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SUNSHINE GAS PIPELINE CO. - 25 YEARS
RETURN AND INCOME TAXES
ON DEFERRED RECOVERY

LINE NO.	DESCRIPTION	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	(col. 1)	(col.2)	(col.3)	(col.4)	(col.5)	(col.6)	(col.7)	(col.8)	(col.9)	(col.10)	(col.11)	(col.12)
	RETURN											
1	Average Cumulative Deferred Return	$17,420	$52,437	$87,897	$111,529	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298
2	Reserve for amortization	0	6,941	8,782	4,588	1,732	2,332	3,049	3,893	4,898	6,096	7,519
3	Net Deferred Return	$17,420	$45,496	$79,115	$106,941	$115,566	$114,966	$114,249	$113,405	$112,400	$111,202	$109,779
4	Return	11.43% $1,991	11.37% $5,173	11.29% $8,935	11.72% $12,530	11.72% $13,540	11.72% $13,470	11.72% $13,386	11.72% $13,287	11.72% $13,169	11.72% $13,029	11.72% $12,862
	INCOME TAXES											
5	Return	$1,991	$5,173	$8,935	$12,530	$13,540	$13,470	$13,386	$13,287	$13,169	$13,029	$12,862
6	Less: Interest	0	0	0	0	0	0	0	0	0	0	0
7	Tax base	$1,991	$5,173	$8,935	$12,530	$13,540	$13,470	$13,386	$13,287	$13,169	$13,029	$12,862
8	Fed Taxes @ 34.0%	$1,025	$2,665	$4,603	$6,455	$6,975	$6,939	$6,896	$6,845	$6,784	$6,712	$6,626
9	State taxes @ 5.5%	176	456	788	1,105	1,194	1,188	1,180	1,172	1,161	1,149	1,134
10	Total income taxes	$1,201	$3,121	$5,391	$7,560	$8,169	$8,127	$8,076	$8,017	$7,945	$7,861	$7,760

04-16-93 03:24 PM

Exhibit ___ (PRC-9)
Docket No. 920807-GP

04-19-93 03:24 PM

SUNSHINE GAS PIPELINE CO. - 25 YEARS
RETURN AND INCOME TAXES
ON DEFERRED RECOVERY

16-Apr-93

LINE NO.	DESCRIPTION	2006	2007	2008	2009	2010	2011	2012	2013	2014
	(col. 1)	(col.13)	(col.14)	(col.15)	(col.16)	(col.17)	(col.18)	(col.19)	(col.20)	(col.21)
	RETURN									
1	Average Cumulative Deferred Return	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298	$117,298
2	Reserve for amortization	9,203	11,205	13,585	16,411	19,766	23,756	28,495	34,122	40,808
3	Net Deferred Return	$108,095	$106,093	$103,713	$100,887	$97,532	$93,542	$88,803	$83,176	$76,490
4	Return	11.72% $12,665	11.72% $12,430	11.72% $12,152	11.72% $11,820	11.72% $11,427	11.72% $10,960	11.72% $10,405	11.72% $9,745	11.72% $8,962
	INCOME TAXES									
5	Return	$12,665	$12,430	$12,152	$11,820	$11,427	$10,960	$10,405	$9,745	$8,962
6	Less: Interest	0	0	0	0	0	0	0	0	0
7	Tax Base	$12,665	$12,430	$12,152	$11,820	$11,427	$10,960	$10,405	$9,745	$8,962
8	Fed Taxes @ 34.3%	$6,524	$6,404	$6,260	$6,089	$5,887	$5,646	$5,360	$5,020	$4,617
9	State taxes @ 5.5%	1,117	1,096	1,072	1,042	1,008	966	917	859	790
10	Total income taxes	$7,641	$7,500	$7,332	$7,131	$6,895	$6,612	$6,277	$5,879	$5,407

Exhibit ___ (PRC-9)
Docket No. 920807-GP

SUNSHINE GAS PIPELINE CO. - 25 YEARS
RETURN AND INCOME TAXES
ON DEFERRED RECOVERY

LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
	(col. 1)	(col.22)	(col.23)	(col.24)	(col.25)	(col.26)
	RETURN					
1	Average Cumulative Deferred Return	$117,298	$117,298	$117,298	$117,298	$117,298
2	Reserve for amortization	48,749	58,185	69,391	82,703	98,518
3	Net Deferred Return	$68,549	$59,113	$47,907	$34,595	$18,780
4	Return	11.72%	11.72%	11.72%	11.72%	11.72%
		$8,032	$6,926	$5,613	$4,053	$2,200
	INCOME TAXES					
5	Return	$8,032	$6,926	$5,613	$4,053	$2,200
6	Less: Interest	0	0	0	0	0
7	Tax base	$8,032	$6,926	$5,613	$4,053	$2,200
8	Fed Taxes @ 34.0%	$4,137	$3,568	$2,892	$2,088	$1,134
9	State taxes @ 5.5%	708	611	495	357	194
10	Total income taxes	$4,845	$4,179	$3,387	$2,445	$1,328

04-16-93 03:24 PM
Exhibit ___ (PRC-9)
Docket No. 920807-GP

Florida Power
CORPORATION

March 16, 1993

Stephen Watsey
Vice President
Purchasing and Stores

Mr. James F. Cordes
ANR Southern Pipeline Company
Coastal Tower
9 Greenway Plaza
Houston, Texas 77046-0995

RE: SunShine Pipeline Project (the "SunShine Project") and SunShine Interstate Pipeline Project (the "SITCO Project") collectively (the "Projects")

Dear Mr. Cordes:

Effective February 15, 1993, ANR Southern Pipeline Company (ANR Southern), Florida Power Corporation (FPC), Power Energy Services Corporation (PESCORP), and Power Interstate Energy Services Corporation (PIESCORP) agreed to the terms of my February 12, 1993 letter (the "Letter Agreement") concerning the SunShine Pipeline Project and the SunShine Interstate Pipeline Project (collectively "the Projects"). The purpose of the instant letter is to amend certain provisions of the Letter Agreement.

Paragraph 2 of the Letter Agreement provides that PESCORP shall have the right to exercise the Primary Option "until a date ten days after the date that the Florida Public Service Commission (FPSC) or a panel of FPSC hearing officers issues its final order, no longer subject to rehearing or further FPSC review, with respect to the application for a determination of need for the SunShine Project (the 'First Expiration Date')...." Paragraph 3 of the Letter Agreement grants PIESCORP the same Primary Option until the First Expiration Date.

ANR Southern acknowledges that the decisions of PESCORP and PIESCORP as to whether to exercise their respective Primary Options depend in part upon FPSC approval, prior to the First Expiration Date, of FPC's request for FPSC approval to set an approved return on equity for FPC's investment in the Projects, and effect a true-up to the allowed return through its fuel adjustment clause or other rate mechanism. It now appears that the FPSC will not act on FPC's request until a date after the First Expiration Date, as defined in the Letter Agreement, and the uncertainty created by this sequence of events could cause PESCORP and PIESCORP to exercise their Primary Options. ANR Southern desires that PESCORP and PIESCORP maintain a substantial equity ownership in the Projects and the partnerships entered into by ANR Southern, PESCORP and PIESCORP to pursue the Projects. ANR Southern, FPC, PESCORP and PIESCORP agree that it is in their mutual best interests to extend the First Expiration date in order to better afford FPC the opportunity to achieve the regulatory approvals it seeks. Therefore, ANR Southern, FPC, PESCORP and PIESCORP have agreed to extend the First Expiration Date by deleting the first sentence of paragraph 2 of the Letter Agreement, and substituting in its place the following:

> PESCORP shall have the right and option (a "Primary Option") until the earlier of December 31, 1993 or ten days after the date the Florida Public Service Commission (FPSC) or a panel of FPSC commissioners issues its final order, no longer subject to rehearing or further FPSC review, with respect to FPC's application for FPSC approval to set an approved return on equity for FPC's investment in the Projects and effect a true-up to the allowed return through its

fuel adjustment clause or other rate mechanism (the "First Expiration Date"), by written notice to require ANR Southern, or at ANR Southern's election a party designated by ANR Southern, to acquire from PESCORP up to all of PESCORP's 33 1/3% equity ownership interest in the SunShine Project and the SunShine Development Partnership; provided, that if PESCORP elects to retain an equity interest in the SunShine Project and the Sunshine Development Partnership, it must retain at least a 5% interest.

If the foregoing accurately reflects your understanding of our agreement with respect to the subject matter set out above, please so indicate by signing in the space provided below, and returning a signed counterpart hereof to me.

Very truly yours,

Florida Power Corporation

By: Stephen Watsey
Stephen Watsey

Power Energy Services Corporation

By: Stephen Watsey

Power Interstate Energy Services Corporation

By: Stephen Watsey

ACCEPTED AND AGREED TO THIS 16TH DAY OF MARCH, 1993.

ANR Southern Pipeline Company

By: James F Cordes
James F. Cordes

October 28, 1992 Planned Volumes
Sunshine Is Facing A Sizable Revenue Shortfall

Unit Rate $ 0.5250 /MMDth
Rate of Return: 10.42%

	Sunshine		ANR 10/28/92 Planned Volumes		Revenue Shortfall	
year	MDQ (MMDth/day)	Implied Revenues ($ Millions)	MDQ (MMDth/day)	Implied Revenues ($ Millions)	By year ($ Millions)	Present Value ($ Millions)
1995	250	47.9	219	42.0	5.9	5.9
1996	250	47.9	219	42.0	5.9	5.4
1997	250	47.9	219	42.0	5.9	4.9
1998	425	81.4	399	76.5	5.0	3.7
1999	550	105.4	399	76.5	28.9	19.5
2000	550	105.4	399	76.5	28.9	17.6
2001	550	105.4	399	76.5	28.9	16.0
2002	550	105.4	399	76.5	28.9	14.5
2003	550	105.4	399	76.5	28.9	13.1
2004	550	105.4	399	76.5	28.9	11.9
2005	550	105.4	399	76.5	28.9	10.7
2006	550	105.4	399	76.5	28.9	9.7
2007	550	105.4	399	76.5	28.9	8.8
2008	550	105.4	399	76.5	28.9	8.0
2009	550	105.4	399	76.5	28.9	7.2
2010	550	105.4	399	76.5	28.9	6.5
2011	550	105.4	399	76.5	28.9	5.9
2012	550	105.4	399	76.5	28.9	5.4
2013	550	105.4	399	76.5	28.9	4.9
2014	550	105.4	399	76.5	28.9	4.4
2015	550	105.4	399	76.5	28.9	4.0
2016	550	105.4	399	76.5	28.9	3.6
2017	550	105.4	399	76.5	28.9	3.3
2018	550	105.4	399	76.5	28.9	3.0
2019	550	105.4	399	76.5	28.9	2.7

	Millions of $
Total Pretax Shortfall (PV in 1995)	200.4
FPC's Equity Investment @ 1/3 Ownership	51.6
Total Equity Invested @ 75%D. / 25%E.	154.7

Existing Florida Investor Owned Utility Generating Plants

		Net Capability	Capacity Factor	Net Generation	Quantity (MMBtu) Gas	Oil	Coal	Total	% Oil
FPL	St Johns River	250	91%	1,962,645		39,053	18,271,283	18,310,337	0%
FPL	St Lucie-Nuclear	1,579	89%	12,118,000				0	
FPC	Crystal River-No	1,434	77%	9,519,166		274,556	88,341,219	88,615,776	0%
FPC	Crystal River-Nuclear	747	76%	4,911,000				0	
GP	Smith*	354	75%	2,290,446		28,110	23,739,703	23,767,813	0%
TE	Big Bend-Coal	1,674	72%	10,451,000			103,446,023	103,446,023	
FPC	Crystal River-So	842	71%	5,210,038		246,667	51,700,283	51,946,950	0%
FPL	Port Everglades	1,148	69%	6,837,128	23,494,228	43,903,743		67,397,971	65%
FPL	Turkey Point	740	60%	3,828,090	18,884,353	20,039,730		38,924,083	51%
FPL	Putnam-CC	468	59%	2,392,288	23,106,732	23,650		23,130,382	0%
FPC	Bartow	442	56%	2,164,852	5,143	21,962,053		21,967,196	100%
TE	Gannon-Coal	1,158	56%	5,579,000			58,374,414	58,374,414	
FPL	Fort Myers	508	53%	2,336,460		22,681,284		22,681,284	100%
FPL	Cape Canaveral	740	48%	3,110,198	7,973,922	22,726,595		30,700,517	74%
GP	Crist*	1,090	46%	4,330,644	893,487	61,528	46,089,514	47,044,529	0%
FPL	Riviera	548	45%	2,134,097	8,105,750	14,019,498		22,125,248	63%
FPL	Cutler	206	37%	659,235	7,784,106			7,784,106	0%
FPC	Anclote	1,034	37%	3,285,947		33,501,653		33,501,653	100%
FPL	Lauderdale	276	35%	847,044	8,901,428	674,045		9,575,473	7%
FPL	Manatee	1,580	35%	4,749,656		47,433,526		47,433,526	100%
FPL	Sanford	871	34%	2,554,192	4,426,602	17,568,142	5,425,831	27,420,575	64%
FPL	Martin	1,580	31%	4,222,336	27,982,749	15,584,025		43,566,774	36%
FPC	Turner	145	25%	317,569		3,447,968		3,447,968	100%
GP	Scholtz*	92	24%	188,530		2,648	2,300,299	2,302,947	0%
FPC	Higgins	123	22%	238,937		2,848,780		2,848,780	100%
FPC	Suwannee	147	22%	275,462	1,698,484	1,560,630		3,259,114	48%
FPL	Turkey Point-Nuclear	1,376	17%	2,013,000				0	
TE	Hookers Point	206	12%	221,920		3,331,004		3,331,004	100%
TE	Phillips-IC	38	10%	34,055		335,484		335,484	100%
FPC	Debary	330	4%	127,741		1,854,111		1,854,111	100%
FPC	Suwannee-GT	195	4%	70,374		1,009,313		1,009,313	100%
FPL	Port Everglades-GT	486	3%	142,863	2,262,191	181,527		2,443,718	7%
FPC	Intercession City-GT	342	3%	96,959		1,361,359		1,361,359	100%
FPL	Lauderdale-GT	972	3%	224,681	3,451,951	292,642		3,744,593	8%
FPC	Bayboro	216	2%	45,454		628,972		628,972	100%
FPC	Turner-GT	194	2%	37,600		555,227		555,227	100%
FPC	Bartow-GT	212	2%	34,377		516,543		516,543	100%
FPC	Higgins-GT	126	2%	19,764	62,251	279,002		341,252	82%
TE	Gannon-CT	14	2%	2,164		41,502		41,502	100%
TE	Big Bend-CT	174	2%	23,549		375,821		375,821	100%
FPC	Avon Park-GT	60	1%	4,507	1,368	76,997		78,365	98%
FPL	Fort Myers-GT	756	1%	33,674		514,989		514,989	100%
GP	Smith-CT	35	0%	1,217		21,578		21,578	100%
FPC	Rio Pinar-GT	17	0%	584		12,549		12,549	100%
FPC	Port St Joe-GT	17	0%	567		13,505		13,505	100%

Source: 1991 Ferc Form 1

October 28, 1992

Mr. Stephen Watsey
Vice President, Purchasing and Stores
Florida Power Corporation
3201 Thirty-fourth Street South
P. O. Box 14042
St. Petersburg, Florida 33733

Re: SunShine Pipeline Company and
SunShine Interstate Transmission Company

Dear Mr. Watsey:

Pursuant to your letter dated October 21, 1992 to Mr. Charles M. Oglesby regarding our company's interest in providing natural gas service to Florida Power Corporation's existing Anclote Plant and the proposed new units in Polk County, Florida, please find enclosed a Term Sheet highlighting the major elements of the proposed long term transportation agreements between the above referenced companies and FPC.

We acknowledge that the Precedent Agreements dated September 11, 1992 that were previously sent to you will require modifications based on the enclosed Term Sheet and our recent discussions on relevant dates. However, we would anticipate that such Precedent Agreements as well as the proposed General Partnership Agreement previously negotiated between our representatives would form the framework of the overall transaction contemplated by our respective companies.

If there is a need to elaborate upon or clarify any particular point contained in the enclosure, please do not hesitate to call at your earliest convenience. Thanking you for the opportunity to participate in this process, I am

Very truly yours,

E. J. Burgin

TERM SHEET

General Parameters

- Capacity

  Option 1

  - SunShine Pipeline Company (SunShine) 219,000 MMBTU/day in 1995 with increase to 399,000 MMBTU/day in 1999

  - SunShine Interstate Transmission Company (SITCO) 324,500 MMBTU/day in 1995 with increase to 504,000 MMBTU/day in 1999

  Option 2

  - SunShine Pipeline Company (SunShine) 239,000 MMBTU/day in 1995 with increase to 419,000 MMBTU/day in 1999

  - SunShine Interstate Transmission Company (SITCO) 344,500 MMBTU/day in 1995 with increase to 524,000 MMBTU/day in 1999

  Option 3

  - SunShine Pipeline Company (SunShine) 219,000 MMBTU/day in 1995 with increase to 444,000 MMBTU/day in 2000

  - SunShine Interstate Transmission Company (SITCO) 324,500 MMBTU/day in 1995 with increase to 549,000 MMBTU/day in 2000

  Option 4

  - SunShine Pipeline Company (SunShine) 239,000 MMBTU/day in 1999 with increase to 464,000 MMBTU/day in 2000

  - SunShine Interstate Transmission Company (SITCO) 344,500 MMBTU/day in 1999 with increase to 569,000 MMBTU/day in 2000

- Capital

  Option 1

  - $641.8 MM Total Project

  Option 2

  - $656.8 MM Total Project

Option 3

- $655.7 MM Total Project

Option 4

- $673.6 MM Total Project

- Rates and Volumes

Option 1

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999

Rate: $0.673/MMBtu
Estimate Fuel: 0.9%

Option 2

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999
Ellaville	20,000	1996

Rate: $0.66/MMBtu
Estimate Fuel: 0.9%

Option 3

Florida Power Corp.	Volumes/Day MMBtu	
Anclote	120,000	1995-1996
Power Park	45,000	1998
Power Park	45,000	1999
Anclote	45,000	2000

Rate: $0.641/MMBtu
Estimate Fuel: 1.0%

Option 4

Florida Power Corp. Volumes/Day MMBtu

"Option 1, 2 and 3" Volumes

Rate: $0.628/MMBtu
Estimate Fuel: 1.1%

- Facilities
  - SunShine will begin at an interconnection with SITCO and extend down the west coast of Florida terminating in Polk County. Laterals will be constructed to serve subsequent volumes not on the mainline route.
  - SITCO will extend from the terminus of Chandeleur Pipeline Company and the outlet of the Chevron Magnolia Plant to a point of interconnection with SunShine at the Okaloosa/Walton county line. The system will also have direct interconnections with Gateway Pipeline, Mobile Bay Pipeline and United Gas Pipe Line
- Regulatory Authority
  - SunShine will be a non-discriminatory transporter built as a Hinshaw exempt Intrastate pipeline under Section 1(c) of the Natural Gas Act (NGA). Its construction and operation will be regulated by the Florida Public Service Commission
  - SITCO will be an open access, transportation only pipeline built and operated under the regulation of the Federal Energy Regulatory Commission (FERC) pursuant to Section 7(c) of the NGA

Rates

Option 1

- SunShine initial rate of 52.5¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.8¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 67.3¢/MMBTU for SunShine and SITCO.

Option 2

- SunShine initial rate of 51.72¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.27¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 66.00¢/MMBTU for SunShine and SITCO.

Option 3

- SunShine initial rate of 49.96¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 14.17¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 64.1¢/MMBTU for SunShine and SITCO.

Option 4

- SunShine initial rate of 49.08¢/MMBTU based on twenty-five years levelized cost-of-service rates
- SITCO initial rate of 13.72¢/MMBTU based on twenty-five years levelized cost-of-service rates
- Total initial rate of 62.80¢/MMBTU for SunShine and SITCO.

- Aggregate initial rate cap of:

  Option 1

  71.8¢/MMBTU

  Option 2

  70.5¢/MMBTU

  Option 3

  70.6¢/MMBTU

  Option 4

- Aggregate rate cap shall be exclusive of surcharges and fuel

- 45% of the aggregate rate cap and each successive rate cap shall be increased annually by the greater of the GNP Implicit Price Deflator or 4%

- For the first twenty years of the term of FPC's contract, the aggregate rate cap shall be capped at:

  84¢/MMBtu for Option 1.

  83.5¢/MMBtu for Option 2.

  83¢/MMBtu for Option 3.

  82¢/MMBtu for Option 4.

- Aggregate rate cap for the first contract year may be increased by the percentage increase in the GNP Implicit Price Deflator for the period between February 1, 1995 and the actual in-service date, if later

- Within the aggregate rate cap, rates on SunShine and SITCO may be adjusted from time to time through normal ratemaking procedures of the Florida Public Service Commission or the Federal Energy Regulatory Commission, respectively

- Subject to FERC ruling on the discriminatory nature of rate cap treatment, Sunshine reserves the right to adjust its rate cap accordingly to be in compliance with FERC policy

Agency Agreement

- At the request of Shipper, SunShine Marketing Company would act as agent to hold and manage capacity on SunShine and SITCO.

Fuel

- Total fuel on the combined SunShine and SITCO System to be capped at 2.5%.

FGT Upstream Pipeline Interconnections

State	Company	Capacity (MMCf/Day)
LOUISIANA	ANR	90
	Acadian	35
	Columbia Gulf	90
	CSX	140
	Louisiana Intrastate	125
	Sabine	150
	Southern Natural*	420
	Tennessee	130
	Texas Eastern	120
	Texas Gas	85
	Transcontinental	640
	Trunkline	300
	United Gas	240
	Williams	120
Louisiana Total		2,685
TEXAS	Dow	80
	Houston Pipeline	400
	Matagorda (MOPS)	240
	Natural Gas Pipeline	35
	Texas Eastern	55
	United Gas	90
	United Texas	110
	Valero	55
Texas Total		1,065
Other Total		260
TOTAL		4,010

* Requires meter station upgrade of Southern's facilities at Franklinton to accomodate increase in capacity from 258 MMCf/Day.

Source: FGT Phase III Certification Application, Exhibit H, Docket No. CP92-182-000, Nov 15,1991.

Of

Mexi

PIPELINE
- EXISTING PIPELINE & SIZE
- JOINT OWNERSHIP
- MAJOR RIVER CROSSING-SUBMERGED
- MAJOR RIVER CROSSING-AERIAL
- FLOW

MEASUREMENT
- EXISTING METER STATION

COMPRESSOR STATIONS
- EXISTING COMPRESSOR STATION
- FIELD COMPRESSOR

TOPOGRAPHY
- GAS PRODUCING FIELDS
- MAJOR CITIES
- CITIES OR TOWNS
- OPERATING HEADQUARTERS
- WAREHOUSE
- ENRON GAS PROCESSING CO.

ABBREVIATIONS

FPU	FLORIDA PUBLIC UTILITIES
FPC	FLORIDA POWER CORPORATION
CFG	CENTRAL FLORIDA GAS
CUCO	CITY GAS COMPANY
PGS	PEOPLES GAS SYSTEM
FP&L	FLORIDA POWER & LIGHT COMPANY
WFNG	WEST FLORIDA NATURAL GAS

FLORIDA GAS TRANSMISSION COMPANY

HOUSTON, TEXAS

FACILITY PLANNING DEPARTMENT

GAS TRANSMISSION SYSTEM

DATE: JANUARY 1980

T E X A S
M E X I C O
Gulf
HOUSTON EXCH.
NGPL EXCH
GALENA
SHENANDO
JONES CREEK
N. WITHERS
HELEN GOHLKE
S.W. HELEN GOHLKE
N. LA WARD
MARKHAM
BRAZOS
HPL EXCH.
VALERO EXCH.
TEXAS EASTERN EXCH.
CLARA GRISCOLL
INGRAM
CORPUS PASS
SHIP CHANNEL
S. MUSTANG ISL.
S. CORPUS CHRISTI
MOPS
TIJERINA CANALES
GRIPPER
GUADALUPE
STARR PLT.
N. RINCON & PEASQUITES
N. MONTE CHRISTO
CORTEZ
OBLATE
SHARYLAND
SO. MCALLEN
POTRERO LOPENO

SOUTH CAROLINA
GEORGIA
ALABAMA
FLORIDA
Atlantic Ocean
Mexico