**FLORIDA PUBLIC SERVICE COMMISSION**

**Fletcher Building**

**101 East Gaines Street**

**Tallahassee, Florida 32399-0850**

**M E M O R A N D U M**

**SEPTEMBER 24, 1992**

**TO : DIRECTOR OF RECORDS AND REPORTING**

**FROM : DIVISION OF APPEALS (RULE)**

**DIVISION OF ELECTRIC AND GAS (FLOYD, SHINE)**

**DIVISION OF RESEARCH AND REGULATORY REVIEW (HEWITT, HARLOW)**

**RE : DOCKET NO. 920606-EI: PROPOSED ADOPTION OF RULE 25‑17.0021, F.A.C., GOALS FOR ELECTRIC UTILITIES, AND RULE 25‑17.0025, F.A.C., CONSERVATION PERFORMANCE INCENTIVE FACTOR; PROPOSED AMENDMENT TO RULE 25‑17.001, F.A.C., GENERAL INFORMATION, RULE 25‑17.003, F.A.C., ENERGY AUDITS, RELATED PROVISIONS, AND RULE 25‑17.006, F.A.C., ELECTRIC UTILITY SYSTEM CONSERVATION END USE DATA; AND PROPOSED REPEAL OF RULE 25‑17.005, F.A.C., EVALUATION OF ELECTRIC UTILITY CONSERVATION EFFORTS, AND RULE 25‑17.007, F.A.C., NORMALIZATION OF ELECTRIC UTILITY LOAD DATA.**

**AGENDA:OCTOBER 6, 1992 - CONTROVERSIAL AGENDA - PARTIES MAY PARTICIPATE**

**PANEL:FULL COMMISSION**

**CRITICAL DATES:NONE**

**SPECIAL INSTRUCTIONS:I:\PSC\APP\WP\920606.RCM**

**CASE BACKGROUND**

In 1980, the Commission adopted conservation goals pursuant to Section 366.80 - 366.85, Florida Statutes (the Florida Energy Efficiency and Conservation Act, or "FEECA") which was passed that year by the Florida legislature. All electric utilities, regardless of size, including municipals and cooperatives, were required to comply with FEECA, as were natural gas utilities with annual sales greater than or equal to 100 million therms. The specific numeric energy and demand reduction goals were contained in Rule 25-17.002, F.A.C.

The goals adopted by the Commission were designed to increase the conservation of expensive resources, such as petroleum fuels, and to reduce the growth rates of electric consumption, especially of weather-sensitive peak demand. In simple terms, the goals were: (1) to reduce the use of oil by 25% by 1989, so that consumption in 1990 would not exceed 58,734,000 barrels; (2) to reduce the growth rate of energy sales to 75% of the growth rate in residential customers by 1989; and (3) to reduce the growth rate in peak demand to 72.25% of the growth rate in residential customers by 1989. These goals extended only through 1989.

The legislative sunset review of FEECA occurred during the 1989 regular session. The major changes made to FEECA were the addition of language to encourage cogeneration and the limitation of the application of the Act to electric utilities with more than 500 gigawatt-hours of annual retail sales. Thereafter, Order No. 22176, issued November 14, 1989, required the electric utilities subject to FEECA to submit plans and programs consistent with the numeric goals embodied in 25-17.002, F.A.C.

After the expiration of the specific demand and energy numeric goals in Rule 25-17.002, the Commission decided to adopt as FEECA goals the general non-numeric goal statements expressed in 25-17.001 F.A.C. Rule 25-17.002 was therefore repealed by Order No. 22758, issued on April 2, 1990 in Docket No. 820517-EU. Later, the Commission directed staff to develop more specific goals.

Staff developed specific numeric conservation goals for electric utilities and revised associated conservation rules. On June 24, 1992, staff held a workshop to discuss the rules. Thereafter, the proposed rules were revised based on oral and written workshop comments. This recommendation discusses the new rules, rule amendments, and rule repeal recommended by staff.

**DISCUSSION OF ISSUES**

**ISSUE 1:** Should the Commission propose the adoption of Rule 25-17.0021, F.A.C., Goals for Electric Utilities and Rule 25-17.0025, F.A.C. Conservation Performance Incentive Factor; the amendment of Rule 25-17.001, F.A.C., General Information; Rule 25-17.003, F.A.C., Energy Audits, Related Provisions; and Rule 25-17.006, F.A.C., Electric Utility System Conservation End Use Data; and the repeal of Rule 25-17.005, F.A.C., Evaluation of Electric Utility Conservation Efforts and Rule 25-17.007, F.A.C., Normalization of Electric Utility Load Data?

**RECOMMENDATION:** Yes.

**STAFF ANALYSIS:** According to Sections 366.80 - 366.85, Florida Statutes, (The Florida Energy Efficiency and Conservation Act, or "FEECA"), the Commission is required to adopt goals and approve plans related to energy conservation. In accordance with this legislative direction, staff believes that Rule 25-17.001, F.A.C., General Information, should be amended to place equal emphasis on cost-effectively reducing weather-sensitive peak demand and reducing energy consumption. The rule currently places primary emphasis on reduction of weather-sensitive peak demand, but staff believes that effective conservation demands reduction of energy consumption in general.

Attached is a document showing a side-by-side comparison of the present rules with the recommended changes and comments on specific rule provisions. The following discussion is a general overview of the rules.

**Rule 17.0021, Goals for Electric Utilities.**

Staff believes that specific numeric goals are preferable to the current non-specific goal statements contained in Rule 25-17.001. The attached rule contains a two-part process: first, the Commission will set specific numerical demand and energy savings goals for each FEECA utility, based upon each utility's reasonably achievable kilowatt and kilowatt-hour savings within various end-use categories. Next, each utility will submit for Commission approval a demand side management plan comprised of programs designed to meet its specific goals.

Thereafter, utilities must submit annual reports summarizing the achievements of their programs. The Commission will compare their achieved energy and demand savings with their goals. The results achieved by investor-owned utilities shall be taken into account when setting rates, pursuant to Section 366.82(4), Florida Statutes, and will determine whether the utility is rewarded or penalized pursuant to Rule 25-17.0025.

**Rule 25-17.0025, Conservation Performance Incentive Factor.**

In order to encourage more aggressive conservation, staff recommends that the Commission adopt an incentive/penalty mechanism. Utilities may be reluctant to adopt effective conservation programs that tend to increase or place upward pressure on rates. Therefore, the rule provides a financial incentive for utilities to meet or exceed their conservation goals, and penalizes utilities that fail to meet their goals.

The conservation performance incentive factor ("CPIF") is based on a sharing of the benefits associated with conservation, and is recovered through the energy conservation cost recovery docket. For example, high efficiency heat pumps save both energy and demand on the system. The amount of that benefit will be determined on a program-specific basis. The utility will receive 20% of the benefit associated with incremental heat pump installations above its target. A more specific example is included on pages 28 and 29 of this recommendation, entitled "Narrative for CPIF Example". The incentive factor will be similar in operation to the Generating Performance Incentive Factor used by the Commission in connection with the fuel cost recovery docket.

**Rule 25-17.003, Energy Audits; Related Provisions.**

The present rule requires utilities to perform a specific number of audits. Staff believes that each utility's audit penetration rates should be set along with its other goals, and therefore recommends that paragraph (7) of the current rule be deleted.

**Rule 25-17.005, Evaluation of Electric Utility Conservation Efforts.**

Staff recommends the repeal of this rule. It establishes reporting requirements and defines terminology and methodology in connection with Rule 25-17.002, which was repealed in 1990. The terms and requirements of the rule are not longer applicable under the recommended rules.

**Rule 25-17.006, Electric Utility Conservation End Use Data.**

This rule should be amended to update references to other rules, require utilities to develop and report statewide data, and update the medium and data structure for reporting.

**Rule 25-17.007, Normalization of Electric Utility Load Data.**

Staff recommends the repeal of this rule, which establishes requirements for normalizing load data under Rule 15-17.002, which was repealed in 1990.

**Economic Impact:**

Staff has prepared a detailed economic impact statement, which is attached hereto as pages 6 - 27.

**ISSUE 2:** Should the rules be filed with the Secretary of State and the docket closed if there are no comments or requests for hearing?

**RECOMMENDATION:** Yes.

**STAFF ANALYSIS:** If no comments or requests for hearing are timely filed, the rules should be filed for adoption with the Secretary of State and this docket should be closed.

M E M O R A N D U M

September 18, 1992

TO: DIVISION OF APPEALS (RULE)

FROM: DIVISION OF RESEARCH AND REGULATORY REVIEW (HEWITT, HARLOW)

SUBJECT: ECONOMIC IMPACT STATEMENT FOR DOCKET NO. 920606-EG; PROPOSED REVISIONS TO RULES 25-17.001, 25-17.003, AND 25-17.006, FAC; PROPOSED REPEAL OF RULES 25-17.005 AND 25-17.007, FAC; AND PROPOSED RULES 25-17.0021 AND 25-17.0025, FAC, CONSERVATION GOALS FOR ELECTRIC UTILITIES

SUMMARY OF THE RULE

In the above-referenced docket, the Commission is proposing to revise Rules 25-17.001 through 25-17.007, FAC. The proposed rules and rule amendments address the demand-side management (DSM) efforts of electric utilities. In particular, the proposed action provides for establishing specific DSM goals, and placing equal emphasis on cost-effectively reducing weather-sensitive peak demand and reducing energy consumption. Each utility would be required to submit a menu of conservation programs that will achieve the full potential for conservation within its service territory and provide an assessment of the annual cost-effective KW and KWH savings reasonably achievable in selected program categories. Additional annual reporting requirements will be necessary. The revised residential customer survey will now require statewide aggregates for reported data and the use of FoxPro for data base structure. The proposed action would also establish a Conservation Performance Incentive Factor (CPIF) designed to increase the DSM efforts of investor-owned utilities (IOUs). Previous rules setting general conservation goals would be repealed.

DIRECT COSTS TO THE AGENCY AND OTHER STATE OR LOCAL GOVERNMENT ENTITIES

The proposed rules and rule amendments are designed to increase the cost-effective demand-side energy efficiency efforts and programs of Florida electric utilities. New proceedings would be held to establish specific numerical goals for each affected electric utility based on studies of the potential energy and demand savings in Florida and each utility's service territory. The Commission will review each utility's DSM plan to determine whether the plan is sufficient to meet the established goals. The Commission may add or modify programs in a utility's proposed plan. Each additional DSM proceeding or program filing would require evaluation on a case-by-case basis. The short-term agency costs would include additional administrative and professional staff expenses. The magnitude of the increased costs cannot be determined at this time, but would depend on the number of proceedings and the number of new programs. In the longer term, as the newer programs are imple­mented and goals set, agency costs should levelize as the initial reviews give way to monitoring and analyzing progress reports of the DSM programs.

The Commission will also review the individual programs included in each IOU's DSM plan to determine whether the program will be eligible for the Conservation Performance Incentive Factor. This will require staff review of the demand and energy savings of each program, the difficulty of measuring such savings, and other related factors. Additional staff time will be required to calculate the corresponding incentive or penalty for each program eligible for the CPIF at each Conservation Cost Recovery Hearing.

Local government entities that have electric utility systems would be required to conform to the reporting and DSM program development. Data requests were sent to the affected municipalities and six responded. For the municipal electric utilities' responses, see the section on "Municipal Electric Utilities" (page 9) and Attachment 2.

COSTS AND BENEFITS TO THOSE PARTIES DIRECTLY AFFECTED BY THE RULE

Four groups were identified as being potentially directly affected by the proposed rule action. These included IOUs, municipal utilities, rural electric cooperatives, and ratepayers. In order to assess the costs and/or bene­fits of the proposed rule action, data requests were sent to the affected IOUs, cooperatives, and municipals. Each of the four groups are discussed separately.

INVESTOR-OWNED UTILITIES

Data responses were received from four of the five IOUs surveyed. A summary of their responses is in Attachment 1. IOUs would be subject to all requirements of the proposed rulemaking action, including the CPIF. The major areas of expected cost increases associated with the implementation of these rule amendments were identified as: the costs involved in identifying, implementing, and monitoring incremental conservation programs; and the costs associated with additional reporting requirements and hearing participation.

1. Tampa Electric Company (TECO). TECO responded that it could not identify any additional costs and benefits associated with the amended rules' goals of reduced KW demand growth and energy consumption. This is because these are the same goals found in the Florida Energy Efficiency and Conservation Act (FEECA), which they have operated under since 1980.

TECO expects the proposed requirement to integrate additional high thermally efficient cogenerators within the company's territory to have little effect on costs or benefits. The company estimated that the rule change will have little impact for TECO with respect to adding additional cogenerators because the company is already adding such facilities when cost-effective in order to remain competitive. Locating such cogenerators near load centers is also expected to have little impact on costs or benefits. Since the company's territory is geographically compact, little or no improvements are expected in the efficiency of power delivery within the area due to the location of cogenerators near load centers.

Costs of attending a hearing to set DSM goals were estimated to be $20,000 to $40,000. Estimates for program assessment were $5,000 to $10,000 initially, with the potential for studies to reach $300,000 to $500,000. Implementation costs cannot be assessed until the Commission establishes goals for each utility. Expected costs for TECO to participate in a proceeding to review and modify these goals is $10,000 to $20,000. Additional reporting costs to provide a plan to meet the goals are expected to be minimal.

Only minor cost differences are expected with respect to the proposed annual report on DSM program results. However, these costs have the potential to reach $300,000 to $500,000, if determining the "actual achieved results" requires significant monitoring and evaluation studies. Providing statewide aggregates of these results should result in minor increases in costs.

The company expects to incur the following costs with respect to the proposed changes to the Residential Customer Survey: (1) minor impact to change the reporting medium to FoxPro; (2) $30,000 to provide statewide aggregates of current data; and (3) minor costs to provide statewide aggregates for forecast data.

TECO responded that the proposed CPIF will tend to raise the costs per KWH sold, depending on the "levels and types of cost-effectiveness that are used to screen and evaluate DSM measures." Benefits of the CPIF could not be calculated without information concerning specific goals. Additional costs associated with participating in the Conservation Cost Recovery Hearing, due to the addition of the CPIF, are estimated at $5,000 to $10,000 per year.

2. Gulf Power Company (Gulf). Gulf expects no additional costs associated with the proposed requirement to reduce KW demand growth and energy consumption. The company states, "Through its current conservation programs, Gulf Power has, is, and will continue to reduce the growth rates of KW and energy." Gulf indicated that it is impossible for the value of benefits and costs to be estimated without the specific goals required by the Commission. However, the company expects that the incremental costs for reporting, evaluations, and better estimates of conservation savings could increase by $500,000 to $5,000,000 annually. This assumes that no program is required by the Commission which fails the rate impact test, and that no significant additional personnel or payment of rebates is required in order to increase customer participation rates. Gulf stated that if the total resource test is used to evaluate programs, these costs could be much higher, and cross-subsidization between participants and nonparticipants would occur.

Gulf indicated that program assessment costs are difficult to measure without specific goals. However, incremental annual assessment costs from $750,000 to $2,000,000 are expected if the Commission imposes more stringent measurement requirements. Benefits from implementing these incremental programs are also hard to measure without specific goals, however, Gulf indicated that savings in operating and maintenance expenses and fuel would approximate 1.7 cents per KWH saved.

Participation in hearings to set DSM goals was estimated at $84,000. This estimate includes $9,000 for attending a five-day hearing and an additional $75,000 for preparation. Costs of participating in a proceeding to review and modify these goals is anticipated to be $52,000, including expenses incurred in preparation and attending the hearing. Costs of providing a plan to meet these goals may reach $50,000 and could be higher if the services of consultants are necessary.

Reporting costs would also be increased by the proposed annual report concerning the actual achieved results of each program, and the requirement to provide statewide aggregates of these results. Gulf expects an annual increase in reporting costs of $25,000 to provide program results. However, these costs may be increased by an additional $25,000 if interrogatories are necessary. Costs are not expected to exceed $5,000 for providing the statewide aggregates of these results.

As previously stated, benefits to the company from the proposed CPIF cannot be estimated without specific goals. However, Gulf stated:

If unit goals are unbiased, then the expected reward should be zero. The gains from exceeding the goals in some programs should exactly offset the losses incurred in the programs where unit goals were not obtained. This is a long-run assumption and actual results could vary significantly from zero on an annual basis.

The anticipated incremental costs with respect to the addition of the CPIF to the Conservation Cost Recovery Hearing was estimated to be $7,200 annually. This estimate will be increased by an additional $25,000 if interrogatories are necessary.

The company indicated that increased conservation efforts could erode its competitive position in the short run to the extent that rates are increased relative to those of close competitors. Gulf also suggested that a reallocation of resources by the company to meet CPIF requirements may detract from the company's competitive position. In the long run, however, the competitive position could be improved if conservation measures are installed which pass the rate impact test and reduce or defer the need for additional generators.

The proposed change in the reporting medium of the Residential Customer Survey to FoxPro is expected to require minimal costs. The company responded that an estimate of providing statewide aggregates of current data for the Residential Customer Survey is "best estimated by the FPSC staff, as data on individual climate zones are presented to FPSC staff, and they have previously accomplished this merge of data." Estimates of the costs associated with providing statewide aggregates of forecast data could not be furnished without details concerning the uses and scope of the data.

Gulf indicated that little significant costs are expected due to the additional emphasis placed on the integration of high thermally efficient cogenerators within its territory. Gulf presently evaluates and encourages the installation of such cogenerators when appropriate and cost-effective. However, additional costs could occur if additional personnel and computer costs are made necessary by additional technical evaluation of proposed projects. No significant costs were attributed to locating cogenerators near load centers as long as connection points to transmission lines with available capacity are near the cogenerators. However, additional costs may be incurred if IOUs are required to evaluate sites for cogenerators. The company also noted the possibility of decreased transmission losses due to siting cogenerators near load centers.

3. Florida Power Corporation (FPC). FPC cannot provide estimates of the costs necessary to meet the requirement to reduce KW demand growth and energy consumption without information on specific targets. If such targets exceed the DSM plan currently followed by FPC, additional costs would be significant. Costs of participating in goal setting hearings were estimated to be $365,000, assuming a ten-year evaluation period. This includes $300,000 for an FPC-specific study, report preparation costs of $60,000, and expenses required to attend the hearing of $5,000. The costs of participating in a proceeding to review and modify these goals were also estimated to be $365,000. Additional program assessment costs, implementation costs, and the benefits expected from additional DSM efforts will be dependent on the goals set by the Commission.

The costs to provide the Commission with a plan to meet the established goals are expected to be negligible, if the Commission sets goals that are within FPC's current DSM plans. However, if the goals exceed this current plan, additional costs would be significant. FPC expects minimal cost increases associated with the requirement to provide annual company-specific and statewide aggregates of actual achieved results.

Changes to the Residential Customer Survey are expected to result in the following additional costs: (1) $5,000 to change the reporting medium to FoxPro; (2) $35,000 to provide statewide aggregates of current data; and (3) low impact to provide statewide aggregates of forecast data.

FPC anticipates minimal rewards to the company from the proposed CPIF. However, the incentive factor may have major competitive implications,

. . . if the target setting process leaves some utilities with a greater probability of achieving a significant reward (or penalty) in relation to other utilities. For example, a utility that has done nothing with respect to DSM may be able to achieve rewards simply because it can easily attract initial participation levels. [A utility] Utilities with a significant history of DSM activity, however, may suffer a penalty because it has already achieved the majority of its saturation potential. In this latter case, attracting additional customers may be very difficult and costly. Since the rule does not address how targets will be set, and since Florida Power has been proactive in its DSM efforts, the potential exists for FPC to suffer a negative competitive impact due to the proposed rule.

Costs associated with participating in the Conservation Cost Recovery Hearing associated with the addition of the CPIF are expected to be $95,000 initially. This includes $85,000 for the development of a reporting system, $5,000 for labor, and $5,000 for administrative costs. Ongoing annual costs are anticipated to total $35,000, including labor, administrative, and computer processing time.

In regard to the integration of high thermally efficient cogenerators, FPC responded that the, "Integration of high thermal efficiency cogenerators results in savings to the company and to a large thermal energy user such as the University of Florida." For example, FPC expects savings of $17,900,000 to FPC ratepayers over the initial term of the university's steam contract. Annual savings to the university, including fuel and boiler operating costs are expected to be $2,000,000 initially, increasing to $6,000,000. With respect to siting such cogenerators near load centers, FPC responded:

There are theoretical advantages to locating cogenerators near load centers. However, in practice, there can be both increases and/or decreases in system losses and local load flows. There are usually no savings on a transmission and distribution facility by locating cogenerators near a load center. Typically, transmission and distribution facilities are sized to serve the entire load of a facility regardless of whether self-generation or cogeneration exists. The utility usually is required to serve the entire load requirements unless the cogenerator has multiple generation sources.

4. Florida Power & Light (FPL). FPL responded that incentive plans are not necessary for the company to invest in conservation measures. The company replied:

Incentives for utilities to invest in conservation measures have been suggested as a way to provide the proper economic signal to make such investments rather than in new power plants or other alternatives. However, since FPL is currently pursuing all conservation programs that are found to be cost-effective, imposition of such incentives for these programs should not be necessary. Should the Commission, however, determine that incentives are appropriate, then incentives should be provided only to the extent that they are cost-effective so that the cost of providing electricity to the utility's customers would be lower than otherwise may have occurred without the program.

The company believes that most of the costs attributable to the proposed rule cannot be quantified without more specific information. For example, the amount of the incentive cannot be estimated without the results of the statewide DSM study currently being conducted by the Florida Energy Office. Information concerning the exact programs required by the Commission would also be necessary for FPL to provide cost estimates.

The costs of attending hearings required by the proposed rule also could not be estimated. FPL points out that these costs may vary widely depending on the specifics of the hearing. The company states, "As reported in FPL's 1991 FERC Form No. 1, for example, the regulatory expenses were $37,262 for the Conservation Cost Recovery Factor (Docket No. 910002-EG) and $296,350 for the Annual Planning Hearings."

COOPERATIVE UTILITIES

The Florida Rural Electric Cooperatives Association responded to the data request on behalf of Clay Electric Cooperative, Inc.; Lee County Electric Cooperative, Inc.; Sumter Electric Cooperative, Inc.; Talquin Electric Cooperative, Inc.; and Withlacoochee River Electric Cooperative, Inc. Estimates for the costs of assessing and implementing incremental conservation programs could not be given without information concerning specific goal requirements. Likewise the expected energy savings and additional reporting costs were also not reported. However, the cooperatives expect increased labor costs associated with the annual reporting requirement of the proposed action. The cooperatives also stressed that the 90-day time period to develop the required DSM plan was an insufficient time frame in which to determine the most effective way to address the proposed energy and demand goals.

The estimated costs of attending the goal setting hearing were $20,000 per cooperative. The costs incurred to attend the hearing to review and modify the goals were also estimated to be $20,000 per cooperative.

The expected cost of the change in medium used to report the results of the Residential Customer Survey is expected to be $5,000 per cooperative. The cost of providing statewide aggregates of current and forecasted data was not reported.

MUNICIPAL ELECTRIC UTILITIES

Municipal utilities would be subject to all requirements of the proposed action, with the exception of the CPIF. Six municipal utilities responded to the data request. For a summary of their responses, consult Attachment 2 at the end of this economic impact statement.

1. Lakeland Electric and Water. Lakeland stated that the costs associated with the proposed rule will depend greatly on the number of potential programs evaluated and the number ultimately determined to be cost-effective. Savings addressed in the response can only be subjective as the actual savings expected cannot be identified until the analysis of all potential programs is completed and those determined to be cost-effective are identified and implemented.

The following are estimates of the costs to participate in a proceeding to provide an assessment of the annual cost-effective KW and KWH savings reasonably achievable in each of the end-use categories specified by the Commission at least every ten years: (a) cost of participating in goal setting hearings - $2,320; and (b) the estimated cost of program assessment - $8,880. The costs involved in implementing the incremental programs and net energy savings cannot be determined until the completion of all potential program evaluations and the programs to be implemented have been selected. These costs will vary dramatically with the customer type, type of program to be implemented, number of customers in the target group, and the number of customers ultimately expected to participate in the program.

The City of Lakeland indicated that there would be some short-term revenue loses associated with the integration of high thermal efficiency cogenerators in its service area if those cogenerators served retail load presently being served by Lakeland. Rates to other retail customers would have to increase accordingly to cover fixed charges. In the long run, some of these costs would be offset by the savings resulting from the ability to defer future generation. In addition, locating cogenerators near load centers would reduce Lakeland's transmission and distribution investments and maintenance costs. Lakeland did not quantify an associated net benefit or cost.

2. Jacksonville Electric Authority (JEA). Jacksonville stated that they cannot estimate the total costs until they know what JEA's goals will be. The cost to JEA of participating in the goal hearings would be about $25,000 for a five-day hearing with legal fees. The cost to JEA of assessing the programs would be about $250,000 (five person-years) plus legal fees. The costs of implementing the programs cannot be estimated until specific programs are identified in the hearings. The cost of participating in a modification proceeding would be about $25,000 for a five-day hearing with legal fees. The incremental cost of the annual report described in 25-17.0021(5) would be about $10,000 each year, according to which programs are included. JEA also estimated that additional costs with respect to the Residential Customer Survey would include: (1) the cost to change software to FoxPro, plus about $1,000 in training time; (2) approximately $10,000 each year to provide a statewide aggregate for current data, depending on which specific programs each utility is implementing; and (3) approximately $10,000 each year to provide a statewide aggregate for forecast data, depending on which specific programs each utility is implementing. For other factors, JEA cannot estimate the costs and benefits until they know what the goals will be.

3. City of Tallahassee. Tallahassee cannot project additional total costs until the specific goals are set for reduction of KW/KWH. Additional costs for staff may be necessary depending on the goals and the types of programs which may be required by the Commission. The city is currently developing a new Energy Conservation Plan which should address most of the objectives of the rule revisions.

The cost of participating in goal setting hearings would be approximately $30,000 including legal services. The cost of program assessment is difficult to project but could reach $250,000 including staff/consultant support and computer needs. Costs of participating in additional proceedings to review and modify goals could reach $30,000 if the proceeding is protracted. The reporting costs of an annual report were an estimated $7,000, or $10,000 including staff analysis, report development/review, and printing. The cost of purchasing software and training for the FoxPro format was estimated at $1,500. Tallahassee expects the Florida Coordinating Group (FCG) to undertake the task of aggregating statewide totals.

4. City of Ocala. The Florida Municipal Power Agency (FMPA) is responsible for the Ocala power supply and provided the analysis for the proposed rule changes. The estimated cost for participating in the goal setting hearing was a total of $50,000 in labor and administrative costs. An estimated $100,000 in labor and administrative costs would be necessary to provide detailed program assessment, including the cost of interactive effects.

5. Gainesville Regional Utilities (GRU). Gainesville Regional Utilities recently completed a robust Least Cost Planning Study. The study determined an economically optimal combination of supply and demand-side resources to meet GRU's prospective energy requirements. GRU projects having a 4.1 percent reduction in energy due to planned DSM programs by the year 2000 and altering this plan would require DSM programs beyond a level that is "cost-effective."

GRU estimated that it would incur $52,400 of additional costs to participate in the DSM programs to the extent of the proposed rule and would accrue no benefits. The breakdown of costs were: (1) the cost of participating in the goal setting hearing - $5,800; (2) the cost of program assessment, including the cost of assessing interactive effects - $33,200; and (3) the cost of participating in a proceeding to review and modify the goals - $13,400. GRU currently evaluates the relative effectiveness of its DSM programs at three- to four-year intervals. The cost to evaluate annually under the proposed rule would increase costs from $5,000 to $20,000 annually, or an additional $15,000 per year. GRU estimated that it would incur approximately $5,000 in costs to participate in the provision of statewide aggregate forecast data. GRU believes the statewide data could be aggregated by the FCG or the Commission itself.

GRU believes if the proposed rule is implemented, it would realize an unfavorable or detrimental impact upon its productivity since it is already aggressively pursuing "cost-effective" DSM programs. Staff resources would have to be diverted from planned efforts and projects that represent economic benefits to ratepayers. Therefore, GRU believes that the proposed rule would cause GRU ratepayers to forgo immediate and long-term economic benefits.

6. Orlando Utilities Commission. Orlando estimated that the costs to participate in the goal setting hearing would be $11,800. Developing a new conservation plan was estimated at $25,000. Costs to attend a proceeding to review and modify goals were estimated to be $12,000. Total costs estimated for program assessment were $3,120. Annual cost for program monitoring and evalua­tion was estimated to be $25,000 per year. Additional efforts for reporting would be $884 per year. Calculating and reporting statewide aggregates would cost $944 per year. FoxPro software costs would be $544 per year, as would be the cost for statewide aggregate current data and forecast data; or $1,632 per year.

RATEPAYERS

Since one of the goals of DSM programs is to defer the construction of new base load plants, and encouraging cogeneration of high thermal efficiency is explicit in the proposed rule changes, successful implementation of the goals should lower participant ratepayers' total bills and delay rate increases for all ratepayers. Theoretically, if only cost-effective DSM programs are approved and the savings exceed associated costs, ratepayers should benefit. However, the actual impact on rates will depend on whether the required programs are cost- effective in practice, and whether the anticipated savings materialize.

SUMMARY

In general, utilities found it difficult to estimate the expected costs or benefits of additional conservation efforts prompted by the proposed action without information concerning specific DSM goals. However, most utilities expected little change in DSM costs or benefits due to the similarities between the goal of the proposed rule, to reduce KW demand growth and energy consumption, and the requirements of FEECA.

Clearly, the major costs to utilities are the more stringent requirements for program assessment and measurement of program results. Estimates of these costs ranged from $8,800 to $2,000,000. The magnitude of these costs will vary depending on the type of program and the difficulty in measuring results.

As a whole, the IOUs expected little or no benefit or penalty from the proposed CPIF. However, they emphasized the difficulty of providing such an estimate without knowledge of the DSM goals required relative to their current DSM plans.

With regard to benefits, increased utility conservation efforts could be used as a substitute for additional electricity production, leading to the reduced use of fuel resources and the possible deferral or avoidance of constructing new generating facilities. Such incremental conservation efforts would be economically efficient as long as the cost of the conservation programs is less than the avoided cost of the available supply option. In the long run, consumers may possibly benefit due to lower rate increases associated with the deferral of construction of additional generating capacity. However, consumers may face short-run rate increases associated with the reduction in total KWH sales, depending on whether all projects approved are cost-effective. Consumers who are program participants may experience short-run bill reductions. Bills for nonparticipants may increase in the short run, even if these ratepayers have already installed conservation measures. In the long run, even if long-term electric bills remain the same or are higher, society could still benefit from increased conservation efforts given the environmental benefit provided by reduced emissions. Decreased utility generation and emissions will have the added benefit of reducing the number of emissions allowances required to comply with the Clean Air Act Amendments, beginning in 1995.

REASONABLE ALTERNATIVE METHODS

Reasonable alternatives to the proposed action include:

***1. Making no change to current rules concerning additional utility DSM efforts -*** Several utilities responded that under FEECA requirements, they are currently pursuing plans to reduce KW demand growth and energy consumption. According to Lakeland Electric and Water:

The proposed rule revisions, while more comprehensive, would include most of the areas that Lakeland would have evaluated independently and implemented where the cost-to-benefit ratios were sufficient to justify the investment in developing a program. Therefore, Lakeland would have continued to add conservation/load management programs to its conservation plan until all those programs with sufficiently large cost-to-benefit ratios would have been included. Lakeland would have ultimately arrived at the same position using its own internal evaluation methods.

The two basic approaches to utility conservation are "command-and-control" and incentives. Commission staff is proposing a combination of these two approaches for IOUs, and the command-and-control approach for non-IOUs. Staff chose to propose incentives for the IOUs because they believe that certain conservation measures, such as those that save a great deal more energy than demand, will not be pursued without such incentives. Staff believes that a positive incentive will work better for IOUs than mandatory requirements.

If the Commission does not adopt the proposed rule, there will be foregone savings from conservation programs that would have otherwise been pursued. These savings cannot be quantified until utilities submit plans for meeting the goals. Many of the programs that would be pursued under the staff proposal could cause slight increases in rates due to higher energy conservation cost recovery (ECCR) costs, but total customer bills would be lowered due to participating in energy saving conservation programs.

***2. Increasing the time allotted for utilities to provide their plan for meeting the DSM goals -*** Several utilities indicated that the 90-day time frame is insufficient to develop the most efficient way to meet the required goals. However, staff believes that 90 days is sufficient. Individual utilities can petition for additional time if it is believed to be necessary.

***3. Applying the CPIF in full revenue requirements hearings -*** TECO suggested that the CPIF should be handled as a part of a full revenue requirements hearing in order to lower regulatory costs. The company believes that the CPIF should be put within the context of the overall efficiency of the specific utility's operations. However, companies generally do not have a full rate case on an annual basis, and currently, four years may pass between each case. In order for incentives to be effective, they must be applied in such a way as to provide management with clear and timely signals concerning their actions. Putting the CPIF within the Conservation Cost Recovery hearings will give each utility more immediate feedback on their DSM efforts.

***4. Reducing the frequency of the reporting requirement on actual achieved DSM results -*** Gainesville Regional Utilities responded:

It is GRU's current practice to periodically evaluate the relative effectiveness of its DSM programs. Such evaluations currently occur in three to four-year intervals. In essence, conducting the evaluations annually will cause the current cost of the evaluation to quadruple. The annual cost of the evaluation under the proposed rule will increase to $20,000 annually from the $5,000 (annualized) currently being expended.

Staff believes that annual reports are desirable in order to provide for timely monitoring of utility activities. The annual reporting requirement also allows for the provision of timely information to the legislative and other governmental agencies.

***5. Installing alternate incentive mechanisms or removal of disincentives -***

(a)Decoupling - This ratemaking mechanism is designed to "decouple" a utility's revenues from electricity sales by allowing a utility to recover some portion of the revenues lost when DSM projects reduce KWH sales. Staff believes that decoupling has the effect of removing disincentives which will not necessarily result in additional conservation efforts.

(b)Bounties or Bonus on Return on Equity (ROE) - Utilities may have greater incentives to increase DSM efforts if they receive a set dollar benefit, or bounty, according to the number of participants in each DSM program. Additional conservation efforts may also be encouraged by the possibility of earning a predetermined bonus applied to the rate of return on equity. Staff believes that the proposed rule is superior to these mechanisms because the incentive is tied to the actual savings achieved.

(c)Shared Savings Between the Utility and the Customer - Staff believes that shared savings are already achieved by the proposed rule through lower utility bills for program participants.

***6. Increasing government efforts concerning end-uses and end-users -***Gainesville Regional Utilities responded:

GRU staff generally concur with policy makers that believe there still exists considerable energy savings that can be achieved for the State, with associated economic benefits accruing to the State. However, GRU staff does not feel that the orientation of the proposed rule will do much to effect those benefits in an equitable manner. Therefore, as an alternative GRU staff suggests that some of the public policy making effort that has tended to focus primarily upon electric utilities be re-directed to end-uses and end-users, e.g., more stringent appliance efficiency standards, revising and enforcing the building code, etc. GRU believes that revisions in these areas will do far more towards effecting energy savings in an equitable manner.

Although staff concurs with GRU that additional conservation benefits would be gained from the government actions suggested, these actions are outside the realm of the Commission.

***7. Calculating the statewide aggregates within the Commission for each of the following -***  (a) Annual actual achieved results of DSM efforts; (b) Residential Customer Survey current data; and (c) Residential Customer Survey forecast data.

Staff's proposed rule envisions a statewide aggregation of DSM results and Residential Customer Survey data performed by the Florida Coordinating Group, as indicated in Section 25-17.006(3)e and Section (5) of the End-Use rule.

***8. Relaxing the requirement to provide estimates of actual achieved results -*** Lakeland responded:

Section 4(9) of Proposed Rule 25-17.0021 indicates the requirement to develop a methodology for measuring the actual kilowatt and kilowatt-hour savings achieved form each program. While in theory this is simple, in practice this is a very complex and very expensive undertaking especially with those programs which address demand and energy reductions in a conventional way, such as insulation and weather stripping. While not impossible or technically unachievable, the costs associated with such a requirement, especially for smaller utilities, can easily convert a very beneficial cost-effective program . . . to a program which is not cost-effective. . . .

Staff envisions extensive sharing of data obtained from submetering experiments and engineering and post bill analysis. Staff would like to put together regional savings for each type of measure which could be used by a number of utilities in that particular region.

***9. Repealing 25-17.006, Electric Utility System Conservation End-Use Data -*** According to Lakeland Electric and Water:

The Commission should give serious thought to repealing Rule 25-17.006, Electric Utility System Conservation End-Use Data. Having knowledge of the origination and original intent of this rule nearly ten years ago, Lakeland feels there has been insufficient use of the data submitted to justify the continuation of the requirements under this section of the rule. The Commission should seriously review the information being collected and its usefulness over the last several years. Lakeland feels that much of this information has never been used and that which has cannot justify the magnitude of expense and effort associated with its collection and reporting.

The collection of this data is necessary to assist the Commission in understanding how energy is used in Florida. This in turn helps the Commission determine the conservation potential available within the state.

IMPACT ON SMALL BUSINESSES

No direct impact on small businesses is foreseen as none of the affected utilities qualifies as a small business as defined in Section 288.703(1), Florida Statutes (1991). Small businesses may benefit indirectly from installing or selling DSM services, capital equipment, and appliances. The extent of increased activity for small businesses would be dependent on the number of new programs, types of programs, and the extent that individual businesses are able to share in the new activity; but the impact is not quantifiable at this time. Small businesses may also benefit from new DSM programs that lower their energy bills. Depending on the types of programs approved by the Commission, some small businesses that have already employed energy saving methods may have higher rates as a result of DSM programs. The actual net savings or costs are undeterminable.

IMPACT ON COMPETITION

In general, because of the nature of the proposed rule action, little impact is expected on competition with respect to electric utilities. However, the proposed action may affect competition between the suppliers of DSM programs and related products.

IMPACT ON EMPLOYMENT

The impact of the proposed rule changes on employment should be positive. Additional personnel would likely be required by utilities to develop and implement new DSM programs. The Commission would require more staff to evaluate, analyze, and then monitor DSM programs that meet cost-effectiveness standards. Additional employment would be generated by businesses supplying DSM services, appliances, and equipment. Additional high thermal efficiency cogeneration projects would increase construction employment in the short run and operating and maintenance jobs in the long run. The total increase in employment would depend on the number of cost-effective DSM programs and cogeneration projects that are adopted and implemented.

METHODOLOGY

Data requests were sent to affected electric utilities to obtain input on the expected costs and benefits. Two workshops were held to develop acceptable rule changes and obtain input from interested parties. Discussions were held with Commission staff members.

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| --- | --- | --- | --- | --- | --- |
| ATTACHMENT 1: INVESTOR‑OWNED ELECTRIC DSM RULE COSTS | | | | | |
|  | | | | | |
|  | | IOUs | | | |
| Data Questions | | TECO | GULF | FPC | FPL |
| 1. | Costs or benefits to  reduce KW demand growth | ND | $500,000  up to $5 million | ND | ND |
| 2. | Costs or benefits to  integrate cogenerators | None | NQ | Positive | ND |
| 3. | Costs or benefits locating  cogenerators near load | None | Minimal | NQ | ND |
| 4.a. | Cost of participating  in goal‑setting hearings | $30,000 | $84,000 | $365,000 | Varies widely |
| 4.b. | Cost of Program  Assessment | $7,500  up to $500,000 | $750,000  up to $2 million | NQ | ND |
| 4.c. | Cost of implementing the  Incremental Programs | ND | ND | NQ | ND |
| 4.d. | Net value of energy savings | ND | ND | NQ | ND |
| 4.e. | Cost of participating in  a proceeding to review  and modify goals | $15,000 | $52,000 | $365,000 | Varies widely |
| 5. | Incremental costs or proposed  reporting requirements | Minimal | $50,000 | NQ | ND |
| 6. | Cost of Annual reporting of  actual achieved results | Minor | $25,000  up to $50,000 | Minimal | ND |
| 7. | Cost of calculating and  reporting annual statewide  actual achieved results | Minimal | $5,000 | Minimal | ND |
| 8. | Costs of changing the  residential survey |  |  |  |  |
| 8.a. | Change to FoxPro format | Minimal | Minimal | $5,000 | ND |
| 8.b. | Statewide aggregate current  data cost | Up to  $30,000 | NQ | $35,000 | ND |
| 8.c. | Statewide aggregate forecast  data cost | Minimal | ND | Minimal | ND |
| 9. | Cons. Plan Incentive Factor Hearing | $5,000  to $10,000/yr | $7,200 | 1st Year $95,000  Subsequently $35,000 | ND |
| 10. | Costs or benefits of: |  |  |  |  |
| 10.a. | Competition | ND | NQ | Negative | ND |
| 10.b. | Employment | ND | Increase | Minimal | ND |
| 10.c. | Investment | ND | $3,000,000 & up | Minimal | ND |
| 10.d. | Productivity | ND | NQ | Minimal | ND |
| 10.e. | Innovation | ND | NQ | Minimal | ND |
|  | First Year Total ‑ $1,993,700 | $72,500 | $1,421,200 | $500,000 | ND |
|  | Subsequent Year Total\* ‑ $1,117,000 | $45,000 | $632,000 | $440,000 | ND |
|  | \*Does not include initial assessment costs but includes annual review proceedings.  ND = Not determinable  NQ = Not quantifiable | | | | |

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| --- | --- | --- | --- | --- | --- | --- | --- |
| ATTACHMENT 2: MUNICIPAL ELECTRIC DSM RULE COSTS | | | | | | | |
|  |  | MUNIs | | | | | |
| Data Questions | | Lakeland | JEA | Tallahassee | Ocala | Orlando | Gainesville |
| 1. | Costs or benefits to  reduce KW demand growth | ND | ND | ND | ND | ND | ND |
| 2. | Costs or benefits to  integrate cogenerators | NQ | None | None | None | None | None |
| 3. | Costs or benefits locating  cogenerators near load | NQ | NA | Positive  Benefit | None | NQ | None |
| 4.a. | Cost of participating  in goal‑setting hearings | $2,320 | $25,000 | $30,000 | $50,000 | $11,800 | $5,800 |
| 4.b. | Cost of Program  Assessment | $8,880 | $250,000 | $250,000 | $100,000 | $3,120 | $33,200 |
| 4.c. | Cost of implementing the  Incremental Programs | ND | NQ | Unknown | Unknown | NQ | None |
| 4.d. | Net value of energy savings | ND | NQ | Unknown | Unknown | NQ | None |
| 4.e. | Cost of participating in  a proceeding to review  and modify goals | $2,320 | $25,000 | $30,000 | $50,000 | $11,800 | $13,400 |
| 5. | Incremental costs or proposed  reporting requirements | $1,280 | NQ | NQ | $100,000 | $25,000 | None |
| 6. | Cost of Annual reporting of  actual achieved results | $1,280 | $10,000 | $8,500 | $50,000 | $25,884 | $15,000 |
| 7. | Cost of calculating and  reporting annual statewide  actual achieved results | No basis | $10,000 | FCG | $10,000 | $944 | FCG |
| 8. | Costs of changing the  residential survey |  |  |  |  |  |  |
| 8.a. | Change to FoxPro format | None | $1,455 | $1,500 | $5,000 | $544 | Nominal |
| 8.b. | Statewide aggregate current  data cost | No basis | $10,000 | FCG | $2,500 | $544 | NQ |
| 8.c. | Statewide aggregate forecast  data cost | No basis | $10,000 | FCG | $2,500 | $544 | $5,000 |
| 9. | Cons. Plan Incentive Factor | No basis | NA | NA | None | None | Positive |
| 10. | Costs or benefits of: |  |  |  |  |  |  |
| 10.a. | Competition | No effect | NQ | NQ | NQ | None | Positive |
| 10.b. | Employment | Minimal | NQ | NQ | NQ | None | None |
| 10.c. | Investment | ND | NQ | NQ | None | None | None |
| 10.d. | Productivity | Minimal | NQ | NQ | Opportunity Cost | None | Negative |
| 10.e. | Innovation | Little impact | NQ | NQ | None | None | Negative |
|  | First Year Total ‑ $1,075,300 | $13,760 | $316,455 | $290,000 | $320,000 | $68,380 | $59,000 |
|  | Subsequent Year Total\* ‑ $429,540 | $4,880 | $66,000 | $40,000 | $220,000 | $65,260 | $33,400 |
|  | \*Does not include initial assessment costs but includes annual review proceedings.  ND = Not determinable  NQ = Not quantifiable  NA = Not applicable  FCG = Florida Coordinating Group | | | | | | |

NARRATIVE FOR CPIF EXAMPLE

The attached is a numeric example which illustrates the Conservation Performance Incentive Factor (CPIF) specified by rule 25-17.0025. The investor-owned utility is rewarded for programs that exceed a specified target penetration level based on a percentage of the net benefits of the program. A penalty is assessed if the program does not achieve the target penetration level based on a percentage of the savings that would have been achieved had the target level been met.

Suppose a utility's approved conservation plan consists of three programs: Program 1, Program 2 and Program 3 as shown on the attached example. There are 100 installations targeted for Program 1, 150 installations targeted for Program 2, and 200 installations targeted for program 3. (NOTE: These are incremental installations for the period in question.) Let us further suppose that the actual installations for the period are 110, 175, and 195, respectively, for programs 1, 2 and 3. Finally, suppose that the net benefit per installation for Program 1 is $4, the net benefit per installation for Program 2 is $3, and the net benefit per installation for Program 3 is $2. If we denote the reward for Program i by Ri and the penalty for Program i by Pi, then rewards and penalties are calculated as follows.

Program 1 generates a positive reward R1 because actual installations (110) exceed targeted installations (100). This amount is calculated by:

R1 = (110-100) x $4 x 20% = $8.00.

There is no penalty for Program 1, so P1 = $0. Program 2 generates a positive reward R2 since actual installations exceed targeted installations by 25 installations. So, the reward is calculated by:

R2 = (175-150) x $3 x 20% = $15.00.

There is no penalty for Program 2, so P2 = $0. Program 3, on the other hand, generates a penalty since actual installations (195) are less than targeted installations (200). This penalty is calculated by:

P3 = (200-195) x $2 x 20% = $2.00.

There is no reward for Program 3, so R3 = $0.

The net reward for all three programs is calculated as:

NET REWARD = (R1-P1) + (R2-P2) + (R3-P3)

= $8 + $15 - $2 = $21.

**CONSERVATION PERFORMANCE INCENTIVE FACTOR**

**EXAMPLE**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Program | Targeted  Installations  (Ti) | Actual  Installations  (Ai) | Targeted minus  Actual | Net Benefit per  Installation | Reward  (Ri) | Penalty  (Pi) | Net  Reward |
| Program 1 | 100 | 110 | 10 | $4 | $8 | $0 | $8 |
| Program 2 | 150 | 175 | 25 | $3 | $15 | $0 | $15 |
| Program 3 | 200 | 195 | -5 | $2 | $0 | $2 | $-2 |
|  |  |  |  | Total | $23 | $2 | $21 |

R1 = 10 x $4 x 20% = $8

P1 = $0

R2 = 25 x $3 x 20% = $15

P2 = $0

R3 = $0

P3 = 5 x $2 x 20% = $2

TOTAL NET REWARD = (R1-P1) + (R2-P2) + (R3-P3)

= $8 + $15 - $2 = $21

|  |  |  |
| --- | --- | --- |
| **[BLANK PAGE INSERT FOR FORMATTING]**  **25‑17.001 General Information**  **25‑17.002 Goals for Electric Utilities (Repealed)**  **25‑17.003 Energy Audits; Related Provisions**  **25‑17.004 Goals for Natural Gas Utilities (Repealed)**  **25‑17.005Evaluation of Electric Utility Conservation Efforts**  **25‑17.006 Electric Utility System Conservation End‑Use Data**  **25‑17.007 Normalization of Electric Utility Load Data**  **25‑17.008Conservation and Self-Service Wheeling Cost Effectiveness Data Reporting Format**  **25‑17.009 Reserved**  **25‑17.010 Reserved**  **25‑17.011 Energy Conservation Loan Guarantee**  **25‑17.012 through 25‑17.014 Reserved**  **25‑17.015 Conservation Cost Recovery**  **25‑17.016 Oil‑Backout Cost Recovery Factor**  **25‑17.001 General Information.**  (1) The terms system and utility, as used in this Rule, shall be synonymous and have the same definition as "utility" as defined in section 366.82(1), F.S.  (2) The Florida Energy Efficiency and Conservation Act requires increasing the efficiency of the electric and natural gas systems of Florida and the end use of these sources of energy by reducing weather sensitive peak demand, oil consumption and kilowatt hour consumption to the extent cost effective.  (3) Reducing weather sensitive peak demand on the electric system to the extent cost effective is the first priority. Reducing weather sensitive peak demand benefits not only the individual customer who reduces his demand, but also all other customers on the system, both of whom realize the immediate benefits of reducing the fuel costs of the most expensive form of generation and the longer term benefits of deferring additional higher cost capacity. The general goals and methods for increasing the overall efficiency of the bulk electric power system and natural gas system of Florida are broadly stated since these methods are an ongoing part of the practice of every well‑managed utility's programs and will be continued.  These methods are to:  **Generating Utilities**  (a) Review and revise utility operating practices such as maintenance scheduling, daily and longer term unit commitment practices through the power broker system to facilitate economic dispatch on both a daily and extended basis and to reduce oil consumption to the extent cost effective.  (b) Plan development of the bulk power system over time so that the most cost effective combination of generating units, associated facilities and other technologies is developed for meeting generation requirements.  (c) Increase the efficiency of each generating unit and associated operating practices to the extent cost effective.  **All Utilities**  (d) Aggressively integrate nontraditional sources of power generation into the various utility service areas to the extent cost effective, including planning site development to facilitate development of potential cogenerators near generating units.  (e) Increase the efficiency of transmission and distribution systems to the extent cost effective.  (f) Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects in individual service areas. In this context, the Commission anticipates that an aggressive research program would include both technological research, research on load behavior and related problems and market‑related research.  (4) The Commission shall continuously review the relationship between demand and energy, both present and anticipated. In making its determinations of need pursuant to the Florida Electrical Power Plant Siting Act, the Commission shall take these relationships into account so that sufficient capacity will be authorized to meet anticipated needs. These goals represent a starting point for establishing energy conservation programs for all electric utilities. There is no absolute assurance that these goals will be fully achieved within the expected time frames, although the best efforts by the electric utilities to achieve them will be required. In any proceeding for determining whether new capacity is needed, the length and nature of experience under the goals will be considered. The goals will not be used exclusively because the Commission recognizes that they may not be achieved and that the estimates on which they are based may be incorrect. To increase the accuracy of these estimates the Commission anticipates that intensive and extensive research will be required, including both technological research and studies of the market penetration potentials of various conservation measures and their effectiveness in reducing KW demand and KWH consumption as well as studies of consumer behavior.  (5) Rules 25‑17.001 through 25‑17.005 shall not be construed or applied to restrict growth in the supply of electric power or natural gas necessary to support economic development by industrial or commercial enterprises. Rather, these rules should be construed as enhancing job‑producing economic growth by lowering energy costs from what they otherwise would be if these goals are not achieved.  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended l2/30/82, formerly 25‑17.01.**  **25‑17.002 Goals for Electric Utilities.**  **General Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended 1/19/82, l2/30/82, formerly 25‑17.02, Repealed 4/2/90.**  **25‑17.003 Energy Audits; Related Provisions.**  (1) Purpose: This rule specifies the minimum requirements for performing energy audits by each utility subject to the requirements of this rule.  (2) Applicability: This rule applies to each utility as defined in s. 366.82(1), F.S.  (3) Definitions:  (a) "Alternative (Walk‑Through) Audit" means an energy audit as defined in Chapter 25‑17.51(8), F.A.C.  (b) "Commercial Audit" means an energy analysis of a commercial building and its associated energy systems to determine its energy efficiency and to identify for the customer those cost effective measures which may improve its energy efficiency.  (c) "Energy Conservation Audit" means an energy audit as defined in Chapter 25‑17.51(6), F.A.C.  (d) "Industrial Audit" means an energy analysis of an industrial facility and its associated energy systems to determine its energy efficiency and to identify for the customer those cost effective measures which may improve its energy efficiency.  (4) Each utility shall notify its residential, commercial, and industrial customers of the availability of energy audits at least once every six months. Notification of audit availability, at a minimum, must be made by use of notices in billing statements or other means that involves direct notification to the customer. The announcement of the Residential Conservation Audits as required in Chapter 25‑17.53(3)(c) can count as one of the biannual notifications for the residential customers.  (5) For each customer requesting either an Energy Conservation Audit or an Alternative Audit, each utility shall provide the requested audit to the customer in accordance with the provisions of Chapter 25‑17.51 through 25‑17.65, F.A.C.  (6) For each customer requesting either a Commercial Audit or an Industrial Audit, each utility shall provide or arrange to provide the requested audit to the customer within 120 days of the date the customer makes the request. The utility may recover the actual expenses incurred by providing audits from those commercial or industrial customers requesting such audits.  (7) In lieu of the performance of energy audits as stated above, each utility may perform energy audits as follows:  By January 1, 1982, the overall annual rate for energy audits shall be 150,000, by January 1, 1984, the overall rate shall be 250,000. Each electric utility shall determine the portion of these goals applicable to it by January 1, 1982, by multiplying the number of residential customers on its system who consumed over 9,000 KWH during 1979 by 142,012 and dividing the result by the total number of such customers in the state, and by January 1, 1984 use the same formula but multiply by 236,672.  **Specific Authority: 366.05(1), 350.127(2), F.S.**  **Law Implemented: 366.82(5), F.S.**  **History: New 12/2/80, Amended 12/30/82, formerly 25‑17.03, Amended 11/24/86.**  **25‑17.004 Goals for Natural Gas Utilities.**  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended l2/30/82, formerly 25‑17.04, Repealed 4/2/90.**  **25‑17.005 Evaluation of Electric Utility Conservation Efforts.**  (1) This rule defines terminology, establishes reporting requirements and describes the method used to determine whether an electric utility has met its conservation goals; and it establishes reporting requirements to enable the Commission to monitor the implementation and cost‑effectiveness of utilities' conservation programs.  (2) The methods in this rule apply to all electric utilities as defined in 366.82, F.S.  (3) The following definitions apply:  (a) "Test Year" means the twelve month period beginning January 1 for Net Energy for Load, and beginning November 1 for Winter System Peak and Summer System Peak.  (b) "Base Period" means the 1980 calendar year for comparison with the Net Energy for Load test year and the period November 1, 1979 through October 31, 1980 for the comparison with the test year for Winter System Peak and Summer System Peak.  (c) "Winter System Peak" means the highest one hour system demand occurring between November 1 and the following March 31 during cold weather conditions.  (d) "Summer System Peak" means the highest one‑hour system demand occurring between April 1 and the following October 31 during warm weather conditions.  (e) "Net Energy for Load" means net system generation plus energy received from Class I and Class II systems minus energy delivered to Class I and Class II Systems for the calendar year.  (f) "Adjusted Winter System Peak" means Winter System Peak minus non‑jurisdictional point‑of‑delivery demand, interruptible demand, demand subject to load control, and minus any other adjustments specified in Rule 25‑17.002(3).  (g) "Adjusted Summer System Peak" means Summer System Peak minus non‑jurisdictional point‑of‑delivery demand, interruptible demand, demand subject to load control, and minus any other adjustments specified in Rule 25‑17.002(3).  (h) "Adjusted Net Energy for Load" means Net Energy for Load minus output to non‑jurisdictional customers (sales may be used if actual output data are not available) minus other adjustments specified in Rule 25‑17.002(3).  (i) "Weather Adjusted Winter System Peak" means Adjusted Winter System Peak plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.  (j) "Weather Adjusted Summer System Peak" means Adjusted Summer System Peak plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.  (k) "Weather Adjusted Net Energy for Load" means Adjusted Net Energy for Load plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.  (l) "Goals" mean the target levels of winter end use KW demand, summer end use KW demand, and end use KWH consumption calculated and adjusted as specified in Rule 25‑17.002 and the number of energy audits calculated to be the utility's allocation under the provisions of Rule 25‑17.003(1) and (2). For purposes of comparison with utility performance in the test year, goals shall be differentiated by the terms KW‑Goal(Winter), KW‑Goal(Summer), KWH‑Goal, and Audits‑Goal respectively, and shall be modified as described below:  KW‑Goal(Winter) shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(d) to the 1979‑1980 Weather Adjusted Winter System Peak.  KW‑Goal(Summer) shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(d) to the 1980 Weather Adjusted Summer System Peak.  KWH‑Goal shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(c) and 25‑17.002(1)(e) to the 1980 Weather Adjusted Net Energy for Load.  Audits‑Goal shall be as calculated in accordance with the provisions of Rule 25‑17.003.  (m) "Audits‑Actual" means the number of energy audits actually performed by the utility and includes Energy Conservation Audits, Customers Assisted (Mail‑In) Audits, Alternative (Walk‑Through) Audits, Industrial Audits and Commercial Audits. Alternative Audits shall be considered as audits performed if the procedure for conducting them has been approved by the Commission, in accordance with Rule 25‑17.059(1)(c).  (n) "Normal Weather Year" means expected weather conditions for a utility's service area, derived from statistical analysis of a minimum of ten consecutive years of weather data or upon the Typical Meteorological Year, as defined by the National Weather Service.  (o) "Supporting Documentation" means a narrative discussion of procedures used and assumptions made and a concise, detailed presentation of formulas used, provided in sufficient detail to allow the Commission staff, using standard statistical and mathematical procedures to replicate the results reported by the utility.  (4) Each utility shall provide the following data to the Commission by April 30 of each year, beginning in 1985.  (a) Test year KW‑Goal(Summer) and KW‑Goal(Winter) and KWH‑Goal as defined in Rule 25‑17.005(3).  (b) Test Year Weather Adjusted Summer System Peak, Weather Adjusted Winter System Peak and Weather Adjusted Net Energy for Load.  (c) Current Audits‑Goal for the same period as the KWH test year.  (d) Audits‑Actual for the same period as the KWH test year. Any difference from the sum of Residential, Commercial and Industrial audits reported on the Annual FEECA Program Report shall be explained.  (5) Information provided in accordance with 25‑17.005(4) above shall be used to determine whether each utility has achieved or has not achieved each of its four conservation goals.  (a) The Summer end‑use KW demand goal is achieved if Weather Adjusted Summer System Peak is less than or equal to KW‑Goal(Summer).  (b) The Winter end‑use KW demand goal is achieved if Weather Adjusted Winter System Peak is less than or equal to KW‑Goal(Winter).  (c) The KWH consumption goal is achieved if Weather Adjusted Net Energy for Load is less than or equal to KWH‑Goal.  (d) The audit goal is achieved if Audits‑Actual is greater than or equal to Audits‑Goal.  (6) Each utility shall submit a semi‑annual program progress report for the first half of each calendar year and an annual program progress report for each calendar year in a format described by the Commission. Each report shall be due 30 days after the close of each semi‑annual or annual period. A utility may submit additional information along with its report. Reports shall provide, at a minimum, the information detailed below.  (a) The FEECA Program Progress Report shall include a separate listing of each program which includes:  1. The name of the utility;  2.The period (semi‑annual or annual) and calendar year the report covers;  3.The program name;  4.The program start date;  5.The assumed annual KWH savings per installation;  6.The assumed winter coincident peak KW reduction per installation;  7.The assumed summer coincident peak KW reduction per installation;  8.Current period planned, current period actual, planned program to date, program to date actual, and difference between planned and actual data on the following:  a. Number of audits or installations, etc.;  b. Annual GWH savings;  c. Winter MW reduction;  d. Summer MW reduction;  e. Total program cost of utility; and  f. Cost per audit or installation, etc.  9.Any comments pertaining to the program.  10.The investor‑owned electric utilities shall also report as part of the annual report the following for each of the categories listed in subsection (6)(a)8. above:  a. Value of KWH saved;  b. Value of deferred generating unit or purchased electrical power;  c. Energy benefit/cost ratio; and  d. Total benefit/cost ratio.  (b) The FEECA Program Executive Summary for all programs shall include a brief overview of utility's conservation program efforts and accomplishments during the reporting period.  (c) Any other information required by Commission order.  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended 12/30/82, 6/19/84, formerly 25‑17.05, Amended 9/14/88.**  **25‑17.006 Electric Utility System Conservation End Use Data.**  (l) PURPOSE: The purpose of this rule is to provide for the periodic submission of certain conservation information and other related information to the Commission. Applications of this Rule include:  (a) gathering information to review and revise conservation goals pursuant to Rule 25‑17.002, F.A.C.;  (b) gathering information to estimate the potential kilowatt hour (KWH) and kilowatt demand (KW) savings achievable through various conservation measures and conservation technologies;  (c) to monitor the effectiveness of the Florida Model Energy Efficiency Code, developed under s. 553.900, F.S., et. seq., and modifications made thereto; and  (d) gathering information to enable the Commission to analyze conservation alternatives to mitigate the need to construct new power plants in Florida.  (2) APPLICABILITY: This rule shall apply to all electric utilities that had total sales of electric energy for purposes other than resale in excess of 500 gigawatt hours for the calendar year l980.  (3) Residential KWH Consumption Data: Starting with the l98l calendar year, and each year thereafter, each electric utility shall:  (a) Categorize all customers (structures) who were or had been connected to the utility system for permanent service during the calendar year by the year of first connection and by the following customer groups:  l.Residential, single family, unattached.  2.Residential, single family, attached.  3.Residential, mobile home or trailers.  Customers (structures) first connected to the system on or before December 31, 1980 shall be categorized as having a 1980 year of first connection.  (b) Using standard statistical sampling procedures, develop sample groups by customer group as specified in subsection (3)(a) above and calendar year of structure connection beginning with 1980.  (c) For each sample group developed pursuant to subsection (3)(a), compute the average annual energy consumption in units of kilowatt hours per customer. The computed value shall be statistically reliable at a 90% confidence level and a +/‑ 5% relative accuracy. The average annual energy consumption shall be determined by adding the active customers for each month, dividing that sum by 12 and dividing that result into the total annual consumption for those customers. Active customers are those members of the sample group to whom bills were issued during that month.  (d) For each sample group developed pursuant to subsection (3)(a), compute the average monthly energy consumption in units of kilowatt hours per customer. The computation shall be made for each month of the calendar year. The computed values shall be statistically reliable at a 90% confidence level and a +/‑ 5% relative accuracy.  (e) Report the results of subsections (3)(c) and (3)(d), by March 1st of the following calendar year. Also, report the total number of customers at year end by each customer group specified in subsection (3)(a) connected to the utility system for permanent service during the calendar year.  (f) The requirement that customers (structures) be categorized by year of first connection to the utility system is for the purpose of approximating the year of construction.  (4) Residential Goal Setting Information:  (a) Residential Customer Survey: Starting with calendar year l986 and every four years thereafter, each electric utility shall "collect" certain information on the appliance stock, housing characteristics, household demographic characteristics and twelve months of kilowatt hour billing history for its proportionate share of a representative sample of residential customers (structures).  l.For the purposes of obtaining the data described in subsection (4)(a), a representative sample of residential customers sufficient to yield 1,350 usable, complete observations shall be field interviewed by representatives of the utility in each of the following climatological zones.  a.Northern: Baker, Bay, Bradford, Calhoun, Clay, Columbia, Dixie, Duval, Escambia, Franklin, Gadsden, Gulf, Hamilton, Holmes, Jackson, Jefferson, Lafayette, Leon, Liberty, Madison, Nassau, Okaloosa, Santa Rosa, St. Johns, Suwannee, Taylor, Union, Wakulla, Walton, Washington.  b.Central: Alachua, Citrus, DeSoto, Flagler, Gilchrist, Hardee, Hernando, Highlands, Hillsbrough, Lake, Levy, Marion, Okeechobee, Orange, Osceola, Pasco, Polk, Putnam, Seminole, Sumter, Volusia.  c.Central Coastal: Brevard, Charlotte, Collier, Glades, Hendry, Indian River, Lee, Manatee, Martin, Monroe (excluding the Florida Keys), Pinellas, Sarasota, St. Lucie.  d.Southeast: Broward, Dade, Palm Beach, and the Florida Keys.  2.For each climatological zone, each utility shall sample a proportion of the l350 customers based on its percentage of residential customers in each of the regions.  a.By November 1st prior to the survey year each utility will provide to the Commission staff the number of its residential customers residing in each of the four climate zones as of June 30th prior to the survey year.  b.By January 15th of the survey year Commission staff will allocate the prescribed sample points to each utility based on the information submitted pursuant to subsection 2.a.  3.For each climatological zone, each utility shall stratify its residential customers by customer group as defined in subsection (3)(a) and draw a representative sample from each customer group proportional to that group's percentage of the total residential customers in the climatological zone.  4.The information on appliance stocks, housing characteristics, household demographic and the twelve months of KWH billing history shall be gathered using a survey instrument prescribed by the Commission by January 15th of the survey year. Nothing in this paragraph shall be construed to prohibit an electric utility from adding additional questions to its own survey it believes useful.  5.Each utility shall report the survey information and billing history on each individual respondent to the Commission on or before September lst of the calendar year immediately following the survey year. This information shall be reported such that no individual customer's identity can be determined. The information reporting format shall be prescribed by the Commission prior to April lst of the survey year. The medium for reporting the information shall be 9 track magnetic tape unless another medium is approved in writing by the Commission staff.  6.The following guidelines shall apply to customers described in subsection (4)(a) 1. above:  a.Customers must be customers of record as of July 1st of the survey year.  b.Customers must be continuously billed for a twelve consecutive calendar month period between July 1st of the year prior to the survey year and July 31st of the survey year. The twelve calendar consecutive month period shall be the same for all survey customers.  c.Seasonal customers billed in accordance with sub‑section (4)(a)6.b. may be counted toward the required number of sample customers.  7.The survey year shall be an even numbered calendar year beginning with the 1986 calendar year and every four years thereafter. The term survey year shall not be construed to limit completion of the survey to that even numbered calendar year.  8.The reporting year shall be an odd numbered calendar year beginning with the 1987 calendar year and every four years thereafter.  (b) Forecasts of Residential Appliance Stocks and Housing Characteristics: Starting with calendar year l987 and every four years thereafter, each electric utility shall report to the Commission forecasts of the market penetration of certain appliance stocks and housing characteristics.  l.Using its best estimates, each electric utility shall report the percentage of market penetration of each appliance listed in subparagraphs 4.a. ‑ 4.m. for each year of the forecast horizon.  2.Using its best estimates, each electric utility shall report the market penetration of each housing characteristics listed in subparagraphs 5.a.‑5.d. for each year of the forecast horizon.  3.The forecast horizon shall be at least 10 years and the use of a 20 year forecast period is encouraged.  4.Appliance stocks shall be:  a.High efficiency central air conditioners with a seasonal Energy Efficiency Rating (SEER) greater than or equal to 11.0.  b.Low efficiency central air conditioners with a SEER less than 11.00.  c.High efficiency heat pumps with a Coefficient Of Performance (COP) greater than or equal to 3.0 and a SEER greater than or equal to l0.0.  d.Low efficiency heat pumps with a Coefficient Of Performance (COP) less than 3.0 and a SEER less than 10.0.  e.Window or wall air conditioners.  f.Central resistance space heaters.  g.Non central resistance space heaters permanently affixed to the building structure.  h.Non‑electric heating.  i.Resistance water heaters.  j.Heat pump water heaters.  k.Solar water heaters.  l.Waste heat recovery water heaters.  m.Non‑electric water heating.  5. Housing characteristics shall be:  a. The number of residential structures having ceiling insulation R values between:  i. R‑O and R‑7  ii. R‑8 and R‑15  iii. R‑16 and R‑22  iv. R‑23 and greater.  b.For each R value group listed immediately above:  i. the average wall insulation R value  ii. the average window area as a percentage of wall area  iii. the average floor area of conditioned space  6.The forecasts shall be provided for each customer group identified in subparagraph (3)(a).  7.The forecasts shall be provided to the Commission on or before December 3lst of the reporting year. As part of the forecasts provided, each utility shall provide a narrative report that describes the forecast methodology and it shall report all assumptions and the justification for each assumption used in the forecast.  (c) Residential Rate Class Load Data: Starting with calendar year 1987 and every two years thereafter, each investor‑owned utility, subject to this rule, shall report to the Commission by June 1st of the reporting year the scaled residential class load profile, defined in (4)(c)4., according to the following procedure:  1.During any consecutive twelve (12) month period within the two calendar years immediately preceding the reporting year, each electric utility shall gather residential class load research data in accordance with Rule 25‑6.0437, F.A.C.  2.Using the residential class load research data, specified in (4)(c)1., each utility shall develop a residential class load profile using either the Mean Per Unit Methodology or the Combined Ratio Estimation Methodology to expand the hourly kw/customer load research data into a residential class load profile. This load profile shall consist of consecutive hourly demand values representative of the residential class's hourly demands during the twelve (12) month period described in (4)(c)1.  3. Each utility shall weather adjust each hourly demand value in the residential class load profile, developed in (4)(c)2. The weather adjustment shall be for differences in weather variables between the hourly weather conditions for the twelve month period described in (4)(c)1. and the corresponding average hourly weather conditions for the utility's service area derived from a statistical analysis of at least ten consecutive years of weather data or upon the Typical Meteorological Year as defined by the National Weather Service.  4. To the extent that the weather adjusted residential class profile developed in subsection (4)(c)3. coincides with the calendar year immediately preceding the reporting year, the utility shall report that load profile data. For other time periods the residential class load profile developed in subsection (4)(c)2. shall be projected and reported for the corresponding months in the calendar year immediately preceding the reporting year. The method for making these projections shall, in the best judgment of the reporting utility, be such as to reflect residential class load levels which would have occurred under average weather conditions as specified in subsection (4)(c)3.  5.The reporting year shall be an odd‑numbered calendar year beginning with the 1987 calendar year.  **Specific Authority: 366.05(1), 350.127(2), F.S.**  **Law Implemented: 366.05(1), 366.82(2), F.S.**  **History: New 6/14/82, Amended 2/21/85, formerly 25‑l7.06, Amended 9/7/87.**  **25‑17.007 Normalization of Electric Utility Load Data.**  (1) This rule establishes the requirement for normalizing load data so as to allow comparison of utility performance in conservation to established conservation goals, defines which electric utilities are required to file normalized data and outlines a uniform reporting format.  (2) Under this rule, all electric utilities having unadjusted retail sales in excess of 500 GWH in any calendar year shall report normalized load data. Other electric utilities may report normalized load data. Once normalized data have been filed, a utility must continue to file normalized data each year, unless a specific request to discontinue is approved by the Commission.  (3) The definitions in Rule 25‑17.005(3) apply.  (4) Data shall be reported in a spread sheet format to be prescribed by the Commission. Separate spread sheets are to be prepared for Winter System Peak, Summer System Peak and for Net Energy for Load. Adjustments shall be shown both on an aggregate and on a per residential customer basis. The spread sheet shall include the following as a minimum:  (a) Winter System Peak, Summer System Peak, or Net Energy for Load for the base period and for the test year;  (b) Adjustments for Wholesale Customers;  (c) Adjustments for Interruptible Customers (for Winter System Peak and for Summer System Peak);  (d) Other adjustments specified by Rule 25‑17.003;  (e) Firm Winter System Peak, Firm Summer System Peak, or Firm Net Energy for Load;  (f) Load Management Potential at Winter System Peak or Summer System Peak;  (g) Actual Load Management under control at Winter System Peak or Summer System Peak;  (h) Adjusted Winter System Peak, Adjusted Summer System Peak; or Adjusted Net Energy for Load;  (i) Weather adjustments resulting in increases to (h);  (j) Weather adjustments resulting in decreases from (h);  (k) Weather Adjusted Winter System Peak, Weather Adjusted Summer System Peak, or Weather Adjusted Net Energy for Load; and  (l) Supporting documentation explaining all adjustments, including a narrative explanation of each adjustment made on the spread sheet.  (5) Load data shall be normalized for the effect of changes in weather variables including at least temperature, heating degree days, and cooling degree days, or surrogates for those variables. The National Weather Service is to be the source of raw weather data, unless a specific variance is approved by the Commission staff. Calculations shall include weighting of the weather data from multiple weather reporting stations to allow for the affected proportions of the customer population.  (6) Each utility may initially use its internal normalization methods, subject to approval by Commission staff. Once approved, a method shall be used consistently from year to year unless a utility's written request to modify its methods is approved by Commission staff. Any such request shall provide a comparison of the three most recent years' data, and the base period data normalized using both the approved method and the proposed new method. Variances between results of the two methods must be explained and supporting documentation provided.  (7) Initially, each utility shall submit its proposed methodology including supporting documentation by June 15, 1984. Staff shall approve or reject the proposal by August 15, 1984. If rejecting the proposal, staff shall provide reasons for the rejection and shall recommend changes. Within thirty days of receiving notification of disapproval, the utility shall file an amended proposal. Staff shall have thirty days in which to approve or not approve the amended proposal. If the amended proposal is not approved, the dispute shall be submitted to the Commission for resolution.  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 6/19/84, formerly 25‑17.07.** | **[BLANK PAGE INSERT FOR FORMATTING]**  **25‑17.001 General Information**  **25‑17.002 Goals for Electric Utilities (Repealed)**  **25-17.0021 Goals for Electric Utilities (New)**  **25-17.0025 Conservation Performance Incentive Factor (New)**  **25‑17.003 Energy Audits; Related Provisions**  **25‑17.004 Goals for Natural Gas Utilities (Repealed)**  **25‑17.005 Evaluation of Electric Utility Conservation Efforts**  **25‑17.006 Electric Utility System Conservation End‑Use Data**  **25‑17.007 Normalization of Electric Utility Load Data**  **25‑17.008Conservation and Self-Service Wheeling Cost Effectiveness Data Reporting Format**  **25‑17.009 Reserved**  **25‑17.010 Reserved**  **25‑17.011 Energy Conservation Loan Guarantee**  **25‑17.012 through 25‑17.014 Reserved**  **25‑17.015 Conservation Cost Recovery**  **25‑17.016 Oil‑Backout Cost Recovery Factor**  **25‑17.001 General Information.**  (1) The terms system and electric utility, as used in this Rule, shall be synonymous and have the same definition as "electric utility" as defined in section 366.82(1), F.S.  (2) The Florida Energy Efficiency and Conservation Act requires increasing the efficiency of the electric systems of Florida, increase the conservation of expensive resources, such as petroleum fuels, to ~~and the end use of these sources of energy by reducing~~ reduce weather sensitive peak demand, ~~oil consumption~~ and kilowatt hour consumption to the extent cost effective.  (3) Reducing weather sensitive peak demand on the electric system to the extent cost effective is ~~the first~~ a priority. Reducing weather sensitive peak demand benefits not only the individual customer who reduces his demand, but also all other customers on the system, both of whom realize the immediate benefits of reducing the fuel costs of the most expensive form of generation and the longer term benefits of deferring the need for or construction of additional ~~higher cost~~ generating capacity.  (4) Another priority is increasing the efficiency of the end-use consumption of electricity to the extent cost-effective. The reduction of kilowatt-hour consumption particularly during peak periods resulting from increased end-use efficiency will reduce fuel costs to all customers and contribute to the deferral of additional generating capacity.  (5) In addition to specific goals, ~~The~~ general goals and methods for increasing the overall efficiency of the bulk electric power system ~~and natural gas system~~ of Florida are broadly stated since these methods are an ongoing part of the practice of every well‑managed electric utility's programs and ~~will~~ shall be continued.  These methods are to:  **Generating Electric Utilities**  (a) Review and revise utility operating practices such as maintenance scheduling, daily and longer term unit commitment practices through the power broker system to facilitate economic dispatch on both a daily and extended basis and to reduce ~~oil consumption~~ the use of expensive fuel resources, such as petroleum fuels, to the extent cost effective.  (b) Plan development of the bulk power system over time so that the most cost effective combination of generating units, associated facilities and other technologies is developed for meeting generation requirements.  (c) Increase the efficiency of each generating unit and associated operating practices to the extent cost effective.  **All Electric Utilities**  (d) Aggressively integrate nontraditional sources of power generation including cogenerators with high thermal efficiency into the various utility service areas near utility load centers to the extent cost effective and reliable. ~~including planning site development to facilitate development of potential cogenerators near generating units.~~  (e) Increase the efficiency of transmission and distribution systems to the extent cost effective.  (f) Aggressively pursue research, development and demonstration projects jointly with others as well as individual projects in individual service areas. In this context, the Commission anticipates that an aggressive research program would include both technological research, research on load behavior and related problems and market‑related research.  (6)~~(4)~~ The Commission shall continuously review the relationship between demand and energy, both present and anticipated. In making its determinations of need pursuant to the Florida Electrical Power Plant Siting Act, the Commission shall take these relationships into account so that sufficient capacity will be authorized to meet anticipated needs. These goals represent a starting point for establishing demand-side management ~~energy conservation~~ programs for all electric utilities. While ~~There~~ there is no absolute assurance that these goals will be fully achieved within the expected time frames, ~~although~~ the best efforts by the electric utilities to achieve them will be required. In any proceeding for determining whether new capacity is needed, the length and nature of experience under the goals will be considered. The goals will not be used exclusively because the Commission recognizes that they may not be achieved and that the estimates on which they are based may prove to be incorrect. To increase the accuracy of these estimates the Commission anticipates that ~~intensive and extensive~~ research will be required, including both technological research and studies of the market penetration potentials of various demand-side management ~~conservation~~ measures and their effectiveness in reducing KW demand and KWH consumption as well as studies of consumer behavior.  (7)~~(5)~~ Rules 25‑17.001 through 25‑17.005 shall not be construed ~~or applied~~ to restrict growth in the supply of electric power or natural gas necessary to support economic development by industrial or commercial enterprises. Rather, these rules should be construed so as to meet growth in the most cost effective and efficient manner. ~~enhancing job-producing economic growth by lowering energy costs from what they otherwise would be if these goals are not achieved.~~  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended l2/30/82, formerly 25‑17.01.**  **25‑17.002 Goals for Electric Utilities.**  **General Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended 1/19/82, l2/30/82, formerly 25‑17.002 Repealed 4/2/90.**  **25-17.0021 Goals for Electric Utilities.**  (1) The Commission shall establish numerical goals for each affected electric utility, as defined by s. 366.82(1), F.S., to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels. The goals shall be based on an assessment of the total cost effective kilowatt and kilowatt-hour savings reasonably achievable through demand-side management in each utility's service area over a ten-year period.  (2) The Commission shall set goals at least once every ten years. The Commission on its own motion or petition by a utility may initiate a proceeding to review and, if appropriate, modify the goals. All modifications of the approved goals, plans and programs shall only be on a prospective basis.  (3) In a proceeding to establish goals, each utility shall provide an assessment of the cost effective annual kilowatt and kilowatt-hour savings reasonably achievable in its service territory through demand-side management in each of but not limited to the following categories for a period of ten years:  1. Building Envelope Efficiency  2. Lighting Efficiency  3. Heating Equipment Efficiency  4. Air Conditioning Equipment Efficiency  5. Appliance Efficiency  6. Power Equipment/Motor Efficiency  7. Peak Load Shaving  8. Water Heating  9. Refrigeration Equipment  10. Freezing Equipment  11. Solar Energy  12. Energy Substitutes for Electricity  13. High Thermal Efficient Self Service Cogeneration  14. Other.  The assessment provided by the utility shall be based on the utility's most recent applicable planning process and shall describe the interactive effects, including overlapping effects, rebound effects, free riders, and interactions with appliance efficiency standards.  (4) Within 90 days of a final order establishing or modifying goals, each utility shall submit for Commission approval a demand side management plan designed to meet the goals referred to in Section (1) of this rule which shall include demand-side management programs aimed at providing energy conservation and demand reductions. The following information shall be submitted for each program for a ten-year projected horizon period:  1. the program name;  2. the program start date;  3. a statement of the policies and procedures detailing the operation and administration of the program;  4. the total number of customers or appropriate unit of measure in each class of customer (i.e. residential, commercial, industrial, etc.) for each year in the planning horizon;  5. the total number of eligible customers or appropriate unit of measure in each class of customers (ie. residential, commercial, industrial, etc.) for each year in the planning horizon;  6. an estimate of the annual number of customers or appropriate unit of measure in each class projected to participate in the program, including a description of how the estimate was derived;  7. the cumulative penetration levels of the program by year calculated as the percentage of projected cumulative participating customers or appropriate unit of measure by year to the total customers eligible to participate in the program;  8. estimates on an appropriate unit of measure basis of the per customer and program total annual KWH reduction, winter KW reduction, and summer KW reduction, both at the customer meter and the generation level, attributable to the program. A summary of all assumptions used in the estimates will be included;  9. a methodology for measuring actual kilowatt and kilowatt-hour savings achieved from each program, including a description of research design, instrumentation, use of control groups, and other details sufficient to ensure that results are valid;  10. an estimate of the cost-effectiveness of the program using the cost-effectiveness tests required pursuant to Rule 25-17.008.  The Commission shall compare the projected cumulative kilowatt and kilowatt-hour savings associated with each utility's proposed demand side management plan to the goals established for each utility. If the Commission finds that a utility's conservation plan will not meet its goals, the Commission may require the utility to modify its proposed programs or adopt additional programs.  (5) Each utility shall submit an annual report no later than March 1 of each year summarizing their demand side management plan and the total actual achieved results for its approved demand side management plan, in the preceding calendar year for the items described in items 1 through 14 listed below. The report shall contain, at a minimum, a summation of the utility's demand and energy savings resulting from the approved demand side management plan, and the following information for each approved program:  1. the name of the utility;  2. the name of the program and program start date;  3. the calendar year the report covers;  4. total number of customers or appropriate unit of measure by customer class for each year of the planning horizon;  5. total number of customers or appropriate unit of measure eligible to participate in the program for each year of the planning horizon;  6. total number of customers or appropriate unit of measure projected to participate in the program for each year of the planning horizon;  7. the potential cumulative penetration level of the program to date calculated as the percentage of projected participating customers to date to the total eligible customers in the class;  8. the actual number of program participants and current cumulative number of program participants;  9. the actual cumulative penetration level of the program calculated as the percentage of actual cumulative participating customers to the number of eligible customers in the class;  10. a comparison of the actual cumulative penetration level of the program to the potential cumulative penetration level of the program;  11. a justification for variances larger than 15% between the potential cumulative penetration level and the actual cumulative penetration level achieved;  12. using on-going measurement and evaluation results the annual KWH reduction, the winter KW reduction, and the summer KW reduction, both at the meter and the generation level, per installation and program total, based on the utility's approved measurement/evaluation plan;  13. the per installation cost and the total program cost of the utility;  14. a levelized allocation of the life-cycle present worth net benefits for each year of the planning horizon attributable to demand savings;  15. a levelized allocation of life-cycle present worth net benefits for each year of the planning horizon attributable to energy savings.  25-17.0025 Conservation Performance Incentive Factor.  (1) The purpose of the Conservation Performance Incentive Factor (CPIF) is to provide a financial incentive to investor owned utilities in the form of monetary rewards and penalties to aggressively pursue their approved demand-side management programs. The Conservation Performance Incentive Factor shall be calculated in each Conservation Cost Recovery hearing.  (2) The Commission shall determine which programs of each utility will be eligible for inclusion in this incentive provision. In making this determination the Commission shall consider the demand and energy savings of the programs and other relevant factors.  (3) CPIF rewards shall be recovered by the utility through the Energy Conservation Cost Recovery (ECCR) clause and flow directly to the stockholders. CPIF penalties shall be a credit to conservation expenses recovered by the utility through the ECCR clause. The Commission shall establish a target level for the incremental number of new installations for each program eligible for an incentive. The targeted level established for each program shall take into account the reasonably achievable market penetration potential and the level of disincentives that may be inherent in the program, such as lost revenues and adverse impacts on rates. The Commission shall also establish the net dollar benefit per installation for each program eligible for an incentive. A reward or penalty based on 20% of net savings shall be calculated for each program based on a comparison of actual installations relative to targeted installations.  (4) The Conservation Performance Incentive Factor shall be calculated mathematically as follows:  LetTi = the target number of incremental installations for program i for the period.  Ai = the actual number of incremental installations for program i for the period.  Bi = the net dollar benefit per installation for program i for the period.  Also, let  Ri = sum of (Ai - Ti) x Bi x 20% for all programs where Ai > Ti  Ri = 0, otherwise.  Pi = sum of (Ti - Ai) x Bi x 20% for all programs where Ti > Ai  Pi = 0, otherwise.  The total net reward is calculated as follows:  NET REWARD = sum of (Ri - Pi) for i = 1 to n  where n is the total number of programs eligible for an incentive.  **25‑17.003 Energy Audits; Related Provisions.**  (1) Purpose: This rule specifies the minimum requirements for performing energy audits by each utility subject to the requirements of this rule.  (2) Applicability: This rule applies to each utility as defined in s. 366.82(1), F.S.  (3) Definitions:  (a) "Alternative (Walk‑Through) Audit" means an energy audit as defined in Chapter 25‑17.51(8), F.A.C.  (b) "Commercial Audit" means an energy analysis of a commercial building and its associated energy systems to determine its energy efficiency and to identify for the customer those cost effective measures which may improve its energy efficiency.  (c) "Energy Conservation Audit" means an energy audit as defined in Chapter 25‑17.51(6), F.A.C.  (d) "Industrial Audit" means an energy analysis of an industrial facility and its associated energy systems to determine its energy efficiency and to identify for the customer those cost effective measures which may improve its energy efficiency.  (4) Each utility shall notify its residential, commercial, and industrial customers of the availability of energy audits at least once every six months. Notification of audit availability, at a minimum, must be made by use of notices in billing statements or other means that involves direct notification to the customer. The announcement of the Residential Conservation Audits as required in Chapter 25‑17.53(3)(c) can count as one of the biannual notifications for the residential customers.  (5) For each customer requesting either an Energy Conservation Audit or an Alternative Audit, each utility shall provide the requested audit to the customer in accordance with the provisions of Chapter 25‑17.51 through 25‑17.65, F.A.C.  (6) For each customer requesting either a Commercial Audit or an Industrial Audit, each utility shall provide or arrange to provide the requested audit to the customer within 120 days of the date the customer makes the request. The utility may recover the actual expenses incurred by providing audits from those commercial or industrial customers requesting such audits.  ~~(7) In lieu of the performance of energy audits as stated above, each utility may perform energy audits as follows:~~  ~~By January 1, 1982, the overall annual rate for energy audits shall be 150,000, by January 1, 1984, the overall rate shall be 250,000. Each electric utility shall determine the portion of these goals applicable to it by January 1, 1982, by multiplying the number of residential customers on its system who consumed over 9,000 KWH during 1979 by 142,012 and dividing the result by the total number of such customers in the state, and by January 1, 1984 use the same formula but multiply by 236,672.~~  **Specific Authority: 366.05(1), 350.127(2), F.S.**  **Law Implemented: 366.82(5), F.S.**  **History: New 12/2/80, Amended 12/30/82, formerly 25‑17.03, Amended 11/24/86.**  **25‑17.004 Goals for Natural Gas Utilities.**  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended l2/30/82, formerly 25‑17.04, Repealed 4/2/90.**  **25‑17.005 Evaluation of Electric Utility Conservation Efforts.**  ~~(1) This rule defines terminology, establishes reporting requirements and describes the method used to determine whether an electric utility has met its conservation goals; and it establishes reporting requirements to enable the Commission to monitor the implementation and cost‑effectiveness of utilities' conservation programs.~~  ~~(2) The methods in this rule apply to all electric utilities as defined in 366.82, F.S.~~  ~~(3) The following definitions apply:~~  ~~(a) "Test Year" means the twelve month period beginning January 1 for Net Energy for Load, and beginning November 1 for Winter System Peak and Summer System Peak.~~  ~~(b) "Base Period" means the 1980 calendar year for comparison with the Net Energy for Load test year and the period November 1, 1979 through October 31, 1980 for the comparison with the test year for Winter System Peak and Summer System Peak.~~  ~~(c) "Winter System Peak" means the highest one hour system demand occurring between November 1 and the following March 31 during cold weather conditions.~~  ~~(d) "Summer System Peak" means the highest one‑hour system demand occurring between April 1 and the following October 31 during warm weather conditions.~~  ~~(e) "Net Energy for Load" means net system generation plus energy received from Class I and Class II systems minus energy delivered to Class I and Class II Systems for the calendar year.~~  ~~(f) "Adjusted Winter System Peak" means Winter System Peak minus non‑jurisdictional point‑of‑delivery demand, interruptible demand, demand subject to load control, and minus any other adjustments specified in Rule 25‑17.002(3).~~  ~~(g) "Adjusted Summer System Peak" means Summer System Peak minus non‑jurisdictional point‑of‑delivery demand, interruptible demand, demand subject to load control, and minus any other adjustments specified in Rule 25‑17.002(3).~~  ~~(h) "Adjusted Net Energy for Load" means Net Energy for Load minus output to non‑jurisdictional customers (sales may be used if actual output data are not available) minus other adjustments specified in Rule 25‑17.002(3).~~  ~~(i) "Weather Adjusted Winter System Peak" means Adjusted Winter System Peak plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.~~  ~~(j) "Weather Adjusted Summer System Peak" means Adjusted Summer System Peak plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.~~  ~~(k) "Weather Adjusted Net Energy for Load" means Adjusted Net Energy for Load plus or minus any changes made to mathematically adjust, in accordance with Rule 25‑17.007, for differences in weather conditions between the test year and the Normal Weather Year or the base period and the Normal Weather Year.~~  ~~(l) "Goals" mean the target levels of winter end use KW demand, summer end use KW demand, and end use KWH consumption calculated and adjusted as specified in Rule 25‑17.002 and the number of energy audits calculated to be the utility's allocation under the provisions of Rule 25‑17.003(1) and (2). For purposes of comparison with utility performance in the test year, goals shall be differentiated by the terms KW‑Goal(Winter), KW‑Goal(Summer), KWH‑Goal, and Audits‑Goal respectively, and shall be modified as described below:~~  ~~KW‑Goal(Winter) shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(d) to the 1979‑1980 Weather Adjusted Winter System Peak.~~  ~~KW‑Goal(Summer) shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(d) to the 1980 Weather Adjusted Summer System Peak.~~  ~~KWH‑Goal shall be calculated by applying the target growth rates calculated in Rule 25‑17.002(1)(a) through (1)(c) and 25‑17.002(1)(e) to the 1980 Weather Adjusted Net Energy for Load.~~  ~~Audits‑Goal shall be as calculated in accordance with the provisions of Rule 25‑17.003.~~  ~~(m) "Audits‑Actual" means the number of energy audits actually performed by the utility and includes Energy Conservation Audits, Customers Assisted (Mail‑In) Audits, Alternative (Walk‑Through) Audits, Industrial Audits and Commercial Audits. Alternative Audits shall be considered as audits performed if the procedure for conducting them has been approved by the Commission, in accordance with Rule 25‑17.059(1)(c).~~  ~~(n) "Normal Weather Year" means expected weather conditions for a utility's service area, derived from statistical analysis of a minimum of ten consecutive years of weather data or upon the Typical Meteorological Year, as defined by the National Weather Service.~~  ~~(o) "Supporting Documentation" means a narrative discussion of procedures used and assumptions made and a concise, detailed presentation of formulas used, provided in sufficient detail to allow the Commission staff, using standard statistical and mathematical procedures to replicate the results reported by the utility.~~  ~~(4) Each utility shall provide the following data to the Commission by April 30 of each year, beginning in 1985.~~  ~~(a) Test year KW‑Goal(Summer) and KW‑Goal(Winter) and KWH‑Goal as defined in Rule 25‑17.005(3).~~  ~~(b) Test Year Weather Adjusted Summer System Peak, Weather Adjusted Winter System Peak and Weather Adjusted Net Energy for Load.~~  ~~(c) Current Audits‑Goal for the same period as the KWH test year.~~  ~~(d) Audits‑Actual for the same period as the KWH test year. Any difference from the sum of Residential, Commercial and Industrial audits reported on the Annual FEECA Program Report shall be explained.~~  ~~(5) Information provided in accordance with 25‑17.005(4) above shall be used to determine whether each utility has achieved or has not achieved each of its four conservation goals.~~  ~~(a) The Summer end‑use KW demand goal is achieved if Weather Adjusted Summer System Peak is less than or equal to KW‑Goal(Summer).~~  ~~(b) The Winter end‑use KW demand goal is achieved if Weather Adjusted Winter System Peak is less than or equal to KW‑Goal(Winter).~~  ~~(c) The KWH consumption goal is achieved if Weather Adjusted Net Energy for Load is less than or equal to KWH‑Goal.~~  ~~(d) The audit goal is achieved if Audits‑Actual is greater than or equal to Audits‑Goal.~~  ~~(6) Each utility shall submit a semi‑annual program progress report for the first half of each calendar year and an annual program progress report for each calendar year in a format described by the Commission. Each report shall be due 30 days after the close of each semi‑annual or annual period. A utility may submit additional information along with its report. Reports shall provide, at a minimum, the information detailed below.~~  ~~(a) The FEECA Program Progress Report shall include a separate listing of each program which includes:~~  ~~1.The name of the utility;~~  ~~2.The period (semi‑annual or annual) and calendar year the report covers;~~  ~~3.The program name;~~  ~~4.The program start date;~~  ~~5.The assumed annual KWH savings per installation;~~  ~~6.The assumed winter coincident peak KW reduction per installation;~~  ~~7.The assumed summer coincident peak KW reduction per installation;~~  ~~8.Current period planned, current period actual, planned program to date, program to date actual, and difference between planned and actual data on the following:~~  ~~a. Number of audits or installations, etc.;~~  ~~b. Annual GWH savings;~~  ~~c. Winter MW reduction;~~  ~~d. Summer MW reduction;~~  ~~e. Total program cost of utility; and~~  ~~f. Cost per audit or installation, etc.~~  ~~9.Any comments pertaining to the program.~~  ~~10.The investor‑owned electric utilities shall also report as part of the annual report the following for each of the categories listed in subsection (6)(a)8. above:~~  ~~a. Value of KWH saved;~~  ~~b. Value of deferred generating unit or purchased electrical power;~~  ~~c. Energy benefit/cost ratio; and~~  ~~d. Total benefit/cost ratio.~~  ~~(b) The FEECA Program Executive Summary for all programs shall include a brief overview of utility's conservation program efforts and accomplishments during the reporting period.~~  ~~(c) Any other information required by Commission order.~~  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 12/2/80, Amended 12/30/82, 6/19/84, formerly 25‑17.05, Amended 9/14/88.**  **25‑17.006 Electric Utility System Conservation End Use Data.**  (l) PURPOSE: The purpose of this rule is to provide for the periodic submission of certain conservation information and other related information to the Commission. Applications of this Rule include:  (a) gathering information to review and revise conservation goals pursuant to Rule ~~25‑17.002~~ 25-17.0021, F.A.C.;  (b) gathering information to estimate the potential kilowatt hour (KWH) and kilowatt demand (KW) savings achievable through various conservation measures and conservation technologies;  (c) to monitor the effectiveness of the Florida Model Energy Efficiency Code, developed under s. 553.900, F.S., et. seq., and modifications made thereto; and  (d) gathering information to enable the Commission to analyze conservation alternatives to mitigate the need to construct new power plants in Florida.  (2) APPLICABILITY: This rule shall apply to all electric utilities that had total sales of electric energy for purposes other than resale in excess of 500 gigawatt hours for the calendar year l980.  (3) Residential KWH Consumption Data: Starting with the l98l calendar year, and each year thereafter, each electric utility shall:  (a) Categorize all customers (structures) who were or had been connected to the utility system for permanent service during the calendar year by the year of first connection and by the following customer groups:  l.Residential, single family, unattached.  2.Residential, single family, attached.  3.Residential, mobile home or trailers.  Customers (structures) first connected to the system on or before December 31, 1980 shall be categorized as having a 1980 year of first connection.  (b) Using standard statistical sampling procedures, develop sample groups by customer group as specified in subsection (3)(a) above and calendar year of structure connection beginning with 1980.  (c) For each sample group developed pursuant to subsection (3)(a), compute the average annual energy consumption in units of kilowatt hours per customer. The computed value shall be statistically reliable at a 90% confidence level and a +/‑ 5% relative accuracy. The average annual energy consumption shall be determined by adding the active customers for each month, dividing that sum by 12 and dividing that result into the total annual consumption for those customers. Active customers are those members of the sample group to whom bills were issued during that month.  (d) For each sample group developed pursuant to subsection (3)(a), compute the average monthly energy consumption in units of kilowatt hours per customer. The computation shall be made for each month of the calendar year. The computed values shall be statistically reliable at a 90% confidence level and a +/‑ 5% relative accuracy.  (e) Report the results of subsections (3)(c) and (3)(d), by March 1st of the following calendar year. Also, report the total number of customers at year end by each customer group specified in subsection (3)(a) connected to the utility system for permanent service during the calendar year. The utilities shall also calculate and report statewide aggregates for these data within 90 days of the due date of the individual utility reports.  (f) The requirement that customers (structures) be categorized by year of first connection to the utility system is for the purpose of approximating the year of construction.  (4) Residential Goal Setting Information:  (a) Residential Customer Survey: Starting with calendar year l986 and every four years thereafter, each electric utility shall "collect" certain information on the appliance stock, housing characteristics, household demographic characteristics and twelve months of kilowatt hour billing history for its proportionate share of a representative sample of residential customers (structures).  l.For the purposes of obtaining the data described in subsection (4)(a), a representative sample of residential customers sufficient to yield 1,350 usable, complete observations shall be field interviewed by representatives of the utility in each of the following climatological zones.  a.Northern: Baker, Bay, Bradford, Calhoun, Clay, Columbia, Dixie, Duval, Escambia, Franklin, Gadsden, Gulf, Hamilton, Holmes, Jackson, Jefferson, Lafayette, Leon, Liberty, Madison, Nassau, Okaloosa, Santa Rosa, St. Johns, Suwannee, Taylor, Union, Wakulla, Walton, Washington.  b.Central: Alachua, Citrus, DeSoto, Flagler, Gilchrist, Hardee, Hernando, Highlands, Hillsbrough, Lake, Levy, Marion, Okeechobee, Orange, Osceola, Pasco, Polk, Putnam, Seminole, Sumter, Volusia.  c.Central Coastal: Brevard, Charlotte, Collier, Glades, Hendry, Indian River, Lee, Manatee, Martin, Monroe (excluding the Florida Keys), Pinellas, Sarasota, St. Lucie.  d.Southeast: Broward, Dade, Palm Beach, and the Florida Keys.  2.For each climatological zone, each utility shall sample a proportion of the l350 customers based on its percentage of residential customers in each of the regions.  a.By November 1st prior to the survey year each utility will provide to the Commission staff the number of its residential customers residing in each of the four climate zones as of June 30th prior to the survey year.  b.By January 15th of the survey year Commission staff will allocate the prescribed sample points to each utility based on the information submitted pursuant to subsection 2.a.  3.For each climatological zone, each utility shall stratify its residential customers by customer group as defined in subsection (3)(a) and draw a representative sample from each customer group proportional to that group's percentage of the total residential customers in the climatological zone.  4.The information on appliance stocks, housing characteristics, household demographic and the twelve months of KWH billing history shall be gathered using a survey instrument prescribed by the Commission by January 15th of the survey year. Nothing in this paragraph shall be construed to prohibit an electric utility from adding additional questions to its own survey it believes useful.  5.Each utility shall report the survey information and billing history on each individual respondent to the Commission on or before September lst of the calendar year immediately following the survey year. This information shall be reported such that no individual customer's identity can be determined. The information reporting format shall be prescribed by the Commission prior to April lst of the survey year. The medium for reporting the information shall be 3 and one-half inch microcomputer diskette using a FoxPro database structure ~~9 track magnetic tape~~ unless another medium is approved in writing by the Commission staff. The utilities shall also submit aggregated data on a statewide basis within 90 days of the due date of the individual utility reports.  6.The following guidelines shall apply to customers described in subsection (4)(a) 1. above:  a.Customers must be customers of record as of July 1st of the survey year.  b.Customers must be continuously billed for a twelve consecutive calendar month period between July 1st of the year prior to the survey year and July 31st of the survey year. The twelve calendar consecutive month period shall be the same for all survey customers.  c.Seasonal customers billed in accordance with sub‑section (4)(a)6.b. may be counted toward the required number of sample customers.  7.The survey year shall be an even numbered calendar year beginning with the 1986 calendar year and every four years thereafter. The term survey year shall not be construed to limit completion of the survey to that even numbered calendar year.  8.The reporting year shall be an odd numbered calendar year beginning with the 1987 calendar year and every four years thereafter.  (b) Forecasts of Residential Appliance Stocks and Housing Characteristics: Starting with calendar year l987 and every four years thereafter, each electric utility shall report to the Commission forecasts of the market penetration of certain appliance stocks and housing characteristics.  l.Using its best estimates, each electric utility shall report the percentage of market penetration of each appliance listed in subparagraphs 4.a. ‑ 4.m. for each year of the forecast horizon.  2.Using its best estimates, each electric utility shall report the market penetration of each housing characteristics listed in subparagraphs 5.a.‑5.d. for each year of the forecast horizon.  3.The forecast horizon shall be at least 10 years and the use of a 20 year forecast period is encouraged.  4.Appliance stocks shall be:  a.High efficiency central air conditioners with a seasonal Energy Efficiency Rating (SEER) greater than or equal to 11.0.  b.Low efficiency central air conditioners with a SEER less than 11.00.  c.High efficiency heat pumps with a Coefficient Of Performance (COP) greater than or equal to 3.0 and a SEER greater than or equal to l0.0.  d.Low efficiency heat pumps with a Coefficient Of Performance (COP) less than 3.0 and a SEER less than 10.0.  e.Window or wall air conditioners.  f.Central resistance space heaters.  g.Non central resistance space heaters permanently affixed to the building structure.  h.Non‑electric heating.  i.Resistance water heaters.  j.Heat pump water heaters.  k.Solar water heaters.  l.Waste heat recovery water heaters.  m.Non‑electric water heating.  5. Housing characteristics shall be:  a. The number of residential structures having ceiling insulation R values between:  i. R‑O and R‑7  ii. R‑8 and R‑15  iii. R‑16 and R‑22  iv. R‑23 and greater.  b.For each R value group listed immediately above:  i. the average wall insulation R value  ii. the average window area as a percentage of wall area  iii. the average floor area of conditioned space  6.The forecasts shall be provided for each customer group identified in subparagraph (3)(a).  7.The forecasts shall be provided to the Commission on or before December 3lst of the reporting year. As part of the forecasts provided, each utility shall provide a narrative report that describes the forecast methodology and it shall report all assumptions and the justification for each assumption used in the forecast. The utilities shall also provide a statewide forecast within 90 days of the due date of the individual utility reports.  (c) Residential Rate Class Load Data: Starting with calendar year 1987 and every two years thereafter, each investor‑owned utility, subject to this rule, shall report to the Commission by June 1st of the reporting year the scaled residential class load profile, defined in (4)(c)4., according to the following procedure:  1.During any consecutive twelve (12) month period within the two calendar years immediately preceding the reporting year, each electric utility shall gather residential class load research data in accordance with Rule 25‑6.0437, F.A.C.  2.Using the residential class load research data, specified in (4)(c)1., each utility shall develop a residential class load profile using either the Mean Per Unit Methodology or the Combined Ratio Estimation Methodology to expand the hourly kw/customer load research data into a residential class load profile. This load profile shall consist of consecutive hourly demand values representative of the residential class's hourly demands during the twelve (12) month period described in (4)(c)1.  3. Each utility shall weather adjust each hourly demand value in the residential class load profile, developed in (4)(c)2. The weather adjustment shall be for differences in weather variables between the hourly weather conditions for the twelve month period described in (4)(c)1. and the corresponding average hourly weather conditions for the utility's service area derived from a statistical analysis of at least ten consecutive years of weather data or upon the Typical Meteorological Year as defined by the National Weather Service.  4. To the extent that the weather adjusted residential class profile developed in subsection (4)(c)3. coincides with the calendar year immediately preceding the reporting year, the utility shall report that load profile data. For other time periods the residential class load profile developed in subsection (4)(c)2. shall be projected and reported for the corresponding months in the calendar year immediately preceding the reporting year. The method for making these projections shall, in the best judgment of the reporting utility, be such as to reflect residential class load levels which would have occurred under average weather conditions as specified in subsection (4)(c)3.  5.The reporting year shall be an odd‑numbered calendar year beginning with the 1987 calendar year.  **Specific Authority: 366.05(1), 350.127(2), F.S.**  **Law Implemented: 366.05(1), 366.82(2), F.S.**  **History: New 6/14/82, Amended 2/21/85, formerly 25‑l7.06, Amended 9/7/87.**  **25‑17.007 Normalization of Electric Utility Load Data.**  ~~(1) This rule establishes the requirement for normalizing load data so as to allow comparison of utility performance in conservation to established conservation goals, defines which electric utilities are required to file normalized data and outlines a uniform reporting format.~~  ~~(2) Under this rule, all electric utilities having unadjusted retail sales in excess of 500 GWH in any calendar year shall report normalized load data. Other electric utilities may report normalized load data. Once normalized data have been filed, a utility must continue to file normalized data each year, unless a specific request to discontinue is approved by the Commission.~~  ~~(3) The definitions in Rule 25‑17.005(3) apply.~~  ~~(4) Data shall be reported in a spread sheet format to be prescribed by the Commission. Separate spread sheets are to be prepared for Winter System Peak, Summer System Peak and for Net Energy for Load. Adjustments shall be shown both on an aggregate and on a per residential customer basis. The spread sheet shall include the following as a minimum:~~  ~~(a) Winter System Peak, Summer System Peak, or Net Energy for Load for the base period and for the test year;~~  ~~(b) Adjustments for Wholesale Customers;~~  ~~(c) Adjustments for Interruptible Customers (for Winter System Peak and for Summer System Peak);~~  ~~(d) Other adjustments specified by Rule 25‑17.003;~~  ~~(e) Firm Winter System Peak, Firm Summer System Peak, or Firm Net Energy for Load;~~  ~~(f) Load Management Potential at Winter System Peak or Summer System Peak;~~  ~~(g) Actual Load Management under control at Winter System Peak or Summer System Peak;~~  ~~(h) Adjusted Winter System Peak, Adjusted Summer System Peak; or Adjusted Net Energy for Load;~~  ~~(i) Weather adjustments resulting in increases to (h);~~  ~~(j) Weather adjustments resulting in decreases from (h);~~  ~~(k) Weather Adjusted Winter System Peak, Weather Adjusted Summer System Peak, or Weather Adjusted Net Energy for Load; and~~  ~~(l) Supporting documentation explaining all adjustments, including a narrative explanation of each adjustment made on the spread sheet.~~  ~~(5) Load data shall be normalized for the effect of changes in weather variables including at least temperature, heating degree days, and cooling degree days, or surrogates for those variables. The National Weather Service is to be the source of raw weather data, unless a specific variance is approved by the Commission staff. Calculations shall include weighting of the weather data from multiple weather reporting stations to allow for the affected proportions of the customer population.~~  ~~(6) Each utility may initially use its internal normalization methods, subject to approval by Commission staff. Once approved, a method shall be used consistently from year to year unless a utility's written request to modify its methods is approved by Commission staff. Any such request shall provide a comparison of the three most recent years' data, and the base period data normalized using both the approved method and the proposed new method. Variances between results of the two methods must be explained and supporting documentation provided.~~  ~~(7) Initially, each utility shall submit its proposed methodology including supporting documentation by June 15, 1984. Staff shall approve or reject the proposal by August 15, 1984. If rejecting the proposal, staff shall provide reasons for the rejection and shall recommend changes. Within thirty days of receiving notification of disapproval, the utility shall file an amended proposal. Staff shall have thirty days in which to approve or not approve the amended proposal. If the amended proposal is not approved, the dispute shall be submitted to the Commission for resolution.~~  **Specific Authority: 366.05(1), 366.82(1)‑(4), F.S.**  **Law Implemented: 366.82(1)‑(4), F.S.**  **History: New 6/19/84, formerly 25‑17.07.** | Clarifies that this rule is limited to electric utilities  Consistent with Legislative intent stated in FEECA, 366.81, F.S.  This change, along with new paragraph (4), is a policy change that places equal emphasis on cost-effectively reducing weather sensitive peak demand and reducing energy consumption. This reflects the fact that reduction in energy consumption, particularly peak period energy consumption may have a beneficial effect on power plant deferral, the environment, and may also reduce consumption of expensive resources, such as petroleum fuels. This is consistent with the legislative intent stated in 366.81, F.S.  Natural gas will be addressed in a separate rule.  Clarifies that this rule is limited to electric utilities.  Consistent with Legislative intent stated in FEECA, 366.81, F.S.  Rule is limited to electric utilities.  This provision encourages electric utilities to integrate high thermal efficiency cogenerators within their territories. High thermal efficiency projects save fuel. The new language clarifies that it is preferable to have cogenerators located near load centers rather than near existing generating units.  Demand-side management includes both demand and energy reduction programs.  Defining the full potential for conservation savings is not an exact science. The utilities and its customers are operating in a marketplace where the various interactions may cause the utility to not achieve its full conservation potential. This provision clarifies that utilities are obligated to use best efforts to achieve their goals.  Demand-side management includes demand and energy reduction programs.  Enhancing job-producing economic growth does not come within the purview of the FPSC.  This proposed rule contains changes from the current general goals as stated in 25-17.001, to specific KW and KWH goals. These specific goals will be based on studies of the potential energy and demand savings in Florida and the utilities' service territories. The ten year period for conservation goals coincides with the utility's ten year site plans identifying the generation expansion plans.  This provision allows the Commission to review and modify the conservation goals when additional information becomes available.  This provision addresses the major end use sectors and requires the utilities to evaluate the potential cost-effective KW and KWH savings within each of these sectors.  The FEECA utilities (i.e., those electric utilities with more than 500 GWH annual sales) are required to submit a menu of conservation programs consistent with the cost-effective KW and KWH savings potential within each end use category.  Knowledge of interactive effects is necessary to determine actual demand and energy savings.  The utility's demand side management plan will include conservation programs and specific information relating to the Commission's goals. Utilities are encouraged to develop programs that will achieve the full potential for conservation within their service areas. To the extent that a utility's conservation plan will not meet its goals. Subsection (4) specifies that the Commission may explore whether additional programs or modifications to existing programs, such as increasing the number of participating customers, will enable the utility to better reach its goal. Action by the Commission to add or modify programs is discretionary rather than mandatory because the utility may prove that the goals are unattainable in the "real world" or that expanding programs would not be cost effective.  An annual progress report required to be filed with the Commission identifying the results of the utility's demand side management plan, including information specific to each demand side management program within the plan. This report will be used to measure the utility's progress in meeting its plan.  The total number of customers within the customer class.  Eligible customers or unit of measure (ie. lighting fixtures) eligible to participate in the program.  Projected participation levels  Potential cumulative penetration level of the conservation program.  Actual number of program participants and current cumulative number of program participants.  Actual cumulative penetration level of program.  Compare actual cumulative penetration level to the potential cumulative penetration level of the program.  Provide justification for program penetration variances larger than 15%.  Report actual energy and demand savings using the utility's approved measurement plan.  Report per installation and total program cost.  Levelized allocation of benefits attributed to demand savings.  Levelized allocation of benefits attributed to energy savings.  CPIF rewards will be recovered by the utility through the ECCR clause and will flow directly to the stockholders and act as an incentive for the utilities to achieve their maximum conservation potential. Penalties will be a credit to the ECCR clause, thereby reducing the customers ECCR charge. The CPIF measures actual performance relative to targeted performance.    Certain programs may be excluded from the CPIF provision because of difficulty in measuring demand and energy savings.  Targets are set at a minimum threshold level so that performance above targets will result in monetary rewards for the utility and performance below targets result in monetary penalties to the utility.  The theme of the CPIF is for the utilities to strive for excellence. The amount of reward is thought to be large enough to encourage more utility participation in conservation.  Energy audit penetration rates are addressed in the new conservation goals section 25-17.0021.  Rule 25-17.005 is being eliminated because it refers to the old rule (25-17.002) on KW and KWH goals which was repealed. This methodology is no longer applicable under the new proposal.  This section describes the current semi-annual and annual FEECA reports that are submitted by FEECA utilities. This information will now be included in 25-17.021(5).  Inserts new rule reference. 25-17.002 has been repealed.  It is contemplated that the utilities will work through the FCG to aggregate and prepare a statewide report.  Updates the medium and data structure to be used in reporting the data.  It is contemplated that the utilities will work through the FCG to produce a statewide report.  It is contemplated that the utilities will work through the FCG to produce a statewide forecast.  This rule relates to the original rule on goals which was repealed and should be repealed in its entirety. This methodology is no longer applicable to the new rule being proposed. |