Steel Hector & Davis
Tallahassee, Florida

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February 5, 1996

By Hand Delivery

B.anca S. Bayó, Director
Records and Reporting
Florida Public Service Commission
4075 Esplanade Way, Room 110
Tallahassee, Florida 32399-0850

960130-EG

Re: Commercial/Industrial Load Control Program

Dear Ms. Bayó:

Enclosed for filing on behalf of Florida Power & Light Company are the original and fifteen (15) copies of Petition Of Florida Power & Light Company To Limit Availability Of Commercial/Industrial Load Control Program.

If you or your Staff have any questions regarding this filing, please contact me.

Very truly yours,

Charles A. Guyton

Charles A. Guyton

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TAL/14321

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DOCUMENT NUMBER-DATE
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Tallahassee, FL 32301-1804
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition of Florida Power &	**)**	**Docket No.**	960130-EG
Light Company To Limit Availability	**)**		
Of Commercial/Industrial Load	**)**	**Filed:**	**February 5, 1996**
Control Program	**)**		

PETITION OF FLORIDA POWER & LIGHT COMPANY TO LIMIT AVAILABILITY OF COMMERCIAL/INDUSTRIAL LOAD CONTROL PROGRAM

Florida Power & Light Company ("FPL"), pursuant to Sections 366.06 and 366.82(2), Florida Statutes (1993) and Florida Administrative Code Rule 25-6.0438, hereby petitions the Florida Public Service Commission ("Commission") to limit availability to FPL's Commercial/Industrial Load Control ("CILC") Program by approving the tariff sheets attached as Appendix A to this petition. In support of its petition, FPL states:

1. FPL is an investor owned electric utility regulated by the Commission pursuant to Chapter 366, Florida Statutes. FPL is subject to the Florida Energy Efficiency and Conservation Act (FEECA"), Sections 366.80-366.85 and 403.519, Florida Statutes (1993), and its Energy Conservation Cost Recovery ("ECCR") clause is subject to the Commission's jurisdiction. FPL is substantially affected thereby.

2. FPL's address is 9250 West Flagler Street, Miami, FL 33174. Correspondence, notices, orders and other documents concerning this Petition should be sent to:

Charles A. Guyton
Steel Hector & Davis
Suite 601
215 South Monroe Street
Tallahassee, FL 32301

William G. Walker, III
Vice President, Regulatory Affairs
Florida Power & Light Company
9250 West Flagler Street
Miami, FL 33174

3. The objective of FPL's CILC Program is to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortfalls. The CILC Program is available to customers that allow FPL to control 200 kW or more of their load. Customers can participate by allowing FPL to control directly selected switchgear in the customer's facility or to transfer the load to the customer's standby generator. The customer receives service under a lower rate in return for allowing FPL to control its load.

4. FPL initiated an experimental CILC project in 1987 and has had an approved CILC Program as part of its DSM Plan since October 1990. Modifications to FPL's CILC Program were approved most recently as part of the Commission's approval of FPL's DSM Plan in Docket No. 941170-EG.

5. FPL seeks to modify its CILC Program by limiting availability to customers who have executed CILC Agreements as of the date of the filing of this petition. Essentially, FPL seeks to close its CILC Program to additional customers.

6. FPL seeks to limit CILC Program availability due to cost-effectiveness considerations. FPL's analysis underlying its recently approved DSM Plan showed that the cost-effective incremental level of CILC for the period 1995 through 2000 was, at least, 137 MW(at the meter). That is an incremental MW level over and above the 335 MW (at the meter) already being served under CILC through 1994. The cost-effectiveness runs underlying that analysis as well as the Commission required program information for CILC filed in Docket No. 941170-EG are attached as Appendix B to this petition. As of the date of this petition, FPL has already received executed CILC Agreements totaling (at the meter) approximately 150 MW. However, FPL has recently received notice from customers totalling 1.3 MW that they desire to withdraw from their

CILC service, and it is reasonable to expect over time that other existing customers may opt out of CILC service. In addition, it is reasonable to assume that some of the customers who have signed up for CILC service as of the date of the filing of this petition to take service at some time in the future will not take the service. Thus, while it is prudent to slightly oversubscribe CILC service to account for program attrition, FPL believes it has essentially signed the level of CILC that will ultimately equate to the level of CILC shown to be cost-effective in the DSM Plan Approval docket. Consequently, FPL is seeking to limit the CILC rate availability to customers who, as of February 5. 1996, were either already being served under the CILC rate or were not yet being served under the CILC rate but who have executed CILC Agreements. This would close the CILC rate to all customers who have not yet signed a CILC Agreement. Filing sooner to limit CILC availability was thought by FPL to unnecessarily complicate the DSM Plan Approval docket, but now that FPL's Plan has been approved, FPL believes it is prudent and consistent with the Commission's Non-Firm Service Rule, Florida Administrative Code Rule 25-4.6048, to seek to limit CILC availability, even though the Commission encouraged FPL in Docket No. 94110-EG to exceed its conservation goals and made the failure to achieve conservation goals potentially subject to penalties.

7. FPL's supplemental analysis of cost-effectiveness, which is attached as Appendix C and is premised upon assumptions consistent with the analyses used to approve FPL's DSM Plan, shows that additional CILC placed on the rate in 1996 to meet a 2004 combined cycle unit (the next resource need on FPL's system assuming the DSM Plan approval assumptions and implementation of FPL's approved DSM Plan) is not cost-effective. Additional CILC on FPL's system may well become cost-effective at some date in the future; however, under the present circumstances its availability should be limited as requested by FPL. FPL will continue to analyze CILC as a potential

DSM option in its planning process, and, if appropriate, may petition the Commission at some point in the future to reopen a CILC rate and related agreement to new customers.

8. FPL asks that the Commission act expeditiously on this application. Although FPL is essentially at the total MW shown to be cost-effective in its DSM Plan filing, FPL believes there is a substantial potential of significantly exceeding the cost-effective level if the rate stays open. FPL anticipates that there are customers with as much as an additional 70 MW poised to sign up for CILC. Expeditious Commission action to limit availability could potentially avoid a customer rush to sign up and the similar problems which arose when a limited QF Standard Offer was made available.

WHEREFORE, FPL respectfully petitions the Commission to approve the tariff sheets filed as Appendix A and limit the availability of CILC on FPL's system to customers either already taking service under the CILC rate schedule or with executed CILC Agreements received by FPL as of February 5, 1996.

Respectfully submitted,

Steel Hector & Davis
Suite 601
215 South Monroe Street
Tallahassee, FL 32301

Attorneys for Florida Power
& Light Company

By: Charles A. Guyton
Charles A. Guyton

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Petition Of Florida Power & Light Company To Limit Availability Of Commercial/Industrial Load Control Program was mailed this 5th day of February, 1996 to the following:

Jack Shreve, Esquire
John Roger Howe, Esquire
Office of Public Counsel
111 West Madison Street
Room 812
Tallahassee, Florida 32399-1400

Charles A. Guyton

TAL/14320-1

APPENDIX A

COMMERCIAL/INDUSTRIAL LOAD CONTROL PROGRAM
(OPTIONAL)
(Closed Schedule)

RATE SCHEDULE: CILC-1

AVAILABLE:

In all territory served. Available to any commercial or industrial customer to which the load control provisions of this schedule can feasibly be applied,~~through the execution of a Commercial/Industrial Load Control Program Agreement with the Company.~~ who, as of February 5, 1996, was either taking service pursuant to this schedule or had a fully executed copy of a Commercial/Industrial Load Control Agreement with the Company.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer as a part of the Commercial/Industrial Load Control Program Agreement between the Customer and the Company, who agrees to allow the Company to control at least 200 kw of the Customer's load, or agrees to operate backup generation equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kw of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a "Commercial/Industrial Load Control Program Agreement" with the Company for service under this schedule. To establish the initial qualification for service under this schedule, the Customer must have had an On-Peak Demand (as defined below) during the summer rating period (April through October) for at least three of the previous twelve (12) months of at least 200 kw greater than the Firm Demand or Controllable Demand (as applicable) level specified in Section 4 of the Commercial/Industrial Load Control Program Agreement. This controlled load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz at any available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to control by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Maximum Demand for delivery voltage below 69 kv. Standby Service is not provided hereunder. Resale of service is not permitted hereunder.

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level:		Distribution below 69 kv		Transmission 69 kv & above
		CILC-1(G)	CILC-1(D) 500 kw & above	CILC-1(T)
Maximum Demand Level:		200-499 kw		
Customer Charge:		$600.00	$ 600.00	$ 3,200.00
Demand Charges:				
Base Demand Charges:				
per kw of Maximum Demand in excess of 10 kw		$ 2.43	-	-
per kw of Maximum Demand		-	$2.43	None
per kw of Load Control On-Peak Demand. Where Firm kw is < 10 kw, the Load Control On-Peak Demand shall be adjusted by the difference between 10 kw and Firm kw		$ 1.16	-	-
per kw of Load Control On-Peak Demand		-	$1.16	$ 1.15
per kw of Firm On-Peak Demand in excess of 10 kw		$ 5.85	-	-
per kw of Firm On-Peak Demand		-	$5.85	$ 6.25
Capacity Payment Charge	See Sheet No. 8.030			
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kwh		1.457¢	1.142¢	0.951¢
Off-Peak Period charge per kwh		1.457¢	1.142¢	0.951¢
Conservation Charge	See Sheet No. 8.030			
Environmental Charge	See Sheet No. 8.030			
Additional Charges:				
Fuel Charge	See Sheet No. 8.030			
Franchise Fee	See Sheet No. 8.031			
Tax Clause	See Sheet No. 8.031			

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

(Continued from Sheet No. 8.651)

LOAD CONTROL:

Control Condition:

The Customer's controllable load served under this rate schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.

Frequency: The Control Conditions will typically result in less than fifteen (15) control periods per year and will not exceed twenty-five (25) control periods per year. Typically, the Company will not initiate a control period within six (6) hours of a previous control period.

Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a control period.

Duration: The duration of a single period of load control will typically be four (4) hours and will not exceed six (6) hours.

In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.

Customer Responsibility:

Upon the successful installation of the load control equipment and/or any necessary backup generation equipment, a test of this equipment will be conducted between the hours of 7 a.m. and 6 p.m., Monday through Friday, excluding holidays, as specified in the Commercial/Industrial Load Control Program Agreement.

The Customer shall be responsible for providing and maintaining the appropriate equipment required to allow the Company to electrically control the Customer's load, as specified in the Commercial/Industrial Load Control Program Agreement.

The Company will control the controllable portion of the Customer's service for a one-hour period (during designated on-peak periods), once per year for Company testing purposes on the first Wednesday in November or, if not possible, at a mutually agreeable time and date, if the Customer's load has not been successfully controlled during a load control event in the previous twelve (12) months. Testing purposes include the testing of the load control equipment to ensure that the load is able to be controlled within the agreed specifications.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued On Sheet No. 8.653)

(Continued from Sheet No. 8.652)

LOAD CONTROL PERIOD:

All hours established by the Company during a monthly billing period in which:

1. the Customer's load is controlled (which includes the operation of the Customer's generation equipment), or
2. the Customer is billed pursuant to the Continuity of Service Provision.

DEMAND:

Demand is the kw to the nearest whole kw, as determined from the Company's metering equipment, for a 30-minute period as adjusted for power factor.

ON-PEAK DEMAND:

On-Peak Demand is the kw to the nearest whole kw, as determined from the Company's metering equipment, for a 30-minute period of Customer's greatest use for the designated on-peak periods during the month as adjusted for power factor.

MAXIMUM DEMAND:

Maximum Demand shall be the greater of the current month's demand whenever it occurs or the highest demand for the prior twenty-three (23) months. A Customer's Maximum Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

2. Demand reductions resulting from the installation of other permanent and quantifiable efficiency measures, upon verification by FPL; or

3. Permanent changes to customer facilities that result in a permanent loss of electric load, including any fuel substitution resulting in permanently reduced electricity consumption, upon verification by FPL.

The re-established Maximum Demand shall be the higher of the actual demand registered in the next billing period following the Customer's written request or the prior Maximum Demand minus the calculated demand reduction. Requests to re-establish the Maximum Demand may be processed up to twice per calendar year when more than one efficiency measure is installed or where the same efficiency measure is installed in phases.

CALCULATION OF FIRM DEMAND AND LOAD CONTROL ON-PEAK DEMAND

There will be two methods of calculating the Firm Demand and Load Control On-Peak Demand for the Customer, depending on the type of demand designated in the Commercial/Industrial Load Control Program Agreement.

THIS SECTION IS APPLICABLE TO CUSTOMERS DESIGNATING A FIRM DEMAND LEVEL:

FIRM ON-PEAK DEMAND:

The Customer's monthly Firm On-Peak Demand shall be the lesser of the "Firm Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company, or the Customer's highest on-peak demand during the month. The level of "Firm Demand" specified in the Customer's Commercial/Industrial Load Control Program Agreement shall not be exceeded during the periods when the Company is controlling the Customer's load.

(Continued on Sheet No. 8.654)

(Continued from Sheet No. 8.653)

LOAD CONTROL ON-PEAK DEMAND:

Load Control On-Peak Demand shall be the Customer's highest demand for the designated on-peak periods during the month less the Customer's "Firm Demand".

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS FOR CUSTOMERS DESIGNATING FIRM DEMAND LEVEL:

Customers notified of a load control event should meet their Firm Demand during periods when the Company is controlling load. However, energy will be made available during control periods if the Customer's failure to meet its Firm Demand is a result of one of the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or

2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or

3. adding firm load that was not previously non-firm load to the Customer's facility, or

4. an event affecting local, state or national security, or

5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the "Firm Demand") for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt-hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rate schedule as described in TERM OF SERVICE.

If the Customer exceeds the "Firm Demand" during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed the difference between the Firm On-Peak Demand Charge and the Load Control On-Peak Demand Charge for the excess kw for the prior sixty (60) months or the number of months the Customer has been billed under this rate schedule, whichever is less, and

2. billed a penalty charge of $1.00 per kw of excess kw for each month of rebilling.

Excess kw for rebilling and penalty charges is determined by taking the difference between the maximum demand during the Load Control Period and the Customer's "Firm Demand". For rebilling under paragraph 1 above, where Firm kw is <10 kw, the maximum demand during the Load Control Period shall be adjusted by the difference between 10 kw and Firm kw. The Customer will not be rebilled or penalized twice for the same excess kw in the calculation described above.

(Continued on Sheet No. 8.655)

(Continued from Sheet No. 8.654)

THIS SECTION IS APPLICABLE TO CUSTOMERS DESIGNATING A CONTROLLABLE DEMAND LEVEL:

FIRM ON-PEAK DEMAND:

The Customer's monthly Firm On-Peak Demand shall be the On-Peak Demand during the month less the "Controllable Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company.

LOAD CONTROL ON-PEAK DEMAND:

Load Control On-Peak Demand shall be the "Controllable Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company.

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS FOR CUSTOMERS DESIGNATING A CONTROLLABLE DEMAND LEVEL:

Customers notified of a load control event should achieve the Controllable Demand Level during periods when the Company is controlling load, except under the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or
2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or
3. adding firm load that was not previously non-firm load to the Customer's facility, or
4. an event affecting local, state or national security, or
5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the "Firm Demand") for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rate schedule as described in TERM OF SERVICE.

If the Customer does not achieve the Controllable Demand level during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed the difference between the Firm On-Peak Demand Charge and the Load Control On-Peak Demand Charge for the rebilling kw for the prior sixty (60) months or the number of months the Customer has been billed under this rate schedule, whichever is less, and

(Continued on Sheet No. 8.656)

(Continued from Sheet No. 8.655)

2. billed a penalty charge of $1.00 per kw of excess kw for each month of rebilling

The kw for rebilling and penalty charges is determined by taking the difference between the Controllable Demand and the maximum demand actually reduced during the Load Control Period. For rebilling under paragraph 1 above, where Firm kw is <10 kw, the maximum demand during the Load Control Period shall be adjusted by the difference between 10 kw and Firm kw. The Customer will not be rebilled or penalized twice for the same excess kw in the calculation described above.

As long as the Customer's load reduction from the operation of the control circuit results in a demand during the control period that is at or below the calculated Firm Demand for that billing period, the Customer will not be required to pay the penalty and rebilling charges.

TERM OF SERVICE:

During the first year of service under this schedule, the Customer will determine whether or not this program is appropriate for the Customer and may request to exit the program subject to the Provisions for Early Termination. It is intended that the Company will continue to provide and the Customer will continue to take service under this rate schedule for the life of the generating unit which has been avoided by the rate. There is, however, a five-year termination notice provision which will allow either the Customer or the Company to terminate service under this schedule should there be circumstances under which the termination of the Customer's participation or the Company's offering of the program is desired.

Service under this rate schedule shall continue, subject to Limitation of Availability, until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination. Should a Customer terminate service or be removed by the Company and later desire to resume service under this rate schedule, the Customer must provide five (5) years' written notice prior to resuming service under this schedule.

The Company may terminate service under this rate schedule at any time for the Customer's failure to comply with the terms and conditions of this rate schedule or the Commercial/Industrial Load Control Program Agreement. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the Customer's failure to comply. The Company may then terminate service under this rate schedule at the end of the 90-day notice period unless the Customer takes measures necessary to eliminate, to the Company's satisfaction, the compliance deficiencies described by the Company. Notwithstanding the foregoing, if, at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under this rate schedule and bill the Customer under the otherwise applicable firm service rate schedule.

PROVISIONS FOR EARLY TERMINATION:

Transfers, with less than five (5) years' written notice, to any firm retail rate schedule for which the Customer would qualify, may be permitted if it can be shown that such transfer is in the best interests of the Customer, the Company and the Company's other customers.

If the Customer no longer wishes to receive electric service in any form from the Company, or decides to cogenerate to serve all of the previously controlled Load Control On-Peak Demand and to take interruptible standby service from the Company, the Customer may terminate the Commercial/Industrial Load Control Program Agreement by giving at least thirty (30) days' advance written notice to the Company.

(Continued on Sheet No. 8.657)

(Continued from Sheet No. 8.656)

If service under this schedule is terminated for any reason, the Customer will not be rebilled as specified in Charges for Early Termination if:

a. it has been demonstrated to the satisfaction of the Company that the impact of such transfer of service on the economic cost-effectiveness of the Company's CILC program is in the best interests of the Customer, the Company and the Company's other customers, or

b. the Customer is required to transfer to another retail rate schedule as a result of Commission Rule 25-6.0438, F.A.C., or

c. the termination of service under this rate schedule is the result of either the Customer's ceasing operations at its facility (without continuing or establishing similar operations elsewhere in the Company's service area), or a decision by the Customer to cogenerate to serve all of the previously controlled Load Control On-Peak Demand and to take interruptible standby service from the Company, or

d. any other Customer(s) with demand reduction equivalent to, or greater than, that of the existing Customer(s) agree(s) to take service under this schedule and the MW demand reduction commitment to the Company's Generation Expansion Plan has been met and the new replacement Customer(s) has (have) the equipment installed and is (are) available to perform load control, or

e. FPL determines that the Customer's MW reduction is no longer needed in accordance with the FPL Numeric Commercial/Industrial Conservation Goals.

In the event the Customer pays the Charges for Early Termination because no replacement Customer(s) is (are) available as specified in paragraph d. above, but the replacement Customer(s) does(do) become available within 12 months from the date of termination of service under this schedule or FPL later determines that there is no need for the MW reduction in accordance with the FPL Numeric Commercial/Industrial Conservation Goals, then the Customer will be refunded all or part of the rebilling and penalty in proportion to the amount of MW obtained to replace the lost capacity less the additional cost incurred by the Company to serve those MW during any load control periods which may occur before the replacement Customer(s) became available.

Charges for Early Termination:

In the event that:

a) service is terminated by the Company for any reason(s) specified in this section, or

b) there is a termination of the Customer's existing service and, within twelve (12) months of such termination of service, the Company receives a request to re-establish service of similar character under a firm service or a curtailable service rate schedule, or under this schedule with a shift from non-firm load to firm service,

    i) at a different location in the Company's service area, or

    ii) under a different name or different ownership, or

    iii) under other circumstances whose effect would be to increase firm demand on the Company's system without the requisite five (5) years' advance written notice, or

c) the Customer transfers the controllable portion of the Customer's load to "Firm Demand" or to a firm or a curtailable service rate schedule without providing at least five (5) years' advance written notice,

(Continued on Sheet No. 8.658)

(Continued on Sheet No. 8.657)

then the Customer will be:

1. rebilled under the otherwise applicable firm or curtailable service rate schedule for the shorter of (a) the most recent prior sixty (60) months during which the Customer was billed for service under this rate schedule, or (b) the number of months the Customer has been billed under this rate schedule, and

2. billed a penalty charge of $1.00 per kw times the number of months rebilled in No. 1 above times the highest Load Control On-Peak Demand occurring during the current month or the prior twenty-three (23) months.

SPECIAL PROVISIONS:

1. Control of the Customer's load shall be accomplished through the Company's load management systems by use of control circuits connected directly to the Customer's switching equipment or the Customer's load may be controlled by use of an energy management system where the firm demand or controllable demand level can be established or modified only by means of joint access by the Customer and the Company.

2. The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned load control equipment.

3. It shall be the responsibility of the Customer to determine that all electrical equipment to be controlled is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

4. The Company is not required to install load control equipment if the installation cannot be economically justified.

5. Billing under this schedule will commence after the installation, inspection and successful testing of the load control equipment.

6. Maintenance of generation equipment necessary for the implementation of load control will not be scheduled during periods where the Company projects that it would not be able to withstand the loss of its largest unit and continue to serve firm service customers.

CONTINUITY OF SERVICE PROVISION:

In order to minimize the frequency and duration of interruptions or requests that the Customer operate its backup generation equipment, the Company will attempt to obtain reasonably available additional capacity and/or energy during periods for which interruptions or operation of the Customer's backup generation equipment may be requested. The Company's obligation in this regard is no different than its obligation in general to purchase power to serve its Customers during a capacity shortage; in other words, the Company is not obligated to account for, or otherwise reflect in its generation planning and construction, the possibility of providing capacity and/or energy under this Continuity of Service Provision. Any non-firm customers so electing to receive capacity and/or energy which enable(s) the Company to continue service to the Customer's non-firm loads during these periods will be subject to the additional charges set forth below.

(Continued on Sheet No. 8.659)

(Continued from Sheet No. 8.658)

In the event a Customer elects not to have its non-firm load interrupted pursuant to this Schedule, the Customer shall pay, in addition to the normal charges provided hereunder, a charge reflecting the additional costs incurred by the Company in continuing to provide service, less the applicable class fuel charge for the period during which the load would otherwise have been controlled (see Sheet No. 8.830). This incremental charge shall apply to the non-firm customer for all consumption above the Customer's Firm Demand during the time in which the non-firm load would otherwise have been controlled. If, for any reason during such period, this capacity and/or energy is (are) no longer available or cannot be accommodated by the Company's system, the terms of this Special Provision will cease to apply and interruptions will be required for the remainder of such period unless energy use is for one of the conditions outlined under "Provisions for Energy Use During Control Periods".

Any customer served under this rate schedule may elect to minimize the interruptions through the procedure described above. The initial election must be made in the Commercial/Industrial Load Control Program Agreement. Any adjustment or change to the election must be provided to the Company with at least 24 hours' written notice (not including holidays and weekends) and must be by mutual agreement, in writing, between the Customer and the Company. In such case, the written notice will replace any prior election with regard to this Continuity of Service Provision.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision(s) of this schedule and said "General Rules and Regulations for Electric Service", the provision(s) of this schedule shall apply.

DEFINITIONS:

Generating Capacity Emergency:

A Generating Capacity Emergency exists when any one of the electric utilities in the state of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations.

Force Majeure:

Force Majeure for the purposes of this schedule means causes not within the reasonable control of the Customer affected and not caused by the negligence or lack of due diligence of the Customer. Such events or circumstances may include acts of God, strikes, lockouts or other labor disputes or difficulties, wars, blockades, insurrections, riots, environmental constraints lawfully imposed by Federal, State, or local governmental bodies, explosions, fires, floods, lightning, wind, accidents to equipment or machinery, or similar occurrences.

Backup Generation Equipment:

Backup generation equipment shall be Customer-provided generation equipment and switch gear. This generation equipment will be utilized for emergency purposes, including periods when the Company is controlling load.

COMMERCIAL/INDUSTRIAL LOAD CONTROL PROGRAM AGREEMENT

This Agreement is made this __________ day of ____________________, 19______, by and between ______________________________ (hereinafter called the "Customer"), located at ____________________ ________________ in ______________, Florida, and FLORIDA POWER & LIGHT COMPANY, a corporation organized under the laws of the State of Florida (hereinafter called the "Company"). This agreement is available and applicable only for customers who, as of February 5, 1996, were either taking service under the CILC Schedule or had fully executed copies of an earlier approved version of this agreement.

WITNESSETH

For and in consideration of the mutual covenants and agreements expressed herein, the Company and the Customer agree as follows:

1. The Company agrees to furnish and the Customer agrees to take electric service subject to the terms and conditions of the Company's Commercial/Industrial Load Control Program Schedule CILC-1 ("Schedule CILC-1") as currently approved or as may be modified from time to time by the Florida Public Service Commission ("Commission"). The Customer understands and agrees that, whenever reference is made in this Agreement to Schedule CILC-1, both parties intend to refer to Schedule CILC-1 as it may be modified from time to time. A copy of the Company's presently approved Schedule CILC-1 is attached hereto as Exhibit A and is hereby made an integral part of this Agreement.

2. Service under Schedule CILC-1 shall continue, subject to Limitation of Availability, until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination. Should the Customer terminate service or be removed by the Company and later desire to resume service under Schedule CILC-1, the Customer must provide five (5) years' written notice prior to resuming service under Schedule CILC-1.

3. Service under Schedule CILC-1 will be subject to determinations made under Commission Rules 25-17.0021(4), F.A.C. Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Service -Terms and Conditions, or any other Commission determination(s).

4. The Customer agrees either (i) to not exceed a usage level of ______kw ("Firm Demand") during the periods when the Company is controlling the Customer's service, or (ii) to provide a load reduction of ______ kw ("Controllable Demand") during periods when the Company is controlling the Customer's service. If the Customer chooses to operate backup generation equipment in parallel with FPL, the Customer shall enter into an interconnection agreement with the Company prior to operating such equipment in parallel with the Company's electrical system. The "Firm Demand" level (as applicable) shall not be exceeded during periods when the Company is controlling load; nor shall the "Controllable Demand" level (as applicable) be reduced during periods when the Company has requested that the Customer operate its equipment to meet the "Controllable Demand" level. Upon mutual agreement of the Company and the Customer, the Customer's "Firm Demand" or "Controllable Demand" may be subsequently raised or lowered, so long as the change in the "Firm Demand" or "Controllable Demand" level is not a result of a transfer of load from the controllable portion of the Customer's load. The Customer shall notify the Company, in writing, at least ninety (90) days prior to either adding firm load, or reducing or removing any of the Customer's backup generation equipment.

(Continued from Sheet No. 9.490)

5. Prior to the Customer's receipt of service under Schedule CILC-1, the Customer must provide the Company access at any reasonable time to inspect any and all of the Customer's load control equipment and/or backup generation equipment, and must also have received approval from the Company that the load control equipment is satisfactory to effect control of the Customer's load, and/or the backup generation equipment is satisfactory to contribute to the Controllable Demand level. The Customer shall be responsible for meeting any applicable electrical code standards and legal requirements pertaining to the installation, maintenance and repair of the load control and/or backup generation equipment. It is expressly understood that the initial approval and later inspections by the Company are not for the purpose of, and the Customer is not to rely upon any such inspection(s) for, determining whether the load control and/or backup generation equipment has been adequately maintained or is in compliance with any applicable electrical code standards or legal requirements.

6. The Customer agrees to be responsible for the determination that all electrical equipment to be controlled and/or backed up is in good repair and working condition. The Company shall not be responsible for the repair, maintenance or replacement of the Customer's equipment.

7. Within two (2) years of this Agreement, the Customer agrees (i) to perform the necessary changes to allow control of a portion of the Customer's load and/or (ii) to install or have in place backup generation equipment to contribute to the Controllable Demand level. Schedule CILC-1 cannot apply earlier than this date unless the Company so agrees. Should the Customer fail to complete the above work by the above-specified date, or should the Customer fail to begin taking service under Schedule CILC-1 during that year, this Agreement shall become null and void unless otherwise agreed by the Company.

8. Upon completion of the installation of the load control equipment and/or any necessary backup generation equipment, a test of this equipment will be conducted between the hours of 7 a.m. and 6 p.m. Monday through Friday, excluding holidays. Written notice of the test shall be provided to the Company at least five (5) business days in advance of the date of the test, and the Company shall be afforded the opportunity to witness the test. The test of the load control equipment will consist of a period of load control of not less than one hour. Effective upon the completion of the testing of the load control equipment and/or the backup generation equipment, the Customer will agree (as applicable) to either a "Firm Demand" or a "Controllable Demand". Service under Schedule CILC-1 cannot commence prior to the installation of load control equipment or any necessary backup generation equipment and the successful completion of the test.

9. In order to minimize the frequency and duration of interruptions under the CILC Program, the Company will attempt to obtain reasonably available additional capacity and/or energy under the Continuity of Service Provision in Schedule CILC-1. The Customer elects/does not elect to continue taking service under the Continuity of Service Provision. Service will be provided only if capacity and/or energy can be obtained by the Company and can be transmitted and distributed to non-firm Customers without any impairment of the Company's system or service to firm Customers. The Customer may countermand the election specified above by providing written notice to the Company pursuant to the guidelines set forth in Schedule CILC-1. The Company's obligations under this Section 9 are subject to the terms and conditions specifically set forth in Schedule CILC-1.

(Continued on Sheet No. 9.492)

(Continued from Sheet No. 9.491)

10. The Company may terminate this Agreement at any time if the Customer's load control equipment fails to permit the Company to effect control of the Customer's load, and/or if the Customer's equipment fails to meet the Controllable Demand level. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the failure or malfunction of the Customer's load control equipment and/or backup generation equipment. The Company may then terminate this Agreement at the end of the 90-day notice period unless the Customer takes measures necessary to remedy, to the Company's satisfaction, the deficiencies in the load control equipment and/or the backup generation equipment. Notwithstanding the foregoing, if at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under the Schedule CILC-1, to bill the Customer under the otherwise applicable firm service rate schedule and to apply the rebilling and penalty provisions enumerated under "Charges for Early Termination" in Schedule CILC-1.

11. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of control of electric service pursuant to the terms of Schedule CILC-1 by remote control or otherwise, and/or installation, operation or maintenance of the Customer's generation equipment to meet the Controllable Demand level.

12. This Agreement supersedes all previous agreements and representations, either written or oral, heretofore made between the Company and the Customer with respect to matters herein contained.

13. This Agreement may not be assigned by the Customer without the prior written consent of the Company. The Customer shall, at a minimum, provide to the Company a copy of the articles of incorporation or partnership agreement of the proposed assignee, and a copy of such assignee's most recent annual report at the time an assignment is requested.

14. This Agreement is subject to the Company's "General Rules and Regulations for Electric Service" and the Rules of the Commission.

IN WITNESS WHEREOF, the Customer and the Company have caused this Agreement to be duly executed as of the day and year first above written.

CUSTOMER (private)

Company:____________________

Signed:____________________

Name:____________________

Title:____________________

CUSTOMER (public)

Governmental Entity:____________________

Signed:____________________

Name:____________________

Title:____________________

FLORIDA POWER & LIGHT COMPANY

Signed:____________________

Name:____________________

Title:____________________

Attest:

By:____________________
Clerk/Deputy Clerk

COMMERCIAL/INDUSTRIAL LOAD CONTROL PROGRAM
(OPTIONAL)
(Closed Schedule)

RATE SCHEDULE: CILC-1

AVAILABLE:

In all territory served. Available to any commercial or industrial customer to which the load control provisions of this schedule can feasibly be applied, who, as of February 5, 1996, was either taking service pursuant to this schedule or had a fully executed copy of a Commercial/Industrial Load Control Agreement with the Company.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer as a part of the Commercial/Industrial Load Control Program Agreement between the Customer and the Company, who agrees to allow the Company to control at least 200 kw of the Customer's load, or agrees to operate backup generation equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kw of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a "Commercial/Industrial Load Control Program Agreement" with the Company for service under this schedule. To establish the initial qualification for service under this schedule, the Customer must have had an On-Peak Demand (as defined below) during the summer rating period (April through October) for at least three of the previous twelve (12) months of at least 200 kw greater than the Firm Demand or Controllable Demand (as applicable) level specified in Section 4 of the Commercial/Industrial Load Control Program Agreement. This controlled load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz at any available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to control by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Maximum Demand for delivery voltage below 69 kv. Standby Service is not provided hereunder. Resale of service is not permitted hereunder.

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MONTHLY RATE:

		Distribution below 69 kv		Transmission 69 kv & above
Delivery Voltage Level:		CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level:		200-499 kw	500 kw & above	
Customer Charge:		$600.00	$ 600.00	$ 3,200.00
Demand Charges:				
Base Demand Charges:				
per kw of Maximum Demand in excess of 10 kw		$ 2.43	-	-
per kw of Maximum Demand		-	$2.43	None
per kw of Load Control On-Peak Demand. Where Firm kw is < 10 kw, the Load Control On-Peak Demand shall be adjusted by the difference between 10 kw and Firm kw		$ 1.16	-	-
per kw of Load Control On-Peak Demand		-	$1.16	$ 1.15
per kw of Firm On-Peak Demand in excess of 10 kw		$ 5.85	-	-
per kw of Firm On-Peak Demand		-	$5.85	$ 6.25
Capacity Payment Charge	See Sheet No. 8.030			
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kwh		1.457¢	1.142¢	0.951¢
Off-Peak Period charge per kwh		1.457¢	1.142¢	0.951¢
Conservation Charge	See Sheet No. 8.030			
Environmental Charge	See Sheet No. 8.030			
Additional Charges:				
Fuel Charge	See Sheet No. 8.030			
Franchise Fee	See Sheet No. 8.031			
Tax Clause	See Sheet No. 8.031			

Minimum: The Customer Charge plus the Base Demand Charges.

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(Continued from Sheet No. 8.651)

LOAD CONTROL:

Control Condition:

The Customer's controllable load served under this rate schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.

Frequency: The Control Conditions will typically result in less than fifteen (15) control periods per year and will not exceed twenty-five (25) control periods per year. Typically, the Company will not initiate a control period within six (6) hours of a previous control period.

Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a control period.

Duration: The duration of a single period of load control will typically be four (4) hours and will not exceed six (6) hours.

In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.

Customer Responsibility:

Upon the successful installation of the load control equipment and/or any necessary backup generation equipment, a test of this equipment will be conducted between the hours of 7 a.m. and 6 p.m., Monday through Friday, excluding holidays, as specified in the Commercial/Industrial Load Control Program Agreement.

The Customer shall be responsible for providing and maintaining the appropriate equipment required to allow the Company to electrically control the Customer's load, as specified in the Commercial/Industrial Load Control Program Agreement.

The Company will control the controllable portion of the Customer's service for a one-hour period (during designated on-peak periods), once per year for Company testing purposes on the first Wednesday in November or, if not possible, at a mutually agreeable time and date, if the Customer's load has not been successfully controlled during a load control event in the previous twelve (12) months. Testing purposes include the testing of the load control equipment to ensure that the load is able to be controlled within the agreed specifications.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

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(Continued from Sheet No. 8.652)

LOAD CONTROL PERIOD:

All hours established by the Company during a monthly billing period in which:

1. the Customer's load is controlled (which includes the operation of the Customer's generation equipment), or
2. the Customer is billed pursuant to the Continuity of Service Provision.

DEMAND:

Demand is the kw to the nearest whole kw, as determined from the Company's metering equipment, for a 30-minute period as adjusted for power factor.

ON-PEAK DEMAND:

On-Peak Demand is the kw to the nearest whole kw, as determined from the Company's metering equipment, for a 30-minute period of Customer's greatest use for the designated on-peak periods during the month as adjusted for power factor.

MAXIMUM DEMAND:

Maximum Demand shall be the greater of the current month's demand whenever it occurs or the highest demand for the prior twenty-three (23) months. A Customer's Maximum Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

2. Demand reductions resulting from the installation of other permanent and quantifiable efficiency measures, upon verification by FPL; or

3. Permanent changes to customer facilities that result in a permanent loss of electric load, including any fuel substitution resulting in permanently reduced electricity consumption, upon verification by FPL.

The re-established Maximum Demand shall be the higher of the actual demand registered in the next billing period following the Customer's written request or the prior Maximum Demand minus the calculated demand reduction. Requests to re-establish the Maximum Demand may be processed up to twice per calendar year when more than one efficiency measure is installed or where the same efficiency measure is installed in phases.

CALCULATION OF FIRM DEMAND AND LOAD CONTROL ON-PEAK DEMAND

There will be two methods of calculating the Firm Demand and Load Control On-Peak Demand for the Customer, depending on the type of demand designated in the Commercial/Industrial Load Control Program Agreement.

THIS SECTION IS APPLICABLE TO CUSTOMERS DESIGNATING A FIRM DEMAND LEVEL:

FIRM ON-PEAK DEMAND:

The Customer's monthly Firm On-Peak Demand shall be the lesser of the "Firm Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company, or the Customer's highest on-peak demand during the month. The level of "Firm Demand" specified in the Customer's Commercial/Industrial Load Control Program Agreement shall not be exceeded during the periods when the Company is controlling the Customer's load.

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(Continued from Sheet No. 8.653)

LOAD CONTROL ON-PEAK DEMAND:

Load Control On-Peak Demand shall be the Customer's highest demand for the designated on-peak periods during the month less the Customer's "Firm Demand".

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS FOR CUSTOMERS DESIGNATING A FIRM DEMAND LEVEL:

Customers notified of a load control event should meet their Firm Demand during periods when the Company is controlling load. However, energy will be made available during control periods if the Customer's failure to meet its Firm Demand is a result of one of the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or

2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or

3. adding firm load that was not previously non-firm load to the Customer's facility, or

4. an event affecting local, state or national security, or

5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the "Firm Demand") for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt-hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rate schedule as described in TERM OF SERVICE.

If the Customer exceeds the "Firm Demand" during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed the difference between the Firm On-Peak Demand Charge and the Load Control On-Peak Demand Charge for the excess kw for the prior sixty (60) months or the number of months the Customer has been billed under this rate schedule, whichever is less, and

2. billed a penalty charge of $1.00 per kw of excess kw for each month of rebilling.

Excess kw for rebilling and penalty charges is determined by taking the difference between the maximum demand during the Load Control Period and the Customer's "Firm Demand". For rebilling under paragraph 1 above, where Firm kw is <10 kw, the maximum demand during the Load Control Period shall be adjusted by the difference between 10 kw and Firm kw. The Customer will not be rebilled or penalized twice for the same excess kw in the calculation described above.

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(Continued from Sheet No. 8.654)

THIS SECTION IS APPLICABLE TO CUSTOMERS DESIGNATING A CONTROLLABLE DEMAND LEVEL:

FIRM ON-PEAK DEMAND:

The Customer's monthly Firm On-Peak Demand shall be the On-Peak Demand during the month less the "Controllable Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company.

LOAD CONTROL ON-PEAK DEMAND:

Load Control On-Peak Demand shall be the "Controllable Demand" level specified in the Customer's Commercial/Industrial Load Control Program Agreement with the Company.

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS FOR CUSTOMERS DESIGNATING A CONTROLLABLE DEMAND LEVEL:

Customers notified of a load control event should achieve the Controllable Demand Level during periods when the Company is controlling load, except under the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or

2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or

3. adding firm load that was not previously non-firm load to the Customer's facility, or

4. an event affecting local, state or national security, or

5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the "Firm Demand") for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rate schedule as described in TERM OF SERVICE.

If the Customer does not achieve the Controllable Demand level during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed the difference between the Firm On-Peak Demand Charge and the Load Control On-Peak Demand Charge for the rebilling kw for the prior sixty (60) months or the number of months the Customer has been billed under this rate schedule, whichever is less, and

(Continued on Sheet No. 8.656)

(Continued from Sheet No. 8.655)

2. billed a penalty charge of $1.00 per kw of excess kw for each month of rebilling.

The kw for rebilling and penalty charges is determined by taking the difference between the Controllable Demand and the maximum demand actually reduced during the Load Control Period. For rebilling under paragraph 1 above, where Firm kw is <10 kw, the maximum demand during the Load Control Period shall be adjusted by the difference between 10 kw and Firm kw. The Customer will not be rebilled or penalized twice for the same excess kw in the calculation described above.

As long as the Customer's load reduction from the operation of the control circuit results in a demand during the control period that is at or below the calculated Firm Demand for that billing period, the Customer will not be required to pay the penalty and rebilling charges.

TERM OF SERVICE:

During the first year of service under this schedule, the Customer will determine whether or not this program is appropriate for the Customer and may request to exit the program subject to the Provisions for Early Termination. It is intended that the Company will continue to provide and the Customer will continue to take service under this rate schedule for the life of the generating unit which has been avoided by the rate. There is, however, a five-year termination notice provision which will allow either the Customer or the Company to terminate service under this schedule should there be circumstances under which the termination of the Customer's participation or the Company's offering of the program is desired.

Service under this rate schedule shall continue, subject to Limitation of Availability, until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination. Should a Customer terminate service or be removed by the Company and later desire to resume service under this rate schedule, the Customer must provide five (5) years' written notice prior to resuming service under this schedule.

The Company may terminate service under this rate schedule at any time for the Customer's failure to comply with the terms and conditions of this rate schedule or the Commercial/Industrial Load Control Program Agreement. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the Customer's failure to comply. The Company may then terminate service under this rate schedule at the end of the 90-day notice period unless the Customer takes measures necessary to eliminate, to the Company's satisfaction, the compliance deficiencies described by the Company. Notwithstanding the foregoing, if, at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under this rate schedule and bill the Customer under the otherwise applicable firm service rate schedule.

PROVISIONS FOR EARLY TERMINATION:

Transfers, with less than five (5) years' written notice, to any firm retail rate schedule for which the Customer would qualify, may be permitted if it can be shown that such transfer is in the best interests of the Customer, the Company and the Company's other customers.

If the Customer no longer wishes to receive electric service in any form from the Company, or decides to cogenerate to serve all of the previously controlled Load Control On-Peak Demand and to take interruptible standby service from the Company, the Customer may terminate the Commercial/Industrial Load Control Program Agreement by giving at least thirty (30) days' advance written notice to the Company.

(Continued on Sheet No. 8.657)

(Continued from Sheet No. 8.656)

If service under this schedule is terminated for any reason, the Customer will not be rebilled as specified in Charges for Early Termination if:

a. it has been demonstrated to the satisfaction of the Company that the impact of such transfer of service on the economic cost-effectiveness of the Company's CILC program is in the best interests of the Customer, the Company and the Company's other customers, or

b. the Customer is required to transfer to another retail rate schedule as a result of Commission Rule 25-6.0438, F.A.C., or

c. the termination of service under this rate schedule is the result of either the Customer's ceasing operations at its facility (without continuing or establishing similar operations elsewhere in the Company's service area), or a decision by the Customer to cogenerate to serve all of the previously controlled Load Control On-Peak Demand and to take interruptible standby service from the Company, or

d. any other Customer(s) with demand reduction equivalent to, or greater than, that of the existing Customer(s) agree(s) to take service under this schedule and the MW demand reduction commitment to the Company's Generation Expansion Plan has been met and the new replacement Customer(s) has (have) the equipment installed and is (are) available to perform load control, or

e. FPL determines that the Customer's MW reduction is no longer needed in accordance with the FPL Numeric Commercial/Industrial Conservation Goals.

In the event the Customer pays the Charges for Early Termination because no replacement Customer(s) is (are) available as specified in paragraph d. above, but the replacement Customer(s) does(do) become available within 12 months from the date of termination of service under this schedule or FPL later determines that there is no need for the MW reduction in accordance with the FPL Numeric Commercial/Industrial Conservation Goals, then the Customer will be refunded all or part of the rebilling and penalty in proportion to the amount of MW obtained to replace the lost capacity less the additional cost incurred by the Company to serve those MW during any load control periods which may occur before the replacement Customer(s) became available.

<u>Charges for Early Termination:</u>

In the event that:

a) service is terminated by the Company for any reason(s) specified in this section, or

b) there is a termination of the Customer's existing service and, within twelve (12) months of such termination of service, the Company receives a request to re-establish service of similar character under a firm service or a curtailable service rate schedule, or under this schedule with a shift from non-firm load to firm service,

    i) at a different location in the Company's service area, or

    ii) under a different name or different ownership, or

    iii) under other circumstances whose effect would be to increase firm demand on the Company's system without the requisite five (5) years' advance written notice, or

c) the Customer transfers the controllable portion of the Customer's load to "Firm Demand" or to a firm or a curtailable service rate schedule without providing at least five (5) years' advance written notice,

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(Continued on Sheet No. 8.657)

then the Customer will be:

1. rebilled under the otherwise applicable firm or curtailable service rate schedule for the shorter of (a) the most recent prior sixty (60) months during which the Customer was billed for service under this rate schedule, or (b) the number of months the Customer has been billed under this rate schedule, and

2. billed a penalty charge of $1.00 per kw times the number of months rebilled in No. 1 above times the highest Load Control On-Peak Demand occurring during the current month or the prior twenty-three (23) months.

SPECIAL PROVISIONS:

1. Control of the Customer's load shall be accomplished through the Company's load management systems by use of control circuits connected directly to the Customer's switching equipment or the Customer's load may be controlled by use of an energy management system where the firm demand or controllable demand level can be established or modified only by means of joint access by the Customer and the Company.

2. The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned load control equipment.

3. It shall be the responsibility of the Customer to determine that all electrical equipment to be controlled is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

4. The Company is not required to install load control equipment if the installation cannot be economically justified.

5. Billing under this schedule will commence after the installation, inspection and successful testing of the load control equipment.

6. Maintenance of generation equipment necessary for the implementation of load control will not be scheduled during periods where the Company projects that it would not be able to withstand the loss of its largest unit and continue to serve firm service customers.

CONTINUITY OF SERVICE PROVISION:

In order to minimize the frequency and duration of interruptions or requests that the Customer operate its backup generation equipment, the Company will attempt to obtain reasonably available additional capacity and/or energy during periods for which interruptions or operation of the Customer's backup generation equipment may be requested. The Company's obligation in this regard is no different than its obligation in general to purchase power to serve its Customers during a capacity shortage; in other words, the Company is not obligated to account for, or otherwise reflect in its generation planning and construction, the possibility of providing capacity and/or energy under this Continuity of Service Provision. Any non-firm customers so electing to receive capacity and/or energy which enable(s) the Company to continue service to the Customer's non-firm loads during these periods will be subject to the additional charges set forth below.

(Continued on Sheet No. 8.659)

(Continued from Sheet No. 8.658)

In the event a Customer elects not to have its non-firm load interrupted pursuant to this Schedule, the Customer shall pay, in addition to the normal charges provided hereunder, a charge reflecting the additional costs incurred by the Company in continuing to provide service, less the applicable class fuel charge for the period during which the load would otherwise have been controlled (see Sheet No. 8.830). This incremental charge shall apply to the non-firm customer for all consumption above the Customer's Firm Demand during the time in which the non-firm load would otherwise have been controlled. If, for any reason during such period, this capacity and/or energy is (are) no longer available or cannot be accommodated by the Company's system, the terms of this Special Provision will cease to apply and interruptions will be required for the remainder of such period unless energy use is for one of the conditions outlined under "Provisions for Energy Use During Control Periods".

Any customer served under this rate schedule may elect to minimize the interruptions through the procedure described above. The initial election must be made in the Commercial/Industrial Load Control Program Agreement. Any adjustment or change to the election must be provided to the Company with at least 24 hours' written notice (not including holidays and weekends) and must be by mutual agreement, in writing, between the Customer and the Company. In such case, the written notice will replace any prior election with regard to this Continuity of Service Provision.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision(s) of this schedule and said "General Rules and Regulations for Electric Service", the provision(s) of this schedule shall apply.

DEFINITIONS:

Generating Capacity Emergency:

A Generating Capacity Emergency exists when any one of the electric utilities in the state of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations.

Force Majeure:

Force Majeure for the purposes of this schedule means causes not within the reasonable control of the Customer affected and not caused by the negligence or lack of due diligence of the Customer. Such events or circumstances may include acts of God, strikes, lockouts or other labor disputes or difficulties, wars, blockades, insurrections, riots, environmental constraints lawfully imposed by Federal, State, or local governmental bodies, explosions, fires, floods, lightning, wind, accidents to equipment or machinery, or similar occurrences.

Backup Generation Equipment:

Backup generation equipment shall be Customer-provided generation equipment and switch gear. This generation equipment will be utilized for emergency purposes, including periods when the Company is controlling load.

COMMERCIAL/INDUSTRIAL LOAD CONTROL PROGRAM AGREEMENT

This Agreement is made this ____________ day of ________________________, 19______, by and between ____ (hereinafter called the "Customer"), located at ____________________ ________________ in ________________, Florida, and FLORIDA POWER & LIGHT COMPANY, a corporation organized under the laws of the State of Florida (hereinafter called the "Company"). This agreement is available and applicable only for customers who, as of February 5, 1996, were either taking service under the CILC Schedule or had fully executed copies of an earlier approved version of this agreement.

WITNESSETH

For and in consideration of the mutual covenants and agreements expressed herein, the Company and the Customer agree as follows:

1. The Company agrees to furnish and the Customer agrees to take electric service subject to the terms and conditions of the Company's Commercial/Industrial Load Control Program Schedule CILC-1 ("Schedule CILC-1") as currently approved or as may be modified from time to time by the Florida Public Service Commission ("Commission"). The Customer understands and agrees that, whenever reference is made in this Agreement to Schedule CILC-1, both parties intend to refer to Schedule CILC-1 as it may be modified from time to time. A copy of the Company's presently approved Schedule CILC-1 is attached hereto as Exhibit A and is hereby made an integral part of this Agreement.

2. Service under Schedule CILC-1 shall continue, subject to Limitation of Availability, until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination. Should the Customer terminate service or be removed by the Company and later desire to resume service under Schedule CILC-1, the Customer must provide five (5) years' written notice prior to resuming service under Schedule CILC-1.

3. Service under Schedule CILC-1 will be subject to determinations made under Commission Rules 25-17.0021(4), F.A.C. Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Service -Terms and Conditions, or any other Commission determination(s).

4. The Customer agrees either (i) to not exceed a usage level of ______kw ("Firm Demand") during the periods when the Company is controlling the Customer's service, or (ii) to provide a load reduction of ______ kw ("Controllable Demand") during periods when the Company is controlling the Customer's service. If the Customer chooses to operate backup generation equipment in parallel with FPL, the Customer shall enter into an interconnection agreement with the Company prior to operating such equipment in parallel with the Company's electrical system. The "Firm Demand" level (as applicable) shall not be exceeded during periods when the Company is controlling load; nor shall the "Controllable Demand" level (as applicable) be reduced during periods when the Company has requested that the Customer operate its equipment to meet the "Controllable Demand" level. Upon mutual agreement of the Company and the Customer, the Customer's "Firm Demand" or "Controllable Demand" may be subsequently raised or lowered, so long as the change in the "Firm Demand" or "Controllable Demand" level is not a result of a transfer of load from the controllable portion of the Customer's load. The Customer shall notify the Company, in writing, at least ninety (90) days prior to either adding firm load, or reducing or removing any of the Customer's backup generation equipment.

(Continued from Sheet No. 9.490)

5. Prior to the Customer's receipt of service under Schedule CILC-1, the Customer must provide the Company access at any reasonable time to inspect any and all of the Customer's load control equipment and/or backup generation equipment, and must also have received approval from the Company that the load control equipment is satisfactory to effect control of the Customer's load, and/or the backup generation equipment is satisfactory to contribute to the Controllable Demand level. The Customer shall be responsible for meeting any applicable electrical code standards and legal requirements pertaining to the installation, maintenance and repair of the load control and/or backup generation equipment. It is expressly understood that the initial approval and later inspections by the Company are not for the purpose of, and the Customer is not to rely upon any such inspection(s) for, determining whether the load control and/or backup generation equipment has been adequately maintained or is in compliance with any applicable electrical code standards or legal requirements.

6. The Customer agrees to be responsible for the determination that all electrical equipment to be controlled and/or backed up is in good repair and working condition. The Company shall not be responsible for the repair, maintenance or replacement of the Customer's equipment.

7. Within two (2) years of this Agreement, the Customer agrees (i) to perform the necessary changes to allow control of a portion of the Customer's load and/or (ii) to install or have in place backup generation equipment to contribute to the Controllable Demand level. Schedule CILC-1 cannot apply earlier than this date unless the Company so agrees. Should the Customer fail to complete the above work by the above-specified date, or should the Customer fail to begin taking service under Schedule CILC-1 during that year, this Agreement shall become null and void unless otherwise agreed by the Company.

8. Upon completion of the installation of the load control equipment and/or any necessary backup generation equipment, a test of this equipment will be conducted between the hours of 7 a.m. and 6 p.m. Monday through Friday, excluding holidays. Written notice of the test shall be provided to the Company at least five (5) business days in advance of the date of the test, and the Company shall be afforded the opportunity to witness the test. The test of the load control equipment will consist of a period of load control of not less than one hour. Effective upon the completion of the testing of the load control equipment and/or the backup generation equipment, the Customer will agree (as applicable) to either a "Firm Demand" or a "Controllable Demand". Service under Schedule CILC-1 cannot commence prior to the installation of load control equipment or any necessary backup generation equipment and the successful completion of the test.

9. In order to minimize the frequency and duration of interruptions under the CILC Program, the Company will attempt to obtain reasonably available additional capacity and/or energy under the Continuity of Service Provision in Schedule CILC-1. The Customer elects/does not elect to continue taking service under the Continuity of Service Provision. Service will be provided only if capacity and/or energy can be obtained by the Company and can be transmitted and distributed to non-firm Customers without any impairment of the Company's system or service to firm Customers. The Customer may countermand the election specified above by providing written notice to the Company pursuant to the guidelines set forth in Schedule CILC-1. The Company's obligations under this Section 9 are subject to the terms and conditions specifically set forth in Schedule CILC-1.

(Continued on Sheet No. 9.492)

(Continued from Sheet No. 9.491)

10. The Company may terminate this Agreement at any time if the Customer's load control equipment fails to permit the Company to effect control of the Customer's load, and/or if the Customer's equipment fails to meet the Controllable Demand level. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the failure or malfunction of the Customer's load control equipment and/or backup generation equipment. The Company may then terminate this Agreement at the end of the 90-day notice period unless the Customer takes measures necessary to remedy, to the Company's satisfaction, the deficiencies in the load control equipment and/or the backup generation equipment. Notwithstanding the foregoing, if at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under the Schedule CILC-1, to bill the Customer under the otherwise applicable firm service rate schedule and to apply the rebilling and penalty provisions enumerated under "Charges for Early Termination" in Schedule CILC-1.

11. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of control of electric service pursuant to the terms of Schedule CILC-1 by remote control or otherwise, and/or installation, operation or maintenance of the Customer's generation equipment to meet the Controllable Demand level.

12. This Agreement supersedes all previous agreements and representations, either written or oral, heretofore made between the Company and the Customer with respect to matters herein contained.

13. This Agreement may not be assigned by the Customer without the prior written consent of the Company. The Customer shall, at a minimum, provide to the Company a copy of the articles of incorporation or partnership agreement of the proposed assignee, and a copy of such assignee's most recent annual report at the time an assignment is requested.

14. This Agreement is subject to the Company's "General Rules and Regulations for Electric Service" and the Rules of the Commission.

IN WITNESS WHEREOF, the Customer and the Company have caused this Agreement to be duly executed as of the day and year first above written.

CUSTOMER (private)

Company:____________________

Signed:____________________

Name:____________________

Title:____________________

CUSTOMER (public)

Governmental Entity:____________________

Signed:____________________

Name:____________________

Title:____________________

FLORIDA POWER & LIGHT COMPANY

Signed:____________________

Name:____________________

Title:____________________

Attest:

By:____________________
Clerk/Deputy Clerk

APPENDIX B

Attachment A

Program Name: **Commercial/Industrial Load Control**

Year	(a) Total Number of Customers	(b) Total Number of Target Customers	(c) Annual Number of Program Participants	(d) Cumulative Penetration Level %
1995	**6,356**	**4,972**	**60**	**8.5**
1996	**6,529**	**5,106**	**20**	**8.7**
1997	**6,709**	**5,247**	**17**	**8.8**
1998	**6,890**	**5,389**	**17**	**8.9**
1999	**7,071**	**5,530**	**17**	**9.0**
2000	**7,247**	**5,666**	**17**	**9.1**
2001	**7,417**	**5,798**	**0**	**8.9**
2002	**7,585**	**5,929**	**0**	**8.7**
2003	**7,743**	**6,052**	**0**	**8.5**
2004	**7,898**	**6,172**	**0**	**8.3**

Note:

Since the demand reductions from participants vary from 200 kw to 44,564 kw, the program projections are expressed in MWs. The customer participation levels projected are done to satisfy filing requirements but the MW projections will be targeted regardless of the number of customers required to do so. The "Total Number of Eligible Customers" has been changed to "Total Number of Target Customers" to reflect those market segments that have been most responsive to the CILC program to date.

Column a - The total number of commercial/industrial customers with demand over 200 kw.

Column b - The total number of eligible commercial/industrial with demand over 200 kw.

Column c - The annual number of participants in the program.

Attachment B

Program Name: **Commercial/Industrial Load Control**

At the Meter

Year	Per Customer kwh Reduction	Per Customer Winter kw Reduction	Per Customer Summer kw Reduction	Total Annual kwh Reduction	Total Annual Winter MW Reduction	Total Annual Summer MW Reduction
1995	**87**	**917**	**917**	**5,225.0**	**55**	**55**
1996	**87**	**917**	**917**	**1,748.0**	**18.4**	**18.4**
1997	**87**	**917**	**917**	**1,510.5**	**15.9**	**15.9**
1998	**87**	**917**	**917**	**1,510.5**	**15.9**	**15.9**
1999	**87**	**917**	**917**	**1,510.5**	**15.9**	**15.9**
2000	**87**	**917**	**917**	**1,510.5**	**15.9**	**15.9**
2001	**87**	**917**	**917**	**0**	**0**	**0**
2002	**87**	**971**	**917**	**0**	**0**	**0**
2003	**87**	**971**	**917**	**0**	**0**	**0**
2004	**TBD**	**TBD**	**TBD**	**0**	**0**	**0**

Attachment C

Program Name: **Commercial/Industrial Load Control**

At the Generator

Year	Per Customer kwh Reduction	Per Customer Winter kw Reduction	Per Customer Summer kw Reduction	Total Annual kwh Reduction	Total Annual Winter Mw Reduction	Total Annual Summer Mw Reduction
1995	**94**	**988**	**988**	**5,549**	**59.269**	**59.269**
1996	**94**	**988**	**988**	**1,856**	**19.828**	**19.828**
1997	**94**	**988**	**988**	**1,604**	**17.133**	**17.133**
1998	**94**	**988**	**988**	**1,604**	**17.133**	**17.133**
1999	**94**	**988**	**988**	**1,604**	**17.133**	**17.133**
2000	**94**	**988**	**988**	**1,604**	**17.133**	**17.133**
2001	**94**	**988**	**988**	**0**	**0**	**0**
2002	**94**	**988**	**988**	**0**	**0**	**0**
2003	**94**	**988**	**988**	**0**	**0**	**0**
2004	**TBD**	**TBD**	**TBD**	**0**	**0**	**0**

COMMERCIAL/INDUSTRAL LOAD CONTROL

NPV END 1994 ($000)

	RIM			PART			TRC		
	BENEFITS	COSTS	RATIO	BENEFITS	COSTS	RATIO	BENEFITS	COSTS	RATIO
1995-1996	84,304	58,032	1.45	56,849	343	165.91	84,304	1,932	43.63
1997-2000	47,696	38,677	1.23	37,759	236	159.82	47,696	1,466	32.54
2001-2003									
1995-2003	132,000	96,709	1.36	94,608	579	163.40	132,000	3,398	38.85

INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI95X - CI Load Control

PSC FORM CE 1
PAGE 1 OF 1

I PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.29	kW
(3) kW LINE LOSS PERCENTAGE	7.20	%
(4) GENERATOR kWh REDUCTION PER CUSTOMER	1[illegible]8.7	kWh ****
(5) kWh LINE LOSS PERCENTAGE	5.84	%
(6) GROUP LINE LOSS MULTIPLIER	1.0000	
(7) CUSTOMER kWh INCREASE AT METER	40.9	kWh ****

II ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGRAM	23	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.64957	
(5) K FACTOR FOR T & D	1.66667	

III UTILITY & CUSTOMER COSTS

(1) UTILITY NON RECURRING COST PER CUSTOMER	***	$/CUST
(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
(3) UTILITY COST ESCALATION RATE	***	%**
(4) CUSTOMER EQUIPMENT COST	***	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
(6) CUSTOMER O & M COST	***	$/CUST/YR
(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
* (8) INCREASED SUPPLY COSTS	***	$/CUST/YR
* (9) SUPPLY COSTS ESCALATION RATES	***	%**
* (10) UTILITY DISCOUNT RATE	8.22	%
* (11) UTILITY AFUDC RATE	10.82	%
* (12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
* (13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
* (14) UTILITY REBATE/INCENTIVE ESCALATION RATE	***	%

IV AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	1994	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UN	1997	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	1994-1996	
(4) BASE YEAR AVOIDED GENERATING COST	392	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0	$/kW
(6) BASE YEAR DISTRIBUTION COST	0	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	2.60	%**
(8) GENERATOR FIXED O & M COST	24	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	3.40	%**
(10) TRANSMISSION FIXED O & M COST	0.00	$/kW
(11) DISTRIBUTION FIXED O & M COST	0.00	$/kW
(12) T&D FIXED O&M ESCALATION RATE	3.40	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.011	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION I	3.40	%**
(15) GENERATOR CAPACITY FACTOR	0%	** (in-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	3.72	CENTS PER kWh** (in-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RAT	8.34	%**

V NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	***	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	***	%
(3) DEMAND CHARGE IN CUSTOMER BILL	***	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	***	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 12
**** THIS IS A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUST SHIFTED AWAY FROM PEAK HRS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUST THAT IS PAID BACK DURING OFF-PEAK

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* INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI95X - CI Load Control

YEAR	*(1) UTILITY PROGRAM COSTS WITHOUT INCENTIVES $(000)	*(2) UTILITY INCENTIVES $(000)	*(3) OTHER UTILITY COSTS $(000)	*(4) TOTAL UTILITY PROGRAM COSTS $(000)	*(5) ENERGY CHARGE REVENUE LOSSES $(000)	*(6) DEMAND CHARGE REVENUE LOSSES $(000)	*(7) PARTICIPANT EQUIPMENT COSTS $(000)	*(8) PARTICIPANT O&M COSTS $(000)	*(9) OTHER PARTICIPANT COSTS $(000)	*(10) TOTAL PARTICIPANT COSTS $(000)
1994	0	0	0	0	0	0	0	0	0	0
1995	101	2,406	0	2,507	34	0	202	3	0	205
1996	134	5,618	0	5,751	85	0	67	7	0	75
1997	136	6,423	0	6,559	100	0	0	9	0	9
1998	141	6,423	0	6,564	104	0	0	9	0	9
1999	147	6,423	0	6,569	110	0	0	10	0	10
2000	151	6,423	0	6,574	118	0	0	10	0	10
2001	156	6,423	0	6,578	124	0	0	10	0	10
2002	162	6,423	0	6,585	128	0	0	11	0	11
2003	170	6,423	0	6,592	138	0	0	11	0	11
2004	177	6,423	0	6,600	143	0	0	12	0	12
2005	185	6,423	0	6,608	146	0	0	13	0	13
2006	194	6,423	0	6,617	148	0	0	13	0	13
2007	203	6,423	0	6,626	158	0	0	14	0	14
2008	213	6,423	0	6,636	163	0	0	14	0	14
2009	224	6,423	0	6,646	167	0	0	15	0	15
2010	235	6,423	0	6,658	171	0	0	16	0	16
2011	247	6,423	0	6,670	175	0	0	17	0	17
2012	260	6,423	0	6,683	190	0	0	18	0	18
2013	274	6,423	0	6,697	206	0	0	19	0	19
2014	289	6,423	0	6,711	214	0	0	20	0	20
2015	304	6,423	0	6,726	220	0	0	21	0	21
2016	319	6,423	0	6,742	236	0	0	22	0	22
NOM	4,422	136,477	0	140,899	3,275	0	269	292	0	561
NPV	1,589	55,288	0	56,878	1,155	0	241	102	0	343

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* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

CALCULATION OF GEN K-FACTOR
PROGRAM METHOD SELECTED REV_REQ
PROGRAM NAME: M95X - CI Load Control

YEAR	(2) MID-YEAR RATE BASE $(000)	(3) DEBT $(000)	(4) PREFERRED STOCK $(000)	(5) COMMON EQUITY $(000)	(6) INCOME TAXES $(000)	(7) OTHER TAXES & INSURANCE $(000)	(8) DEPREC. $(000)	(9) DEFERRED TAXES $(000)	(10) TOTAL FIXED CHARGES $(000)	(11) PRESENT WORTH FIXED CHARGES $(000)	(12) CUMULATIVE PW FIXED CHARGES $(000)
1997	44,072	1,839	336	2,539	1,787	705	1,481	104	8,850	8,850	8,850
1998	42,217	1,858	321	2,432	1,112	705	1,481	664	8,572	7,848	16,698
1999	40,118	1,765	305	2,311	1,116	705	1,481	594	8,257	6,921	23,619
2000	38,108	1,677	290	2,195	1,117	705	1,481	510	7,954	6,105	29,724
2001	36,174	1,592	275	2,084	1,117	705	1,481	432	7,664	5,386	35,110
2002	34,318	1,510	261	1,977	1,112	705	1,481	360	7,386	4,751	39,861
2003	32,539	1,431	247	1,874	1,104	705	1,481	295	7,117	4,192	44,053
2004	30,808	1,355	234	1,774	1,098	705	1,481	233	6,858	3,699	47,752
2005	29,117	1,281	221	1,677	1,038	705	1,481	223	6,605	3,261	51,013
2006	27,434	1,207	208	1,580	968	705	1,481	223	6,352	2,871	53,884
2007	25,751	1,133	196	1,483	898	705	1,481	223	6,099	2,524	56,408
2008	24,067	1,059	183	1,386	830	705	1,481	223	5,847	2,215	58,624
2009	22,384	985	170	1,289	761	705	1,481	223	5,594	1,941	60,565
2010	20,701	911	157	1,192	692	705	1,481	223	5,341	1,697	62,261
2011	19,017	837	145	1,095	623	705	1,481	223	5,088	1,480	63,741
2012	17,334	763	132	998	554	705	1,481	223	4,836	1,288	65,029
2013	15,651	689	119	901	485	705	1,481	223	4,583	1,117	66,146
2014	13,967	615	106	805	416	705	1,481	223	4,330	966	67,112
2015	12,284	540	93	708	347	705	1,481	223	4,077	833	67,945
2016	10,601	466	81	611	278	705	1,481	223	3,825	716	68,661
2017	9,102	400	69	[illegible]	588	705	1,481	(146)	3,600	617	69,278
2018	7,976	351	61	459	918	705	1,481	(522)	3,431	538	69,816
2019	7,037	310	53	405	877	705	1,481	(522)	3,290	472	70,288
2020	6,099	268	46	351	839	705	1,481	(522)	3,149	414	70,702
2021	5,161	227	39	297	801	705	1,481	(522)	3,008	362	71,064
2022	4,222	186	32	243	762	705	1,481	(522)	2,867	316	71,380
2023	3,284	144	25	189	724	705	1,481	(522)	2,726	275	71,655
2024	2,346	103	18	135	685	705	1,481	(522)	2,585	239	71,894
2025	1,407	62	11	81	647	705	1,481	(522)	2,444	207	72,100
2026	469	21	4	27	608	705	1,481	(522)	2,303	179	72,279

IN SERVICE COST($000)	43,817
IN SERVICE YEAR	1997
BOOK LIFE (YRS)	30
EFFEC. TAX RATE	38.575
DISCOUNT RATE	8.22%
OTAX & INS RATE	1.61%

CAPITAL STRUCTURE

SOURCE	WEIGHT	COST
DEBT	44%	10.00 %
P/S	8%	9.50 %
C/S	48%	12.00 %

K-FACTOR = CPWFC / IN-SVC COST = 1.64957

0470

page 4a

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

PROGRAM NAME M95X - CI Load Control

PSC FORM CE 1.1A
PAGE 2a OF 2

(1) YEAR	(2) TAX DEPRECIATION SCHEDULE	(3) TAX DEPRECIATION $(000)	(4) ACCUMULATED TAX DEPRECIATION $(000)	(5) BOOK DEPRECIATION $(000)	(6) ACCUMULATED BOOK DEPRECIATION $(000)	(7) BOOK DEPRECIATION FOR DEFERRED TAX $(000)	(8) ACCUMULATED BOOK DEPR FOR DEFERRED TAX $(000)	(9) DEFERRED TAX DUE TO DEPRECIATION $(000)	(10) TOTAL EQUITY AFUDC $(000)	(11) BOOK DEPR RATE MINUS 1/LIFE	(12) (10)*(11) *TAX RATE $(000)	(13) SALVAGE *TAX RATE $(000)	(14) ANNUAL DEFERRED TAX (9)-(12)+(13) $(000)
1997	3.75%	1,624	1,624	1,461	1,461	1,354	1,354	104	3,201	0	0	0	104
1998	7.22%	3,127	4,751	1,461	2,921	1,354	2,708	684	3,201	0	0	0	684
1999	6.68%	2,893	7,643	1,461	4,382	1,354	4,062	594	3,201	0	0	0	594
2000	6.18%	2,676	10,320	1,461	5,842	1,354	5,415	510	3,201	0	0	0	510
2001	5.71%	2,473	12,792	1,461	7,303	1,354	6,769	432	3,201	0	0	0	432
2002	5.28%	2,287	15,079	1,461	8,763	1,354	8,123	360	3,201	0	0	0	360
2003	4.89%	2,118	17,197	1,461	10,224	1,354	9,477	295	3,201	0	0	0	295
2004	4.52%	1,957	19,154	1,461	11,684	1,354	10,831	233	3,201	0	0	0	233
2005	4.46%	1,931	21,085	1,461	13,145	1,354	12,185	223	3,201	0	0	0	223
2006	4.46%	1,931	23,017	1,461	14,606	1,354	13,539	223	3,201	0	0	0	223
2007	4.46%	1,931	24,948	1,461	16,066	1,354	14,892	223	3,201	0	0	0	223
2008	4.46%	1,931	26,880	1,461	17,527	1,354	16,246	223	3,201	0	0	0	223
2009	4.46%	1,931	28,811	1,461	18,987	1,354	17,600	223	3,201	0	0	0	223
2010	4.46%	1,931	30,743	1,461	20,448	1,354	18,954	223	3,201	0	0	0	223
2011	4.46%	1,931	32,674	1,461	21,908	1,354	20,308	223	3,201	0	0	0	223
2012	4.46%	1,931	34,605	1,461	23,369	1,354	21,662	223	3,201	0	0	0	223
2013	4.46%	1,931	36,537	1,461	24,829	1,354	23,016	223	3,201	0	0	0	223
2014	4.46%	1,931	38,468	1,461	26,290	1,354	24,370	223	3,201	0	0	0	223
2015	4.46%	1,931	40,400	1,461	27,751	1,354	25,723	223	3,201	0	0	0	223
2016	4.46%	1,931	42,331	1,461	29,211	1,354	27,077	223	3,201	0	0	0	223
2017	2.25%	974	43,305	1,461	30,672	1,354	28,431	(146)	3,201	0	0	0	(146)
2018	0.00%	0	43,305	1,461	32,132	1,354	29,785	(522)	3,201	0	0	0	(522)
2019	0.00%	0	43,305	1,461	33,593	1,354	31,139	(522)	3,201	0	0	0	(522)
2020	0.00%	0	43,305	1,461	35,053	1,354	32,493	(522)	3,201	0	0	0	(522)
2021	0.00%	0	43,305	1,461	36,514	1,354	33,847	(522)	3,201	0	0	0	(522)
2022	0.00%	0	43,305	1,461	37,975	1,354	35,200	(522)	3,201	0	0	0	(522)
2023	0.00%	0	43,305	1,461	39,435	1,354	36,554	(522)	3,201	0	0	0	(522)
2024	0.00%	0	43,305	1,461	40,896	1,354	37,908	(522)	3,201	0	0	0	(522)
2025	0.00%	0	43,305	1,461	42,356	1,354	39,262	(522)	3,201	0	0	0	(522)
2026	0.00%	0	43,305	1,461	43,817	1,354	40,616	(522)	3,201	0	0	0	(522)

SALVAGE / REMOVAL COST	0.00
YEAR SALVAGE / COST OF REMOVAL	2026
DEFERRED TAXES DURING CONSTRUCTION (SEE PAGE 5)	(1,038)
TOTAL EQUITY AFUDC CAPITALIZED (SEE PAGE 5)	3,201
BOOK DEPR RATE - 1/USEFUL LIFE	0.00

0471

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

PROGRAM NAME M95X - CI Load Control

(1) YEAR	(2) TAX DEPRECIATION SCHEDULE	(3) TAX DEPRECIATION $(000)	(4) DEFERRED TAX $(000)	(5) END OF YEAR NET PLANT IN SERVICE $(000)	(5a)* ACCUMULATED DEPRECIATION $(000)	(5b)* ACCUMULATED DEF TAXES $(000)	(6) BEGINNING YEAR RATE BASE $(000)	(7) ENDING OF YEAR RATE BASE $(000)	(8) MID-YEAR RATE BASE $(000)
1997	3.75%	1,624	104	42,358	1,461	(933)	44,854	43,289	44,072
1998	7.22%	3,127	684	40,898	2,921	(249)	43,289	41,145	42,217
1999	6.68%	2,893	594	39,435	4,382	344	41,145	39,091	40,118
2000	6.18%	2,676	510	37,975	5,842	854	39,091	37,120	38,106
2001	5.71%	2,473	432	36,514	7,303	1,288	37,120	35,228	36,174
2002	5.28%	2,287	360	35,053	8,763	1,648	35,228	33,408	34,318
2003	4.89%	2,118	295	33,593	10,224	1,940	33,408	31,653	32,530
2004	4.52%	1,957	233	32,132	11,684	2,173	31,653	29,958	30,806
2005	4.46%	1,931	223	30,672	13,145	2,396	29,958	28,279	29,117
2006	4.46%	1,931	223	29,211	14,606	2,619	28,279	26,592	27,434
2007	4.46%	1,931	223	27,751	16,066	2,842	26,592	24,909	25,751
2008	4.46%	1,931	223	26,290	17,527	3,064	24,909	23,226	24,067
2009	4.46%	1,931	223	24,829	18,987	3,287	23,226	21,542	22,384
2010	4.46%	1,931	223	23,369	20,448	3,510	21,542	19,858	20,701
2011	4.46%	1,931	223	21,908	21,908	3,733	19,858	18,176	19,017
2012	4.46%	1,931	223	20,448	23,369	3,955	18,176	16,492	17,334
2013	4.46%	1,931	223	18,987	24,829	4,178	16,492	14,809	15,651
2014	4.46%	1,931	223	17,527	26,290	4,401	14,809	13,126	13,967
2015	4.46%	1,931	223	16,066	27,751	4,624	13,126	11,442	12,284
2016	4.46%	1,931	223	14,606	29,211	4,847	11,442	9,759	10,601
2017	2.23%	874	(146)	13,145	30,672	4,700	9,759	8,445	9,102
2018	0.00%	0	(522)	11,684	32,132	4,178	8,445	7,508	7,976
2019	0.00%	0	(522)	10,224	33,593	3,656	7,508	6,568	7,037
2020	0.00%	0	(522)	8,763	35,053	3,134	6,568	5,630	6,099
2021	0.00%	0	(522)	7,303	36,514	2,611	5,630	4,692	5,161
2022	0.00%	0	(522)	5,842	37,975	2,089	4,692	3,753	4,222
2023	0.00%	0	(522)	4,382	39,435	1,567	3,753	2,815	3,284
2024	0.00%	0	(522)	2,921	40,896	1,045	2,815	1,877	2,346
2025	0.00%	0	(522)	1,461	42,358	522	1,877	938	1,407
2026	0.00%	0	(522)	0	43,817	0	938	0	469

* Column not specified in workbook

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(1) YEAR	(2) NO. YEARS BEFORE IN-SERVICE	(3) PLANT ESCALATION RATE	(4) CUMULATIVE ESCALATION FACTOR	(5) YEARLY EXPENDITURE (%)	(6) ANNUAL SPENDING ($/kW)	(7) CUMULATIVE AVERAGE SPENDING ($/kW)
1994	-3	0.10%	1.000	13.91%	54.53	27.27
1995	-2	2.00%	1.020	44.55%	178.18	144.12
1996	-1	2.83%	1.053	41.54%	171.47	318.45
				100.00%	405.18	

YEAR	NO. YEARS BEFORE IN-SERVICE	(8) CUMULATIVE SPENDING WITH AFUDC ($/kW)	(8a)* DEBT AFUDC ($/kW)	(8b)* CUMULATIVE DEBT AFUDC ($/kW)	(9) YEARLY TOTAL AFUDC ($/kW)	(9a)* CUMULATIVE TOTAL AFUDC ($/kW)	(9b)* CONSTRUCTION PERIOD INTEREST ($/kW)	(9c)* CUMULATIVE CPI ($/kW)	(9d)* DEFERRED TAXES ($/kW)	(9e)* CUMULATIVE DEFERRED TAXES ($/kW)	(10) INCREMENTAL YEAR-END BOOK VALUE ($/kW)	(11) CUMULATIVE YEAR-END BOOK VALUE ($/kW)
1994	-3	27.27	1.20	1.20	2.98	2.98	2.73	2.73	(0.58)	(0.58)	57.51	57.51
1995	-2	147.10	6.50	7.70	16.13	19.11	14.68	17.41	(3.16)	(3.75)	195.31	252.82
1996	-1	338.55	15.08	22.78	37.38	56.48	33.69	51.10	(7.18)	(10.93)	208.85	461.67
			22.78	31.68	56.48		51.10		(10.93)		461.67	

IN SERVICE YEA	1997
PLANT COSTS	392
AFUDC RATE	10.82%

	BOOK BASIS	BOOK BASIS FOR DEF TAX	TAX BASIS
CONSTRUCTION CASH	38,456	38,456	38,456
EQUITY AFUDC	3,201		
DEBT AFUDC	2,160	2,160	
CPI			4,850
TOTAL	43,817	40,616	43,306

* Column not specified in workbook

0473

INPUT DATA – PART 2
PROGRAM METHOD SELECTED : REV_REQ
PROGRAM NAME M95X - CI Load Control

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(1) YEAR	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS	(4) UTILITY AVERAGE SYSTEM FUEL COST (C/KWH)	(5) AVOIDED MARGINAL FUEL COST (C/KWH)	(6)* INCREASED MARGINAL FUEL COST (C/KWH)	(7) REPLACEMENT FUEL COST (C/KWH)	(8) PROGRAM kW EFFECTIVENESS FACTOR	(9) PROGRAM kWh EFFECTIVENESS FACTOR
1994	0	0	0.00	3.82	1.89	0.00	1.00	1.00
1995	54,997	54,997	0.00	4.89	1.82	0.00	1.00	1.00
1996	73,397	73,397	0.00	5.08	1.82	0.00	1.00	1.00
1997	73,397	73,397	0.00	5.62	2.03	4.28	1.00	1.00
1998	73,397	73,397	0.00	6.01	2.04	4.25	1.00	1.00
1999	73,397	73,397	0.00	7.19	2.19	7.85	1.00	1.00
2000	73,397	73,397	0.00	7.25	2.43	8.21	1.00	1.00
2001	73,397	73,397	0.00	7.78	2.52	8.42	1.00	1.00
2002	73,397	73,397	0.00	8.29	2.58	8.98	1.00	1.00
2003	73,397	73,397	0.00	9.13	2.77	9.28	1.00	1.00
2004	73,397	73,397	0.00	9.88	2.84	9.60	1.00	1.00
2005	73,397	73,397	0.00	10.69	3.14	9.82	1.00	1.00
2006	73,397	73,397	0.00	11.33	3.30	9.52	1.00	1.00
2007	73,397	73,397	0.00	13.55	3.57	9.70	1.00	1.00
2008	73,397	73,397	0.00	13.29	3.81	10.08	1.00	1.00
2009	73,397	73,397	0.00	13.21	3.92	10.57	1.00	1.00
2010	73,397	73,397	0.00	14.48	4.18	10.98	1.00	1.00
2011	73,397	73,397	0.00	15.29	4.14	11.45	1.00	1.00
2012	73,397	73,397	0.00	15.83	4.53	12.84	1.00	1.00
2013	73,397	73,397	0.00	16.92	4.82	13.05	1.00	1.00
2014	73,397	73,397	0.00	17.89	4.88	13.71	1.00	1.00
2015	73,397	73,397	0.00	18.77	5.18	14.19	1.00	1.00
2016	73,397	73,397	0.00	19.82	5.39	15.01	1.00	1.00

* THIS COLUMN IS USED ONLY FOR LOAD SHIFTING PROGRAMS WHICH SHIFT CONSUMPTION TO OFF-PEAK PERIODS.
THE VALUES REPRESENT THE OFF PEAK SYSTEM FUEL COSTS.

04474

AVOIDED GENERATING BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME M95X - CI Load Control

YEAR	(2) AVOIDED GEN UNIT CAPACITY COST $(000)	(3) AVOIDED GEN UNIT FIXED O&M $(000)	(4) AVOIDED GEN UNIT VARIABLE O&M $(000)	(5) AVOIDED GEN UNIT FUEL COST $(000)	(6) REPLACEMENT FUEL COST $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	8,850	2,494	0.132	40	48	11,338
1998	8,572	2,509	0.148	45	49	11,167
1999	8,257	2,716	0.808	252	476	10,750
2000	7,954	2,841	0.058	19	34	10,780
2001	7,664	2,977	0.087	32	58	10,818
2002	7,388	3,114	0.101	35	60	10,478
2003	7,117	3,258	0.189	67	108	10,334
2004	6,858	3,401	0.319	119	184	10,195
2005	6,605	3,554	0.188	72	104	10,127
2006	6,352	3,721	0.187	64	87	10,050
2007	6,099	3,896	0.301	118	153	9,990
2008	5,847	4,087	0.300	119	151	9,903
2009	5,594	4,291	0.175	71	88	9,868
2010	5,341	4,510	0.718	291	348	9,798
2011	5,088	4,745	0.618	255	305	9,784
2012	4,836	4,998	0.814	337	420	9,749
2013	4,583	5,261	1.028	428	521	9,752
2014	4,330	5,540	1.038	432	524	9,779
2015	4,077	5,828	1.021	428	507	9,825
2016	3,825	6,131	1.248	520	624	9,853
NOM	125,238	78,981	9,463	3,742	4,843	204,105
NPV	52,805	26,298	2,624	983	1,381	78,818

04775

AVOIDED T&D AND PROGRAM FUEL SAVINGS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: M95X - CI Load Control

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(1) YEAR	(2) AVOIDED TRANSMISSION CAP COST $(000)	(3) AVOIDED TRANSMISSION O&M COST $(000)	(4) TOTAL AVOIDED TRANSMISSION COST $(000)	(5) AVOIDED DISTRIBUTION CAP COST $(000)	(6) AVOIDED DISTRIBUTION O&M COST $(000)	(7) TOTAL AVOIDED DISTRIBUTION COST $(000)	(8) PROGRAM FUEL SAVINGS $(000)	(8a)* PROGRAM FUEL SAVINGS OFF-PEAK PAYBACK $(000)
1994	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	146	23
1996	0	0	0	0	0	0	353	54
1997	0	0	0	0	0	0	448	65
1998	0	0	0	0	0	0	479	65
1999	0	0	0	0	0	0	574	70
2000	0	0	0	0	0	0	578	77
2001	0	0	0	0	0	0	620	81
2002	0	0	0	0	0	0	661	83
2003	0	0	0	0	0	0	728	88
2004	0	0	0	0	0	0	788	91
2005	0	0	0	0	0	0	852	100
2006	0	0	0	0	0	0	904	105
2007	0	0	0	0	0	0	1,000	114
2008	0	0	0	0	0	0	1,060	121
2009	0	0	0	0	0	0	1,053	125
2010	0	0	0	0	0	0	1,155	133
2011	0	0	0	0	0	0	1,219	132
2012	0	0	0	0	0	0	1,271	144
2013	0	0	0	0	0	0	1,350	147
2014	0	0	0	0	0	0	1,426	156
2015	0	0	0	0	0	0	1,487	165
2016	0	0	0	0	0	0	1,561	172
NOM.	0	0	0	0	0	0	19,823	2,313
NPV	0	0	0	0	0	0	6,470	790

* THESE VALUES REPRESENT THE COST OF THE INCREASED FUEL CONSUMPTION DUE TO GREATER OFF-PEAK ENERGY USAGE. USED FOR LOAD SHIFTING PROGRAMS ONLY.

04476

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME MI95X - CI Load Control

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	101	205	0	306	0	0	123	0	123	(182)	(167)
1996	0	134	75	0	209	0	0	299	0	299	90	(91)
1997	0	136	9	0	145	11,339	0	383	0	11,722	11,577	8,793
1998	0	141	9	0	150	11,167	0	414	0	11,581	11,430	16,825
1999	0	147	10	0	158	10,750	0	504	0	11,253	11,097	23,884
2000	0	151	10	0	161	10,780	0	501	0	11,281	11,119	30,514
2001	0	156	10	0	166	10,618	0	540	0	11,158	10,992	36,441
2002	0	162	11	0	173	10,476	0	579	0	11,054	10,881	41,814
2003	0	170	11	0	181	10,334	0	640	0	10,974	10,793	46,692
2004	0	177	12	0	189	10,195	0	697	0	10,892	10,703	51,122
2005	0	185	13	0	198	10,127	0	752	0	10,879	10,681	55,170
2006	0	194	13	0	207	10,050	0	798	0	10,848	10,641	58,982
2007	0	203	14	0	217	9,960	0	966	0	10,927	10,710	62,263
2008	0	213	14	0	227	9,903	0	939	0	10,842	10,614	65,350
2009	0	224	15	0	239	9,868	0	928	0	10,798	10,558	68,161
2010	0	235	16	0	251	9,798	0	1,021	0	10,819	10,568	70,736
2011	0	247	17	0	264	9,784	0	1,087	0	10,871	10,607	73,105
2012	0	260	18	0	278	9,749	0	1,126	0	10,875	10,597	75,270
2013	0	274	19	0	293	9,752	0	1,202	0	10,954	10,661	77,266
2014	0	288	20	0	308	9,779	0	1,271	0	11,049	10,741	79,105
2015	0	304	21	0	324	9,825	0	1,331	0	11,156	10,832	80,804
2016	0	319	22	0	341	9,853	0	1,409	0	11,262	10,921	82,372
NOM	0	4,422	561	0	4,983	204,105	0	17,510	0	221,615	216,632	
NPV	0	1,589	343	0	1,932	78,618	0	5,686	0	84,304	82,372	

Discount Rate: 9.22 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 43.63

04477

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: M95X - CI Load Control

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(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILLS $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O&M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0
1995	46	0	2,406	0	2,452	202	3	0	205	2,248	2,058
1996	115	0	5,618	0	5,733	67	7	0	75	5,658	6,801
1997	135	0	6,423	0	6,558	0	9	0	9	6,549	11,827
1998	141	0	6,423	0	6,564	0	9	0	9	6,554	16,432
1999	148	0	6,423	0	6,571	0	10	0	10	6,561	20,653
2000	157	0	6,423	0	6,580	0	10	0	10	6,570	24,523
2001	167	0	6,423	0	6,590	0	10	0	10	6,579	28,071
2002	173	0	6,423	0	6,596	0	11	0	11	6,585	31,322
2003	186	0	6,423	0	6,609	0	11	0	11	6,597	34,304
2004	193	0	6,423	0	6,616	0	12	0	12	6,604	37,038
2005	197	0	6,423	0	6,620	0	13	0	13	6,607	39,541
2006	200	0	6,423	0	6,623	0	13	0	13	6,609	41,834
2007	214	0	6,423	0	6,637	0	14	0	14	6,623	43,938
2008	221	0	6,423	0	6,643	0	14	0	14	6,629	45,868
2009	226	0	6,423	0	6,649	0	15	0	15	6,634	47,632
2010	231	0	6,423	0	6,654	0	16	0	16	6,638	49,250
2011	237	0	6,423	0	6,659	0	17	0	17	6,642	50,733
2012	257	0	6,423	0	6,679	0	18	0	18	6,662	52,094
2013	279	0	6,423	0	6,701	0	19	0	19	6,683	53,344
2014	289	0	6,423	0	6,712	0	20	0	20	6,692	54,491
2015	297	0	6,423	0	6,719	0	21	0	21	6,699	55,541
2016	318	0	6,423	0	6,741	0	22	0	22	6,719	56,506
NOM	4,426	0	136,477	0	140,903	269	292	0	561	140,342	
NPV	1,580	0	55,268	0	56,849	241	102	0	343	56,506	

In Service of Gen Unit: 1997

Discount Rate : 9.22

Benefit/Cost Ratio (Col(6) / Col(10)) 165.91

0478

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI95X - CI Load Control

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PAGE 1 OF 1

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	101	2,406	34	0	2,541	123	0	0	0	123	(2,418)	(2,214)
1996	0	134	5,818	85	0	6,037	299	0	0	0	299	(5,738)	(6,851)
1997	0	136	6,423	100	0	6,659	11,722	0	0	0	11,722	5,063	(2,870)
1998	0	141	6,423	104	0	6,668	11,581	0	0	0	11,581	4,912	482
1999	0	147	6,423	110	0	6,679	11,253	0	0	0	11,253	4,574	3,424
2000	0	151	6,423	116	0	6,690	11,281	0	0	0	11,281	4,591	6,128
2001	0	156	6,423	124	0	6,702	11,158	0	0	0	11,158	4,456	8,531
2002	0	162	6,423	128	0	6,713	11,054	0	0	0	11,054	4,341	10,674
2003	0	170	6,423	136	0	6,730	10,974	0	0	0	10,974	4,244	12,583
2004	0	177	6,423	143	0	6,743	10,892	0	0	0	10,892	4,150	14,311
2005	0	185	6,423	146	0	6,754	10,879	0	0	0	10,879	4,125	15,874
2006	0	194	6,423	148	0	6,764	10,848	0	0	0	10,848	4,084	17,281
2007	0	203	6,423	158	0	6,784	10,927	0	0	0	10,927	4,143	18,607
2008	0	213	6,423	163	0	6,799	10,842	0	0	0	10,842	4,043	19,782
2009	0	224	6,423	167	0	6,814	10,798	0	0	0	10,798	3,983	20,843
2010	0	235	6,423	171	0	6,829	10,819	0	0	0	10,819	3,990	21,815
2011	0	247	6,423	175	0	6,845	10,871	0	0	0	10,871	4,026	22,714
2012	0	260	6,423	190	0	6,873	10,875	0	0	0	10,875	4,002	23,532
2013	0	274	6,423	206	0	6,903	10,954	0	0	0	10,954	4,051	24,290
2014	0	289	6,423	214	0	6,925	11,049	0	0	0	11,049	4,124	24,998
2015	0	304	6,423	220	0	6,946	11,158	0	0	0	11,158	4,211	25,658
2016	0	319	6,423	236	0	6,978	11,262	0	0	0	11,262	4,284	26,272
NOM.	0	4,422	136,477	3,275	0	144,174	221,615	0	0	0	221,615	77,441	
NPV	0	1,589	55,288	1,155	0	58,032	84,304	0	0	0	84,304	26,272	

Discount Rate: 9.22

Benefit/Cost Ratio (Col(12) / Col(7)): 1.45

04479

III. UTILITY & CUSTOMER COSTS (1995$ PER CUSTOMER: 1 kW @ GENERATOR)

GSLD RATE CLASS	CILC	
(1) UTILITY NON RECURRING COST PER CUSTOMER	$0.1268	Excludes capital costs.
(2) UTILITY RECURRING COST PER CUSTOMER	$1.5290	
(4) CUSTOMER EQUIPMENT COST (INCREMENTAL)	$3.4000	
(6) CUSTOMER O&M COST	$0.1034	
(12) UTILITY NON RECURRING REBATE/INCENTIVE	$0.0000	
(13) UTILITY RECURRING REBATE/INCENTIVE	$81.2000	
(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	0%	

III. (3,5,7,9) ESCALATION RATES

	CPI	PPI-CAP
1993	3.3%	2.2%
1994	3.4%	2.7%
1995	3.4%	2.3%
1996	3.5%	2.3%
1997	3.8%	2.9%
1998	4.2%	3.4%
1999	4.5%	3.6%
2000	4.6%	3.6%
2001	4.8%	3.6%
2002	4.6%	3.6%
2003	4.6%	3.7%
2004	4.4%	3.8%
2005	4.5%	3.9%
2006	4.7%	4.0%
2007	4.7%	4.2%
2008	4.9%	4.3%
2009	5.0%	4.4%
2010	5.1%	4.4%
2011	5.2%	4.5%
2012	5.3%	4.6%
2013	5.3%	4.5%
	5.3%	4.5%
	5.2%	4.5%

V. NON-FUEL ENERGY AND DEMAND CHARGES

	GSLD	
(1) NON FUEL COST IN CUSTOMER BILL	1.58	(1995 c/kWh)
(2) NON-FUEL ESCALATION RATE	0 % *	
(3) DEMAND CHARGE IN CUSTOMER BILL	8.06	(1995 $/kW-MONTH)
(4) DEMAND CHARGE ESCALATION RATE	0 % *	

* Values apply to first year only.

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01/30/95

INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME M01R - CI Load Control

PSC FORM CE 1
PAGE 1 OF 1

I PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.29	kW
(3) kW LINE LOSS PERCENTAGE	7.20	%
(4) GENERATOR kWh REDUCTION PER CUSTOMEF	108.7	kWh *****
(5) kWh LINE LOSS PERCENTAGE	5.84	%
(6) GROUP LINE LOSS MULTIPLIER	1.0000	
(7) CUSTOMER kWh INCREASE AT METER	40.9	kWh *****

II ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PRO	27	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.65680	
(5) K FACTOR FOR T & D	1.66867	

III UTILITY & CUSTOMER COSTS

(1) UTILITY NON RECURRING COST PER CUSTOMI	***	$/CUST
(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
(3) UTILITY COST ESCALATION RATE	***	%**
(4) CUSTOMER EQUIPMENT COST	***	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
(6) CUSTOMER O & M COST	***	$/CUST/YR
(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
* (8) INCREASED SUPPLY COSTS	***	$/CUST/YR
* (9) SUPPLY COSTS ESCALATION RATES	***	%**
* (10) UTILITY DISCOUNT RATE	9.22	%
* (11) UTILITY AFUDC RATE	10.92	%
* (12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
* (13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
* (14) UTILITY REBATE/INCENTIVE ESCALATION RAT	***	%

IV AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	1994	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UN	2001	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	1994-2000	
(4) BASE YEAR AVOIDED GENERATING COST	556	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0	$/kW
(6) BASE YEAR DISTRIBUTION COST	0	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	2.60	%**
(8) GENERATOR FIXED O & M COST	21	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	3.40	%**
(10) TRANSMISSION FIXED O & M COST	0.00	$/kW
(11) DISTRIBUTION FIXED O & M COST	0.00	$/kW
(12) T&D FIXED O&M ESCALATION RATE	3.40	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.018	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION I	3.40	%**
(15) GENERATOR CAPACITY FACTOR	52%	** (in-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	3.29	CENTS PER kWh** (in-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RAT	8.34	%**

V NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	****	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	****	%
(3) DEMAND CHARGE IN CUSTOMER BILL	****	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	****	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 12
**** ITEM IS NOT APPLICABLE FOR THIS DSM PROGRAM
***** THIS PROGRAM IS PRIMARILY A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUSTOMER SHIFTED AWAY FROM PEAK HOURS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUSTOM AFTER ADJUSTING ONE OF THESE NUMBERS TO PLACE BOTH AT THE METER OR AT THE GENERATOR, THE DIFFERENCE BETWEEN THE TWO IS THE ANNUAL KWH/CUSTOMER REDUCTION

00481

* INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME M01R - CI Load Control

01/30/95

YEAR	*(1) UTILITY PROGRAM COSTS WITHOUT INCENTIVES $(000)	*(2) UTILITY INCENTIVES $(000)	*(3) OTHER UTILITY COSTS $(000)	*(4) TOTAL UTILITY PROGRAM COSTS $(000)	*(5) ENERGY CHARGE REVENUE LOSSES $(000)	*(6) DEMAND CHARGE REVENUE LOSSES $(000)	*(7) PARTICIPANT EQUIPMENT COSTS $(000)	*(8) PARTICIPANT O&M COSTS $(000)	*(9) OTHER PARTICIPANT COSTS $(000)	*(10) TOTAL PARTICIPANT COSTS $(000)
1994	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0
1997	31	696	0	727	11	0	58	1	0	59
1998	64	2,087	0	2,150	34	0	58	3	0	61
1999	99	3,478	0	3,577	59	0	58	5	0	63
2000	138	4,869	0	5,006	88	0	58	8	0	66
2001	140	5,565	0	5,705	107	0	0	9	0	9
2002	145	5,565	0	5,711	111	0	0	10	0	10
2003	150	5,565	0	5,716	119	0	0	10	0	10
2004	156	5,565	0	5,721	124	0	0	10	0	10
2005	161	5,565	0	5,726	126	0	0	11	0	11
2006	168	5,565	0	5,733	128	0	0	11	0	11
2007	176	5,565	0	5,741	137	0	0	12	0	12
2008	185	5,565	0	5,750	142	0	0	12	0	12
2009	194	5,565	0	5,759	145	0	0	13	0	13
2010	204	5,565	0	5,769	148	0	0	14	0	14
2011	214	5,565	0	5,779	152	0	0	14	0	14
2012	226	5,565	0	5,791	164	0	0	15	0	15
2013	238	5,565	0	5,803	179	0	0	16	0	16
2014	250	5,565	0	5,815	185	0	0	17	0	17
2015	263	5,565	0	5,828	190	0	0	18	0	18
2016	277	5,565	0	5,842	204	0	0	19	0	19
2017	291	5,565	0	5,856	210	0	0	20	0	20
2018	306	5,565	0	5,871	223	0	0	21	0	21
2019	322	5,565	0	5,887	229	0	0	22	0	22
2020	339	5,565	0	5,904	236	0	0	23	0	23
NOM	4,736	122,433	0	127,168	3,453	0	232	313	0	546
NPV	1,230	36,560	0	37,789	887	0	157	79	0	236

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

0482

page 3

CALCULATION OF GEN K-FACTOR
PROGRAM METHOD SELECTED REV_REQ
PROGRAM NAME M01R - CI Load Control

01/30/05

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PAGE 1 OF 2

	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	MID-YEAR RATE BASE $(000)	DEBT $(000)	PREFERRED STOCK $(000)	COMMON EQUITY $(000)	INCOME TAXES $(000)	OTHER TAXES & INSURANCE $(000)	DEPREC. $(000)	DEFERRED TAXES $(000)	TOTAL FIXED CHARGES $(000)	PRESENT WORTH FIXED CHARGES $(000)	CUMULATIVE PW FIXED CHARGES $(000)
2001	63,074	2,775	479	3,833	2,538	1,008	2,083	158	12,870	12,870	12,870
2002	60,423	2,658	459	3,480	1,804	1,008	2,083	981	12,272	11,236	23,906
2003	57,423	2,527	436	3,308	1,810	1,008	2,083	853	11,822	9,909	33,815
2004	54,548	2,400	415	3,142	1,811	1,008	2,083	734	11,390	8,741	42,557
2005	51,787	2,279	394	2,983	1,810	1,008	2,083	622	10,975	7,712	50,269
2006	49,134	2,162	373	2,830	1,803	1,008	2,083	520	10,577	6,804	57,073
2007	46,578	2,049	354	2,683	1,581	1,008	2,083	427	10,180	6,004	63,077
2008	44,112	1,941	335	2,541	1,578	1,008	2,083	339	9,823	5,297	68,374
2009	41,697	1,835	317	2,402	1,494	1,008	2,083	325	9,460	4,671	73,045
2010	39,290	1,729	299	2,263	1,395	1,008	2,083	325	9,099	4,113	77,158
2011	36,882	1,623	280	2,124	1,298	1,008	2,083	325	8,737	3,616	80,774
2012	34,475	1,517	262	1,986	1,198	1,008	2,083	325	8,376	3,174	83,948
2013	32,067	1,411	244	1,847	1,089	1,008	2,083	325	8,014	2,780	86,729
2014	29,659	1,305	225	1,708	1,001	1,008	2,083	325	7,653	2,431	89,160
2015	27,252	1,199	207	1,570	902	1,008	2,083	325	7,291	2,120	91,280
2016	24,844	1,093	189	1,431	804	1,008	2,083	325	6,930	1,845	93,125
2017	22,437	987	171	1,292	705	1,008	2,083	325	6,569	1,601	94,727
2018	20,029	881	152	1,154	606	1,008	2,083	325	6,207	1,385	96,112
2019	17,622	775	134	1,015	508	1,008	2,083	325	5,846	1,195	97,306
2020	15,214	669	116	876	409	1,008	2,083	325	5,484	1,026	98,333
2021	13,069	575	99	753	847	1,008	2,080	(200)	5,162	684	99,217
2022	11,454	504	87	660	1,315	1,008	2,080	(735)	4,920	772	99,989
2023	10,107	445	77	582	1,260	1,008	2,080	(735)	4,717	677	100,666
2024	8,759	385	67	505	1,205	1,008	2,080	(735)	4,515	594	101,259
2025	7,412	326	56	427	1,150	1,008	2,080	(735)	4,313	519	101,778
2026	6,064	267	46	349	1,095	1,008	2,080	(735)	4,110	453	102,231
2027	4,716	208	36	272	1,039	1,008	2,080	(735)	3,908	394	102,625
2028	3,369	148	26	194	984	1,008	2,080	(735)	3,706	342	102,968
2029	2,021	89	15	116	929	1,008	2,080	(735)	3,503	296	103,264
2030	674	30	5	39	874	1,008	2,080	(735)	3,301	256	103,520

IN SERVICE COST ($000)	0
IN SERVICE YEAR	2001
BOOK LIFE (YRS)	30
EFFEC. TAX RATE	38.575
DISCOUNT RATE	9.22%
OTAX & INS RATE	1.81%

CAPITAL STRUCTURE

SOURCE	WEIGHT	COST
DEBT	44%	10.00 %
P/S	8%	9.50 %
C/S	48%	12.00 %

K-FACTOR = CPWFC / IN-SVC COST = 1.65890

0483

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

01/00/95

PROGRAM NAME M01R - CI Load Control

PSC FORM CE 1.1A
PAGE 2a OF 2 * (this page not contained in workbook)

(1) YEAR	(2) TAX DEPRECIATION SCHEDULE	(3) TAX DEPRECIATION $(000)	(4) ACCUMULATED TAX DEPRECIATION $(000)	(5) BOOK DEPRECIATION $(000)	(6) ACCUMULATED BOOK DEPRECIATION $(000)	(7) BOOK DEPRECIATION FOR DEFERRED TAX $(000)	(8) ACCUMULATED BOOK DEPR FOR DEFERRED TAX $(000)	(9) DEFERRED TAX DUE TO DEPRECIATION $(000)	(10) TOTAL EQUITY AFUDC $(000)	(11) BOOK DEPR RATE MINUS 1/LIFE	(12) (10)*(11) *TAX RATE $(000)	(13) SALVAGE *TAX RATE $(000)	(14) ANNUAL DEFERRED TAX (9)-(12)+(13) $(000)
2001	3.75%	2,310	2,310	2,083	2,083	1,905	1,905	156	5,314	0	0	0	156
2002	7.22%	4,448	6,758	2,083	4,165	1,905	3,811	981	5,314	0	0	0	981
2003	6.68%	4,116	10,874	2,083	6,248	1,905	5,716	853	5,314	0	0	0	853
2004	6.18%	3,808	14,682	2,083	8,330	1,905	7,622	734	5,314	0	0	0	734
2005	5.71%	3,518	18,200	2,083	10,413	1,905	9,527	622	5,314	0	0	0	622
2006	5.28%	3,253	21,453	2,083	12,496	1,905	11,433	520	5,314	0	0	0	520
2007	4.89%	3,013	24,466	2,083	14,578	1,905	13,338	427	5,314	0	0	0	427
2008	4.52%	2,785	27,250	2,083	16,661	1,905	15,244	339	5,314	0	0	0	339
2009	4.46%	2,748	29,998	2,083	18,743	1,905	17,149	325	5,314	0	0	0	325
2010	4.46%	2,748	32,746	2,083	20,826	1,905	19,055	325	5,314	0	0	0	325
2011	4.46%	2,748	35,494	2,083	22,909	1,905	20,960	325	5,314	0	0	0	325
2012	- 4.46%	2,748	38,242	2,083	24,991	1,905	22,866	325	5,314	0	0	0	325
2013	4.46%	2,748	40,990	2,083	27,074	1,905	24,771	325	5,314	0	0	0	325
2014	4.46%	2,748	43,737	2,083	29,156	1,905	26,677	325	5,314	0	0	0	325
2015	4.46%	2,748	46,485	2,083	31,239	1,905	28,582	325	5,314	0	0	0	325
2016	4.46%	2,748	49,233	2,083	33,322	1,905	30,487	325	5,314	0	0	0	325
2017	4.46%	2,748	51,981	2,083	35,404	1,905	32,393	325	5,314	0	0	0	325
2018	4.46%	2,748	54,729	2,083	37,487	1,905	34,298	325	5,314	0	0	0	325
2019	4.46%	2,748	57,477	2,083	39,569	1,905	36,204	325	5,314	0	0	0	325
2020	4.46%	2,748	60,224	2,083	41,652	1,905	38,109	325	5,314	0	0	0	325
2021	2.25%	1,388	61,611	2,083	43,735	1,905	40,015	(200)	5,314	0	0	0	(200)
2022	0.00%	0	61,611	2,083	45,817	1,905	41,920	(735)	5,314	0	0	0	(735)
2023	0.00%	0	61,611	2,083	47,900	1,905	43,826	(735)	5,314	0	0	0	(735)
2024	0.00%	0	61,611	2,083	49,982	1,905	45,731	(735)	5,314	0	0	0	(735)
2025	0.00%	0	61,611	2,083	52,065	1,905	47,637	(735)	5,314	0	0	0	(735)
2026	0.00%	0	61,611	2,083	54,148	1,905	49,542	(735)	5,314	0	0	0	(735)
2027	0.00%	0	61,611	2,083	56,230	1,905	51,448	(735)	5,314	0	0	0	(735)
2028	0.00%	0	61,611	2,083	58,313	1,905	53,353	(735)	5,314	0	0	0	(735)
2029	0.00%	0	61,611	2,083	60,395	1,905	55,258	(735)	5,314	0	0	0	(735)
2030	0.00%	0	61,611	2,083	62,478	1,905	57,164	(735)	5,314	0	0	0	(735)

SALVAGE / REMOVAL COST	0.00
YEAR SALVAGE / COST OF REMOVAL	2029
DEFERRED TAXES DURING CONSTRUCTION (SEE PAGE	(1,715)
TOTAL EQUITY AFUDC CAPITALIZED (SEE PAGE 5)	5,314
BOOK DEPR RATE - 1/USEFUL LIFE	0.00

0484

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

01/30/95

PROGRAM NAME:MI01R - CI Load Control

PSC FORM CE 1.1A
PAGE 2b OF 2

(1)	(2)	(3)	(4)	(5)	(5a)*	(5b)*	(6)	(7)	(8)
YEAR	TAX DEPRECIATION SCHEDULE	TAX DEPRECIATION $(000)	DEFERRED TAX $(000)	END OF YEAR NET PLANT IN SERVICE $(000)	ACCUMULATED DEPRECIATION $(000)	ACCUMULATED DEF TAXES $(000)	BEGINNING YEAR RATE BASE $(000)	ENDING OF YEAR RATE BASE $(000)	MID-YEAR RATE BASE $(000)
2001	3.75%	2,310	156	60,395	2,083	(1,559)	64,193	61,954	63,074
2002	7.22%	4,448	981	58,313	4,165	(578)	61,954	58,891	60,423
2003	6.68%	4,116	853	56,230	6,248	274	58,891	55,956	57,423
2004	6.18%	3,808	734	54,148	8,330	1,008	55,956	53,139	54,548
2005	5.71%	3,518	622	52,065	10,413	1,630	53,139	50,435	51,787
2006	5.28%	3,253	520	49,982	12,496	2,150	50,435	47,832	49,134
2007	4.89%	3,013	427	47,900	14,578	2,577	47,832	45,323	46,578
2008	4.52%	2,785	339	45,817	16,661	2,916	45,323	42,901	44,112
2009	4.46%	2,748	325	43,735	18,743	3,241	42,901	40,493	41,697
2010	4.46%	2,748	325	41,652	20,826	3,566	40,493	38,086	39,290
2011	4.46%	2,748	325	39,569	22,909	3,891	38,086	35,678	36,882
2012	4.47%	2,748	325	37,487	24,991	4,216	35,678	33,271	34,475
2013	4.46%	2,748	325	35,404	27,074	4,541	33,271	30,863	32,067
2014	4.46%	2,748	325	33,322	29,156	4,866	30,863	28,456	29,659
2015	4.46%	2,748	325	31,239	31,239	5,191	28,456	26,048	27,252
2016	4.46%	2,748	325	29,156	33,322	5,516	26,048	23,641	24,844
2017	4.46%	2,748	325	27,074	35,404	5,841	23,641	21,233	22,437
2018	4.46%	2,748	325	24,991	37,487	6,166	21,233	18,825	20,029
2019	4.46%	2,748	325	22,908	39,569	6,491	18,825	16,418	17,622
2020	4.46%	2,748	325	20,826	41,652	6,816	16,418	14,010	15,214
2021	2.23%	1,386	(200)	18,743	43,735	6,615	14,010	12,128	13,069
2022	0.00%	0	(735)	16,661	45,817	5,880	12,128	10,781	11,454
2023	0.00%	0	(735)	14,578	47,900	5,145	10,781	9,433	10,107
2024	0.00%	0	(735)	12,496	49,982	4,410	9,433	8,085	8,759
2025	0.00%	0	(735)	10,413	52,065	3,675	8,085	6,738	7,412
2026	0.00%	0	(735)	8,330	54,148	2,940	6,738	5,390	6,064
2027	0.00%	0	(735)	6,248	56,230	2,205	5,390	4,043	4,716
2028	0.00%	0	(735)	4,165	58,313	1,470	4,043	2,695	3,369
2029	0.00%	0	(735)	2,083	60,395	735	2,695	1,348	2,021
2030	0.00%	0	(735)	0	62,478	0	1,348	0	674

* Column not specified in workbook

0485

01/30/95

(1) YEAR	(2) NO. YEARS BEFORE IN-SERVICE	(3) PLANT ESCALATION RATE	(4) CUMULATIVE ESCALATION FACTOR	(5) YEARLY EXPENDITURE (%)	(6) ANNUAL SPENDING ($/kW)	(7) CUMULATIVE AVERAGE SPENDING ($/kW)
1994	-7	0.00%	1.000	0.00%	0.00	0.00
1995	-6	2.60%	1.026	0.00%	0.00	0.00
1996	-5	2.63%	1.053	0.84%	4.92	2.46
1997	-4	3.15%	1.086	1.03%	10.03	8.93
1998	-3	3.62%	1.126	12.00%	81.35	55.62
1999	-2	7.85%	1.169	60.50%	393.17	292.88
2000	-1	3.80%	1.214	24.00%	162.01	570.47
				100.00%	851.48	

YEAR	NO. YEARS BEFORE IN-SERVICE	(8) CUMULATIVE SPENDING WITH AFUDC ($/kW)	(8a)* DEBT AFUDC ($/kW)	(8b)* CUMULATIVE DEBT AFUDC ($/kW)	(9) YEARLY TOTAL AFUDC ($/kW)	(9a)* CUMULATIVE TOTAL AFUDC ($/kW)	(9b)* CONSTRUCTION PERIOD INTEREST ($/kW)	(9c)* CUMULATIVE CPI ($/kW)	(9d)* DEFERRED TAXES ($/kW)	(9e)* CUMULATIVE DEFERRED TAXES ($/kW)	(10) INCREMENTAL YEAR-END BOOK VALUE ($/kW)	(11) CUMULATIVE YEAR-END BOOK VALUE ($/kW)
1994	-7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1996	-5	2.46	0.11	0.11	0.27	0.27	0.25	0.25	(0.05)	(0.05)	5.19	5.19
1997	-4	10.20	0.45	0.56	1.12	1.39	1.02	1.28	(0.22)	(0.27)	11.14	16.33
1998	-3	57.01	2.52	3.08	6.25	7.64	5.69	6.95	(1.22)	(1.49)	87.61	103.94
1999	-2	300.52	13.29	16.37	32.99	40.62	29.98	36.94	(6.44)	(7.93)	426.15	530.09
2000	-1	611.10	27.24	43.61	67.60	108.22	60.74	97.68	(12.92)	(20.86)	229.61	759.70
			43.61	63.72	108.22		97.68		(20.86)		759.70	

0486

IN SERVICE YEA	2001
PLANT COSTS	558
AFUDC RATE	10.92%

	BOOK BASIS	BOOK BASIS FOR DEF TAX	TAX BASIS
CONSTRUCTION CASH	53,578	53,578	53,578
EQUITY AFUDC	5,314		
DEBT AFUDC	3,508	3,508	
CPI			8,033
TOTAL	[illegible]	57,164	61,611

* Column not specified in workbook

INPUT DATA – PART 2
PROGRAM METHOD SELECTED : REV_REQ
PROGRAM NAME M601R - CI Load Control

(1) YEAR	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS	(4) UTILITY AVERAGE SYSTEM FUEL COST (C/KWH)	(5) AVOIDED MARGINAL FUEL COST (C/KWH)	(6)* INCREASED MARGINAL FUEL COST (C/KWH)	(7) REPLACEMENT FUEL COST (C/KWH)	(8) PROGRAM kW EFFECTIVENESS FACTOR	(9) PROGRAM kWh EFFECTIVENESS FACTOR
1994	0	0	0.00	3.82	1.89	0.00	1.00	1.00
1995	0	0	0.00	4.89	1.82	0.00	1.00	1.00
1996	0	0	0.00	5.08	1.82	0.00	1.00	1.00
1997	15,800	15,800	0.00	5.82	2.03	0.00	1.00	1.00
1998	31,700	31,700	0.00	6.01	2.04	0.00	1.00	1.00
1999	47,600	47,600	0.00	7.19	2.19	0.00	1.00	1.00
2000	63,500	63,500	0.00	7.25	2.43	0.00	1.00	1.00
2001	63,500	63,500	0.00	7.78	2.52	5.01	1.00	1.00
2002	63,500	63,500	0.00	8.29	2.59	5.43	1.00	1.00
2003	63,500	63,500	0.00	8.13	2.77	5.37	1.00	1.00
2004	63,500	63,500	0.00	9.68	2.84	5.95	1.00	1.00
2005	63,500	63,500	0.00	10.89	3.14	5.89	1.00	1.00
2006	63,500	63,500	0.00	11.33	3.30	6.32	1.00	1.00
2007	63,500	63,500	0.00	13.56	3.57	6.85	1.00	1.00
2008	63,500	63,500	0.00	13.29	3.81	7.04	1.00	1.00
2009	63,500	63,500	0.00	13.21	3.92	7.57	1.00	1.00
2010	63,500	63,500	0.00	14.48	4.18	8.37	1.00	1.00
2011	63,500	63,500	0.00	15.29	4.14	8.53	1.00	1.00
2012	63,500	63,500	0.00	15.93	4.53	8.98	1.00	1.00
2013	63,500	63,500	0.00	16.82	4.82	9.57	1.00	1.00
2014	63,500	63,500	0.00	17.89	4.88	10.14	1.00	1.00
2015	63,500	63,500	0.00	18.77	5.18	10.51	1.00	1.00
2016	63,500	63,500	0.00	19.82	5.39	11.12	1.00	1.00
2017	63,500	63,500	0.00	20.98	5.88	11.73	1.00	1.00
2018	63,500	63,500	0.00	20.88	5.95	12.38	1.00	1.00
2019	63,500	63,500	0.00	22.02	6.25	13.09	1.00	1.00
2020	63,500	63,500	0.00	23.24	6.57	13.77	1.00	1.00

* THIS COLUMN IS USED ONLY FOR LOAD SHIFTING PROGRAMS WHICH SHIFT CONSUMPTION TO OFF-PEAK PERIODS.

AVOIDED GENERATING BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI01R - CI Load Control

YEAR	(2) AVOIDED GEN UNIT CAPACITY COST $(000)	(3) AVOIDED GEN UNIT FIXED O&M $(000)	(4) AVOIDED GEN UNIT VARIABLE O&M $(000)	(5) AVOIDED GEN UNIT FUEL COST $(000)	(6) REPLACEMENT FUEL COST $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	12,670	2,270	89	12,231	18,699	8,560
2002	12,272	2,374	97	13,894	21,082	7,525
2003	11,822	2,483	102	15,200	21,087	8,539
2004	11,380	2,592	108	16,820	23,529	7,101
2005	10,975	2,709	105	16,507	21,778	8,521
2006	10,577	2,838	97	15,276	20,518	8,270
2007	10,183	2,970	88	13,793	18,294	8,779
2008	9,823	3,115	80	13,180	17,248	8,957
2009	9,460	3,271	88	14,829	19,809	8,040
2010	9,089	3,438	93	15,847	21,808	8,670
2011	8,737	3,817	69	11,715	15,484	8,654
2012	8,379	3,809	58	9,562	12,587	9,215
2013	8,014	4,010	57	9,755	12,822	8,915
2014	7,653	4,223	62	10,657	14,183	8,403
2015	7,281	4,442	77	12,500	16,340	7,988
2016	6,930	4,673	69	11,825	15,718	7,880
2017	6,569	4,916	70	12,039	15,906	7,629
2018	6,207	5,172	73	12,477	16,846	7,283
2019	5,846	5,441	79	13,472	18,092	6,745
2020	5,484	5,724	83	14,113	19,064	6,340
NOM	179,398	74,084	1,840	265,398	360,409	160,089
NPV	53,028	17,033	462	72,800	100,145	42,968

0488

AVOIDED T&D AND PROGRAM FUEL SAVINGS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI01R - CI Load Control

01/30/95

PSC FORM CE 2.2
PAGE 1 OF 1

(1) YEAR	(2) AVOIDED TRANSMISSION CAP COST $(000)	(3) AVOIDED TRANSMISSION O&M COST $(000)	(4) TOTAL AVOIDED TRANSMISSION COST $(000)	(5) AVOIDED DISTRIBUTION CAP COST $(000)	(6) AVOIDED DISTRIBUTION O&M COST $(000)	(7) TOTAL AVOIDED DISTRIBUTION COST $(000)	(8) PROGRAM FUEL SAVINGS $(000)	(8a)* PROGRAM FUEL SAVINGS OFF-PEAK PAYBACK $(000)
1994	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	48	7
1998	0	0	0	0	0	0	158	21
1999	0	0	0	0	0	0	311	38
2000	0	0	0	0	0	0	438	59
2001	0	0	0	0	0	0	538	70
2002	0	0	0	0	0	0	573	72
2003	0	0	0	0	0	0	631	77
2004	0	0	0	0	0	0	683	79
2005	0	0	0	0	0	0	739	87
2006	0	0	0	0	0	0	783	91
2007	0	0	0	0	0	0	838	99
2008	0	0	0	0	0	0	919	105
2009	0	0	0	0	0	0	913	108
2010	0	0	0	0	0	0	1,000	116
2011	0	0	0	0	0	0	1,058	114
2012	0	0	0	0	0	0	1,101	125
2013	0	0	0	0	0	0	1,169	128
2014	0	0	0	0	0	0	1,236	135
2015	0	0	0	0	0	0	1,297	143
2016	0	0	0	0	0	0	1,370	149
2017	0	0	0	0	0	0	1,442	157
2018	0	0	0	0	0	0	1,442	164
2019	0	0	0	0	0	0	1,521	173
2020	0	0	0	0	0	0	1,605	182
NOM.	0	0	0	0	0	0	21,907	2,487
NPV	0	0	0	0	0	0	5,332	623

01/30/96

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI01R - CI Load Control

PSC FORM CE 2.3
PAGE 1 OF 1

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0	0
1997	0	31	59	0	91	0	0	41	0	41	(49)	(38)
1998	0	64	61	0	125	0	0	134	0	134	10	(31)
1999	0	99	63	0	162	0	0	273	0	273	111	40
2000	0	136	66	0	202	0	0	380	0	380	177	145
2001	0	140	9	0	149	8,560	0	468	0	9,028	8,879	4,933
2002	0	145	10	0	155	7,525	0	501	0	8,026	7,871	8,819
2003	0	150	10	0	160	8,539	0	555	0	9,094	8,934	12,857
2004	0	156	10	0	166	7,181	0	604	0	7,785	7,619	16,011
2005	0	161	11	0	172	8,521	0	652	0	9,172	9,000	19,421
2006	0	168	11	0	179	8,270	0	692	0	8,962	8,783	22,468
2007	0	176	12	0	188	8,779	0	837	0	9,616	9,428	25,463
2008	0	185	12	0	197	8,957	0	813	0	9,770	9,573	28,247
2009	0	194	13	0	207	8,040	0	804	0	8,845	8,638	30,547
2010	0	204	14	0	217	6,670	0	885	0	7,555	7,337	32,336
2011	0	214	14	0	229	8,654	0	942	0	9,596	9,367	34,428
2012	0	226	15	0	241	9,215	0	976	0	10,191	9,950	36,459
2013	0	238	16	0	254	8,915	0	1,042	0	9,957	9,703	38,275
2014	0	250	17	0	267	8,403	0	1,101	0	9,504	9,237	39,857
2015	0	263	18	0	281	7,966	0	1,153	0	9,120	8,839	41,243
2016	0	277	19	0	296	7,880	0	1,221	0	9,100	8,805	42,507
2017	0	291	20	0	311	7,628	0	1,285	0	8,913	8,602	43,638
2018	0	306	21	0	327	7,203	0	1,277	0	8,580	8,233	44,629
2019	0	322	22	0	344	6,745	0	1,349	0	8,094	7,750	45,483
2020	0	339	23	0	362	6,340	0	1,424	0	7,764	7,402	46,230
												#VALUE!
												#VALUE!
												#VALUE!
NOM	0	4,736	546	0	5,281	160,069	0	19,409	0	179,478	174,197	
NPV	0	1,230	238	0	1,468	42,986	0	4,710	0	47,696	46,230	

Discount Rate: 9.22 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 32.54

00490

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: MI01R - CI Load Control

01/30/95

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(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILLS $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O&M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0
1997	15	0	696	0	710	58	1	0	59	651	500
1998	46	0	2,087	0	2,133	58	3	0	61	2,071	1,456
1999	80	0	3,478	0	3,558	58	5	0	63	3,495	2,248
2000	119	0	4,869	0	4,988	58	8	0	66	4,923	2,900
2001	145	0	5,565	0	5,710	0	9	0	9	5,701	3,074
2002	150	0	5,565	0	5,715	0	10	0	10	5,706	2,817
2003	161	0	5,565	0	5,726	0	10	0	10	5,716	2,584
2004	167	0	5,565	0	5,732	0	10	0	10	5,722	2,368
2005	171	0	5,565	0	5,736	0	11	0	11	5,725	2,169
2006	173	0	5,565	0	5,738	0	11	0	11	5,727	1,987
2007	185	0	5,565	0	5,750	0	12	0	12	5,739	1,823
2008	191	0	5,565	0	5,756	0	12	0	12	5,744	1,670
2009	196	0	5,565	0	5,761	0	13	0	13	5,748	1,530
2010	200	0	5,565	0	5,765	0	14	0	14	5,751	1,402
2011	205	0	5,565	0	5,770	0	14	0	14	5,756	1,285
2012	222	0	5,565	0	5,787	0	15	0	15	5,772	1,180
2013	242	0	5,565	0	5,807	0	16	0	16	5,791	1,083
2014	251	0	5,565	0	5,816	0	17	0	17	5,799	993
2015	257	0	5,565	0	5,822	0	18	0	18	5,804	910
2016	276	0	5,565	0	5,841	0	19	0	19	5,822	836
2017	284	0	5,565	0	5,849	0	20	0	20	5,829	768
2018	302	0	5,565	0	5,867	0	21	0	21	5,846	704
2019	310	0	5,565	0	5,875	0	22	0	22	5,853	645
2020	319	0	5,565	0	5,885	0	23	0	23	5,862	591
NOM	4,687	0	122,433	0	127,100	233	313	0	546	126,553	
NPV	1,190	0	38,560	0	37,750	157	79	0	236	37,523	

In Service of Gen Unit: 2001

Discount Rate: 9.22

Benefit/Cost Ratio (Col(6) / Col(10)): 159.82

000491

01/30/96

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME M01R - CI Load Control

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PAGE 1 OF 1

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0	0	0
1997	0	31	696	11	0	738	41	0	0	0	41	(697)	(534)
1998	0	84	2,067	34	0	2,184	134	0	0	0	134	(2,050)	(1,440)
1999	0	99	3,478	59	0	3,636	273	0	0	0	273	(3,363)	(2,164)
2000	0	136	4,869	88	0	5,094	380	0	0	0	380	(4,715)	(2,777)
2001	0	140	5,565	107	0	5,813	9,028	0	0	0	9,028	3,215	1,734
2002	0	145	5,565	111	0	5,822	8,026	0	0	0	8,026	2,204	1,088
2003	0	150	5,565	119	0	5,835	9,094	0	0	0	9,094	3,259	1,473
2004	0	156	5,565	124	0	5,844	7,785	0	0	0	7,785	1,941	803
2005	0	161	5,565	126	0	5,853	9,172	0	0	0	9,172	3,320	1,254
2006	0	168	5,565	128	0	5,861	8,962	0	0	0	8,962	3,101	1,078
2007	0	176	5,565	137	0	5,878	9,616	0	0	0	9,616	3,737	1,187
2008	0	185	5,565	142	0	5,891	8,770	0	0	0	8,770	2,879	1,128
2009	0	194	5,565	145	0	5,904	8,845	0	0	0	8,845	2,941	783
2010	0	204	5,565	148	0	5,917	7,555	0	0	0	7,555	1,638	399
2011	0	214	5,565	152	0	5,931	9,596	0	0	0	9,596	3,665	818
2012	0	226	5,565	164	0	5,955	10,191	0	0	0	10,191	4,236	886
2013	0	238	5,565	179	0	5,981	9,957	0	0	0	9,957	3,975	744
2014	0	250	5,565	185	0	6,001	9,504	0	0	0	9,504	3,503	600
2015	0	263	5,565	190	0	6,019	9,120	0	0	0	9,120	3,101	498
2016	0	277	5,565	204	0	6,046	9,100	0	0	0	9,100	3,054	419
2017	0	291	5,565	210	0	6,066	8,913	0	0	0	8,913	2,846	374
2018	0	308	5,565	223	0	6,095	8,560	0	0	0	8,560	2,465	297
2019	0	322	5,565	229	0	6,117	8,094	0	0	0	8,094	1,977	218
2020	0	339	5,565	236	0	6,141	7,764	0	0	0	7,764	1,623	184
NOM.	0	4,736	122,433	3,453	0	130,621	179,478	0	0	0	179,478	48,857	
NPV	0	1,230	38,580	867	0	38,677	47,696	0	0	0	47,696	9,019	

Discount Rate: 9.22

Benefit/Cost Ratio (Col(12) / Col(7)) : 1.23

INPUT DATA - CONTINUED
PROGRAM METHOD SELECTED: REV REQ
PROGRAM NAME: COMMERCIAL/INDUSTRIAL LOAD CONTROL (1997 - 2000)

III. UTILITY & CUSTOMER COSTS (1995$ PER CUSTOMER; 1 kw @ GENERATOR)

GSLD RATE CLASS	CILC	
(1) UTILITY NON RECURRING COST PER CUSTOMER	$0.1268	Excludes capital costs.
(2) UTILITY RECURRING COST PER CUSTOMER	$1.5290	
(4) CUSTOMER EQUIPMENT COST (INCREMENTAL)	$3.4000	
(6) CUSTOMER O&M COST	$0.1034	
(12) UTILITY NON RECURRING REBATE/INCENTIVE	$0.0000	
(13) UTILITY RECURRING REBATE/INCENTIVE	$81.2000	
(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	0%	

III. (3,5,7,9) ESCALATION RATES

	CPI	PPI-CAP
1993	3.3%	2.2%
1994	3.4%	2.7%
1995	3.4%	2.3%
1996	3.5%	2.3%
1997	3.8%	2.9%
1998	4.2%	3.4%
1999	4.5%	3.6%
2000	4.6%	3.6%
2001	4.8%	3.6%
2002	4.6%	3.6%
2003	4.6%	3.7%
2004	4.4%	3.8%
2005	4.5%	3.9%
2006	4.7%	4.0%
2007	4.7%	4.2%
2008	4.9%	4.3%
2009	5.0%	4.4%
2010	5.1%	4.4%
2011	5.2%	4.5%
2012	5.3%	4.6%
2013	5.3%	4.5%
2014	5.3%	4.5%
2015-2023	5.2%	4.5%

V. NON-FUEL ENERGY AND DEMAND CHARGES

	GSLD	
(1) NON FUEL COST IN CUSTOMER BILL	1.58	(1995 c/kWh)
(2) NON-FUEL ESCALATION RATE	0 % *	
(3) DEMAND CHARGE IN CUSTOMER BILL	8.06	(1995 $/kW-MONTH)
(4) DEMAND CHARGE ESCALATION RATE	0 % *	

* Values apply to first year only.

0493

APPENDIX C

INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME C/I LOAD CONTROL - 97

I. PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.29	kW
(3) kW LINE LOSS PERCENTAGE	7.20	%
(4) GENERATOR kWh REDUCTION PER CUSTOMER	106.7	kWh *****
(5) kWh LINE LOSS PERCENTAGE	5.84	%
(6) GROUP LINE LOSS MULTIPLIER	1.0000	
(7) CUSTOMER kWh INCREASE AT METER	40.9	kWh *****

II. ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGR	29	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.65688	
(5) K FACTOR FOR T & D	1.86867	

III. UTILITY & CUSTOMER COSTS

(1) UTILITY NON RECURRING COST PER CUSTOMER	***	$/CUST
(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
(3) UTILITY COST ESCALATION RATE	***	%**
(4) CUSTOMER EQUIPMENT COST	***	$/CUST
(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
(6) CUSTOMER O & M COST	***	$/CUST/YR
(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
* (8) INCREASED SUPPLY COSTS	***	$/CUST/YR
* (9) SUPPLY COSTS ESCALATION RATES	***	%**
* (10) UTILITY DISCOUNT RATE	9.22	%
* (11) UTILITY AFUDC RATE	10.82	%
* (12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
* (13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
* (14) UTILITY REBATE/INCENTIVE ESCALATION RATE	***	%

IV. AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	1994	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2004	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	1994-2003	
(4) BASE YEAR AVOIDED GENERATING COST	506	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0	$/kW
(6) BASE YEAR DISTRIBUTION COST	0	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	2.60	%**
(8) GENERATOR FIXED O & M COST	21	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	3.40	%**
(10) TRANSMISSION FIXED O & M COST	0.00	$/kW
(11) DISTRIBUTION FIXED O & M COST	0.00	$/kW
(12) T&D FIXED O&M ESCALATION RATE	3.40	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.018	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION RAT	3.40	%**
(15) GENERATOR CAPACITY FACTOR	59%	** (In-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	4.20	CENTS PER kWh** (In-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RATE	9.34	%**

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	***	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	***	%
(3) DEMAND CHARGE IN CUSTOMER BILL	***	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	***	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 12
**** ITEM IS NOT APPLICABLE FOR THIS DSM PROGRAM

***** THIS PROGRAM IS PRIMARILY A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUSTOMER SHIFTED AWAY FROM PEAK HOURS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUSTOMER THAT AFTER ADJUSTING ONE OF THESE NUMBERS TO PLACE BOTH AT THE METER OR AT THE GENERATOR, THE DIFFERENCE BETWEEN THE TWO IS THE ANNUAL KWH/CUSTOMER REDUCTION

* INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME CA LOAD CONTROL - 97

YEAR	*(1) UTILITY PROGRAM COSTS WITHOUT INCENTIVES $(000)	*(2) UTILITY INCENTIVES $(000)	*(3) OTHER UTILITY COSTS $(000)	*(4) TOTAL UTILITY PROGRAM COSTS $(000)	*(5) ENERGY CHARGE REVENUE LOSSES $(000)	*(6) DEMAND CHARGE REVENUE LOSSES $(000)	*(7) PARTICIPANT EQUIPMENT COSTS $(000)	*(8) PARTICIPANT O&M COSTS $(000)	*(9) OTHER PARTICIPANT COSTS $(000)	*(10) TOTAL PARTICIPANT COSTS $(000)
1994	0	0	0	0	0	0	0	0	0	0
1995	2	41	0	42	1	0	3	0	0	3
1996	3	172	0	125	2	0	3	0	0	4
1997	5	203	0	208	3	0	3	0	0	4
1998	5	244	0	249	4	0	0	0	0	0
1999	6	244	0	249	4	0	0	0	0	0
2000	6	244	0	249	4	0	0	0	0	0
2001	6	244	0	250	5	0	0	0	0	0
2002	6	244	0	250	5	0	0	0	0	0
2003	6	244	0	250	5	0	0	0	0	0
2004	7	244	0	250	5	0	0	0	0	0
2005	7	244	0	251	6	0	0	0	0	0
2006	7	244	0	251	6	0	0	0	0	0
2007	8	244	0	251	6	0	0	1	0	1
2008	8	244	0	252	6	0	0	1	0	1
2009	8	244	0	252	6	0	0	1	0	1
2010	9	244	0	253	6	0	0	1	0	1
2011	9	244	0	253	7	0	0	1	0	1
2012	10	244	0	253	7	0	0	1	0	1
2013	10	244	0	254	8	0	0	1	0	1
2014	11	244	0	255	8	0	0	1	0	1
2015	12	244	0	256	8	0	0	1	0	1
2016	12	244	0	256	9	0	0	1	0	1
2017	13	244	0	256	9	0	0	1	0	1
2018	13	244	0	257	10	0	0	1	0	1
2019	14	244	0	258	10	0	0	1	0	1
2020	15	244	0	258	10	0	0	1	0	1
2021	16	244	0	259	11	0	0	1	0	1
2022	16	244	0	260	11	0	0	1	0	1
NOM	251	6,456	0	6,707	183	0	10	17	0	27
NPV	66	2,099	0	2,165	48	0	9	4	0	13

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK

CALCULATION OF GEN K-FACTOR
PROGRAM METHOD SELECTED REV_REQ
PROGRAM NAME C/I LOAD CONTROL - 97

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PAGE 1 OF 2

	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	MID-YEAR RATE BASE $(000)	DEBT $(000)	PREFERRED STOCK $(000)	COMMON EQUITY $(000)	INCOME TAXES $(000)	OTHER TAXES & INSURANCE $(000)	DEPREC $(000)	DEFERRED TAXES $(000)	TOTAL FIXED CHARGES $(000)	PRESENT WORTH FIXED CHARGES $(000)	CUMULATIVE PW FIXED CHARGES $(000)
2004	3,096	136	24	178	125	49	102	8	622	622	622
2005	2,966	131	23	171	79	49	102	48	602	552	1,173
2006	2,819	124	21	162	79	49	102	42	580	486	1,660
2007	2,678	118	20	154	79	49	102	36	560	429	2,089
2008	2,542	112	19	146	79	49	102	31	539	379	2,468
2009	2,412	106	18	139	79	49	102	26	519	334	2,802
2010	2,288	101	17	132	78	49	102	21	500	295	3,096
2011	2,165	95	16	125	77	49	102	17	482	260	3,356
2012	2,047	90	16	118	73	49	102	16	464	229	3,585
2013	1,929	85	15	111	68	49	102	16	447	202	3,787
2014	1,810	80	14	104	64	49	102	16	429	178	3,965
2015	1,692	74	13	97	59	49	102	16	411	156	4,121
2016	1,574	69	12	91	54	49	102	16	393	136	4,257
2017	1,456	64	11	84	49	49	102	16	376	119	4,377
2018	1,338	59	10	77	44	49	102	16	358	104	4,481
2019	1,220	54	9	70	39	49	102	16	340	91	4,571
2020	1,101	48	8	63	35	49	102	16	322	79	4,650
2021	983	43	7	57	30	49	102	16	305	68	4,718
2022	865	38	7	50	25	49	102	16	287	59	4,777
2023	747	33	6	43	20	49	102	16	269	50	4,827
2024	642	28	5	37	42	49	102	(10)	253	43	4,870
2025	562	25	4	32	65	49	102	(36)	241	38	4,908
2026	498	22	4	29	62	49	102	(36)	232	33	4,941
2027	430	19	3	25	59	49	102	(36)	222	29	4,971
2028	364	16	3	21	56	49	102	(36)	212	25	4,996
2029	298	13	2	17	54	49	102	(36)	202	22	5,018
2030	232	10	2	13	51	49	102	(36)	192	19	5,038
2031	165	7	1	10	48	49	102	(36)	182	17	5,054
2032	99	4	1	6	46	49	102	(36)	172	15	5,069
2033	33	1	0	2	43	49	102	(36)	162	13	5,081

IN SERVICE COST ($000)	3,067
IN SERVICE YEAR	2004
BOOK LIFE (YRS)	30
EFFEC. TAX RATE	38.575
DISCOUNT RATE	9.22%
OTAX & INS RATE	1.61%

CAPITAL STRUCTURE

SOURCE	WEIGHT	COST
DEBT	44%	10.00 %
P/S	8%	9.50 %
C/S	48%	12.00 %

K-FACTOR = CPWFC / IN-SVC COST = 1.65668

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

PROGRAM NAME CI LOAD CONTROL - 97

PSC FORM CE 1.1A
PAGE 2a OF 2 * (this page not contained in workbook)

(1) YEAR	(2) TAX DEPRECIATION SCHEDULE	(3) TAX DEPRECIATION $(000)	(4) ACCUMULATED TAX DEPRECIATION $(000)	(5) BOOK DEPRECIATION $(000)	(6) ACCUMULATED BOOK DEPRECIATION $(000)	(7) BOOK DEPRECIATION FOR DEFERRED TAX $(000)	(8) ACCUMULATED BOOK DEPR FOR DEFERRED TAX $(000)	(9) DEFERRED TAX DUE TO DEPRECIATION $(000)	(10) TOTAL EQUITY AFUDC $(000)	(11) BOOK DEPR RATE MINUS 1/LIFE	(12) (10)*(11) *TAX RATE $(000)	(13) SALVAGE *TAX RATE $(000)	(14) ANNUAL DEFERRED TAX (9)-(12)+(13) $(000)
2004	3.75%	113	113	102	102	94	94	8	261	0	0	0	8
2005	7.22%	218	332	102	204	94	187	48	261	0	0	0	48
2006	6.68%	202	534	102	307	94	281	42	261	0	0	0	42
2007	6.18%	187	721	102	409	94	374	36	261	0	0	0	36
2008	5.71%	173	893	102	511	94	468	31	261	0	0	0	31
2009	5.29%	160	1,053	102	613	94	561	26	261	0	0	0	26
2010	4.89%	148	1,201	102	716	94	655	21	261	0	0	0	21
2011	4.52%	137	1,338	102	818	94	748	17	261	0	0	0	17
2012	4.46%	135	1,473	102	920	94	842	16	261	0	0	0	16
2013	4.46%	135	1,607	102	1,022	94	935	16	261	0	0	0	16
2014	4.46%	135	1,742	102	1,125	94	1,029	16	261	0	0	0	16
2015	4.46%	135	1,877	102	1,227	94	1,122	16	261	0	0	0	16
2016	4.46%	135	2,012	102	1,329	94	1,216	16	261	0	0	0	16
2017	4.46%	135	2,147	102	1,431	94	1,310	16	261	0	0	0	16
2018	4.46%	135	2,282	102	1,533	94	1,403	16	261	0	0	0	16
2019	4.46%	135	2,417	102	1,636	94	1,497	16	261	0	0	0	16
2020	4.46%	135	2,552	102	1,738	94	1,590	16	261	0	0	0	16
2021	4.46%	135	2,687	102	1,840	94	1,684	16	261	0	0	0	16
2022	4.46%	135	2,821	102	1,942	94	1,777	16	261	0	0	0	16
2023	4.46%	135	2,956	102	2,045	94	1,871	16	261	0	0	0	16
2024	2.23%	68	3,024	102	2,147	94	1,964	(10)	261	0	0	0	(10)
2025	0.00%	0	3,024	102	2,249	94	2,058	(36)	261	0	0	0	(36)
2026	0.00%	0	3,024	102	2,351	94	2,151	(36)	261	0	0	0	(36)
2027	0.00%	0	3,024	102	2,454	94	2,245	(36)	261	0	0	0	(36)
2028	0.00%	0	3,024	102	2,556	94	2,338	(36)	261	0	0	0	(36)
2029	0.00%	0	3,024	102	2,658	94	2,432	(36)	261	0	0	0	(36)
2030	0.00%	0	3,024	102	2,760	94	2,526	(36)	261	0	0	0	(36)
2031	0.00%	0	3,024	102	2,862	94	2,619	(36)	261	0	0	0	(36)
2032	0.00%	0	3,024	102	2,965	94	2,713	(36)	261	0	0	0	(36)
2033	0.00%	0	3,024	102	3,067	94	2,806	(36)	261	0	0	0	(36)

SALVAGE / REMOVAL COST	0.00
YEAR SALVAGE / COST OF REMOVAL	2029
DEFERRED TAXES DURING CONSTRUCTION (SEE PAGE 4)	(94)
TOTAL EQUITY AFUDC CAPITALIZED (SEE PAGE 5)	261
BOOK DEPR RATE - 1/USEFUL LIFE	0.00

DEFERRED TAX AND MID-YEAR RATE BASE CALCULATION
PROGRAM METHOD SELECTED: REV_REQ

PROGRAM NAME CA LOAD CONTROL - 97

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PAGE 2b OF 2

(1) YEAR	(2) TAX DEPRECIATION SCHEDULE	(3) TAX DEPRECIATION $(000)	(4) DEFERRED TAX $(000)	(5) END OF YEAR NET PLANT IN SERVICE $(000)	(5a)* ACCUMULATED DEPRECIATION $(000)	(5b)* ACCUMULATED DEF TAXES $(000)	(6) BEGINNING YEAR RATE BASE $(000)	(7) ENDING OF YEAR RATE BASE $(000)	(8) MID-YEAR RATE BASE $(000)
2004	3.75%	113	8	2,965	102	(77)	3,151	3,041	3,096
2005	7.22%	218	48	2,862	204	(28)	3,041	2,891	2,966
2006	6.68%	202	42	2,760	307	13	2,891	2,747	2,819
2007	6.18%	187	36	2,658	409	50	2,747	2,608	2,678
2008	5.71%	173	31	2,556	511	80	2,608	2,478	2,542
2009	5.28%	160	26	2,454	613	108	2,478	2,348	2,412
2010	4.89%	148	21	2,351	716	127	2,348	2,225	2,286
2011	4.52%	137	17	2,249	818	143	2,225	2,106	2,165
2012	4.46%	135	16	2,147	920	159	2,106	1,988	2,047
2013	4.46%	135	16	2,045	1,022	175	1,988	1,870	1,929
2014	4.46%	135	16	1,942	1,125	191	1,870	1,751	1,810
2015	4.46%	135	16	1,840	1,227	207	1,751	1,633	1,692
2016	4.46%	135	16	1,738	1,329	223	1,633	1,515	1,574
2017	4.46%	135	16	1,636	1,431	239	1,515	1,397	1,456
2018	4.46%	135	16	1,533	1,533	255	1,397	1,279	1,338
2019	4.46%	135	16	1,431	1,636	271	1,279	1,160	1,220
2020	4.46%	135	16	1,329	1,738	287	1,160	1,042	1,101
2021	4.46%	135	16	1,227	1,840	303	1,042	924	983
2022	4.46%	135	16	1,125	1,942	319	924	806	865
2023	4.46%	135	16	1,022	2,045	335	806	688	747
2024	2.25%	68	(10)	920	2,147	325	688	595	642
2025	0.00%	0	(36)	818	2,249	309	595	529	562
2026	0.00%	0	(36)	716	2,351	253	529	463	496
2027	0.00%	0	(36)	613	2,454	216	463	397	430
2028	0.00%	0	(36)	511	2,556	180	397	331	364
2029	0.00%	0	(36)	409	2,658	144	331	265	298
2030	0.00%	0	(36)	307	2,760	108	265	198	232
2031	0.00%	0	(36)	204	2,862	72	198	132	165
2032	0.00%	0	(36)	102	2,965	36	132	66	99
2033	0.00%	0	(36)	0	3,067	0	66	0	33

* Column not specified in workbook

(1) YEAR	(2) NO. YEARS BEFORE IN-SERVICE	(3) PLANT ESCALATION RATE	(4) CUMULATIVE ESCALATION FACTOR	(5) YEARLY EXPENDITURE (%)	(6) ANNUAL SPENDING ($/kW)	(7) CUMULATIVE AVERAGE SPENDING ($/kW)
1994	-10	0.00%	1.000	0.00%	0.00	0.00
1995	-9	2.60%	1.026	0.00%	0.00	0.00
1996	-8	2.63%	1.053	0.00%	0.00	0.00
1997	-7	3.15%	1.086	0.00%	0.00	0.00
1998	-6	3.62%	1.126	0.00%	0.00	0.00
1999	-5	3.83%	1.169	0.84%	5.46	2.73
2000	-4	3.86%	1.214	1.66%	11.21	11.06
2001	-3	3.93%	1.262	13.00%	91.21	62.27
2002	-2	3.88%	1.311	60.50%	440.92	328.33
2003	-1	3.95%	1.363	24.00%	181.82	639.70
				100.00%	730.61	

YEAR	NO. YEARS BEFORE IN-SERVICE	(8) CUMULATIVE SPENDING WITH AFUDC ($/kW)	(8a)* DEBT AFUDC ($/kW)	(8b)* CUMULATIVE DEBT AFUDC ($/kW)	(9) YEARLY TOTAL AFUDC ($/kW)	(9a)* CUMULATIVE TOTAL AFUDC ($/kW)	(9b)* CONSTRUCTION PERIOD INTEREST ($/kW)	(9c)* CUMULATIVE CPI ($/kW)	(9d)* DEFERRED TAXES ($/kW)	(9e)* CUMULATIVE DEFERRED TAXES ($/kW)	(10) INCREMENTAL YEAR-END BOOK VALUE ($/kW)	(11) CUMULATIVE YEAR-END BOOK VALUE ($/kW)
1994	-10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	-9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1996	-8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1997	-7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1998	-6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1999	-5	2.73	0.12	0.12	0.30	0.30	0.27	0.27	(0.06)	(0.06)	5.76	5.76
2000	-4	11.36	0.50	0.62	1.25	1.56	1.13	1.41	(0.24)	(0.30)	12.45	18.21
2001	-3	63.81	2.82	3.44	7.00	8.55	6.37	7.77	(1.37)	(1.67)	98.21	116.42
2002	-2	336.88	14.90	18.34	36.97	45.52	33.61	41.38	(7.22)	(8.89)	477.89	594.31
2003	-1	685.21	30.54	48.88	75.80	121.31	68.11	109.49	(14.49)	(23.38)	257.61	851.92
			48.88	71.41	121.31		109.49		(23.38)		851.92	

IN SERVICE YEAR	2004
PLANT COSTS	556
AFUDC RATE	10.92%

	BOOK BASIS	BOOK BASIS FOR DEF TAX	TAX BASIS
CONSTRUCTION CASH	2,630	2,630	2,630
EQUITY AFUDC	261		
DEBT AFUDC	176	176	
CPI			394

* Column not specified in workbook

INPUT DATA -- PART 2
PROGRAM METHOD SELECTED : REV_REQ
PROGRAM NAME: CI LOAD CONTROL - 97

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(1) YEAR	(2) CUMULATIVE TOTAL PARTICIPATING CUSTOMERS	(3) ADJUSTED CUMULATIVE PARTICIPATING CUSTOMERS	(4) UTILITY AVERAGE SYSTEM FUEL COST (C/kWh)	(5) AVOIDED MARGINAL FUEL COST (C/kWh)	(6)* INCREASED MARGINAL FUEL COST (C/kWh)	(7) REPLACEMENT FUEL COST (C/kWh)	(8) PROGRAM kW EFFECTIVENESS FACTOR	(9) PROGRAM kWh EFFECTIVENESS FACTOR
1994	0	0	0.00	3.82	1.89	0.00	1.00	1.00
1995	928	928	0.00	4.89	1.72	0.00	1.00	1.00
1996	1,856	1,856	0.00	5.06	1.82	0.00	1.00	1.00
1997	2,784	2,784	0.00	5.62	2.03	0.00	1.00	1.00
1998	2,784	2,784	0.00	6.01	2.04	0.00	1.00	1.00
1999	2,784	2,784	0.00	7.19	2.19	0.00	1.00	1.00
2000	2,784	2,784	0.00	7.25	2.43	0.00	1.00	1.00
2001	2,784	2,784	0.00	7.78	2.52	0.00	1.00	1.00
2002	2,784	2,784	0.00	8.29	2.59	0.00	1.00	1.00
2003	2,784	2,784	0.00	9.13	2.77	0.00	1.00	1.00
2004	2,784	2,784	0.00	9.68	2.84	5.95	1.00	1.00
2005	2,784	2,784	0.00	10.69	3.14	5.89	1.00	1.00
2006	2,784	2,784	0.00	11.33	3.30	6.32	1.00	1.00
2007	2,784	2,784	0.00	13.55	3.57	6.65	1.00	1.00
2008	2,784	2,784	0.00	13.25	3.81	7.04	1.00	1.00
2009	2,784	2,784	0.00	13.21	3.92	7.57	1.00	1.00
2010	2,784	2,784	0.00	14.48	4.18	8.37	1.00	1.00
2011	2,784	2,784	0.00	15.29	4.14	8.53	1.00	1.00
2012	2,784	2,784	0.00	15.93	4.53	8.98	1.00	1.00
2013	2,784	2,784	0.00	16.82	4.62	9.57	1.00	1.00
2014	2,784	2,784	0.00	17.89	4.89	10.14	1.00	1.00
2015	2,784	2,784	0.00	18.77	5.18	10.51	1.00	1.00
2016	2,784	2,784	0.00	19.62	5.30	11.12	1.00	1.00
2017	2,784	2,784	0.00	20.06	5.66	11.73	1.00	1.00
2018	2,784	2,784	0.00	20.86	5.96	12.38	1.00	1.00
2019	2,784	2,784	0.00	22.02	6.25	13.06	1.00	1.00
2020	2,784	2,784	0.00	23.24	6.57	13.77	1.00	1.00
2021	2,784	2,784	0.00	24.52	6.90	14.53	1.00	1.00
2022	2,784	2,784	0.00	25.89	7.25	15.32	1.00	1.00

* THIS COLUMN IS USED ONLY FOR LOAD SHIFTING PROGRAMS WHICH SHIFT CONSUMPTION TO OFF-PEAK PERIODS.

AVOIDED GENERATING BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: C1 LOAD CONTROL - 97

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YEAR	(2) AVOIDED GEN UNIT CAPACITY COST $(000)	(3) AVOIDED GEN UNIT FIXED O&M $(000)	(4) AVOIDED GEN UNIT VARIABLE O&M $(000)	(5) AVOIDED GEN UNIT FUEL COST $(000)	(6) REPLACEMENT FUEL COST $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)
1994	0	0	0	0	0	0
1995	0	0	0	0	0	0
1996	0	0	0	0	0	0
1997	0	0	0	0	0	0
1998	0	0	0	0	0	0
1999	0	0	0	0	0	0
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	622	113	5	728	1,030	438
2005	602	119	5	723	853	596
2006	580	124	4	659	888	479
2007	559	130	4	604	799	487
2008	539	136	4	577	758	501
2009	519	143	4	649	858	457
2010	500	150	4	685	948	394
2011	482	158	3	513	678	479
2012	464	167	2	419	551	501
2013	447	176	2	427	566	486
2014	429	185	3	487	621	482
2015	411	194	3	547	715	441
2016	393	205	3	522	688	435
2017	376	215	3	527	699	422
2018	358	226	3	548	729	405
2019	340	236	3	590	792	380
2020	322	251	4	618	835	360
2021	305	264	4	631	858	345
2022	287	277	4	651	890	329
NOM	8,536	3,472	67	11,081	14,881	8,305
NPV	1,977	639	15	2,403	3,224	1,809

AVOIDED T&D AND PROGRAM FUEL SAVINGS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CI LOAD CONTROL - 97

PSC FORM CE 2.2
PAGE 1 OF 1

(1) YEAR	(2) AVOIDED TRANSMISSION CAP COST $(000)	(3) AVOIDED TRANSMISSION O&M COST $(000)	(4) TOTAL AVOIDED TRANSMISSION COST $(000)	(5) AVOIDED DISTRIBUTION CAP COST $(000)	(6) AVOIDED DISTRIBUTION O&M COST $(000)	(7) TOTAL AVOIDED DISTRIBUTION COST $(000)	(8) PROGRAM FUEL SAVINGS $(000)	(8a)* PROGRAM FUEL SAVINGS OFF-PEAK PAYBACK $(000)
1994	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	2	0
1996	0	0	0	0	0	0	8	1
1997	0	0	0	0	0	0	14	2
1998	0	0	0	0	0	0	18	2
1999	0	0	0	0	0	0	22	3
2000	0	0	0	0	0	0	22	3
2001	0	0	0	0	0	0	24	3
2002	0	0	0	0	0	0	25	3
2003	0	0	0	0	0	0	28	3
2004	0	0	0	0	0	0	30	3
2005	0	0	0	0	0	0	32	4
2006	0	0	0	0	0	0	34	4
2007	0	0	0	0	0	0	41	4
2008	0	0	0	0	0	0	40	5
2009	0	0	0	0	0	0	40	5
2010	0	0	0	0	0	0	44	5
2011	0	0	0	0	0	0	46	5
2012	0	0	0	0	0	0	48	5
2013	0	0	0	0	0	0	51	6
2014	0	0	0	0	0	0	54	6
2015	0	0	0	0	0	0	57	6
2016	0	0	0	0	0	0	60	7
2017	0	0	0	0	0	0	63	7
2018	0	0	0	0	0	0	63	7
2019	0	0	0	0	0	0	67	8
2020	0	0	0	0	0	0	70	8
2021	0	0	0	0	0	0	74	8
2022	0	0	0	0	0	0	78	9
NOM.	0	0	0	0	0	0	1,156	133
NPV	0	0	0	0	0	0	280	33

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CI LOAD CONTROL - 97

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(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	2	3	0	5	0	0	2	0	2	(3)	(3)
1996	0	3	4	0	7	0	0	6	0	6	(1)	(3)
1997	0	5	4	0	9	0	0	12	0	12	3	(1)
1998	0	5	0	0	6	0	0	16	0	16	10	6
1999	0	6	0	0	6	0	0	19	0	19	13	15
2000	0	6	0	0	6	0	0	19	0	19	13	22
2001	0	6	0	0	6	0	0	20	0	20	14	30
2002	0	6	0	0	7	0	0	22	0	22	15	37
2003	0	6	0	0	7	0	0	24	0	24	17	45
2004	0	7	0	0	7	438	0	26	0	464	457	234
2005	0	7	0	0	7	495	0	29	0	523	516	430
2006	0	7	0	0	8	479	0	30	0	510	502	604
2007	0	8	1	0	8	497	0	37	0	534	526	771
2008	0	8	1	0	9	501	0	36	0	536	528	894
2009	0	8	1	0	9	457	0	35	0	492	483	1,053
2010	0	9	1	0	10	394	0	39	0	433	423	1,158
2011	0	9	1	0	10	479	0	41	0	520	510	1,270
2012	0	10	1	0	11	501	0	43	0	544	533	1,379
2013	0	10	1	0	11	486	0	46	0	532	521	1,478
2014	0	11	1	0	12	462	0	48	0	510	498	1,562
2015	0	12	1	0	12	441	0	50	0	491	479	1,637
2016	0	12	1	0	13	435	0	53	0	488	475	1,705
2017	0	13	1	0	14	422	0	56	0	478	465	1,766
2018	0	13	1	0	14	405	0	56	0	461	447	1,820
2019	0	14	1	0	15	380	0	59	0	439	424	1,867
2020	0	15	1	0	16	360	0	62	0	422	406	1,908
2021	0	16	1	0	17	345	0	66	0	411	395	1,944
2022	0	16	1	0	18	329	0	70	0	399	381	1,976
NOM	0	251	27	0	278	8,306	0	1,023	0	9,329	9,050	
NPV	0	66	13	0	79	1,809	0	246	0	2,055	1,976	

Discount Rate: 8.22 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 25.98

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CI LOAD CONTROL - 97

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(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILLS $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O&M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0
1995	1	0	41	0	41	3	0	0	3	38	35
1996	2	0	122	0	124	3	0	0	4	121	138
1997	4	0	203	0	207	3	0	0	4	204	291
1998	5	0	244	0	249	0	0	0	0	249	487
1999	6	0	244	0	249	0	0	0	0	249	627
2000	6	0	244	0	250	0	0	0	0	249	774
2001	6	0	244	0	250	0	0	0	0	250	908
2002	7	0	244	0	250	0	0	0	0	250	1,032
2003	7	0	244	0	251	0	0	0	0	250	1,145
2004	7	0	244	0	251	0	0	0	0	250	1,248
2005	7	0	244	0	251	0	0	0	0	251	1,343
2006	8	0	244	0	251	0	0	0	0	251	1,430
2007	8	0	244	0	252	0	1	0	1	251	1,510
2008	8	0	244	0	252	0	1	0	1	251	1,583
2009	9	0	244	0	252	0	1	0	1	252	1,650
2010	9	0	244	0	252	0	1	0	1	252	1,712
2011	9	0	244	0	253	0	1	0	1	252	1,768
2012	10	0	244	0	253	0	1	0	1	253	1,819
2013	11	0	244	0	254	0	1	0	1	253	1,867
2014	11	0	244	0	255	0	1	0	1	254	1,910
2015	11	0	244	0	255	0	1	0	1	254	1,950
2016	12	0	244	0	256	0	1	0	1	255	1,987
2017	12	0	244	0	256	0	1	0	1	255	2,020
2018	13	0	244	0	257	0	1	0	1	256	2,051
2019	14	0	244	0	257	0	1	0	1	256	2,079
2020	14	0	244	0	258	0	1	0	1	257	2,105
2021	14	0	244	0	258	0	1	0	1	257	2,129
2022	15	0	244	0	258	0	1	0	1	257	2,151
NOM	247	0	6,456	0	6,702	10	17	0	27	6,675	
NPV	65	0	2,099	0	2,164	9	4	0	13	2,151	

In Service of Gen Unit: 2004

Discount Rate: 9.22

Benefit/Cost Ratio (Col(6) / Col(10)) 168.44

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CI LOAD CONTROL - 97

PSC FORM CE 2.5
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(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
1994	0	0	0	0	0	0	0	0	0	0	0	(0)	(0)
1995	0	2	41	1	0	43	2	0	0	0	2	(41)	(37)
1996	0	3	122	2	0	127	6	0	0	0	6	(121)	(139)
1997	0	5	203	3	0	211	12	0	0	0	12	(199)	(291)
1998	0	5	244	4	0	253	16	0	0	0	16	(237)	(458)
1999	0	6	244	4	0	253	19	0	0	0	19	(234)	(608)
2000	0	6	244	4	0	254	19	0	0	0	19	(235)	(747)
2001	0	6	244	5	0	254	20	0	0	0	20	(234)	(873)
2002	0	6	244	5	0	255	22	0	0	0	22	(233)	(990)
2003	0	6	244	5	0	255	24	0	0	0	24	(231)	(1,093)
2004	0	7	244	5	0	256	404	0	0	0	404	208	(1,000)
2005	0	7	244	6	0	256	523	0	0	0	523	267	(905)
2006	0	7	244	6	0	257	510	0	0	0	510	253	(817)
2007	0	8	244	6	0	257	534	0	0	0	534	277	(729)
2008	0	8	244	6	0	258	535	0	0	0	536	279	(648)
2009	0	8	244	6	0	258	482	0	0	0	482	234	(580)
2010	0	9	244	6	0	259	433	0	0	0	433	174	(544)
2011	0	9	244	7	0	260	520	0	0	0	520	260	(486)
2012	0	10	244	7	0	261	544	0	0	0	544	283	(426)
2013	0	10	244	8	0	262	532	0	0	0	532	270	(377)
2014	0	11	244	8	0	263	510	0	0	0	510	247	(335)
2015	0	12	244	8	0	263	491	0	0	0	491	228	(299)
2016	0	12	244	9	0	265	488	0	0	0	488	224	(267)
2017	0	13	244	9	0	266	478	0	0	0	478	213	(236)
2018	0	13	244	10	0	267	461	0	0	0	461	194	(210)
2019	0	14	244	10	0	268	439	0	0	0	439	171	(187)
2020	0	15	244	10	0	269	422	0	0	0	422	153	(162)
2021	0	16	244	11	0	270	411	0	0	0	411	141	(169)
2022	0	16	244	11	0	271	399	0	0	0	399	128	(158)
NOM.	0	251	6,456	183	0	6,809	9,328	0	0	0	9,328	2,439	
NPV	0	68	2,099	46	0	2,213	2,055	0	0	0	2,055	(158)	

Discount Rate 9.22

Benefit/Cost Ratio (Col(12) / Col(7)) : 0.93