FLORIDA PUBLIC SERVICE COMMISSION
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TO: DIRECTOR, DIVISION OF RECORDS AND REPORTING (BAYO) FPSC - Records/Reporting

FROM: DIVISION OF ELECTRIC & GAS (JENKINS, TRAPP, FLOYD, BALLINGER, DUDLEY, BREMAN, HARLOW, WHEELER) DIVISION OF AUDITING & FINANCIAL ANALYSIS (STALLCUP, MAUREY, MCNULTY, SLEMKEWICZ) DIVISION OF LEGAL SERVICES (ELIAS, WAGNER)

RE: DOCKET NO. 961477-EQ - FLORIDA POWER CORPORATION - PETITION FOR EXPEDITED APPROVAL OF SETTLEMENT AGREEMENT WITH LAKE COGEN, LTD. BY FLORIDA POWER CORPORATION

AGENDA: 06/24/97 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: NONE

SPECIAL INSTRUCTIONS: S:\PSC\EAG\WP\961477EQ.RCM

ATTACHMENTS NOT PART OF WORDPERFECT DOCUMENT

CASE BACKGROUND

Florida Power Corporation (FPC) and Lake Cogen Ltd. (Lake), a qualifying facility (QF), entered into a Negotiated Contract (Contract) on March 13, 1991. The term of the Contract is 20 years, beginning July 1, 1993 when the facility began commercial operation, and expiring July 31, 2013. Committed capacity under the Contract is 110 megawatts, with capacity payments based on a 1991 pulverized coal-fired avoided unit. The Contract was one of eight QF contracts which were originally approved for cost recovery by the Commission in Order No. 24734, issued July 1, 1991, in Docket No. 910401-EQ.

In August, 1994, a dispute arose between FPC and Lake regarding the interpretation of the energy pricing methodology as defined by Section 9.1.2 of the Contract. Section 9.1.2 of the Contract is as follows:

> Except as otherwise provided in section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based

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> upon the Firm Energy Cost calculated on an hour-by hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Reference Plant, the Fuel Multiplier, and the Avoided Unit Heat Rate, plus the Avoided Unit Variable O&M, if applicable, for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

In 1991, the time at which FPC entered into its contract with Lake, FPC's forecasts indicated that as-available energy prices would exceed firm energy prices throughout the entire term of the Contract. Based on these projections, prior to August 1994, FPC paid Lake firm energy payments for all energy delivered from the cogeneration facility. In 1994, FPC conducted an internal audit of its cogeneration contracts. Because of falling coal, oil, and natural gas prices, excess generation during low load conditions, and exceptional nuclear performance, FPC's modeling of the avoided unit indicated that during certain hours, firm energy prices would be greater than as-available energy prices indicating that the avoided unit would be cycled off in FPC's dispatch. FPC adjusted its payments to Lake and other cogenerators to reflect these changes in the operation of the avoided unit. This reduced the total energy payment to Lake and ultimately led to the pricing dispute.

On July 21, 1994, FPC filed a petition (Docket No. 940771-EQ) seeking a declaratory statement that Section 9.1.2 of the negotiated contract was consistent with then Rule 25-17.0832(4)(b), Florida Administrative Code. This rule referenced avoided energy payments for standard offer contracts, and was a basis for evaluating negotiated contracts. Several cogenerators, including Lake, filed motions to dismiss FPC's petition. FPC later amended its petition and asked the Commission to determine whether its implementation of Section 9.1.2 was lawful under Section 366.051, Florida Statutes, and consistent with Rule 25-17.0832(4)(b), Florida Administrative Code. In Order No. PSC-95-0210-FOF-EQ, the Commission granted the motions to dismiss on the grounds that the Commission did not have jurisdiction to adjudicate a dispute over a provision in a negotiated contract. However, the Order recognized the Commission's continued responsibility for cost recovery review. The Order is attached to this recommendation as Attachment 1.

Subsequent to the filing of FPC's petition in Docket No. 940771-EQ, Lake and other QFs, filed lawsuits in the state courts for breach of contract. On January 23, 1996, the Fifth Judicial

Circuit Court issued a Partial Summary Judgement (Summary Judgement) for Lake in Case No. 94-2354-CA-01 regarding the energy pricing dispute. The Partial Summary Judgement is attached to this recommendation as Attachment 2.

On November 25, 1996, FPC filed a petition for approval of a Settlement Agreement between FPC and Lake. The modifications to the Contract pursuant to the Settlement Agreement have the following components:

1) A revised energy pricing methodology for future energy payments and settlement of a coal transportation issue.

2) Restructuring of variable O&M and capacity payments.

3) Reimbursement for the historic energy pricing dispute.

4) Curtailment of energy during off-peak periods from 110 MW to 92 MW.

5) A buy-out of the last three years and seven months of the Contract, resulting in a termination date of December 31, 2009, rather than July 31, 2013.

The cost for the buy-out will be paid to Lake in monthly payments from November, 1996 to December, 2008. On December 11, 1996, FPC paid Lake $5,512,056 to reimburse the QF for the disputed portion of energy payments made during the period August 9, 1994 through October 31, 1996. FPC requests that the Settlement Agreement be approved on an expedited basis, including confirmation that the Negotiated Contract between FPC and Lake, as modified by the Settlement Agreement, continues to qualify for cost recovery.

FPC believes that the Settlement Agreement will result in approximately $26.6 million Net Present Value (NPV) in benefits to its ratepayers through 2013. These benefits are based on a comparison of costs between Lake prevailing in the lawsuit and the modified Contract. FPC's cost-effectiveness analysis is attached to this recommendation as Attachment 3.

DISCUSSION OF ISSUES

ISSUE 1: Can the Commission deny cost recovery of a portion of the energy payments made to Lake regardless of the outcome of the current litigation?

RECOMMENDATION: Yes. Jurisdiction over retail cost recovery is exclusive to this Commission. An adjudication of rights between a utility and a qualifying facility by a court is not dispositive of the utility's authorization to recover these costs from the ratepayers. [ELIAS]

STAFF ANALYSIS: As mentioned in the Case Background, a Summary Judgement regarding the energy pricing dispute was reached in the Lake civil litigation against FPC. However, this finding is not dispositive of the issue of cost recovery from the ratepayers. This issue was discussed at length during Oral Argument in Docket Nos. 940357-EQ, 940771-EQ, and 940797-EQ. While a court of competent jurisdiction has made a decision that determines the rights under a contract between the utility and a cogenerator, this Commission and the utility's ratepayers are not, by that fact alone, bound by that decision for cost recovery purposes. In arriving at its decision that the interpretation of negotiated QF contracts is a matter of civil court jurisdiction, the Commission recognized the difference between the adjudication of contract rights between the parties to the contract, and cost recovery from the ratepayers. This consensus position was most clearly articulated in the following exchanges between a Commissioner and Mr. Watson, representing Pasco Cogen:

COMMISSIONER: And my question to you is: Once a court has interpreted that contract, are we bound to allow recovery based on that interpretation?

MR. WATSON: I don't think you're bound. I think the parties are bound. And I think if you disallow a portion of the payments that Florida Power makes to my client under the contract, and Florida Power Corp then invokes the reg-out clause and says, "we paid you that money, but the Commission didn't let us recover it from our ratepayers, therefore give it back under the reg-out clause, I think there are different issues that arise there than you have before you right now. I think you have absolute authority over the costs that you permit Florida Power Corporation to pass onto its ratepayers. I mean, you have got that under 366.06. But that doesn't give you authority over the terms and conditions of the contract that Florida Power has with Pasco Cogen or the Southern Company or Georgia Power or XYZ Typewriter Company or Hertz Rent-a-Car. You don't have any jurisdiction to interpret the terms of those contracts. You can look at the costs that flow from the contracts and say, "We think this is too much" or "We think this is okay and we're going to permit you to recover X of the X plus Y." (TR 53-54)

Mr. Watson further clarified the parties' position with the following exchange:

MR. WATSON: ...let me complete that bright line distinction very briefly. There's cost recovery and that's something you clearly have jurisdiction over; there's Florida Power's obligation to my client under the contract; and those are totally separate items. For cost recovery purposes, you -- well, the court may say, "We find that Florida Power's obligation under the contract is to pay Pasco Cogen the firm energy price whenever its avoided unit would have operated." Okay. You look at that court order and you look at the contract, if you want to; I don't care how you do it. But you say, "For cost recovery purposes, we're only going to let Florida Power pass on to its ratepayers the as-available energy cost." Well, guess what Florida Power is going to have to pay us? They're going to have to pay us a firm energy price, we have a court order that says so.

COMMISSIONER: Okay.

MR. WATSON: You pass on the as-available, their stockholders pay the rest.

COMMISSIONER: In that situation, would the regulatory-out clause not be implemented?

MR. WATSON: Maybe, maybe not. That's not the issue here today. (TR 63-64)

The uncertainty of the application of the regulatory-out clause with respect to cost-recovery was also supported by Mr. McGlothlin, representing Orlando Cogen Limited, when he stated:

> If that amount resulted in some different amount than the court said that we were entitled to recover, then the question arises, how does the reg-out clause come into play? Well, perhaps the reg-out clause will come into play so as to deny the QFs the amounts that they contend they are entitled to, but perhaps not. That will be also for the court to determine, the interpretation and the application of the reg-out clause. (TR 91)

Mr. Sasso, representing FPC, agreed that the Commission could differ with the Circuit Court's decision, but he had a slightly different view about the application of the regulatory-out clause when he stated:

> A court has been asked -- several courts have been asked to look at this matter. But a court cannot provide authoritative and meaningful relief in this matter. I would differ with Mr. Watson's answer to the Chairman's question about this. A court may render an interpretation of the contract and determine that the cogens are right and that Florida Power Corporation has to pay them firm payments all the time throughout the life of this contract; but that is not the issue that this Commission will ultimately resolve, which is: What payment levels are authorized by this Commission? What payment amounts will be approved by this Commission for cost recovery purposes? And if this Commission decides that the court was in error, that the Commission meant one thing when it approved these orders and, by goodness, that's what's going to be approved for cost recovery purposes, the reg-out clause will come into play. And that will happen after the court's determination, will not be the matter that is before the court, and the court's order will not speak to it. The reg-out clause will be triggered and the QFs will be denied the illusory benefit of their court effort. (TR 78-79)

Staff believes that all these statements fairly describe the correct interpretation of the applicable law. Based on these statements, it appears that the parties involved in the Lake proceeding recognize that Commission approval for cost-recovery is not per se controlled by a circuit court's decision, and that the application of the regulatory-out clause is a separate issue.

As expressed in Order No. PSC-95-0210-FOF-EQ, jurisdiction to resolve contractual disputes in negotiated QF contracts rests with the civil courts. However, jurisdiction over cost recovery is the sole responsibility of the Florida Public Service Commission governed by Section 366.051, Florida Statutes, Section 210 of PURPA, and Part III of Rule Chapter 25-17, F.A.C. Staff further believes that this Commission has the obligation to ensure that payments to QFs are in accordance with the terms of the contract, as understood by this Commission, at the time the contracts were originally approved for cost recovery. The Commission has stated on numerous occasions that it will not revisit its cost recovery approvals, absent fraud, misrepresentation or mistake. Staff contends that a finding, by a court of competent jurisdiction, that a contract payment stream is different from the basis upon which this Commission approved the contract is such a "mistake". This is separate factual issue. Whether this enables FPC to invoke a regulatory-out clause is also a separate issue, not currently before the Commission. Whether punitive damages, anti-trust damages, attorneys' fees awards, costs, interest, or payments above the amounts contemplated by the original contract approval awarded by a civil court should be recovered from the ratepayers are matters properly considered by the Commission, and only by the Commission.

The Commission has recognized that its participation as a party, amicus curie, or fact-finder after referral by a civil court in these type disputes can further judicial economy, assist in assuring consistent interpretation by the courts of Commission-approved contracts, and help protect the interests of the ratepayers in this type of dispute. Staff will pursue participation in the civil court cases, where appropriate, and with Commission approval, as a means of assuring that these disputes are consistently and efficiently resolved.

ISSUE 2: Should the Settlement Agreement between Florida Power Corporation and Lake Cogen, Ltd. (Lake) be approved for cost recovery?

PRIMARY RECOMMENDATION: Yes. Approval of the Settlement Agreement mitigates the risks associated with the uncertainty of civil litigation. On balance because there is more monetary risk in rejecting the Settlement Agreement than approving it, giving at least some intuitive recognition to the reduced need for replacement capacity due to deregulation increases the Settlement Agreement's cost-effectiveness, and using traditional regulatory rate base accounting as the basis to calculate simple payback, the contract buy-out should be approved. [JENKINS, FLOYD]

ALTERNATIVE RECOMMENDATION: No. The proposed Settlement Agreement should not be approved because it is not cost-effective. The modifications to the Contract result in a net overpayment of avoided costs of approximately $17.1 million NPV. Chapter 366.051, Florida Statutes, Section 210 of PURPA and this Commission's Rules require that QF payments not exceed a utility's full avoided costs. [TRAPP, BALLINGER, DUDLEY, HARLOW, ELIAS]

SECOND ALTERNATIVE RECOMMENDATION: No. The proposed Settlement Agreement should be denied since it cannot be shown to be cost-effective. Based on reasonable economic and legal assumptions, sensitivity analyses indicate that the likelihood of the agreement yielding ratepayer losses is roughly equivalent to the likelihood of it yielding ratepayer savings. [MCNULTY, STALLCUP]

PRIMARY STAFF ANALYSIS: As discussed in the Case Background, the Fifth Judicial Circuit Court issued a Partial Summary Judgement for Lake in Case No. 94-2354-CA-01 regarding the energy pricing dispute. Page two, subsection one of the Order granting Partial Summary Judgement states:

> A Partial Summary Judgement is hereby entered for Lake Cogen and against FPC on the issue of liability for FPC's failure to pay Lake Cogen at the firm energy cost rate when the avoided unit with operational characteristics of an operable 1991 Pulverized Coal Unit contemplated by the Lake Cogen-FPC Agreement would have been operating and at the as-available energy cost rate during those times when said avoided unit would not have been operating.

The basic problem is that the Lake Partial Summary Judgement order sides with Lake whose court position is that the 1991 avoided pulverized coal unit should be completely modeled. But complete modeling is not specified. Depending on what "complete" parameters are selected, the unit may be subject to cycling. "Complete" modeling may show that the unit would not be cycling. No cycling translates into a high contract cost making the buy-out cost effective.

FPC's court position is that the avoided 1991 pulverized coal unit should be modeled based on four operating parameters specified in the Contract, namely, fuel costs, heat rate, variable operation & maintenance costs, and a fuel multiplier. Using these four parameters to model how the 1991 pulverized coal unit would have operated translates into a lower contract cost making the buy out not cost-effective.

Staff simply does not know what "complete" parameters the judge would ultimately select. Nor does staff know whether to assume the higher or lower contract costs in determining cost-effectiveness.

Possible court outcomes if the $470.0 million (present worth) settlement is not approved include:

Cost-Effectiveness Analysis ($Millions NPV)		
Court Outcome	Contract Costs	Compared to Settlement
FPC Prevails	452.8	(17.1)
Lake Prevails	496.6	26.6
Settlement	470.0	----

(Numbers may not add due to rounding)

The table above shows the monetary risk of approving the settlement is less than the monetary risk of rejecting the settlement.

The Contract buy-out's cost-effectiveness is increased if you assume that replacement capacity and energy in the later years of the Contract are not needed. While an argument can be made that FPC may need more replacement capacity and energy than currently projected, the emerging competitive wholesale power market is driving prices and FPC's need for additional utility capacity downward. Some of FPC's wholesale customers are already switching suppliers thereby freeing up capacity to serve future growth. Also, deregulation at the retail level is on the horizon and many customers may be switching power suppliers, further relieving FPC of the need for additional capacity to serve the remaining customers. Hence, including 100% of the replacement capacity and energy cost understates the cost-effectiveness of the Contract buy out.

The first alternative recommendation is to deny approval of the Settlement Agreement because it is above avoided cost. Ordinarily, staff would not recommend approval of any cost recovery stream obligating customers to pay more than avoided costs. The problem is that if the Settlement Agreement is denied, the civil court judge will define avoided cost and not the Commission. Based on the discussion in Issue No. 1, whether the Commission could deny recovery of costs awarded by the civil court and thereby enable FPC to successfully invoke the regulatory out clause is speculative. Rather than possibly denying a portion of cost recovery if we do not agree with the court's decision, our best course of action is to weigh the possible outcomes of the judge's decision.

The problem with the second alternative recommendation is that inflation and fuel price sensitivities are added to the two court outcomes. Without the sensitivities, the Settlement Agreement is not cost-effective if the judge were to rule in favor of FPC and is cost-effective if the judge were to rule in favor of Lake. Adding the inflation and fuel price sensitivities does not change this result. The sensitivities lend no guidance on how to weigh the two court outcomes.

The payback issue consists of the intergenerational inequity issue and the risk issue. The intergenerational inequity issue is unclear in this docket because cogeneration purchased power contracts have inverted payment streams to ensure performance in the later years. Compared to setting base rates using traditional regulatory accounting, cost recovery of the inverted cogeneration purchased power payment stream defers to future customers costs that would have been recovered in base rates from existing customers. Thus, existing customers are already paying less than their fair share of cost. For residential customers, adding an approximately 50 cents per 1000 Kilowatt-hours surcharge until 2009 to recover the buy-out cost helps correct the present intergenerational inequity.

The risk issue arises because the Settlement Agreement is not projected to be conveying benefits until 2009. The longer it takes an investment decision to convey benefits, the riskier the investment compared to other alternatives. Before deciding whether 12 years (1997 to 2009) is too long, and therefore too risky, the exact nature of the risk should be analyzed. The majority of risk is the cost of replacement capacity and energy in 2009 through 2013. The assumptions that have been made regarding the replacement capacity are: (1) the capacity and energy will be needed because deregulation will not occur or, if it does, few customers will opt to switch suppliers, (2) electric generation technology will be frozen, that is, power plant efficiency will not materially increase before 2009, (3) the cost of the present frozen technology will escalate with inflation, (4) short term (four year) replacement capacity will not be available on the recently deregulated wholesale market, and (5) the price of natural gas will escalate faster than the contract reference delivered coal price at Crystal River Plant. Primary staff believes some, but not likely all, of these assumptions adverse to the Settlement Agreement's cost-effectiveness will occur. Hence, the cost of replacement capacity should not be calculated by simply multiplying the 110 contracted for Megawatts times the inflated to 2009 annual revenue requirements plus variable costs, including fuel. Some weight should be given to the likelihood of some of the above listed tacit assumptions not occurring.

In summary:

1. The Settlement Agreement saves an estimated present worth $26.6 million compared to the Settlement Agreement being denied, Lake prevailing in civil court, the Commission allowing a lesser amount for cost recovery, the regulatory out clause being invoked, and that action being overturned on appeal.

2. The Settlement Agreement loses an estimated present worth $17.1 million compared to the Settlement Agreement being denied and FPC prevailing in civil court.

3. The first alternative argues that the Settlement Agreement is above avoided costs but ignores the fact that the court and possibly not the Commission will define avoided costs.

4. The inflation and fuel price sensitivities discussed in the second alternative only show the Settlement Agreement to be cost-effective if Lake prevails in civil court or not cost effective if FPC prevails.

5. The resulting surcharge if the Settlement Agreement is approved decreases the current intergenerational inequity.

6. The payback period is not a significant issue because the risk of ratepayers being harmed on a present worth basis due to uncertainty of the assumed costs of replacement capacity and

energy in 2009 through 2012 is the dominant present worth cost and these costs appear to be overstated or may not exist at all should deregulation occur.

With items nos. three through six above put in their proper perspective, approval or disapproval of the Settlement Agreement should be based on items nos. one and two only. Because the potential present worth $26.6 million benefit exceeds the potential present worth $17.1 million loss, the Settlement Agreement should be approved.

ALTERNATIVE STAFF ANALYSIS: Approval of a newly negotiated contract is based on avoided cost as defined by the utility's next identified capacity addition. However, in evaluating contract modifications, "avoided cost" becomes the existing contract. In this case, approval of the original contract recognized that energy payments would be calculated using the parameters specified in the Contract and were not fixed. FPC's modeling of the avoided unit is consistent with this Commission's order approving the Contract and more closely approximates avoided cost. Energy payments under the modified contract reflect Lake's court position of 100% firm energy, which clearly exceeds avoided cost. This revision, plus the remaining components of the Settlement Agreement, requires that FPC's ratepayers commit to pay approximately $17.1 million NPV over what they would pay under the Contract before the Settlement Agreement. Staff recognizes the risk associated with litigation, however as discussed in Issue 1, this Commission is not bound to a circuit court's decision which proposes recovery of QF payments that are in excess of a utility's avoided cost.

As discussed in the Case Background, the proposed Settlement Agreement contains five modifications to FPC's and Lake's existing contract. The net cost or benefit of each of these modifications is shown in the table below. A discussion of each modification is contained in the following sections.

NET SAVINGS OF FPC/LAKE SETTLEMENT AGREEMENT ($Millions NPV)	
Component	Savings
Energy Pricing & Coal Transportation Agreement	($24.9)
Capacity and Variable O&M	$12.1
Historic Pricing Dispute	($5.3)

Curtailment	$2.4
Buy-out	($1.2)
TOTAL	($17.1)

(Numbers may not add due to rounding)

This table represents the savings, whether positive or negative, of each component of the Settlement Agreement compared to the existing contract.

Revised Energy Pricing and Coal Transportation Agreement

Revised Energy Pricing

Pursuant to Rule 25-17.0836, F.A.C., this Commission is required to evaluate modifications to a negotiated contract against both the existing contract and the current value of the purchasing utility's avoided cost. The modified Contract requires FPC's ratepayers to pay firm energy prices every hour that Lake generates electricity. In other words, the modified contract assumes the avoided unit will be available and fully dispatched 100 percent of the time. Obviously, no real unit operates in this manner. Furthermore, this would also presume that had FPC built the "avoided-unit", this Commission would want FPC to run the unit without regard for any changes in operating expenses. As expressed by two Commissioners at the April 1, 1997, Agenda Conference, that would not be an appropriate burden for FPC's ratepayers[1]. FPC's modeling of the avoided unit, which results in a mixture of firm and as-available energy prices, more closely approximates actual avoided energy costs and is consistent with this Commission's order approving the existing contract. As with all avoided cost calculations, Section 9.1.2 of the Contract was constructed as a pricing proxy and was not intended to be fully representative of a real operable "bricks-and-mortar" generating unit. The goal of the contractual language was to ensure that, consistent with Section 210 of PURPA and our cogeneration rules, FPC would not be put in a situation where it would be required to purchase energy at a cost greater than what it could either purchase elsewhere or generate itself. The revised energy pricing methodology, 100% firm, will render this goal meaningless.

[1] Discussion during April 1, 1997 Agenda Conference, Item No. 3, Docket 961407-EQ.

Coal Transportation Agreement

The firm energy price under the Settlement Agreement will be determined using the higher of the actual monthly inventory charge-out price of coal at CR 1&2 or $1.76/MMBtu. This floor is based on the average price of coal at CR 1&2 in 1996 plus an $0.08/MMBtu adder. This adder was included to prevent a potential dispute between FPC and Lake similar to the one between FPC and Pasco regarding FPC's coal procurement and transportation actions. This is another example of how the proposed energy pricing methodology is not representative of avoided cost. Though the Settlement Agreement eliminates any potential for litigation concerning FPC's coal procurement actions, staff believes this was unnecessary. The Contract contains no provisions governing the modes of transporting fuel to the Reference Plant. Furthermore, FPC should take any and all actions which, legally, lowers the cost of providing electricity to its ratepayers such that that cost is fair and reasonable as required by Section 366.03 Florida Statutes. Furthermore, this lower cost should be reflected in FPC's calculation of avoided costs.

The result of these provisions of the Settlement Agreement is energy costs that are approximately $24.9 million NPV greater than what FPC is currently authorized to recover today. Approving these provisions will put the Commission in a position of violating Chapter 366.051, Florida Statutes, Section 210 of PURPA and this Commission's Rules governing cost recovery of cogeneration contracts.

Staff recognizes the benefits of electricity produced by cogeneration and small power producers and the requirements to purchase such power when available. This benefit was also recognized by FERC when it established Section 210 of PURPA and was recognized by the Florida Legislature when drafting 366.051, of the Florida Statutes. However, both FERC and the Florida Legislature recognized that these arrangements would not always be beneficial to both parties. To ensure that benefits remained with a utility's ratepayers, PURPA and the Florida Statutes established that rates for the purchase of power from QFs shall not exceed a utility's avoided cost. Such assurance was necessary to avoid situations that would require a utility to purchase electricity from a QF when in fact it could produce or purchase alternative power at a lower cost.

Public utilities, over which this Commission has rate setting authority, are required to provide adequate, reliable electric service at fair and reasonable rates. In the administration of cogeneration contracts, Chapter 366.051, Florida Statutes, states in part:

> In fixing rates for power purchased by public utilities from cogenerators or small power producers, the commission shall authorize a rate equal to the purchasing utility's full avoided costs.

This Commission's rules are consistent with the guidelines set out in the Florida Statutes and PURPA. Specifically, Rule 25-17.0825, Florida Administrative Code states in part:

> As-available energy sold by a qualifying facility shall be purchased by the utility at a rate, in cents per kilowatt-hour, **not to exceed the utility's avoided energy cost**. (Emphasis added)

Rule 25-17.0832(2) states in part that:

> Negotiated contracts will be considered prudent for cost recovery purposes if it is demonstrated by the utility that the purchase of firm capacity and energy from the qualifying facility pursuant to the rates, terms, and other conditions of the contract can reasonably be expected to contribute towards deferral or avoidance of additional capacity construction or other capacity related costs by the purchasing utility at a cost to the utility's ratepayers **which does not exceed full avoided costs**, giving consideration to the characteristics of the capacity and energy to be delivered by the qualifying facility under the contract. (Emphasis added)

and Rule 25-17.086 states that:

> Where purchases from a qualifying facility will impair the utility's ability to give adequate service to the rest of its customers or, due to operational circumstances, purchases from qualifying facilities will **result in costs greater than those which the utility would incur if it did not make such purchases**, or otherwise place an undue burden on the utility, the utility shall be relieved of its obligation under Rule 25-17.082 to purchase electricity from a qualifying facility. (Emphasis added)

The Commission's decision in Docket No. 940771-EQ, Order No. PSC-95-0210-FOF-EQ, specifically recognized these constraints. Staff believes that where cost recovery review finds that a utility is requesting recovery of QF payments that exceed its full avoided costs, those costs are subject to disallowance.

When the Commission initially approves a negotiated contract, the determination of avoided costs is based on the utility's next identified capacity addition. At that point in time, the contract is evaluated for cost recovery purposes in accordance with the above referenced rules. However, in evaluating contract modifications, continued cost recovery is based on savings compared to the existing contract.

Rule 25-17.036(6) requires that:

> The modifications and concessions of the utility and developer shall be evaluated against both the **existing contract and the current value of the purchasing utility's avoided cost**. (Emphasis added)

Absent a modification, the utility's ratepayers remain obligated to pay costs as specified within the current contract. Therefore, modifications which result in costs above the existing contract are not appropriate for approval.

The proposed Settlement Agreement asks the Commission to approve an energy payment which exceeds both the existing contract and current avoided costs and therefore should be denied.

Restructuring of Capacity Payments and Variable O&M

The Settlement Agreement removes variable O&M expenses from the energy payment, and includes it in the capacity payment. The revised capacity payments, including the variable O&M amount, are approximately $12.1 million NPV less than capacity and variable O&M payments under the original contract. This provision of the Settlement Agreement is projected to reduce FPC's ratepayers cost liability in addition to providing a more stable revenue stream for Lake. However, the benefits of this provision of the Settlement Agreement do not outweigh the negative impact of the 100% firm energy payment.

Historic Pricing Dispute

The Settlement Agreement provides for FPC to pay Lake $5,512,056 as reimbursement, with interest, for the disputed energy payments during the period August 9, 1994 through October, 31, 1996. FPC paid the settlement payment to Lake on December, 11, 1996. However, as discussed in Issue 3, the Commission voted to exclude this payment for recovery, because the costs at that time had not been approved for recovery by the Commission. As discussed earlier staff believes that FPC's modeling of the avoided unit, which results in a mixture of firm and as-available energy prices, more closely approximates actual avoided energy costs and is consistent with this Commission's order approving the existing contract. Staff believes that FPC's ratepayers are not liable for costs in excess of actual avoided energy costs and recovery of the disputed amount should not be allowed.

Curtailment

Lake has agreed to curtail energy deliveries from 110 MW to 92 MW during the thirteen off-peak hours as defined by the Settlement Agreement. In addition, Lake will be treated as a Group A NUG under FPC's Generation Curtailment Plan as approved pursuant to Order No. PSC-95-1133-FOF-EQ, issued September 11, 1995. This provision will confer benefits to FPC in the form of increased flexibility during low load situations when generation exceeds load requirements as well as allowing FPC to replace the curtailed energy, if needed, at a lower system energy cost.

FPC projects that this provision of the Settlement Agreement will result in a savings of approximately $2.4 Million NPV as compared to the existing contract. Existence of these savings further demonstrates that approving 100% firm energy pricing will result in payments which exceed FPC's avoided energy cost. Furthermore, these savings are overstated as FPC has the authority to curtail Lake and other Cogenerators during those hours which the energy is not needed or when such purchases will result in negative avoided costs. According to Rule 25-17.086, Florida Administrative Code, a utility is relieved of its obligation to purchase electricity from a QF due to operational circumstances or when such purchases will result in costs greater than those which the utility would incur if it did not make such purchases. Despite this authority, staff recognizes that a voluntary curtailment agreement could avoid litigation.

Contract Buy-out

Lake and FPC have agreed to terminate the Contract three years and seven months earlier than originally proposed. In exchange for this provision, FPC will pay Lake monthly payments from 1996 through 2008 totaling approximately $50.4 Million. Since the current contract is greater than today's avoided costs, this provision will allow FPC's ratepayers to purchase market priced power sooner. After the revised contract terminates, FPC will be able to obtain capacity and energy at a cost it believes will be less than the existing contract. FPC's cost projections for replacement capacity and energy are based on currently budgeted amounts for its Polk Unit. Staff agrees with this methodology in that the projections have a more defined basis and FPC's current projections indicate that the replacement capacity and energy will come from a similar type of combined-cycle technology.

When compared to FPC's modeling of the avoided unit, which more closely approximates avoided energy cost, the buy-out portion of the Settlement Agreement is not cost effective. In fact, the Contract buy-out will actually result in approximately $1.2 Million NPV of additional costs to FPC's ratepayers.

Conclusion

As discussed in the Case Background, the energy payments are the subject of the current litigation between FPC and Lake. Reduced energy payments to Lake are a direct consequence of low load conditions, nuclear unit performance, and fluctuations in coal, oil, and natural gas prices. This potential was clearly recognized within Section 9.1.2 of the Contract and within this Commission's order approving the existing contract. Staff is not asking the Commission to revisit its original decision to approve the Contract, but recommending enforcement of the Contract's terms and denial of the proposed contract modifications. Staff recommends that FPC's modeling of the avoided unit more closely approximates avoided energy cost. Furthermore, staff concurs with the Summary Judgement that "the terms of the agreement are unambiguous and do not require the Court to look outside its four corners for its interpretation of Section 9.1.2 of the Agreement." The Contract entered into by Lake with FPC, specifically identifies the operating characteristics that will be used, and only those, to make such energy pricing determinations. Staff recommends that FPC's energy payment calculations and its confinement to the terms of the Contract is consistent with the Commission's decision to approve the original contract in 1991.

Staff agrees that the Settlement Agreement achieves benefits in the form of curtailment savings and reduced capacity and variable O&M payments. However, compared to the more appropriate method of determining energy payments under the existing contract, the Settlement Agreement increases costs to FPC's ratepayers by approximately $17.1 million NPV. Furthermore, contrary to Section 366.051, Florida Statutes, Section 210 of PURPA, and this Commission's rules, approval of the Settlement Agreement binds FPC's ratepayers to costs in excess of current avoided energy costs. For these reasons, staff recommends that the Settlement Agreement be denied.

SECOND ALTERNATIVE ANALYSIS:

NPV Savings

It is staff's perspective that the proposed Settlement Agreement should be approved only if it can be shown to be cost effective for ratepayers. The agreement is considered to be cost-effective if ratepayer savings, expressed in terms of net present value (NPV), are likely to occur as a result of approving the agreement.

This recommendation is based on weighing both the litigation and economic risks to ratepayers associated with the proposed Settlement Agreement to determine its cost-effectiveness. Litigation risk refers to the current dispute regarding the level and amount of disputed energy payments to be made by FPC to Lake as would be mandated by the civil court. Economic risk refers to fluctuating fuel prices and inflation.

These ratepayer risks are quantified within the context of two base case cost-effectiveness scenarios constructed by staff. The first cost-effectiveness scenario is based on the assumption that FPC will win the energy pricing dispute completely, and the second cost-effectiveness scenario is based on the assumption that FPC will lose the dispute completely. Economic sensitivities are constructed around both of these base case scenarios.

In both scenarios and in all sensitivities to these base cases, staff utilized the Gross Domestic Product Implicit Price Deflator (GDP-IPD) instead of the Consumer Price Index (CPI-U) to represent the impact of inflation upon prices. GDP-IPD is a better measure of inflation since it more closely matches the types of expenditures being estimated (O&M expenses and the cost of generating capacity construction). The impact of using GDP-IPD instead of CPI-U is to add about $1.0 million in ratepayer NPV savings over the term of the contract.

In the first base case scenario, FPC is assumed to win the right to all disputed energy payments (including both historic and future payments) through a future court judgement. The cumulative ratepayer savings (losses) over the entire term of the contract, based on the substitution of GDP-IPD for CPI-U, is -$16.1 million (see table below). In the second base case scenario, Lake is assumed to win the court judgement. The "Lake wins" base case NPV savings is $27.6 million.

For each of these base case scenarios, the sensitivity to changes in fuel prices was measured by substituting alternate fuel forecasts for coal and natural gas into the calculations used to measure the NPV savings. Two alternate fuel forecasts were used: the 1997 Annual Energy Outlook forecast (AEO) prepared by the U.S. Department of Energy (DOE) and the February 1997 forecast from Data Resources Incorporated (DRI). Both of these alternate fuel forecasts were developed by the DOE and DRI as the most likely outcome of all future fuel price possibilities.

Staff calculated a set of inflation rate sensitivity tests under each of the different fuel forecast assumptions. The DRI forecast of "Pessimistic GDP" was used to create the "High Inflation" sensitivities. Averaged over an 11-year time horizon (1997-2007), the "Pessimistic GDP" is 1.9 percentage points higher than the "Median GDP" (Mid-range GDP). One half of this variation was used to create the "Moderately High Inflation" sensitivities.

The DRI forecast of "Optimistic GDP" was used to create the "Low Inflation" sensitivities. Averaged over an 11-year time horizon (1997-2007), the "Optimistic GDP" is 0.8 percentage points lower than the "Median GDP". One half of this variation was used to create the "Moderately Low Inflation" sensitivities.

These inflation sensitivities effect generating capacity costs, O&M expenses, the coal and natural gas prices, as well as the discount rate.

Sensitivity Results

The sensitivity results are summarized in the table below:

SETTLEMENT AGREEMENT SENSITIVITIES ($Millions NPV)			
Fuel Forecast	Inflation Assumption (see "Note")	NPV if FPC Prevails	NPV if Lake Prevails
FPC 9603	Low Inflation	($15.4)	$29.2
	Mod. Low Inflation	($15.7)	$28.5
	Median	($16.1)	$27.6
	Mod. High Inflation	($17.5)	$25.3
	High Inflation	($19.1)	$22.9
DRI, 2/97	Low Inflation	($22.6)	$22.2
	Mod. Low Inflation	($23.2)	$21.2
	Median	($24.0)	$20.0
	Mod. High Inflation	($26.1)	$16.9
	High Inflation	($28.4)	$13.7
Annual Energy Outlook (AEO), 1997	Low Inflation	($20.6)	$24.5
	Mod. Low Inflation	($21.5)	$23.0
	Median	($22.6)	$21.6
	Mod. High Inflation	($24.8)	$18.4
	High Inflation	($27.2)	$15.3
DRI and Annual Energy Outlook Average (AEO)	Low Inflation	($21.6)	$23.3
	Mod. Low Inflation	($22.4)	$22.1
	Median	($23.3)	$20.8
	Mod. High Inflation	($25.5)	$17.6
	High Inflation	($27.8)	$14.5
DRI, AEO Overall Average	Average (across inflation sensitivities)	($24.1)	$19.7

Note: The "High Inflation" sensitivities appearing above are based on inflation estimates which are, on average, 1.9 percentage points higher than the median GDP-IPD, consistent with DRI's "Pessimistic" Inflation Forecast. These sensitivities have no counterpart in the FPC/Pasco staff recommendation. "Moderately High Inflation" sensitivities appearing above are similar to the "Base plus 1.0 Percentage Point" sensitivities appearing in Staff's Second Alternative Recommendation in Docket No. 961407-EQ (FPC/Pasco Settlement).

Staff makes three observations from its risk analysis. First, the largest element of risk associated with approval of FPC's petition originates from how the Commission perceives a civil court proceeding would resolve the contract pricing dispute between FPC and Lake. If the Commission believes the court would rule in favor of FPC's position, ratepayer savings will almost certainly be negative (from -$28.4 million to -$15.4 million). Conversely, if the Commission believes the court would rule in favor of Lake's position, the ratepayer savings would almost certainly be positive (from $13.7 million to $29.2 million). Second, from the sensitivity analyses, Staff notes that if the independent fuel forecasts were used in place of FPC's fuel forecast, the resultant NPV Savings would decrease by approximately $7.0 million on average. Third, Staff observes that including a high-inflation assumption causes NPV Savings to decrease by about $5.0 million on average.

The average NPV for all sensitivities pertaining to the "FPC Prevails" position is -$24.1 million. The average NPV for all sensitivities pertaining to the "Lake Prevails" position is $19.7 million. This analysis indicates that it is very unclear whether ratepayers would benefit from this agreement. The likelihood of the agreement yielding ratepayer losses is roughly equivalent to the likelihood of it yielding ratepayer savings. Therefore, the agreement cannot be shown to be cost-effective.

Payback Period and Cost Exposure

While cumulative ratepayer NPV savings is the primary issue to be considered in this cost-effectiveness analysis, there are two other important ratepayer concerns which should be addressed. These two factors are the payback period (i.e. the time required for ratepayers' early investment to be recouped) and the cost-exposure (i.e. ratepayers' early investment). From a ratepayer perspective, both of these factors associated with the agreement should be minimized. Long payback periods represent a kind of financial risk to the individual ratepayer. For example, a ratepayer may relocate to another service area after incurring the costs of the agreement but prior to receiving its benefits. By relocating, he has effectively provided a subsidy to the remaining ratepayers. His share of the early-period cost-exposure is his subsidy to the remaining ratepayers. The greater the cost exposure, the greater the subsidy.

Exact guidelines for determining the acceptable level of disparity in the timing of ratepayer costs and ratepayer benefits have not been established by this Commission. However, it may be useful to compare the timing of costs and benefits of previously considered settlement agreements with the timing of costs and benefits of the FPC/Lake Settlement Agreement. Attachment 4 is a line graph and table which compares the cumulative NPVs among the various agreements throughout the contracts' respective terms. Disputed historic payments are not included, and no staff adjustments are included.

The graph shows that the cumulative ratepayer NPVs are negative during the early years of each of the agreements. However, the NPVs eventually turn positive for each of the agreements, according to FPC, during the contract buy-out years. The graph also shows that there is considerable variation in payback period and cost-exposure between the various agreements.

The FPC/Pasco agreement is the agreement which is most like the FPC/Lake agreement in both the payback period and the magnitude of cumulative end-of-contract NPV. They are expected to achieve payback earlier than the other agreements (i.e. 15 years rather than 22-24 years). Their ultimate cumulative NPV's are almost the same ($26.9 million (FPC/Lake) and $27.5 (FPC/Pasco). However, the FPC/Lake agreement does not require ratepayers to carry nearly as much loss during the early years of the agreement as does the FPC/Pasco agreement ($15.2 million compared to $30.2 million).

FPC expects the FPC/Lake agreement to attain payback much earlier than the Commission-approved FPC/Auburndale agreement. The FPC/Lake agreement requires considerably less than half as much cost exposure compared to the FPC/OCL agreement, yet the FPC/Lake agreement is expected achieve payback in seven fewer years.

Despite these favorable comparisons to other agreements, Staff notes that the FPC/Lake agreement contains a mismatch in the timing of ratepayer costs and benefits. FPC ratepayers are not expected to realize positive net savings until 15 years after incurring costs associated with the FPC/Lake agreement, and the amount of cost-exposure is about $15.0 million.

Conclusion

Staff is concerned that the proposed FPC/Lake agreement exposes ratepayers to potential litigation and economic risks. Sensitivity analyses reveal that the likelihood of the agreement yielding ratepayer losses in roughly equivalent to the likelihood of it yielding ratepayer savings. Thus, the Settlement Agreement cannot be shown to be cost-effective and should therefore be denied.

ISSUE 3: If approved, how should the settlement payment and revised capacity and energy payments pursuant to the Settlement Agreement be recovered from the ratepayers?

RECOMMENDATION: The energy settlement payment of $5.5 million and the ongoing energy payments made pursuant to the Settlement Agreement should be recovered through the Fuel and Purchased Power Cost Recovery (Fuel) Clause. The capacity payments as determined and paid pursuant to the Settlement Agreement should be recovered through the Capacity Cost Recovery Clause. The recovery of payments made prior to their inclusion for recovery through the adjustment clauses should include interest from the date the payments were made. Should the Settlement Agreement not be approved, any necessary adjustments to the Fuel Clause to reflect the method of pricing energy under the Contract prior to the Settlement Agreement should be made at the next Fuel Adjustment hearing. [WHEELER]

STAFF ANALYSIS: On December 11, 1996 FPC made a payment of $5.5 million to Lake pursuant to the Settlement Agreement. This payment results from the settlement of the dispute regarding the pricing of energy payments pursuant to the contract for the period August, 1994 through October, 1996. It represents the difference between recalculated energy payments for the period and the actual energy payments, as well as accrued interest. Because the settlement payment relates solely to disputed energy payments, staff believes that it is appropriate to recover it through the Fuel Clause.

Pursuant to the Settlement Agreement, Lake and FPC have agreed upon the method to be used in calculating the energy and capacity payments for the remaining term of the contract. The resulting energy and capacity payments should be recovered through the Fuel and Capacity Cost Recovery Clauses, respectively. The projected fuel costs which were included for recovery at the February Fuel Adjustment hearing were based on the new method of pricing energy. Should the Settlement Agreement not be approved, any necessary adjustments to the Fuel Clause to reflect the energy pricing in effect prior to the settlement should be made at the next Fuel Adjustment hearing.

At the February 19, 1997 Fuel Adjustment hearing, the Commission voted to exclude for recovery for the April through September 1997 projection period approximately $11.4 million in fuel and capacity costs associated with the FPC/Lake Settlement Agreement, because the costs at that time had not been approved for recovery. Accordingly, adjustments were made to remove from recovery the monthly payments attributable to the buy-out of a portion of the contract, the $5.5 million energy settlement payment and the increase in capacity payments which resulted from the Settlement Agreement. If the Commission decides that these costs are appropriate for recovery through the Fuel and Capacity clauses, staff recommends that any payments made by FPC pursuant to the Settlement Agreement accrue interest from the date they were made.

ISSUE 4: If the Settlement Agreement is approved, what is the appropriate method for recovering the Special Monthly Payments associated with terminating the contract on December 31, 2009?

RECOMMENDATION: If the Settlement Agreement is approved, 72 percent of the special monthly payments should be recovered through the Capacity Cost Recovery Clause and 28 percent should be recovered through the Fuel and Purchased Power Cost Recovery Clause. This split between the clauses reflects the fact that the payments are justified based on anticipated capacity and energy savings in the buy-out years. The recovery of payments made prior to their inclusion for recovery through the adjustment clauses should include interest from the date the payments were made. [WHEELER]

STAFF ANALYSIS: As a part of the Settlement Agreement, the term of the Contract was reduced by three years and seven months. The Contract thus will terminate on December 31, 2009, instead of July 31, 2013. In return for shortening the contract, FPC agreed to make monthly payments to Lake beginning in November, 1996 and ending in December, 2005. FPC is seeking to recover these payments from its ratepayers exclusively through the Capacity Cost Recovery Clause (CCRC). Staff believes that in the case of the Lake payments, there are compelling reasons to recover a portion of these payments through the Fuel and Purchased Power Cost Recovery Clause (Fuel Clause).

The CCRC is a mechanism which is intended to recover capacity charges paid by the utility for power purchased from other utilities and from cogenerators, provided such costs are not already recovered in base rates. The CCRC is intended to allocate such costs to the rate classes in the same manner as demand-related production plant costs are allocated in rate cases. In the case of FPC's last rate case, production plant costs were allocated to the classes based on their estimated contributions to the 12 monthly system peak hours. Such a method is based on the premise that fixed production plant expenses are incurred to meet the system peak demand. Thus, costs which are recovered through the CCRC are allocated to the rate classes based on their estimated contribution to peak demand, using the latest available load research data. By contrast, expenses which are recovered through the Fuel Clause are allocated on an energy, or per kilowatt hour basis.

The Contract buy-out is justified by FPC based on both energy and capacity savings. Thus in effect the buy-out payments are purchasing demand and energy savings during the buy-out years. Staff believes that the buy-out payment costs should be allocated to the rate classes in proportion to the estimated energy and demand savings they will provide in the buy-out years. This allocation can be achieved by splitting the recovery of the buy-out payments between the Fuel Clause and the CCRC.

The estimated energy and capacity savings during the buy-out years 2010 through 2013 were arrived at by estimating what would have been paid based on Lake's contract interpretation and subtracting from that amount, the estimated cost of replacement energy and capacity. The nominal energy and capacity savings which result from this analysis are shown in the following table:

SAVINGS OF FPC/LAKE SETTLEMENT AGREEMENT ($Millions Nominal)			
YEAR	CAPACITY	ENERGY	TOTAL
2010	$25.4	$10.1	$35.4
2011	$27.2	$10.7	$38.0
2012	$29.2	$11.2	$40.4
2013	$18.2	$6.9	$25.2
TOTAL	$100.0	$38.9	$138.9

(Numbers may not add due to rounding)

The above analysis reflects an adjustment to the replacement capacity and energy analysis presented by FPC. FPC's analysis included the fixed transportation component in the cost for replacement capacity. Staff shifted the fixed gas transportation component from capacity to energy. Firm natural gas transportation tariff rates are a component of the delivered fuel costs which are recovered through the Fuel Clause. These costs increase or decrease depending on the quantity of natural gas actually burned, and thus should be classified as an energy-related expense for purposes of the replacement case.

Since the capacity savings of approximately $100.0 million represent 72 percent of the total $138.9 million in savings, the staff recommends that 72 percent of the Special Monthly Payment costs be recovered through the CCRC. The remaining 28 percent reflecting energy savings should be recovered through the Fuel Clause.

At the February 19, 1997 Fuel Adjustment hearing, the Commission voted to exclude for recovery for the April through September 1997 projection period the fuel and capacity costs associated with the Settlement Agreement, because the costs at that time had not been approved for recovery by the Commission. If the Commission decides at the June 24, 1997 agenda conference that these costs are appropriate for recovery through the Fuel and Capacity clauses, staff recommends that any payments made by FPC pursuant to the Settlement Agreement accrue interest from the date they were made.

ISSUE 5: Should this docket be closed?

RECOMMENDATION: Yes. If no person whose substantial interests are affected by the Commission's proposed agency action files a protest within twenty-one days of the issuance of this order, this docket should be closed.

STAFF ANALYSIS: If no person whose substantial interests are affected, files a request for a Section 120.57, Florida Statutes, hearing within twenty-one days of the issuance of this order, no further action will be required and this docket should be closed.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for determination that implementation of contractual pricing mechanism for energy payments to qualifying facilities complies with Rule 25-17.0832, F.A.C., by Florida Power Corporation.	DOCKET NO. 940771-EQ ORDER NO. PSC-95-0210-FOF-EQ ISSUED: February 15, 1995

The following Commissioners participated in the disposition of this matter:

SUSAN F. CLARK, Chairman
J. TERRY DEASON
JOE GARCIA
JULIA L. JOHNSON
DIANE K. KIESLING

ORDER GRANTING MOTIONS TO DISMISS

BACKGROUND

In 1991 and 1992, Florida Power Corporation (FPC) entered into eleven negotiated cogeneration contracts with various cogenerators. Those contracts provide approximately 735 megawatts (MW) out of approximately 1,045 MWs of cogenerated capacity that FPC will have on its system by the end of 1995. The negotiated contracts in question are between FPC and the following cogenerators: Seminole Fertilizer, Lake Cogen Limited, Pasco Cogen Limited, Auburndale Power Partners, Orlando Cogen Limited, Ridge Generating Station, Dade County, Polk Power Partners-Mulberry, Polk Power Partners-Royster, EcoPeat Avon Park, and CFR Biogen.

The contracts all contain the following provision, section 9.1.2:

> Except as otherwise provided in Section 9.1.1 hereof, for each billing month beginning with the Contract In-Service Date, the QF will receive electric energy payments based on the Firm Energy Cost calculated on an hour-by-hour basis as follows: (i) the product of the average monthly inventory chargeout price of fuel burned at the Avoided Unit Fuel Reference Plant, the Fuel Multiplier, and the Avoided

> Unit Heat Rate, plus the Avoided Unit Variable O&M, if applicable, for each hour that the Company would have had a unit with these characteristics operating; and (ii) during all other hours, the energy cost shall be equal to the As-Available Energy Cost.

This provision establishes the method to determine when cogenerators are entitled to receive firm energy payments or as-available energy payments under the contract. The Commission reviewed the 11 negotiated contracts and found them to be cost-effective for FPC's ratepayers under the criteria established in Rules 25-17.082 and 25-17.0832(2), Florida Administrative Code.[1] The information the Commission received at that time was based on simplified assumptions to arrive at the estimated energy payments.

Recently, FPC states, it reviewed the operational status of the avoided unit described in section 9.1.2 of the contracts during minimum load conditions. FPC determined that the avoided unit would be scheduled off during certain minimum load hours of the day. On July 18, 1994, FPC notified the parties to the contracts that it would begin implementing section 9.1.2, effective August 1, 1994. Prior to that time FPC had paid cogenerators firm energy prices at all hours.

Three days later, on July 21, 1994, FPC filed a petition seeking our declaratory statement that section 9.1.2 of its negotiated cogeneration contracts is consistent with Rule 25-17.0832(4)(b), Florida Administrative Code. Rules 25-17.0832(4)(a) and (b) provide:

> (4) Avoided energy payments.
> (a) For the purpose of this rule, avoided energy costs associated with firm energy sold to a utility by a qualifying facility pursuant to a utility's standard offer contract shall commence with the in-service date of the avoided unit specified in the contract. Prior to the in-service date of the avoided unit, the qualifying facility may sell as-available energy to the utility pursuant to Rule 25-17.0825(2)(a).

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[1] See Order No. 24099, issued February 12, 1991 in Docket No. 900917-EQ; Order No. 24734, issued July 1, 1991 in Docket No. 910401-EQ; Order No. 24923, issued August 19, 1991 in Docket No. 910549-EQ; and Order No. PSC-92-0129-FOF-EQ, issued March 31, 1992 in Docket No. 900383-EQ.

> (b) To the extent that the avoided unit would have been operated, had that unit been installed, avoided energy costs associated with firm energy shall be the energy cost of this unit. To the extent that the avoided unit would not have been operated, firm energy purchased from qualifying facilities shall be treated as as-available energy for the purposes of determining the megawatt block size in Rule 25-17.0825 (2)(a).

Several cogenerators petitioned for leave to intervene and questioned whether the declaratory statement was the appropriate procedure to resolve the issue. In addition, in September 1994, OCL, Pasco, Lake, Metro-Dade County, and Auburndale filed motions to dismiss on the grounds that we do not have jurisdiction to consider FPC's petition. Also, subsequent to the filing of FPC's petition, Pasco Cogen and Lake Cogen initiated lawsuits in the state courts for breach of contract and declaratory judgment.

On November 1, 1994, FPC amended its petition and asked the Commission to determine whether its implementation of section 9.1.2 is lawful under Section 366.051, Florida Statutes, and consistent with Rule 25-17.0832(4)(b), Florida Administrative Code. FPC also requested a formal evidentiary proceeding. Thereafter the cogenerators filed additional motions to dismiss the amended petition.

On January 5, 1995, we heard oral argument on the motions to dismiss filed in this docket and the motions to dismiss filed in two other dockets involving cogeneration contracts. We have fully considered the merits of the motions to dismiss, and we find that they should be granted. Our reasons for this decision are set out below.

DECISION

In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA), to develop ways to lessen the country's dependence on foreign oil and natural gas. PURPA encourages the development of alternative power sources in the form of cogeneration and small power production facilities. In developing PURPA, Congress identified three major obstacles that hindered the development of a strong cogeneration market. First, monopoly electric utilities resisted purchasing power from other generation suppliers instead of building their own generating units. Second, monopoly electric utilities could refuse to sell needed backup power to cogenerators. Third, cogenerators and small power producers could be subject to extensive, expensive federal and state regulation as electric utilities.

PURPA contains several provisions designed to overcome these obstacles. Section 210(a) directs the Federal Energy Regulatory Commission (FERC) to promulgate rules to encourage the development of alternative sources of power, including rules that require utilities to offer to buy power from and sell power to qualifying cogeneration and small power production facilities (QFs). Section 210(b) directs FERC to set rates for the purchase of power from QFs that are just and reasonable to the utility's ratepayers and in the public interest, not discriminatory against QF's, and not in excess of the incremental cost to the utility of alternative electric energy. Section 210(e) directs FERC to adopt rules exempting QFs from most state and federal utility regulation, and section 210(f) directs state regulatory authorities to implement FERC's rules.

FERC's regulations implementing PURPA require utilities to purchase QF power at a price equal to the utility's full avoided cost, " the incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. s. 292.101(b)(6). FERC's rules also contain a provision that permits utilities and QFs to negotiate different provisions of purchased power agreements, including price, as long as they are at or below a utilities' avoided cost. 18 C.F.R. s. 292.301.

In compliance with PURPA, Section 366.051, Florida Statutes, provides that Florida's electric utilities must purchase electricity offered for sale by QFs, "in accordance with applicable law". The statute directs the Commission to establish guidelines relating to the purchase of power or energy from QFs, and it permits the Commission to set rates at which a public utility must purchase that power or energy. The statute does not explicitly grant the Commission the authority to resolve contract disputes between utilities and QFs.

The Commission's implementation of Section 366.051 is codified in Rules 25-17.080-25-17.091, Florida Administrative Code, "Utilities Obligations with Regard to Cogenerators and Small Power Producers". The rules generally reflect FERC's guidelines in their purpose and scope. They provide two ways for a utility to purchase QF energy and capacity; by means of a standard offer contract, or an individually negotiated power purchase contract. See Rules 25-17.082(1) and 25-17.0832. The two types of contracts are treated very differently in our rules. The rules require utilities to publish a standard offer contract in their tariffs which we must approve and which must conform to extensive guidelines regarding, for example, determination of avoided units, pricing, cost-effectiveness for cost recovery, avoided energy payments, interconnection, and insurance. Utilities must purchase firm energy and capacity and as-available energy under standard offer contracts if a QF signs the contract. A utility may not refuse to accept a standard offer contract unless it petitions the Commission and provides justification for the refusal. See Rule 25-17.0832(3)(d), Florida Administrative Code.

In contrast, our rules are more limited in their treatment of negotiated contracts. Rule 25-17.082(2), Florida Administrative Code, simply encourages utilities and QFs to negotiate contracts, and provides the criteria the Commission will consider when it determines whether the contract is prudent for cost recovery purposes. Rule 25-17.0834, "Settlement of Disputes in Contract Negotiations", imposes an obligation to negotiate cogeneration contracts in good faith, and provides that either party to negotiations may apply to the Commission for relief if the parties cannot agree on the rates, terms and other conditions of the contract. The rule makes no provision for resolution of a dispute once the contract has been executed and approved for cost recovery.

We use certain standard offer contract rules as guidelines in determining the cost-effectiveness of negotiated contracts for cost recovery purposes, but we have not required any standard provisions to be included in negotiated contracts. In Docket No. 910603-EQ, we specifically addressed the issue of standard provisions for negotiated contracts. In that docket the cogenerators urged us to prescribe certain standard provisions in negotiated contracts and prohibit other provisions, like regulatory out clauses. In Order No.25668, issued February 3, 1992, we said:

> We will not prescribe standard provisions in negotiated contracts, because negotiated contracts are just that --<u>negotiated</u> contracts. Standardized provisions are not necessary in negotiated contracts, and they can impair the negotiating process.
>
> Rule 25-17.0834, Florida Administrative Code, provides a remedy to QFs when a utility does not negotiate in good faith. If a utility insists on an unreasonable requirement, QFs are free to petition the Commission for relief. . . .

> Standardized terms in negotiated contracts could impair negotiating flexibility to the detriment of the utility and the QF. As Witness Dolan stated, "[e]ven if guidelines and standards at a given time did reflect the parties' perceptions, guidelines and standards cannot be modified easily or quickly in response to changes in conditions that bear on the risks and benefits of the transaction". Standard terms that suit the needs of some parties will not suit the needs of other QFs wishing to negotiate contracts. Even in this docket, the QFs do not agree as to which terms should be standardized. . . . It is clear from the differing opinions that negotiated contracts should not contain standard provisions.

Order No. 25668, p. 7

This rather lengthy discussion of the statutes and regulations demonstrates that PURPA and FERC's regulations carve out a limited role for the states in the regulation of the relationship between utilities and qualifying facilities. States and their utility commissions are directed to encourage cogeneration, provide a means by which cogenerators can sell power to utilities under a state-controlled contract if they are unable to negotiate a power purchase agreement, encourage the negotiation process, and review and approve the terms of negotiated contracts for cost recovery from the utilities' ratepayers. That limited role does not encompass continuing control over the fruits of the negotiation process once it has been successful and the contracts have been approved. As Auburndale's attorney pointed out in oral argument, PURPA and FERC's regulations are not designed to open the door to state regulation of what would otherwise be a wholesale power transaction.

While the Commission controls the provisions of standard offer contracts, we do not exercise similar control over the provisions of negotiated contracts. We have interpreted the provisions of standard offer contracts on several occasions,[2] but we have not

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[2] In re: CFR Bio-Gen's Petition For Declaratory Statement Regarding the Methodology to be used in its Standard Offer Cogeneration Contracts with Florida Power Corporation, Order No. 24338, issued April 9, 1991, Docket No. 900877-EI; In re: Complaint by CFR Bio-Gen against Florida Power Corporation for alleged violation of standard offer contract, and request for determination of substantial interest, Order No. 24729, issued July 1, 1991,

interpreted the provisions of negotiated contracts. See Docket No. 840438-EI, In Re: Petition of Tampa Electric Company for Declaratory Statement Regarding Conserv Cogeneration Agreement, Order No. 14207, issued March 31, 1985, where we refused to construe a paragraph of the agreement that concerned renegotiation of contract terms. There we said that while we could interpret our cogeneration rules and decide that the new rules did not apply to preexisting contracts, matters of contractual interpretation were properly left to the civil courts. Our Conserv decision, while not controlling here, does lend support to the proposition that we have limited our involvement in negotiated contracts to the contract formation process and cost recovery review.

The weight of authority from other states that have addressed similar issues supports this position. See, eg. Afton Energy, Inc v. Idaho Power Co., 729 P.2d 400 (Id. 1986); Bates Fabrics, Inc. v. PUC, 447 A.2d 1211 (ME. 1992); Barasch v. Pennsylvania Public Utility Commission, 546 A.2d 1296, reargument denied, 550 A.2d 257 (1988); Erie Associates - Petition for a Declaratory Ruling that Its Power Purchase Contract with New York State Electric & Gas Corporation Remains in Effect, Case 92-E-0032, N.Y. PUC LEXIS 52 (March 4, 1992); Freehold Cogeneration Associates v. Board of Regulatory Commissioners of the State of New Jersey, 1995 WL 4897 (3rd Cir. (N.J. 1995); Fulton Cogeneration Associates v. Niagara Mohawk Power Corporation, Case No. 92-CV-14112 (N.D.N.Y. 1993). The facts vary in these cases, but the general consensus appears to be that under federal and state regulation of the relationship between utilities and cogenerators, state commissions should not generally resolve contractual disputes over the interpretation of negotiated power purchase agreements once they have been established and approved for cost recovery.

In Afton, supra., Idaho Power Company (Idaho Power) and Afton Energy, Inc. (Afton) had negotiated a power purchase agreement that included two payment options for the purchase of firm energy and capacity. The options were conditioned on the Idaho Supreme Court's determination whether the Idaho commission had authority to order Idaho Power to negotiate an agreement with Afton or dictate terms and conditions of the agreement. When the Supreme Court made its decision, Idaho Power petitioned the Commission to declare that

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Docket No. 900383-EQ; In re: Petition of Timber Energy Resources, Inc. for a declaratory statement regarding upward modification of committed capacity amount by cogenerators, Order No. 21585, issued July 19, 1989, Docket No. 8890453-EQ; In re: Petition for Declaratory Statement by Wheelabrator North Broward, Inc., Order No. 23110, issued June 25, 1990, Docket No. 900277-EQ.

the lesser payment option would be in effect. The Commission dismissed the petition, holding that the petition was a request for an interpretation of the contract and that the district court was the proper forum to interpret contracts. The Idaho Supreme Court upheld the Commission's decision.

In Erie Associates, supra., the New York Public Service Commission was asked by the cogenerator to declare that its negotiated purchased power agreement was still in effect even though the utility had cancelled the contract because the cogenerator had failed to post a deposit on time. The Commission stated, at page 127:

> Erie's petition will not be granted. Jurisdiction under the Public Utility Regulatory Policies Act of 1978 (PURPA) is generally limited to supervision of the contract formation process. Once a binding contract is finalized, however, that jurisdiction is usually at an end.
>
> We will not generally arbitrate disputes between utilities and developers over the meaning of contract terms, because such questions do not involve our authority, under PURPA and PSL@66-c, to order utilities to enter into contracts. Requests to arbitrate disputes are simply beyond our jurisdiction, in most cases.
>
> . . . Erie has not justified a departure from the policy of declining to decide breach of contract questions, or identified a source for the authority to exercise jurisdiction over such issues.

FPC has asked us to determine if its implementation of the pricing provision is lawful and consistent with Commission Rule 25-17.0832(4), Florida Administrative Code. We believe that FPC's request is really a request to interpret the meaning of the contract term. FPC is not asking us to interpret the rule. It is asking us to decide that its interpretation of the contract's pricing provision is correct. We believe that endeavor would be inconsistent with the intent of PURPA to limit our involvement in negotiated contracts once they have been established. Furthermore, we agree with the cogenerators that the pricing methodology outlined in Rule 25-17.0832(4), Florida Administrative Code, is intended to apply to standard offer contracts, not negotiated contracts. We have clearly said that we would not require any standard provisions, pricing or otherwise, for negotiated contracts. Therefore, whether FPC's implementation of the pricing provision is consistent with the rule is really irrelevant to the parties' dispute over the meaning of the negotiated provision. In this case, we will defer to the courts to resolve that dispute. We note however, that courts have the discretion to refer matters to us for consideration to maintain uniformity and to bring the Commission's specialized expertise to bear upon the issues at hand.

We disagree with FPC's proposition that when the Commission issues an order approving negotiated cogeneration contracts for cost recovery, the contracts themselves become an order of the Commission that we have continuing jurisdiction to interpret. It is true that the Supreme Court has determined that territorial agreements merge into Commission orders approving them, but territorial agreements are not valid commercial purchased power contracts. They are otherwise unlawful, anticompetitive agreements that have no validity under the law until we approve them. Furthermore, territorial agreements involve the provision of retail electric service over which we have exclusive and preemptive authority. As explained above, we do not enjoy such authority over QFs or their negotiated power purchase contracts.

Under certain circumstances we will exercise continuing regulatory supervision over power purchases made pursuant to negotiated contracts. We have made it clear that we will not revisit our cost recovery determinations absent a showing of fraud, misrepresentation or mistake;[3] but if it is determined that any of those facts existed when we approved a contract for cost recovery, we will review our initial decision. That power has been clearly recognized by the parties through the "regulatory out" provisions of those contracts. We do not think, however, that the regulatory out provisions of negotiated contracts somehow confer continuing responsibility or authority to resolve contract interpretation disputes. Our authority derives from the statutes. United Telephone Company v. Public Service Commission, 496 So.2d 116 (Fla. 1986). It cannot be conferred or inferred from the provisions of a contract.

For these reasons we find that the motions to dismiss should be granted. FPC's petition fails to set forth any claim that the Commission should resolve. We defer to the courts to answer the question of contract interpretation raised in this case. Thus, FPC's petition is dismissed.

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[3] See Docket No. 910603-EQ, In Re: Implementation of Rules 25-17.080 through 25-17.091, Florida Administrative Code, Order No. 25668, issued February 3, 1992.

It is therefore

ORDERED by the Florida Public Service Commission that the Motions to Dismiss filed by Lake Cogen Limited, Pasco Cogen Limited, Auburndale Power Partners, Orlando Cogen Limited, and Metro Dade County/Montenay are granted. Florida Power Corporation's Petition is dismissed. It is further

ORDERED that this docket is hereby closed.

By ORDER of the Florida Public Service Commission, this 15th day of February, 1995.

/s/ Blanca S. Bayó

BLANCA S. BAYÓ, Director
Division of Records and Reporting

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-904-488-8371.

(S E A L)

MCB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Civil Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

IN THE CIRCUIT COURT OF THE FIFTH JUDICIAL CIRCUIT
IN AND FOR LAKE COUNTY, FLORIDA

NCP LAKE POWER, INCORPORATED,
a Delaware corporation,
as General Partner of LAKE
COGEN LTD., a Florida
limited partnership,

Plaintiff,

vs.

FLORIDA POWER CORPORATION,

Defendant.

CASE NO. 94-2354-CA-01

DIVISION NO. 8

ORDER GRANTING PARTIAL SUMMARY JUDGMENT FOR THE PLAINTIFF AND AGAINST THE DEFENDANT

This cause came on to be heard on Plaintiff, NCP LAKE POWER, INCORPORATED's, a Delaware corporation, as General Partner of LAKE COGEN, LTD., a Florida limited partnership ("LAKE COGEN"), Motion for Partial Summary Judgment and Defendant, FLORIDA POWER CORPORATION's ("FPC"), Motion for Partial Summary Judgment and the Court having heard argument from counsel for both parties hereto and otherwise being fully advised in these premises, the Court finds as follows:

A. The pleadings, depositions, answers to interrogatories, admissions, and the affidavits filed in support of the Plaintiff's Motion for Partial Summary Judgment show that there are no genuine issues of material fact concerning the interpretation of Section 9.1.2 of the Negotiated Contract for the Purchase of Firm Capacity and Energy From a Qualifying

Facility Between Lake Cogen Limited and Florida Power Corporation (the "Lake Cogen-FPC Agreement") which is attached to the Plaintiff's Amended Complaint filed herein.

B. Section 9.1.2 of the Agreement between the parties, read in conjunction with the entire Agreement is unambiguous as it relates to the type of unit used to model the calculation of the electric energy payments to the Plaintiff.

C. Section 9.1.2 of the Agreement, together with the other pertinent sections of the Agreement, requires the Defendant FPC to make electric energy payments to the Plaintiff with reference to modeling the operation of a real, operable 1991 Pulverized Coal Unit, having the characteristics required by law to be installed on such a unit as well as all other characteristics associated with such a unit, as selected by the Plaintiff in Section 8.2.1 of the Agreement and described in Appendix "C", Schedules 3 and 4 of the Agreement.

D. The Court has also considered the Defendant's Motion for Partial Summary Judgment and finds that the terms of the Agreement at issue are unambiguous and do not require the Court to look outside its four corners for its interpretation of Section 9.1.2 of the Agreement. However, the Court disagrees with the Defendant's conclusions regarding the interpretation of the Agreement at issue before the Court.

IT IS THEREFORE, ORDERED AND ADJUDGED that:

1. A Partial Summary Judgment is hereby entered for LAKE COGEN and against FPC on the issue of liability for FPC's failure to pay LAKE COGEN at the firm energy cost rate when the avoided unit with operational characteristics of an operable 1991 Pulverized Coal Unit contemplated by the Lake Cogen-FPC Agreement would have been operating and

at the as-available energy cost rate during those times when said avoided unit would not have been operating.

2. The Defendant's Motion for Partial Summary Judgment is denied to the extent that it is inconsistent with this Order.

DONE AND ORDERED in Chambers at Tavares, Lake County, Florida this 23 day of January, 1996.

DON F. BRIGGS
CIRCUIT JUDGE

LAKE Settlement

Exhibit C
Second Revised

Calculation of Savings from Settlement of Energy Dispute and Early Termination Buy-out

	(a) Total Payments according to FPC Position	(b) Total Payments according to adjusted LCL Position	(c1) Total Payments to Lake according to Settlement	(c2) Cost of Replacement minus Value of Curtailment	(c) Net Settlement Costs	(b-c) Ratepayer Savings/(Cost)
1996	$6,707,799	$6,920,110	$8,259,484	$129,583	$8,389,066	($1,468,957)
1997	$40,790,413	$42,963,822	$45,864,939	$773,271	$46,638,210	($3,674,388)
1998	$41,962,331	$44,213,717	$46,236,965	$548,803	$46,785,768	($2,572,051)
1999	$42,458,018	$45,587,640	$48,087,253	$997,738	$49,084,991	($3,497,351)
2000	$44,518,830	$47,232,714	$49,994,905	$809,673	$50,804,578	($3,571,864)
2001	$46,354,756	$49,028,072	$50,773,566	$833,849	$51,607,214	($2,579,141)
2002	$47,830,717	$51,042,106	$50,038,262	$840,923	$50,879,185	$162,921
2003	$49,702,362	$52,908,429	$52,234,028	$827,101	$53,061,129	($152,700)
2004	$50,715,452	$54,936,737	$54,191,263	$856,721	$55,047,984	($111,247)
2005	$51,928,143	$57,138,353	$55,975,641	$845,287	$56,820,929	$317,425
2006	$54,011,863	$59,423,702	$58,969,849	$866,020	$59,835,869	($412,167)
2007	$55,910,949	$61,788,815	$61,517,010	$877,004	$62,394,014	($605,199)
2008	$57,766,982	$64,171,072	$64,173,537	$889,546	$65,063,083	($892,011)
2009	$59,570,852	$66,491,039	$61,443,406	$897,227	$62,340,632	$4,150,407
2010	$61,708,538	$69,192,712	$0	$33,763,225	$33,763,225	$35,429,487
2011	$63,946,417	$72,026,367	$0	$34,071,473	$34,071,473	$37,954,894
2012	$66,334,918	$75,067,759	$0	$34,701,877	$34,701,877	$40,365,882
2013	$40,088,273	$45,555,742	$0	$20,393,431	$20,393,431	$25,162,311
Cumulative	$881,297,404	$965,688,909	$707,760,108	$133,922,551	$841,682,658	$124,006,250
NPV @ 8.67%	$452,844,819	$491,335,265	$422,107,126	$42,585,197	$464,692,322	$26,642,942

COMPARISON OF CUMULATIVE RATEPAYER NPV ASSOCIATED WITH FPC/QF SETTLEMENT AGREEMENTS
(In millions of dollars*)

YEAR	Lake NPV	Pasco NPV	OCL NPV	Auburndale NPV
1995	$0.0	$0.0	$0.0	$0.0
1996	($1.5)	($1.5)	$0.0	($1.9)
1997	($5.0)	($8.8)	($8.5)	($3.7)
1998	($7.2)	($16.8)	($18.2)	($5.3)
1999	($10.1)	($22.5)	($26.2)	($6.8)
2000	($12.8)	($26.7)	($33.6)	($8.2)
2001	($14.5)	($28.8)	($40.4)	($8.2)
2002	($14.4)	($30.0)	($40.4)	($8.2)
2003	($14.5)	($30.2)	($40.4)	($8.2)
2004	($14.6)	($29.8)	($40.4)	($8.2)
2005	($14.4)	($29.3)	($40.4)	($8.2)
2006	($14.6)	($27.7)	($40.4)	($8.2)
2007	($14.8)	($26.1)	($40.4)	($8.2)
2008	($15.2)	($24.8)	($40.4)	($8.2)
2009	($13.7)	($12.8)	($40.4)	($8.2)
2010	($2.2)	($1.4)	($40.4)	($8.2)
2011	$8.2	$10.0	($40.4)	($8.2)
2012	$20.3	$21.1	($40.4)	($8.2)
2013	$28.7	$27.5	($40.4)	($8.2)
2014			($32.3)	($6.9)
2015			($24.3)	($5.6)
2016			($16.5)	($4.3)
2017			($8.8)	($3.0)
2018			($1.5)	($1.7)
2019			$6.7	($0.5)
2020			$12.8	$0.7
2021			$19.7	$1.9
2022			$26.4	$3.1
2023			$32.9	$4.3
2024				$5.1

* All data reflects FPC's estimate of ratepayer savings deflated to real terms per the discount factor used in each Settlement Agreement.