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M E M O R A N D U M

February 23, 1996

TO:
____ DIVISION OF APPEALS
____ DIVISION OF AUDITING AND FINANCIAL ANALYSIS
____ DIVISION OF COMMUNICATIONS
XX DIVISION OF ELECTRIC AND GAS
____ DIVISION OF RESEARCH
____ DIVISION OF WATER AND WASTEWATER
____ DIVISION OF LEGAL SERVICES

FROM: DIVISION OF RECORDS AND REPORTING (WILLIAMS)

RE: CONFIDENTIALITY OF CERTAIN INFORMATION

DOCUMENT NO: **02218-96**

DESCRIPTION: **Composite Exhibit No. 23 (RK-5) of Ralph Killian's direct testimony.**

SOURCE: **FLORIDA POWER CORPORATION**

DOCKET NO.: **950110-EI**

The above material was received with a request for confidentiality (attached). Please prepare a recommendation for the attorney assigned to the case by completing the section below and forwarding a copy of this memorandum, together with a brief memorandum supporting your recommendation, to the attorney. Copies of your recommendation should also be provided to the Division of Records and Reporting and to the Division of Appeals.

Please read each of the following and check if applicable.

___ The document(s) is (are), in fact, what the utility asserts

02218-96

UNREDACTED VERSION
CONTAINS CONFIDENTIAL INFORMATION

<u>SUBJECT TO REQUEST FOR CONFIDENTIAL CLASSIFICATION</u>

ATTACHMENT A

FLORIDA POWER CORPORATION
DOCKET NO. 950110-EI

Justification Matrix for
REQUEST FOR CONFIDENTIAL CLASSIFICATION

COGENERATION REVIEW and
COGENERATION AND PURCHASED POWER STRATEGIC PROPOSAL

BATES NUMBER	LINE	JUSTIFICATION
400189	16-19	Information at lines 16 through 19 projects the cost to FPC and its parent company of any downgrades in various bond and commercial paper ratings over the next 5 years. Disclosure of these non-public financial forecasts would provide lenders information they would not otherwise have in determining their charges to FPC. As a result, disclosure would subject FPC to an increase in the charges and fees to FPC for bonds and commercial paper.
400213	11-14 (below table)	The information at lines 11 through 14 projects FPC's total debt to capital ratio and pre-tax interest coverage. Again, disclosure of this information would weaken FPC's bargaining position in the financial markets and subject FPC to higher costs and fees for financing transactions than would otherwise have been incurred absent disclosure of this information.
400214	Table 2 and lines 6-19 (below Table)	Table 2 and lines 6 through 19 are a continuation of the discussion at Bates Number 400213 and should be considered confidential for the reasons given above.
400215	1-3	The information at lines 1 through 3 also is a continuation of the discussion of confidential information appearing at Bates Numbers 400213 and 400214. Accordingly, it should be considered confidential for the reasons given above.

400224	26-38	The information at lines 26 through 38 identifies FPC's strategies with respect to purchases of cogenerated power, specifically buy-outs or buy-downs. Disclosure of FPC's negotiation strategy in advance would weaken FPC's bargaining position and would reduce FPC's ability to negotiate terms favorable to FPC and its ratepayers.
400231	3-10	The information at lines 3 through 10 discusses equity financing strategies and forecasts the impact of those strategies. Disclosure of the financial strategies would undermine FPC's ability to implement them at a more favorable cost than would be obtained had the information not been disclosed. Disclosure of the volume of FPC's projected equity needs would likely result in a decrease in the price of the stock to the harm of FPC's business interests.
400239	9-12	The information at lines 9 through 12 reflects FPC's strategies to maintain low coal prices. Disclosure of this information would adversely impact FPC's ability to implement its strategies by revealing them in advance thus reducing FPC's ability to accurately identify disparities in such costs and seek a reduction where necessary.

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Florida Power
CORPORATION

COGENERATION REVIEW

An Assessment of Florida Power's Qualifying Facility (Cogeneration) Purchases

PRELIMINARY

Energy Distribution Department
December 1993

Confidential Material
FPC Use only
400184

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COGENERATION REVIEW

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EXECUTIVE SUMMARY

Florida Power Corporation (FPC) has contracted for nearly 1,100 MW of firm capacity from qualifying facilities (QFs) since the passage of the Public Utilities Regulatory Policy Act (PURPA) in 1978. PURPA and the FPSC rules which implemented PURPA, obligated electric utilities to purchase capacity from QFs if the capacity is needed and the QF payments are below the utility's avoided cost. Therefore, FPC signed the QF contracts based upon the avoided costs at the time. The overwhelming majority of the QF contracts are based upon pulverized coal plants while the majority of QFs are actually natural gas combined cycle plants. The price of natural gas has been lower than projected by FPC and the availability of gas transportation has increased since the QF contracts were signed. In addition, the capital and construction costs have significantly decreased. Therefore, at the present time, the QF contracts are not cost effective when compared to FPC built natural gas fired combined cycle units. Based upon current natural gas forecasts, the QFs in aggregate would require a reduction of 4% (high gas forecast) to 24% (expected gas forecast), to equal current avoided costs. The table below shows the comparison of the cost per MWH of QF capacity and energy versus the cost per MWH of a FPC natural gas combined cycle plant. The cost per MWH of the Miller Purchase is included for reference purposes only.

Year	$/MWH QF	$/MWH* FPC CC	$/MWH Miller Purchase	QF% of Total Capacity
1994	43.83	45.44	40.01	4.4%
1995	50.65	46.06	39.56	10.5%
1996	52.56	46.69	39.13	11.4%
1997	55.05	47.14	39.33	12.0%
1998	58.83	47.70	39.11	12.0%
*FPC's combined cycle cost assumes a new site				

The cost effectiveness of QF contracts will also be affected by many factors including the cost of natural gas and changes in environmental laws (e.g. CO_2 tax). The resources need to be assigned to properly evaluate and implement, if feasible, all of the options available to increase the cost effectiveness of the QF contracts. These contracts pose a significant threat to FPC's competitive position.

QF capacity payments are calculated based upon value of deferral methodology. This methodology calculates the value of deferring the need for the construction of capacity annually. Therefore, the cost starts lower than traditional revenue requirements but increases by approximately 5% per year. Conversely, traditional revenue requirements start higher than value of deferral payments but decrease over time.

The net present value as of January 1, 1994, of all of the QF capacity payments is $2.7 billion, assuming an interest rate of 10%. FPC has concerns that these QF contracts may lower our current (Standard & Poor's) AA-bond rating. Standard & Poor's (S & P) methodology states that these off-balance sheet obligations should be considered to be debt equivalents. These obligations are adjusted by a risk factor which ranges from 10% minimum up to 50% for take-and-pay contracts. The risk factor is multiplied by the net present value (NPV) of the QF contracts to determine the utilities imputed debt. FPC cogeneration contracts should be assigned the lowest risk factor of 10%.

A downgrade of FPC's bond rating could cost FPC an additional $372,000 for first mortgage bonds and cost Progress Capital Holdings an additional $150,000 for medium-term bonds and another $315,000 for commercial paper. A bond derating therefore represents a potential cost of $837,000 over the next five years for all Florida Progress.

In addition, FPC has become concerned about FPC's ability to accept this QF capacity during periods of minimum load. FPC's minimum load is approximately 1,800 to 2,000 MW, which occurs during mild weather conditions. This entire load could be served by FPC's nuclear plant and the QFs if the QFs did not reduce their capacity. During these periods, the output of FPC's steam units would have to be reduced as much as possible or cycled off. Cycling off steam units increases their O&M costs and renders them unavailable to meet the rapidly growing load a few hours later; forcing FPC to serve the load uneconomically. FPC has agreements in place, and is continuing negotiations with the QFs, to resolve this problem without additional payments to the QFs.

For all of the above reasons, FPC has investigated a buy out of some of the QF projects such as Auburndale, Lake Cogen and Pasco Cogen. The FPC investigation included three different scenarios. These were (1) operating as a QF project, (2) operating as a utility generator or (3) a buy out of FPC's contractual obligation. At this time, it is not financially viable to purchase these projects under these scenarios. If circumstances change (e.g. natural gas prices), these and other projects should be reevaluated. A copy of these analyses may be obtained from Robert Dolan, Manager of Cogeneration Contracts and Administration. To date, FPC considered it uneconomical to buy out any QF contract.

FERC's PURPA regulations, adopted by the Florida Public Service Commission, provide that approved QF rates do not become unjust and unreasonable because the utility's avoided cost at the time the QF comes into service is different than the utility's avoided cost at the time the QF contract was entered into. Therefore, FPC must find another method to reduce the cost of QF contracts. One method could be to buy down QF contracts.

When the contract with Pasco Cogen (106 MW) is taken as an example, the payment required to reduce their capacity payment to match FPC's embedded cost is $46 million. This figure assumes a 20% discount rate and uses FPC's expected fuel forecast. Buy down costs can be dramatically altered by the fuel forecast used, the QF's interest rate, the QF's expected rate of return, inflation, and other factors.

Many of the QF contracts require that the QFs ability to deliver their capacity shall not be encumbered by interruptions in their fuel supply. FPC has therefore placed one QF in default (Orlando CoGen, 72 MW) because they do not have a back up fuel. Two other QFs (Tiger Bay, 217.75 MW and Orange Cogen, 74 MW) have been notified that they will be in default if they do not have a back up fuel supply in place when they begin to receive capacity payments.

FPC is not currently pursuing additional capacity from non-utility generation sources. However, recommendations are made in this review should additional contracted capacity be required or mandated.

The FPSC has approved a bidding rule that only applies to generation which requires a determination of need (steam greater than 75 MW) and may be waived. The FPSC rule is as follows:

> *"Rule 25-22082(9) The Commission may waive this rule or any part thereof upon a showing that the waiver would likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers or is otherwise in the public interest".*

Peakers and potentially repowering may not require bidding. The Governor and Cabinet did not endorse the PPSA's task recommendation that all capacity additions be bid.

BACKGROUND

Please note that the total cogeneration capacity stated at various time in this review may vary depending on the subject. This variance is due to the fact that the cogeneration contracts have the ability to adjust their committed capacity. Depending on the application, the most appropriate total capacity figure will be used.

Review of the Requirements of the Public Utility Regulatory Policies Act

In 1978, the Public Utility Regulatory Policies Act (PURPA) was enacted and then amended in 1980. PURPA's constitutionality was challenged in Mississippi. Upon appeal, the U.S. Supreme Court found that PURPA was constitutional in 1982. Section 210 of that statute addresses cogeneration and small power production, the primary focus of this section. See Appendix 8 for a copy of PURPA.

Congress' goal in passing PURPA was to reduce the U.S. dependence on foreign oil by diversifying energy supply and reducing consumption. PURPA encouraged small alternative power producers (including hydro and renewables), and cogeneration resources. Congress sought to overcome the reluctance of utilities to deal with alternative power providers and conservation by requiring utilities to purchase from a class of defined small power production and cogeneration facilities that could achieve qualifying facility (QF) status. Congress also required utilities to interconnect and to supply backup power. As for the reluctance of alternative producers to become regulated by virtue of selling power in a traditionally regulated industry, congress exempted QFs from most of the regulatory burdens including Public Utility Company Holding Act (PUCHA) placed on investor-owned utilities.

Congress divided QF regulation between the Federal Energy Regulatory Commission (FERC) and the state public service commission where the purchasing utility is located. It is important to keep in mind that in most cases the sale of QF power to an electric utility is a wholesale, not a retail, transaction. As such, jurisdiction normally would lie with FERC. However, PURPA directs that certain Federal regulatory functions, such as the determination of avoided costs, be delegated from FERC to the states. PURPA gives FERC broad discretion to establish, through its rules and regulations, the parameters of the economic transactions between electric utilities and QFs. In turn, the individual states are bound to follow these FERC requirements.

A QF can be either a cogenerator or a small power producer. As a general matter a cogeneration facility simultaneously produces electric energy and forms of useful thermal energy, such as heat or steam used for industrial, commercial, heating or cooling purposes. A small power production facility is a facility that produces electricity from biomass, waste, hydro, renewable resources, or geothermal energy.

Criteria for Cogeneration Facilities

PURPA defines a qualifying cogeneration facility as a cogeneration facility which FERC determines by rule meets size, fuel use and fuel efficiency and such other requirements as FERC may prescribe, and is owned by a person not primarily engaged in the generation or sale of electric power. This broad definition leaves significant discretion in the hands of FERC.

FERC's rules define a qualifying cogeneration facility in terms of a topping-cycle and bottoming-cycle facility. A topping-cycle facility is one in which the energy input into the facility is first used to produce useful electric power, and the waste heat from power production is then used to provide useful thermal energy. A bottom-cycling facility involves the reverse process. The energy input is first applied to a useful thermal energy process and the emerging waste heat is then used to produce electricity. Most cogeneration facilities, such as natural gas-fired combined cycle facilities, are topping-cycle. An example of a topping cycle is Pasco Cogen Limited in Dade City. Pasco Cogen is a natural gas combined cycle plant. Two aero-derivative gas turbines are fired by natural gas. The exhaust heat is then captured in a heat recovery steam generator (HRSG). The steam generated in the HRSG produces electricity from a steam turbine. Low pressure steam is taken off the steam turbine and used in the Lykes Pasco citrus processing plant.

Bottoming-cycle facilities tend to built when there is an established industrial process producing waste heat, such as the process used to produce sulfuric acid. An example of a bottoming-cycle cogenerator is Cargill Fertilizer (formerly Seminole Fertilizer). The Cargill Fertilizer plant makes sulfuric acid from sulfur. This chemical (exothermic) process produces excess heat which is captured in a recovery boiler; the steam from the boiler is used to generate electricity.

For topping-cycle facilities, the useful thermal energy output of the facility must, during any calendar year, be no less than 5 percent of the total energy output. In addition, the useful power output plus half of the useful thermal energy output for a natural gas or oil facility, must be greater than 45% of the total energy output of the facility. If the useful thermal energy output is greater than 15% of the total energy output of the facility, then the efficiency standard is 42.5%.

FERC opinions generally have provided that a thermal output is "useful" if it has an independent business purpose with some economic justification. FERC has found business purposes to be presumptively useful when use of a facility's thermal output constitutes a common industrial or commercial process.

FERC rules allow FERC to waive the operating and efficiency standards contained in its rules if FERC finds that a facility will produce significant energy savings. For example, FERC has waived its thermal host requirements applicable to cogeneration facilities when QFs have temporarily lost their thermal hosts but are actively searching for a replacement host.

Criteria for Small Power Production Facilities

PURPA's definition of a small power production facility is essentially the same as the broadly-worded definition for qualifying cogeneration facilities, leaving significant definition discretion to FERC. A qualifying small power production facility is one which FERC determines meets such fuel use, fuel efficiency and reliability requirements as FERC prescribes by rule. FERC's rules provide that the power production capacity of a small power production facility, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 MW. Facilities are defined to be at the same site if they are located within one mile of each other. In 1990, Congress lifted the 80 MW limitation for small power producers that are fueled by certain waste products or by renewable energy. Generally these waste products are byproducts of industrial processes, such as coal waste. Likewise, the 80 MW limit does not apply to tire-burning plants. However, the limit still applies to municipal solid waste (MSW) facilities.

FERC's rules provide that at least 75 percent of the primary energy source of a small power production facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof. The rules further provide that the use of oil, natural gas and coal as a fuel may not in the aggregate exceed 25 percent of the total energy input of the facility during any calendar year.

Criteria For QF Ownership

PURPA provides that a cogeneration or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration or small power production facilities). Under FERC rules, facilities are considered owned by a person primarily engaged in the generation or sale of electric power if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company or companies, primarily engaged in the sale of electricity, or any combination thereof. QF status is based on the sale of net output from the facility. That is, for purposes of size, efficiency and ownership, the power utilized on site is subtracted from the gross output of the facility at the point of sale.

Obtaining QF Status

FERC's rules provide that QFs must apply to FERC for certification. This is typically done prior to project financing and construction. Hence, applications usually describe a *proposed* facility. FERC rules require that applications must contain enough information for FERC to determine whether PURPA's qualifying facility requirements will be met. FERC generally will accept the representations of the applicant as true. FERC's rules provide that QF status may be revoked if a QF which has been certified fails to comply with any statement contained in its application for certification. For this reason QFs sometimes amend their applications and request FERC recertification during the course of their project development.

Regulatory Exemptions Enjoyed By QFs

QFs are generally exempt from the Federal Power Act, the Public Utility Holding Company Act, and most state regulations. The only significant portions of the Federal Power Act from which QFs have not been exempted involve interconnection and wheeling, and are discussed below. If a project loses QF status during its lifetime, it is subject to regulation as a public utility.

State Regulation Of QFs

PURPA directs FERC to issue rules "as it determines necessary to encourage cogeneration and small power production," and which also require utilities to offer to purchase electric power from QFs. PURPA directs that in turn, each state regulatory authority charged with regulating electric utilities must "implement" PURPA rules. FERC issued its rules in 1979. In 1981, the Florida Public Service Commission (FPSC) adopted FERC's rules and issued additional, complementary rules of its own. The FPSC revised its cogeneration and small power production rules in 1984 and 1990. These rules are discussed in the section on the development of cogeneration at FPC.

Utility Obligation To Purchase QF Power

PURPA directed FERC to enact regulations which require all electric utilities, not just investor-owned utilities, to purchase electricity produced by QFs. FERC's regulations provide that each electric utility shall purchase any energy and capacity made available to it from a QF to which the utility is directly interconnected, or from a QF that causes such energy or capacity to be delivered to the utility. However, FERC's rules also provide that if there are operational circumstances in which purchases of QF power will result in the utility bearing costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, the utility will not be required to purchase power from QFs.

Rates For Purchases By Electric Utilities From QFs

PURPA provides that various traditional regulatory requirements, such as the just and reasonable standard and the public interest standard, govern rates for sales by QF to electric utilities. PURPA also requires that utilities purchase at rates which shall not discriminate against QFs, and that such rates shall not exceed the incremental or avoided cost to the electric utility of alternative electric energy. The incremental cost of alternative electric energy is statutorily defined as the cost to the electric utility of the electric energy which, but for the purchase from the QF, the utility would have generated or purchased from another source.

The states administratively establish the avoided cost rates that utilities pay for power purchased from QFs, in accordance with the requirements set forth in FERC's rules. FERC does not prescribe a specific methodology for the states' calculations of avoided cost. However, FERC regulations direct that in determining avoided costs, utilities shall, to the extent practicable, take into account the availability of capacity or energy from a QF during daily and seasonal peak periods, the ability of the utility to dispatch the QF, the terms of the purchase contact (including its duration, termination notice requirements and sanctions for non-compliance), the coordination of scheduled outages, the usefulness of QF power during utility system emergencies, the individual and aggregate value of energy and capacity from QFs on the utility's system, the smaller capacity increments and the shorter lead time available with additions of capacity from QFs, and the ability of the utility to avoid costs by deferring capacity additions, reducing fossil fuel use, or lowering line losses.

FERC's rules explicitly provide that nothing in the rules requires an electric utility to pay more than avoided cost. However, the rules stipulate that a rate set at full avoided cost satisfies the just and reasonable and public interest standards. Rates may be less than avoided cost if the state public service commission determines that a lower rate is just and reasonable, in the public interest, and is sufficient to encourage cogeneration and small power production. In a case in which the rate for purchases are based upon estimates of avoided costs over the term of a contract, the rates do not violate FERC rules if they differ from avoided costs at the actual time of delivery.

The rates paid by utilities to QFs contain an energy and capacity component. FERC's rules provide that utilities must only pay for the capacity value of power purchased when the purchase allows the utility to reduce its own capacity-related costs by deferring construction or firm power purchases. FERC's rules provide that rates for as-available energy purchases, at the QFs option, can be based on the avoided energy cost at the time of delivery or on an avoided energy cost calculated at the time the utility contracts to receive the energy over a specified future term.

Utility Obligation To Sell To QFs

PURPA directed FERC to enact regulations which require all electric utilities to offer to sell electricity to QFs. These rates, like purchase rates, must be just and reasonable, in the public interest and non-discriminatory. FERC requires that upon request of a QF, each electric utility shall provide supplementary power, back-up power, maintenance power or interruptible power. State public service commissions may waive the requirement to supply any of these four services if compliance would impair the utility's ability to render adequate service to its customers or place an undue burden on the utility.

Interconnection

FERC's regulations provide that electric utilities must agree to interconnect with any QFs in their service territory, unless such interconnection would expose the utility to additional regulation under the Federal Power Act. Utilities also must offer to operate in parallel with a QF. FERC rules also provide that interconnection costs, including costs of connection, metering, transmission, distribution and safety equipment be borne by the QF.

Wheeling

PURPA obligates electric utilities to offer to purchase QF power made available to them. It does not restrict this obligation to purchases of power from QFs to which the utility is directly interconnected. FERC's rules provide that if a QF agrees, an electric utility directly interconnected to that QF may transmit the energy or capacity to any other electric utility, which utility in turn is obligated to purchase the power or energy. The FPSC has required utilities in Florida to wheel electricity for QFs since 1984 utilizing the rates, terms, and conditions specified by FERC.

Under the Energy Policy Act of 1992, any individual or company generating wholesale power can apply to FERC for an order requiring an electric utility to provide transmission services. The order may also require the utility to expand its transmission capacity.

Retail Sales and Self-Service Wheeling

Florida law only allows for retail sales from a QF to the thermal host if the thermal host is a government body (e.g. the University of Florida and Florida State University). Self-service wheeling is prohibited unless the FPSC finds that provision of this service is not likely to result in higher cost electrical service to the general body of ratepayers.

There are two retail sales cases that FPC has been involved in with QFs. In the first, Timber Energy requested permission to serve the industrial park in Telogia where they are located. The FPSC ruled that Timber Energy could serve these customers but, if they did, they would have become regulated by the FPSC. Currently, there are no other businesses in the industrial park and Timber Energy is not interested in becoming a regulated utility.

In a second case, Mulberry requested permission to serve its thermal host as part of a fixed rent payment. The FPSC staff has recommended that this is a retail sale and it should not be allowed. The FPSC will vote on this issue during the upcoming Proposed Agency Action (PAA) scheduled for February 1, 1994.

There have been at least two requests for retail wheeling involving QFs. Both cases were denied by the FPSC as not being cost effective for the general body of ratepayers. These were the Metro Dade Downtown Government Center (FP&L) and W.R. Grace (TECO). In both cases, the QFs argued that it was cost effective for them to build either a transmission line or distribution line to the load thus bypassing the utility in question. The

FPSC ruled that this should not be a determining factor in whether retail wheeling should be ordered.

Exempt Wholesale Generators and Independent Power Producers

An exempt wholesale generator (EWG) is a defined term under the recently-enacted Energy Policy Act of 1992 (EPACT): *any person engaged, directly or indirectly through affiliates, and exclusively, in the business of owning and/or operating all or part of a facility used for the generation of electricity exclusively for sale at wholesale.* Additionally, Section 712 of EPACT requires state regulatory commissions to perform a general evaluation of:

1. The impact of purchased power contracts on a utility's cost of capital and retail rates;

2. Whether Non-Utility Generators (NUGs) have an unfair advantage over utilities or threaten system reliability because of their debt leveraging;

3. Should regulators preapprove power purchase contracts; and

4. Should regulators require assurances of adequate fuel supplies.

The FPSC has decided to evaluate these impacts on a case-by-case basis.

EWG status can be obtained only through application to FERC. Owners of EWGs are not subject to the Holding Company Act, and are not regulated as persons primarily engaged in the sale or transmission of electricity under the Federal Power Act. Unlike the QFs, electric utilities are not obligated to offer to purchase from EWGs. Thus, it is expected that EWGs will compete strongly with IPP's and QFs on price and terms and conditions of sale.

Utilities may not contract purchased power from an affiliated EWG unless the utility receives a state public service commission order finding that the transaction will benefit consumers, does not violate state law, will not provide the EWG with any unfair advantage by virtue of its affiliation, and is in the public interest.

The term independent power producer (IPP) is not a defined term under the Federal Power Act, PURPA, or EPACT. An IPP is commonly considered to be a seller of electricity at wholesale which fails to qualify as an EWG. The most significant legal consequence of failure to qualify as a QF is that electric utilities are not obligated to purchase the output of IPP's and EWG's. Failure to qualify as either a QF or EWG also means that the generator is not exempt from the Holding Company Act, and is subject to regulation under the Federal Power Act.

Because utilities are not required to purchase the output from IPP's, those facilities, like EWGs, must compete strongly with QFs on price and terms and conditions of sale. However, the presence of IPPs in the wholesale market likely will diminish over time with the advent of EWG status created by the Energy Policy Act of 1992. Independent generators are expected to strive for EWG status in order to avoid the strictures of the Holding Company Act.

FERC recently abandoned a proposed rulemaking, instigated in 1988, which would have exempted IPPs from many of the regulatory burdens of the Federal Power Act. However, in a series of case-by-case decisions, FERC has accomplished much of the IPP deregulation that it proposed. The most significant Federal Power Act burden as far as IPPs are concerned, is the requirement that all sellers of power must sell at a "just and reasonable" rate. Traditionally, FERC has required that rates be cost-based in order to be just and reasonable. However, FERC case law establishes that FERC will approve an IPP rate if it determines that the IPP lacks market power, and that the rate is market-based; that is, established through bidding or arms-length negotiation. EWGs are subject to the same just and reasonable standard as IPPs, therefore, it is anticipated that FERC will approve EWG rates on a similar basis.

Development of Cogeneration at FPC

1. Pre-PURPA (prior to 1978)

   Prior to the passage of PURPA, Florida Power Corporation had three contracts with cogenerators. Two contracts were for self-service generation only, with no sales to FPC. These were both for 1 MW and were located at the University of Florida and Minute Maid Dunedin (later H.P. Hood Company). The third contract was with St. Joe Forest Products. This contract allowed St. Joe Forest Products to delivery power to FPC (City of Port St. Joe) under emergency conditions. The interconnection was also used to provide backup power to St. Joe Forest Products.

2. Post PURPA pre-FPSC rules (1978-1982).

   During the period of rule development between the passage of PURPA and the completion of the Florida rules in 1982, FPC negotiated with prospective cogenerators in the spirit of PURPA and under terms of the anticipated Florida rules. These contracts can be separated into two types:

   a. Interconnection without sales to FPC.

      Citrus World #1 - November 1979
      Ben Hill Griffin - November 1981
      Buckeye Cellulose (Procter & Gamble) - August 1980

b. As-available contracts signed during this period.

Occidental Chemical Swift Creek #2 - January, 1980
US AgriChem - October, 1982
Pinellas Waste Recovery #1 - May 13, 1980

During this same period, negotiations were held with Biomass Monticello and Biomass Madison, which resulted in interconnections to purchase as-available energy from each of these 7.5 MW plants.

3. FPSC rules for as-available energy implemented (1982-1984).

The FPSC implemented rules for the sale of as-available energy in 1982. Any existing QF contracts that benefited from the FPSC rules were amended to incorporate those rules. Credit for variable O&M charges and for avoided plant start-up were added. The contract for Pinellas Waste Recovery was not modified since it was based on a formula for determining avoided cost that gave them more revenue than the newly defined as-available rate (COG-1).

The only contract signed during this period was for 20 MW additional capacity at the Pinellas Solid Waste Plant. This was signed in December, 1983.

4. FPSC rules for firm contracts implemented (1984-1990).

A statewide avoided unit was used as a basis for pricing capacity credits for cogenerators under the COG-2 firm rate. The draft of the rules was based on the statewide avoided unit being the next major generating unit to be built in the state by any of the investor owned utilities. Tampa Electric Company was planning to build two 700 MW coal fired power plants and the FPSC indicated that they were considering designating those as the statewide avoided unit in the draft. However, before the rules could be finalized, Tampa Electric withdrew their plans for the 1,400 MW facility and substituted a smaller combined cycle unit. In reconsideration of the rules, the FPSC determined that it would be in the best interest of the state to have a large coal fired unit rather than several small units planned by each of the utilities. Therefore, two fictitious 1992, 700 MW coal fired generating plants were designated as the statewide avoided unit and the pricing was based on estimates of the cost of building a plant at that time, along with escalations in capital and O&M costs utilizing TECO Big Bend #4 coal prices.

Based upon the 1992 statewide avoided unit, Florida Power Corporation developed a standard offer contract effective April 30, 1984, and several small power producers were proposed. However, only one contract was actually signed and that was with Timber Energy for 12.765 MW. The Biomass units were in bankruptcy and attempted to recover in order to sign a firm contract under the 1992 unit pricing. However, they were unsuccessful. A number of other proposals were made but none came to fruition while the 1992 unit was in effect. A contract was negotiated with the Corporation for Future

Resources (CFR) for 50 MW under the COG-2, Option B pricing schedule which allowed for the financial parameters to change annually requiring a recalculation of the capacity payment each year.

The next unit that was selected as a statewide avoided unit was a 1995 pulverized coal unit. This was a single 500 MW unit coal fired unit with its coal pricing based upon deliveries to Tampa Electric Big Bend #4. Signed up under this 1995 unit were, Bay County Resource Recovery, Biomass Madison and Jefferson (later sold to LFC), Lake County Resource Recovery, Pasco County Resource Recovery, and Pinellas Mid County Resource Recovery.

Until this time, all QF payments were assigned a risk factor of 0.80 because of the uncertainties involved. The risk factor reduced the capacity payments to 80% of the avoided costs. During the period that the 1995 statewide avoided unit was in effect, a law was passed granting the waste incinerators signed up under the standard offer pricing to have the 80 percent risk factor increased to 100 percent. This raised the 1995 price per KW from $16.04/KW/Month to $20.06/KW/Month for these incinerators, and changed the price of FPC's contracts with Pinellas County, Pasco County, and Lake County. Bay County was not affected because it was a special contract with negotiated rates for payment of early front loaded capacity payments which had already begun.

Contracts for three equally sized units totalling 156 MW were negotiated with General Peat Resources based on the 1995 unit. These had some front end loading of the capacity payments, and also required a higher on-peak capacity factor than did the standard contract (these contracts later returned to a normal payment schedule). After we signed these contracts, we petitioned the FPSC to closeout the 1995 unit, because 500 MW had been signed against it. However, FPC was unaware that another contract had been signed by Florida Power & Light. Because this contract had been signed, it did not allow enough capacity to satisfy all three of the General Peat contracts. Contracts for the second and third units were held in abeyance but were eventually approved against the new statewide avoided unit. Timber Energy signed an additional contract for 6 MW under the pricing of the 1995 unit, and CFR signed for an additional 24 MW under the 1995 pricing.

In 1989, the FPSC decided that the next statewide avoided unit would be a 385 MW FP&L combined cycle unit with a 1993 in-service date. This 1993 plant was converted to a 1996 500 MW coal plant by the FPSC on their own motion in October of 1989. The 40 MW Pinellas County Resource Recovery (PCRR) contract includes the 1995 coal payment schedule if the plant is completed before 1995. However, if the plant is completed during 1995, then the payments for the 1996 coal plant will apply. If the PCRR facility is completed after January 1, 1996, the then current avoided unit payments will apply.

5. FPSC "new" rules for firm contracts (1990-present).

As a result of the oversubscription of the 500 MW statewide avoided unit, the FPSC amended the state rules. The new state rules are based on a utility specific unit. See Appendix 4 for the FPSC's current cogeneration regulations.

6. 1991 Bid for QF Capacity

A change in our forecasting parameters in 1990 indicated that we had some capacity shortages, particularly in the 1993-1994 time range. In addition, FPC was developing two cogeneration projects with Peoples Gas, and needed the negotiations for these projects to be kept at "arms-length" to avoid a conflict of interest. These reasons, along with FPC's desire to build its own capacity in Polk County without bidding, resulted in FPC issuing a RFP in January 1991, for capacity that could be on-line prior to December 1993. A contract format was developed based on a coal unit priced at 1991 prices for offer to qualifying facilities that could be on-line by the end of 1993. Approximately 450 MW was needed, and more than double this amount was proposed to FPC. However, the decision was made to contract for approximately 600 MW to allow for a 25% dropout rate. This dropout rate was considered conservative. Between October 1990, through March 1991, contracts were signed with Seminole Fertilizer (47 MW), Lake Cogen Limited (102 MW), Pasco Cogen Limited (102 MW), Orlando CoGen Limited (72 MW), Royster Phosphates (28 MW), El Dorado Energy (103.8 MW), Mulberry Energy (72 MW), Dade County Resource Recovery (43 MW), and Ridge Generating Station (36 MW). Also negotiated on a similar basis, was EcoPeat (36.5 MW).

Currently, the only dropouts that we have had is a reduction of 32 MW of capacity from Seminole Fertilizer, and the indefinite postponement of 40 MW that had been contracted earlier with Pinellas County. CFR had been considered "dead" and its capacity was not included in the satisfaction of our needs. CFR had an option B contract for 50 MW based on the 1992, unit and a 24 MW contract based on the 1995 unit. The contract was for service at a specific location (near Drifton) and it was later determined that the contract potentially caused a negative impact on our ability to import the Miller purchase from the Southern Company. We did not give CFR permission to move the contract to the Hinson area and it appeared the project would fold at its contractual location. However, there was considerable interest in CFR by the FPSC; subsequently an FPSC order was made to accommodate CFR. This resulted in FPC and CFR negotiating a dispatchable contract based on the 1991-1995 unit. This contract did not allow a capacity redesignation of +10% that was allowed in the contracts written as a result of the 1991 bid. The net effect of these changes from the original strategy is the addition of CFR substantially equals the reduction in Seminole Fertilizer and the removal of the 40 MW of Pinellas County capacity from our forecast.

7. Polk County Combined Cycle Need Case Proposed Units 1-4

   FPC petitioned the FPSC to build 4-235 MW combined cycle units in Polk County. The FPSC approved the certificate of need for units 1 and 2, but deferred action on units 3 and 4. This was done because there is adequate time to consider these units without impacting construction schedules, and too many uncertainties including load, fuel, and conservation forecasts. In fact, since the FPSC ruling, the projected load growth has declined.

   Pursuant to Order No. 25805, Docket No. 910759-EI, Page 43, the FPSC stated "Florida Power has demonstrated that it reasonably considered capacity purchases from other utilities and non-utility generators to meet future generation needs. In the past, Florida Power has purchased significant amounts of QF capacity..."

8. 1997 Combustion Turbine Standard Offer

   It was assumed that we would have our 25 percent dropout rate on future projects when the need for a 1997 combustion turbine rated at 150 MW was determined. Based on this assumption, we had 80 MW of standard offer and 70 MW of negotiated contracts. A standard offer contract of 74.9 MW was accepted during a two week open season. After an extensive evaluation, Panda Energy was selected among the several standard offer contracts received. That left 5.1 MW of standard offer open. The remaining 70 MW has been removed from the plan due to the QFs that did not fail as expected. See Appendix 2 for a complete list of QF projects.

9. New Capacity Needs

   FPC's Ten-Year Site Plan forecasts the energy and capacity requirements for the company during the next ten years and proposes generating capacity additions and removals to meet these needs. It takes into account the contribution from the qualifying facilities under contract. In the 1993 Ten-Year Site Plan, the only planned generating capacity not already under contract or under construction is the Polk County Units 1 & 2. The Ten-Year Site Plan was filed March 26, 1993, with the Bureau of State Planning Division of Resource Planning and Management of the Department of Community Affairs. Currently, FPC is updating the Integrated Resource Plan and is expecting to file it with the FPSC during March 1994.

10. FPSC Rules for Firm Contracts

    The FPSC has proposed a hearing in 1994 to revise the cogeneration rules based upon the recently adopted bidding requirements. The initial workshop is scheduled for February 14, 1994.

Bidding Rules

On December 7, 1993, the FPSC adopted a rule which requires electric utilities to engage in a competitive bidding process prior to filing a need determination under the Power Plant Siting Act (PPSA) unless the utility can demonstrate that competitive bidding is not in the public interest. Prior to the passage of this rule, the FPSC's informal guidelines encouraged investor-owned utilities to bid new generation. These guidelines generally did not result in new baseload projects being bid because utilities successfully justified why bidding was not the best decision for new generation. This process did not appear to be a major problem, until the FP&L Cypress Energy project. At that point, the FPSC decided to issue a proposed bidding rule. Concurrently, the Governor appointed a task force to review the PPSA. The competitive bidding issue is one of many areas reviewed and the task force considered whether legislative changes should be recommended.

The FPSC's approved bidding rule generally provides the following:

- Electric utilities must establish and use a fair selection process for new generation if the generation addition requires certification under the PPSA.

- Electric utilities can use any selection method, although bidding is encouraged.

- The electric utilities have an obligation to serve and an ensuring responsibility to plan, develop, and manage its resources.

- If purchased power is not found to be in the best interest of ratepayers, the electric utility must provide the FPSC with an explanation.

- Bidding is encouraged for all generation which requires a certificate of need. A certificate of need is currently required for all generators with a steam cycle capacity greater than 75 MW.

- If a certificate of need is not required (i.e. combustion turbines, repowering or combined cycle units with a steam cycle of less than 75 MW), then bidding is not mandatory.

Specifically, the rule would:

1. Require all electric utilities (IOU's, coops and munis) to issue a Request for Proposals (RFP) prior to filing a petition for determination of need, unless to do so is not in the best interest of the utilities ratepayers.

2. Require each utility RFP to identify the MW size, timing, and price and non-price attributes of the generating unit which the utility plans to build, absent a more economical or reliable alternative.

3. Require the utility to provide timely notice of its issuance of an RFP in major newspapers and publications with statewide and national circulation.

4. Require the utility to evaluate proposals (which may include non-utility generators, utility generators, turnkey offerings, and other generating supply alternatives) from which a manageable group of potentially viable and cost-effective finalists would be selected.

5. Require the utility to negotiate in good faith with the finalists to the solicitation process to achieve the most economical and reliable alternative to its next planned generating unit.

6. Limit the ability of non-participants to the RFP process to challenge the outcome of the selection process at a need determination proceeding. The selection process may be challenged at any time, either on the Commission's own motion or by a justified compliant by a substantially affected party.

7. Provide for a case-by-case waiver from issuing an RFP based on a Commission finding that such a waiver is in the best interests of the utility's ratepayers.

The FPSC did not adopt the staff's alternate rule which, had very detailed bidding criteria.

FPC generally supports the FPSC rule because it does not mandate bidding or require the selection of non-utility generators.

Florida Power believes generation resources should be managed using a "portfolio approach." Florida Power's current generation mix and diverse fuel sources are good examples of this principle.

Florida Power believes that if purchased power does not exceed a utility's reserve margin, the utility has the burden of proof to show why it did not select purchased power; however, once the reserve margin threshold is reached, then the utility should have to prove why purchased power is better than building new generation.

Florida Power proposed that the portfolio approach be used and that the burden of proof should change when the threshold is exceeded. Florida Power's position is based on the negative impacts that purchases have on utility cost of capital, planning flexibility, reliability and the obligation-to-serve.

Through its testimony, Florida Power stated that:

- High levels of purchased power contracts adversely affect a utility's credit quality.

- Evaluation criteria for purchased power contracts should be established to assign a level of equity to neutralize the off-balance sheet debt for the utility to maintain its capital structure. The additional cost of equity would then be imputed onto the bid.

- Contracting for capacity does not result in all the benefits of ownership.

- The utility has an obligation-to-serve and an ensuing responsibility to plan, develop and manage its resources.

The Other Key Intervenors

- Florida Competitive Energy Producers Association (CEPA) - IPP trade association which includes Destec, Air Products, Cogentrix, Falcon Seaboard, Jay Makowski and Ark Energy.

- Legal Environmental Assistance Foundation (LEAF) - environmental conservation group

The Position of the IPPs

The IPP's expressed a need for a highly structured regulatory framework for the bidding process, including the selection criteria. This would put all parties on an equal basis by allowing all competitors access to the utility's optimization model and system operational data.

The IPP's felt that it would not be appropriate for the utility to control the bidding process. Currently, the utility, with no regulatory oversight or approval, determines the capacity need, drafts & publishes the RFP, receives and evaluates the bids, and selects the winner. Only at the end of the process is there FPSC involvement. They recommended that a neutral and unbiased party make the major decisions when the utility is a participant.

In addition, they want to establish procedures for utilities to automatically bid out all additional capacity needs once the Ten-Year Site Plan is filed.

The IPP's maintained that long-term purchase contracts do not effect the utility's cost of capital. In the absence of a disallowance, the buy option has no financial detriment on the purchasing utility when compared to building.

The IPP's stated that the buy versus build decision should be made in the broader context, that being whichever offers the ratepayer the best deal in terms of cost, risk and reliability.

Due to the passage of a competitive bidding rule, Florida Power is anticipating that the Power Plant Siting Act task force's expected recommendation for mandatory bidding will be ignored by the Florida State legislature next spring, since the FPSC will have already acted to resolve the perceived problems from the current need determination process. However, the proposed legislation from the PPSA task force would impose very stringent rules on utilities, greatly favoring conservation and IPP's.

Power Plant Siting Act (PPSA)

At a meeting on December 14, 1993, the Governor and Cabinet deferred action on the PPSA Task Force Report at the request of Secretary of State Jim Smith. The Task Force Report was considered at the cabinet meeting on January 25, 1994 and accepted. The report still must find a sponsor to introduce it as a bill to the legislature. If such a bill is introduced, FPC plans to lobby against it.

The creation of the PPSA Task Force was in response to the FP&L Cypress Need Case (800 MW coal plant in the Everglades). This Need Petition was denied by the FPSC.

On August 18, 1993, Commissioner of Education Betty Castor obtained Cabinet approval of her motion to appoint a task force to develop proposed legislation to amend the PPSA. The task force returned to the Cabinet on November 23, 1993, with proposed legislative language and/or recommendations for rulemaking for implementing the following Department of Environmental Protection (DEP) report recommendations:

a. Procedural streamlining of the Power Plant Siting Act; and
b. Creation of a more effective and balanced need determination and site certification process to ensure a competitive process by requiring mandatory bidding of all generating capacity needs within a seven year time frame, as well as, consideration of environmental impacts and citizen participation.
c. Provisions for the filing of Ten-Year Integrated Resource Plans (IRP's) by all electric utilities; requiring the preparation of a State Energy Trends and Conditions Report as well as a State Electric Energy Plan.

Additionally, the task force will further review "decoupling" and "environmental externalities" and recommend what action should be taken.

Bidding

The PPSA task force also returned recommendations on the proposed bidding legislation, summarized as follows.

Capacity addition assessment; procedures:

If, based upon the 10 year energy plan the electric utility requires a capacity addition within the seven year period following the filing of the energy plan, the electric utility shall be required to bid any capacity additions. In addition, the utility will be required to file a notice with the commission identifying each such capacity addition by MW size, in-service date, and type (baseload, intermediate, peaking), and shall serve a copy thereof on each person on the mailing list of potential capacity suppliers required to be kept by utilities.

The electric utility shall make available all data underlying its planning documents, including computer models and data bases. In addition, a public utility must file a bid package which shall include:

1. A power purchase agreement incorporating terms and conditions acceptable to the public utility;
2. The bid criteria including the assessment of the environmental impacts associated with electrical power plants in accordance with the rules adopted by the DEP;
3. A statement of whether the utility or any utility affiliate intends to submit a bid. If the utility or any utility affiliate intends to submit a bid, the identity and qualifications of the person(s) proposed by the utility to receive and evaluate bids. The utility or any utility affiliate shall bid using the same format as other bidders.

Integrated Resource Planning

The PPSA task force recommendations for rulemaking on IRP is summarized below.

1. The Governor and Cabinet strongly encourage the Florida Public Service Commission to adopt and implement a least-cost integrated resource planning rule which creates:

   A) A requirement that electric utilities adopt and implement integrated resource plans which:

      i) evaluate the full range of utility and non-utility resource alternatives;
      ii) provide the lowest system cost consistent with reliability, diversity, dispatchability;
      iii) treat utility and non-utility demand and supply resources on a consistent and integrated basis; and
      iv) account for verification of savings, including durability.

   B) A Commission determination of statewide energy capacity needs that are:

      i) developed on a regular basis;
      ii) based on utility integrated resource plans, and
      iii) used to evaluate utility petitions for determinations of need for new power plants.

   C) Requirements for timely opportunities for public input throughout both the integrated resource planning and statewide energy capacity need determination processes.

2. . The Governor and Cabinet monitor the Public Service Commission's ongoing dockets to set conservation goals for Florida's investor-owned electric utilities and seek legislative reform if basic reforms are not forthcoming from the FPSC. "Decoupling" was not specifically addressed since the FPSC already has an open docket on "Decoupling."

In a letter to the Governor and the Cabinet on December 9, 1993, the FPSC agreed that the DEP is the appropriate agency to identify the environmental criteria for electrical power plants. However, the FPSC expressed reservations on the Task Force recommendation on competitive bidding. The Commission stated that:

> *"The seven year lead time appears to be too inflexible and could result in the construction of too much or too little generating capacity. The Commission oversees a utility planning process that is dynamic and very sensitive to changes in weather, economic conditions, population growth and technology. Locking into a project to meet a projected need for capacity seven years in advance of that need unnecessarily limits the available options for meeting that need and seriously constrains the Commission's ability to ensure the utility is pursuing the most cost-effective and reliable alternative to construction of additional generation capacity."*

The FPSC went on to state that:

> *"The proposed bidding procedure places too much emphasis on PSC pre-approval of the bid package and too little on PSC review of the prudent of the final regulatory review process.....The Commission's primary statutory responsibility is to ensure utility ratepayers have safe, reliable, and adequate service at fair, just and reasonable prices....If the Commission has no opportunity for a final review of a plant selected for construction, our ability to ensure that the choice is the most prudent and cost-effective will be seriously impaired."*

In addition, the Commission concluded that:

> *"A competitive bidding process should be used as a **tool*** (emphasis added) *to assist the Commission in fulfilling our statutory obligation to insure that the electric utilities provide reliable service at the lowest cost."*

COGENERATION CONCERNS

During this period of rapid growth of QF capacity, financial incentives for the host or purchasing utility have been and continue to be ignored. Without the inclusion of financial incentives for the utility, the QF purchases pose additional risks for the purchasing utility without compensation.

Since the passage in 1984 of the FPSC rules allowing firm purchases from QFs, FPC has purchased nearly 1,100 MW of firm capacity. These firm purchases account for 13.1% of our generation resources, and over $231 million in capacity payments, in 1997. The 1994 NPV of these capacity payments is approximately $2.7 billion (assuming a 10% discount rate). A detailed analysis is included in Appendix 3.

Due to this large commitment, FPC and the FPSC have tried through contractual terms and regulation to mitigate some of the risks involved in QF purchases. These contractual terms allow for performance based contracts.

When executed, all QF contracts were equal to or below the Company's forecasted avoided cost as defined and approved by the FPSC. Capacity payments are structured using the value of deferral methodology so that they are low during the early years of the contract and escalate at a rate approximately equal to inflation over time, thus reducing "rate shock", and insuring QF performance for the entire contract. Fuel costs are indexed to actual fuel prices at FPC's generating units or generating units located within Florida. Additional avoided fuel cost payments, where applicable, are based on actual system marginal fuel costs. Most of FPC's contracted capacity is based on avoiding coal capacity, except for 74.9 MW which is combustion turbine based.

FPC has three basic types of cogeneration contracts: one based on a state wide avoided unit (TECO Big Bend 4), one based on a FPC avoided unit (CR-6 with scrubbers), and one based on a 1997 combustion turbine avoided unit. These account for 31%, 62%, and 7%, respectively, of the total contracted cogeneration capacity. The median composite capacity factor of these contracts is 80%, but many of the larger FPC avoided unit contracts have a 90% capacity factor. The state-wide avoided unit contracts are paid an energy price based on the lesser of TECO's Big Bend #4 coal, or FPC's actual avoided energy cost. The FPC avoided unit contracts are paid an energy price based on Crystal River 1 & 2 coal (also referred to as Crystal River South). Most contracts provide for proration of capacity payments below the committed capacity factor level, and all contracts have a minimum performance level below which no capacity payments are made. Most of the capacity under contract has on-peak availability performance requirements with a weighted average of 89%, which assures that the capacity is available when it is most needed by FPC. This also reduces the capacity payment if the QF does not meet its capacity factor obligation.

The contracted cogeneration capacity constitutes a large share of FPC's resources for many reasons. First, FPC's load growth over the past several years has not increased as forecasted, as well as, future load growth forecasts have been lowered. Second, many contracts that were suspected to fail will in fact be placed into service; also, most cogenerators will likely exercise a contract option allowing them to redesignate their capacity commitment upwards by 10 %.

Historically, FPC has always maintained a diverse fuel mix, thereby the aggregate fuel portfolio risk is reduced. After FPC completes Polk County Units 1 and 2 and the Anclote fuel conversion, and most of the cogenerator projects are in service, more than 2400 MW of FPC's electrical resources will be natural gas fueled (although the over 850 MW of cogeneration will be priced as coal or #2 oil). Finally, since most of the cogenerators do not operate on load control, FPC will be in a position where its control and therefore its reliability is hindered.

While only one of FPC's contracts is currently dispatchable, all have energy pricing provisions which give the seller an additional incentive to produce energy during peak periods either through the performance adjustment or the lesser of language.

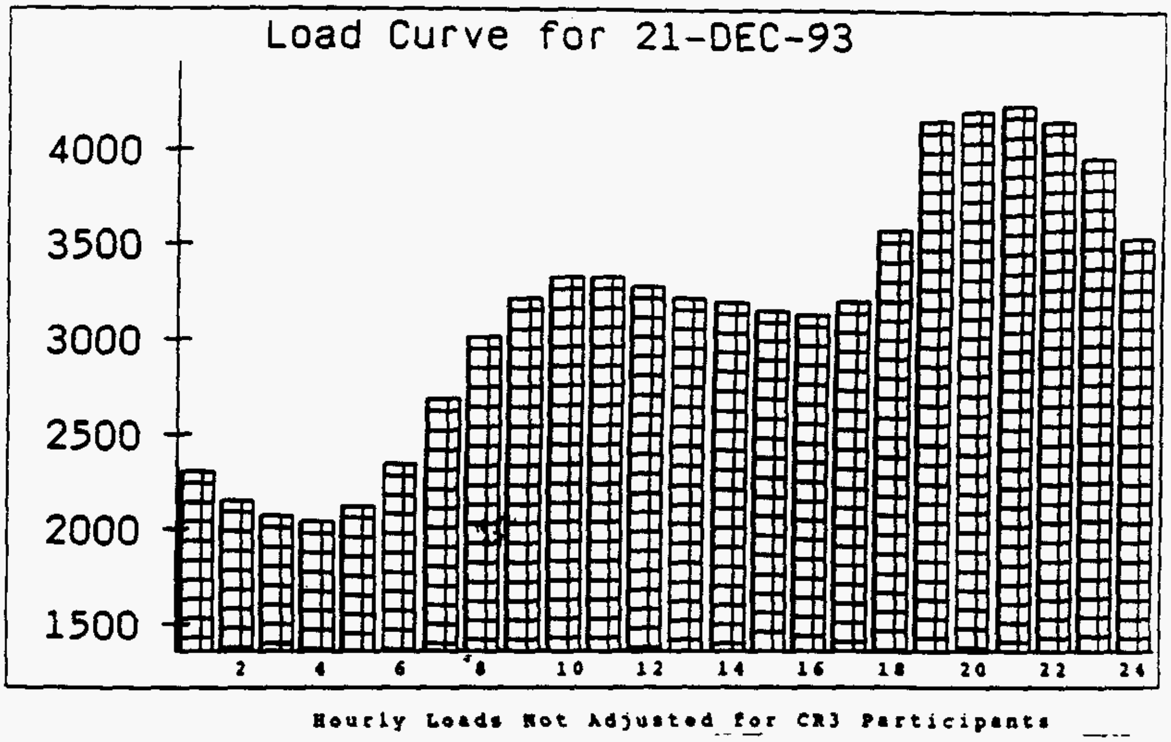
All FPC's contracts require that the sellers coordinate their scheduled outages with the Company.

In addition to increasing power costs, FPC's power purchase contracts constrain both FPC's and the cogenerator's flexibility. FPC cannot change dispatching procedures, the long-term reliability of some of these projects is in question, and the cogenerator's themselves cannot shut down to repower, change fuels, or complete otherwise economical modifications. Such constraints lead to disputes, risks, and higher costs to the ratepayers.

Operational Risks

The FPC system can experience drastic daily net load swings. For example, the net system load might be 1,800 MW at 4 a.m., but by 6 p.m. the net system load could rise to 4,200 MW. This net system load growth may increase by as much as 500-600 MW in each hour, further exacerbating the operational problem. A plot of a typical November day follows. These load swings have worsened over time; historical monthly peak demand has been growing at three times the rate of the historical monthly minimum demand. This presents difficult control problems for FPC's Energy Control Center (ECC). The North American Electric Reliability Council (NERC) requires all utilities to maintain control over their generation resources. Without proper control over generation resources, system reliability and security are at risk. The ECC must maintain scheduled power flows into and out of our system on a real time basis utilizing very stringent criteria.

Principally, minimum load conditions are increasingly onerous for the ECC who must also be prepared to economically serve the peak load later the same day. FPC's base load capacity at minimum load control conditions (which are under revision) added to the contracted cogeneration capacity can be greater than many of the minimum load conditions, yet that same base load capacity will be needed to meet the peak hours later in the day. FPC has ongoing negotiations with QFs to reduce their off-peak generation at no additional cost to FPC. If the QFs reduce their total output from 1,100 MW to 400 or 500 MW through scheduling and dispatch, then this minimum load condition will be mitigated except during extreme system conditions.



Financial Concerns

Currently, there are no financial incentives given to utilities for conservation programs (including cogeneration) in Florida. Recent FPSC and legislative attempts to include conservation incentives have been delayed or canceled. At the same time, there are no legal road blocks to prevent future implementations of conservation incentives.

Some industry analysts oppose financial incentives to encourage utilities to purchase supply resources, and cites competitive procurement as the answer. Competitive procurements only provide financial incentives for the customers of the utility. Some QFs have proposed a shared rate of return methodology in which any income over a specified rate of return would be shared between the utility and the QF. However, all benefits from this type of arrangement, including purchases, usually result in savings by the utility customers. FPC leased a retired plant to a QF developer using this approach. This lease has been terminated at the request of the QF developer.

Presently, QF purchases potentially provide incentives for the customers and QFs. Incentives for utilities would have to be introduced to help offset some of the financial risks involving the utility. These incentives could include a shared savings approach. The customer and the utility would split the difference between the avoided costs and the contractual costs. Another method would be to tie the incentive payment directly to the performance of the contract (Utility Contract Management). A similar approach is presently being used in Florida for utility generation known as the Generation Performance Incentive Factor (GPIF). This gives the utility financial incentives or penalties for the actual performance versus expected performance of utility owned generation.

A third approach would be a sale lease-back arrangement with the utility being the lessee and operator of the facility. This lease could also contain a fixed or negotiated buy out price at the conclusion of the lease, or be structured as a lease purchase.

Financial incentives for the purchasing utility need to be implemented to mitigate some of the financial and operational risks involved in purchasing QF capacity. Such, incentives would make QF purchases more attractive to utilities.

1. Bond Rating

An additional concern is the impact on FPC's financial bond rating due to purchases such as QF, IPP, and inter/utility purchases. Currently, purchases from IPP's, EWG's and utilities are voluntary.

By 1997, cogeneration purchases will account for 12.0% of FPC's total capacity. These contracts are based upon FPC's avoided cost on TECO's pulverized coal units (309 MW), FPC pulverized coal units (692 MW), or a distillate peaker (75 MW). FPSC rules require that they approve all cogeneration contracts and that the costs must be at or below the avoided cost approved by the FPSC at the time of approval. FPC's contracts range in term from 10 to 30 years with a weighted average maturity of 25 years.

Purchased power contracts have become a significant percentage of the capacity of many electric utilities, therefore the bond rating agencies have examined the impacts of these contracts more closely. Standard & Poors (S&P), Moody's, Duff & Phelps, and Fitch have all recently issued pronouncements on purchased power. The rating agencies consider the capacity payments to be long-term fixed contractual obligations to be treated similar to a lease. Additionally, they consider these off-balance sheet debt obligations to have no benefit to reward utility equity holders for taking risks.

S&P's approach appears to be the most logical and consistently applied. However, S&P has recently downgraded VEPCO and SoCal Ed and has begun publishing the debt to total capital ratios and the pre-tax interest coverage ratios adjusted for purchased power on credit reports for many utilities, including Florida Power and Light. The ratios are being published primarily where purchased power exceeds 15%

of the total generating capacity. See Appendix 5 for S&P's analysis of a utility buy versus build decision.

S&P applies a debt equivalency or risk spectrum from 0 to 100% to the obligation of the purchased power contract. The risk factor is determined by several factors. Under the most favorable determination, S&P's methodology would add a 10% risk factor for all of FPC's QF and purchase contracts. S&P applies a 10% discount rate (which it assumes to approximate a utility's average cost of capital) to determine the net present value (NPV) of these off-balance sheet obligations. This would impute $317 million of debt in 1994, rising to $356 million in 1998. The figures in Table 1 are calculated in millions:

Table 1

	NPV of QF Contracts	NPV of Purchase Contracts	Total	Imputed Debt @10% Risk Factor	Interest Expense @10%
1994	2,657	512	3,169	317	32
1995	2,834	527	3,361	336	34
1996	2,932	512	3,444	344	34
1997	3,009	496	3,505	351	35
1998	3,079	480	3,559	356	36

This imputed debt raises FPC's total debt to capital ratio to approximately 50% and the pre-tax interest coverage to an average of approximately 3.2 over the next five years. The figures in Table 2 show these ratio for the next few years, as well as the rating criteria from AA and A bonds.

Table 2

	Unadjusted (1)		Adjusted	
	Pre-Tax Int. Coverage	Total Debt/ Total Cap.	Pre-Tax Int. Coverage	Total Debt/ Total Cap.
1992	3.65	45.2%		
1993	3.67	48.8%		
1994	3.72	46.3%	3.11	50.9%
1995	3.90	45.8%	3.22	50.6%
1996	4.00	44.7%	3.29	49.7%
1997	4.09	44.1%	3.35	49.0%
1998	3.91	45.0%	3.23	49.8%
AA	>3.5	<47%	>3.5	<47%
A	>2.75	<52%	>2.75	<52%

(1) Assumes $280 million of new equity from 1994-98, including $130 million in 1994

The market is currently giving much less credence to the methodologies of Moody's and Duff & Phelps. Moody's approach would impute a purchased power debt component of $2.2 billion in 1998, while the Duff & Phelps figure is $1 billion. Both of these imputed debt totals are substantially higher than the totals using the S&P methodology.

The financial impacts of the S&P adjusted ratios imply a potential bond rating downgrade, and the other rating agencies are likely to follow S&P's lead. A downgrade from the current AA- rating to A+ would add approximately 10 basis points to Florida Power's first mortgage bond cost in the current market environment. This translates into approximately $372,000 on the cumulative $372 million of first mortgage bonds projected to be issued in 1994-1998. A downgrade from A-1+ to A-1 would not likely add materially to Florida Power's commercial paper cost.

This potential downgrading would impact Progress Capital Holdings by causing a downgrade from A to A- for medium-term notes. This would add approximately 15 basis points to the medium-term note cost in today's market. The points equate to approximately $150,000 on the cumulative $100 million of projected medium-term notes to be issued in 1994-1998. A likely downgrade from A-1 to A-2 would add about 15 basis points to Progress Capital Holdings commercial paper cost. This equates to approximately $315,000 on an expected average commercial paper balance of about $210 million. Any future downgrade to BBB will cause a loss of financing flexibility thereby intensifying pressure to maintain at least an A-2 commercial paper rating.

2. Cost Effectiveness

With the exception of one 74.9 MW contract (Panda), all the QF contracts signed since 1990 are based upon a pulverized coal plant as the avoided unit. These contracts represent over 790 MW and were signed at a time when natural gas prices were forecasted by FPC to be much higher than reflected in current forecasts.

A comparison of FPC's natural gas price forecast prepared in 1990 vs. the forecast prepared in 1993 follows. As can be seen, the current forecast is significantly lower than that produced in 1990.

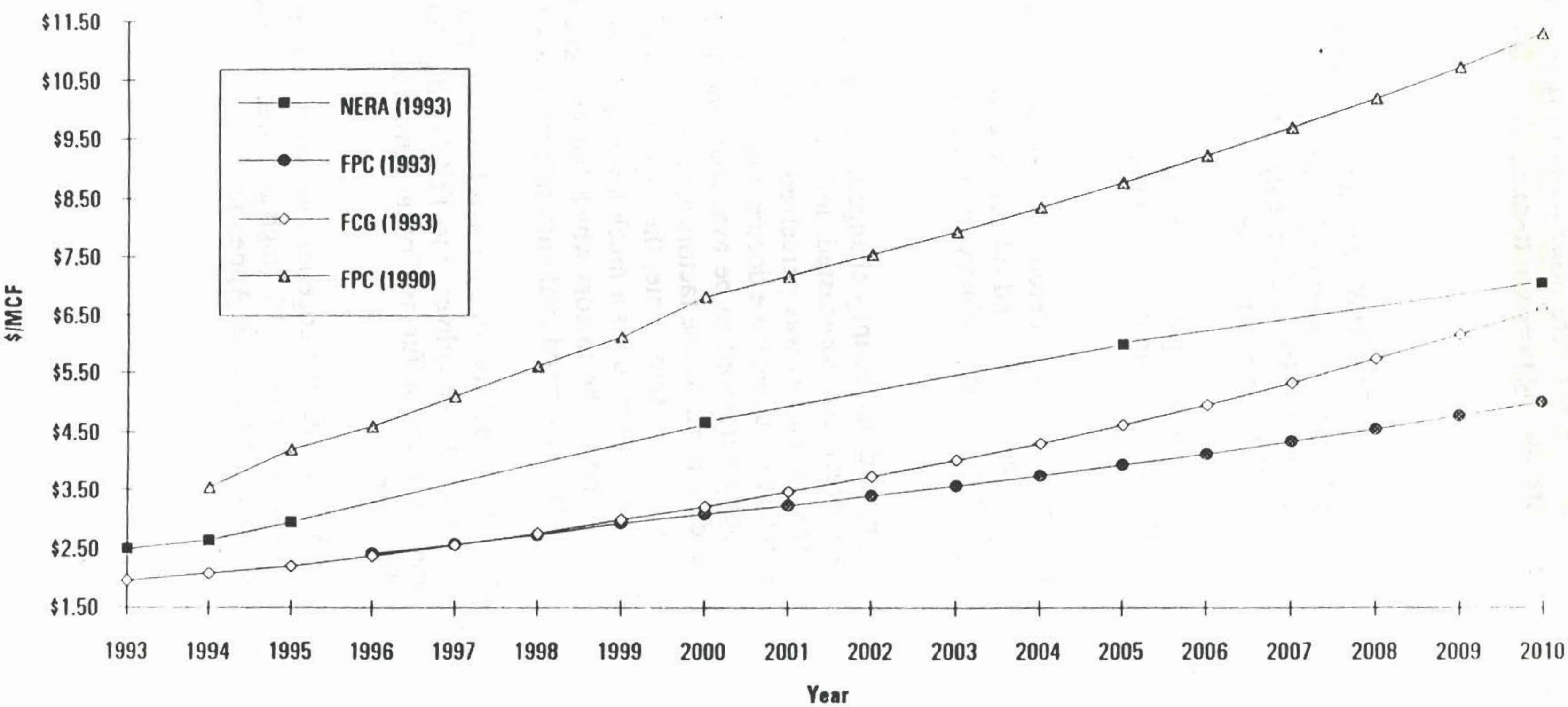
In 1990, natural gas was considered a somewhat limited resource, inflation expectations were relatively high, and oil prices were expected to be controlled by OPEC. All these factors led the industry to expect significantly higher prices in the future.

By 1993, expectations had significantly changed. Actual prices in the market had not grown to the levels previously forecasted, inflation was lower than expected, and OPEC control of the oil market was perceived to be moderate rather than strong. Several extensive industry studies have documented a larger resource base of natural gas than was previously perceived to be available, and technology has lowered the cost of resource development. These factors have led to a significantly lower forecast of natural gas prices. At the same time, the expected price of coal was also lower. but not as dramatically. The result is a much lower differential cost spread between natural gas and coal; one of the factors which has changed FPC's plans for future generating capacity from pulverized coal units to natural gas fueled combined cycles.

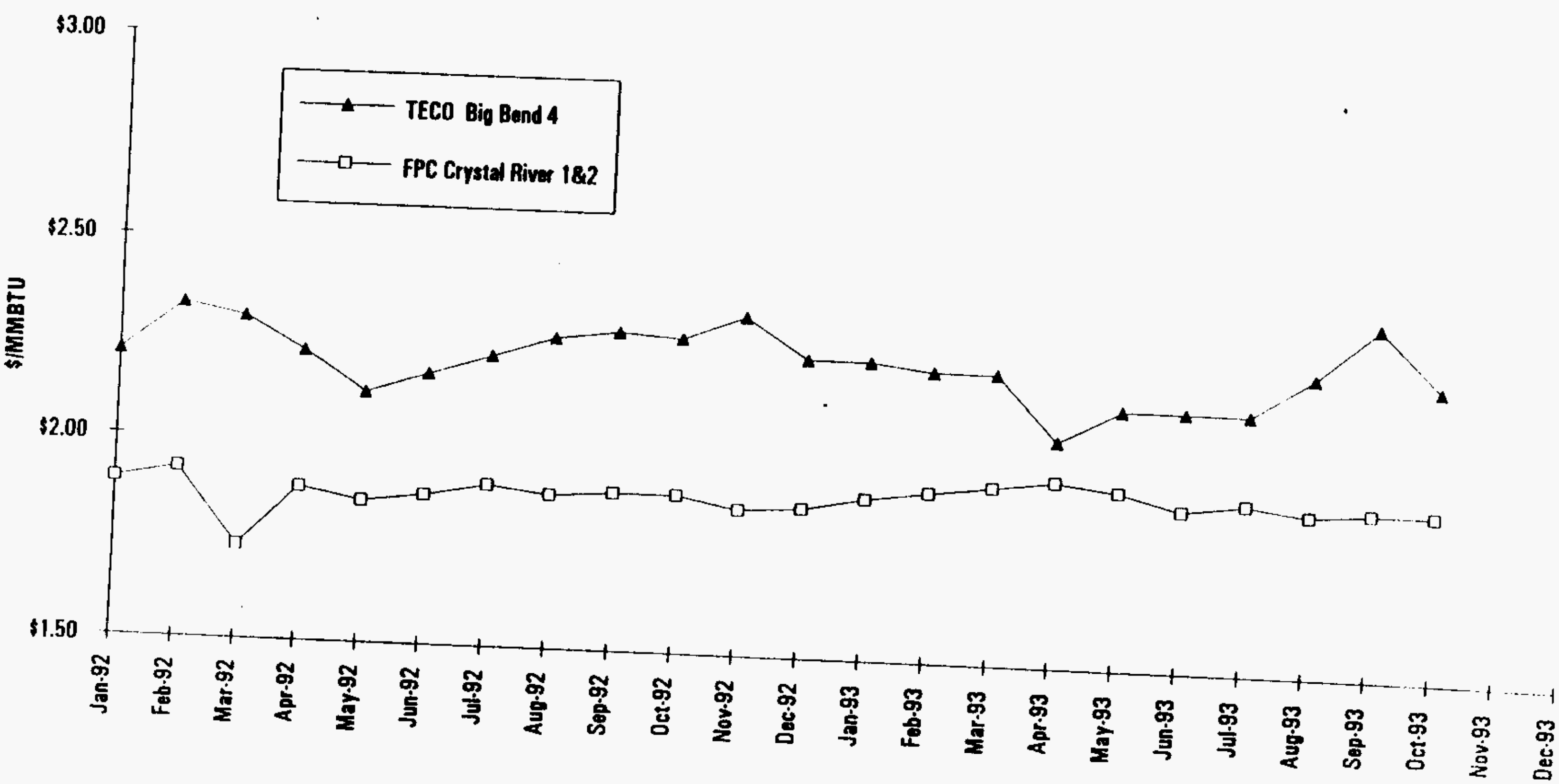
It should be noted that the fuel cost of contracts based upon a statewide avoided unit are based upon the price of coal delivered to TECO's Big Bend #4 plant. This coal contains three times as much sulfur as Crystal River 1 & 2 coal but costs TECO approximately 10% more.

Based upon the 1993 forecasts, the cogeneration contracts are currently need to be reduced by 4% (low gas forecast) to 24% (high gas forecast) assuming a discount rate of 8.81%. An analysis can be seen in Appendix 1.

Natural Gas Price Forecasts



COMPARATIVE FUEL COST



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The table below shows the comparison of the total cost per MWh of QF capacity versus the total cost per MWh of a natural gas combined cycle plant.

Year	$/MWh QF	$/MWh* FPC CC	QF % of Total Capacity
1994	43.83	45.44	4.4%
1995	50.65	46.06	10.5%
1996	52.56	46.69	11.4%
1997	55.05	47.14	12.0%
1998	57.83	47.70	12.0%
1999	59.72	48.82	10.9%
2000	62.45	49.51	10.9%
2001	65.17	50.19	10.4%
2002	67.29	51.37	10.4%
*FPC's combined cycle cost assumes a new site			

Accounting

The Securities and Exchange Commission (SEC) and various rating agencies are expressing serious concerns regarding the ramifications to an electric utility when it enters into a purchased power contract. These ramifications are defined as financial and business risks, regulatory risks, unit availability and/or capacity factor, involvement in construction and/or operation, credit ratings, and capital costs. As a result, the rating agencies are beginning to make pro forma adjustments to fixed charge coverage ratios and leverage ratios in order to compensate for the risks associated with these purchased power contracts, and the SEC is reviving its scrutiny of these contracts and pressing the electric industry for more in-depth disclosure in the management discussion and analysis and footnotes to the financial statements. In some cases, the SEC is requiring the actual recording of the obligation on the financial statements.

Characteristics of Purchased Power Contracts

Purchased Power Contracts vary widely in terms and conditions. However, there are certain terms and conditions that have financial accounting and disclosure requirements. Some of these contract conditions include:

Requirement to Purchase - Covers the output of a specific generating unit or group of units. Typically a large percentage, if not all of the output.

Long Term Nature - Frequently covers the useful life of a specific generating unit.

Capacity Payments - Typically expressed in terms of a specific dollar amount per kilowatt of capacity which must be paid regardless of whether the utility purchases any energy from the QF. In most contracts a distinction is made between firm capacity and as-available capacity. Accounting implications result from the close relationship between capacity payments and the QF's debt service.

Dispatchability - Allows the purchasing utility to determine if there is a need for power on a real-time basis.

Regulatory Recovery/Regulatory Out Clause - Determines the financial risk associated with purchased power contracts. If regulatory recovery is timely (i.e. a cost recovery clause) and if the contract allows the purchasing utility to cancel the contract at any time that the regulatory body disallows recovery of the purchased power cost in rates, then financial risk is reduced. This clause is in most of FPC's cogeneration contracts and represents 98% of FPC's capacity commitments on a net present value basis.

Because of these conditions, purchased power contracts either represent a significant executory contractual commitment or, in other instances, an outright liability (Capital Lease) of the electric utility which should be reported on the financial statements.

Executory Contract or Capital Lease

When a purchased power contract is accounted for as an executory contract, it is included in the operating expenses of the income statement rather than being treated as a long term liability. The purchasing utility is required to make significant disclosures in the footnotes to its financial statements, as well as disclosure in its management discussion and analysis. If the purchasing utility is required to account for the purchased power contract as a capital lease, then the present value of its obligation under the contract is recorded as long-term debt with a corresponding asset (the generating unit or units) reported along with other utility assets in its financial statements.

The required disclosure includes certain aspects of the Terms of the Purchased Power Contract. For example, the date of expiration, the utility's share of output purchased, the annual cost of power, the annual minimum debt service (capacity payments), the aggregate remaining capacity payments under the contract (for each of the succeeding five years) , the nature of the variable payments (energy payments) under the contract and the amount of the contract payments for years being reported on.

Some of the features of a purchased power contract that distinguish the contract as a capital lease rather than an executory contract include specificity, purchaser risk, purchaser/operator, renewal/purchase options. Specificity is defined as the source of the generating facility that makes the power available and the amount of power made available to the purchasing utility from the generating facility. Purchaser risk includes construction risk (i.e purchasing utility contracts for power before the facility is built and the price of power is dependent on construction cost) and operating risk (i.e amount of fixed payments as compared to the potential reliability of the generating unit and price dependent on unforeseen changes in O&M costs, such as fuel).

Accounting and Financial Disclosure Guidance

A review of the authoritative accounting literature indicates that there are few pronouncements dealing with purchased power contracts. The two primary pronouncements are SEC Staff Accounting Bulletin No. 40, Topic 10D "Long -Term Contracts for Purchase of Electric Power", and Statement of Financial Accounting Standards No. 47 "Disclosure of Long-Term Obligations" ("FAS NO. 47"). In addition, the electric utility industry is being directed by the SEC to consider the following accounting pronouncements when evaluating accounting and/or financial reporting obligations: FAS No. 5 "Accounting for Contingencies", FAS No. 13 "Accounting for Leases", and FAS No. 105 " Disclosure of Information about Financial Instruments with Off-Balance Sheet Risk and Financial Instruments with Concentrations of Credit Risk".

Accounting For Purchased Power Contracts at FPC

As of December 31, 1992, FPC had entered into long-term purchased power contracts with non utility electricity generators for 1,086 megawatts of capacity. In most cases these contracts account for 100% of the generating capacity of each of the facilities.

The expected annual capacity payments for the next five years (1993-1997) range from $24.6 million in 1993 to $231.1 in 1997. If all units were to come on line as contracted, FPC would incur $11.4 billion in capacity payments over the period of 1993 through 2025. The present value of these payments discounted at 10% is $2.7 billion.

On September 10, 1993, pursuant to a FPSC Notice of Proposed Rulemaking, FPC filed comments and supporting testimony concerning proposed amendments to Rules 25-22.081 and 25-22.082, FAC. The central issue in the proposed rulemaking revolves around what role competition should play in the acquisition of new generating resources in Florida or "buy vs. build". The objective is to strike a balance between encouraging the cost savings which may be available through competition while recognizing the utility's obligation to serve and ensuing responsibility to plan, develop and manage its generating resources. FPC's comments and direct testimony is attached as Appendix 10.

FPC currently accounts for these costs on its books and records as executory contracts and not capital leases. This decision is based upon a review of many factors, including the terms of the contract, the share of plant output being purchased by FPC and control of the output (dispatchability). Please see Appendix 9 for a complete list of the factors. FPC shares the results of its review annually with KPMG Peat Marwick and discusses changes that have occurred in each contract in order to assess that the current accounting practice is in compliance with SEC guidelines.

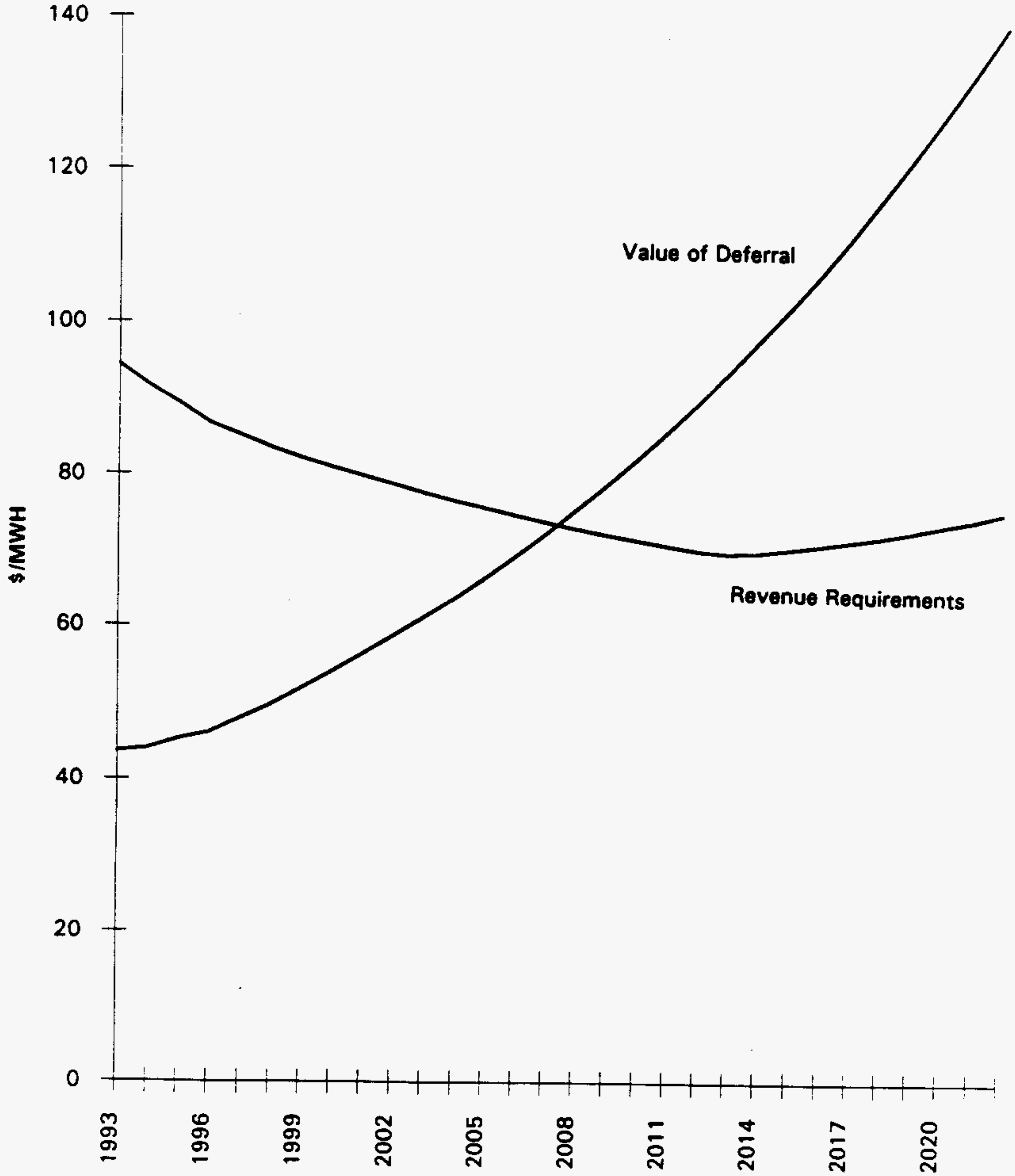
The SEC is considering changes to the accounting rules pertaining to power purchase agreements.

Rate Impacts

Cogeneration payments will add significantly to FPC's rates in the future. A more detailed discussion on the rate impacts of cogeneration contracts will be provided in the integration of the strategic planning process.

QF capacity payments are calculated based upon value of deferral methodology. This methodology calculates the annual value of deferring the need to construct new capacity. The value of deferral cost therefore starts lower than traditional revenue requirements but increases at approximately 5% per year. These payments were calculated using a discount rate of 9.96%. This rate is higher than current rates and adds to the dramatic increase in capacity payments over time. Traditional utility revenue requirements start higher than value of deferral payments but decrease over time reflecting the high capital cost of generation. See accompanying graph.

Value of Deferal vs. Revenue Requirements



Tax Impacts

Bay County has opted for early capacity payments as allowed by state law. These early payments began in March 1988 for an avoided unit with any in-service date of January 1995. FPC has previously been advised by its outside tax counsel that early payments made to Bay County beginning 1988 were in the nature of a payment for a future benefit and not currently deductible. FPC Tax Administration Department it currently considering pursuing a current deduction for these capacity payments through the IRS Appeals process. The argument is that benefit for capacity is received over the term of the contract, beginning in 1988. FPC's liability for capacity payments is tied to a minimum performance standard by the QF. If this standard is not met, no capacity payments are owed.

Because of QF generation, FPC is able to defer construction of generation facilities. In fact, in planning future generation needs, FPC takes into account the 11 MW from Bay County in much the same way that it considers generation from its own plants and counts on this generation from 1988 through 2012.

Buying Out or Buying Down Existing QF Contracts

The buy out of one or more cogen projects represents one possible alternative to solving the operation and financial problems associated with FPC's cogeneration contracts. However, complex methodology, negotiating, liability, and rate issues must be resolved before a buy out can be accomplished. Although all these issues are important, there are three elements of a buy out that are critical; viability, price and rate recovery.

The buy out option could apply to either an existing unit (defined for purposes here as one that is completed or well under construction) or to a contract for power from a future unit. Existing and future cogeneration units selling power to FPC fall into three groups, including (1) county-owned facilities burning solid waste (garbage burners), (2) natural gas fired combined cycle units with a steam host (CCs), and (3) a few small units that burn non-conventional fuels (wood/tire burners). CC units on natural gas represent the largest single group among these, representing a total of approximately 850 MW of generation capacity. As a result, for simplicity the following discussion will assume the buy out of a CC unit, but the arguments would generally apply to the other types of units as well.

If FPC purchased an existing cogeneration unit, it is expected that the transaction would include the assumption of certain contracts by FPC, including obligations to the steam host, if any, and to fuel suppliers. As a result, although FPC would then have discretion over unit dispatch, it would also be placed in a position to directly experience the economic penalties resulting from any reduction in the capacity factor of the unit. These penalties would include the effects of take-or-pay gas supply and transportation contracts and the cost of providing replacement steam to a steam host. It would be expected that FPC would take action to mitigate the size and duration of any penalty for reduced dispatch based on the planned mode of operation of acquired units.

The price paid for an existing combined cycle cogeneration unit on a $/KW basis may be higher than that of an equivalent amount of capacity designed purely for electric generation. The cogeneration function of the plant requires investment in steam production and delivery facilities, with the cost of this investment offset by steam sales. Also, the price paid in a buy out may be expected to reflect the going concern value of the plant and contracts for sale of output in addition to the book value of the facilities. The book value of six existing CC-based cogeneration projects (as defined above) taken together may be approximately $400 million, representing 480 MW of capacity.

A buy out price depends on project-specific risks and circumstances, after-tax discount rates between 15% and over 20% have been employed by many utilities to calculate a net present value (NPV). This NPV may have been further discounted for risk if key permits or other project elements were not in place. This NPV was interpreted as the value of the project to the cogenerator and the minimum buy out price.

The potential change in utility costs due to a termination has been calculated by FPC and other utilities by running a costing model and without the cogeneration project in operation. No utility has so far actually estimated the impact of a buy out on retail rates. A demonstration of substantial cost savings at the production cost level has appeared sufficient.

After forecasting power costs with and without the cogenerator, the forecasts are compared to measure potential cost or ratepayer savings for state commission approval. Utilities have made this comparison in both undiscounted and discounted terms. Undiscounted savings for equal total cost under the PPA (Power Purchase Agreement), less total cost to replace the power, less the amount paid to the developer to terminate the PPA. Discounted savings are calculated by the same formula, however, present values are employed rather than undiscounted totals. To calculate present values, the discount rate most often employed has been the utility's cost of capital which is between 9% and 12%.

The discount rate employed to calculate NPV is potentially controversial. Utilities and State Commissions have not yet debated using the ratepayer's or some other discount rate. Ratepayer's discount rates are typically below the utility's cost of capital, and using a lower discount rate will cause the present value of savings to rise.

The discussion of the buyer's and seller's perspectives above leads to the minimum and maximum prices under which a buy out makes sense to both the developer and the utility. Agreeing on a price between these extremes is the challenge of negotiations. Other utilities have commented that this has been the most difficult aspect of the buy outs they completed.

The minimum price is set by the developer; it is the value of the project if development proceeds. The maximum price is set by the utility; it is the price at which risk-adjusted ratepayer benefits are zero. Any price agreed on between these two is a win/win for the developer and the utility. Both are better off than if the project had gone into service. The task of negotiation is to determine the sharing within this win/win zone.

After establishing a purchase price, the capital requirements for FPC to buy out a given project may depend on FPC's ability to assume project debt versus issuing new first mortgage bonds to refinance project debt. The existing debt for a project may need to be refinanced due to terms and restrictions of the existing debt, or conflicts between the existing debt and FPC's first mortgage bond indenture. However, there may also be prepayment penalties for retiring existing project debt. Most of the buy outs completed to date involve a single cash payment to the developer, although buy outs could be accomplished utilizing several payments to the developers.

Another issue effecting utilities is prudence reviews and cost disallowance by state regulatory commissions. Several utilities have expressed the view that a failure to evaluate and pursue economical contract restructurings may be interpreted by a commission as a breach of fiduciary duty and lead to purchased power cost disallowance.

The basis for favorable regulatory treatment of a buy out transaction will be a demonstration that the buy out alternative is more cost effective to customers than the existing power purchase contract. The FPSC has returned favorable rulings in cases where fuel contracts have been bought out by both Tampa Electric and Gulf Power when a savings to customers due to the buy out has been demonstrated. Another State commission has disallowed recovery of buy out costs on the commission's assessment of the viability of the NUG project.

Cogeneration units that produce both electricity and steam are generally structured to recognize the electric output as being the more valuable product. In order to attract a steam host, steam may be priced at a level that does not fully support the investment in steam producing facilities. Such a shift in revenue allocation relative to cost is immaterial to the existing cogeneration owner, but may pose a problem for FPC's regulatory treatment of this investment if it is perceived by the FPSC as a subsidy to the steam host.

To date, most buy outs by other utilities have occurred in areas with little near-term need for capacity. Accordingly, avoided cost projections have focused on energy alone.

An alternative to a buy out is to lower the payments to the QF's (buy down). The above discussion relates to both buy outs and buy downs. A buy down may be a more attractive alternative than a buy out considering FPC's circumstances. The buy down payment to the developer could be distributed over many years and not structured as a single payment.

Tax Implications of Buy Outs

The tax ramification faced by FPC in buying out its contract obligation to purchase electricity from co-generators is whether such expense of the buy-out is ordinary and necessary business expense and, as such, is deductible under Internal Revenue Code (Code) Section 162 or must be capitalized under Code Section 263.

Recently, three private letter rulings (PLR) addressed the tax issues involved when a taxpayer negotiates a buy-out of a long-term supply contract. In PLR 9334005, the taxpayer (a public utility) entered into an agreement and mutual release from a burdensome long-term coal supply contract whereby the taxpayer paid the coal company a large sum of money for such release from the contract. However, the taxpayer immediately proceeded to enter into a new, more favorable contract for the purchase of coal from the same coal company.

The Internal Revenue Service (Service) ruled that the termination of the old contract and the execution of the new contract are not separate events. Rather, they are part of a single overall plan. The taxpayer's testimony before the state utility commission describing the settlement agreement and the termination agreement indicated that both the new agreement and the termination agreement were components of the settlement, and that the settlement agreement with the coal company resulted in substantial rights and benefits to the taxpayer. Thus, the Service ruled that benefits from the settlement extended over the life of the new contract and the monies paid by the taxpayer for settlement had to be capitalized under Code Section 263.

However, in PLR 9240005 and PLR 9123004, a favorable ruling was issued by the Service to the taxpayers because the facts were somewhat different. In both cases, the taxpayers (regulated public utilities) had entered into burdensome high-priced coal contracts in earlier years and negotiated a "buy-out" of such contracts. The taxpayers did not negotiate new coal contracts with their previous coal suppliers and looked only to the spot market for future coal purchases.

The Service ruled in both above-mentioned rulings that the payments made to the coal producers to terminate the coal supply contracts were made to reduce expenses, rather than to secure a more favorable contract with the coal producer. Therefore, the Service held that the contract termination payments were ordinary and necessary business expenses deductible under Code Section 162.

Alternately, purchase of the assets of a cogeneration facility is treated differently. The purchase of such a facility would be the purchase of a trade or business. The purchase price paid for the assets of the facility would first be allocated to the tangible real and personal property of the facility [based on fair market value (FMV)], and depreciated accordingly. Any amount of the purchase price exceeding the FMV of tangible real and personal property would be considered intangible assets and amortized over 15 years, under Code Section 197.

Therefore, the amount paid to terminate a burdensome high priced contract may result in an ordinary and necessary business expense and be currently deductible under Code Section 162, if it can be shown that the termination of the contract was intended to reduce cost rather than secure some future benefit according to Private Letter Rulings. Recently, the IRS has been very aggressive in imputing future benefits to taxpayers resulting from business transactions as a basis for capitalizing expenses.

Note: Holdings in Private Letter Rulings only apply to taxpayers requesting the ruling. Other taxpayers can use only as substantial authority to avoid penalties.

Regulatory Treatment

There appears to be two basic approaches to the regulatory treatment of an FPC-owned cogeneration unit. One approach is to include the entire cogeneration investment in FPC's electric rate base, including assets devoted to both electric generation and steam production. Revenues from steam sales are credited to the fuel adjustment to reduce the net cost of fuel for the unit. Assuming sufficient steam sales revenue, the cost of power from the unit should be fully recoverable. This is the regulatory methodology employed for FPC's University of Florida cogeneration unit. For this unit, the price of steam is initially low then escalates in future years. This revenue pattern results in an initial subsidy by electric ratepayers to the steam host which is reversed later in the life of the project.

A second regulatory treatment for utility-owned cogeneration facilities would treat the electric side of the plant as a traditional regulated generation plant investment and the steam side of the project as a non-regulated investment. This method would allocate revenue, expense and investment between electric and steam operations and require that each side of the plant operate financially on a stand-alone basis.

The regulatory treatment which puts the entire cogeneration investment in rate base and treats steam revenues as a credit to fuel is simpler and would generally be preferred by FPC. However, such an investment would either have a substantial negative impact on earnings or require a rate case to provide for recovery of the investment. After a buy out, it is expected that the unit would run on the FPC system subject to economic dispatch. The definition of economic dispatch for an acquired unit may depend on both the characteristics of unit and the regulatory treatment it is afforded by the FPSC. The economics of any given cogeneration project would be different under economic dispatch versus the existing operating mode which maximizes the capacity factor of the unit. Estimates of generation costs for candidate cogeneration projects after a buy out will be essential to the demonstration of overall cost effectiveness for the proposed buy out.

In principle, the option would exist to continue operation of the unit or to decommission it. It is not expected that decommissioning would be an attractive option because FPC would be purchasing relatively new combined cycle capacity and would continue to need the capacity to meet system load requirements. Regardless of the price paid in a buy out, after FPC takes ownership, that price is a sunk cost. Thereafter, the value of the capacity to the

FPC system would be based only upon the costs and operating characteristics of the unit relative to other generation alternatives.

Regulatory Impacts

Regulatory risk of the existing QF contracts in Florida is virtually nonexistent because the FPSC and Florida Legislature have encouraged contracts for capacity with qualifying facilities and all contracts are pre-approved by the FPSC. With the exception of one contract, all others have a regulatory out provision which provides for renegotiation of payments to a level that is allowed for recovery as well as a refund of disallowed payments from the QF. It should be noted that neither FPC or the QF can evoke the regulatory out provision and must defend the contract as stipulated in these contracts.

With the exception of certain disallowances associated with self-dealing, no disallowance of payments to the QF have occurred to date. It is not expected that QF payments will be contested by state commissions, since contracts with QFs are governed in part by federal law and generally have the support of state commissions.

At FPC, approximately 90% of the fuel and capacity costs are regulated by the FPSC and the remaining 10% is regulated by FERC. The 90% of the capacity and energy costs are fully recoverable through the fuel adjustment clause and the capacity cost recovery clause at the FPSC. The fuel adjustment at the FPSC is updated every six months, or sooner if necessary. The remaining capacity and non-fuel costs are recovered at FERC in annual rate cases. See Appendix 7 for FERC audit rulings.

Termination of QF Contracts

In general, contracts can be unilaterally terminated only under circumstances, such as the following:

- Material breach or nonperformance
- One party prevents performance by the other
- Fraud
- Mistake (both parties)
- Duress, coercion, or intimidation
- Impossibility of performance
- Failure of consideration
- Substantial frustration of the principal purpose of the contract

Unjust enrichment is a concept used to terminate, rescind, or modify an oral contract when one party unjustly benefits from the contract However, the concept of unjust enrichment does not apply to written contracts such as FPC's cogeneration contracts.

While public service commissions have significant authority to remake contracts in the regulated utility area, as a general matter, a contract is not contrary to the public interest simply because it is unprofitable to the utility that entered into it. Likewise, FERC's PURPA regulations, adopted by the FPSC, provide that approved QF rates do not become unjust and unreasonable because the utility's avoided cost at the time the QF comes into service is different than the utility's avoided cost at the time the QF contract was entered into.

CURRENT OF STRATEGY

Need For New Capacity

The desirability of Florida Power Corporation buying out its existing cogeneration contracts is highly dependent upon FPC's need for additional generation capacity. In turn, the need for capacity is a function of several major assumptions. These include:

1. The Long-Term Demand and Energy Forecast.

2. The approved additions and retirements of FPC's generation capacity.

3. The planned additions and maintenance of FPC's Demand-Side Management (DSM) programs.

Depending upon what assumptions are made, FPC's need for capacity can vary a great deal. The Load and Capacity Report in Appendix 11 provides the details of FPC's need for capacity through 2003 for strategic planning purposes. (Generally, FPC's need for capacity is driven by a need to satisfy the 15% winter reserve margin. Additionally, all results must be verified to ensure that the 0.1 days/year Loss of Load Probability criterion is not violated.)

The Load and Capacity report assumes that DSM programs are expanded by 40 MW each year from 1993 levels, the Siemens and Polk County units are completed on schedule, the Turner and Higgins steam plants are placed in extended cold shutdown, and all 1,100 MW of cogeneration comes on-line as planned.

The column of the Load and Capacity report titled "New FPC capacity (MW)" indicates the capacity additions necessary to maintain the 15% winter reserve margin. These capacity additions are not cumulative, therefore the additions are those required for each year. These results identify a need for additional capacity in the winter of 1999/2000, as well as in the winter of 2001/2002.

If the present DSM programs are modified, FPC could require additional capacity by the end of 1999. This would mean that the cancellation of a purchased power contract would cause a need to build or buy additional capacity. With the current FPSC position on bidding, it is highly likely that this new capacity need would be met through a competitive bidding process.

The elimination of any of the existing cogeneration contracts could cause a need for additional capacity. A possible buy out proposal should consider the cost involved in replacing the existing capacity. The need for new capacity makes a buy out very difficult. In states were cogeneration buy outs have been successful, no replacement capacity has been required.

Operational Strategy

The energy needs from QFs is variable with load, maintenance outages, and fuel costs. When only variable energy costs are considered in production cost simulation studies, the various cogeneration contracts dispatch at approximately a 70% capacity factor. This is less than the contracted capacity factor, but significant nonetheless. At minimum load conditions, hourly deterministic computer simulations have shown a need to load follow (adjust cogenerator output to the system load) as well as cycle (turn cogenerator off or on) on a daily basis.

Ideally, FPC would schedule, dispatch, and operate the various cogenerator units in the same manner its other plants are operated/dispatched. There is a certain need to load follow with at least 300-600 MW of cogeneration capacity over the course of a typical day. Additionally, there is a fast approaching regular need to cycle some cogenerators and FPC base load capacity during minimum load hours (i.e. 2 AM to 6 AM). When these cogeneration contracts were negotiated it was forecasted that load, including minimums, would increase at a higher rate than has actually occurred. In addition, it was anticipated that the economic incentives for not generating during low load conditions would also address these concerns.

Since the various cogenerators have a wide cost structure range, some would elect to generate energy even when FPC's as available costs are as low as $16/MWh. Therefore, many of the cogenerators would not voluntarily curtail their output.

FPC has been engaged in renegotiations with some cogenerators, without additional costs to FPC's ratepayers, to obtain dispatch and scheduling or cycling rights. Niagara Mohawk and PG&E have been forced to pay QFs to obtain dispatch rights during minimum load periods utilizing an auction type approach. FPC is actively pursuing these negotiations through the FPSC rule 25-17.086 "Periods During Which Purchases Are Not Required". This regulation has limited application during extreme conditions only. The implementation of this regulation by FPC would undoubtedly result in immediate cogenerator litigation. The regulation speaks to curtailments when "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, but instead generated an equivalent amount of energy itself." However, the same regulation requires the utility to verify the claim to the FPSC on each occurrence. FPC has decided to implement an actual curtailment prior to a hearing at the FPSC. It has not been determined if FPC waived certain rights by signing contracts with the various parties.

The cogeneration contracts based on a FPC avoided coal unit (62% of the total QF contract capacity) receive firm energy payments when a unit of this type would have been scheduled on. FPC is currently negotiating certain dispatch and scheduling rights during these hours which will result in a very limited requirement (if at all) to cycle any of FPC's coal units. These include Orlando CoGen (79.2 MW), and Auburndale (114.2 MW). Also, FPC has concluded negotiations with Tiger Bay (220 MW), Mulberry (110 MW), and Dade County (43 MW). Informal agreements have been made with Pasco Cogen (106 MW) and Lake

Cogen (107 MW) to curtail their output to 95 MW during off-peak hours. These negotiations have resulted in a total reduction of 200 MW to date.

Financial Strategy

1. In order to maintain FPC's current bond rating, FPC could bring its total debt/total capital and pre-tax interest coverage ratios for 1994-1998 back into line with AA standards by issuing approximately $120 million of new equity. A new rate case would, therefore, be required unless O&M costs could be cut to recover the equity cost. The equity infusion would translate into an annual revenue requirement of about $15 million (assuming a 12% return on equity and a 7% interest savings credit to our ratepayers). The California Public Utilities Commission may have set a precedent by recently denying Southern California Edison's request for additional equity associated with its power purchase contracts. In addition, competitive pressures to maintain low rates must be weighed against a potential rate case. FP&L, which has a similar amount of purchased power, has expressed a desire to avoid a rate case. This is not an issue with TECO, due to their minimal amount of purchased power.

2. Another alternative would be for FPC to petition the FPSC to collect an annual surcharge on our total capacity payments. This would avoid one time rate relief, thereby significantly reducing the burden to ratepayers. The surcharge could be collected annually through the Capacity Cost Recovery Clause.

   While this alternative does not immediately address S&P's imputed debt, the equity requirement could be accumulated over a period of 9 years with a 5% surcharge. This would result in an increase in our rates. Therefore, competitive pressures will probably make this alternative unattractive.

3. A third alternative is to buy out some of the existing QF contracts. However, it is not certain that buy out could be accomplished and, even if FPC were successful, it may not be soon enough to avoid rating agency impact (i.e. lowering of FPC's bond rating). In addition, despite lower forecasts, a future capacity need is still projected and the FPSC would require the displaced QF capacity to be bid out. The purchase price for projects at or near completion would very likely be uneconomical, however the buy out of projects not yet under construction should prove to be less costly. Recently, projects that are complete have become available for buy out.

   FPC has evaluated the ownership implications of several existing cogeneration projects, including Auburnbdale, Lake Cogen, and Pasco Cogen. These evaluations have concluded that FPC ownership is not an attractive option at this time (because of the reasons discussed here as well as circumstances specific to each project). In the case of Auburndale, for example, a purchase price of $90-100 million would be required for FPC to avoid an increase in rates due to the buy out. FPC has determined, that from Mission Energy's perspective, the project has a current value of $125 million to $140 million at a 15% nominal discount rate. Therefore, the value to FPC from a ratepayer neutral perspective, is substantially below the total estimated project cost of $150.8 million and Mission Energy's estimated hard costs to completion of $124 million. It was recommended that FPC adopt a "wait-and-see" posture toward ultimately purchasing the project and adding it to the rate base. Expected negative cash flows during the initial years of operation may cause Mission Energy to experience enough of a financial burden to consider a larger discount than would be available now.

Future contracts are those that have not begun construction of facilities, but may be at various stages of development relative to commitments for fuel, financing or equipment. The buy out of future contracts is probably only possible prior to the project making major financial commitments. FPC could approach the holder of a contract with a request to cancel the contract in exchange for a payment from FPC. If the offer were accepted, then presumably FPC would amortize the payment for accounting purposes, and petition the PSC for authority to set up a regulatory asset and recover the payment from ratepayers through the capacity cost recovery clause. Under the circumstances, this request would likely result in an investigation or audit of the circumstances that gave rise to the buy out payment.

A demonstration of cost savings to the customer due to the buy out of a future contract will depend on the plan to replace the contracted capacity. The contract could be replaced by FPC owned capacity, a new purchased power contract based on a natural gas-fired combined cycle containing an economic dispatch provision, or, if the capacity is not needed in the same time frame, a plan to defer the addition of this capacity.

4. A fourth alternative would be to pursue regulatory action to lower the price paid to the QFs. Some utilities have gone to court to lower the capacity payments on QF contracts without compensating the QF. These cases have not been successful for three reasons. First, general contract law does not allow changes to a contract because it no longer benefits one party. Second, public service commissions cannot declare a contract to be not in the public interest because is it unprofitable to the utility. Third, PURPA regulations provide that QF rates do not become unjust and unreasonable because the utility's avoided cost at the time the QF comes into service is different than the utility's avoided cost at the time the QF contract was entered into.

5. A fifth alternative would be to renegotiate lower QF payments. This alternative would require FPC to offer a one time settlement to compensate the QF's for the lower payments. Potentially this settlement could be collected like the surcharge over several years or as a one-time payment (via the Capacity Cost Recovery Clause). The economics of this option may not be viable because of the required settlement but should be thoroughly investigated.

The total NPV of the cost difference between the cogeneration contracts and the cost for FPC to generate the same energy with combined cycle natural gas plants is shown in the table below. The table reflects the different rate of return that may be expected by the cogenerators and also utilizes the expected and high natural gas forecasts.

Discount Rate	NPV of Cost Difference Expected Gas Prices ($000)	NPV of Cost Difference at High Gas Prices ($000)
10%	$848,400	$134,900
15%	$570,000	$96,300
20%	$406,200	$74,000
25%	$304,500	$60,300
30%	$238,300	$51,400

As demonstrated by the chart above, the negotiated discount rate and the fuel forecast utilized, dramatically varies the buy down costs to the developer. In addition, buy down costs can be influenced by numerous other factors (e.g. interest rates, inflation, etc.).

Two graphs follow that illustrates the effect of lowering the capacity or the fuel payment for the two major types of QF contracts. These are (1) contracts based upon an FPC avoided unit utilizing Crystal River coal and (2) contracts based upon a statewide avoided unit utilizing coal delivered to TECO's Big Bend 4 plant. These costs are plotted against the embedded cost of FPC owned generation and are for the year 1997. These graphs show the magnitude of payment reductions required to match FPC's embedded cost of generation. It can be seen from these graphs that the contracts based upon Crystal River coal require a 43% reduction in capacity payments to match FPC's embedded cost in 1997. Similarly, a 55% reduction of the capacity payment would be required for the contracts based upon TECO's Big Bend coal to match FPC's embedded cost.

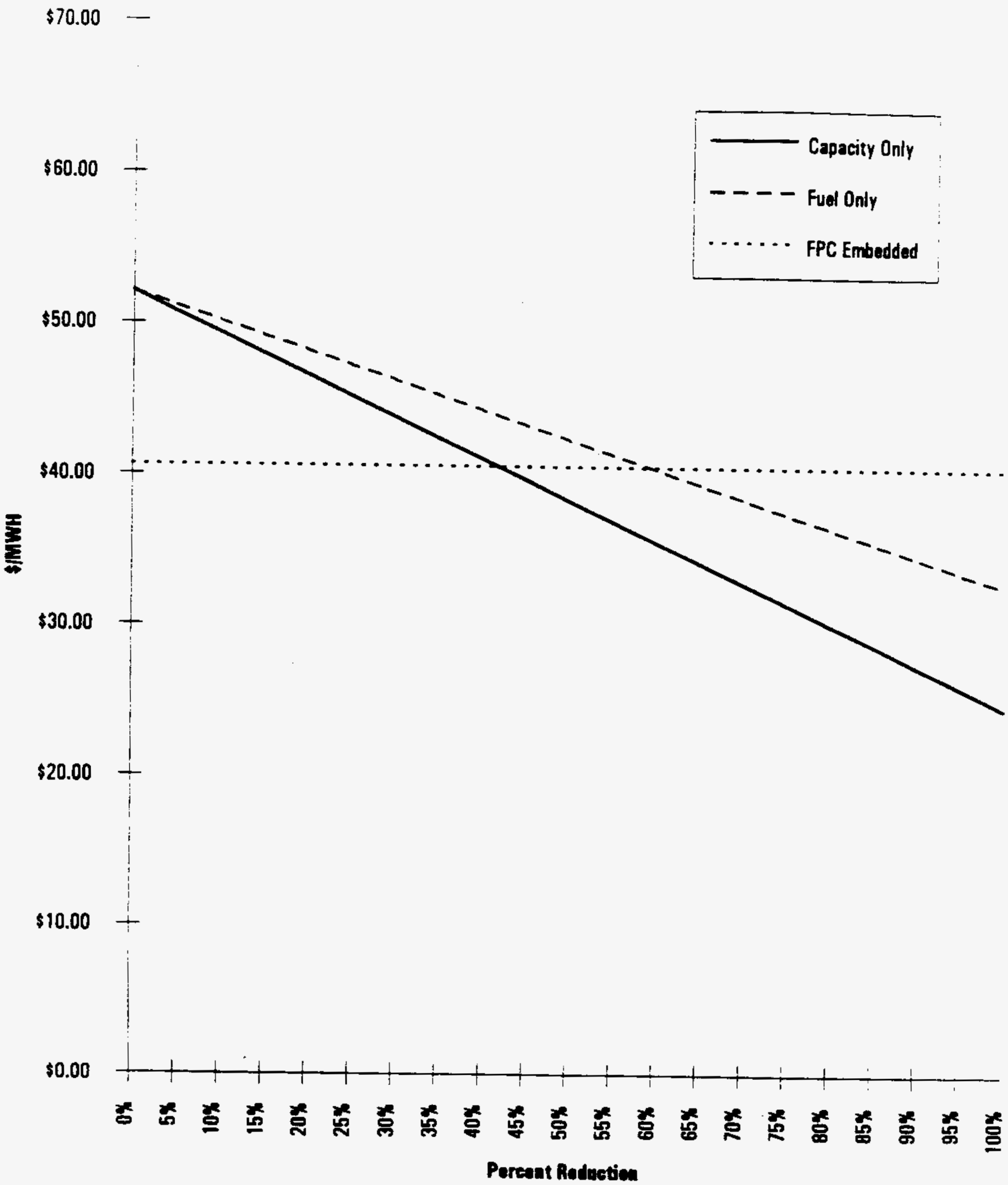
As an example, to reduce capacity payments for Pasco Cogen to match FPC's embedded cost (43%) would require a payment to Pasco Cogen of $46 million assuming FPC's expected fuel costs and a discount rate of 20%. The following table reflects required payment for Pasco Cogen with varying assumptions. Factors other than fuel forecast, including the cost of capital for the QF and the QF's financing, also effect the buy down price.

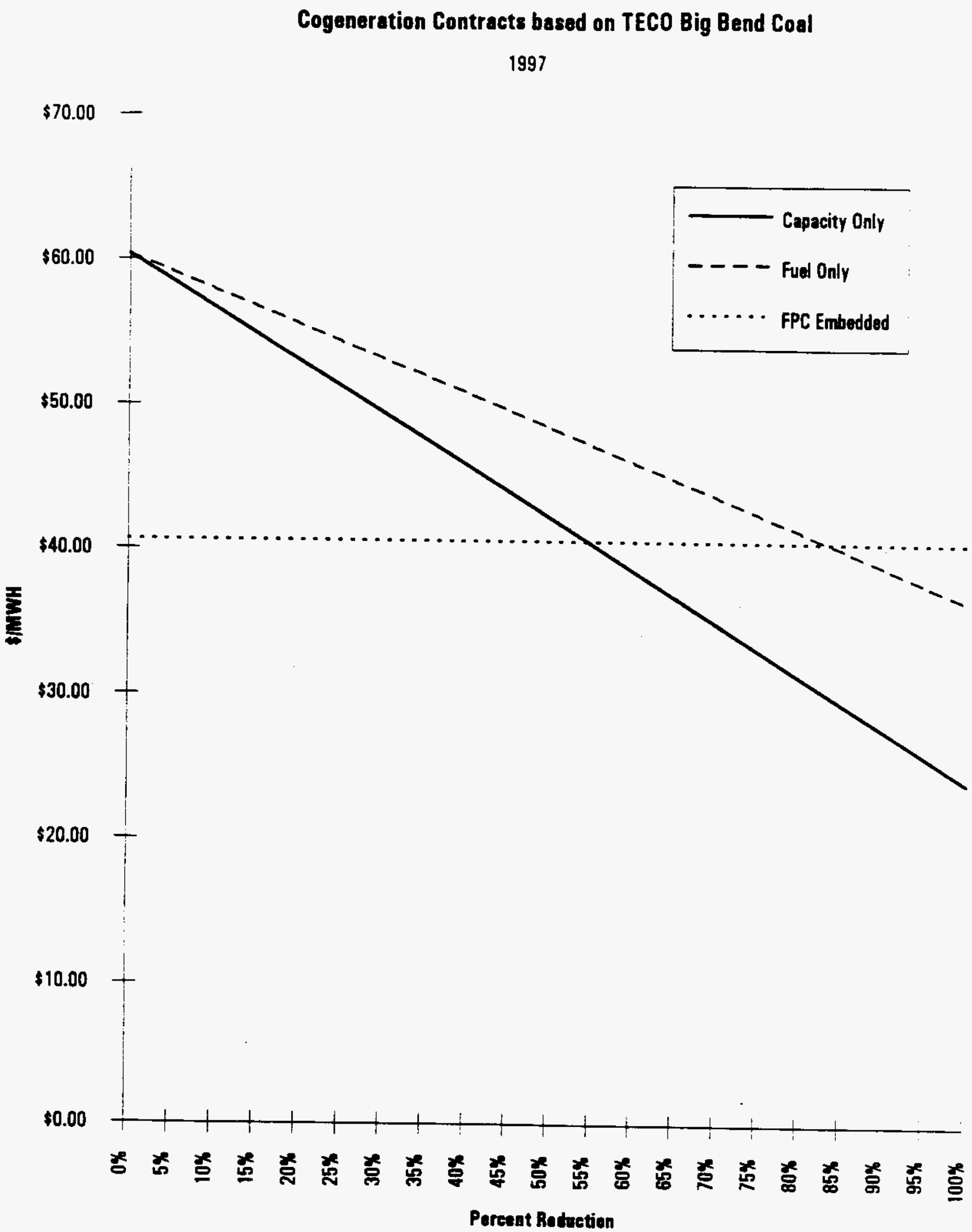
Payment Required to Reduce Pasco Cogen's Capacity Payment to FPC's Embedded Cost		
Discount Rate	NPV at Expected Fuel Forecast ($000)	NPV at High Fuel Forecast ($000)
10%	$88,700	$14,100
15%	$61,800	$10,400
20%	$46,000	$8,400
25%	$36,100	$7,100
30%	$29,400	$6,300

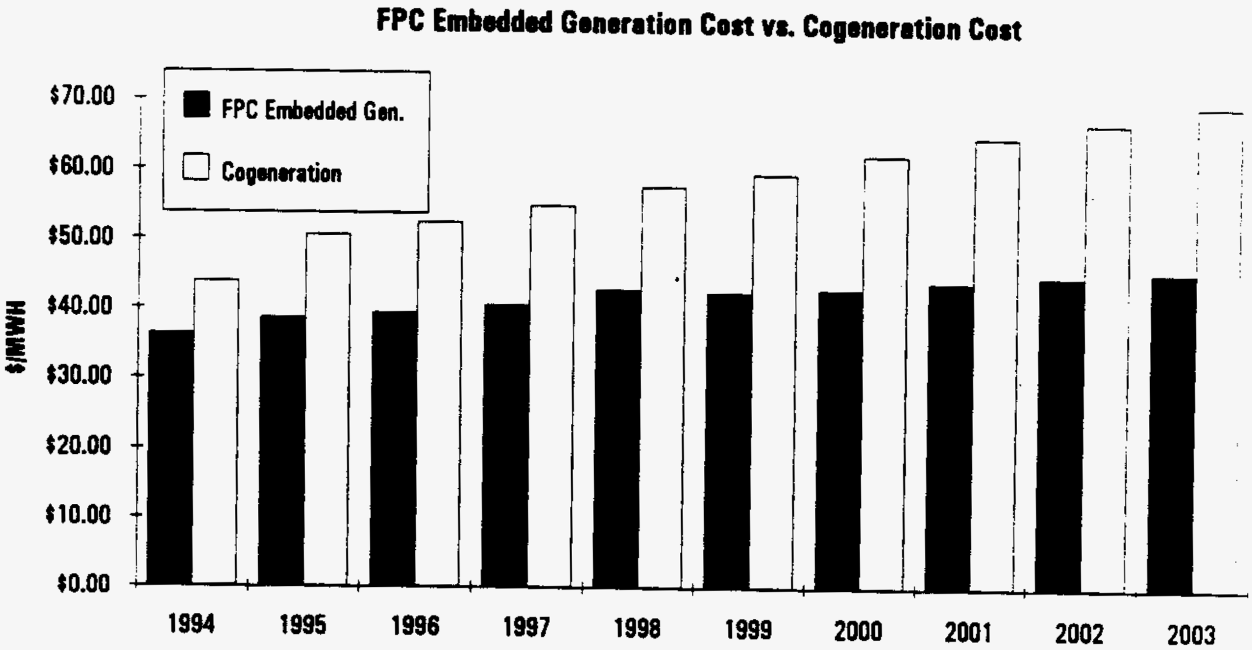
A bar graph also follows which illustrates the comparative rise of the cost of cogeneration capacity and energy versus the rise of the cost of FPC's embedded capacity and energy costs. This graph shows the growing disparity between FPC's embedded cost and the cost of cogeneration contracts.

Cogeneration Contracts based on Crystal River Coal

1997




Cogeneration Contracts based on TECO Big Bend Coal
1997
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/MWH
Capacity Only
Fuel Only
FPC Embedded
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
Percent Reduction


FPC Embedded Generation Cost vs. Cogeneration Cost
FPC Embedded Gen.
Cogeneration
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/MWH
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003

RECOMMENDATION

Florida Power Corporation must continue to address the financial and operational impacts placed upon it by cogeneration contracts. This means taking any actions available to minimize the negative impacts these contracts may have on FPC and our ratepayers. These actions include:

* The resources need to be assigned to properly evaluate and implement, if feasible, all of the options available to increase the cost effectiveness of the QF contracts. These contracts pose a significant threat to FPC's competitive position.

* Ensuring that any future cogeneration contracts reference the most economical avoided unit for the type of generation required. Most of the current cogeneration contracts FPC has are for base load coal units, because fuel forecasts reflected a higher cost for natural gas than industry expectations. Before additional non-utility generation is purchased, FPC's forecasts should be reviewed closely and compared with industry expectations.

* Ensuring that any future cogeneration contracts have full dispatchability. Currently, one FPC QF contract has dispatchability using automatic generation control (AGC); as experience is gained with this contract, future contracts will better define the other rights FPC requires (e.g. VAR dispatchability using AGC).

* Addressing the contractual terms that have allowed all these contracts to all survive. These terms include: (1) the ability for the QF to adjust their capacity, (most current contracts allow a change of ± 10%). In the future, only decreases should be contractually allowed unless otherwise negotiated with FPC; (2) the ability for the QF to change their fuel type. Past evaluations of cogeneration contracts have included fuel type to encourage fuel diversity; however, the contracts did not specify the fuel type to be used. As a result, many of the contracts have been allowed to combine and relocate utilizing mostly natural gas, thus reducing the fuel diversity. Future cogeneration contracts should specify the fuel type; (3) the lack of a defined amount of backup fuel. Current contracts do not specify the amount of backup fuel required by QFs if they do not have a firm fuel supply. A minimum of 72 hours of backup fuel should be required; and (4) the ability of the QF to include either variable O&M or 20% of the fuel cost in their capacity (fixed) payments. Past cogeneration contracts have included options which fix costs that are normally variable; this should not be allowed in future contracts.

* Continuing to obtain dispatch and cycling rights from as many cogenerators as possible through negotiations with no additional cost to FPC's ratepayers. Active enforcement of the purchased power contracts has provided some of the impetus for serious negotiation with the QFs. If necessary, obtain FPSC approval of a curtailment procedure for the eventuality that cogenerators will need to be cycled off during critical minimum load conditions. FPC has created a task force to address this eventuality.

* Review regulatory options to improve the cost-effectiveness of QF contracts based upon both statewide and FPC avoided units. The Legal Department is continuing to perform this review but to date has not discovered any viable options.

* Ensuring that any future cogeneration contracts do not allow the increase of capacity payments over those of the avoided unit. Most of the current cogeneration contracts call for a multiplier of the ratio of the committed on-peak capacity factor to the minimum on-peak capacity factor of the avoided unit to be applied to the capacity payment.

* Maintaining low coal prices. The price of coal for Crystal River 1 & 2 and TECO's Big Bend 4 plant are the basis of the energy payments to almost all the contracts. Therefore, maintaining low coal prices lowers the cost of the contracts. FPC is reviewing methods to reduce TECO Big Bend 4 coal prices.

* Evaluating opportunities to buy out contracts should continue and be acted upon promptly. Past evaluations have not provided cost-effective opportunities to buy out a cogenerator; however, there are many factors affecting these evaluations which are ever changing (e.g. natural gas forecasts).

With the passage of the Energy Policy Act of 1992 (EPACT), the future impact of QFs appears to be decreasing. The Exempt Wholesale Generators (EWGs) created by EPACT will likely have the ability to be less expensive and more flexible than QFs because they do not have to satisfy the PURPA requirements, including the steam host needs. Presently, utilities do not have an obligation to purchase from EWGs, unlike QFs purchases. However, the FPSC recently passed bidding rules for generation capacity addition. These rules require utilities to purchase from the lowest bidder regardless of whether they are a qualifying facility under PURPA, an EWG, or an Independent Power Producer (IPP).

APPENDIX 1

Comparison of Rev. Requirements for Cogen Case vs. 5 Combined Cycle Case

Expected Gas Prices

	Cogen Capacity Rev. Req. ($000)	Cogen Energy Rev. Req. ($000)	TOTAL Rev. Req. ($000)	TOTAL Diff. Rev. Req. ($000)	5 CC Capital Rev. Req. ($000)	Energy + O&M Rev. Req. ($000)	TOTAL Rev. Req. ($000)
1994	$89,065	$114,564	$203,629	$56,401	$53,843	$93,385	$147,228
1995	$165,820	$181,490	$347,309	$51,842	$107,474	$187,993	$295,467
1996	$215,798	$178,725	$394,522	$26,774	$131,733	$236,015	$367,748
1997	$231,097	$193,488	$424,585	$58,538	$125,602	$240,445	$366,047
1998	$242,846	$203,245	$446,091	$77,399	$119,843	$248,849	$368,692
1999	$255,001	$205,610	$460,611	$84,031	$114,419	$262,161	$376,580
2000	$268,317	$213,361	$481,678	$105,404	$109,244	$267,030	$376,274
2001	$282,323	$220,389	$502,712	$120,622	$104,194	$277,896	$382,090
2002	$293,528	$225,533	$519,062	$130,549	$99,173	$289,340	$388,513
2003	$307,444	$232,262	$539,706	$144,969	$94,152	$300,585	$394,737
2004	$323,429	$240,060	$563,489	$160,019	$89,131	$314,339	$403,470
2005	$338,505	$239,912	$578,418	$170,805	$84,111	$323,502	$407,613
2006	$356,699	$248,384	$605,083	$196,872	$79,091	$329,120	$408,211
2007	$375,956	$257,192	$633,148	$219,454	$74,070	$339,624	$413,694
2008	$374,902	$255,418	$630,319	$210,064	$69,049	$351,206	$420,255
2009	$394,959	$264,568	$659,527	$233,382	$64,532	$361,613	$426,145
2010	$416,398	$274,229	$690,627	$256,350	$61,044	$373,233	$434,277
Cumulative Revenue Requirements			$8,680,516	$2,303,475			$6,377,041
Cumulative NPV Revenue Requirements		8.81%	$3,998,449	$941,544			$3,056,905

PS930638
Base Contracts w/Expected Gas

PS930640
Must Run CC's w/Expected Gas

<u>24% Higher Revenue Requirements</u>

400241

400242

Comparison of Rev. Requirements for Cogen Case vs. 5 Combined Cycle Case

High Gas Prices

	Cogen Capacity Rev. Req. ($000)	Cogen Energy Rev. Req. ($000)	TOTAL Rev. Req. ($000)	TOTAL Diff. Rev. Req. ($000)	5 CC Capital Rev. Req. ($000)	Energy + O&M Rev. Req. ($000)	TOTAL Rev. Req. ($000)
1994	$89,065	$114,564	$203,629	$38,922	$53,843	$110,864	$164,707
1995	$185,820	$161,490	$347,309	$18,194	$107,474	$221,641	$329,115
1996	$215,798	$178,725	$394,522	($17,256)	$131,733	$280,045	$411,778
1997	$231,097	$193,488	$424,585	$4,018	$125,602	$294,965	$420,567
1998	$242,846	$203,245	$446,091	$12,644	$119,843	$313,604	$433,447
1999	$255,001	$205,610	$460,611	$16,467	$114,419	$329,725	$444,144
2000	$268,317	$213,361	$481,678	$10,592	$109,244	$361,842	$471,086
2001	$282,323	$220,389	$502,712	$2,405	$104,194	$396,113	$500,307
2002	$293,528	$225,533	$519,062	$8,259	$99,173	$411,630	$510,803
2003	$307,444	$232,262	$539,706	$16,151	$94,152	$429,403	$523,555
2004	$323,429	$240,060	$563,489	$26,295	$89,131	$448,063	$537,194
2005	$338,505	$239,912	$578,418	$26,403	$84,111	$467,904	$552,015
2006	$356,699	$248,384	$605,083	$36,244	$79,091	$489,748	$568,839
2007	$375,956	$257,192	$633,148	$46,443	$74,069	$512,636	$586,705
2008	$374,902	$255,418	$630,319	$23,473	$69,049	$537,797	$606,846
2009	$394,959	$264,568	$659,527	$33,015	$64,532	$561,980	$626,512
2010	$416,398	$274,229	$690,627	$41,073	$61,044	$588,510	$649,554
Cumulative Revenue Requirements			$8,680,516	$343,342			$8,337,174
Cumulative NPV Revenue Requirements		8.81%	$3,998,449	$147,966			$3,850,483

PS930641
Base Contracts w/high gas

PS930642
Must Run CC's w/high gas

4% Higher Revenue Requirements

APPENDIX 2

Capacity On-Line

The following is a list of all QF projects that are currently under contract with FPC.

FLORIDA POWER CORPORATION Operating QF Contracts		
Mr. Bob Van Deman Pinellas County Resource Recovery 1 & 2 2800 110th Ave. N. St. Petersburg, Fla. 33702 813/464-7565 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Costs: Fixed Cost:	55.75 MW April, 1983 & June, 1986 Solid Waste Truck N/A Pinellas County, Fla. Wheelabrator County Bond Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $20.06/KW/Mo. in 1995
Mr. Ed Peters Timber Energy PO Box 199 Telogia, Fla. 32360 904/379-8341 Contract Date: April, 1992	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	12.765 MW July, 1986 Wood Truck N/A Telogia, Fla. Timber Energy Bonds Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $16.04/KW/Mo. in 1995
Mr. Ted Sieckman / LFC 4000 Kruse Way Place Bldg. 1 Suite 255 Lake Oswego, Oregon 97035 503/636-9620 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	8.5 MW September, 1989 Wood Truck N/A Madison, Fla. LFC Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $16.04/KW/Mo. in 1995

FLORIDA POWER CORPORATION Operating QF Contracts		
Mr. Ted Sieckman / LFC 4000 Kruse Way Place Bldg. 1 Suite 255 Lake Oswego, Oregon 97035 503/636-9620 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	8.5 MW June, 1990 Wood Truck N/A Monticello, Fla. LFC Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $16.04/KW/Mo. in 1995
Mr. Wm. G. Hudson Bay County 3400 Transmitter Rd. Panama City, Fla. 32404 904/784-6129 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	11 MW April, 1988 Solid Waste Truck N/A Panama City, Fla. Westinghouse County Bond Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($23.01/MWh in 1994) or FPC Marginal Fuel $7.39/KW/Mo. in 1994
Mr. George Ball-Ilovera Lake County 3830 Rogers Industrial Pk. Rd. Okahumpka, Fla. 34762 904/365-1611 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	12.75 MW September, 1990 Solid Waste Truck N/A Okahumpka, Fla. Ogden-Martin County Bond Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $20.06/KW/Mo. in 1995

FLORIDA POWER CORPORATION Operating QF Contracts		
Mr. Bob Sitz Pasco County PO Box 5478 Hudson, Fla. 34674 813/856-2917 Contract Date: January, 1995	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	23 MW March, 1991 Solid Waste Truck N/A Near Hudson, Fla. Ogden-Martin County Bond Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel $20.06/KW/Mo. in 1995
Mr. Jorge Marin Dade County 111 NW 1st St., Suite 2800 Miami, Fla. 33128 305/594-1547 Contract Date: November, 1991	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	43 MW November, 1991 Solid Waste Truck N/A Miami, Fla. Montenay Power County Bond 9830 BTU/KWh @Crystal River 1&2 ($18.28 MWh in 1994) $12.68/KW/Mo. in 1994

FLORIDA POWER CORPORATION Operating QF Contracts		
Hernan Cortez Cargill Fertilizer Hwy 60 West Bartow, Fla. 33830 813/534-9897	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	15 MW October, 1992 Waste Heat From H_2SO_4 Process Barge and Truck Seminole Fertilizer Mulberry 60 MW Waste Heat Rec ST Cargill Fertilizer Self-Finance 80% of 9830 BTU/KWh @Crystal River 1&2 ($14.63/MWh in 1994) $19.39/KW/Mo. in 1994
Keith Trostel Lake Cogen Limited North Canadian Power 1551 N. Tustin Ave., Suite 900 Santa Ana, Calif. 92701 714/550-4300	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	102 MW ± 10% July, 1993 Natural Gas Combined Cycle North Canadian Oils Peoples Gas Golden Gem Growers Umatilla 106 MW 2-LM 6000 CC North Canadian Sale/Lease Back GECC 9830 BTU/KWh @Crystal River 1&2 ($18.28 MWh in 1994) $12.68/KW/Mo. in 1994
Elliott White Pasco Cogen Limited PO Box 2562 Tampa, Fla. 33601 813/272-0088	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	102 MW ± 10% July, 1993 Natural Gas Combined Cycle North Canadian Oils Peoples Gas Lykes Pasco Dade City 106 MW 2-LM 6000 CC Peoples Cogen/North Canadian Prudential 9830 BTU/KWh @Crystal River 1&2 ($18.28/MWh in 1994) $12.68/KW/Mo. in 1994

FLORIDA POWER CORPORATION **Operating QF Contracts**		
Roger Yott Orlando CoGen Limited LP c/o Air Products & Chemicals 7201 Hamilton Blvd. Allentown, PA 18195 215/481-3497	Contract Capacity:	79.2 MW
	In-Service Date:	September, 1993
	Primary Fuel Type:	Natural Gas Combined Cycle
	Fuel Supplier:	ARCO
	Fuel Transportation:	FGT Phase III
	Steam Host:	Air Products & Chemicals
	Location:	Orlando
	Facility Type:	115 MW ABB 11N CC
	Developer:	Air Products
	Leader Finance Consortium:	The Sumitomo Bank, Ltd.
	Variable Cost:	9830 BTU/KWh @Crystal River 1&2 ($18.28/MWh in 1994)
	Fixed Cost:	$12.62/KW/Mo. in 1994

FLORIDA POWER CORPORATION **QF Contracts Under Construction**		
Macauley Whiting, Jr. Ridge Generating Station LP 400 N. New York Ave., #101 Winter Park, Fla. 32789 407/628-8900	Contract Capacity:	36 MW ± 10%
	In-Service Date:	May 1, 1994
	Primary Fuel Type:	Tires and Wood Waste
	Fuel Supplier:	Various
	Fuel Transportation:	Truck
	Steam Host:	N/A
	Location:	East of Lakeland
	Facility Type:	Mass burn traveling grate
	Developer:	Decker Energy/Wheelabrator
	Leader Finance Consortium:	Wheelabrator
	Variable Cost:	9830 BTU/KWh @Crystal River 1&2 ($18.28/MWh in 1994)
	Fixed Cost:	$12.68/KW.Mo. in 1994

FLORIDA POWER CORPORATION
QF Contracts Under Construction

William Malenius Ark Energy, Inc. 23046 Avenida de la Carlota Suite 400 Laguna Hills, Calif. 92653 714/588-3767 (Mulberry)	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	72 MW ± 10% (Mulberry) 28 MW ± 10% (Royster) August 15, 1994 Natural Gas Combined Cycle Chevron FGT Phase III Ethanol Plant Bartow 115 MW GE Frame 7EA CC Ark Energy/CSW General Electric Credit Corp. 80% of 9830 BTU/KWh @Crystal River 1&2 ($14.62/MWh in 1994) $18.93/KW/mo. in 1994
Jerry Glazer El Dorado Energy Co. 12500 Fair Lakes Circle #420 Fairfax, Virginia 22033 703/222-0445 (Auburndale)	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	103.9 MW ± 10% 35 MW uncommitted June 1, 1994 Natural Gas Combined Cycle Union Pacific Fuels Central Florida Gas, Peoples Gas Fla Distillery/Adams Packing Auburndale 150 MW W Frame 501D CC Mission Energy Mellon Bank 9830 BTU/KWh @Crystal River 1&2 ($23.73/MWh in 1994) $11.10/KW/Mo. in 1994
William Malenius Ark Energy, Inc. 23046 Avenida de la Carlota Suite 400 Laguna Hills, Calif. 92653 714/588-3767 (Orange Cogen)	Contract Capacity: In-Service Date: Primary Fuel Type: Fuel Supplier: Fuel Transportation: Steam Host: Location: Facility Type: Developer: Leader Finance Consortium: Variable Cost: Fixed Cost:	74 MW -10% (CFR) 23 MW (to TECO) December, 1995 Natural Gas Combined Cycle FGT Phase III Orangeco Bartow 106 MW 2 LM6000 CC CFR/AP Cogen/ARK Dispatch Heat Rate Curve @Crystal River 1&2 Full Load $17.95 $13.34/KW/Mo. in 1995

FLORIDA POWER CORPORATION
QF Contracts Under Construction

Bob Taylor	Contract Capacity:	3 @ 57.2 MW (General Peat)
Destec		36.5 MW ± 10% (EcoPeat)
2500 CityWest Blvd. Suite 150		6 MW (Timber Energy)
Houston, Texas 77042	In-Service Date:	January, 1995
713/735-4330	Primary Fuel Type:	Natural Gas Combined Cycle
(Tiger Bay)	Fuel Supplier:	ARCO
	Fuel Transportation:	FGT Phase III
	Steam Host:	Agrichem
	Location:	Fort Meade
	Facility Type:	220 MW GE Frame 7F CC
	Developer:	General Peat/Destec/EcoEnergy
	Leaser Finance Consortium:	Fuji Bank
	Variable Cost:	Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC Marginal Fuel
	Fixed Cost:	$16.04/KW/Mo. in 1995

FLORIDA POWER CORPORATION
QF Contracts Not Yet Under Construction

Darol Lindloff	Contract Capacity:	74.9 MW
Panda-Kathleen L.P.	In-Service Date:	January, 1997
4100 Spring Valley, Suite 1001	Primary Fuel Type:	Natural Gas Combined Cycle
Dallas, Texas 75244	Fuel Supplier:	
214/980-7159	Fuel Transportation:	
	Steam Host:	Erly Juice
	Location:	Lakeland
	Facility Type:	No final decision
	Developer:	Panda
	Variable Cost:	Lesser of 11,610 BTU/KWh @Bartow Peaker Oil ($66.41 in 1997) or FPC marginal fuel
	Fixed Cost:	$5.79/KW/Mo. in 1997

FLORIDA POWER CORPORATION
QF Contracts Not Yet Under Construction

Bob Van Deman Pinellas Resource Recovery 2800 110th Ave. N. St. Petersburg, Fla. 33702 813/464-7565	Contract Capacity:	40 MW
	In-Service Date:	January, 1996
	Primary Fuel Type:	Solid Waste
	Fuel Supplier:	
	Fuel Transportation:	Truck
	Steam Host:	N/A
	Location:	Pinellas County
	Facility Type:	Mass burn traveling grate
	Developer:	Wheelabrator
	Leader Finance Consortium:	
	Variable Cost:	Lesser of 9790 BTU/KWh @TECO Big Bend #4 ($21.75/MWh in 1995) or FPC marginal fuel
	Fixed Cost:	$20.06/KW/Mo. in 1995

APPENDIX 3

Forecasted Payments for All Firm Cogeneration Contracts
(With Probabilities Applied)

Year	$/MWH	Total Payment (000)	Capacity Payment (000)	Energy Payment (000)	MW	MWH (000)
1994	43.83	203,629	89,065	114,564	622	4,646
1995	50.65	347,210	185,762	161,448	944	6,855
1996	52.56	394,418	215,736	178,682	1,030	7,505
1997	55.05	424,474	231,032	193,442	1,086	7,711
1998	57.83	445,971	242,776	203,195	1,086	7,711
1999	59.72	460,488	254,927	205,561	1,086	7,711
2000	62.45	481,548	268,238	213,310	1,086	7,711
2001	65.17	502,576	282,240	220,336	1,086	7,711
2002	67.29	518,918	293,440	225,479	1,076	7,711
2003	69.97	539,555	307,350	232,206	1,073	7,711
2004	73.05	563,330	323,328	240,002	1,073	7,711
2005	75.36	578,258	338,399	239,860	1,067	7,673
2006	78.84	604,915	356,586	248,329	1,067	7,673
2007	82.49	632,970	375,835	257,135	1,067	7,673
2008	85.63	630,132	374,773	255,359	1,049	7,359
2009	89.59	659,330	394,823	264,507	1,021	7,359
2010	93.82	690,418	416,253	274,165	1,021	7,359
2011	98.27	723,158	439,005	284,153	1,021	7,359
2012	102.87	757,035	463,010	294,025	1,021	7,359
2013	108.97	718,443	445,934	272,509	929	6,593
2014	123.78	535,449	350,594	184,855	645	4,326
2015	128.06	529,839	346,248	183,591	615	4,137
2016	134.28	555,564	365,647	189,917	615	4,137
2017	141.62	556,666	375,691	180,976	559	3,931
2018	148.61	584,156	396,915	187,241	559	3,931
2019	155.97	613,095	419,390	193,706	559	3,931
2020	163.74	643,616	443,180	200,437	559	3,931
2021	171.92	675,785	468,389	207,397	559	3,931
2022	182.95	706,102	495,076	211,025	548	3,859
2023	189.12	729,896	511,494	218,402	548	3,859
2024	225.43	530,653	397,023	133,630	350	2,354
2025	203.87	145,555	96,594	48,961	96	714

Forecasted Cogeneration Payments for Bay County

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	40.36	2,878,144	975,480	1,902,664	1,833,288	69,376
1995	44.35	3,162,748	1,624,920	1,537,828	1,499,065	38,763
1996	46.80	3,337,308	1,726,560	1,610,748	1,570,764	39,984
1997	49.84	3,554,144	1,833,480	1,720,664	1,679,421	41,243
1998	53.85	3,839,980	1,948,320	1,891,660	1,849,118	42,542
1999	54.82	3,909,104	2,069,760	1,839,344	1,795,462	43,882
2000	57.81	4,122,507	2,199,120	1,923,387	1,878,122	45,265
2001	60.64	4,323,788	2,336,400	1,987,388	1,940,697	46,690
2002	63.63	4,537,234	2,482,920	2,054,314	2,006,153	48,161
2003	66.79	4,762,796	2,638,680	2,124,116	2,074,438	49,678
2004	70.15	5,002,378	2,803,680	2,198,698	2,147,455	51,243
2005	70.27	5,010,936	2,979,240	2,031,696	1,978,660	53,037
2006	73.92	5,271,268	3,165,360	2,105,908	2,051,015	54,893
2007	77.80	5,547,369	3,363,360	2,184,009	2,127,195	56,814
2008	81.89	5,839,464	3,574,560	2,264,904	2,206,101	58,803
2009	86.20	6,146,898	3,797,640	2,349,258	2,288,397	60,861
2010	90.86	6,478,617	4,036,560	2,442,057	2,379,066	62,991
2011	95.77	6,828,660	4,290,000	2,538,660	2,473,465	65,196
2012	100.68	7,178,845	4,557,960	2,620,885	2,553,407	67,478
2013	37.95	2,705,801	0	2,705,801	2,635,962	69,839
2014	39.18	2,793,499	0	2,793,499	2,721,215	72,284
2015	40.45	2,884,070	0	2,884,070	2,809,256	74,814
2016	41.76	2,977,609	0	2,977,609	2,900,177	77,432
2017	43.11	3,074,215	0	3,074,215	2,994,073	80,142
2018	44.51	3,173,989	0	3,173,989	3,091,042	82,947
2019	45.96	3,277,036	0	3,277,036	3,191,186	85,850
2020	47.45	3,383,465	0	3,383,465	3,294,610	88,855
2021	48.99	3,493,387	0	3,493,387	3,401,422	91,965
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Cargill

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	57.00	5,977,060	3,488,400	2,488,660	1,917,188	571,472
1995	58.88	6,174,312	3,666,600	2,507,712	1,906,881	600,832
1996	60.47	6,340,384	3,853,800	2,486,584	1,855,343	631,240
1997	63.04	6,610,319	4,050,000	2,560,319	1,896,573	663,746
1998	65.61	6,879,996	4,255,200	2,624,796	1,927,496	697,300
1999	68.52	7,184,985	4,473,000	2,711,985	1,979,033	732,952
2000	71.55	7,503,005	4,703,400	2,799,605	2,028,904	770,700
2001	74.69	7,831,579	4,941,000	2,890,579	2,080,033	810,546
2002	77.98	8,176,890	5,193,000	2,983,890	2,132,450	851,440
2003	81.44	8,540,019	5,459,400	3,080,619	2,186,187	894,432
2004	85.07	8,920,248	5,738,400	3,181,848	2,241,279	940,569
2005	88.91	9,322,839	6,030,000	3,292,839	2,304,035	988,803
2006	92.92	9,743,683	6,336,000	3,407,683	2,368,548	1,039,135
2007	97.16	10,188,231	6,661,800	3,526,431	2,434,868	1,091,563
2008	N/A	0	0	0	0	0
2009	N/A	0	0	0	0	0
2010	N/A	0	0	0	0	0
2011	N/A	0	0	0	0	0
2012	N/A	0	0	0	0	0
2013	N/A	0	0	0	0	0
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for Orange Cogen

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	N/A	0	0	0	0	0
1996	53.17	24,126,799	12,507,480	11,619,319	9,453,122	2,166,197
1997	55.98	25,403,545	13,146,840	12,256,705	9,981,308	2,275,397
1998	59.32	26,916,315	13,819,500	13,096,815	10,708,698	2,388,117
1999	60.74	27,563,818	14,525,460	13,038,358	10,530,594	2,507,764
2000	63.67	28,889,378	15,264,720	13,624,658	10,990,317	2,634,341
2001	66.38	30,122,434	16,043,940	14,078,494	11,310,641	2,767,853
2002	69.23	31,415,236	16,869,780	14,545,456	11,640,556	2,904,900
2003	72.16	32,744,845	17,715,600	15,029,245	11,980,355	3,048,889
2004	75.27	34,154,933	18,621,360	15,533,573	12,330,344	3,203,229
2005	78.56	35,649,927	19,573,740	16,076,187	12,711,141	3,365,046
2006	82.00	37,209,700	20,572,001	16,637,700	13,103,845	3,533,855
2007	85.59	38,839,665	21,621,173	17,218,492	13,508,832	3,709,661
2008	89.35	40,546,218	22,723,853	17,822,365	13,926,491	3,895,874
2009	93.29	42,332,495	23,882,769	18,449,726	14,357,225	4,092,501
2010	97.41	44,201,786	25,100,790	19,100,996	14,801,446	4,299,550
2011	101.71	46,154,138	26,380,931	19,773,208	15,259,584	4,513,624
2012	106.22	48,199,974	27,726,358	20,473,616	15,732,078	4,741,538
2013	110.94	50,339,684	29,140,402	21,199,282	16,219,386	4,979,896
2014	115.88	52,580,649	30,626,563	21,954,086	16,721,976	5,232,110
2015	121.04	54,923,637	32,188,518	22,735,120	17,240,335	5,494,785
2016	126.44	57,376,428	33,830,132	23,546,296	17,774,963	5,771,333
2017	132.10	59,943,608	35,555,469	24,388,140	18,326,376	6,061,764
2018	138.03	62,633,396	37,368,798	25,264,598	18,895,110	6,369,489
2019	144.22	65,444,032	39,274,606	26,169,425	19,481,713	6,687,712
2020	150.72	68,391,020	41,277,611	27,113,409	20,086,756	7,026,654
2021	157.51	71,473,110	43,382,769	28,090,341	20,710,824	7,379,517
2022	164.63	74,702,933	45,595,291	29,107,642	21,354,523	7,753,119
2023	172.08	78,083,198	47,920,650	30,162,548	22,018,479	8,144,069
2024	179.88	81,622,727	50,364,604	31,258,124	22,703,336	8,554,787
2025	188.05	85,329,250	52,933,198	32,396,052	23,409,762	8,986,290

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Forecasted Cogeneration Payments for Dade County

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	43.58	14,037,539	6,392,880	7,644,659	5,889,214	1,755,446
1995	45.25	14,576,305	6,873,120	7,703,185	5,857,551	1,845,634
1996	46.14	14,862,282	7,224,000	7,638,282	5,699,239	1,939,043
1997	48.00	15,460,303	7,595,520	7,864,783	5,825,889	2,038,894
1998	49.80	16,040,202	7,977,360	8,062,842	5,920,876	2,141,966
1999	51.90	16,715,668	8,385,000	8,330,668	6,079,188	2,251,480
2000	54.06	17,413,100	8,813,280	8,599,820	6,232,384	2,367,436
2001	56.32	18,141,474	9,262,200	8,879,274	6,389,440	2,489,834
2002	58.69	18,902,827	9,736,920	9,165,907	6,550,454	2,615,453
2003	61.15	19,695,319	10,232,280	9,463,039	6,715,525	2,747,514
2004	63.75	20,532,595	10,758,600	9,773,995	6,884,757	2,889,238
2005	66.50	21,420,494	11,305,560	10,114,934	7,077,530	3,037,404
2006	69.38	22,346,033	11,878,320	10,467,713	7,275,701	3,192,012
2007	72.40	23,319,682	12,487,200	10,832,482	7,479,420	3,353,062
2008	75.55	24,334,499	13,121,880	11,212,619	7,688,844	3,523,775
2009	78.88	25,406,123	13,797,840	11,608,283	7,904,132	3,704,151
2010	82.32	26,514,078	14,494,440	12,019,638	8,125,447	3,894,190
2011	85.94	27,681,111	15,237,480	12,443,631	8,352,960	4,090,671
2012	89.73	28,903,519	16,016,640	12,886,879	8,586,843	4,300,036
2013	98.52	26,621,400	15,424,530	11,196,870	7,405,615	3,791,255
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for Auburndale

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	41.46	22,982,263	9,824,626	13,157,637	10,136,244	3,021,392
1995	42.53	40,420,495	17,691,864	22,728,631	17,282,997	5,445,634
1996	43.28	41,133,459	18,596,328	22,537,131	16,815,889	5,721,242
1997	44.99	42,761,041	19,555,608	23,205,433	17,189,576	6,015,857
1998	46.65	44,332,113	20,542,296	23,789,817	17,469,840	6,319,976
1999	48.59	46,177,556	21,597,504	24,580,052	17,936,949	6,643,103
2000	50.58	48,068,021	22,693,824	25,374,197	18,388,960	6,985,237
2001	52.66	50,043,700	23,844,960	26,198,740	18,852,361	7,346,379
2002	54.84	52,122,785	25,078,320	27,044,465	19,327,441	7,717,024
2003	57.11	54,273,961	26,352,792	27,921,169	19,814,492	8,106,677
2004	59.50	56,548,146	27,709,488	28,838,658	20,313,818	8,524,840
2005	62.04	58,965,616	29,121,000	29,844,616	20,882,605	8,962,012
2006	64.68	61,472,836	30,587,328	30,885,508	21,467,317	9,418,190
2007	67.47	64,125,067	32,163,288	31,961,779	22,068,402	9,893,377
2008	70.37	66,877,456	33,794,064	33,083,392	22,686,318	10,397,074
2009	73.43	69,785,289	35,534,472	34,250,817	23,321,535	10,929,283
2010	76.60	72,794,236	37,329,696	35,464,540	23,974,537	11,490,002
2011	79.93	75,963,810	39,248,256	36,715,554	24,645,825	12,069,729
2012	83.41	79,272,419	41,249,040	38,023,379	25,335,908	12,687,472
2013	87.03	82,711,086	43,332,048	39,379,038	26,045,313	13,333,725
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Lake Cogen

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	44.03	37,854,164	17,447,986	20,406,179	15,720,302	4,685,877
1995	45.48	39,107,695	18,545,292	20,562,403	15,635,784	4,926,620
1996	46.38	39,881,203	19,492,048	20,389,155	15,213,195	5,175,960
1997	48.25	41,488,258	20,494,496	20,993,762	15,551,266	5,442,496
1998	49.84	42,852,319	21,329,870	21,522,449	15,804,819	5,717,630
1999	51.66	44,416,534	22,179,166	22,237,368	16,227,408	6,009,960
2000	53.81	46,262,745	23,306,920	22,955,825	16,636,339	6,319,486
2001	56.07	48,206,071	24,504,289	23,701,782	17,055,574	6,646,208
2002	58.40	50,210,329	25,743,427	24,466,902	17,485,375	6,981,527
2003	60.68	52,172,999	26,912,949	25,260,049	17,926,006	7,334,043
2004	63.09	54,242,181	28,152,087	26,090,094	18,377,742	7,712,352
2005	65.81	56,586,321	29,586,145	27,000,176	18,892,319	8,107,857
2006	68.67	59,045,602	31,103,740	27,941,862	19,421,303	8,520,559
2007	71.64	61,592,582	32,677,027	28,915,555	19,965,100	8,950,456
2008	74.55	64,097,045	34,166,776	29,930,269	20,524,123	9,406,146
2009	77.59	66,712,569	35,726,140	30,986,429	21,098,798	9,887,631
2010	80.99	69,634,513	37,550,039	32,084,474	21,689,565	10,394,909
2011	84.54	72,687,654	39,471,398	33,216,256	22,296,872	10,919,384
2012	88.25	75,875,729	41,476,294	34,399,435	22,921,185	11,478,250
2013	92.15	46,218,891	25,437,123	20,781,768	13,745,070	7,036,697
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for Lake County

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	26.68	2,503,382	0	2,503,382	2,412,102	91,280
1995	54.07	5,100,543	3,069,180	2,031,363	1,980,362	51,001
1996	57.13	5,389,604	3,261,960	2,127,644	2,075,036	52,607
1997	60.86	5,741,222	3,468,510	2,272,712	2,218,448	54,265
1998	65.59	6,187,011	3,688,830	2,498,181	2,442,207	55,974
1999	67.32	6,350,801	3,921,390	2,429,411	2,371,673	57,737
2000	71.14	6,711,071	4,170,780	2,540,291	2,480,736	59,556
2001	74.83	7,058,740	4,433,940	2,624,800	2,563,368	61,432
2002	78.75	7,428,636	4,715,460	2,713,176	2,649,809	63,367
2003	82.89	7,819,164	5,013,810	2,805,354	2,739,991	65,363
2004	87.31	8,235,909	5,332,050	2,903,859	2,836,437	67,422
2005	88.54	8,351,869	5,670,180	2,681,689	2,611,907	69,782
2006	93.39	8,809,395	6,029,730	2,779,665	2,707,441	72,224
2007	98.54	9,295,016	6,412,230	2,882,786	2,808,035	74,752
2008	103.98	9,808,806	6,819,210	2,989,596	2,912,228	77,368
2009	109.75	10,353,178	7,252,200	3,100,978	3,020,902	80,076
2010	115.93	10,936,279	7,712,730	3,223,549	3,140,670	82,879
2011	122.48	11,553,478	8,202,330	3,351,148	3,265,368	85,780
2012	129.16	12,183,699	8,724,060	3,459,639	3,370,858	88,782
2013	136.22	12,849,602	9,277,920	3,571,682	3,479,793	91,889
2014	143.69	6,777,181	4,933,485	1,843,696	1,796,144	47,553
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for LFC Madison

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	26.68	1,528,484	0	1,528,484	1,472,751	55,733
1995	48.80	2,929,700	1,636,080	1,293,620	1,262,480	31,140
1996	51.55	3,094,780	1,740,120	1,354,660	1,322,540	32,120
1997	54.89	3,295,485	1,849,260	1,446,225	1,413,093	33,132
1998	59.19	3,553,679	1,966,560	1,587,119	1,552,943	34,176
1999	60.57	3,636,550	2,091,000	1,545,550	1,510,297	35,252
2000	63.94	3,838,877	2,223,600	1,615,277	1,578,914	36,363
2001	67.18	4,033,241	2,364,360	1,668,881	1,631,372	37,508
2002	70.61	4,239,269	2,514,300	1,724,969	1,686,279	38,690
2003	74.24	4,456,914	2,673,420	1,783,494	1,743,586	39,909
2004	78.12	4,689,902	2,843,760	1,846,142	1,804,977	41,166
2005	78.58	4,717,504	3,023,280	1,694,224	1,651,617	42,606
2006	82.80	4,971,315	3,215,040	1,756,275	1,712,177	44,098
2007	87.29	5,240,685	3,419,040	1,821,645	1,776,004	45,641
2008	92.04	5,525,656	3,636,300	1,889,356	1,842,118	47,239
2009	97.07	5,827,835	3,867,840	1,959,995	1,911,103	48,892
2010	102.45	6,150,621	4,112,640	2,037,981	1,987,378	50,603
2011	108.15	6,492,950	4,373,760	2,119,190	2,066,816	52,374
2012	113.93	6,839,698	4,652,220	2,187,478	2,133,271	54,207
2013	120.03	7,206,012	4,948,020	2,257,992	2,201,887	56,105
2014	126.47	7,592,984	5,262,180	2,330,804	2,272,735	58,068
2015	133.31	8,003,750	5,597,760	2,405,990	2,345,889	60,101
2016	140.52	8,436,349	5,952,720	2,483,629	2,421,424	62,204
2017	148.18	8,895,961	6,332,160	2,563,801	2,499,419	64,381
2018	156.27	9,381,650	6,735,060	2,646,590	2,579,955	66,635
2019	164.82	9,895,542	7,163,460	2,732,082	2,663,115	68,967
2020	173.89	10,439,766	7,619,400	2,820,366	2,748,986	71,381
2021	183.50	11,016,455	8,104,920	2,911,535	2,837,657	73,879
2022	193.66	11,626,724	8,621,040	3,005,684	2,929,219	76,465
2023	203.12	12,194,681	9,091,770	3,102,911	3,023,770	79,141
2024	212.88	12,780,913	9,577,596	3,203,317	3,121,407	81,911
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for LFC Jefferson

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	26.68	1,528,484	0	1,528,484	1,472,751	55,733
1995	47.31	3,001,860	1,636,080	1,365,780	1,334,641	31,140
1996	49.96	3,169,991	1,740,120	1,429,871	1,397,751	32,120
1997	53.19	3,374,742	1,849,260	1,525,482	1,492,350	33,132
1998	57.33	3,637,306	1,966,560	1,670,746	1,636,570	34,176
1999	58.64	3,720,745	2,091,000	1,629,745	1,594,492	35,252
2000	61.87	3,925,816	2,223,600	1,702,216	1,665,853	36,363
2001	64.98	4,122,892	2,364,360	1,758,532	1,721,024	37,508
2002	68.27	4,331,800	2,514,300	1,817,500	1,778,811	38,690
2003	71.75	4,552,483	2,673,420	1,879,063	1,839,154	39,909
2004	75.48	4,788,858	2,843,760	1,945,098	1,903,933	41,166
2005	75.56	4,794,449	3,023,280	1,771,169	1,728,562	42,606
2006	79.61	5,051,277	3,215,040	1,836,237	1,792,139	44,098
2007	83.91	5,323,905	3,419,040	1,904,865	1,859,224	45,641
2008	88.45	5,612,254	3,636,300	1,975,954	1,928,715	47,239
2009	93.27	5,917,994	3,867,840	2,050,154	2,001,262	48,892
2010	98.43	6,245,040	4,112,640	2,132,400	2,081,797	50,603
2011	103.89	6,591,837	4,373,760	2,218,077	2,165,702	52,374
2012	109.40	6,941,353	4,652,220	2,289,133	2,234,926	54,207
2013	115.22	7,310,513	4,948,020	2,362,493	2,306,388	56,105
2014	121.36	7,700,411	5,262,180	2,438,231	2,380,163	58,068
2015	127.88	8,114,185	5,597,760	2,516,425	2,456,324	60,101
2016	134.75	8,549,876	5,952,720	2,597,156	2,534,952	62,204
2017	142.04	9,012,667	6,332,160	2,680,507	2,616,126	64,381
2018	149.75	9,501,624	6,735,060	2,766,564	2,699,929	66,635
2019	157.90	10,018,875	7,163,460	2,855,415	2,786,448	68,967
2020	166.53	10,566,553	7,619,400	2,947,153	2,875,772	71,381
2021	175.68	11,146,792	8,104,920	3,041,872	2,967,993	73,879
2022	185.36	11,760,710	8,621,040	3,139,670	3,063,205	76,465
2023	194.37	12,332,419	9,091,770	3,240,649	3,161,507	79,141
2024	203.67	12,922,508	9,577,596	3,344,912	3,263,001	81,911
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Timber New

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	51.69	1,977,792	1,154,880	822,912	805,062	17,850
1996	54.61	2,089,662	1,228,320	861,342	842,929	18,413
1997	58.12	2,223,752	1,305,360	918,392	899,400	18,993
1998	62.52	2,392,245	1,388,160	1,004,085	984,494	19,591
1999	64.21	2,456,897	1,476,000	980,897	960,689	20,208
2000	67.78	2,593,560	1,569,600	1,023,960	1,003,115	20,845
2001	71.26	2,726,706	1,668,960	1,057,746	1,036,245	21,501
2002	74.95	2,867,945	1,774,800	1,093,145	1,070,967	22,178
2003	78.85	3,017,239	1,887,120	1,130,119	1,107,241	22,877
2004	83.04	3,177,210	2,007,360	1,169,850	1,146,253	23,598
2005	N/A	0	0	0	0	0
2006	N/A	0	0	0	0	0
2007	N/A	0	0	0	0	0
2008	N/A	0	0	0	0	0
2009	N/A	0	0	0	0	0
2010	N/A	0	0	0	0	0
2011	N/A	0	0	0	0	0
2012	N/A	0	0	0	0	0
2013	N/A	0	0	0	0	0
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for EcoPeat

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	61.64	8,018,295	4,907,133	3,111,162	2,365,747	745,414
1996	63.36	16,485,235	10,315,338	6,169,897	4,603,617	1,566,281
1997	66.08	17,193,356	10,840,500	6,352,856	4,705,919	1,646,936
1998	68.81	17,902,592	11,389,752	6,512,840	4,782,646	1,730,194
1999	71.88	18,701,909	11,972,730	6,729,179	4,910,524	1,818,655
2000	75.09	19,536,023	12,589,434	6,946,589	5,034,270	1,912,320
2001	78.40	20,397,731	13,225,410	7,172,321	5,161,133	2,011,188
2002	81.88	21,303,781	13,899,930	7,403,851	5,291,194	2,112,658
2003	85.54	22,256,857	14,612,994	7,643,863	5,424,532	2,219,331
2004	89.38	23,254,824	15,359,784	7,895,040	5,561,230	2,333,810
2005	93.44	24,310,737	16,140,300	8,170,437	5,716,944	2,453,493
2006	97.68	25,414,758	16,959,360	8,455,398	5,877,019	2,578,379
2007	102.17	26,581,462	17,831,418	8,750,044	6,041,575	2,708,469
2008	106.85	27,799,124	18,742,020	9,057,104	6,210,740	2,846,364
2009	111.76	29,077,507	19,700,802	9,376,705	6,384,640	2,992,065
2010	116.89	30,411,927	20,702,946	9,708,981	6,563,410	3,145,570
2011	122.26	31,809,554	21,758,088	10,051,466	6,747,186	3,304,280
2012	127.90	33,275,732	22,866,228	10,409,504	6,936,107	3,473,397
2013	133.78	34,808,003	24,027,366	10,780,637	7,130,318	3,650,319
2014	140.01	36,428,389	25,260,774	11,167,615	7,329,967	3,837,648
2015	146.50	38,115,168	26,547,180	11,567,988	7,535,206	4,032,783
2016	153.28	39,880,736	27,896,220	11,984,516	7,746,192	4,238,325
2017	160.43	41,739,706	29,322,348	12,417,358	7,963,085	4,454,274
2018	167.92	43,690,029	30,820,746	12,869,283	8,186,051	4,683,232
2019	175.75	45,726,670	32,391,414	13,335,256	8,415,261	4,919,995
2020	183.98	47,867,245	34,043,988	13,823,257	8,650,888	5,172,369
2021	192.59	50,106,731	35,778,468	14,328,263	8,893,113	5,435,150
2022	201.61	52,455,334	37,599,672	14,855,662	9,142,120	5,713,542
2023	211.12	54,929,915	39,526,872	15,403,043	9,398,099	6,004,944
2024	221.05	57,513,238	41,540,796	15,972,442	9,661,246	6,311,196
2025	231.48	60,225,544	43,660,716	16,564,828	9,931,761	6,633,067

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Forecasted Cogeneration Payments for General Peat

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	51.69	56,564,850	33,029,568	23,535,282	23,024,761	510,521
1996	54.61	59,764,334	35,129,952	24,634,382	24,107,780	526,602
1997	58.12	63,599,314	37,333,296	26,266,018	25,722,828	543,190
1998	62.52	68,418,214	39,701,376	28,716,838	28,156,537	560,301
1999	64.21	70,267,244	42,213,600	28,053,844	27,475,693	577,950
2000	67.78	74,175,813	44,890,560	29,285,253	28,689,098	596,156
2001	71.26	77,983,799	47,732,256	30,251,543	29,636,609	614,935
2002	74.95	82,023,240	50,759,280	31,263,960	30,629,655	634,305
2003	78.85	86,293,024	53,971,632	32,321,392	31,667,106	654,286
2004	83.04	90,868,220	57,410,496	33,457,724	32,782,828	674,896
2005	83.42	91,292,005	61,034,688	30,257,317	29,558,800	698,517
2006	87.98	96,277,891	64,905,984	31,371,907	30,648,942	722,965
2007	92.82	101,573,052	69,024,384	32,548,668	31,800,399	748,269
2008	97.94	107,178,171	73,410,480	33,767,691	32,993,232	774,458
2009	103.37	113,125,489	78,084,864	35,040,625	34,239,060	801,564
2010	109.18	119,483,490	83,026,944	36,456,546	35,626,927	829,619
2011	115.35	126,230,483	88,298,496	37,931,987	37,073,331	858,656
2012	121.59	133,060,936	93,920,112	39,140,824	38,252,116	888,709
2013	128.19	140,280,437	99,891,792	40,388,645	39,468,832	919,813
2014	135.16	147,910,849	106,234,128	41,676,721	40,724,714	952,007
2015	142.57	156,015,261	113,008,896	43,006,365	42,021,038	985,327
2016	150.37	164,553,845	120,174,912	44,378,933	43,359,120	1,019,814
2017	158.66	173,630,963	127,835,136	45,795,827	44,740,320	1,055,507
2018	167.43	183,227,469	135,968,976	47,258,493	46,166,044	1,092,450
2019	176.72	193,386,044	144,617,616	48,768,428	47,637,742	1,130,685
2020	186.55	204,149,415	153,822,240	50,327,175	49,156,916	1,170,259
2021	196.98	215,560,362	163,624,032	51,936,330	50,725,112	1,211,219
2022	208.02	227,641,126	174,043,584	53,597,542	52,343,931	1,253,611
2023	218.27	238,859,304	183,546,792	55,312,512	54,015,024	1,297,488
2024	228.85	250,437,761	193,354,762	57,082,999	55,740,100	1,342,900
2025	N/A	0	0	0	0	0

400265

Forecasted Cogeneration Payments for Orlando CoGen Ltd.

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	44.11	29,072,157	13,429,152	15,643,005	12,050,896	3,592,108
1995	45.33	29,876,203	14,113,440	15,762,763	11,986,107	3,776,657
1996	46.21	30,456,194	14,826,240	15,629,954	11,662,158	3,967,796
1997	48.08	31,689,499	15,596,064	16,093,435	11,921,317	4,172,118
1998	49.88	32,874,109	16,375,392	16,498,717	12,115,686	4,383,031
1999	51.98	34,258,505	17,211,744	17,046,761	12,439,635	4,607,126
2000	54.15	35,693,133	18,095,616	17,597,517	12,753,114	4,844,403
2001	56.42	37,186,858	19,017,504	18,169,354	13,074,492	5,094,862
2002	58.78	38,742,793	19,986,912	18,755,881	13,403,970	5,351,911
2003	61.25	40,367,733	21,003,840	19,363,893	13,741,750	5,622,143
2004	63.86	42,087,486	22,087,296	20,000,190	14,088,042	5,912,149
2005	66.62	43,906,610	23,208,768	20,697,842	14,482,507	6,215,336
2006	69.50	45,806,986	24,387,264	21,419,722	14,888,017	6,531,705
2007	72.53	47,807,929	25,641,792	22,166,137	15,304,881	6,861,256
2008	75.69	49,887,838	26,943,840	22,943,998	15,733,418	7,210,580
2009	79.02	52,085,055	28,331,424	23,753,631	16,173,954	7,579,678
2010	82.46	54,352,397	29,757,024	24,595,373	16,626,825	7,968,548
2011	86.10	56,750,144	31,287,168	25,462,976	17,092,376	8,370,600
2012	89.90	59,253,819	32,883,840	26,369,979	17,570,962	8,799,017
2013	93.85	61,857,196	34,547,040	27,310,156	18,062,949	9,247,207
2014	98.02	64,605,256	36,314,784	28,290,472	18,568,712	9,721,760
2015	102.37	67,472,787	38,168,064	29,304,723	19,088,636	10,216,087
2016	106.91	70,466,776	40,106,880	30,359,896	19,623,117	10,736,778
2017	111.71	73,625,646	42,169,248	31,456,398	20,172,565	11,283,833
2018	116.69	76,908,888	44,307,648	32,601,240	20,737,397	11,863,843
2019	121.92	80,360,774	46,579,104	33,781,670	21,318,044	12,463,626
2020	127.39	83,963,505	48,945,600	35,017,905	21,914,949	13,102,956
2021	133.12	87,742,369	51,445,152	36,297,217	22,528,567	13,768,649
2022	139.13	91,701,512	54,068,256	37,633,256	23,159,367	14,473,889
2023	145.43	95,853,833	56,833,920	39,019,913	23,807,830	15,212,083
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Panda

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	N/A	0	0	0	0	0
1996	N/A	0	0	0	0	0
1997	54.75	11,316,660	3,903,039	7,413,621	7,164,022	249,599
1998	60.53	12,510,887	4,098,528	8,412,359	8,153,904	258,455
1999	59.53	12,303,581	4,307,499	7,996,082	7,713,105	282,977
2000	63.22	13,066,813	4,529,952	8,536,861	8,243,573	293,288
2001	65.91	13,622,654	4,759,146	8,863,508	8,546,339	317,169
2002	68.65	14,188,049	5,001,822	9,186,227	8,857,267	328,960
2003	71.53	14,784,448	5,257,980	9,526,468	9,174,242	352,226
2004	74.46	15,388,485	5,527,620	9,860,865	9,495,341	365,524
2005	77.55	16,027,487	5,810,742	10,216,745	9,827,677	389,067
2006	80.72	16,683,815	6,107,346	10,576,469	10,171,646	404,823
2007	84.06	17,373,013	6,417,432	10,955,581	10,527,654	427,928
2008	87.52	18,089,237	6,747,741	11,341,496	10,896,122	445,374
2009	91.14	18,837,102	7,091,532	11,745,570	11,277,486	468,084
2010	94.87	19,608,269	7,448,805	12,159,464	11,672,198	487,266
2011	98.82	20,423,394	7,833,042	12,590,352	12,080,725	509,628
2012	102.89	21,264,906	8,230,761	13,034,145	12,503,550	530,595
2013	107.13	22,142,536	8,648,703	13,493,833	12,941,175	552,658
2014	111.59	23,063,187	9,093,609	13,969,578	13,394,116	575,463
2015	116.18	24,012,189	9,551,997	14,460,192	13,862,910	597,282
2016	121.03	25,014,180	10,044,090	14,970,090	14,348,112	621,979
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Pasco Cogen

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	44.02	37,593,547	17,324,241	20,269,306	15,614,859	4,654,447
1995	45.43	38,796,454	18,371,971	20,424,483	15,530,908	4,893,575
1996	46.32	39,562,276	19,309,880	20,252,396	15,111,154	5,141,243
1997	48.19	41,155,907	20,302,959	20,852,948	15,446,957	5,405,991
1998	49.77	42,508,615	21,130,525	21,378,089	15,698,810	5,679,280
1999	51.59	44,060,097	21,971,884	22,088,213	16,118,564	5,969,649
2000	53.73	45,890,949	23,089,099	22,801,850	16,524,752	6,277,098
2001	55.99	47,818,081	24,275,277	23,542,804	16,941,176	6,601,629
2002	58.32	49,805,626	25,502,834	24,302,792	17,368,093	6,934,699
2003	60.60	51,752,046	26,661,427	25,090,619	17,805,769	7,284,850
2004	63.00	53,804,080	27,888,983	25,915,097	18,254,474	7,660,622
2005	65.72	56,128,713	29,309,639	26,819,074	18,765,600	8,053,475
2006	68.58	58,567,495	30,813,051	27,754,444	19,291,037	8,463,408
2007	71.54	61,093,240	32,371,634	28,721,607	19,831,186	8,890,421
2008	74.44	63,576,974	33,847,460	29,729,514	20,386,459	9,343,055
2009	77.48	66,170,841	35,392,251	30,778,590	20,957,280	9,821,311
2010	80.87	69,068,374	37,199,104	31,869,270	21,544,083	10,325,186
2011	84.42	72,095,967	39,102,506	32,993,461	22,147,318	10,846,143
2012	88.12	75,257,368	41,088,665	34,168,703	22,767,443	11,401,260
2013	92.02	45,841,769	25,199,393	20,642,376	13,652,876	6,989,499
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Pasco County

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	26.68	3,763,254	0	3,763,254	3,626,036	137,219
1995	60.79	8,574,021	5,536,560	3,037,461	2,960,793	76,668
1996	64.28	9,065,831	5,884,320	3,181,511	3,102,428	79,083
1997	68.46	9,655,599	6,256,920	3,398,679	3,317,104	81,574
1998	73.68	10,390,996	6,654,360	3,736,636	3,652,492	84,144
1999	75.92	10,707,008	7,073,880	3,633,128	3,546,334	86,794
2000	80.28	11,322,955	7,523,760	3,799,195	3,709,667	89,528
2001	84.55	11,924,104	7,998,480	3,925,624	3,833,276	92,349
2002	89.08	12,564,150	8,506,320	4,057,830	3,962,573	95,258
2003	93.88	13,240,235	9,044,520	4,195,715	4,097,457	98,258
2004	98.99	13,961,632	9,618,600	4,343,032	4,241,679	101,353
2005	100.99	14,242,560	10,228,560	4,014,000	3,909,099	104,901
2006	106.62	15,037,767	10,877,160	4,160,607	4,052,034	108,572
2007	112.61	15,882,053	11,567,160	4,314,893	4,202,521	112,372
2008	118.95	16,776,018	12,301,320	4,474,698	4,358,392	116,305
2009	125.67	17,723,733	13,082,400	4,641,333	4,520,957	120,376
2010	132.86	18,737,792	13,913,160	4,824,632	4,700,043	124,589
2011	140.47	19,811,804	14,796,360	5,015,444	4,886,494	128,950
2012	148.30	20,915,433	15,737,520	5,177,913	5,044,450	133,463
2013	156.57	22,082,343	16,736,640	5,345,703	5,207,569	138,134
2014	165.34	23,318,230	17,799,240	5,518,990	5,376,021	142,969
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for Pinellas County

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	26.68	9,512,735	0	9,512,735	9,165,875	346,861
1995	59.21	21,108,806	13,420,140	7,688,666	7,494,865	193,801
1996	62.60	22,316,323	14,263,080	8,053,243	7,853,338	199,906
1997	66.67	23,769,021	15,166,230	8,602,791	8,396,589	206,203
1998	71.77	25,587,309	16,129,590	9,457,719	9,245,021	212,698
1999	73.89	26,342,626	17,146,470	9,196,156	8,976,758	219,398
2000	78.13	27,853,282	18,236,940	9,616,342	9,390,033	226,309
2001	82.25	29,323,947	19,387,620	9,936,327	9,702,889	233,438
2002	86.64	30,889,519	20,618,580	10,270,939	10,030,148	240,791
2003	91.28	32,543,059	21,923,130	10,619,929	10,371,553	248,376
2004	96.23	34,307,465	23,314,650	10,992,815	10,736,615	256,200
2005	98.04	34,950,998	24,793,140	10,157,858	9,892,691	265,167
2006	103.49	36,894,182	26,365,290	10,528,892	10,254,444	274,448
2007	109.27	38,957,165	28,037,790	10,919,375	10,635,321	284,054
2008	115.40	41,141,154	29,817,330	11,323,824	11,029,828	293,996
2009	121.89	43,456,166	31,710,600	11,745,566	11,441,281	304,286
2010	128.84	45,933,825	33,724,290	12,209,535	11,894,599	314,936
2011	136.20	48,557,612	35,865,090	12,692,522	12,366,563	325,958
2012	143.75	51,249,998	38,146,380	13,103,618	12,766,251	337,367
2013	151.74	54,096,334	40,568,160	13,528,174	13,179,000	349,175
2014	160.19	57,110,446	43,143,810	13,966,636	13,605,240	361,396
2015	169.18	60,312,863	45,893,400	14,419,463	14,045,419	374,045
2016	178.67	63,697,372	48,810,240	14,887,132	14,499,996	387,136
2017	188.73	67,284,532	51,914,400	15,370,132	14,969,446	400,686
2018	199.40	71,088,232	55,219,260	15,868,972	15,454,262	414,710
2019	210.70	75,115,686	58,731,510	16,384,176	15,954,951	429,225
2020	222.68	79,387,506	62,471,220	16,916,286	16,472,039	444,248
2021	235.39	83,917,633	66,451,770	17,465,863	17,006,067	459,796
2022	248.84	88,713,335	70,679,850	18,033,485	17,557,596	475,889
2023	261.31	93,159,731	74,539,980	18,619,751	18,127,206	492,545
2024	274.18	97,747,816	78,522,537	19,225,279	18,715,494	509,784
2025	N/A	0	0	0	0	0

400270

Forecasted Cogeneration Payments for Pinellas County (North)

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	N/A	0	0	0	0	0
1996	61.53	4,042,504	2,558,400	1,484,104	1,447,264	36,840
1997	65.54	4,305,778	2,720,400	1,585,378	1,547,378	38,000
1998	70.57	4,636,130	2,893,200	1,742,930	1,703,733	39,197
1999	72.61	4,770,327	3,075,600	1,694,727	1,654,295	40,432
2000	76.76	5,043,362	3,271,200	1,772,162	1,730,456	41,706
2001	80.80	5,308,731	3,477,600	1,831,131	1,788,112	43,020
2002	85.10	5,591,196	3,698,400	1,892,796	1,848,421	44,375
2003	89.64	5,889,510	3,932,400	1,957,110	1,911,337	45,772
2004	94.49	6,207,827	4,182,000	2,025,827	1,978,613	47,214
2005	96.18	6,319,156	4,447,200	1,871,956	1,823,089	48,867
2006	101.51	6,669,533	4,729,200	1,940,333	1,889,756	50,577
2007	107.18	7,041,493	5,029,200	2,012,293	1,959,946	52,347
2008	113.17	7,435,228	5,348,400	2,086,828	2,032,648	54,179
2009	119.52	7,852,549	5,688,000	2,164,549	2,108,474	56,076
2010	126.32	8,299,252	6,049,200	2,250,052	2,192,014	58,038
2011	133.52	8,772,260	6,433,200	2,339,060	2,278,991	60,070
2012	140.90	9,257,220	6,842,400	2,414,820	2,352,648	62,172
2013	148.70	9,769,860	7,276,800	2,493,060	2,428,712	64,348
2014	156.97	10,312,663	7,738,800	2,573,863	2,507,262	66,600
2015	165.74	10,889,313	8,232,000	2,657,313	2,588,381	68,931
2016	175.02	11,498,697	8,755,200	2,743,497	2,672,153	71,344
2017	184.85	12,144,508	9,312,000	2,832,508	2,758,667	73,841
2018	195.27	12,829,237	9,904,800	2,924,437	2,848,012	76,425
2019	206.30	13,554,183	10,534,800	3,019,383	2,940,282	79,100
2020	218.01	14,323,043	11,205,600	3,117,443	3,035,574	81,869
2021	230.42	15,138,323	11,919,600	3,218,723	3,133,989	84,734
2022	243.55	16,001,328	12,678,000	3,323,328	3,235,628	87,700
2023	255.73	16,801,769	13,370,400	3,431,369	3,340,599	90,769
2024	268.31	17,627,719	14,084,760	3,542,959	3,449,013	93,946
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Ridge Generating Station

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	54.02	12,509,586	7,013,952	5,495,634	4,233,670	1,261,964
1995	54.21	16,735,546	9,351,936	7,383,610	5,614,545	1,769,066
1996	54.00	16,673,336	9,351,936	7,321,400	5,462,800	1,858,599
1997	54.71	16,890,440	9,351,936	7,538,504	5,584,196	1,954,308
1998	55.32	17,080,282	9,351,936	7,728,346	5,675,242	2,053,104
1999	56.15	17,336,998	9,351,936	7,985,062	5,826,987	2,158,075
2000	56.99	17,594,983	9,351,936	8,243,047	5,973,827	2,269,220
2001	57.86	17,862,844	9,351,936	8,510,908	6,124,367	2,386,540
2002	58.75	18,137,586	9,351,936	8,785,650	6,278,702	2,506,948
2003	59.67	18,422,391	9,351,936	9,070,455	6,436,925	2,633,530
2004	60.64	18,720,446	9,351,936	9,368,510	6,599,135	2,769,375
2005	61.69	19,047,241	9,351,936	9,695,305	6,783,911	2,911,394
2006	62.79	19,385,385	9,351,936	10,033,449	6,973,861	3,059,588
2007	63.92	19,735,021	9,351,936	10,383,085	7,169,129	3,213,957
2008	65.10	20,099,388	9,351,936	10,747,452	7,369,864	3,377,588
2009	66.33	20,478,637	9,351,936	11,126,701	7,576,221	3,550,481
2010	67.61	20,872,926	9,351,936	11,520,990	7,788,355	3,732,636
2011	68.92	21,279,330	9,351,936	11,927,394	8,006,429	3,920,965
2012	70.30	21,704,189	9,351,936	12,352,253	8,230,609	4,121,645
2013	71.73	22,144,588	9,351,936	12,792,652	8,461,066	4,331,586
2014	73.21	22,603,789	9,351,936	13,251,853	8,697,975	4,553,877
2015	74.75	23,078,885	9,351,936	13,726,949	8,941,519	4,785,430
2016	76.35	23,573,150	9,351,936	14,221,214	9,191,881	5,029,333
2017	78.02	24,086,775	9,351,936	14,734,839	9,449,254	5,285,585
2018	79.75	24,623,043	9,351,936	15,271,107	9,713,833	5,557,274
2019	81.54	25,175,981	9,351,936	15,824,045	9,985,820	5,838,225
2020	83.42	25,755,060	9,351,936	16,403,124	10,265,423	6,137,700
2021	85.36	26,354,316	9,351,936	17,002,380	10,552,855	6,449,525
2022	87.39	26,980,145	9,351,936	17,628,209	10,848,335	6,779,874
2023	59.20	18,277,749	0	18,277,749	11,152,089	7,125,660
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Timber Energy

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	54.59	5,127,623	3,121,043	2,006,580	1,957,079	49,502
1995	57.29	5,380,913	3,289,158	2,091,756	2,040,695	51,061
1996	60.23	5,657,831	3,467,229	2,190,602	2,137,933	52,669
1997	63.81	5,993,968	3,654,875	2,339,093	2,284,765	54,328
1998	68.35	6,420,051	3,851,711	2,568,340	2,512,300	56,040
1999	69.84	6,559,981	4,060,036	2,499,945	2,442,140	57,805
2000	73.38	6,892,628	4,279,466	2,613,161	2,553,536	59,626
2001	76.77	7,210,718	4,510,768	2,699,950	2,638,446	61,504
2002	78.36	1,840,026	1,142,340	697,686	681,826	15,860
2003	N/A	0	0	0	0	0
2004	N/A	0	0	0	0	0
2005	N/A	0	0	0	0	0
2006	N/A	0	0	0	0	0
2007	N/A	0	0	0	0	0
2008	N/A	0	0	0	0	0
2009	N/A	0	0	0	0	0
2010	N/A	0	0	0	0	0
2011	N/A	0	0	0	0	0
2012	N/A	0	0	0	0	0
2013	N/A	0	0	0	0	0
2014	N/A	0	0	0	0	0
2015	N/A	0	0	0	0	0
2016	N/A	0	0	0	0	0
2017	N/A	0	0	0	0	0
2018	N/A	0	0	0	0	0
2019	N/A	0	0	0	0	0
2020	N/A	0	0	0	0	0
2021	N/A	0	0	0	0	0
2022	N/A	0	0	0	0	0
2023	N/A	0	0	0	0	0
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

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Forecasted Cogeneration Payments for Polk Power Partners

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	59.25	16,760,699	10,047,000	6,713,699	5,172,030	1,541,669
1995	61.20	45,703,936	27,844,080	17,859,856	13,580,750	4,279,107
1996	62.89	46,968,498	29,259,120	17,709,378	13,213,702	4,495,676
1997	65.60	48,991,577	30,757,056	18,234,521	13,507,340	4,727,181
1998	68.31	51,011,018	32,317,296	18,693,722	13,727,568	4,966,154
1999	71.03	53,047,014	33,732,336	19,314,678	14,094,616	5,220,062
2000	73.85	55,149,971	35,211,264	19,938,707	14,449,800	5,488,907
2001	76.76	57,325,918	36,739,296	20,586,622	14,813,935	5,772,687
2002	79.81	59,599,293	38,348,112	21,251,181	15,187,246	6,063,935
2003	82.98	61,970,403	40,030,320	21,940,083	15,569,965	6,370,119
2004	86.29	64,437,450	41,776,416	22,661,034	15,962,328	6,698,706
2005	90.00	67,212,671	43,761,168	23,451,503	16,409,273	7,042,230
2006	94.08	70,256,110	45,986,688	24,269,422	16,868,733	7,400,689
2007	98.36	73,453,541	48,338,400	25,115,141	17,341,057	7,774,084
2008	103.23	55,507,456	36,789,984	18,717,472	12,835,157	5,882,315
2009	107.94	58,040,235	38,662,272	19,377,963	13,194,541	6,183,421
2010	112.88	60,694,246	40,629,600	20,064,646	13,563,988	6,500,658
2011	118.05	63,473,900	42,701,472	20,772,428	13,943,780	6,828,648
2012	123.49	66,399,743	44,887,392	21,512,351	14,334,206	7,178,145
2013	129.18	69,457,194	47,177,856	22,279,338	14,735,564	7,543,774
2014	135.12	72,651,933	49,572,864	23,079,069	15,148,160	7,930,910
2015	141.38	76,016,916	52,110,432	23,906,484	15,572,308	8,334,176
2016	147.93	79,538,835	54,771,552	24,767,283	16,008,333	8,758,951
2017	154.79	83,227,526	57,565,728	25,661,798	16,456,566	9,205,232
2018	161.99	87,098,212	60,502,464	26,595,748	16,917,350	9,678,398
2019	169.50	91,140,491	63,581,760	27,558,731	17,391,036	10,167,695
2020	177.41	95,389,862	66,822,624	28,567,238	17,877,985	10,689,253
2021	185.68	99,835,943	70,225,056	29,610,887	18,378,568	11,232,319
2022	194.38	104,518,382	73,817,568	30,700,814	18,893,168	11,807,646
2023	203.47	109,403,682	77,571,648	31,832,034	19,422,177	12,409,858
2024	N/A	0	0	0	0	0
2025	N/A	0	0	0	0	0

Forecasted Cogeneration Payments for Tiger Bay

Year	$/MWH	Total Payment	Capacity Payment	Energy Payment	Fuel Portion	Variable O&M
1994	N/A	0	0	0	0	0
1995	52.71	66,560,936	39,091,581	27,469,355	26,195,570	1,273,786
1996	56.25	78,339,232	46,673,610	31,665,622	29,554,326	2,111,296
1997	59.61	83,016,422	49,479,156	33,537,266	31,328,146	2,209,119
1998	63.70	88,713,051	52,479,288	36,233,763	33,923,677	2,310,086
1999	65.64	91,426,049	55,662,330	35,763,719	33,346,906	2,416,813
2000	69.15	96,305,396	59,049,594	37,255,802	34,726,483	2,529,320
2001	72.60	101,108,236	62,626,626	38,481,610	35,833,987	2,647,623
2002	76.25	106,194,966	66,434,010	39,760,956	36,991,815	2,769,141
2003	80.10	111,567,120	70,471,746	41,095,374	38,198,880	2,896,494
2004	84.22	117,300,254	74,777,640	42,522,614	39,490,311	3,032,304
2005	85.35	115,602,742	77,174,988	38,427,754	35,275,745	3,152,010
2006	89.84	121,692,649	81,865,344	39,827,305	36,525,961	3,301,344
2007	94.61	128,154,514	86,855,802	41,298,712	37,841,975	3,456,738
2008	99.65	134,977,294	92,152,500	42,824,794	39,203,972	3,620,822
2009	104.99	142,202,995	97,785,666	44,417,329	40,623,701	3,793,629
2010	110.66	149,895,417	103,729,890	46,165,527	42,190,337	3,975,189
2011	116.68	158,040,036	110,056,584	47,983,452	43,820,517	4,162,936
2012	122.80	166,336,668	116,786,340	49,550,328	45,188,223	4,362,105
2013	129.26	175,088,440	123,919,158	51,169,282	46,599,150	4,570,132
2014	136.09	184,339,238	131,494,902	52,844,336	48,054,681	4,789,655
2015	143.32	194,130,429	139,556,076	54,574,353	49,556,244	5,018,110
2016	150.93	204,434,581	148,071,132	56,363,449	51,105,311	5,258,138
2017	159.00	215,370,669	157,157,484	58,213,185	52,703,405	5,509,781
2018	167.53	226,917,498	166,789,722	60,127,776	54,352,095	5,775,681
2019	176.53	239,112,713	177,009,030	62,103,683	56,053,003	6,050,680
2020	186.06	252,016,660	187,866,228	64,150,432	57,807,804	6,342,628
2021	196.14	265,667,094	199,402,500	66,264,594	59,618,225	6,646,369
2022	206.79	280,096,460	211,643,256	68,453,204	61,486,051	6,967,154
2023	216.90	293,789,219	223,073,664	70,715,555	63,413,124	7,302,431
2024	227.35	307,950,999	234,895,558	73,055,441	65,401,346	7,654,095
2025	231.48	60,225,544	43,660,716	16,564,828	9,931,761	6,633,067

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APPENDIX 4

PART III

UTILITIES' OBLIGATIONS WITH REGARD TO COGENERATORS AND SMALL POWER PRODUCERS

25-17.080 Definitions and Qualifying Criteria.

(1) For the purpose of these rules the Commission adopts the Federal Energy Regulatory Commission Rules 292.101 through 292.207, effective March 20, 1980, regarding definitions and criteria that a small power producer or cogenerator must meet to achieve the status of a qualifying facility. Small power producers and cogenerators which fail to meet the FERC criteria for achieving qualifying facility status but otherwise meet the objectives of economically reducing Florida's dependence on oil and the economic deferral of utility power plant expenditures may petition the Commission to be granted qualifying facility status for the purpose of receiving energy and capacity payments pursuant to these rules.

(2) In general, under the FERC regulations, a small power producer is a qualifying facility if:

(a) the small power producer does not exceed 80 MW; and

(b) the primary (at least 50%) energy source of the small power producer is biomass, waste, or another renewable resource; and

(c) the small power production facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.

(3) In general, under the FERC regulations, a cogenerator is a qualifying facility if:

(a) the useful thermal energy output of a topping cycle cogeneration facility is not less than 5% of the facility's total energy output per year; and

(b) the useful power output plus half of the useful thermal energy output of a topping cycle cogeneration facility built after March 13, 1980, with any energy input of natural gas or oil is greater than 42.5% or 45% if the useful thermal energy output is less than 15% of the total energy output of the facility; and

(c) the useful power output of a bottoming cycle cogeneration facility built after March 13, 1980, with any energy input as supplementary firing of natural gas or oil is not less than 45% of the natural gas or oil input on an annual basis; and

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(d) the cogeneration facility is not owned by a person primarily engaged in the generation or sale of electricity. This criterion is met if less than 50% of the equity interest in the facility is owned by a utility, utility holding company, or a subsidiary of them.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, Amended 9/4/83, formerly 25-17.80.

25-17.081 Reserved.

25-17.082 The Utility's Obligation to Purchase; Customer's Selection of Billing Method.

(1) Upon compliance by the qualifying facility with Rule 25-17.087, each utility shall purchase electricity produced and sold by qualifying facilities at rates which have been agreed upon by the utility and qualifying facility or at the utility's published tariff. Each utility shall file a tariff or tariffs and a standard offer contract or contracts for the purchase of energy and capacity from qualifying facilities which reflects the provisions set forth in these rules.

(2) Unless the Commission determines that alternative metering requirements cause no adverse effect on the cost or reliability of electric service to the utility's general body of customers, each tariff and standard offer contract shall specify the following metering requirements for billing purposes:

(a) Hourly recording meters shall be required for qualifying facilities with an installed capacity of 100 kilowatts or more.

(b) For qualifying facilities with an installed capacity of less than 100 kilowatts, at the option of the qualifying facility, either hourly recording meters, dual kilowatt-hour register time-of-day meters, or standard kilowatt-hour meters shall be installed. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

(3)(a) A qualifying facility, upon entering into a contract for the sale of firm capacity and energy or prior to delivery of as-available energy to a utility, shall elect to make either simultaneous purchases from the interconnecting utility and sales to the purchasing utility or net sales to the purchasing utility. Once made, the selection of a billing methodology may only be changed:

1. when a qualifying facility selling as-available energy enters into a negotiated contract or standard offer contract for the sale of firm capacity and energy; or
2. when a firm capacity and energy contract expires or is lawfully terminated by either the qualifying facility or the purchasing utility; or
3. when the qualifying facility is selling as-available energy and has not changed billing methods within the last twelve months; and
4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the qualifying facility and the utility.

Firm capacity and energy contracts in effect prior to the effective date of this rule shall remain unchanged.

(b) If a qualifying facility elects to change billing methods in accordance with this rule, such change shall be subject to the following provisions:

1. upon at least thirty days advance written notice;
2. upon the installation by the utility of any additional metering equipment reasonably required to effect the change in billing and upon payment by the qualifying facility for such metering equipment and its installation; and

3. upon completion and approval by the utility of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the qualifying facility for such alterations.

(c) Should a qualifying facility elect to make simultaneous purchases and sales, purchases of electric service by the qualifying facility from the interconnecting utility shall be billed at the retail rate schedule under which the qualifying facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the qualifying facility to the purchasing utility shall be purchased at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

(d) Should a qualifying facility elect a net billing arrangement, the hourly net energy and capacity sales delivered to the purchasing utility shall be purchased at the utility's avoided energy and capacity rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832; purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

(4)(a) Payments for energy and capacity sold by a qualifying facility shall be rendered monthly by the purchasing utility and as promptly as possible, normally by the twentieth business day following the day the meter is read. The kilowatt-hours sold by the qualifying facility, the applicable avoided energy rate at which payments were made, and the rate and amount of the applicable capacity payment shall accompany the payment by the utility to the qualifying facility.

(b) Where simultaneous purchases and sales are made by a qualifying facility, avoided energy and capacity payments to the qualifying facility may, at the option of the qualifying facility, be shown as a credit to the qualifying facility's bill; the kilowatt-hours produced by the qualifying facility, the avoided energy rate at which payments were made, and the rate and amount of the capacity payment shall accompany the bill to the qualifying facility. A credit shall not exceed the amount of the qualifying facility's bill from the utility and the excess, if any, shall be paid directly to the qualifying facility in accordance with this rule.

(5) A utility may require a security deposit from each interconnected qualifying facility in accordance with Rule 25-6.097 for the qualifying facility's purchase of power from the utility. Each utility's tariff shall contain specific criteria for determining the applicability and amount of a deposit from an interconnected qualifying facility consistent with projected net cash flow on a monthly basis.

(6) Each utility shall keep separate accounts for sales to qualifying facilities and purchases from qualifying facilities.

Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 5/13/81, Amended 9/4/83, formerly 25-17.82, amended 10/25/90.

25-17.0825 As-Available Energy.

(1) As-available energy is energy produced and sold by a qualifying facility on an hour-by-hour basis for which contractual commitments as to the quantity, time, or reliability of delivery are not required. Each utility shall purchase as-available energy from any qualifying facility. As-available energy shall be sold by a qualifying facility and purchased by a utility pursuant to the terms and conditions of a published tariff or a separately negotiated contract.

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. Because of the lack of assurances as to the quantity, time, or reliability of delivery of as-available energy, no capacity payments shall be made to a qualifying facility for the delivery of as-available energy.

(a) Tariff Rates: Each utility shall publish a tariff for the purchase of as-available energy from qualifying facilities. Each utility's published tariff shall state that the rate of payment for as-available energy is the utility's avoided energy cost as defined in subsection (2) of this rule, less the additional costs directly attributable to the purchase of such energy from a qualifying facility. The additional costs directly associated with the purchase of as-available energy from qualifying facilities shall be specifically identified in the utility's tariff.

(b) Contract Rates: Each utility may enter into a separately negotiated contract for the purchase of as-available energy from a qualifying facility. All contracts for the purchase of as-available energy between a qualifying facility and a utility shall be filed with the Commission within 10 working days of their signing. Those qualifying facilities wishing to negotiate a contract for the sale of firm capacity and energy with terms different from those in a utility's standard offer contract may do so pursuant to Rule 25-17.0832(2). Where parties cannot agree on the terms and conditions of a negotiated contract, either party may apply to the Commission for relief pursuant to Rule 25-17.0834.

(2)(a) Avoided energy costs associated with as-available energy are defined as the utility's actual avoided energy cost before the sale of interchange energy. Avoided energy costs associated with as-available energy shall be all costs the utility avoided due to the purchase of as-available energy, including the utility's incremental fuel, identifiable variable operating and maintenance expense, and identifiable variable utility power purchases. Demonstrable utility administrative costs required to calculate avoided energy costs may be deducted from avoided energy payments. Avoided line losses reflecting the voltage at which generation by the qualifying facility is received by the utility shall also be included in the determination of avoided energy costs. Each utility shall calculate its avoided energy cost associated with as-available energy deterministically, on an hour-by-hour basis, after accounting for interchange sales which have taken place, using the utility's actual avoided energy cost for the hour, as affected by the output of the qualifying facilities connected to the utility's system. A megawatt block size at least equal to the most recent available estimate of the combined average hourly generation of all qualifying facilities making energy sales based on the utility's as-available energy rate to the utility shall be used to calculate the utility's hourly avoided energy costs associated with as-available energy. For the purpose of this subsection, interchange sales are inter-utility sales which are provided at the option of the selling utility exclusive of central pool dispatch transactions.

(b) Each utility's tariff shall include a description of the methodology to be used in the calculation of avoided energy cost implementing subsection (2) of this Rule. Each utility's implementation methodology shall specify the method by which the utility's incremental fuel and operating and maintenance costs and line losses are determined.

(3)(a) For qualifying facilities with hourly recording meters, monthly payments for as-available energy shall be made and shall be calculated based on the product of: (1) the utility's actual avoided energy rate for each hour during the month; and (2) the quantity of energy sold by the qualifying facility during that hour.

(b) For qualifying facilities with dual kilowatt-hour register time-of-day meters, monthly payments for as-available energy shall be calculated based on the average of the utility's actual hourly avoided energy rate for the on-peak and off-peak periods during the month.

(c) For qualifying facilities with standard kilowatt-hour meters, monthly payments for as-available energy shall be calculated based on the average of the utility's actual hourly avoided energy rate for the off-peak periods during the month.

(4) Each utility shall file with the Commission by the twentieth business day of the following month, a monthly report of their actual hourly avoided energy costs, the average of their actual hourly avoided energy costs for the on-peak and

off-peak periods during the month, and the average of their actual hourly avoided energy costs for the month with the Commission. A copy shall be furnished to any individual who requests such information.

(5) Upon request by a qualifying facility or any interested person, each utility shall provide within 30 days its most current projections of its generation mix, fuel price by type of fuel, and at least a five year projection of fuel forecasts to estimate future as-available energy prices as well as any other information reasonably required by the qualifying facility to project future avoided cost prices including, but not limited to, a 24 hour advance forecast of hour-by-hour avoided energy costs. The utility may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

(6) Utility payments for as-available energy made to qualifying facilities pursuant to the utility's tariff shall be recoverable by the utility through the Commission's periodic review of fuel and purchased power. Utility payments for as-available energy made to qualifying facilities pursuant to a separately negotiated contract shall be recoverable by the utility through the Commission's periodic review of fuel and purchased power costs if the payments are not reasonably projected to result in higher cost electric service to the utility's general body of ratepayers or adversely affect the adequacy or reliability of electric service to all customers.

Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 9/4/83, formerly 25-17.82, amended 10/25/90.

25-17.083 Firm Energy and Capacity.
Specific Authority: 366.04(1), 366.05(1), 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 9/4/83, formerly 25-17.83, Repealed 10/25/90.

25-17.0831 Contracts.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, amended 9/4/83, formerly 25-17.831, Repealed 10/25/90.

25-17.0832 Firm Capacity and Energy Contracts.

(1) Firm capacity and energy are capacity and energy produced and sold by a qualifying facility and purchased by a utility pursuant to a negotiated contract or a standard offer contract subject to certain contractual provisions as to the quantity, time and reliability of delivery.

(a) Within one working day of the execution of a negotiated contract or the receipt of a signed standard offer contract, the utility shall notify the Director of the Division of Electric and Gas and provide the amount of committed capacity and the avoided unit, if any, to which the contract should be applied.

(b) Within 10 working days of the execution of a negotiated contract for the purchase of firm capacity and energy or within 10 working days of receipt of a signed standard offer contract, the purchasing utility shall file with the Commission a copy of the signed contract and a summary of its terms and conditions. At a minimum, such a summary shall report:

1. the name of the utility and the owner and/or operator of the qualifying facility, who are signatories of the contract;
2. the amount of committed capacity specified in the contract, the size of the facility, the type of the facility its location, and its interconnection and transmission requirements;
3. the amount of annual and on-peak and off-peak energy expected to be delivered to the utility;
4. the type of unit being avoided, its size and its in-service year;
5. the in-service date of the qualifying facility; and

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6. the date by which the delivery of firm capacity and energy is expected to commence.

(c) Prior to the anticipated in-service date of the avoided unit specified in the contract, a qualifying facility which has negotiated a firm capacity and energy contract or has accepted a utility's standard offer contract may sell as-available energy to any utility pursuant to Rule 25-17.0825.

(2) Negotiated Contracts. Utilities and qualifying facilities are encouraged to negotiate contracts for the purchase of firm capacity and energy. Such contracts will be considered prudent for cost recovery purposes if it is demonstrated 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 the 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. Negotiated contracts shall not be evaluated against an avoided unit in a standard offer contract, thus preserving the standard offer for small qualifying facilities as described in subsection (3). In reviewing negotiated firm capacity and energy contracts for the purpose of cost recovery, the Commission shall consider factors relating to the contract that would impact the utility's general body of retail and wholesale customers including:

(a) whether additional firm capacity and energy is needed by the purchasing utility and by Florida utilities from a statewide perspective; and

(b) whether the cumulative present worth of firm capacity and energy payments made to the qualifying facility over the term of the contract are projected to be no greater than:

1. the cumulative present worth of the value of a year-by-year deferral of the construction and operation of generation or parts thereof by the purchasing utility over the term of the contract; calculated in accordance with subsection (4) and paragraph (5)(a) of this rule, providing that the contract is designed to contribute towards the deferral or avoidance of such capacity; or
2. the cummulative present worth of other capacity and energy related costs that the contract is designed to avoid such as fuel, operation and maintenance expenses or alternative purchases of capacity, providing that the contract is designed to avoid such costs; and

(c) to the extent that annual firm capacity and energy payments made to the qualifying facility in any year exceed that year's annual value of deferring the construction and operation of generation by the purchasing utility or other capacity and energy related costs, whether the contract contains provisions to ensure repayment of such payments exceeding that year's value of deferring that capacity in the event that the qualifying facility fails to deliver firm capacity and energy pursuant to the terms and conditions of the contract; provided, however, that provisions to ensure repayment may be based on forecasted data; and

(d) considering the technical reliability, viability and financial stability of the qualifying facility, whether the contract contains provisions to protect the purchasing utility's ratepayers in the event the qualifying facility fails to deliver firm capacity and energy in the amount and times specified in the contract.

(3) Standard Offer Contracts.

(a) Upon petition by a utility or pursuant to a Commission action, each public utility shall submit for Commission approval a tariff or tariffs and a standard offer contract or contracts for the purchase of firm capacity and energy from small qualifying facilities less than 75 megawatts or from solid waste facilities as defined in Rule 25-17.091.

(b) The rates, terms, and other conditions contained in each utility's standard offer contract or contracts shall be based on the need for and equal to the avoided cost of deferring or avoiding the construction of additional generation

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capacity or parts thereof by the purchasing utility. Rates for payment of capacity sold by a qualifying facility shall be specified in the contract for the duration of the contract. In reviewing a utility's standard offer contract or contracts, the Commission shall consider the criteria specified in paragraphs (2)(a) through (2)(d) of this rule, as well as any other information relating to the determination of the utility's full avoided costs.

(c) In lieu of a separately negotiated contract, a qualifying facility under 75 megawatts or a solid waste facility as defined in Rule 25-17.091(1), F.A.C., may accept any utility's standard offer contract. Qualifying facilities which are 75 megawatts or greater may negotiate contracts for the purchase of capacity and energy pursuant to subsection (2). Should a utility fail to negotiate in good faith, any qualifying facility may apply to the Commission for relief pursuant to Rule 25-17.0834, F.A.C.

(d) Within 60 days of receipt of a signed standard offer contract, the utility shall either accept and sign the contract and return it within five days to the qualifying facility or petition the Commission not to accept the contract and provide justification for the refusal. Such petitions may be based on:

1. a reasonable allegation by the utility that acceptance of the standard offer will exceed the subscription limit of the avoided unit or units; or
2. material evidence that because the qualifying facility is not financially or technically viable, it is unlikely that the committed capacity and energy would be made available to the utility by the date specified in the standard offer.

A standard offer contract which has been accepted by a qualifying facility shall apply towards the subscription limit of the unit designated in the contract effective the date the utility receives the accepted contract. If the contract is not accepted by the utility, its effect shall be removed from the subscription limit effective the date of the Commission order granting the utility's petition.

(e) Minimum Specifications. Each standard offer contract shall, at minimum, specify:

1. the avoided unit or units on which the contract is based;
2. the total amount of committed capacity, in megawatts, needed to fully subscribe the avoided unit specified in the contract;
3. the payment options available to the qualifying facility including all financial and economic assumptions necessary to calculate the firm capacity payments available under each payment option and an illustrative calculation of firm capacity payments for a minimum ten year term contract commencing with the in-service date of the avoided unit for each payment option;
4. the date on which the standard contract offer expires. This date shall be at least four years before the anticipated in-service date of the avoided unit or units unless the avoided unit could be constructed in less than four years, or when the subscription limit has been reached;
5. the date by which firm capacity and energy deliveries from the qualifying facility to the utility shall commence. This date shall be no later than the anticipated in-service date of the avoided unit specified in the contract;
6. the period of time over which firm capacity and energy shall be delivered from the qualifying facility to the utility. Firm capacity and energy shall be delivered, at a minimum, for a period of ten years, commencing with the anticipated in-service date of the avoided unit specified in the contract. At a maximum, firm capacity and energy shall be delivered for a period of time equal to the anticipated plant life of the avoided unit, commencing with the anticipated in-service date of the avoided unit;

7. the minimum performance standards for the delivery of firm capacity and energy by the qualifying facility during the utility's daily seasonal peak and off-peak periods. These performance standards shall approximate the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit over the term of the contract;

8. provisions to ensure repayment of payments to the extent that annual firm capacity and energy payments made to the qualifying facility in any year exceed that year's annual value of deferring the avoided unit specified in the contract in the event that the qualifying facility fails to perform pursuant to the terms and conditions of the contract. Such provisions may be in the form of a surety bond or equivalent assurance of repayment of payments exceeding the year-by-year value of deferring the avoided unit specified in the contract.

(f) The Commission may approve contracts that specify:

1. provisions to protect the purchasing utility's ratepayers in the event the qualifying facility fails to deliver firm capacity and energy in the amount and times specified in the contract which may be in the form of an up-front payment, surety bond, or equivalent assurance of payment. Such payment or surety shall be refunded upon completion of the facility and demonstration that the facility can deliver the amount of capacity and energy specified in the contract; and

2. a listing of the parameters, including any impact on electric power transfer capability, associated with the qualifying facility as compared to the avoided unit necessary for the calculation of the avoided cost.

(g) Firm Capacity Payment Options. Each standard offer contract shall also contain, at a minimum, the following options for the payment of firm capacity delivered by the qualifying facility:

1. Value of deferral capacity payments. Value of deferral capacity payments shall commence on the anticipated in-service date of the avoided unit. Capacity payments under this option shall consist of monthly payments escalating annually of the avoided capital and fixed operation and maintenance expense associated with the avoided unit and shall be equal to the value of a year-by-year deferral of the avoided unit, calculated in accordance with paragraph (5)(a) of this rule.

2. Early capacity payments. Each standard offer contract shall specify the earliest date prior to the anticipated in-service date of the avoided unit when early capacity payments may commence. The early capacity payment date shall be an approximation of the lead time required to site and construct the avoided unit. Early capacity payments shall consist of monthly payments escalating annually of the avoided capital and fixed operation and maintenance expense associated with the avoided unit, calculated in conformance with paragraph (5)(b) of the rule. At the option of the qualifying facility, early capacity payments may commence at any time after the specified early capacity payment date and before the anticipated in-service date of the avoided unit provided that the qualifying facility is delivering firm capacity and energy to the utility. Where early capacity payments are elected, the cumulative present value of the capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule.

3. Levelized capacity payments. Levelized capacity payments shall commence on the anticipated in-service date of the avoided unit. The capital portion of capacity payments under this option shall consist of equal monthly payments over the term of the contract, calculated in conformance with paragraph (5)(c) of this rule. The fixed operation and maintenance portion of capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expense associated with the avoided unit calculated in conformance with paragraph (5)(a) of this rule. Where levelized capacity payments are elected, the cumulative present value of the levelized capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule, value of deferral capacity payments.

4. Early levelized capacity payments. Each standard offer contract shall specify the earliest date prior to the anticipated in-service date of the avoided unit when early levelized capacity payments may commence. The early capacity payment date shall be an approximation of the lead time required to site and construct the avoided unit. The capital portion of capacity payments under this option shall consist of equal monthly payments over the term of the contract, calculated in conformance with paragraph (5)(c) of this rule. The fixed operation and maintenance expense shall be calculated in conformance with paragraph (5)(b) of this rule. At the option of the qualifying facility, early levelized capacity payments shall commence at any time after the specified early capacity date and before the anticipated in-service date of the avoided unit provided that the qualifying facility is delivering firm capacity and energy to the utility. Where early levelized capacity payments are elected, the cumulative present value of the capacity payments made to the qualifying facility over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qualifying facility had such payments been made pursuant to subparagraph (3)(g)1 of this rule.

(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.

(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, the avoided energy costs shall be the as-available avoided energy cost of the purchasing utility. During the periods 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).

(c) The energy cost of the avoided unit specified in the contract shall be defined as the cost of fuel, in cents per kilowatt-hour, which would have been burned at the avoided unit plus variable operation and maintenance expense plus avoided line losses. The cost of fuel shall be calculated as the average market price of fuel, in cents per million Btu, associated with the avoided unit multiplied by the average heat rate associated with the avoided unit. The variable operating and maintenance expense shall be estimated based on the unit fuel type and technology of the avoided unit.

(5) Calculation of standard offer contract firm capacity payment options.

(a) Calculation of year-by-year value of deferral. The year-by-year value of deferral of an avoided unit shall be the difference in revenue requirements associated with deferring the avoided unit one year and shall be calculated as follows:

$$VAC_m = \frac{1}{12}\left[KI_n \left[\frac{1 - \frac{(1 \bullet ip)}{(1 + r)^L}}{1 - \frac{(1 + ip)^L}{(1 + r)^L}} \right] + O_n \right]$$

Where, for a one year deferral:

VAC_m = utility's monthly value of avoided capacity, in dollars per kilowatt per month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

I_n = total direct and indirect cost, in mid-year dollars per kilowatt including AFUDC but excluding CWIP, of the avoided unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the avoided unit that would have been paid had the avoided unit been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year, of the avoided unit;

i_p = annual escalation rate associated with the plant cost of the avoided unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the avoided unit(s);

r = annual discount rate, defined as the utility's incremental after tax cost of capital;

L = expected life of the avoided unit; and

n = year for which the avoided unit is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm energy and capacity.

(b) Calculation of early capacity payments. Monthly early capacity payments shall be calculated as follows:

$$A_m = A_c \frac{(1 + ip)^{(m-1)}}{12} + A_o \frac{(1 + io)^{(m-1)}}{12} \quad \text{for } m=1 \text{ to } t$$

Where: A_m = monthly early capacity payments to be made to the qualifying facility for each month of the contract year n, in dollars per kilowatt per month;

i_p = annual escalation rate associated with the plant cost of the avoided unit;

i_o = annual escalation note associated with the operation and maintenance expense of the avoided unit(s);

m = year for which early capacity payments to a qualifying facility are made, starting in year one and ending in the year t;

t = the term, in years, of the contract for the purchase of firm capacity;

$$A_C = F \left[\frac{1 - \dfrac{(1 + ip)}{(1 + r)}}{1 - \left(\dfrac{(1 + ip)}{(1 + r)}\right)^t} \right]$$

Where: F = the cumulative present value in the year that the contractual payments will begin, of the avoided capital cost component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the avoided unit(s); and

r = annual discount rate, defined as the utility's incremental after tax cost of capital; and.

$$A_O = G \left[\frac{1 - \dfrac{(1 + io)}{(1 + r)}}{1 - \left(\dfrac{(1 + io)}{(1 + r)}\right)^t} \right]$$

Where: G = The cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the avoided unit.

(c) Levelized and early levelized capacity payments. Monthly levelized and early levelized capacity payments shall be calculated as follows:

$$P_L = \frac{F}{12} \times \frac{r}{1-(1+r)^{-t}} + O$$

Where: P_L = the monthly levelized capacity payment, starting on or prior to the in-service date of the avoided unit;

F = the cumulative present value, in the year that the contractual payments will begin, of the avoided capital cost component of the capacity payments which would have been made had the capacity payments not been levelized;

r = the annual discount rate, defined as the utility's incremental after tax cost of capital; and

t = the term, in years, of the contract for the purchase of firm capacity.

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with paragraph (5)(a) for levelized capacity payments or with paragraph (5)(b) for early levelized capacity payments.

(6) Sale of Excess Firm Energy and Capacity. To the extent that firm energy and capacity purchased from a qualifying facility pursuant to a standard offer contract or an individually negotiated contract is not needed by the purchasing utility, these rules shall be construed to encourage the

purchasing utility to sell all or part of the energy and capacity to the utility in need of energy and capacity at a mutually agreed upon price which is cost effective to the ratepayers.

(7) Upon request by a qualifying facility or any interested person, each utility shall provide within 30 days its most current projections of its future generation mix including type and timing of anticipated generation additions, and at least a 20-year projection of fuel forecasts, as well as any other information reasonably required by the qualifying facility to project future avoided cost prices. The utility may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

(8)(a) Firm energy and capacity payments made to a qualifying facility pursuant to a separately negotiated contract shall be recoverable by a utility through the Commission's periodic review of fuel and purchased power costs if the contract is found to be prudent in accordance with subsection (2) of this rule.

(b) Upon acceptance of the contract by both parties, firm energy and capacity payments made to a qualifying facility pursuant to a standard offer contract shall be recoverable by a utility through the Commission's periodic review of fuel and purchased power costs.

(c) Firm energy and capacity payments made pursuant to a standard offer contract signed by the qualifying facility, for which the utility has petitioned the Commission to reject, is recoverable through the Commission's periodic review of fuel and purchased power costs if the Commission requires the utility to accept the contract because it satisfies subsection (3) of this rule.

Specific Authority: 350.127, 366.04(1), 366.051, 366.05(8), F.S.
Law Implemented: 366.051, 403.503, F.S.
History: New 10/25/90.

25-17.0833 Planning Hearings.

(1) Upon petition or on its own motion, the Commission shall periodically review optimal generation and transmission plans from a statewide and individual utility perspective. In connection with these proceedings, the Commission shall consider the need for capacity from both a statewide and individual utility perspective, the adequacy of the transmission grid, and other strategic planning concerns affecting the Florida electric grid.

(2) Upon petition, or on its own motion, the Commission, as needed, shall review individual utility generation and expansion plans at any time.

Specific Authority: 366.05(8), 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.0834 Settlement of Disputes in Contract Negotiations.

(1) Public utilities shall negotiate in good faith for the purchase of capacity and energy from qualifying facilities and interconnection with qualifying facilities. In the event that a utility and a qualifying facility cannot agree on the rates, terms, and other conditions for the purchase of capacity and energy, either party may apply to the Commission for relief. Qualifying facilities may petition the Commission to order a utility to sign a contract for the purchase of capacity and energy which does not exceed a utility's full avoided costs as defined in 366.051, Florida Statutes, should the Commission find that the utility failed to negotiate in good faith.

(2) To the extent possible, the Commission will dispose of an application for relief within 90 days of the filing of a petition by either a utility or a qualifying facility.

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(3) If the Commission finds that a utility has failed to negotiate or deal in good faith with qualifying facilities, or has explicitly dealt in bad faith with qualifying facilities, it shall impose an appropriate penalty on the utility as approved by section 350.127, Florida Statutes.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.0835 Wheeling.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), 366.055(3), F.S.
History: New 9/4/83, repealed 10/4/85, formerly 25-17.835.

25-17.084 The Utility's Obligation to Sell.
Upon compliance with Rule 25-17.087, each utility shall sell energy to qualifying facilities at rates which are just, reasonable, and non-discriminatory.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, amended 9/4/83, formerly 25-17.84.

25-17.085 Reserved.

25-17.086 Periods During Which Purchases are not Required.
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. The utility shall notify the qualifying facility(ies) prior to the instance giving rise to those conditions, if practicable. If prior notice is not practicable, the utility shall notify the qualifying facility(ies) as soon as practicable after the fact. In either event the utility shall notify the Commission, and the Commission staff shall, upon request of the affected qualifying facility(ies), investigate the utility's claim. Nothing in this section shall operate to relieve the utility of its general obligation to purchase pursuant to Rule 25-17.082.
Specific Authority: 366.05(9), 350.127(2), F.S.
Law Implemented: 366.05(9), F.S.
History: New 5/13/81, Amended 9/4/83, formerly 25-17.86.

25-17.087 Interconnection and Standards.
(1) Each utility shall interconnect with any qualifying facility which:
(a) is in its service area;
(b) requests interconnection;
(c) agrees to meet system standards specified in this rule; (d) agrees to pay the cost of interconnection; and
(e) signs an interconnection agreement.
(2) Nothing in this rule shall be construed to preclude a utility from evaluating each request for interconnection on its own merits and modifying the general standards specified in this rule to reflect the result of such an evaluation.
(3) Where a utility refuses to interconnect with a qualifying facility or attempts to impose unreasonable standards pursuant to subsection (2) of this rule, the qualifying facility may petition the Commission for relief. The utility shall have the burden of demonstrating to the Commission why

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interconnection with the qualifying facility should not be required or that the standards the utility seeks to impose on the qualifying facility pursuant to subsection (2) are reasonable.

(4) Upon a showing of credit worthiness, the qualifying facility shall have the option of making monthly installment payments over a period no longer than 36 months toward the full cost of interconnection. However, where the qualifying facility exercises that option the utility shall charge interest on the amount owing. The utility shall charge such interest at the 30-day commercial paper rate. In any event, no utility may bear the cost of interconnection.

(5) Application for Interconnection. A qualifying facility shall not operate electric generating equipment in parallel with the utility's electric system without the prior written consent of the utility. Formal application for interconnection shall be made by the qualifying facility prior to the installation of any generation related equipment. This application shall be accompanied by the following:

(a) Physical layout drawings, including dimensions;

(b) All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;

(c) Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the proposed system and to be able to make a coordinated system;

(d) Power requirements in watts and vars;

(e) Expected radio-noise, harmonic generation and telephone interference factor;

(f) Synchronizing methods; and

(g) Operating/instruction manuals.

Any subsequent change in the system must also be submitted for review and written approval prior to actual modification. The above mentioned review, recommendations and approval by the utility do not relieve the qualifying facility from complete responsibility for the adequate engineering design, construction and operation of the qualifying facility equipment and for any liability for injuries to property or persons associated with any failure to perform in a proper and safe manner for any reason.

(6) Personnel Safety. Adequate protection and safe operational procedures must be developed and followed by the joint system. These operating procedures must be approved by both the utility and the qualifying facility. The qualifying facility shall be required to furnish, install, operate and maintain in good order and repair, and be solely responsible for, without cost to the utility, all facilities required for the safe operation of the generation system in parallel with the utility's system.

The qualifying facility shall permit the utility's employees to enter upon its property at any reasonable time for the purpose of inspection and/or testing the qualifying facility's equipment, facilities, or apparatus. Such inspections shall not relieve the qualifying facility from its obligation to maintain its equipment in safe and satisfactory operating condition.

The utility's approval of isolating devices used by the qualifying facility will be required to ensure that these will comply with the utility's switching and tagging procedure for safe working clearances.

(a) Disconnect Switch. A manual disconnect switch, of the visible load break type, to provide a separation point between the qualifying facility's generation system and the utility's system, shall be required. The utility will specify the location of the disconnect switch. The switch shall be mounted separate from the meter socket and shall be readily accessible to the utility and be capable of being locked in the open position with a utility padlock. The utility may reserve the right to open the switch (i.e. isolating the qualifying facility's generation system) without prior notice to the qualifying facility. To the extent practicable, however, prior notice shall be given.

Any of the following conditions shall be cause for disconnection:

1. Utility system emergencies and/or maintenance requirements;
2. Hazardous conditions existing on the qualifying facility's generating or protective equipment as determined by the utility;
3. Adverse effects of the qualifying facility's generation to the utility's other electric consumers and/or system as determined by the utility;
4. Failure of the qualifying facility to maintain any required insurance; or
5. Failure of the qualifying facility to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the qualifying facility's electric generating equipment or the operation of such equipment.

(b) Responsibility and Liability. The utility and the qualifying facility shall each be responsible for its own facilities. The utility and the qualifying facility shall each be responsible for ensuring adequate safeguards for other utility customers, utility and qualifying facility personnel and equipment, and for the protection of its own generating system. The utility and the qualifying facility shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

1. Any act or omission by a party or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;
2. Any defect in, failure of, or fault related to a party's generation system;
3. The negligence of a party or negligence of that party's contractors, agents servants and employees; or
4. Any other event or act that is the result of, or proximately caused by, a party.

For the purposes of this subsection, the term party shall mean either utility or qualifying facility, as the case may be.

(c) Insurance. The qualifying facility shall deliver to the utility, at least fifteen days prior to the start of any interconnection work, a certificate of insurance certifying the qualifying facility's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the qualifying facility as named insured, and the utility as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the qualifying facility, or caused by operation of any of the qualifying facility's equipment or by the qualifying facility's failure to maintain the qualifying facility's equipment in satisfactory and safe operating condition.

The policy providing such coverage shall provide public liability insurance, including property damage, in an amount not less than $300,000 for each occurrence; more insurance may be required as deemed necessary by the utility. In addition, the above required policy shall be endorsed with a provision whereby the insurance company will notify the utility thirty days prior to the effective date of cancellation or material change in the policy.

The qualifying facility shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the utility.

(7) Protection and Operation. It will be the responsibility of the qualifying facility to provide all devices necessary to protect the qualifying facility's equipment from damage by the abnormal conditions and operations which occur on the utility system that result in interruptions and restorations of service by the utility's equipment and personnel. The qualifying facility shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault condition), open circuits, phase unbalance and reversal, over or under frequency condition, and other injurious electrical conditions that may arise on the utility's system and any reclose attempt by the utility.

The utility may reserve the right to perform such tests as it deems necessary to ensure safe and efficient protection and operation of the qualifying facility's equipment.

(a) Loss of Source: The qualifying facility shall provide, or the utility will provide at the qualifying facility's expense, approved protective equipment necessary to immediately, completely, and automatically disconnect the qualifying facility's generation from the utility's system in the event of a fault on the qualifying facility's system, a fault of the utility's system, or loss of source on the utility's system. Disconnection must be completed within the time specified by the utility in its standard operating procedure for its electric system for loss of a source on the utility's system.

This automatic disconnecting device may be of the manual or automatic reclose type and shall not be capable of reclosing until after service is restored by the utility. The type and size of the device shall be approved by the utility depending upon the installation. Adequate test data or technical proof that the device meets the above criteria must be supplied by the qualifying facility to the utility. The utility shall approve a device that will perform the above functions at minimal capital and operating costs to the qualifying facility.

(b) Coordination and Synchronization. The qualifying facility shall be responsible for coordination and synchronization of the qualifying facility's equipment with the utility's electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the utility's system.

(c) Electrical Characteristics. Single phase generator interconnections with the utility are permitted at power levels up to 20 KW. For power levels exceeding 20 KW, a three phase balanced interconnection will normally be required. For the purpose of calculating connected generation, 1 horsepower equals 1 kilowatt. The qualifying facility shall interconnect with the utility at the voltage of the available distribution or the transmission line of the utility for the locality of the interconnection, and shall utilize one of the standard connections (single phase, three phase, wye, delta) as approved by the utility.

The utility may reserve the right to require a separate transformation and/or service for a qualifying facility's generation system, at the qualifying facility's expense. The qualifying facility shall bond all neutrals of the qualifying facility's system to the utility's neutral, and shall install a separate driven ground with a resistance value which shall be determined by the utility and bond this ground to the qualifying facility's system neutral.

(d) Exceptions. A qualifying facility's generator having a capacity rating that can:

1. produce power in excess of 1/2 of the minimum utility customer requirements of the interconnected distribution or transmission circuit; or
2. produce power flows approaching or exceeding the thermal capacity of the connected utility distribution or transmission lines or transformers; or
3. adversely affect the operation of the utility or other utility customer's voltage, frequency or overcurrent control and protection devices; or
4. adversely affect the quality of service to other utility customers; or
5. interconnect at voltage levels greater than distribution voltages,

will require more complex interconnection facilities as deemed necessary by the utility.

(8) Quality of Service. The qualifying facility's generated electricity shall meet the following minimum guidelines:

(a) Frequency. The governor control on the prime mover shall be capable of maintaining the generator output frequency within limits for loads from no-load up to rated output. The limits for frequency shall be 60 hertz (cycles per second), plus or minus an instantaneous variation of less than 1%.

(b) Voltage. The regulator control shall be capable of maintaining the generator output voltage within limits for loads from no-load up to rated output. The limits for voltage shall be the nominal operating voltage level, plus or minus 5%.

(c) Harmonics. The output sine wave distortion shall be deemed acceptable when it does not have a higher content (root mean square) of harmonics than the utility's normal harmonic content at the interconnection point.

(d) Power Factor. The qualifying facility's generation system shall be designed, operated and controlled to provide reactive power requirements from 0.85 lagging to 0.85 leading power factor. Induction generators shall have static capacitors that provide at least 85% of the magnetizing current requirements of the induction generator field. (Capacitors shall not be so large as to permit self-excitation of the qualifying facility's generator field).

(e) DC Generators. Direct current generators may be operated in parallel with the utility's system through a synchronous invertor. The inverter must meet all criteria in these rules.

(9) Metering. The actual metering equipment required, its voltage rating, number of phases, size, current transformers, potential transformers, number of inputs and associated memory is dependent on the type, size and location of the electric service provided. In situations where power may flow both in and out of the qualifying facility's system, power flowing into the qualifying facility's system will be measured separately from power flowing out of the qualifying facility's system.

The utility will provide, at no additional cost to the qualifying facility, the metering equipment necessary to measure capacity and energy deliveries to the qualifying facility. The utility will provide, at the qualifying facility's expense, the necessary additional metering equipment to measure energy deliveries by the qualifying facility to the utility.

(10) Cost Responsibility. The qualifying facility is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers, lines, services, meters, switches, and associated equipment and devices beyond that which would be required to

provide normal service to the qualifying facility if the qualifying facility were a non-generating customer. These costs shall be paid by the qualifying facility to the utility for all material and labor that is required. Prior to any work being done by the utility, the utility shall supply the qualifying facility with a written cost estimate of all its required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to the qualifying facility within 60 days after the qualifying facility supplies the utility with its final electrical plans. The utility shall also provide project timing and feasibility information to the qualifying facility.

(11) Each utility shall submit to the Commission, a standard agreement for interconnection by qualifying facilities as part of their standard offer contract or contracts required by Rule 25-17.0832(3).
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 9/4/83, formerly 25-17.87, Amended 10/25/90.

25-17.088 Transmission Service for Qualifying Facilities.
Specific Authority: 350.127(2), 366.051, F.S.
Law Implemented: 366.051, 366.04(3), 366.055(3), F.S.
History: New 10/4/85, formerly 25-17.88, Amended 2/3/87, Repealed 10/25/90.

25-17.0882 Transmission Service Not Required for Self-Service.
Specific Authority: 350.127(2), 366.05(1), F.S.
Law Implemented: 366.05(9), 366.04(3), 366.055(3), F.S.
History: New 10/4/85, formerly 25-17.882, Repealed 10/25/90.

25-17.0883 Conditions Requiring Transmission Service for Self-service.

Public utilities are required to provide transmission and distribution services to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when the provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers. The determination of whether transmission service for self service is likely to result in higher cost electric service may be made using cost effectiveness methodology employed by the Commission in evaluating conservation programs of the utility, adjusted as appropriate to reflect the qualifying facility's contribution to the utility for standby service and wheeling charges, other utility program costs, the fact that qualifying facility self-service performance can be precisely metered and monitored, and taking into consideration the unique load characteristics of the qualifying facility compared to other conservation programs.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, F.S.
History: New 10/25/90.

25-17.089 Transmission Service for Qualifying Facilities.

(1) Upon request by a qualifying facility, each electric utility in Florida shall provide, subject to the provisions of subsection (3) of this rule, transmission service to wheel as-available energy or firm energy and capacity produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

(2) The rates, terms, and conditions for transmission services as described in subsection (1) and in Rule 25-17.0883 which are provided by an investor-owned utility shall be those approved by the Federal Energy Regulatory Commission.

(3) An electric utility may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non- discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the utility's general body of retail and wholesale customers.
Specific Authority: 366.051, 350.127(2), F.S.
Law Implemented: 366.051, 366.055(3), F.S.
History: New 10/25/90.

25-17.090 Reserved.

25-17.091 Governmental Solid Waste Energy and Capacity.

(1) Definitions and Applicability:

(a) "Solid Waste Facility" means a facility owned or operated by, or on behalf of, local government, the purpose of which is to dispose of solid waste, as that term is defined in section 403.703(13), Fla. Stat. (1988), and to generate electricity.

(b) A facility is owned by or operated on behalf of a local government if the power purchase agreement is between the local government and the electric utility.

(c) A solid waste facility shall include a facility which is not owned or operated by a local government but is operated on its behalf. When the power purchase agreement is between a non-governmental entity and an electric utility, the facility is operated by a private entity on behalf of a local government if:

1. One or more local governments have entered into a long-term agreement with the private entity for the disposal of solid waste for which the local governments are responsible and that agreement has a term at least as long as the term of the contract for the purchase of energy and capacity from the facility; and
2. The Commission determines there is no undue risk imposed on the electric ratepayers of the purchasing utility, based on:
   a. The local government's acceptance of responsibility for the private entity's performance of the power purchase contract, or
   b. Such other factors as the Commission deems appropriate, including, without limitation, the issuance of bonds by the local government to finance all, or a substantial portion, of the costs of the facility; the reliability of the solid waste technology; and the financial capability of the private owner and operator.
3. The requirements of subparagraph 2 shall be satisfied if a local government described in subparagraph 1 enters into an agreement with the purchasing utility providing that in the event of a default by the private entity under the power purchase contract, the local government shall perform the private entity's obligations, or cause them to be performed, for the remaining term of the contract, and shall not seek to renegotiate the power purchase contract.

(d) This rule shall apply to all contracts for the purchase of energy or capacity from solid waste facilities entered into, or renegotiated as provided in subsection (3), after October 1, 1988.

(2) Except as provided in subsections (3) and (4) of this rule, the provisions of Rules 25-17.080 - 25-17.089, Florida Administrative Code, are applicable to contracts for the purchase of energy and capacity from a solid waste facility.

(3) Any solid waste facility which has an existing firm energy and capacity contract in effect before October 1, 1988, shall have a one-time option to renegotiate that contract to incorporate any or all of the provisions of subsection (2) and (4) into their contract. This renegotiation shall be based on the unit that the contract was designed to avoid but applying the most recent Commission-approved cost estimates of Rule 25-17.0832(5)(a), Florida Administrative Code, for the same unit type and in-service year to determine the utility's value of avoided capacity over the remaining term of the contract.

(4) Because section 377.709(4), Fla. Stat., requires the local government to refund early capacity payments should a solid waste facility be abandoned, closed down or rendered illegal, a utility may not require risk-related guarantees as required in Rule 25-17.0832, paragraph (2)(c), (2)(d), (3)(e)8, and (3)(f)1. However, at its option, a solid waste facility may provide such risk related guarantee.

(5) Nothing in this rule shall preclude a solid waste facility from electing advance capacity payments authorized pursuant to section 377.709(3)(b), F.S., which advanced capacity payments shall be in lieu of firm capacity payments otherwise authorized pursuant to this rule and Rule 25-17.0832, F.A.C. The provisions of subsection (4) are applicable to solid waste facilities electing advanced capacity payments.

Specific Authority: 350.127(2), 377.709(5), F.S.
Law Implemented: 366.051, 366.055(3), 377.709, F.S.
History: New 8/8/85, formerly 25-17.91, Amended 4/26/89, 10/25/90.

APPENDIX 5

STANDARD & POOR'S

REPRINT

CREDITWEEK

THE AUTHORITY ON CREDIT QUALITY

MAY 24, 1993

BUY VERSUS BUILD DEBATE REVISITED

"Regardless of whether a utility buys or builds, adding capacity means incurring risk."

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

Table 1
Determining the risk factor

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks.

Market	Need for power Economics
Operating	Performance standards Reliability Dispatchability Control over maintenance Flexibility and diversity
Regulatory	Preapproval Regulatory recovery mechanisms Regulatory out clause

BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover, purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

Nevertheless, in the buy-versus-build debate is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the unfortunate baseload program of the 1970s and early 1980s. A utility could:

- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.

PURCHASES ARE NOT RISK-FREE

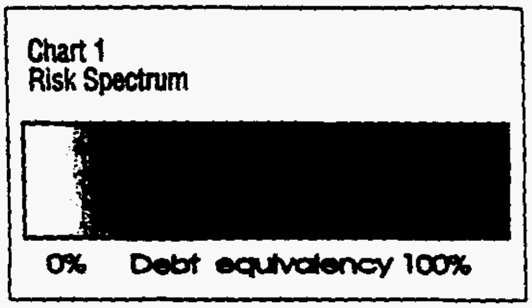
Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed

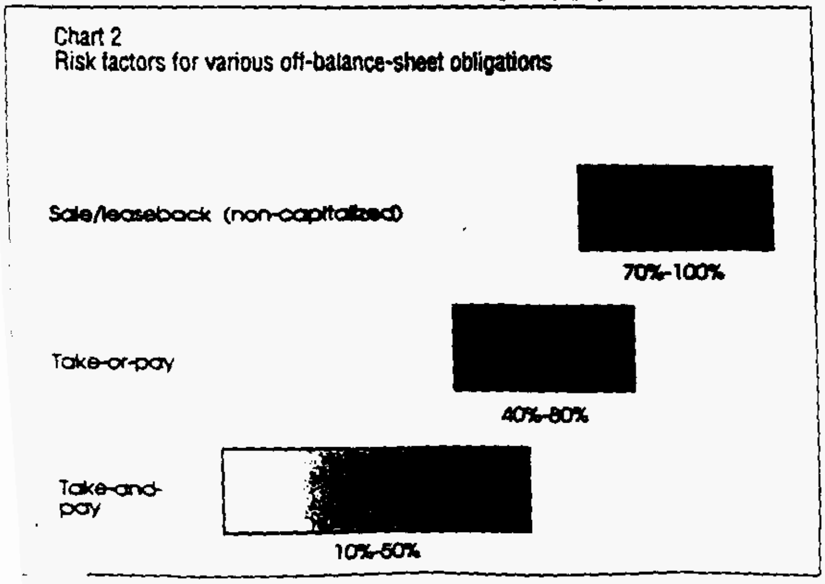
CREDIT COMMENT

charges reduce a utility's financial flexibility, and long-term contractual arrangements represent—at least in part—off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion: the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.



In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&P will estimate the capacity payment.



S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum *(see chart 1)*. A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks *(see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale)*. Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific purchase of expensive nuclear capacity under a firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary *(see table 1 for some of the key factors under each broad risk category)*. Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

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Lower risk factors would be appropriate if:

- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller.

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor.

ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at $115 million in 1993, rise by $5 million per year to $135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is $1.3 billion.

Table 2
ABC Power Co. adjustment to capital structure
(Mil. $ at year-end 1992)

	Original capital structure $	Original capital structure %	Adjusted capital structure $	Adjusted capital structure %	
Debt	1,400	54	1,400	49	} 58
Adjustment to debt	—	—	265	9	
Preferred stock	200	8	200	7	
Common equity	1,000	38	1,000	35	

Table 3
ABC Power Co. adjustment to pretax interest coverage
(Mil. $ year-end 1992)

		Orig. pretax int. cov.			Adj. pretax int. cov.
Net income	120			300	
Income taxes	65	300		+27	
Interest expense	115	115	= 2.6x	115	= 2.3x
Pretax available	300			+27	

Interest associated with adjusted debt = $265 million x 10%

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of $265 million. The risk factor is chosen based on qualitativ analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes $265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of $1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the $265 million debt adjustment is multiplied by a 10% interest rate to arrive at $27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses.

The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buy-versus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position.

Curtis Moulton
(212) 208-1651

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APPENDIX 6

3UY VS. BUILD: LET'S BALANCE THE INCENTIVES

BY SUSAN STRATTON MORSE

Don't overstate the risks or ignore the benefits of urchases from ■dependents, particularly given today's state-of-the-art contracting techniques. And don't regulate when market mechanisms are already working

SUSAN STRATTON MORSE IS ECUTIVE VICE PRESIDENT OF ...RSE RICHARD WEISENMILLER & ASSOCIATES OF OAKLAND, CALIF

Buy or build? Utilities, credit rating agencies, state regulators, and independent power producers are all weighing in on what has become one of the hot topics of our industry.

The debate began when the credit-rating agencies started to take a closer look at utility power purchases from independent producers to determine to what extent, if any, long-term purchase contracts were "debt equivalents" that could impair a utility's credit rating. Now, regulators in each of the 50 states are considering the question as a result of Section 712 of the Energy Policy Act of 1992. Section 712 requires state regulatory commissions to examine the following:

1. The impact of purchase power contracts on a utility's cost of capital and retail rates
2. Whether debt leveraging used by IPPs provides them an unfair advantage over utilities or threatens system reliability
3. Whether regulators should preapprove power purchase contracts
4. Whether regulators should require assurances of adequate fuel supplies

California, New York, Michigan, Texas, Iowa, Alabama, Pennsylvania, Oregon, and other states have initiated proceedings to address these issues.

What does this mean for the independent power industry? IPPs, lenders, and investors have a stake in the debate, as the outcome is likely to have a significant impact on the pricing, terms, and financeability of future IPPs. It may also determine how purchases from independent power producers are priced and compared to utility-owned resources, and it may limit a project developer's flexibility in structuring project contracts and arranging project financing.

History has shown us that utilities are capable of pursuing both good and bad build strategies, as well as good and bad buy strategies. In my view, there are no inherent advantages to either option. It all depends on how the buying or building is done.

As the debate continues, my advice is: First, don't overstate the risks or ignore the benefits of purchases from independents, particularly given today's state-of-the-art contracting techniques. Second, don't regulate when market mechanisms are already working in the ratepayer's interest. And third, don't substitute a regulatory fix, such as an incentive mechanism, without carefully understanding the implications. Below, I've highlighted what I see as some of the more important issues to consider as the debate moves forward.

COST OF CAPITAL. The cost of capital issue comes down to a debate over the perceived risks and benefits of a purchase strategy compared to the risks and benefits of the build (or DSM) alternative. For regulators, the question becomes, "If there are risks in purchasing, can these be mitigated through contract terms and/or regulatory treatment?" I believe the answer is yes.

PERCEIVED RISKS. Long-term, take-and-pay purchased power contracts with independents may expose the utility to some risk, essentially (1) demand or market risk and (2) regulatory disallowance risk. The extent to which these risks are borne by utility shareholders and bondholders has generally been overstated. Many of the risks in purchased power can be eliminated through the terms of the contract (termination provisions, dispatchability, indexed pricing, etc.) and through the regulatory process, including, for example,

If there are risks in purchasing, can these be mitigated through contract terms and/or regulatory treatment?

integrated resource planning, competitive bidding, and preapproval of contracts through a streamlined process. In practice, competitive-bidding programs across the nation have shown us that utilities have become more sophisticated in their contracting techniques and have had no difficulty soliciting attractive offers from reputable developers.

OVERLOOKED BENEFITS. Cost-of capital proceedings that examine purchased power often ignore, or at least largely overlook, the less quantifiable benefits (for both ratepayers and shareholders) of a well-designed purchase program: system diversity (fuel type, plant size), avoidance of development and construction risks and costs, avoidance of the need to access the capital markets (preserving the credit of the existing capital structure), and, perhaps most importantly, the potential to improve a utility's competitive position through reduced costs and improved reliability and flexibility. All of the credit rating agencies recognize there are benefits to a purchase strategy that can improve a utility's financial strength.

The extent to which market risk and regulatory disallowance risk are borne by utility shareholders and bondholders has generally been overstated

DEBT LEVERAGE. Utilities often argue that relatively high debt leverage by IPPs is possible because risk is borne by the utility. High debt leverage does not necessarily mean high risk, however. As a lender to the IPP industry for over 10 years, I can say that high leverage is possible when risks have been allocated to reliable and creditworthy fuel suppliers, construction contractors, operators, insurance companies, and other suppliers, as well as a creditworthy purchaser.

The degree of debt leverage and the resulting cost of capital in a project financing represents the capital market's determination of the extent to which the project developer has managed, controlled, and mitigated risks. If the developer can allocate these risks to its suppliers and contractors and can still provide reliable power at a cost below what the utility would have incurred had it built, then utility ratepayers, bondholders, and stockholders all benefit.

RELIABILITY. I have seen no evidence that projects with relatively higher debt leverage have poorer reliability or availability records. Project financings are very tightly controlled through covenants and restrictive language in the financing documents in order to preserve the viability of the project over the long term. Further, security agreements are structured to allow the lender to keep the project running should the owner of the project get into financial difficulties. In the absence of serious technical difficulties, project abandonment is remote.

The capital market has demonstrated its ability to "regulate" the amount of leverage used in project financings according to the market's assessment of risk. Oversight or imposition of debt limits by utility regulators would add another level of control that is not needed.

The financial markets also serve to "regulate" fuel supply arrangements for IPPs. Lenders and equity investors scrutinize fuel supply and transport agreements and the quality of the contracting parties in painstaking detail to be sure that fuel price and supply risks are allocated efficiently. Further scrutiny by regulators adds a layer of review that is not needed and could be costly.

THE NEXT STEP. The debate is now broadening from the relative risks and benefits of building and buying to how to best motivate utility managements to procure the least costly, most reliable resources for their ratepayers. At one level, utility managements have an incentive to build rather than buy, regardless of the relative merits of each.

Under traditional return-on-rate-base ratemaking, the primary way management grows earnings is by investing new capital on which a return can be earned. On the generation side, this means building new plants. On the buy side, should management and utility shareholders be rewarded for pursuing a purchase strategy? Perhaps. If the strategy benefits ratepayers, almost certainly.

Faced with the existing regulatory framework, IPPs may take a "Just-Do-It" position on incentives and return adjustments. In my view, however, there are three challenges associated with utilities earning a return on purchased power:

- Utility management should be given incentives to operate so as to provide low-cost, reliable power, no matter what the source of that power. Calculating the appropriate incentive level would be difficult.
- As rating agencies and the financial community continue to evaluate the risks and benefits of purchasing vs. building, stock and bond prices should reflect these risks. ROE or capital structure adjustments imposed by regulators may result in double counting.
- Mechanisms for earning a return on purchased power must not tilt the playing field further toward a preference for building. Specifically, incentive mechanisms and comparisons between costs of building and costs of purchasing should reflect the risks of each strategy, not just the risks of purchased power. There have been proposals to penalize IPPs in their power supply bids by adding a cost factor to the IPP's bid to "reflect the burden of debt equivalence." When a utility-built option is competing against purchase options, certainly the incremental cost of issuing new debt and equity to build should be included in the build "bid price," reflecting all the risks associated with a build program.

All of the credit-rating agencies recognize there are benefits to a purchase strategy that can improve a utility's financial strength

These challenges are ahead of us. As we go forward in this transitional period from regulated monopolies to competitive resource procurement, we need to make sure that we have a means of balancing incentives so that all resource options are considered on a basis that fully recognizes each resource' unique benefits and costs.

APPENDIX 7

PURCHASED POWER

AREAS OF EXPOSURE

There are two basic areas of exposure; Cogeneration Power Purchases and Interchange Power Purchases. FERC Reg 35.14, and prior FERC Audit rulings state the process to be used in the Wholesale Fuel Adjustment Clause. Each area is specifically identified and addressed. Below is a summary of 35.14 and the Audit Rulings as it relates to these areas:

COGENERATION PURCHASED POWER

FERC 35.14 (2)(ii):

* **Actual identifiable fossil and nuclear fuel costs associated with the purchase. Estimates can be used by taking the actual cogen heat rate and the published tariffs of the fuel suppliers of the cogenerator.**

FERC 35.14 (2)(iii):

* **Total cost of the purchase is less than the TOTAL AVOIDED VARIABLE COSTS that would have been incurred by the buyer had a particular purchase not been made.**

INTERCHANGE PURCHASE POWER

FERC 35.14 (a)(11)(i):

* Definition of Economic Power is power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the buyers total avoided variable cost.

* Energy costs, apart from fuel costs, of power purchased on an economic dispatch basis which did not displace available reserve capacity.

* Energy costs of purchase power, which replaced power unavailable because of a scheduled outage, should not exceed the energy costs of the replaced power.

FERC order 352, docket no RM83-62-000, superceeded by
FERC order 529, 55 FR 47321, dated Nov. 13, 1990:

* Order 352 states that purchase power costs can be put into Wholesale fuel if two conditions are met.....total cost is less than the buyer's total avoided variable cost, and the purpose of the purchase must be solely to displace higher cost generation. The second condition excludes from automatic recovery purchases made to maintain reserve levels or other wise cure a capacity deficiency.

  FERC order 529 superceeds 352 and discusses reserve issues and reliability levels.....Legal counsel should be consulted on this item.

Purchased Power Costs/Co-Generation

Cost of Cogeneration and Small Power Purchases Included in Wholesale Fuel Adjustment Clause (FAC)

The Company improperly included the entire energy cost component of purchased power from cogeneration and small power producers in wholesale fuel adjustment clause billings.

The Company included the entire energy cost component related to the above purchases as a component of fuel cost in the computation of fuel adjustment clause (FAC) billings to wholesale customers. The Company considered that all purchases under these contracts were made under economic dispatch basis because the pricing of energy is based on marginal cost analysis using a production cost simulation model. The Company also included the energy payments to cogenerators and small power producers in the base cost of fuel in wholesale rate filings. The Company did not request specific Commission approval to recover the above mentioned costs from wholesale customers through fuel adjustment clause billings.

Special Condition 9, Fuel Cost Adjustment, paragraphs b(2) and b(3) of the Company's wholesale rate schedule defines the cost components of purchased power recoverable through FAC billings as follows:

> b(2) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in Paragraph b(3)...below...
>
> b(3) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy...

The Division of Audits concluded that the Company's approved wholesale fuel adjustment clause (Special Condition 9, Fuel Cost Adjustment, paragraph b(2)) allows only the actual identifiable fossil fuel component of energy purchased from cogenerators.

The Company was required to (1) revise procedures to include only the actual identifiable fossil fuel associated with purchase power from cogenerators and small power producers in future wholesale fuel adjustment clause calculations, or in the event such information is not directly available from the sellers, use a computed amount of fuel based upon factors derived for actual heat rates furnished by cogenerator and the published tariffs of the fuel suppliers of the cogenerator, and (2) recompute monthly FAC billings to all wholesale customers since January 1, 1982 by including only the actual identifiable fossil fuel costs associated with purchase power from cogenerators and small power producers in the computations, or in the event such information is not directly available from the sellers, use a computed amount of fuel based upon factors derived for actual heat rates furnished by cogenerator and the published tariffs of the fuel suppliers of the cogenerators, and (3) make refunds including interest to all wholesale customers.

Purchased Power Costs/Co-Generation

Inclusion of Purchased Power Cost in Fuel Adjustment Clause Billings

The Company improperly included in wholesale fuel adjustment clause (FAC) billings the total energy cost of all purchased power transactions.

The Company deemed all purchases of power to be made on an "economic dispatch" basis. The energy charges, which included costs other than fuel, in some instances related to purchased power did not replace available reserve capacity.

Part 35.14 of the Regulations under the Federal Power Act, and the Company's FAC tariff, provided for the inclusion in FAC calculations of the total energy costs of power purchased on an "economic dispatch" basis, when such purchases displaced available reserve capacity. The Company's FAC tariff also provided for recovery of the total energy charge of power purchased to replace generation unavailable because of scheduled outages, to the extent that the total energy charge did not exceed the fuel cost of the replaced power. However, Part 35.14 of the Commission's Regulations and the Company's filed FAC tariff did not provide for inclusion in FAC calculations of either (1) energy costs, apart from fuel costs, of power purchased on an economic dispatch basis which did not displace available reserve capacity, and (2) energy costs of purchased power, which replaced power unavailable because of a scheduled outage, to the extent such energy costs exceeded the fuel costs of the replaced power.

Accordingly, DOA concluded that the inclusion in the FAC calculations of total energy costs from purchased power transactions resulted in excessive amounts being recovered through wholesale fuel adjustment clause billings.

The Company was required to (1) revise procedures to comply with the requirements of Part 35.14 of the Regulations under the Federal Power Act and its filed tariff when determining amounts to be recorded through its wholesale fuel adjustment clause, and (2) make appropriate refunds to its wholesale customer, with interest as required by the Commission's Regulations 35.19a (a) (2) (iii).

Cost of Purchased Power from Qualifying Facilities Included in Fuel Adjustment Clause Billings

The Company purchased energy from QFs on an as available basis. The Company included both the demand and energy cost of the purchases in the computation of FAC billings to wholesale customers.

The Commission addressed the question of collection of QF purchases through the FAC in Order No. 352 (Docket No. RM83-62-000, issued December 1983), and rejected the inclusion of QF purchases in FAC billings.

Under the approved wholesale tariff, we concluded that the Company could not include the cost of the QF purchases in wholesale FAC billings.

It was recommended that the Company:

(1) revise procedures to exclude the cost of QF purchased power costs from future wholesale FAC calculations; and

(2) recompute monthly FAC billings to wholesale customers by eliminating the entire cost of purchased power from QFs from the current month's cost of fuel (but not from the base cost of fuel) and make appropriate refunds, with interest computed according to Section 35.19(a) of the Commission's regulations, for any overcollected amounts.

Inclusion of Total Energy Costs of Firm Purchase Power in Wholesale Fuel Adjustment Clause (FAC) Computations

The Company improperly included in wholesale fuel adjustment clause (FAC) billings the total energy charges related to certain purchases of energy that didn't meet the Commission's "economic dispatch" criteria.

The Company followed the practice of including the entire energy cost component (exclusive of capacity or demand charges) associated with firm purchases as an element of fuel cost in computing FAC billings to wholesale customers. The Company generally scheduled the purchase power from these firm purchase power contracts on an "economic dispatch" basis; however, certain of the purchases were made on a "non-economic dispatch" basis to meet contractual requirements.

In Opinion No. 34, Docket No. ER76-398, issued January 15, 1979, the Commission explained the purpose of its economic dispatch criteria as follows:

> ... Order No. 517 states that Section 35.14(a)(2)(iii) was intended to benefit consumers by encouraging energy purchases when the cost of the purchased energy is less than the cost of the purchaser's own generation. Whether the purchase would be cheaper than generation is determined on an hour-by-hour basis. This is what we intended to encourage. By requiring to use the actual hour-by-hour cost in the fuel clause the consumer will benefit as intended.... (emphasis added)

The Commission's policy on economic dispatch was further explained in the Notice Of Proposed Rulemaking in Docket No. RM83-62-000, Treatment of Purchased Power in Fuel Cost Adjustment Clause for Electric Utilities.

Under the conditions of the Company's existing FAC rate schedule, the total energy component of firm purchase power can only be included in FAC tariff billings if it meets the "economic dispatch" criteria on an hour-by-hour basis. When firm purchase power doesn't meet the "economic dispatch" criteria, a company may only include the identifiable fossil and nuclear fuel costs related to such purchases in FAC tariff billings. The Company didn't request specific Commission approval to recover the entire energy payment related to individual purchases made on a non-economic basis in FAC billings.

The Division of Audits concluded that the Company's FAC billings to wholesale customers were overstated during the period under audit to the extent that such billings included payments related to energy purchases that were not on an "economic dispatch" based on the Commission's hour-by-hour criteria.

APPENDIX 8

Part 292—Regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration.

[¶ 25,110]

Subpart A—General Provisions

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

Subpart D—Implementation

Subpart E—Qualification of Cogeneration Facilities for Incremental Pricing Exemption [Removed.]

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities From Certain Federal and State Laws and Regulations

AUTHORITY: Federal Power Act 16 U.S.C. 791a-824r (1982), as amended by Electric Consumers Protection Act of 1986, Pub. L. No. 99-495; Department of Energy Organization Act, 42 U.S.C. 7101-7352 (1982); EO 12009, 3 CFR 1978 Comp., p. 142; Independent Offices Appropriations Act, 31 U.S.C. 9701 (1982); Public Utility Regulatory Policies Act, 16 U.S.C. 2601-2645 (1982), as amended.

SOURCE: The provisions of Subpart A are contained in 45 *Federal Register* 12214, February 25, 1980, effective March 20, 1980, unless otherwise noted. The provisions of Subpart B are contained in 45 *Federal Register* 17959, March 20, 1980, effective March 13, 1980, unless otherwise noted. The provisions of Subparts C and D are contained in 45 *Federal Register* 12214, February 25, 1980, effective March 20, 1980, unless otherwise noted. The provisions of Subpart E are contained in 44 *Federal Register* 65744, November 15, 1979, effective November 9, 1979, unless otherwise noted. The provisions of Subpart F are contained in 45 *Federal Register* 12214, February 25, 1980, effective March 20, 1980, unless otherwise noted.

Subpart A—General Provisions

[¶ 25,111]

§ 292.101 Definitions.

(a) *General rule*. Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions*. The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an 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.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

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(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

[The next page is 15,467.]

Subpart B—Qualifying Cogeneration and Small Power Production Facilities

[¶ 25,121]

§ 292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

[¶ 25,122]

§ 292.202 Definitions.

For purposes of this subpart:

(a) "Biomass" means any organic material not derived from fossil fuels;

(b) "Waste" means by-product materials other than biomass;

(c) "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;

(d) "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy;

(e) "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production;

(f) "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility;

(g) "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process;

(h) "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application;

(i) "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;

(j) "Total energy input" means the total energy of all forms supplied from external sources.

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(k) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(l) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and

(m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.

(n) "Electric utility holding company" means a holding company, as defined in section 2(a)(7) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79b(a)(7) which owns one or more electric utilities, as defined in section 2(a)(3) of that Act, 15 U.S.C. § 79b(a)(3), but does not include any holding company which is exempt by rule or order adopted or issued pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. § 79c(a)(3) or § 79c(a)(5).

(o) "Utility geothermal small power production facility" means a small power production facility which uses geothermal energy as the primary energy resource and of which more than 50 percent is owned either:

(1) By an electric utility or utilities, electric utility holding company or companies, or any combination thereof; or

(2) By any company 50 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote by an electric utility, electric utility holding company, or any combination thereof.

(p) "New dam or diversion" means a dam or diversion which requires, for the purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards of similar adjustable devices);

(q) "Substantial adverse effect on the environment" means a substantial alteration in the existing or potential use of, or a loss of, natural features, existing habitat, recreational uses, water quality, or other environmental resources. Substantial alteration of particular resource includes a change in the environment that substantially reduces the quality of the affected resources; and

(r) "Commitment of substantial monetary resources" means the expenditure of, or commitment to expend, at least 50 percent of the total cost of preparing an application for license or exemption for a hydroelectric project that is accepted for filing by the Commission pursuant to § 4.32(e) of this chapter. The total cost includes (but is not limited to) the cost of agency consultation, environmental studies, and engineering studies conducted pursuant to § 4.38 of this chapter, and the Commission's requirements for filing an application for license exemption.

.01 Subsections (a)-(i), 45 F.R. 17959 (March 20, 1980); subsection (j), 45 F.R. 33958 (May 21, 1980); subsections (k)-(m), 45 F.R. 17959 (March 20, 1980); subsection (n), 45 F.R. 66787 (October 8, 1980); subsection (o), 46 F.R. 19229 (March 30, 1981); subsections (p)-(r), 53 F.R. 26992 (July 18, 1988).

.05 *Historical record.*—Section 292.202 originated in 45 F.R. 17959 (3/20/80), effective 3/13/80.

Subsection (j), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until it was amended in 45 F.R. 33958 (5/21/80), effective 5/15/80:

(j) "Total energy input" means the total energy of all forms supplied from external sources other than supplementary firing to the facility;

Subsection (n) was added by 45 F.R. 52779 (8/8/80), effective 8/4/80, and read as follows until it was amended in 45 F.R. 66787 (10/8/80), effective 9/26/80:

(n) "Electric utility holding company" means a holding company as defined in section 2(a)(7) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(7) which owns one or more electric utility companies, as defined in section 2(a)(3) of that Act, 15 U.S.C. 79b(a)(3).

Subsection (o) newly originated in 46 F.R. 19229 (3/30/81), effective 5/1/81.

Subsection (p) newly originated in 53 F.R. 26992 (7/18/88), effective 9/16/88.

Subsection (q) newly originated in 53 F.R. 26992 (7/18/88), effective 9/16/88.

Subsection (r) newly originated in 53 F.R. 26992 (7/18/88), effective 9/16/88.

[¶ 25,123]

§ 292.203 General requirements for qualification.

(a) *Small power production facilities.* Except as provided in paragraph (c) of this section, a small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in § 292.204(a);

(2) Meets the fuel use criteria specified in § 292.204(b); and

(3) Meets the ownership criteria specified in § 292.206.

(b) *Cogeneration facilities.* A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(1) Meets any applicable operating and efficiency standards specified in § 292.205(a) and (b); and

(2) Meets the ownership criteria specified in § 292.206.

(c) *Hydroelectric small power production facilities located at a new dam or diversion.* (1) Except as provided in paragraph (c)(2) of this section, a hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility if it meets the requirements of:

(i) Paragraph (a) of this section; and

(ii) Section 292.208.

(2) *Moratorium.*—(i) *General rule.* Except as provided in paragraph (c)(2)(ii) of this section, a hydroelectric small power production facility that impounds or diverts the water of a natural watercourse is not a qualifying facility if the moratorium described in section 8(e) of the Electric Consumers Protection Act of 1986 (ECPA), Pub. L. No. 99-495, is in effect. The moratorium applies to a license or an exemption issued on or after October 16, 1986. The moratorium will end at the expiration of the first full session of Congress following the session during which the Commission reports to Congress on the results of the study required by section 8(d) of ECPA.

(ii) *Exemption.* A hydroelectric small power production facility is exempt from the moratorium and can be a qualifying facility if it:

(A) Meets the requirements in paragraph (c)(1) of this section; and

(B) Qualifies for one of the exceptions in §§ 292.209 or 292.210.

.01 Subsection (a), 52 F.R. 5276 (February 20, 1987); subsection (b), 52 F.R. 28464 (July 30, 1987); subsection (c), 53 F.R. 26992 (July 18, 1988).

.05 *Historical record.*—Section 292.203 originated in 45 F.R. 17959 (3/20/80), effective 3/13/80.

Subsection (a), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until its amendment in 52 F.R. 5276 (2/20/87), effective 3/23/87:

(a) *Small power production facilities.* A small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in § 292.204(a);

(2) Meets the fuel use criteria specified in § 292.204(b); and

(3) Meets the ownership criteria specified in § 292.206.

Subsection (b), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until it was amended in 46 F.R. 33025 (6/26/81), effective 7/27/81:

(b) *Cogeneration facilities.* (1) Unless excluded under paragraph (c), a cogeneration facility is a qualifying facility if it:

(i) Meets any applicable operating and efficiency standards specified in § 292.205(a) and (b); and

(ii) Meets the ownership criteria specified in § 292.206.

(2) For purposes of qualification of a cogeneration facility for exemption from incremental pricing, a cogeneration facility must qualify under § 292.205(c).

Subsection (b), appearing in 46 F.R. 33025 (6/26/81), effective 7/27/81, read as follows until its amendment in 52 F.R. 28464 (7/30/87), effective 1/1/88:

(b) *Cogeneration facilities.* (1) A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(i) Meets any applicable operating and efficiency standards specified in § 292.205(a) and (b); and

(ii) Meets the ownership criteria specified in § 292.206.

(2) For purposes of qualification of a cogeneration facility for exemption from incremental pricing, a cogeneration facility must qualify under § 292.205(c).

Subsection (c), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until it was amended in 45 F.R. 33958 (5/21/80), effective 5/15/80:

(c) *Interim exclusion.* (1) Pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility.

(2) A new diesel cogeneration facility is a cogeneration facility:

(i) Which derives its useful power output from a diesel engine, and

(ii) The installation of which began on or after March 13, 1980.

Subsection (c), appearing in 45 F.R. 33958 (5/21/80), effective 5/15/80, read as follows until it was deleted in 46 F.R. 33025 (6/26/81), effective 7/27/81:

(c) *Interim exclusion.* (1) Pending further Commission action, any cogeneration facility which is a new diesel cogeneration facility may not be a qualifying facility.

(2) A new diesel cogeneration facility is a cogeneration facility:

(i) Which derives its useful power output from a diesel engine, and

(ii) The installation of which began on or after March 13, 1980.

(3) Pending further Commission action, any cogeneration facility which is a new dual-fuel cogeneration facility which seeks to obtain qualifying status must follow the procedures set forth in § 292.207(b) of this section.

(4) A new dual-fuel cogeneration facility is a cogeneration facility:

(i) which derives its useful power output from an internal combustion piston engine capable of changing automatically between gas and oil operation, and

(ii) the installation of which began on or after May 15, 1980.

Subsection (c), deleted in 46 F.R. 33025 (6/26/81), effective 7/27/81, was reinstated in 52 F.R. 5276 (2/20/87), effective 3/23/87, and read as follows until its amendment in 53 F.R. 26992 (7/18/88), effective 9/16/88:

(c) *Hydroelectric small power production facilities located at a new dam or diversion.* (1) *General rule.* Except as provided in paragraph (c)(2) of this section and § 292.208 of this part, a hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion is a qualifying facility if:

(i) It meets the requirements in paragraph (a) of this section,

(ii) The Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality, when it issues the license or exemption for the project;

(iii) The Commission finds, when it accepts the application for license or exemption for the project for filing under § 4.32(e) of this chapter, that the project is not located on any segment of a natural watercourse that:

(A) Is included in (or designated for potential inclusion in) a State or National Wild and Scenic River System, or

(B) The State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural or scenic attributes which would be adversely affected by hydroelectric development; and

(iv) The project meets the terms and conditions set by the appropriate fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(2) *Exception*. A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion is not a qualifying facility if the moratorium described in section 8(e) of the Electric Consumers Protection Act of 1986 (ECPA), Pub. L. No. 99-495, is in effect. The moratorium applies to a license or an exemption issued on or after October 16, 1986. The moratorium will end at the expiration of the first full session of Congress following the session during which the Commission reports to Congress on the results of the study required under section 8(d) of ECPA.

[¶ 25,124]

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—(1) *Maximum size*. The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation*. (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

(3) *Waiver*. The Commission may modify the application of subparagraph (2) for good cause.

(b) *Fuel use*. (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

.01 Subsection (a), 45 F.R. 17959 (March 20, 1980); subsection (b), 46 F.R. 19229 (March 30, 1981).

.05 *Historical record*.—Section 292.204 originated in 45 F.R. 17959 (3/20/80), effective 3/13/80.

Subsection (b), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until it was amended in 45 F.R. 33958 (5/21/80), effective 5/15/80:

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 50 percent of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

Subsection (b), appearing in 45 F.R. 33958 (5/21/80, effective 5/15/80, read as follows until it was amended in 46 F.R. 19229 (3/30/81), effective 5/1/81:

(b) *Fuel use.* (1)(i) The primary energy source of the facility must be biomass, waste, renewable resources, or any combination thereof, and more than 75 percent of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent of more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

[¶ 25,125]

§ 292.205 Criteria for qualifying cogeneration facilities.

(a) *Operating and efficiency standards for topping-cycle facilities*—(1) *Operating standard.* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

(b) *Efficiency standards for bottoming-cycle facilities.* (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by subparagraph (1) of this paragraph, there is no efficiency standard.

(c) *Waiver.* The Commission may waive any of the requirements of paragraphs (a) and (b) of this section upon a showing that the facility will produce significant energy savings.

.01 52 F.R. 28464 (July 30, 1987).

.05 *Historical record.*—Section 292.205 originated in 45 F.R. 17959 (3/20/80), effec-

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tive 3/13/80, and read as follows until its amendment in 52 F.R. 28464 (7/30/87), effective 1/1/88:

(a) *Operating and efficiency standards for topping-cycle facilities*—(1) *Operating standard* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

(b) *Efficiency standards for bottoming-cycle facilities.* (1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by subparagraph (1) of this paragraph, there is no efficiency standard.

(c) *Exemption from incremental pricing* (1) Natural gas used in any topping-cycle cogeneration facility is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules if:

(i) The facility meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section and is a qualifying facility under § 292.203(b)(1); or

(ii) The facility is a qualifying facility under Subpart E of this part.

(2) Natural gas used in any bottoming-cycle cogeneration facility, not subject to an exemption from incremental pricing under Subpart E of this part, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production.

(3) Nothing in this subpart affects any exemption provided under Subpart E of this part.

(4) Natural gas used for supplementary firing in any cogeneration facility is not eligible under this part for exemption from incremental pricing.

(d) *Waiver.* The Commission may waive any of the requirements of paragraphs (a), (b) and (c) of this section upon a showing that the facility will produce significant energy savings.

[¶ 25,126]

§ 292.206 Ownership criteria.

(a) *General rule.* A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).

(b) *Ownership test.* For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or public utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or public utility holding company.

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(c) *Exceptions.* For purposes of this section a company shall not be considered to be an "electric utility" company if it:

(1) Is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3), 79c(a)(5); or

(2) Is declared not to be an electric utility company by rule or order of the Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3)(A).

.01 Subsection (a), 45 F.R. 17959 (March 20, 1980); subsection (b), 45 F.R. 52779 (August 8, 1980); subsection (c), 46 F.R. 11251 (2/6/81), effective 1/28/81.

.05 *Historical record.*—Section 292.206 originated in 45 F.R. 17959 (3/20/80), effective 3/13/80.

Subsection (b), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, was amended in 45 F.R. 52779 (8/8/80), effective 8/4/80 by deleting the word "public" and inserting in lieu thereof the word "electric."

Subsection (c) newly originated in 46 F.R. 11251 (2/6/81), effective 1/28/81.

[¶ 25,127]

§ 292.207 Procedures for obtaining qualifying status.

(a) *Qualification.* (1) A small power production facility or cogeneration facility which meets the criteria for qualification set forth in § 292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraph (b)(2)(i) through (iv) of this section.

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application must be accompanied by the fee prescribed in § 381.505 of this chapter and must contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any electric utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) *Notice.* (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the Federal Register. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

(A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;

(B) The primary energy source used or to be used by the facility;

(C) The power production capacity of the facility; and

(D) The location of the facility.

(ii) The notice shall be in the following form:

(Name of Applicant)

Docket No. QF-

Notice of Application for Commission Certification of Qualifying Status of a (Small Power Production) (Cogeneration) Facility

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying (small power production) (cogeneration) facility pursuant to § 292.207 of the Commission's rules.

[Brief description of the facility].

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with § § 385.209 and 385.214 of this chapter. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

(c) *Notice requirements for facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) *Revocation of qualifying status.* (1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section if such facility fails to comply with any of the statements contained in its application for Commission certification.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

.01 Subsection (a), 45 F.R. 17959 (March 20, 1980); subsection (b), 53 F.R. 15374 (April 29, 1988); subsection (c), 45 F.R. 17959 (March 20, 1980).

.05 *Historical record.*—Section 292.207 originated in 45 F.R. 17959 (3/20/80), effective 3/13/80.

Subsection (b), appearing in 45 F.R. 17959 (3/20/80), effective 3/13/80, read as follows until its amendment in 45 F.R. 33603 (5/20/80), effective 5/5/80:

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application shall contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility.

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any public utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

Subsection (b), appearing in 45 F.R. 33603 (5/20/80), effective 5/5/80, was amended in 45 F.R. 52779 (8/8/80), effective 8/4/80, in (b)(2)(v) by deleting the word "public" and inserting in lieu thereof the word "electric."

Subsection (b), appearing in 45 F.R. 52779 (8/8/80), effective (8/4/80, was amended in 47 F.R. 19014 (5/3/82), effective 8/26/82, in (b)(6)(ii) by removing "§ § 1.8 and 1.10 of the Commission's Rules of Practice and Procedure" and adding in lieu thereof "§ § 385.209 and 385.214 of this chapter".

Subsection (b), appearing in 47 F.R. 19014 (5/3/82), effective 8/26/82, was amended in 50 F.R. 40347 (10/3/85), effective 11/4/85, in (b)(2), by inserting in the introductory clauses between the words "shall" and "contain" the phrase "be accompanied by the fee prescribed by Part 381 of this chapter and shall".

Subsection (b), appearing in 50 F.R. 40347 (10/3/85), effective 11/4/85, read as follows until its amendment in 53 F.R. 15374 (4/29/88), effective 5/31/88:

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application shall be accompanied by the fee prescribed by Part 381 of this chapter and shall contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii) The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any electric utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under § 292.205 will be met; and

(ii) The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) *Notice.* (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the Federal Register. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

(A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;

(B) The primary energy source used or to be used by the facility;

(C) The power production capacity of the facility; and

(D) The location of the facility.

(ii) The notice shall be in the following form:

(Name of Applicant)

Docket No. QF-

Notice of Application for Commission Certification of Qualifying Status of a (Small Power Production) (Cogneration) Facility

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Commission an application to be certified as a qualifying (small power production) (cogeneration) facility pursuant to § 292.207 of the Commission's rules.

[Brief description of the facility].

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the

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Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§385.209 and 385.214 of this chapter. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

[¶ 25,128]

§ 292.208 Special requirements for hydroelectric small power production facilities located at a new dam or diversion.

(a) A hydroelectric small power production facility that impounds or diverts the water of a natural watercourse by means of a new dam or diversion (as that term is defined in § 292.202(p)) is a qualifying facility only if it meets the requirements of:

(1) Paragraph (b) of this section;

(2) Section 292.203(c); and

(3) Part 4 of this chapter.

(b) A hydroelectric small power production described in paragraph (a) is a qualifying facility only if:

(1) The Commission finds, at the time it issues the license or exemption, that the project will not have a substantial adverse effect on the environment (as that term is defined in § 292.202(q)), including recreation and water quality;

(2) The Commission finds, at the time the application for the license or exemption is accepted for filing under § 4.32 of this chapter, that the project is not located on any segment of a natural watercourse which:

(i) Is included, or designated for potential inclusion in, a State or National wild and scenic river system; or

(ii) The State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural or scenic attributes which would be adversely affected by hydroelectric development; and

(3) The project meets the terms and conditions set by the appropriate fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act.

(c) For the Commission to make the findings in paragraph (b) of this section an applicant must:

(1) Comply with the applicable hydroelectric licensing requirements in Part 4 of this chapter, including:

(i) Completing the pre-filing consultation process under § 4.38 of this chapter, including performing any environmental studies which may be required under §§ 4.38(b)(2)(i)(D) through (F) of this chapter; and

(ii) Submitting with its application an environmental report that meets the requirements of § 4.41(f) of this chapter, regardless of project size;

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Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

[¶ 25,131]

§ 292.301 Scope.

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase..

[¶ 25,132]

§ 292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

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(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilities.*

(1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the state regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

.01 45 F.R. 12214 (February 25, 1980).

.05 *Historical record*—Section 292.302 originated in 45 F.R. 12214 (2/25/80), effective 3/20/80, and was corrected in 45 F.R. 24126 (4/9/80).

[¶ 25,133]

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

[¶ 25,134]

Sec. 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts of less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.*

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, 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, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

[¶ 25,135]

Sec. 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional services to be provided to qualifying facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

[¶ 25,136]

Sec. 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

[¶ 25,137]

Sec. 292.307 System emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

[¶ 25,138]

Sec. 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

[The next page is 15,545.]

Subpart D—Implementation

[¶ 25,141]

Sec. 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonregulated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

[¶ 25,142]

Sec. 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

[¶ 25,143]

Sec. 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

[The next page is 15,551.]

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Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations

[¶ 25,161]

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b).

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Section 1-18, and 21-30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

.01 46 F.R. 19229 (March 30, 1981).

.05 *Historical record.*—Section 292.601 originated in 45 F.R. 12214 (2/25/80), effective 3/20/80.

Subsection (a), appearing in 45 F.R. 12214 (2/25/80), effective 3/20/80, read as follows until it was amended in 46 F.R. 19229 (3/30/81), effective 5/1/81:

(a) *Applicability.* This section applies to:

(1) qualifying cogeneration facilities; and

(2) qualifying small power production facilities which have a power production capacity which does not exceed 30 megawatts.

Subsection (b), appearing in 45 F.R. 12214 (2/25/80), effective 3/20/80, read as follows until its amendment in 45 F.R. 33958 (5/21/80), effective 5/15/80:

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1-30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b)(1), (2) and (3) of this section.

Subsection (b), appearing in 45 F.R. 33958 (5/21/80), effective 5/15/80, read as follows until it was amended in 46 F.R. 19229 (3/30/81), effective 5/1/81:

(b) *General rule.* Any qualifying facility described in paragraph (a) shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 1-18, and 21-30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (b)(1), (2) and (3) of this section.

[¶ 25,162]

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

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(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) or a utility geothermal small power production facility shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.*

(1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in subparagraph (1).

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

.01 Subsection (a), 45 F.R. 12214 (February 25, 1980); subsection (b), 46 F.R. 19229 (March 30, 1981); subsection (c), 45 F.R. 12214 (February 25, 1980).

Historical record.—Section 292.602 originated in 45 F.R. 12214 (2/25/80), effective 3/20/80.

Subsection (b), appearing in 45 F.R. 12214 (2/25/80), effective 3/20/81, read as follows until it was amended in 46 F.R. 19229 (3/20/81), effective 5/1/81:

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

[The next page is 15,601.]

APPENDIX 9

FLORIDA POWER CORPORATION, PURCHASED POWER CONTRACTS

Question	Miller	Pinellas Co Resource Recovery Existing	Timber Energy	Bay Co Resource Recovery	LFC Jefferson	LFC Madison	Lake Co Resource Recovery	Pasco Co Resource Recovery	Dade Co Resource Recovery	Cargill Fertilizer Formelly Seminole	Lake Cogen	Pasco Cogen
1 Is the project fully financed by the utility?	No	No	No	No	No	No	No	No	No	No	No	No
2 Is the facility located on the utility's property?	No	No	No	No	No	No	No	No	No	No	No	No
3 Is the utility required to purchase 100% of the facility's electrical output?	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
4 Does the utility control the dispatch of the electricity?	No	No	No	No	No	No	No	No	No	No	No	No
5 Is the facility operated by utility personnel?	No	No	No	No	No	No	No	No	No	No	No	No
6 Is the contract a take-or-pay contract?	Yes	No	No	No	No	No	No	No	No	No	No	No
7 Does the contract period cover the useful life of the facility?	No	Yes (1)	No	Yes	Yes	Yes	Yes	Yes	Yes (1)	No	Yes	Yes
8 Has the utility guaranteed repayment of the underlying debt?	No	No	No	No	No	No	No	No	No	No	No	No
9 Does a clause exist in the contract where we will make the facility whole in the end?	No	No	No	No	No	No	No	No	No	No	No	No
10 Does the utility have an arrangement for curtailment? (2)	Full	No	No	No	Currently Negotiating	Currently Negotiating	No	No	Partial	Currently Negotiating	Partial	Partial

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Notes:

1) These units were operational before they had a contract for capacity.
2) The company has made an arrangement with a number of CoGenerators such that under minimum load conditions the company has a limited right to curtail energy purchases as specified in the individual contracts.
3) Royster and Mulberry have been combined into a single contract called Polk Power Partners
4) Gen Peat 1 thru 3, Eco Peat, and Timber 2 have been combined into a single contract called Tiger Bay.
5) Auburndale Power Partner has excess capacity for which they are seeking a to purchase both LFC contracts.
6) Both Mulberry and Orange Cogen. are owned by Ark Energy/CSW. A contract for 23 MW with TECO will be delivered from one or the other facility at any time at any time

FLORIDA POWER CORPORATION, PURCHASED POWER CONTRACTS

Question	Royster (3)	Orlando Cogen	Auburndle Pwr Parter Formally El Dorado	Mulberry Energy (3)	Ridge Generating Station	General Peat 1 (4)	General Peat 2 (4)	General Peat 3 (4)	Pinellas Co Resource Recovery North	Timber Energy 2 (4)	Panda Kathleen	Orange CoGen Formally CFR	EcoPeat (4)
1 Is the project fully financed by the utility?	No	No	No	No	No	No	No	No	No	No	No	No	No
2 Is the facility located on the utility's property?	No	No	No	No	No	No	No	No	No	No	No	No	No
3 Is the utility required to purchase 100% of the facility's electrical output?	Yes	No ~80%	(5) No ~75%	(6) No ~75%	Yes	Yes	Yes	Yes	Yes	Yes	Yes	(6) No ~75%	Yes
4 Does the utility control the dispatch of the electricity?	No	No	No	No	No	No	No	No	No	No	No	Yes	No
5 Is the facility operated by utility personnel?	No	No	No	No	No	No	No	No	No	No	No	No	No
6 Is the contract a take-or-pay contract?	No	No	No	No	No	No	No	No	No	No	No	No	No
7 Does the contract period cover the useful life of the facility?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes
8 Has the utility guaranteed repayment of the underlying debt?	No	No	No	No	No	No	No	No	No	No	No	No	No
9 Does a clause exist in the contract where we will make the facility whole in the end?	No	No	No	No	No	No	No	No	No	No	No	No	No
10 Does the utility have an arrangement for curtailment? (6)	Full	Currently Negotiating	No	Full	Currently Negotiating	Partial	Partial	Partial	No	Currently Negotiating	Currently Negotiating	N/A	Partial

Notes:
1) These units were operational before they had a contract for capacity.
2) The company has made an arrangement with a number of CoGenerators such that under minimum load conditions the company has a limited right to curtail energy purchases as specified in the individual contracts.
3) Royster and Mulberry have been combined into a single contract called Polk Power Partners
4) Gen Peat 1 thru 3, Eco Peat, and Timber 2 have been combined into a single contract called Tiger Bay.
5) Auburndale Power Partner has excess capacity for which they are seeking a to purchase both LFC contracts.
6) Both Mulberry and Orange Cogen. are owned by Ark Energy/CSW. A contract for 23 MW with TECO will be delivered from one or the other facility at any time at any time.

Pre[illegible]d by Business Planning 02-Dec-93

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APPENDIX 10

REVIEW PARTICIPANTS

The following individuals have provided input in this review.

D. P. Develle - Regulatory Accounting

R. D. Dolan - Cogeneration

J. P. Fama - Legal

R. A. Knight - Energy Supply

P. T. Morrison - Tax Administration

R. D. Niekum - Generation Planning

J. E. Orfano - Treasury

R. J. Rocha - Strateguc Analysis

L. G. Schuster - Strategic Analysis

D. D. Williams - Fuels

P. E. Toomey - Strategis Analysis

P. T. Morrison - Tax

C. J. Harper - Energy Control

L. D. Brousseau - Energy Control

S. M. Stuart - System Planning

A. J. Honey - Cogeneration

D. W. Gammon - Cogeneration

K. D. Hall - Cogeneration

APPENDIX 11

LOAD AND CAPACITY REPORT
SEASONAL RESERVE MARGINS

STRATEGIC PLANNING BASE CASE

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED OR ECS FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) NET PEAK DEMAND (MW)	FIRM SALE CAPACITY (MW)	(1) TOTAL PEAK DEMAND (MW)	TOTAL PEAK RESERVE MARGIN (MW)	TOTAL PEAK RESERVE MARGIN (%)	DISPATCHABLE DSM PROGRAMS LOAD MANAGE-MENT (MW)	DISPATCHABLE DSM PROGRAMS INTERR. & VOLT. REDUCT. (MW)	(2) FIRM PEAK DEMAND (MW)	FIRM PEAK RESERVE MARGIN (MW)	FIRM PEAK RESERVE MARGIN (%)
WINTER 93/94	7002	0	600 (3-6)	7602	450	373	8425	7996	0	7996	429	5.37%	977	291	6728	1697	25.22%
SUMMER 94	6516	260 (7)	522 (4-6)	6778	450	527	7755	6765	0	6765	990	14.63%	486	281	5998	1757	29.79%
WINTER 94/95	7602	268 (7)	0	7334	450	910	8694	8333	0	8333	361	4.33%	1017	324	6992	1702	24.34%
SUMMER 95	6778	0	0	6778	450	950	8178	7028	0	7028	1150	16.37%	526	316	6186	1992	32.21%
WINTER 95/96	7334	0	165 (8)	7499	450	1026	8975	8693	0	8693	282	3.24%	1057	370	7266	1709	23.52%
SUMMER 96	6778	0	0	6778	450	1026	8254	7332	400	7732	522	6.75%	566	361	6805	1449	21.29%
WINTER 96/97	7499	0	0	7499	450	1086	9035	9020	0	9020	15	0.16%	1097	390	7533	1502	19.94%
SUMMER 97	6778	0	0	6778	450	1086	8314	7603	450	8053	261	3.24%	606	381	7066	1248	17.66%
WINTER 97/98	7499	0	0	7499	450	1086	9035	9298	0	9298	-263	-2.83%	1137	394	7767	1268	16.32%
SUMMER 98	6778	0	0	6778	450	1086	8314	7821	475	8296	18	0.21%	646	387	7263	1051	14.47%
WINTER 98/99	7499	0	235 (9)	7734	460	1086	9280	9577	0	9577	-297	-3.10%	1177	400	8000	1280	16.00%
SUMMER 99	6778	0	200	6978	460	1086	8524	8046	75	8121	403	4.96%	686	392	7043	1481	21.03%
WINTER 99/00	7734	0	690 (9&10)	8424	460	1086	9970	9854	0	9854	116	1.18%	1217	396	8241	1729	20.98%
SUMMER 00	6978	0	587	7565	460	1086	9111	8265	0	8265	846	10.23%	726	389	7150	1961	27.42%
WINTER 00/01	8424	0	0	8424	460	1086	9970	10129	0	10129	-159	-1.57%	1257	401	8471	1499	17.69%
SUMMER 01	7565	0	0	7565	460	1086	9111	8489	0	8489	622	7.32%	766	394	7329	1782	24.31%
WINTER 01/02	8424	0	470 (11)	8894	460	1086	10440	10401	0	10401	39	0.37%	1297	408	8696	1744	20.05%
SUMMER 02	7565	0	400	7965	460	1086	9511	8708	0	8708	803	9.22%	806	400	7502	2009	26.78%
WINTER 02/03	8894	0	0	8894	460	1086	10440	10673	0	10673	-233	-2.18%	1337	413	8923	1517	17.00%
SUMMER 03	7965	0	0	7965	460	1086	9511	8926	0	8926	585	6.55%	846	406	7674	1837	23.94%

(1) Net & total peak demand assume dispatchable DSM programs are not activated.
(2) Firm peak demand assumes dispatchable DSM programs are activated.
(3) Steam upgrade - 5 MW (Bartow #1 Fan) - to be verified by test
(4) Combustion turbine addition @ Intercession City - 4 units (364/304 MW)
(5) University Project (40/36 MW)
(6) Combustion turbine peak firing temperature increase in Jan. 1994 (191/182 MW)
(7) Turner Steam Units 3-4 & Higgins Steam Units 1-3 (ECS)
(8) Combustion turbine addition @ Intercession City - SIEMENS (165/0 MW)
(9) Future unit addition - Polk County Combined Cycle (235/200 MW)
(10) Combined cycle repowering @ Higgins Steam Units 1-3 (455/387 MW)
(11) Combined cycle repowering @ Turner Steam Units 3-4 (470/400 MW)

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APPENDIX 12

Auburndale Operational Review

- Located near Auburndale.
- Natural gas combined cycle.
- Plan to become commercial in June 1994.
- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.
- Avoided fuel cost is based on Crystal River 1 & 2 coal.
- Contractual on-peak capacity factor is 92%.
- Negotiations are ongoing with Auburndale to reduce their output during minimum load conditions.

Auburndale Financial Review

FPC examined this project in October 1993 to determine if we have any desire to buy into it. Key points to this examination were:

- In the first 12 months of operation, a loss of $7.5 million was projected. However, this did not include revenues from the two LFC contracts.
- The IRR was estimated to range from 4% (high relative natural gas escalator and no sale of their excess capacity of 35 MW) to 11% (low relative natural gas escalator and immediate sale of their excess capacity). LFC represents sales of 17 MW of capacity of the excess of 35 MW.
- The value of this project to FPC is $89 million (adjusted for fuel risk) from a ratepayer neutral perspective.
- Mission Energy perceived value of the project is $125 million to $140 million, utilizing a 15% nominal discount rate.
- Therefore, the value to FPC from a ratepayer neutral perspective is substantially below Mission Energy's perception of the project value.
- The recommendation was to adopt a "wait-and-see" posture toward the purchase of the project, in part,

Bay County Operational Review

- Located near Panama City on U.S. 231
- Solid waste resource recovery plant.
- On-line since 1987.
- Avoided unit is coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%,
- Negotiations are ongoing with Bay County to reduce their output during minimum load conditions.
- Like any other resource recovery plant, Bay County's main objective is to burn refuse. Therefore, their ability to limit their electrical output is minimized.

Bay County Financial Review

FPC has no desire to own and operate a MSW facility. The MSW facility needs to continue operation to dispose of Bay County's garbage stream and reduce landfill usage as mandated by federal law. Financial support is generated from tipping fees, reduced landfill requirements, and from electrical revenues.

Bay County receives early capacity payments as allowed by state law. While these payments provide the same present value as the normal payments, there are potential risks to FPC. Under current tax interpretation, the early payments are not deductible causing a use of FPC's working capital. This tax interpretation is being reviewed to try to eliminate this effect. In addition, the early payments represent a default risk at the end of the contract when performance is required without capacity payments. The capacity account is backed by the County alone as provided by FPSC rules.

Cargill Fertilizer Operational Review

- Located between Bartow and Mulberry on State Road 60.

- A bottoming-cycle plant that produces sulfuric acid.

- On-line since 1992.

- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.

- Avoided fuel cost is based on coal delivered to Crystal River 1 & 2.

- Contractual on-peak capacity factor is 85%.

- FPC is currently in discussions with Cargill to reduce their output during minimum load conditions. Cargill has informally agreed to curtail to 12 MW (a reduction of 20%) during off-peak hours. Cargill is a bottoming-cycle plant and therefore, their electricity production is primary driven by the production of sulfuric acid.

- Cargill would like to satisfy the contract requirements utilizing both of their facilities (formerly Seminole and Gardiner). Both facilities are interconnected with TECO. This would improve Cargill's ability to meet the required capacity factor to receive their full capacity payments. FPC was opposed to Cargill serving this contract from both facilities to prevent Cargill from designating their capacity higher.

Cargill Fertilizer Financial Review

Cargill Fertilizer is a small generation facility dependent on phosphate production for financial viability. Therefore, the contract is viable only if phosphate (fertilizer) sales are cost effective.

The facility uses waste heat from an existing process therefore, providing little fuel related (variable) expense. This project primarily required capital expenditure. While their contract provides more fixed revenue (capacity payment) and less variable revenues (energy payment) the fixed vs variable expenses and revenues do not proportionately match the projects expenses.

Dade County Operational Review

- Dade County is a resource recovery plant and their output is wheeled through FP&L to FPC. Their contractual capacity is 43 MW. The avoided unit is a coal plant with a heat rate of 9830 BTU/KWh. The avoided fuel cost is based upon coal delivered to Crystal River 1 & 2. The contractual capacity factor is 83%.

- Dade County's electrical output has been very erratic. Output swings of 20 MW in 5 minutes are not uncommon. Due to the burden these swings put on FPC's system, FPC sited the FPSC rule that states "purchased from qualifying facilities...place an undue burden on the utility, the utility shall be relieved of its obligation...to purchase electricity from a qualifying facility" and declared Dade County in default of their contract.

- Dade County has agreed to install fuel bins to stabilize their output and the following conditions in exchange for recision of default:

- Reduction of 17 MW between hours 0100 and 0600 from daily schedule peak.
  - 30 times/year, 10 times/month maximum.
  - Curtail in last cogen group in 1995 only.
  - 13 hour notice.

- Dade will coordinate maintenance outages with FPC.

- FPC may request changes to schedule with 10 day notice.

- In 1995, provides exclusion of 4, 9 day outages relating to environmental compliance (72 hour notice).

Dade County Financial Review

FPC has no desire to own and operate a MSW facility. The MSW facility needs to continue operation to dispose of Dade County's garbage stream and reduce landfill usage as mandated by federal law. Financial support is generated from tipping fees, reduced landfill requirements, and from electrical revenues.

Dade County has agreed to capacity payment reductions of $40,000/Mo. until fuel bins are installed. These reductions will decrease by $10,000/Mo. upon the installation of each of the bins.

Lake Cogen Limited Operational Review

- Located in Umatilla on State Road 19.
- Natural gas combined cycle unit.
- Became commercial in July 1993.
- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.
- Avoided fuel cost is based on Crystal River 1 & 2 coal.
- Contractual on-peak capacity factor is 90%.
- Lake has voluntarily reduced their output during off-peak hours by approximately 12 MW or 11%.
- Further reductions may be difficult because of the design of the facility and their gas contracts. However, FPC is continuing to negotiate an agreement with Lake Cogen.

Lake Cogen Limited Financial Review

FPC evaluated purchasing North Canadian Power's (NCP) ownership in this project along with their other projects. The package as a whole was financially marginal causing FPC to pass on NCP's offer.

FPC was not interested in purchasing the Lake Cogen facility due to the sale/lease back agreement with no equity with General Electric Credit Corp. This limited NCP's initial investment but severely limits the projects near term profitability.

A gas contracts using both fixed (5.1%) and CR 1 & 2 with coal based escalators provide hedging against fuel differential risk.

Lake County Operational Review

- Located in Okahumpka
- Solid waste resource recovery plant.
- On-line since 1990.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%.
- Negotiations are ongoing with Lake County to reduce their output during minimum load conditions.
- Like any other resource recovery plant, Lake County's main objective is to burn refuse. Therefore, their ability to limit their electrical output is minimized.

Lake County Financial Review

FPC has no desire to own and operate a MSW facility. The MSW facility needs to dispose of Lake County's garbage stream and reduce landfill usage as mandated by federal law. Financial support is generated from tipping fees, avoided landfill requirements, and from electrical revenues.

LFC Operational Review

- Located near Madison and Monticello.
- Primary fuel is waste wood.
- Been in operation since 1989 and 1990. These projects originally became operational in 1983 and 1985, but were shutdown when their owner went into bankruptcy.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%. However, the historical capacity factor of these units has been very poor (<45%). A major factor causing this low capacity factor is their generating only when FPC's as-available rates are high. Additionally, this cycling has caused additional stress on their equipment that was designed for base load operation thereby increasing their maintenance.
- These projects have been for sale for some time. Auburndale (Mission Energy) has obtained an option to purchase the interests in these projects and moving the contract to their facility currently under construction. In return for allowing the move, FPC will negotiate for the rights to reduce Auburndale's total output during off-peak hours especially minimum load periods. Movement of these contracts to Auburndale will increase their capacity factor at no additional expense to FPC.

Auburndale has obtained an option to purchase these power purchase agreements. Auburndale Power Partners has 35 MW of excess capacity. The 17 MW of capacity payments from the two contracts may provide more complete utilization of investment. (See Auburndale).

Poor performance at the existing facilities has forced LFC to consider the sale of these contracts.

Orange Cogeneration Operational Review

- Located south of Bartow on U.S. 17-98.
- Natural gas combined cycle.
- Planned in-service date is June 1994.
- Avoided unit is a coal plant with a heat rate of between 8584 BTU/KWh to 9456 BTU/KWh depending on the load of the avoided unit.
- Avoided fuel cost is based on Crystal River 1 & 2 coal.
- Contractual on-peak capacity factor is 90%.
- This is a fully dispatchable contract with automatic generator control (AGC).
- FPC has given Orange Cogeneration notice that if they do not obtain backup fuel that they will be declared in default when the project becomes operational.

Orange Cogeneration Financial Review

The dispatchability provided in the contract has increased the uncertainty of the energy delivery and revenues, O&M expenses, fuel expense for transportation and heat rate penalties, and additional construction expenditures in the design of the facility. These additional uncertainties raise concern over the financability of the project.

This facility can override the AGC but must pay a 5% penalty on all energy delivered. This penalty may mitigate some of the operational concerns. These financial uncertainties may make Orange Cogeneration a possible buy out target although the timing may be imprudent.

Orlando CoGen Limited Operational Review

- Located in Orlando Central Park.
- Natural gas combined cycle.
- Became commercial in September 1993.
- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.
- Avoided fuel cost is based on Crystal River 1 & 2 coal.
- Contractual on-peak capacity factor is 93%.
- FPC has placed Orlando CoGen in default of their contract because they do not have a firm fuel transportation or a backup fuel. This condition will persist until FGT Phase III becomes available. Putting Orlando CoGen into default has forced the owners to negotiate with FPC to reduce their output during minimum load conditions.

Orlando CoGen Limited Financial Review

Orlando CoGen has permits and gas contracts which require operation above 94 MW. The high capacity factor allows little margin of error in operation but also creates a highly efficient unit decreasing average operating cost. Orlando CoGen is selling 35 MW to Reedy Creek Improvement District under a dispatchable contract. This capacity was probably sold at an incremental rate. This provides full utilization of the installed capacity. Steam sales provide refrigeration to Air Product's Air Separation facility. Steam sales are probably not a substantial sources of revenues for Orlando CoGen.

Panda-Kathleen Operational Review

- Planned location is west of Lakeland near Interstate 4.
- Natural gas combined cycle.
- Contractual in-service date is January 1997.
- Avoided unit is a distillate oil peaker with a heat rate of 11,610 BTU/KWh.
- Avoided fuel cost is based on Bartow distillate oil.
- Contractual on-peak capacity factor is 90%.
- Construction has not begun on Panda-Kathleen. Panda has requested permission to move to Cargill's citrus processing plant in Frostproof; FPC turned down Panda's request. Cargill also asked that Panda's request be considered but FPC declined.
- Negotiations on curtailments have not begun because FPC doubts the viability of this project.

Panda-Kathleen Financial Review

The steam host for the Panda project has changed ownership. The new owners have placed demands on Panda that they are unwilling to meet. Panda has requested moving to Frostproof but has been turned down by FPC. Panda indicates they may build their own steam host if required. The steam host problems place this contract in jeopardy. Financing a project with combustion turbine based capacity payments may be impossible.

Pasco Cogen Limited Operational Review

- Located in Dade City on U.S. 301.
- Natural gas combined cycle.
- Became commercial in July 1993.
- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.
- Avoided fuel cost is based on Crystal River 1 & 2 coal.
- Contractual on-peak capacity factor is 90%.
- Pasco has voluntarily reduced their output during off-peak hours by approximately 11 MW or 10%.
- Further reductions may be difficult because of the design of the facility and their gas contracts. However, FPC is continuing to negotiate an agreement with Pasco Cogen.

Pasco Cogen Limited Financial Review

FPC evaluated purchasing a portion of (80%) this project. North Canadian offered their ownership in this project along with their ownership of all of their cogenerating facilities. The other projects offered in this group were troublesome causing FPC to pass on the purchase.

A gas contract using both fixed (5.1%) and CR 1 & 2 coal based escalation provides hedging against fuel differential risk.

Pasco County Operational Review

- Located near Hudson.
- Solid waste resource recovery plant.
- On-line since 1991.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%.
- Negotiations are ongoing with Pasco County to reduce their output during minimum load conditions.
- Like any other resource recovery plant, Pasco County's main objective is to burn refuse. Therefore, their ability to limit their electrical output is minimized.

Pasco County Financial Review

FPC has no desire to own and operate a MSW facility. The MSW facility needs to continue operation to dispose of Pasco County's garbage stream and reduce landfill usage as mandated by federal law. Financial support is generated from tipping fees, reduced landfill requirements, and from electrical revenues.

Pinellas County Operational Review

- Located in Pinellas County.
- Solid waste resource recovery plant.
- On-line since 1986.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%.
- Like any other resource recovery plant, Pinellas County's main objective is to burn refuse. Due to their location at FPC's load center, our desire and their ability to limit their electrical output is minimized.

FPC has no desire to own and operate a MSW facility. The MSW facility needs to continue operation to dispose of Pinellas County's garbage stream and reduce landfill usage as mandated by federal law. Financial support is generated from tipping fees, reduced landfill requirements, and from electrical revenues.

Pinellas County North Operational Review

- Located in Pinellas County
- Solid waste resource recovery plant.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh if in-service before January 1995.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant if in-service before January 1995. Otherwise the avoided fuel cost at the time of the in-service date will apply.
- Contractual capacity factor is 70%.
- It looks as if this project will never be constructed by Pinellas County.

Pinellas County North Financial Review

This project is not considered viable due to problems with permitting restrictions and the lack of availability MSW fuel for this project and therefore this contract should not be bought out.

Pinellas County has requested that this contract be moved to the MSW facility in Lee County. The contract specifies that it should be a MSW facility interconnected with FPC and located in Pinellas County. FPC has advised Pinellas County that we will not approve any relocation.

Polk Power Partners (Mulberry) Operational Review

- The Mulberry project is located in Polk County on State Road 555 south of FPC's Barcola Substation. This project is a combination of 2 purchased power contracts. They are the Mulberry Energy contract (72 ± 10% MW) and the Royster Phosphate contract (28 ± 10% MW).

- Natural gas combined cycle.

- Both of these contracts are for an avoided coal plant with a heat rate of 9830 BTU/KWh. The avoided fuel cost is based upon coal delivered to Crystal River 1 & 2.

- Plan to become commercial in August 1994.

- Mulberry filed with the FERC to recertify as a qualifying facility with a new thermal host. Mulberry had originally planned to build a food grade CO_2 plant as its thermal host. Pending legal cases have blocked their construction of the CO_2 plant. Mulberry now intends to build an ethanol plant as their steam host and lease it to a third party. On October 5, 1993, FPC intervened at FERC because we felt Mulberry had not shown that the new steam host was viable. In exchange for FPC's withdrawal of the intervention, Mulberry and FPC entered into an agreement to reduce Mulberry's impact on FPC during minimum load conditions. The highlights of the agreement are:

- Additional maintenance shutdown time when recommended by the combustion turbine manufacturer to be schedule by mutual agreement between Mulberry and FPC.

- Mulberry will curtail all deliveries of power to FPC during the hours of 11:00 pm to 6:00 am from November through March and the hours of 12:00 am to 7:00 am from April through October, unless otherwise requested by FPC.

Polk Partner Partners (Mulberry) Financial Review

The inclusion of the Royster and Mulberry contract provided significant utilization on installed capacity. Polk Power Partners anticipates selling 23 MW to TECO for the first year, providing full utilization of installed capacity.

The project is building their own steam host (ethanol). This causes additional investment in construction costs. Polk Power Partners will lease the ethanol plant (at an attractive price) for someone else to control and operate. This may negate any benefits from steam sales. Polk Power Partners also are reliant on timely completion of FGT Phase III transportation to contain their fuel costs.

Financial closing with General Electric Credit Corporation occurred during the week of December 27, 1993.

Ridge Generating Station Operational Review

- Located east of Lakeland.
- Ridge's fuel is waste wood and tires.
- Plan to become commercial in April 1994.
- Avoided unit is a coal plant with a heat rate of 9830 BTU/KWh.
- Avoided fuel cost is based on Crystal River 1 & 2.
- Contractual on-peak capacity factor is 85%.
- Ridge Generating Station has requested levelized payments (see Financial Review). FPC may allow levelized payments in return for curtailment rights.

Ridge Generating Station Financial Review

Ridge Generating Station is installing a wood waste and tire fueled facility. These facilities require significant capital investment for construction. The fuel costs are low (wood waste) or negative (tires) while the contract has added fixed revenues. The fixed vs variable revenue and expense ratios are not the same. The debt service of this construction requires Ridge to levelize capacity payments (borrow against future payments).

Ridge anticipated an in-service date of April 1, 1994. Ridge would like to levelize their normal payment stream which escalates annually at 5.1%. In 1994, the normal payment is $12.68/KW/Month or $502,128/Month or $6,025,536/Year. The levelized payment is $18.18/KW/Month or $719,928/Month or $8,639,136/Year for a difference of $2.6 million the first year. The resulting capacity account peaks at approximately $41 million. The payment streams are compared using a contract discount rate of 9.96% per year.

Tiger Bay Operational Review

- The Tiger Bay project is located in Polk County on State Road 630 near FPC's Rockland Substation and U. S. Agrichem. This project is a combination of 5 purchased power contracts. They are the three General Peat contracts (57.2 MW each), the EcoPeat Contract (36.5 ± 10% MW), and a Timber Energy Contract (6 MW).

- Natural gas combined cycle.

- The General Peat and Timber Energy contracts are for an avoided coal plant with a heat rate of 9790 BTU/KWh. The avoided fuel cost is based upon coal delivered to TECO's Big Bend #4 plant. These contracts call for the facility to maintain an overall capacity factor of 70%.

- The EcoPeat contract is also based upon an avoided coal plant, but the heat rate is 9830 BTU/KWh. The avoided fuel cost is based upon coal delivered to Crystal River 1 & 2. This contract calls for the facility to maintain an on-peak capacity factor of 85%.

- Plan to become commercial prior to January 1995.

- In exchange for FPC's allowance of these contracts to be combined, Tiger Bay agreed to the following conditions to mitigate FPC's minimum load concerns:

    - A two week maintenance shutdown during January, February, March, October, November, or December. The shutdown will be during the weeks requested by FPC on or before October 31 of the previous year.

    - A two week maintenance shutdown during January, February, October, November, or December to be held during the weeks requested by FPC on or before October 31 of the previous year.

    - A two week consecutive shutdown in March and April of each year. FPC will designate when during the two months the shutdown will occur.

    - Unless requested to do otherwise by FPC, Tiger Bay will operate at no higher than 78% during off-peak hours.

    - FPC has given Tiger Bay notice they if they do not obtain backup fuel that they will be declared in default when the project becomes operational.

Tiger Bay Financial Review

Tiger Bay consists of three combined contracts (General Peat, EcoPeat, and Timber Energy 2). These contracts have different requirements for full payment requiring added performance from the bulk of the contract.

The majority of the facility (177.6 MW of 218 MW) is paid fuel on the basis of the lesser of Big Bend 4 coal and as-available energy price. This provides some natural incentive to reduce or curtail output when the as-available price is low (low load with available generation). This also provides some instability of energy payments due to the heavy reliance on as-available energy prices. The EcoPeat contract (40 MW) was allowed to combine with Tiger Bay in exchange for continued payment of the $1,000,000 lease payment for the Avon Park plant. In addition, FPC will receive 4% equity payments in the amount of 4% of the total project equity ($65,000 in 1995, and $100,000 in 1996).

The gas contract provides coal based hedging to mitigate fuel differential risk.

Financial closing with Fuji Bank occurred during the week of December 27, 1993.

Timber Energy Operational Review

- Located in Telogia (Liberty County).
- Primary fuel is waste wood. Timber Energy has begun to burn compressed cardboard to supplement the waste wood.
- Been in operation since 1986.
- Avoided unit is a coal plant with a heat rate of 9790 BTU/KWh.
- Avoided fuel cost is based on coal delivered to TECO's Big Bend #4 plant.
- Contractual capacity factor is 70%.
- Negotiations are ongoing with Timber Energy to reduce their output during minimum load conditions.

Timber Energy Financial Review

This project is financially viable. Their use of compressed cardboard helps to reduce the fuel cost associated with wood waste. Timber Energy's facility is simple and historically its capacity factor has been above 90%. The contact has less than nine years remaining.