BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's Earnings, Including Effects of Proposed Acquisition of Florida Power Corporation by Carolina Power & Light	DOCKET NO. 000824-EI Submitted for Filing: February 11, 2002

REBUTTAL TESTIMONY
OF
WILLIAM C. SLUSSER

ON BEHALF OF
FLORIDA POWER CORPORATION

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REBUTTAL TESTIMONY OF
WILLIAM C. SLUSSER, JR.

<u>Introduction and Background</u>

Q. Please state your name.

A. My name is William C. Slusser, Jr.

Q. Did you submit Direct Testimony in this case on November 15, 2001?

A. Yes, I did.

Q. Have you reviewed the intervenor testimony filed on behalf of the Florida Industrial Power Users Group (FIPUG) and Publix Super Markets, Inc. (Publix)?

A. Yes. My review focused on the testimony of FIPUG witness Jeffry Pollock and, to a more limited extent, the testimony of Publix witnesses Sheree L. Brown and Theodore J. Kury.

<u>PURPOSE AND ORGANIZATION OF TESTIMONY</u>

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my rebuttal testimony is to respond to certain positions and arguments presented in the testimony of intervenor witnesses Pollock, Brown and Kury regarding (a) the methodology for allocating production capacity costs, (b) the use and calculation of rate credits to recognize the value of interruptible service, (c) the jurisdictional allocation of power marketing expense, and (d) the design of general service rates. My testimony is organized sequentially into these four categories.

PRODUCTION COST ALLOCATION METHODOLOGY

Q. Do you have any general observations to offer after reviewing the testimony of witnesses Pollock and Brown regarding the methodology for production capacity cost allocation?

A. Yes, I would offer the following observations about the intervenor witnesses' testimony on this issue:

1. The witnesses, while differing as to extent, acknowledge that capital substitution principles which recognize energy utilization play a significant role in determining the type of, and capital investment in, production plant Florida Power has built.

2. Witness Pollock's main criticism of Florida Power's Equivalent Peaker Method (EPM), because it recognizes all energy usage rather than usage only up to an economic "break-even point", stems from his reliance on marginal costing practices, instead of the average costing practices this Commission normally requires for ratemaking purposes.

3. Overall, the intervenor witnesses provide no persuasive rationale why the previous production cost allocation methodology they

advocate is more appropriate than the EPM allocation methodology recommended by Florida Power.

Q. Do you find it surprising that the intervenor witnesses who criticize your capital substitution-based EPM cost allocation methodology nonetheless acknowledge that capital substitution principles play a key role in today's generation planning process?

A. No, I would find it surprising if they did not. While these witnesses have the particular interests of their clients to advocate, they are knowledgeable individuals in the subject matter of their testimony, and I would certainly expect them to recognize a principle like capital substitution that has become common place in today's complex and sophisticated generation planning process. The difference we have is that I believe the key role of capital substitution in the planning process should be given comparable recognition when allocating the generation costs that result from this process, while the intervenor witnesses apparently believe the previous allocation methodology is better suited to their clients' interests.

The allocation methodology previously used in setting the rates for Florida Power's customer classes has its origins prior to the late 1960s, since which time the vast majority of the Company's current generating resources have been built. Before this time, the primary causation for the costs of building new plants was the need to meet peak loads. Cost allocation methods that relied heavily or exclusively on monthly peak load responsibility were appropriate. Generation planning was much simpler: A utility had only a conventional steam plant design to consider; fuel and construction costs were relatively inexpensive; there was generally a reliance on one type of fuel; and siting and environmental regulations were much less stringent than today.

By the 1970s, the economic environment for utilities had changed due to the rapid growth in demand for electricity, inflation, high fuel costs, and high construction costs. In addition to building larger steam plants to take advantage of greater efficiencies and economies of scale, new generating options became available, such as combustion turbine peaking units, combined cycle technology, and a variety of capacity possibilities through purchased power. Cost allocation methodologies employed today need to recognize not just the obligation to meet peak load, but the type of generating unit selected for cost-effectiveness reasons. This requires recognition of the present day reality that cost causation is driven by both capacity and energy requirements. The production cost allocation methodology proposed by Florida Power in this case is a modest attempt to meet this objective.

Q. Mr. Pollock claims Florida Power's EPM allocation methodology is a flawed application of capital substitution theory because it allocates capital substitution costs to all energy usage, rather than energy usage only up to an economic "break-even point" between the operation of a peaker and a base load unit. Do you agree?

A. Only to a point. I can agree with Mr. Pollock that the EPM may not fully reflect the marginal costing theory underlying the utility's generation decision-making. However, I disagree that EPM does not represent an equitable and appropriate method for allocating average, embedded costs to rate classes.

First, I agree, as described very well by Mr. Pollock, that the capital substitution investment to build a base load unit instead of a peaking unit is justified by the usage up to the economic break-even point between the two types of units. Beyond this economic break-even point, energy utilization is no longer a factor considered by the utility in the decision to build a base load unit. This analysis, however, although accurate, represents a marginal cost perspective, *i.e.*, the marginal cost of usage greater than the break-even point requires no additional investment. The problem with this perspective is that, for the most part, utility ratemaking is based on average costing practices in order to avoid the inequities and practical difficulties that can result from the use of marginal costing when setting rates.

The following hypothetical example illustrates the problem with Mr. Pollock's break-even marginal costing theory in a ratemaking context. Assume the construction of a new toll bridge could be justified by a usage of at least 100 cars per day. If the bridge were built, under Mr. Pollock's marginal costing theory, a toll would be assessed to the first 100 cars using the bridge; the 101st car and those thereafter would travel the bridge for free. Under average costing practices, all usage that benefits from a capital substitution investment would contribute equally to its cost. In the case of the hypothetical toll bridge, equity dictates that all users of the bridge should be assessed the same toll charge, since all bridge goers benefit equally from their use of the bridge.

Second, Mr. Pollock's "break-even point" criticism of Florida Power's EPM suggests that too much production cost is allocated on the basis of energy. In actuality, the opposite is true. The EPM proposed by Florida Power in this case allocates 25% of its production costs on an energy basis. However, the Company's actual production investment above the amount that would have existed if capacity had been built only to meet peak load (*i.e.*, peaking capacity) would easily justify allocating well over 50% of its total production investment on an energy basis. Moreover, allocating even this higher level of production costs based on energy usage would still not be excessive, since it would amount to only about 25% of the fuel cost savings achieved by the additional investment.

While Florida Power's proposed EPM is only a modest step in recognizing the important role capital substitution plays in the selection of the Company's production capacity, I consider it to be a significant and necessary improvement over the inadequate recognition given by the previous allocation methodology.

Q. Witness Pollock claims the Commission rejected a proposed EPM in a 1990 Gulf Power rate case? Do you consider that case to hold any significance with respect to the EPM proposal put forward by Florida Power in this case?

A. No, I do not. I recently reviewed the Gulf Power order cited by Mr. Pollock (Order No. 23573 in Docket No. 891345-EI) and was surprised to find that the short quotation in his testimony was, in fact, the order's *entire* discussion of the EPM proposed in that case. That single sentence hardly provides the kind of reasoned analysis that should be given great weight twelve years later.

Moreover, unlike this case, the EPM in the Gulf Power case was not designed by the utility based on the characteristics of its generating system, but was proposed by the Office of Public Counsel in opposition to the utility's cost allocation methodology. The decision to reject Public Counsel's proposal is even less surprising in light of the rationale the Commission had previously expressed for refusing to deviate from Gulf Power's heavy reliance on monthly peak load costing responsibility, based on its unique situation as a part of the Southern Company operating system. In Docket No. 820150-EU, the Commission stated:

> Because Gulf buys and sells reserve capacity from other Southern operating companies based on the level of its monthly reserve margins, which, in turn, are the result of the size of Gulf's monthly system peaks, the size of all monthly peaks have an

important impact on the cost of serving Gulf's retail customers. Thus the majority of production costs should be allocated on the basis of each class' contribution to all of the monthly peaks.

Gulf Power's unique relationship with the Southern system was described by the Commission again in the final order from Gulf's next rate case (Docket No. 840086-EI). To the extent the cursory treatment of the EPM in the 1990 Gulf Power case should otherwise be given any weight at all, the Commission's express recognition of Gulf Power's unique circumstances clearly distinguishes that case from the present Florida Power case.

Q. Mr. Pollock disagrees with the Company that production investment costs related to environmental concerns are generally a function of energy usage. Does his position have merit?

A. None that I can discern. I find myself baffled by Mr. Pollock's statement that Florida Power only incurred these investments in air and water pollution control facilities simply as a prerequisite to operate. In point of fact, much of Florida Power's environmental-related investments were made years after the plant in question was constructed and were required to satisfy air and water pollution regulations that had been triggered due to extended hours of operation at these plants. The more significant of these investments include (1) cooling towers at Crystal River Units 1 & 2, (2) continuous emission monitoring equipment at the DeBary and Intercession City plants, (3) air tempering coils at the

Anclote plant, and (4) low NOx burners at Crystal River Unit 2. Contrary to Mr. Pollock's unfounded allegation, it is clear that the majority of Florida Power's environmental-related costs are a function of the plants' actual or expected hours of operation, not simply their design capacity.

Q. Intervenor witness Brown argues that the Commission should not change from the 12 CP & 1/13 AD cost allocation methodology in this proceeding without changing the corresponding allocation of fuel costs. Do you agree?

A. No, I do not. As explained earlier, Florida Power believes it to be a more equitable and administratively efficient practice to establish rates on the basis of average costs. No one disputes the fact that all kWh's of energy are not produced at the same fuel cost, even within the same rate class, and some attempts have actually been made to recognize this, such as by differentiating costs seasonally through the former practice of setting two fuel adjustment charges each year, and by differentiating daily cost variations through the application of time-of-use rates. This does not mean, however, every cost difference, no matter how minor, should be recognized in setting rates, since doing so would severely compromise the equitable and administrative advantages of average cost rates.

This is particularly true in the case of the cost difference identified by Ms. Brown, who suggests that her relatively high load factor client should bear less fuel cost responsibility for peaking generation. I don't mean to sound flippant, but when the characteristics of Florida Power's generating system are considered, her suggestion is simply not worth the trouble. Over 95% of Florida Power's system requirements are generated from base/intermediate generation, with less than 5% from peaking units. This small contribution of peaking energy results in average fuel costs being only slightly higher than the fuel costs of base/intermediate generation. Since all the Company's rate classes exhibit this overwhelming dependence on base/intermediate generation to service their load, the additional refinement to the recovery of fuel costs that Ms. Brown suggests would accomplish extremely little, on either an overall or customer class basis, while significantly complicating the fuel cost recovery process.

<u>Interruptible Service Rate Credits</u>

Q. Mr. Pollock contends that Florida Power did not adequately support its cost-effectiveness calculations for the Interruptible Service rate credit. What is your response to this contention?

A. I disagree with Mr. Pollock; Florida Power's cost-effectiveness calculations for the IS credit have been well supported. The Company prepared its calculations using the DSView module of the Strategist planning model (previously called Proscreen), which has been used to perform all of its DSM program cost-effectiveness calculations since 1993. Over this period, the model has been utilized by Florida Power to present its calculations in numerous DSM filings before the Commission and has been accepted by Staff and intervenors, including FIPUG, in these proceedings. The quality and quantity of information provided in this proceeding is consistent with the information provided without objection in these prior proceedings. This information includes the model's output reports provided at the outset in the MFRs that I sponsor, which show the year-by-year benefit and cost components for each of the Commission's three prescribed cost-effectiveness tests, as well as the net present value calculations used to derive the benefit-to-cost ratios. Through discovery, Florida Power provided additional information, including an input report of all assumptions associated with each of the avoidable generation units used in the model, which I personally provided to FIPUG at my deposition.

Q. Have you reviewed Mr. Pollock's claim that Florida Power's cost-effectiveness calculations contain several flaws?

A. Yes. Mr. Pollock described what he considered to be four flaws in Florida Power's cost-effective calculations for the Interruptible Service credit, which were reviewed with the model's vendor, NewEnergy Associates. We concluded that two of these items did, in fact, represent errors in the modeling process. The first error concerns the failure to model a reserve margin requirement when determining the amount of deferred capacity that results from a given amount of interruptible load. The second error relates to a timing mismatch in the first year of the analysis, where the model included the costs of interruptible credits but did not show any avoided generation capacity benefit. After correcting these errors the model was re-run to calculate a corrected cost-effective credit for Interruptible Service, which is $3.08 per coincident kW of interruptible load. My Exhibit No. ____ (WCS-5) provides the model output reports and input assumptions supporting the calculation of the corrected credit.

The remaining two items are not actually flaws in the sense of the modeling errors just described, but are simply Mr. Pollock's opinion that two of the assumptions would have been "more appropriate" if modeled differently. After reviewing the changes suggested by Mr. Pollock, we concluded that they lacked sufficient merit to warrant further consideration.

The first of these items is Mr. Pollock's opinion that a range of credits should be calculated by modeling a range of potential fuel costs associated with each avoided generating unit. Although his testimony gives no hint of what would be done with this range of credits, the answer is almost certain to be problematic given the Company's need to establish a single credit that results in a single rate, not a range of rates, for its interruptible tariff.

The other item relates to Mr. Pollock's opinion that "the model appears to assume that FPC would have to operate less fuel-efficient generating units" if the next planned unit addition is not built, an assumption he describes as "overly pessimistic". In the first place, the model doesn't assume the results of its run, it calculates them. Secondly, it is beyond me why Mr. Pollock chose to explain the model's results by ascribing negative human behavior to it and ignore the most obvious, straight-forward explanation. If a utility's next planned unit is more fuel-efficient than the average of its existing units, as one would normally expect to be the case, the model would naturally show an increased use of less fuel-efficient generation without this planned unit. In other words, the model would be able to simulate the operation of a more fuel-efficient generating system with the next planned unit included in the run than with it excluded. I see nothing pessimistic about this modeling result.

Q. In his answer to the question on page 26 of his testimony, Mr. Pollock accepts as true the question's premise that "FPC asserts that a benefit-to-cost ratio of 1.2 should be applied to guard against the risk that actual interruptions may prove to be infrequent." Is this the reason Florida Power has used a 1.2 benefit-to-cost ratio to calculate a cost effective Interruptible Service credit?

A. Not at all. While Florida Power supports this cost-effectiveness standard, its use in calculating the IS credit is not a matter of Company discretion. Commission Order No. PSC-96-0842-FOF-EI, issued July 1, 1996 in Docket No. 950645-EI, made it clear that Florida Power's Interruptible Service and Curtailable Service programs must meet a cost-effectiveness ratio of 1.2. More to the point, the reason for requiring this cost-effectiveness margin has nothing to do with the possibility of infrequent interruptions; it was adopted simply to provide the Company's ratepayers with a degree of protection from unfavorable variances in actual benefits and costs that may be realized over time, compared to the benefits and costs simulated in the projected cost-effectiveness calculations.

I have no idea why Mr. Pollock believes that Florida Power has justified its use of a 1.2 benefit-to-cost ratio on the need to guard against the risk that actual interruptions may prove to be infrequent. I completely agree with Mr. Pollock that the value of interruptible load is its "interruptibility", irrespective of whether it is actually interrupted. This philosophy has been consistently demonstrated by the Company in the design of its interruptible and curtailable rates, where credit payments have always been based on the amount of interruptible load, not on the frequency of interruptions.

Q. Mr. Pollock also expressed disagreement with Florida Power's IS-2 rate design, which employs a billing load factor as a proxy for a coincidence factor in applying the credit. Why has Florida Power included this feature in its IS-2 rate design?

A. To begin with, this is not a new rate design feature. It is the continuation of a feature that was reviewed by the Commission in Docket No. 950645-EI, when Florida Power established its new, cost-effective IS-2 rate offering for prospective interruptible customers commencing service after June 11, 1996. The Commission specifically addressed and approved this rate design feature in its final Order No. PSC-96-0842-FOF-EI. The Company proposes to continue this rate feature for the same reason it was initially proposed; the load factor proxy is theoretically more accurate and more equitable than a fixed credit based solely on maximum demand. It is also an administratively expedient method of estimating a customer's coincident demand for billing purposes. Mr. Pollock's suggestion of quantifying the customer's load on the day of, the day before, and the day after an interruption would impose highly burdensome analysis requirements and billing delays, without any assurance of any meaningful improvement in the estimation of coincident demand.

Q. Mr. Pollock also proposes that Florida Power reduce the IS-2 tariff's notice period for transferring to firm service from three years to two years. Does Florida Power believe a two-year notice period is sufficient?

A. Although Florida Power could build a combustion turbine or possibly arrange an off-system firm purchase in less than two years, this may not be the lowest cost solution to satisfying the additional system firm load requirement created by a transfer of interruptible load to firm service. The Company needs at least three years notice to properly reflect a load change in its generation facilities plan and determine the additional resources required on a "least cost system impact" basis.

Q. Mr. Pollock recommends that if the Company's other interruptible rate proposals are accepted, the IS-1 rate should not be completely closed, as the Company also proposes, but instead, current IS-1

customers should be grandfathered under the rate for a period of two years in order to allow them to explore other options "before imposing a dramatic and unexpected rate increase on them." What is Florida Power's response to this recommendation?

A. Florida Power cannot support Mr. Pollock's recommendation. Although Florida Power appreciates the significant increase current IS-1 customers would experience when transferred to the new IS-2 rate, this proposed action is the natural consequence of widely known Commission policies and prior actions, and should have been expected by the IS-1 customers for a number of years.

The Commission has recognized Florida Power's Interruptible Service as a Demand-Side Management (DSM) program since 1992. As an approved DSM program, the Commission allows the cost of credits paid to Interruptible Service customers to be recovered through the Energy Conservation Cost Recovery clause. To obtain DSM program approval under the Commission's cost effectiveness criterion, Florida Power must demonstrate through prescribed calculations that the credits for interruptible customers have been established at a cost effective level.

In 1994, Docket No. 941171-EG was opened to determine whether utility DSM programs met the Commission's approval criteria, including the cost-effectiveness criterion. The Company's analysis at that time had showed that both the Interruptible and Curtailable Service programs were no longer cost-effective. The Commission then opened Docket No. 950645-EI to consider the treatment of these two programs. In that proceeding, the Commission approved a stipulation between FIPUG and Florida Power that closed the IS-1 and CS-1 rates to new customers effective April 16, 1996, and deferred the issues pertaining to the appropriate rate treatment of existing IS-1 and CS-1 customers until Florida Power's next general rate case. Also in that proceeding, the Commission approved the offering of new cost-effective rates, IS-2 and CS-2, applicable to customers commencing service after the new rates' effective date of June 11, 1996. Thus, the IS-1 and CS-1 customers have known, or should have known, since 1996 that their rate status was temporary and at risk, and that their credits would likely be revised downward to cost-effective levels at the time of the Company's next general rate case, which, of course, is this now pending case.

Jurisdictional Allocation Of Power Marketing Expense

Q. Publix witness Brown notes in her testimony that Florida Power has allocated to its retail business all of its budgeted power marketing expenses in the amount of $4,897,000 for the 2002 test period. Is this a correct jurisdictional cost allocation of the Company's power marketing expenses?

A. No. The Company acknowledges that this jurisdictional allocation, or lack thereof, was in error and thanks Ms. Brown for her attention to detail that brought this error to light. This expense should have been assigned and allocated in the following manner: (a) $2,692,000 is directly assignable to the FERC jurisdictional business, and (b) $2,205,000 is allocable 2.354% to FERC jurisdictional business and 97.646% to FPSC jurisdictional business.

GENERAL SERVICE RATE DESIGN

Q. **Publix witness Kury claims Florida Power's General Service Demand (GSD) rates do not recognize the value of high load factor customers to the Florida Power system. Do you agree?**

A. No, I do not. To the contrary, Florida Power's overall general service rate structure provides increasingly lower effective rates as a customer's load factor increases. First, any general service customer using more than 24,000 kWh's annually will realize lower billings under the Company's demand rates compared to its non-demand rates if the customer exceeds a 22% monthly load factor. Second, billing records show that those customers having load factors in the order of 50% or more generally obtain even lower effective rates by electing service under the Company's optional time-of-use demand rate. Third, any customer that exceeds a 72% monthly load factor is assured a lower effective rate under this time-of-use demand rate. Finally, the optional time-of-use demand rate provides typical, good load factor customers a reduction of at least 0.599 cents per kWh (or about 11%) for additional energy usage compared to other general service non-demand or standard demand rates.

To demonstrate this latter point, I have prepared Exhibit _______(WCS-6), which shows general service customer billings at present rates on page 1 and at proposed rates on page 2. The exhibit illustrates the calculation of total monthly billings for customer load factors varying in increments of 5% up to 100% under Florida Power's four general service rate schedules: GS Non-Demand, Standard Rate (GS-1); GS Non-Demand, Optional TOU Rate (GST-1); GS Demand, Standard Rate (GSD-1); and GS Demand, Optional TOU Rate (GSDT-1). A total monthly billing is calculated for each rate schedule and also as an effective rate per kWh. The charge for an additional kWh at each load factor increment is also calculated and shown in the exhibit's last column. The exhibit shows that customers having the characteristics of Publix (75% load factor) can purchase additional energy under the proposed GSDT-1 rate at 4.914 cents per kWh, compared to 5.513 cents per kWh under the proposed GSD-1 rate, 6.565 cents per kWh under the proposed GST-1 rate, and 8.010 cents per kWh under the proposed GS-1 rate. This demonstrates that Florida Power's GSDT-1 rate provides high load factor customers significantly greater price incentive to improve load factor compared to the other general service rates.

Q. Mr. Kury expresses his concern over a two-part Real Time Pricing (RTP) rate design the Company is currently studying, and advocates an RTP rate similar to one offered by Gulf Power that

reflects actual marginal energy costs. Do you have any comments regarding Florida Power's design of a possible RTP rate?

A. Yes. I have several comments. First, Florida Power has not proposed an RTP rate to take issue with in this proceeding. Second, I find it interesting to note that Florida Power did, in fact, offer a one-part RTP rate in 1996 that was very similar in design to the Gulf rate that Mr. Kury advocates. After two years, during which not a single customer had chosen to take service under this offering, the rate was withdrawn for lack of customer interest. Third, Florida Power continues to monitor innovative rate offerings of other utilities and is evaluating the design and experience of a number of utilities that have two-part RTP rates, including Florida Power & Light, Georgia Power, and Carolina Power & Light. Fourth, Mr. Kury is critical of a two-part rate design that employs a customer baseline load pattern because he claims a customer like Publix does not have the capability to alter its load, other than by the addition of new stores. This is problematic. If a customer cannot change its baseline load pattern by shifting usage from peak or high cost hours to off-peak or low cost hours, there is obviously no potential for utility cost savings with which to justify the offering of such a rate in the first place. Finally, Florida Power is receptive to discussions with its customers or their consultants regarding new or improved rate designs. Of course, as most larger customers understand, Florida Power does not have authority to implement a new or revised rate design; before implementation can occur the rate design must first be filed with this Commission for approval, which also provides interested parties an opportunity to comment on its appropriateness during the Commission's review process.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

IC/CS Cost-Effectiveness Results -- All Existing IS/CS	
	RIM=1.2
PARTICIPANT INCENTIVE (ANNUAL $)	$10,861,369
Coincident Annual Peak kW Load Reduction	313.19
PARTICIPANT INCENTIVE ($/KW-MONTH) (At the Generator)	$2.89
Factor to Convert Generator kW to Meter kW	0.94
PARTICIPANT INCENTIVE ($/KW-MONTH) (At the Meter)	$3.08

Revised
02/07/02

RATE IMPACT MEASURE TEST - WITH INCENTIVES SET TO RESULT IN A RIM OF 1.20

PROGRAM: INTERRUPTIBLE/CURTAILABLE

	BENEFITS					COSTS							
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) REVENUE GAINS $(000)	(5) **TOTAL BENEFITS** $(000)	(6) TOTAL FUEL & O&M INCREASE $(000)	(7) INCREASED T&D CAP. COSTS $(000)	(8) INCREASED GEN. CAP. COSTS $(000)	(9) UTILITY PROGRAM COSTS $(000)	(10) INCENTIVE PAYMENTS $(000)	(11) REVENUE LOSSES $(000)	(12) **TOTAL COSTS** $(000)	(13) **NET BENEFITS TO ALL CUSTOMERS** $(000)
2001	291	0	10,087	0	10,378	0	0	0	75	10,861	351	11,287	-909
2002	951	0	10,303	0	11,254	0	0	0	75	10,861	230	11,166	88
2003	616	0	10,519	0	11,136	0	0	0	75	10,861	268	11,204	-68
2004	1,166	0	11,288	0	12,454	0	0	0	75	10,861	102	11,039	1,416
2005	1,307	0	11,497	0	12,803	0	0	0	75	10,861	104	11,040	1,763
2006	0	0	15,400	0	15,400	12,258	0	0	75	10,861	146	23,341	-7,941
2007	0	0	15,724	0	15,724	13,217	0	0	75	10,861	204	24,357	-8,633
2008	0	0	17,541	0	17,541	12,710	0	0	75	10,861	106	23,752	-6,210
2009	0	0	17,783	0	17,783	11,459	0	0	75	10,861	212	22,607	-4,824
2010	0	0	16,735	0	16,735	1,568	0	0	75	10,861	108	12,613	4,122
2011	2,705	0	15,938	0	18,643	0	0	0	75	10,861	112	11,048	7,595
2012	3,142	0	15,867	0	19,010	0	0	0	75	10,861	111	11,048	7,962
2013	3,222	0	16,201	0	19,423	0	0	0	75	10,861	111	11,048	8,375
2014	3,507	0	16,541	0	20,048	0	0	0	75	10,861	151	11,087	8,960
2015	3,594	0	16,888	0	20,482	0	0	0	75	10,861	203	11,139	9,343
2016	3,761	0	17,243	0	21,004	0	0	0	75	10,861	203	11,139	9,865
2017	3,235	0	17,605	0	20,840	0	0	0	75	10,861	203	11,139	9,701
2018	3,394	0	17,975	0	21,368	0	0	0	75	10,861	203	11,139	10,229
2019	3,429	0	18,352	0	21,781	0	0	0	75	10,861	203	11,139	10,642
2020	3,737	0	18,738	0	22,474	0	0	0	75	10,861	203	11,139	11,335
2021	3,267	0	19,131	0	22,398	0	0	0	75	10,861	203	11,139	11,259
2022	3,323	0	19,533	0	22,855	0	0	0	75	10,861	203	11,139	11,716
2023	3,948	0	19,943	0	23,891	0	0	0	75	10,861	203	11,139	12,752
2024	3,994	0	20,362	0	24,355	0	0	0	75	10,861	203	11,139	13,216
2025	4,325	0	20,789	0	25,114	0	0	0	75	10,861	253	11,189	13,925
2026	4,353	0	21,226	0	25,579	0	0	0	75	10,861	253	11,189	14,390
2027	5,961	0	21,672	0	27,632	0	0	0	75	10,861	165	11,101	16,531
2028	5,462	0	22,127	0	27,589	0	0	0	75	10,861	165	11,102	16,487
2029	6,185	0	22,591	0	28,776	0	0	0	75	10,861	168	11,105	17,671
2030	6,031	0	23,066	0	29,096	0	0	0	75	10,861	227	11,164	17,933
NOMINAL	84,904	0	518,664	0	603,568	51,212	0	0	2,250	325,841	5,574	384,876	218,692
NPV	18,301	0	163,289	0	181,590	28,896	0	0	825	119,535	2,068	151,325	30,265

UTILITY DISCOUNT RATE: 9.22%
BENEFIT/COST RATIO: 1.20

PARTICIPANT TEST - WITH INCENTIVES SET TO RESULT IN A RIM OF 1.20

PROGRAM: INTERRUPTIBLE/CURTAILABLE

	BENEFITS				COSTS			
YEAR	(1) SAVINGS IN PARTICIPANT'S BILL $(000)	(2) INCENTIVE PAYMENTS $(000)	(3) OTHER PARTICIPANT'S BENEFITS $(000)	(4) TOTAL BENEFITS $(000)	(5) PARTICIPANT'S COST $(000)	(6) PARTICIPANT'S BILL INCREASE $(000)	(7) TOTAL COSTS $(000)	(8) NET BENEFITS TO PARTICIPANTS $(000)
2001	351	10,861	0	11,212	0	0	0	11,212
2002	230	10,861	0	11,091	0	0	0	11,091
2003	268	10,861	0	11,129	0	0	0	11,129
2004	102	10,861	0	10,964	0	0	0	10,964
2005	104	10,861	0	10,965	0	0	0	10,965
2006	146	10,861	0	11,008	0	0	0	11,008
2007	204	10,861	0	11,065	0	0	0	11,065
2008	106	10,861	0	10,967	0	0	0	10,967
2009	212	10,861	0	11,073	0	0	0	11,073
2010	108	10,861	0	10,970	0	0	0	10,970
2011	112	10,861	0	10,973	0	0	0	10,973
2012	111	10,861	0	10,973	0	0	0	10,973
2013	111	10,861	0	10,973	0	0	0	10,973
2014	151	10,861	0	11,012	0	0	0	11,012
2015	203	10,861	0	11,064	0	0	0	11,064
2016	203	10,861	0	11,064	0	0	0	11,064
2017	203	10,861	0	11,064	0	0	0	11,064
2018	203	10,861	0	11,064	0	0	0	11,064
2019	203	10,861	0	11,064	0	0	0	11,064
2020	203	10,861	0	11,064	0	0	0	11,064
2021	203	10,861	0	11,064	0	0	0	11,064
2022	203	10,861	0	11,064	0	0	0	11,064
2023	203	10,861	0	11,064	0	0	0	11,064
2024	203	10,861	0	11,064	0	0	0	11,064
2025	253	10,861	0	11,114	0	0	0	11,114
2026	253	10,861	0	11,114	0	0	0	11,114
2027	165	10,861	0	11,026	0	0	0	11,026
2028	165	10,861	0	11,027	0	0	0	11,027
2029	168	10,861	0	11,030	0	0	0	11,030
2030	227	10,861	0	11,089	0	0	0	11,089
NOMINAL	5,574	325,841	0	331,415	0	0	0	331,415
NPV	2,068	119,535	0	121,604	0	0	0	121,604

UTILITY DISCOUNT RATE: 9.22%
BENEFIT/COST RATIO: 9999

TOTAL RESOURCE COST TEST

PROGRAM: INTERRUPTIBLE/CURTAILABLE

	BENEFITS					COSTS						
YEAR	(1) TOTAL FUEL & O&M SAVINGS $(000)	(2) AVOIDED T&D CAP. COSTS $(000)	(3) AVOIDED GEN. CAP. COSTS $(000)	(4) OTHER PARTICIPANT BENEFITS $(000)	(5) TOTAL BENEFITS $(000)	(6) PARTICIPANT'S COST $(000)	(7) TOTAL FUEL & O&M INCREASE $(000)	(8) INCREASED T&D CAP. COSTS $(000)	(9) INCREASED GEN. CAP. COSTS $(000)	(10) UTILITY PROGRAM COSTS $(000)	(11) TOTAL COSTS $(000)	(12) NET BENEFITS $(000)
2001	291	0	10,087	0	10,378	0	0	0	0	75	75	10,303
2002	951	0	10,303	0	11,254	0	0	0	0	75	75	11,179
2003	616	0	10,519	0	11,136	0	0	0	0	75	75	11,061
2004	1,166	0	11,288	0	12,454	0	0	0	0	75	75	12,379
2005	1,307	0	11,497	0	12,803	0	0	0	0	75	75	12,728
2006	0	0	15,400	0	15,400	0	12,258	0	0	75	12,333	3,067
2007	0	0	15,724	0	15,724	0	13,217	0	0	75	13,292	2,432
2008	0	0	17,541	0	17,541	0	12,710	0	0	75	12,785	4,757
2009	0	0	17,783	0	17,783	0	11,459	0	0	75	11,534	6,249
2010	0	0	16,735	0	16,735	0	1,568	0	0	75	1,643	15,092
2011	2,705	0	15,938	0	18,643	0	0	0	0	75	75	18,568
2012	3,142	0	15,867	0	19,010	0	0	0	0	75	75	18,935
2013	3,222	0	16,201	0	19,423	0	0	0	0	75	75	19,348
2014	3,507	0	16,541	0	20,048	0	0	0	0	75	75	19,973
2015	3,594	0	16,888	0	20,482	0	0	0	0	75	75	20,407
2016	3,761	0	17,243	0	21,004	0	0	0	0	75	75	20,929
2017	3,235	0	17,605	0	20,840	0	0	0	0	75	75	20,765
2018	3,394	0	17,975	0	21,368	0	0	0	0	75	75	21,293
2019	3,429	0	18,352	0	21,781	0	0	0	0	75	75	21,706
2020	3,737	0	18,738	0	22,474	0	0	0	0	75	75	22,399
2021	3,267	0	19,131	0	22,398	0	0	0	0	75	75	22,323
2022	3,323	0	19,533	0	22,855	0	0	0	0	75	75	22,780
2023	3,948	0	19,943	0	23,891	0	0	0	0	75	75	23,816
2024	3,994	0	20,362	0	24,355	0	0	0	0	75	75	24,280
2025	4,325	0	20,789	0	25,114	0	0	0	0	75	75	25,039
2026	4,353	0	21,226	0	25,579	0	0	0	0	75	75	25,504
2027	5,961	0	21,672	0	27,632	0	0	0	0	75	75	27,557
2028	5,462	0	22,127	0	27,589	0	0	0	0	75	75	27,514
2029	6,185	0	22,591	0	28,776	0	0	0	0	75	75	28,701
2030	6,031	0	23,066	0	29,096	0	0	0	0	75	75	29,021
NOMINAL	84,904	0	518,664	0	603,568	0	51,212	0	0	2,250	53,462	550,106
NPV	18,301	0	163,289	0	181,590	0	28,896	0	0	825	29,721	151,869

UTILITY DISCOUNT RATE: 9.22%
BENEFIT/COST RATIO: 6.11

Combined Interruptible/Curtailable Cost-Effectiveness Evaluation Results -- For all Existing IS/CS Customers
Results for RIM Ratio = 1.2

	2001	2002	2003	2004	2005	2006	2007	2008	2009
YEARLY CHANGE IN DEF CAPACITY	-360.17	-360.17	-360 17	-375.83	-375 83	-375 83	-375.83	-375.83	-375 83
Nominal Benefits (Thousands of $)									
CAPACITY BENEFIT:	$10,087.00	$10,303 06	$10,519 40	$11,288.22	$11,496 61	$15,400 16	$15,723 60	$17,541 30	$17,783.30
PRODUCTION COST BENEFIT:	$291 00	$951.00	$616.13	$1,166 13	$1,306.63	$0 00	$0.00	$0 00	$0.00
REVENUE BENEFIT	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL BENEFIT·	$10,378.00	$11,254.06	$11,135.53	$12,454 35	$12,803.23	$15,400.16	$15,723 60	$17,541.30	$17,783.30
Nominal Costs (Thousands of $)									
CAPACITY COST·	$0 00	$0.00	$0 00	$0 00	$0 00	$0.00	$0 00	$0.00	$0.00
PRODUCTION COST	$0 00	$0.00	$0 00	$0.00	$0.00	$12,258.13	$13,216.75	$12,709 50	$11,459.13
REVENUE COST	$350.81	$229.82	$267.65	$102 22	$103 90	$146 50	$203.77	$105.89	$211.59
INCENTIVE COST·	$10,861.37	$10,861 37	$10,861 37	$10,861.37	$10,861 37	$10,861 37	$10,861 37	$10,861.37	$10,861.37
MKT PROG COST.	$75 00	$75 00	$75 00	$75 00	$75 00	$75 00	$75.00	$75.00	$75.00
TOTAL COST.	$11,287 17	$11,166 19	$11,204 02	$11,038 59	$11,040 27	$23,340 99	$24,356.89	$23,751.76	$22,607.08
NOMINAL NET BENEFITS	-$909 17	$87.87	-$68 49	$1,415 76	$1,762 96	-$7,940 83	-$8,633 29	-$6,210.47	-$4,823.78
UTILITY DISCOUNT RATE	9.22%								
Annual PV Benefits (Thousands of $)									
PV CAPACITY BENEFIT·	$10,087 00	$9,433 31	$8,818 34	$8,664 01	$8,079.06	$9,908 65	$9,262.73	$9,461 21	$8,782.03
PV PRODUCTION COST BENEFIT	$291.00	$870 72	$516 49	$895 03	$918 21	$0 00	$0 00	$0.00	$0.00
PV REVENUE BENEFIT·	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0.00	$0.00
PV TOTAL BENEFIT.	$10,378 00	$10,304 03	$9,334 83	$9,559.04	$8,997.27	$9,908.65	$9,262.73	$9,461.21	$8,782 03
Annual PV Costs (Thousands of $)									
PV CAPACITY COST	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00	$0.00
PV PRODUCTION COST	$0.00	$0 00	$0.00	$0 00	$0.00	$7,887 02	$7,785.95	$6,855 09	$5,658 93
PV REVENUE COST·	$350 81	$210 42	$224.37	$78 46	$73.02	$94.26	$120 04	$57.12	$104.49
PV INCENTIVE COST.	$10,861 37	$9,944.49	$9,105 01	$8,336 39	$7,632 66	$6,988 33	$6,398.40	$5,858.27	$5,363.73
PV MKT PROG COST	$75 00	$68 67	$62.87	$57 56	$52.71	$48 26	$44.18	$40 45	$37 04
PV TOTAL COST.	$11,287.17	$10,223 58	$9,392.25	$8,472 41	$7,758 38	$15,017.87	$14,348.57	$12,810 93	$11,164.19
PV NET BENEFITS	-$909 17	$80.46	-$57.42	$1,086 63	$1,238.89	-$5,109.22	-$5,085.84	-$3,349.72	-$2,382 16
Cumulative PV Benefits (Thousands of $)									
ACCUM PV CAPACITY BENEFIT	$10,087 00	$19,520 31	$28,338.65	$37,002.66	$45,081.72	$54,990 37	$64,253.10	$73,714.31	$82,496.34
ACCUM PV PRODUCTION COST BENEFIT:	$291.00	$1,161.72	$1,678.21	$2,573 24	$3,491.46	$3,491 46	$3,491 46	$3,491 46	$3,491.46
ACCUM PV REVENUE BENEFIT·	$0.00	$0.00	$0 00	$0 00	$0.00	$0 00	$0.00	$0.00	$0 00
ACCUM PV TOTAL BENEFIT:	$10,378 00	$20,682 03	$30,016 86	$39,575 91	$48,573 18	$58,481.83	$67,744.56	$77,205.76	$85,987.79
Cumulative PV Costs (Thousands of $)									
ACCUM PV CAPACITY COST.	$0.00	$0 00	$0 00	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00
ACCUM PV PRODUCTION COST:	$0.00	$0 00	$0.00	$0 00	$0 00	$7,887.02	$15,672.97	$22,528 07	$28,186 99
ACCUM PV REVENUE COST:	$350 81	$561.23	$785 60	$864.05	$937.07	$1,031 33	$1,151 36	$1,208 48	$1,312 97
ACCUM PV INCENTIVE COST:	$10,861 37.	$20,805 86	$29,910 86	$38,247.25	$45,879.91	$52,868 24	$59,266.65	$65,124.92	$70,488.65
ACCUM PV MKT PROG COST.	$75 00	$143 67	$206.54	$264.11	$316 81	$365.07	$409.25	$449.70	$486.74
ACCUM PV TOTAL COST:	$11,287 17	$21,510 75	$30,903 00	$39,375 41	$47,133 79	$62,151.66	$76,500.24	$89,311.16	$100,475 35
CUMULATIVE PV NET BENEFITS	-$909 17	-$828 72	-$886 13	$200 50	$1,439.39	-$3,669 83	-$8,755.68	-$12,105 40	-$14,487.56
ACCUM PV B/C.	0.92	0 96	0 97	1.01	1 03	0 94	0.89	0.86	0 86

	2010	2011	2012	2013	2014	2015	2016	2017
YEARLY CHANGE IN DEF CAPACITY	-375.83	-375.83	-375.83	-375 83	-375.83	-375 83	-375.83	-375.83
Nominal Benefits (Thousands of $)								
CAPACITY BENEFIT:	$16,735.13	$15,937.50	$15,867.47	$16,200.66	$16,540.82	$16,888 22	$17,242.87	$17,604 98
PRODUCTION COST BENEFIT:	$0.00	$2,705.25	$3,142.38	$3,222.00	$3,506 75	$3,593.88	$3,760 75	$3,235.38
REVENUE BENEFIT	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00	$0 00
TOTAL BENEFIT·	$16,735.13	$18,642.75	$19,009.84	$19,422.66	$20,047 57	$20,482.09	$21,003 62	$20,840 35
Nominal Costs (Thousands of $)								
CAPACITY COST·	$0.00	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00	$0 00
PRODUCTION COST	$1,568.13	$0.00	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00
REVENUE COST	$108.24	$111 77	$111.48	$111 44	$150.87	$202.68	$202 65	$202 65
INCENTIVE COST·	$10,861 37	$10,861.37	$10,861.37	$10,861 37	$10,861.37	$10,861.37	$10,861 37	$10,861.37
MKT PROG COST.	$75 00	$75.00	$75 00	$75 00	$75.00	$75 00	$75.00	$75 00
TOTAL COST.	$12,612 74	$11,048.14	$11,047.84	$11,047.81	$11,087 24	$11,139 05	$11,139.01	$11,139 02
NOMINAL NET BENEFITS	$4,122.39	$7,594 61	$7,962.00	$8,374 86	$8,960 33	$9,343.04	$9,864 60	$9,701 34
UTILITY DISCOUNT RATE								
Annual PV Benefits (Thousands of $)								
PV CAPACITY BENEFIT·	$7,566 75	$6,597 79	$6,014.28	$5,622.21	$5,255.68	$4,913 08	$4,592.79	$4,293.39
PV PRODUCTION COST BENEFIT	$0 00	$1,119 92	$1,191.06	$1,118 15	$1,114 23	$1,045.52	$1,001 71	$789 02
PV REVENUE BENEFIT·	$0.00	$0.00	$0 00	$0 00	$0 00	$0.00	$0.00	$0 00
PV TOTAL BENEFIT.	$7,566 75	$7,717.71	$7,205.34	$6,740.35	$6,369.91	$5,958 60	$5,594.50	$5,082 42
Annual PV Costs (Thousands of $)								
PV CAPACITY COST	$0 00	$0.00	$0.00	$0.00	$0 00	$0 00	$0.00	$0.00
PV PRODUCTION COST	$709.02	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00	$0 00
PV REVENUE COST·	$48.94	$46 27	$42.25	$38 67	$47 94	$58.96	$53 98	$49 42
PV INCENTIVE COST.	$4,910.94	$4,496.38	$4,116.81	$3,769.28	$3,451.09	$3,159.76	$2,893.02	$2,648.80
PV MKT PROG COST	$33.91	$31.05	$28.43	$26 03	$23 83	$21 82	$19.98	$18.29
PV TOTAL COST.	$5,702.82	$4,573.70	$4,187.49	$3,833.98	$3,522.86	$3,240 54	$2,966 98	$2,716 51
PV NET BENEFITS	$1,863 93	$3,144.01	$3,017.85	$2,906 37	$2,847 06	$2,718 05	$2,627.53	$2,365.90
Cumulative PV Benefits (Thousands of $)								
ACCUM PV CAPACITY BENEFIT	$90,063 09	$96,660 88	$102,675 16	$108,297.37	$113,553 04	$118,466 12	$123,058.91	$127,352 31
ACCUM PV PRODUCTION COST BENEFIT:	$3,491.46	$4,611.37	$5,802.43	$6,920 58	$8,034 82	$9,080.34	$10,082.05	$10,871 07
ACCUM PV REVENUE BENEFIT·	$0.00	$0 00	$0.00	$0.00	$0 00	$0.00	$0.00	$0.00
ACCUM PV TOTAL BENEFIT:	$93,554 54	$101,272.25	$108,477.59	$115,217 95	$121,587 86	$127,546.46	$133,140.96	$138,223.38
Cumulative PV Costs (Thousands of $)								
ACCUM PV CAPACITY COST.	$0.00	$0 00	$0 00	$0 00	$0.00	$0 00	$0 00	$0 00
ACCUM PV PRODUCTION COST:	$28,896.02	$28,896.02	$28,896 02	$28,896.02	$28,896 02	$28,896 02	$28,896.02	$28,896 02
ACCUM PV REVENUE COST:	$1,361.91	$1,408.18	$1,450.44	$1,489 11	$1,537.05	$1,596 01	$1,649 99	$1,699 41
ACCUM PV INCENTIVE COST:	$75,399 59	$79,895 97	$84,012 78	$87,782.06	$91,233 15	$94,392 91	$97,285 94	$99,934.74
ACCUM PV MKT PROG COST.	$520.65	$551.70	$580.13	$606 15	$629 98	$651.80	$671.78	$690 07
ACCUM PV TOTAL COST:	$106,178 17	$110,751.87	$114,939.36	$118,773.34	$122,296.20	$125,536.75	$128,503.72	$131,220.24
CUMULATIVE PV NET BENEFITS	-$12,623 63	-$9,479 62	-$6,461.77	-$3,555 40	-$708.34	$2,009 71	$4,637 24	$7,003.14
ACCUM PV B/C.	0.88	0.91	0 94	0 97	0 99	1 02	1 04	1.05

Combined Interruptible/Curtailable Cost-Effe
Results for RIM Ratio = 1.2

	2018	2019	2020	2021	2022	2023
YEARLY CHANGE IN DEF CAPACITY	-375.83	-375 83	-375.83	-375.83	-375 83	-375.83
Nominal Benefits (Thousands of $)						
CAPACITY BENEFIT:	$17,974 70	$18,352.17	$18,737.57	$19,131 03	$19,532.79	$19,942 99
PRODUCTION COST BENEFIT:	$3,393.63	$3,429.25	$3,736.63	$3,267.38	$3,322.63	$3,948.25
REVENUE BENEFIT:	$0 00	$0 00	$0 00	$0.00	$0.00	$0.00
TOTAL BENEFIT:	$21,368 33	$21,781 42	$22,474 20	$22,398 41	$22,855 41	$23,891.24
Nominal Costs (Thousands of $)						
CAPACITY COST:	$0.00	$0 00	$0 00	$0.00	$0.00	$0 00
PRODUCTION COST:	$0.00	$0 00	$0 00	$0.00	$0.00	$0.00
REVENUE COST:	$202.65	$202.65	$202 65	$202 65	$202.65	$202.65
INCENTIVE COST:	$10,861.37	$10,861 37	$10,861.37	$10,861.37	$10,861.37	$10,861.37
MKT PROG COST.	$75.00	$75 00	$75 00	$75.00	$75.00	$75.00
TOTAL COST·	$11,139 02	$11,139.02	$11,139.02	$11,139.02	$11,139.02	$11,139.02
NOMINAL NET BENEFITS:	$10,229.31	$10,642.41	$11,335 18	$11,259.39	$11,716.40	$12,752.23
UTILITY DISCOUNT RATE:						
Annual PV Benefits (Thousands of $)						
PV CAPACITY BENEFIT.	$4,013.51	$3,751.88	$3,507.29	$3,278.65	$3,064.92	$2,865.12
PV PRODUCTION COST BENEFIT:	$757.75	$701.07	$699.42	$559.96	$521.36	$567.23
PV REVENUE BENEFIT	$0 00	$0.00	$0 00	$0.00	$0.00	$0 00
PV TOTAL BENEFIT	$4,771.27	$4,452.94	$4,206 71	$3,838.61	$3,586.27	$3,432.35
Annual PV Costs (Thousands of $)						
PV CAPACITY COST.	$0 00	$0 00	$0.00	$0.00	$0.00	$0.00
PV PRODUCTION COST:	$0.00	$0 00	$0.00	$0.00	$0.00	$0.00
PV REVENUE COST·	$45.25	$41.43	$37.93	$34.73	$31.80	$29.11
PV INCENTIVE COST:	$2,425.20	$2,220.47	$2,033 03	$1,861 41	$1,704.27	$1,560.40
PV MKT PROG COST·	$16.75	$15 33	$14.04	$12 85	$11.77	$10.77
PV TOTAL COST	$2,487.20	$2,277 23	$2,085.00	$1,908 99	$1,747.84	$1,600.29
PV NET BENEFITS	$2,284 07	$2,175.71	$2,121.72	$1,929 62	$1,838 44	$1,832.05
Cumulative PV Benefits (Thousands of $)						
ACCUM PV CAPACITY BENEFIT.	$131,365 82	$135,117.70	$138,624 99	$141,903.64	$144,968 55	$147,833 67
ACCUM PV PRODUCTION COST BENEFIT:	$11,628 82	$12,329.89	$13,029 31	$13,589.27	$14,110 63	$14,677.85
ACCUM PV REVENUE BENEFIT	$0.00	$0 00	$0.00	$0 00	$0.00	$0.00
ACCUM PV TOTAL BENEFIT:	$142,994 64	$147,447.58	$151,654.30	$155,492.90	$159,079 18	$162,511.52
Cumulative PV Costs (Thousands of $)						
ACCUM PV CAPACITY COST:	$0 00	$0.00	$0 00	$0.00	$0.00	$0.00
ACCUM PV PRODUCTION COST:	$28,896 02	$28,896.02	$28,896 02	$28,896.02	$28,896.02	$28,896.02
ACCUM PV REVENUE COST·	$1,744 66	$1,786.09	$1,824 02	$1,858.75	$1,890 55	$1,919 66
ACCUM PV INCENTIVE COST:	$102,359.94	$104,580.41	$106,613.44	$108,474.85	$110,179.12	$111,739 52
ACCUM PV MKT PROG COST:	$706 82	$722 15	$736 19	$749 04	$760 81	$771.58
ACCUM PV TOTAL COST:	$133,707 43	$135,984 67	$138,069 66	$139,978.65	$141,726.49	$143,326 78
CUMULATIVE PV NET BENEFITS.	$9,287 21	$11,462.92	$13,584.63	$15,514 25	$17,352.69	$19,184.74
ACCUM PV B/C·	1.07	1 08	1 10	1.11	1 12	1 13

	2024	2025	2026	2027	2028	2029	2030
YEARLY CHANGE IN DEF CAPACITY	-375.83	-375 83	-375.83	-375.83	-375.83	-375.83	-375 83
Nominal Benefits (Thousands of $)							
CAPACITY BENEFIT:	$20,361.76	$20,789 37	$21,225 92	$21,671.71	$22,126.80	$22,591 48	$23,065 91
PRODUCTION COST BENEFIT:	$3,993.50	$4,324.50	$4,353.25	$5,960.50	$5,461.75	$6,184.50	$6,030.50
REVENUE BENEFIT:	$0.00	$0 00	$0.00	$0.00	$0 00	$0 00	$0 00
TOTAL BENEFIT:	$24,355 26	$25,113 87	$25,579.17	$27,632.21	$27,588 55	$28,775.98	$29,096 41
Nominal Costs (Thousands of $)							
CAPACITY COST:	$0.00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00
PRODUCTION COST:	$0 00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
REVENUE COST:	$202.65	$252 64	$252.64	$165.03	$165 15	$168.37	$227 29
INCENTIVE COST:	$10,861 37	$10,861.37	$10,861.37	$10,861.37	$10,861.37	$10,861.37	$10,861.37
MKT PROG COST.	$75 00	$75.00	$75.00	$75.00	$75 00	$75.00	$75 00
TOTAL COST·	$11,139 02	$11,189.01	$11,189 01	$11,101.40	$11,101.52	$11,104.74	$11,163.66
NOMINAL NET BENEFITS:	$13,216.24	$13,924.86	$14,390.16	$16,530.81	$16,487.02	$17,671.25	$17,932 74
UTILITY DISCOUNT RATE:							
Annual PV Benefits (Thousands of $)							
PV CAPACITY BENEFIT.	$2,678 34	$2,503.74	$2,340.52	$2,187.95	$2,045.31	$1,911 98	$1,787.34
PV PRODUCTION COST BENEFIT:	$525 30	$520.82	$480 02	$601.76	$504.86	$523.41	$467.29
PV REVENUE BENEFIT	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
PV TOTAL BENEFIT	$3,203.63	$3,024 55	$2,820.54	$2,789.71	$2,550.18	$2,435 39	$2,254 64
Annual PV Costs (Thousands of $)							
PV CAPACITY COST.	$0 00	$0.00	$0.00	$0 00	$0.00	$0 00	$0.00
PV PRODUCTION COST:	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0 00
PV REVENUE COST·	$26.66	$30 43	$27.86	$16.66	$15.27	$14.25	$17.61
PV INCENTIVE COST:	$1,428.68	$1,308 07	$1,197.65	$1,096.55	$1,003.98	$919 23	$841 63
PV MKT PROG COST·	$9.87	$9.03	$8.27	$7.57	$6 93	$6 35	$5 81
PV TOTAL COST	$1,465.20	$1,347.53	$1,233.78	$1,120.78	$1,026 18	$939 83	$865.05
PV NET BENEFITS	$1,738.43	$1,677.02	$1,586.76	$1,668 93	$1,524.00	$1,495.57	$1,389 58
Cumulative PV Benefits (Thousands of $)							
ACCUM PV CAPACITY BENEFIT.	$150,512.01	$153,015.75	$155,356 27	$157,544.21	$159,589.53	$161,501.51	$163,288 85
ACCUM PV PRODUCTION COST BENEFIT:	$15,203.15	$15,723 96	$16,203.98	$16,805.75	$17,310 61	$17,834.02	$18,301 32
ACCUM PV REVENUE BENEFIT	$0 00	$0 00	$0.00	$0.00	$0.00	$0.00	$0 00
ACCUM PV TOTAL BENEFIT:	$165,715.16	$168,739.71	$171,560 25	$174,349 96	$176,900.14	$179,335.53	$181,590.17
Cumulative PV Costs (Thousands of $)							
ACCUM PV CAPACITY COST:	$0.00	$0.00	$0.00	$0.00	$0 00	$0 00	$0 00
ACCUM PV PRODUCTION COST:	$28,896.02	$28,896.02	$28,896.02	$28,896.02	$28,896.02	$28,896 02	$28,896 02
ACCUM PV REVENUE COST·	$1,946 31	$1,976.74	$2,004.60	$2,021.26	$2,036.53	$2,050 78	$2,068 39
ACCUM PV INCENTIVE COST:	$113,168.20	$114,476 27	$115,673.92	$116,770.47	$117,774.46	$118,693.69	$119,535.32
ACCUM PV MKT PROG COST:	$781.45	$790 48	$798 75	$806.32	$813 26	$819.60	$825.42
ACCUM PV TOTAL COST:	$144,791.98	$146,139.52	$147,373 29	$148,494 08	$149,520.26	$150,460.08	$151,325 14
CUMULATIVE PV NET BENEFITS.	$20,923 18	$22,600 20	$24,186 96	$25,855.89	$27,379 88	$28,875 45	$30,265.03
ACCUM PV B/C·	1 14	1.15	1.16	1.17	1.18	1.19	1 20

AVOIDABLE GENERATION COSTS

CTF LM P (3 UNITS) PURCHASE(s) 2001 ONLY		
(1) BASE YEAR	2001	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2001	
(3) WINTER CAPACITY	182	MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST	290	$/KW
(5) GENERATOR COST ESCALATION RATE	0.00	%
(6) GENERATOR FIXED O&M COST	2.63	$/KW-YR
(7) GENERATOR FIXED O&M ESCALATION RATE	0.00	%
(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.168	¢/KWH
(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	0.00	%
(10) GENERATOR CAPACITY FACTOR	5	%
(11) AVOIDED GENERATING UNIT FUEL COST	5.94	¢/KWH
(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	0.00	%

CTF LM G (3 UNITS) COMBUSTION TURBINE(s)			CCM G COMBINED CYCLE		
(1) BASE YEAR	2001		(1) BASE YEAR	2001	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2002		(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2008	
(3) WINTER CAPACITY	182	MW	(3) WINTER CAPACITY	366	MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST	290	$/KW	(4) BASE YEAR AVOIDED GENERATING UNIT COST	400	$/KW
(5) GENERATOR COST ESCALATION RATE	2.10	%	(5) GENERATOR COST ESCALATION RATE	2.10	%
(6) GENERATOR FIXED O&M COST	2.63	$/KW-YR	(6) GENERATOR FIXED O&M COST	2.68	$/KW-YR
(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%	(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%
(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.168	¢/KWH	(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	0.248	¢/KWH
(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%	(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%
(10) GENERATOR CAPACITY FACTOR	5	%	(10) GENERATOR CAPACITY FACTOR	50	%
(11) AVOIDED GENERATING UNIT FUEL COST	4.43	¢/KWH	(11) AVOIDED GENERATING UNIT FUEL COST	3.09	¢/KWH
(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%	(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%
CTF G COMBUSTION TURBINE			**CCM F COMBINED CYCLE**		
(1) BASE YEAR	2001		(1) BASE YEAR	2001	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2004		(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2009	
(3) WINTER CAPACITY	182	MW	(3) WINTER CAPACITY	579	MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST	290	$/KW	(4) BASE YEAR AVOIDED GENERATING UNIT COST	338	$/KW
(5) GENERATOR COST ESCALATION RATE	2.10	%	(5) GENERATOR COST ESCALATION RATE	2.10	%
(6) GENERATOR FIXED O&M COST	2.63	$/KW-YR	(6) GENERATOR FIXED O&M COST	1.67	$/KW-YR
(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%	(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%
(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	1.168	¢/KWH	(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	0.214	¢/KWH
(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%	(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%
(10) GENERATOR CAPACITY FACTOR	5	%	(10) GENERATOR CAPACITY FACTOR	50	%
(11) AVOIDED GENERATING UNIT FUEL COST	3.00	¢/KWH	(11) AVOIDED GENERATING UNIT FUEL COST	3.12	¢/KWH
(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%	(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%
CCM F COMBINED CYCLE			**3CTEA G COMBUSTION TURBINE(s)**		
(1) BASE YEAR	2001		(1) BASE YEAR	2001	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2006		(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2011	
(3) WINTER CAPACITY	579	MW	(3) WINTER CAPACITY	275	MW
(4) BASE YEAR AVOIDED GENERATING UNIT COST	338	$/KW	(4) BASE YEAR AVOIDED GENERATING UNIT COST	325	$/KW
(5) GENERATOR COST ESCALATION RATE	2.10	%	(5) GENERATOR COST ESCALATION RATE	2.10	%
(6) GENERATOR FIXED O&M COST	1.67	$/KW-YR	(6) GENERATOR FIXED O&M COST	5.30	$/KW-YR
(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%	(7) GENERATOR FIXED O&M ESCALATION RATE	2.10	%
(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	0.214	¢/KWH	(8) AVOIDED GEN UNIT VARIABLE O&M COSTS	0.988	¢/KWH
(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%	(9) GENERATOR VARIABLE O&M COST ESCALATION RATE	3.00	%
(10) GENERATOR CAPACITY FACTOR	50	%	(10) GENERATOR CAPACITY FACTOR	5	%
(11) AVOIDED GENERATING UNIT FUEL COST	3.03	¢/KWH	(11) AVOIDED GENERATING UNIT FUEL COST	3.18	¢/KWH
(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%	(12) AVOIDED GEN UNIT FUEL ESCALATION RATE	1.00	%

FLORIDA POWER CORPORATION
General Service Customer Billing
BY LOAD FACTOR
Total Demand & Energy Charges @ Present Rates
Reflects Billing Adjustments as of 04/01/01

Customer Monthly Load Factor	****GS Non-Demand, Standard Rate**** (GS-1) Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh	****GS Demand, Standard Rate **** (GSD-1) Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh
0%	0.00	-	8.107	0.00	-	16.204
5%	2.96	8.11	8.107	5.91	16.20	5.526
10%	5.92	8.11	8.107	7.93	10.87	5.526
15%	8.88	8.11	8.107	9.95	9.09	5.526
20%	11.84	8.11	8.107	11.97	8.20	5.526
25%	14.79	8.11	8.107	13.98	7.66	5.526
30%	17.75	8.11	8.107	16.00	7.31	5.526
35%	20.71	8.11	8.107	18.02	7.05	5.526
40%	23.67	8.11	8.107	20.03	6.86	5.526
45%	26.63	8.11	8.107	22.05	6.71	5.526
50%	29.59	8.11	8.107	24.07	6.59	5.526
55%	32.55	8.11	8.107	26.08	6.50	5.526
60%	35.51	8.11	8.107	28.10	6.42	5.526
65%	38.47	8.11	8.107	30.12	6.35	5.526
70%	41.43	8.11	8.107	32.14	6.29	5.526
75%	44.38	8.11	8.107	34.15	6.24	5.526
80%	47.34	8.11	8.107	36.17	6.19	5.526
85%	50.30	8.11	8.107	38.19	6.15	5.526
90%	53.26	8.11	8.107	40.20	6.12	5.526
95%	56.22	8.11	8.107	42.22	6.09	5.526
100%	59.18	8.11	-	44.24	6.06	-

Customer Monthly Load Factor	Typical Usage Split % On-Peak	% Off-Peak	**GS Non-Demand, Optional TOU Rate** (GST-1) Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh	**GS Demand, Optional TOU Rate** (GSDT-1) Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh
0%	-	-	0.00	-	10.220	0.00	-	16.798
5%	48.0%	52.0%	3.73	10.22	9.709	6.13	16.80	6.015
10%	46.0%	54.0%	7.27	9.96	9.198	8.33	11.41	5.826
15%	44.0%	56.0%	10.63	9.71	8.687	10.45	9.55	5.636
20%	42.0%	58.0%	13.80	9.45	8.495	12.51	8.57	5.565
25%	40.5%	59.5%	16.90	9.26	8.112	14.54	7.97	5.423
30%	39.0%	61.0%	19.86	9.07	7.729	16.52	7.54	5.281
35%	37.5%	62.5%	22.69	8.88	7.345	18.45	7.22	5.139
40%	36.0%	64.0%	25.37	8.69	6.962	20.32	6.96	4.997
45%	34.5%	65.5%	27.91	8.50	6.579	22.15	6.74	4.855
50%	33.0%	67.0%	30.31	8.30	6.195	23.92	6.55	4.713
55%	31.5%	68.5%	32.57	8.11	5.812	25.64	6.39	4.571
60%	30.0%	70.0%	34.69	7.92	5.429	27.31	6.24	4.429
65%	28.5%	71.5%	36.67	7.73	6.834	28.93	6.10	4.950
70%	28.0%	72.0%	39.17	7.66	6.707	30.73	6.01	4.902
75%	27.5%	72.5%	41.62	7.60	6.579	32.52	5.94	4.855
80%	27.0%	73.0%	44.02	7.54	6.451	34.29	5.87	4.808
85%	26.5%	73.5%	46.37	7.47	6.323	36.05	5.81	4.760
90%	26.0%	74.0%	48.68	7.41	6.195	37.79	5.75	4.713
95%	25.5%	74.5%	50.94	7.35	6.068	39.51	5.70	4.665
100%	25.0%	75.0%	53.16	7.28	-	41.21	5.65	-

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FLORIDA POWER CORPORATION
General Service Customer Billing
BY LOAD FACTOR

Total Demand & Energy Charges @ Proposed Rates
Reflects Billing Adjustments as of 04/01/01 modified
to include the effects of a 12CP & 25%AD method and reduced IS/CS credits

	****GS Non-Demand, Standard Rate**** (GS-1)			****GS Demand, Standard Rate **** (GSD-1)		
Customer Monthly Load Factor	Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh	Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh
0%	0.00	-	8.010	0.00	-	16.191
5%	2.92	8.01	8.010	5.91	16.19	5.513
10%	5.85	8.01	8.010	7.92	10.85	5.513
15%	8.77	8.01	8.010	9.93	9.07	5.513
20%	11.69	8.01	8.010	11.95	8.18	5.513
25%	14.62	8.01	8.010	13.96	7.65	5.513
30%	17.54	8.01	8.010	15.97	7.29	5.513
35%	20.47	8.01	8.010	17.98	7.04	5.513
40%	23.39	8.01	8.010	19.99	6.85	5.513
45%	26.31	8.01	8.010	22.01	6.70	5.513
50%	29.24	8.01	8.010	24.02	6.58	5.513
55%	32.16	8.01	8.010	26.03	6.48	5.513
60%	35.08	8.01	8.010	28.04	6.40	5.513
65%	38.01	8.01	8.010	30.06	6.33	5.513
70%	40.93	8.01	8.010	32.07	6.28	5.513
75%	43.86	8.01	8.010	34.08	6.22	5.513
80%	46.78	8.01	8.010	36.09	6.18	5.513
85%	49.70	8.01	8.010	38.10	6.14	5.513
90%	52.63	8.01	8.010	40.12	6.11	5.513
95%	55.55	8.01	8.010	42.13	6.07	5.513
100%	58.47	8.01	-	44.14	6.05	-

	Typical Usage Split		**GS Non-Demand, Optional TOU Rate** (GST-1)			**GS Demand, Optional TOU Rate** (GSDT-1)		
Customer Monthly Load Factor	% On-Peak	% Off-Peak	Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh	Total Monthly Bill $/kw	Effective Billing Cents/kwh	Charge per additional kwh Cents/kwh
0%	-	-	0.00	-	10.015	0.00	-	16.809
5%	48.0%	52.0%	3.66	10.01	9.531	6.14	16.81	5.960
10%	46.0%	54.0%	7.13	9.77	9.047	8.31	11.38	5.789
15%	44.0%	56.0%	10.44	9.53	8.562	10.42	9.52	5.619
20%	42.0%	58.0%	13.56	9.29	8.381	12.47	8.54	5.554
25%	40.5%	59.5%	16.62	9.11	8.018	14.50	7.95	5.426
30%	39.0%	61.0%	19.55	8.93	7.655	16.48	7.53	5.298
35%	37.5%	62.5%	22.34	8.74	7.292	18.42	7.21	5.170
40%	36.0%	64.0%	25.00	8.56	6.928	20.30	6.95	5.042
45%	34.5%	65.5%	27.53	8.38	6.565	22.14	6.74	4.914
50%	33.0%	67.0%	29.93	8.20	6.202	23.94	6.56	4.786
55%	31.5%	68.5%	32.19	8.02	5.839	25.68	6.40	4.658
60%	30.0%	70.0%	34.32	7.84	5.476	27.38	6.25	4.529
65%	28.5%	71.5%	36.32	7.65	6.807	29.04	6.12	4.999
70%	28.0%	72.0%	38.81	7.59	6.686	30.86	6.04	4.957
75%	27.5%	72.5%	41.25	7.53	6.565	32.67	5.97	4.914
80%	27.0%	73.0%	43.64	7.47	6.444	34.46	5.90	4.871
85%	26.5%	73.5%	46.00	7.41	6.323	36.24	5.84	4.828
90%	26.0%	74.0%	48.30	7.35	6.202	38.01	5.78	4.786
95%	25.5%	74.5%	50.57	7.29	6.081	39.75	5.73	4.743
100%	25.0%	75.0%	52.79	7.23	-	41.48	5.68	-