State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

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

DATE: June 16, 2022

TO: Adam J. Teitzman, Commission Clerk, Office of Commission Clerk

FROM: Jacob Imig, Attorney

RE: 20220000 Ten Year Site Plan Workshop

Please add the following document to the 20220000 docket.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: 2022 Ten Year Site Plans) DOCKET NO. 20220000-OT
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FLORIDA RISING'S &
ENVIRONMENTAL CONFEDERATION OF SOUTHWEST FLORIDA'S
<u>2022 TEN YEAR SITE PLAN POST-WORKSHOP COMMENTS</u>

Florida Rising and the Environmental Confederation of Southwest Florida ("ECOSWF") file these comments regarding the 2022 Ten Year Site Plans, specifically, the Ten Year Site Plan filed by Florida Power & Light Co. ("FPL"). In short, FPL's recommended plan based on hypothetical "extreme Winter" scenarios is divorced from sensible utility planning and appears solely designed to justify ever-expanding generation costs on an extremely overbuilt system, in order to further increase FPL's already excessive profits. The unfortunate cost of this continued plan for gross-overbuilding will be ever-more ordinary Floridians who will suffer because they cannot afford FPL's record-setting electricity bills. Too many families already cannot afford electricity from FPL, with tens of thousands already having been disconnected for their inability to keep up with FPL's ever-increasing bills. Any further increases, justified by FPL's Ten Year Site Plan, will only push more Floridians over the brink. The Commission must find that FPL's recommended plan is not suitable. Furthermore, if the Commission is inclined to find it is suitable, and also inclined to give such a finding *any* weight in a future proceeding, it must do so via an evidentiary proceeding under chapter 120, as Florida Rising's and ECOSWF's substantial interests would be impaired by any such precedential decision.

BACKGROUND

Florida Rising is a membership-based organization dedicated to building broader multiracial movements with individuals from historically marginalized communities to seize power and govern to advance social, economic, and racial justice. Florida Rising has over a thousand members in FPL's service territory who are FPL customers who will face higher electricity rates and thus higher bills to pay for FPL's unneeded investments in fossil-fuel infrastructure. Beyond advocating for economic equity, Florida Rising is also committed to climate justice and pushing for a regenerative future and a just transition that puts frontline communities as the center of energy policy, disaster response, food policy, and all climate change initiatives. A substantial number of Florida Rising's members live in FPL's service area and are customers receiving electricity service from FPL and will be substantially affected by the outcome of this proceeding as FPL ratepayers if the Commission finds FPL's recommended plan "suitable" and gives that decision any precedential weight.

ECOSWF has members consisting of business entities, other organizations, and individuals living in southwest Florida that reside in FPL's service territory and are FPL customers. ECOSWF was organized for the purpose of conserving the natural resources of southwest Florida, implement energy efficiency improvements and alternatives, and to engage in actions in the furtherance of energy conservation and alternative energy source development.

I. NO JUSTIFICATION TO PLAN FOR HYPOTHETICAL EXTREME WINTER PEAKS

FPL offers little to justify the use of extreme winter peaks in its planning process. In fact, FPL offers *no* probability analysis for the scenario around which it recommends planning its entire system. Such a plan, based on a far-fetched scenario that *could*, but may never happen, is not helpful. What if instead, FPL had presented a ten year plan based on the use of natural gas being imminently outlawed due to its climate change implications? That *could* happen—and is arguably more probable in the future than FPL's hypothetical winter peaks—but it may never occur, and a ten year site plan based on such a hypothetical premise could not be found suitable. *Compare* FPL Response to Staff's 3rd Data Request, Request No. 2 c.i.,[1] available at http://www.psc.state.fl.us/library/filings/2022/03136-2022/03136-2022.pdf ("There were no probability studies conducted to determine the chance of an extreme Winter event occurring in the future. . . . FPL cannot predict when or how often such extreme Winter events will occur . . ."), *with* FPL Response to Staff's First Data Request, Request No. 74, available at http://www.psc.state.fl.us/library/filings/2022/02850-2022/02850-2022.pdf ("FPL does not have sufficient information on the probability of any future proposed GHG [Greenhouse gas] NSPS [New Source Pollution Standard] which could cause adverse impacts on its generating fleet.").

In its as-filed plan FPL grasps at two separate events to attempt to justify its hypothetical winter peaks: the December 1989 record cold winter event where FPL was unable to meet all load (apparently due to their own negligence as detailed below), and the January 2010 winter event, where FPL was able to meet all load. *See* FPSC Ten-Year Site Plan Workshop FPL TYSP Comparison at 3, available at http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2022/FPL_Presentation.pdf (pointing to those two events as justification); FPL Response to Staff's 3rd Data Request, Request No. 2 b. (acknowledging that the 1989 event resulted in forced outages, although "FPL does not have records of the number of customers affected," and 2010 event had no forced outages).

[1] All citations, unless otherwise noted, are to documents filed in this docket, Docket No. 20220000-OT.

A. The 1989 Event

Regarding the 1989 event, the blame for lost load appears to fall on FPL's poor management and immediate planning, and not at all on a lack of generating resources. Reporting from the time indicates that although the severe cold was predicted several days in advance, "FPL apparently made no alterations in its holiday-weekend staffing and maintenance plans." *Power Company Needs to Warm Up to its Responsibilities to the Public*, South Florida Sun-Sentinel, Dec. 29, 1989, available at https://www.sun-sentinel.com/news/fl-xpm-1989-12-29-8902170510-story.html. Reporting from the PSC indicated that FPL did not adequately prepare its generating resources, losing 23% of its generating capacity versus a statewide average loss of 10% (and given FPL's size relative to the State, this seems to indicate almost all of the generating losses were from FPL). Adam Yeomans, *Blackouts: Blame Plane, Not Capacity Breakdowns Caused Christmas Outages*, Orlando Sentinel, Mar. 4, 1990, available at https://www.orlandosentinel.com/news/os-xpm-1990-03-04-9003043797-story.html. Furthermore, many of the actual outages did not result from lack of generation, but "overloaded distribution circuits [which] in some cases actually melted distribution lines and destroyed neighborhood transformers." *In re: Investigation into the Cold Weather Capacity Shortfall Emergency Occurring in Peninsular, Florida, December 23-25, 1989*, Docket No. 900071-EG, Order No. 22708 at 6 (Fla. Pub. Serv. Comm'n, March 20, 1990) available at http://www.psc.state.fl.us/library/filings/1990/02473-1990/02473-1990.pdf (hereinafter "1989 Event Order"). In that order, the Commission took final agency action and formally adopted a February 2, 1990 report entitled *Peninsular Florida Cold Weather Capacity Shortfall Emergency December 23-25, 1989*. *Id.* at 2. Since that report does not appear to be available online, it is appended to these comments as Attachment 1, and will be referred to as "1989 Event Report."

Notably, many utilities in north Florida, like Gulf Power, which had properly winterized their equipment and kept their generating resources online, did not experience *any* forced outages, 1989 Event Report at 22-23 (no rolling blackouts in Panhandle, including Tallahassee, or by Gainesville Regional Utilities), even though the Panhandle and north central Florida experienced the most snowfall and the coldest temperatures, 1989 Event Report at 4-5 (noting temperatures of 14 degrees at 6am December 24, 1989 in Tallahassee versus temperatures of 33 degrees in Miami).

At the time, FPL itself used different planning criteria, with a planned 15% summer reserve margin and a loss of load probability of 0.1 days per year, and no planned winter reserve margin (FPL only added a 15% winter reserve margin in 1997). 1998 FPL Ten Year Site Plan at 35 (undocketed), available at http://www.psc.state.fl.us/library/filings/1998/03429-1998/03429-1998.pdf. Such planning led to projections of an 8% winter reserve margin for Peninsular Florida. Fla. Pub. Serv. Comm'n 1997 Review of Ten-Year Site Plans at 3 (undocketed), available at http://www.psc.state.fl.us/library/filings/1997/13338-1997/13338-1997.pdf.

A Commission review of the 1989 event shows just how much FPL is to blame for any outages in FPL's territory at that time. Several FPL generating plants went offline for failure to be sufficiently weatherized, with critical water lines freezing, including the (shared with JEA) St. Johns Units 1 and 2 (1248 MW), Martin Unit 1 (790 MW) and Sanford Unit 3 (139 MW). 1989 Event Order at 8. Other FPL plants just did not have fuel available, including Cutler Units 5 and 6 (68 MW and 131 MW). *Id.* at 9. At other FPL plants, oil filters became clogged and the plants had to be taken off-line to replace the filters, including at the Port Everglades and Fort Lauderdale Gas Turbines (1458 MW). *Id.* at 8. Furthermore, because of corrosion of terminal boards at Turkey Point, FPL had to take Turkey Point Unit 4 (688 MW) offline for the duration of the event and Turkey Point Unit 3 (688 MW) offline for part of the event. *Id.* at 10. All of these failures were not the result of extreme cold temperatures, but due to FPL's poor planning for foreseeable winter weather (i.e., gas plants can easily operate below freezing if properly winterized) and mismanagement. All of the above add up to 5,210 MW of generating units that should or could have been online for the 1989 event.[2] In other words, from the available records, the only cause of FPL's inability to meet all firm load during the 1989 event was FPL's own mismanagement. Consider that the Commission's 1989 Event Order recommended ten actions to avoid a recurrence of the events: 1. Improve phone capacity; 2. Enhance public education on conservation; 3. Implement more cost-effective conservation programs; 4. Look at the building code to consider more gas heating in homes; 5. Expedite expansion of addition gas pipelines into the State; 6. Winterize existing plants; 7. Ensure fuel filter systems can work during cold weather; 8. Ensure alternate fuel is available; 9. Look at reactivation of generating units on extended cold stand-by; and 10. Reflect the impact of the experience in future forecasts and planning. *Id.* at 6-10. Notably, not a single recommendation included adding new generation or postponing the retirement of current generation.

The more detailed report issued and adopted by the Commission further underscores that it was not for a lack of generation that caused the outages, even though FPL had smaller reserve margins at the time. The peak load experienced by FPL's system was 15,586 MW on the morning of December 24 (estimated 1,600 MW of unserved load), although the most unserved load (estimated) was on the morning of December 25 (2,700 MW). 1989 Event Report at 141. During the event, FPL had 1,240 MW out for scheduled maintenance—that is, maintenance FPL

[2] Although commentors have been unable to find FPL's calculated reserve margin for 1989, commentors do know that FPL did not have any specific targeted winter reserve margin.

scheduled for one of the coldest parts of the year, with no planned winter reserve margin—including Port Everglades Unit 4 (369 MW), Manatee Unit 2 (790 MW), Port Everglades CT Unit 1 (40.5 MW) and Ft. Lauderdale CT Unit 16 (40.5 MW). 1989 Event Report at 141-42. Forced outages explain the rest of why FPL was unable to meet its firm load requirements. Turkey Point Unit 4 produced no power during the critical hours due to the corrosion of terminal boards, for a loss of 688 MW. *Id.* at 143-45. If FPL had simply not planned its scheduled maintenance during a time when winter peaks were reasonably foreseeable, and had not temporarily broken Turkey Point Unit 4, it would have easily served all demand on December 24, 1989 (1,240 plus 688 is greater than 1,600). But there was so much more generating capacity that FPL was not able to use through its own mismanagement. Table 1 helps summarize this information from the 1989 Event Report at pages 141-145, examining the units offline on the morning of December 25th, during the peak unserved load (although, as mentioned previously, peak load was the previous day).

Table 1: Units Offline During December 25, 1989 Peak Unserved Load

Unit	Capacity Lost	Reason	Additional Notes
Port Everglades 4	369 MW	Scheduled Maintenance	
Manatee 2	790 MW	Scheduled Maintenance	
Port Everglades CT 1	40.5 MW	Scheduled Maintenance	
Ft. Lauderdale CT 16	40.5 MW	Scheduled Maintenance	
Turkey Point 4	688 MW	Corrosion of Terminal Boards on Main Steam Isolation Valve	
Turkey Point 3	688 MW	Corrosion of Terminal Boards on Main Steam Isolation Valve	Started to come back on-line, but produced 0 MW during Peak Feeder Rotation at 8am
Cutler 5	68 MW	No fuel	
Cutler 6	131 MW	No fuel	

St. Johns River Power Park 1	0 MW	Drum level sensing line frozen, Main Transformer Overheating	Produced full power at 8am during Peak Feeder Rotation, but went off-line at several points during the 1989 event.
St. Johns River Power Park 2	0 MW	Drum level sensing line frozen	Produced full power at 8am during Peak Feeder Rotation, but went off-line at some points during the 1989 event.
Manatee 1	790 MW	Water Wall Tube Leaks	Also offline earlier in event due to poor boiler chemistry due to acid leak into condensate system.
Fort Lauderdale GT 1	346 MW	Lack of fuel/clogged fuel filters.	Partially on-line, produced 140 MW out of 486 MW nameplate
Fort Lauderdale GT 2	99 MW	Lack of fuel/clogged fuel filters.	Partially on-line, produced 346 MW out of 445 MW nameplate
Port Everglades Gas Turbines	111 MW	Lack of fuel/clogged fuel filters.	Partially on-line, produced 334 MW out of 445 MW nameplate
Putnam 2	130 MW	Fire on insulation due to a fuel line leak on one of the turbine units.	Partially on-line, produced 104 MW out of 234 MW nameplate
Martin 1	0 MW	Frozen drum level sensing line, boiler feed pump trip-invertor malfunction, boiler feed pump starting problems, feed pump control circuit ground.	Produced full power at 8am during Peak Feeder Rotation, but went off-line at several points during the 1989 event.
St. Lucie 1	0 MW	Frozen sensing line on 1A feed pump.	Produced full power at 8am during Peak Feeder Rotation, but produced limited power during part of the 1989 event.
Sanford 3	75 MW	Frozen acid and caustic lines in water plant resulting in low condensate, boiler control problems (December 26)	Partially on-line at 8am during Peak Feeder Rotation (was coming back on-line at time, but still 75 MW below nameplate)

Cape Canaveral 2	0 MW	Travelling screen sheared a pin	Produced full power at 8am during Peak Feeder Rotation, but produced limited power during part of the 1989 event.
Total Capacity Lost	4,366 MW		

4,366 MW could have been available with proper planning and maintenance. Even deducting the 1,240 MW for scheduled maintenance still means that an additional 3,166 MW would have been available, if not for the forced outages due to the reasons shown in Table 1. This 3,166 MW is significantly greater than the max feeder rotation of 2,800 MW experienced at 8am on December 25, 1989. In sum, even then, with a much higher loss of load probability and no winter reserve margin planning (and 15% summer), FPL had sufficient generating resources to meet all firm load for that record cold event.

Despite all of the above and 33 years later, FPL is now sounding the alarm that it may not have enough generating resources to deal with another event like that of 1989. Although planning for such a scenario that may never occur is not a sound basis for utility planning in the first place, FPL also fails to adequately justify its projected demand during such an event—as James Wilson pointed out in his presentation at the workshop, "What are the appliances that could suddenly add over 9,000 MW??" James Wilson Presentation at 7, available at http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2022/VoteSolar_Presentation.pdf. In other words, an electric space heater can only be plugged in and turned on once—just because there may be more demand for heating does not mean that the heater can use electricity beyond its rated capacity. Such flimsy justifications—a possible cold weather event which may never happen spiking load from appliances that may or may not exist—is not a basis for finding a plan suitable. Instead, FPL needs to stick to its own criteria: ensuring sufficient generation, and no more, to put the blackout risk at once every ten years. FPL has provided zero evidence that declining to adopt its plan will result in rolling blackouts more than once every ten years. That is itself evidence that FPL's system is already being overbuilt. In fact, further proof of FPL's overbuilding is that it has not had a rolling blackout in 33 years, since the very 1989 event that would have been prevented through run-of-the-mill utility competence and proper management of its power plants. The 1989 event cannot and does not demonstrate the need today for additional generation.

B. The 2010 Event[3]

The 2010 event, if anything, shows how overbuilt FPL's system already was in 2010, let alone how overbuilt it is now. The 2010 event was extensively discussed in *In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1 by Florida Power & Light Company*, Docket No. 150196-EI (Fla. Pub. Serv. Comm'n, 2015). As shown in that proceeding, in 2010, the loss of load probability was projected to be 0.002255 days per year, or about 1 day every 450 years, and FPL claimed that they came close to a rolling blackout on January 11, 2010. Vol. 4 at 494 (Sim). The events on January 11, 2010, do not disprove the accuracy of the loss of load probability criterion—it bears emphasizing that there was *no* loss of load that day, i.e., there was no blackout. Vol. 4 at 538 (Sim). The extraordinary events of that day, and the fact that FPL was able to keep the power on without any rolling blackouts, demonstrate how reliable the FPL system already was at the time, and it has only become more reliable since then (as discussed below, the loss of load probably now is many orders of magnitude lower than it was in 2010).

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[3] All references in this section, unless otherwise noted, are to Docket No. 150196-EI, available at http://www.psc.state.fl.us/ClerkOffice/DocketFiling?docket=20150196.

First, the January 11, 2010 event had a record 919 heating degree hours, more than FPL had ever experienced before, even more than the 1989 event. Ex. 72. This led to a record weather impact of adding 4,410 MW peak to the system. Ex. 72. This was almost 1,000 MW higher than the next highest winter weather impact event, that being the 1989 event. Ex. 72; Vol. 4 at 475 (Feldman). As a result, FPL faced its all-time highest peak load. Vol. 4 at 537 (Sim). During the 2010 event, FPL had 1,980 MW of capacity that was not available. Vol. 4 at 554-55 (Sim). As FPL noted, its largest generating unit had 1,515 MW of capacity, and it typically only planned for 687 MW of generation to be unavailable. Ex. 70 at 20. Having 1,980 MW of capacity unavailable was unusual. Vol. 4 at 556 (Sim).

Despite not having 1,980 MW of capacity available, and its highest peak ever, FPL was able to sell 526 MW in emergency sales to another utility in Florida. Vol. 4 at 538 (Sim); Ex. 70 at 25. Even after selling 526 MW of power during the highest peak event, FPL still had 1,144 MW of reserves available in the form of load management. Vol. 4 at 538 (Sim).

Hypothetically, even if FPL had used a 15% planned reserve margin in 2010, instead of the 20% FPL currently uses and had used during the 2010 event (and currently maintains a reserve margin even higher than 20%) FPL could still have sold (assuming 526 MW was the sale) 458 MW of power to another utility during the 2010 event, Ex. 69 at 2 (526 minus 68), and still have maintained all firm load for FPL customers with an unusual 1,980 MW of capacity out of service. Although FPL has argued that this might mean that there would have been a blackout for some other customers not in FPL service territory, it is not FPL's duty to plan adequate reserves for all the utilities in Florida—nor would it be appropriate for FPL's customers to wind up responsible for such unnecessary additions to their rate base. Florida Administrative Code Rule 25-6.035 sets out the requirements for reserves for sharing energy reserves. FPL, of course, complies with that requirement. The fact that even with a 15% reserve margin, FPL could lose 1,980 MW of capacity, and still sell at least 458 MW of power to another utility while maintaining all firm load for its customers during its highest peak ever is proof that FPL had a reliable system then and now, when it has reached almost impossible-to-believe high reserve margins and low loss of load probability.

II. FPL CURRENTLY HAS EXCESSIVE GENERATION

While FPL certainly had sufficient generating resources in both the 1989 event and the 2010 event, FPL has an extreme excess of generation resources now. As noted above, in the 2010 event, FPL had a loss of load probability of once every 450 years (which seems to be accurate given the extreme cold, the forced outages, the sales of electricity to other utilities, and still no issue maintaining all load). FPL currently has a loss of load probability of 0.000001 days per year, or once every *million* years (and this is possibly rounded up), and an astounding reserve margin of 25.7%. Staff's First Data Request, Request No. 33, Attachment 1 of 1, Tab 1 of 1. This is proof that FPL's system is incredibly overbuilt, and the Commission should be looking for ways to *reduce* FPL's rate base, not increase it. Under the "Business as Usual Plan," which FPL recommends against, FPL's own calculations show the loss of load probability increasing to a high of 0.003444 in 2027, or once every 290 years, still perfectly reliable and many (almost 30) times more reliable than the 0.1 industry standard. However, even that rise is strange given that just one year before (2026), the loss of load probability is 0.000002, or once every 500,000 years, yet no units are retired in those years other than 4 MW (Broward South) in 2027 and 596 MW of solar are added in both those years. *Id.*; FPL 2022 Ten Year Site Plan at 22. It is also strange because summer peak demand is not projected to increase significantly (28,800 MW to 29,103 MW), nor is winter (P50) demand (23,936 MW to 24,201 MW). FPL 2022 Ten Year Site

Plan at 77-78. Without additional information from FPL, it is hard to know what is driving such a dramatic increase in loss of load probability, as there is nothing apparent in the presented ten year site plan. Given FPL's current excessive generation, FPL has not offered any reasoned basis for the Commission to accept its recommended plan, which would have FPL maintain even *more* generation, and is likely to lead to adding even *more* generation, than the excesses it already has.

III. FPL BILLS ARE ALREADY TOO HIGH

As of 2020, the most recent year for which data is available, FPL had the 13th highest residential electricity bills of the top 50 investor-owned utilities in the nation, with average revenue per month per residential customer of over $122. 2020 Annual Electric Power Industry Report, Form EIA-861 detailed data files, spreadsheet "Sales_Ult_Cust_2020," available at https://www.eia.gov/electricity/data/eia861/zip/f8612020.zip.[4] Since that time, FPL has finagled a massive base rate increase and multiple large fuel rate increases. This year, FPL expects its residential customers to use—lower than recent years and lower than projected in future years—an average of 1,090 kWh per month (increased to 1,115 kWh per month if its planning for hypothetical extreme winter peaks is accepted, although commentors are perplexed by how finding FPL's plan suitable would lead residential customers to use more electricity). FPL 2022 TYSP at 70 (with yearly values divided by 12). As of June 2022, for Northwest Florida, this usage of 1,090 kWh would equate to a monthly bill of approximately $166, and for Peninsular Florida FPL, would equate to a monthly bill of approximately $129, not including franchise fees,

[4] Spreadsheet has been sorted so that top 50 investor-owned utilities (by Megawatt-hour sales) are included, and average monthly bill per residential customer has been calculated by dividing revenue from residential customers by number of residential customers and by 12. The result is included as Attachment 2.

gross receipts tax, or the regulatory assessment fee. (https://www.fpl.com/content/dam/fplgp/us/en/rates/pdf/res-june-2022.pdf for Peninsular Florida FPL rates and https://www.fpl.com/content/dam/fplgp/us/en/northwest/pdf/rates/june-2022-res-rates-rules-and-regulations.pdf for Northwest Florida FPL rates). That $166 as an average, monthly bill, would easily make FPL the most expensive investor-owned utility in the nation based on that 2020 comparison, the most recent available. Alabama Power Company was the most expensive IOU in 2020, by a decent amount. As best commentors can tell, applying the natural disaster recovery rate and energy cost recovery clauses published by Alabama Power, along with current rates for June, the same amount of power (1,090 kWh), would cost approximately $160 from Alabama Power. (https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/Rates/FD1.pdf for residential family dwelling rates and https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/bill-calculation-factors/Bill_Calculation_Factors_2022.pdf for clause factors). In 2020, FPL customers averaged use of 1,169 kWh. Attachment 2 (dividing residential sales by customers and by 12, and multiplying by 1,000). Alabama Power customers averaged 1,133 kWh. *Id.* If anything, this shows that Alabama Power residential customers tend to use less electricity than FPL customers, and hence, Alabama Power's average monthly bill would be even lower than that indicated for FPL Northwest Florida customers in the $166 versus $160 calculation above. Based on the available data in this limited review, FPL's Northwest Florida customers currently have the *highest* bills in the nation of the 50 largest investor-owned utilities.

FPL frequently touts its low residential "bills"—but it simply isn't true. FPL does have lower rates than many utilities, but rates are only one part of an electricity bill, the other part is usage. And here is where FPL has simply failed to help people lower their usage, employing some of the lowest energy efficiency in the nation. A 2020 report from ACEEE showed that FPL was ranked 50 out of 52 utilities when it came to energy efficiency savings as a percentage of retail sales in 2018. Grace Relf, et al., *2020 Utility Energy Efficiency Scorecard* 26 (American Council for an Energy-Efficient Economy 2020), available at https://www.aceee.org/sites/default/files/pdfs/u2004%20rev_0.pdf. FPL has not tried to increase its performance since then, striving simply to meet the low goals set for it by the Commission and nothing more.

All of these incredibly high bills have led to people being unable to afford their electricity bills. The latest data made available to commentors show that FPL's disconnections in Northwest Florida have been increasing rapidly, with almost 8,000 disconnections in February of this year for non-payment. FPL Answers to Staff Questions Regarding Northwest Florida (undocketed) (Mar. 18, 2022), Attachment 3 at 6. As was shown in the FPL rate case, members of Florida Rising and ECOSWF were already struggling to pay their electric bills before FPL increased its base rates and subsequently increased its fuel rates. Anything that further increases rates must be avoided unless absolutely necessary. FPL's recommended plan could not be less necessary.

IV. FPL'S RECOMMENDED PLAN WILL INCREASE RATES

FPL's plan for planning for hypothetical extreme winter peaks is a recipe to further increase rates. Transmission and distribution additions alone are expected to cost $467 million if the Commission finds this plan suitable. FPL Presentation "Power Delivery Winterization Update," Attachment 4 at 2. The bill impact for the changes (mostly to generation capacity) needed to comply with FPL's recommended plan for hypothetical extreme winter peaks varies depending on the assumptions being made and when FPL did the analysis. On the low end was the analysis provided in response to Staff's Third Data Request, Request No. 22, attachment 1, cumulative total net present value cost of $82,445,000,000 versus $82,249,000,000 (business as usual), for a total CPVRR of "only" a couple hundred million dollars. To meet a LOLP of 0.1 with 1989 actual temperatures, FPL projected a CPVRR of about $4 billion over the 2021 Ten Year Site Plan. FPL Presentation "Planning for Severe Winter Peak Loads: A Presentation to the FPSC Staff," Attachment 5 at 40. A different analysis, looking at battery storage to meet the requirements of a 1989-like winter, found a CPVRR different of almost $7 billion if FPL's plan is approved. FPL Response to Staff's Third Data Request, Request No. 2, Attachment No. 22, Tab 4. What is clear is that if FPL is allowed to plan its generation, transmission, and distribution around a hypothetical winter peak which may never occur, it *will* cost FPL's customers hundreds of millions, and most likely many, many billions of dollars in the form of higher bills, all at the same time FPL will be increasing rate base, devaluating solar, and enhancing its profits. Like almost all things FPL proposes for approval at the Commission, this would enhance its profits. Commentors do not believe that it is a coincidence that FPL's deviation here from all accepted industry practices will lead to higher profits, but rather is the *reason* for the departure. If FPL were truly concerned about keeping electricity flowing to residential homes, it would be looking for ways to make bills more affordable by decreasing its profits and increasing energy efficiency and demand-side management programs. Instead, the opposite is true, and here FPL reveals what really motivates it, including what motivates this proposal: ever expanding profit. And although higher profit is in the interest of FPL, it is not in the interest of Floridians and is not a basis for finding FPL's plan suitable. The Commission must find FPL's recommended plan for hypothetical extreme winter peaks unsuitable for planning purposes.

V. SUBSTANTIAL INTERESTS

If the Commission is inclined to find FPL's recommended plan suitable, and is inclined to give such a finding any weight such that FPL would take certain actions which may increase rates, then ECOSWF's and Florida Rising's substantial interests would be at stake. FPL has already indicated that if its business-as-usual plan is deemed suitable and its recommended plan is not found suitable, absent other direction, it would retire generation units as currently scheduled, and would immediately retire Manatee Units 1 & 2, no doubt saving ratepayers money and taking those units out of rate base. FPL Response to Staff's Third Data Request, Request No. 3 d.i. ECOSWF and Florida Rising are both composed of FPL ratepayers who cannot afford further rate increases. Florida Rising itself is a ratepayer of FPL. If the Commission were to find FPL's recommended plan suitable, and thus greenlight these additional expenses by FPL for inclusion in FPL's rate base and operating expenses, then the Commission must afford parties an opportunity to challenge that decision. § 120.569(1), Fla. Stat. The Commission must give proper notice and proceed accordingly how it always does when substantial interests are at stake, issuing proposed agency action and allowing parties an opportunity to petition to challenge such action, or proceeding through a docketed process with an evidentiary hearing and right to intervene in order to reach final agency action. Alternatively, the Commission must signal that its decision to find the recommended plan "suitable" has no weight and that FPL should not rely on such a decision to expect cost-recovery in future proceedings, as in those proceedings such spending would be fully open to challenge, as would any other spending by the utility that had not received Commission prior-approval for which the utility seeks recovery. Either way, there must be an entry point to challenge such spending, and the Commission must signal which entry point it intends to make available to parties such as ECOSWF and Florida Rising.

CONCLUSION

The Commission should not allow FPL to derail decades of established utility planning and practice by allowing FPL to start planning its system for hypothetical winter peaks that may never occur, and for which FPL offers no probability analysis for occurring. FPL's ratepayers and the people of Florida should not be on the hook for such unjustified spending. FPL already has one of the most reliable networks, and by far, far more generation than required, than any other utility in the nation. Incremental reliability improvements are worthless if people cannot even afford to be connected to the grid.

Respectfully submitted this 15th day of June, 2022.

/s/ Bradley Marshall
Bradley Marshall
Florida Bar No. 0098008
bmarshall@earthjustice.org
Jordan Luebkemann
Florida Bar No. 1015603
jluebkemann@earthjustice.org
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, Florida 32301
(850) 681-0031
(850) 681-0020 (facsimile)
Counsel for Florida Rising and Environmental Confederation of Southwest Florida

Attachment 1

PENINSULAR FLORIDA

COLD WEATHER CAPACITY

SHORTFALL EMERGENCY

DECEMBER 23-25, 1989

DIVISION OF ELECTRIC AND GAS

FLORIDA PUBLIC SERVICE COMMISSION

FEBRUARY 2, 1990

Note: The opinions expressed in this report are those of the Division of Electric and Gas and may or may not reflect the opinions of the Florida Public Service Commissioners.

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INTRODUCTION

During the Christmas holidays (1989), Florida experienced extremely cold weather throughout the state. As a consequence of the arctic cold front which moved into and became stationery over the state, widespread shortages of electric generation were experienced by Florida's electric utilities. For a three day period beginning Saturday evening, December 23, and continuing through midday Monday, December 25, customer demand outstripped available generating capacity resulting in rotating blackouts to homes throughout peninsular Florida.

On January 3, 1990, the Commission staff held a public workshop to discuss the reasons for the statewide power shortages with executives from each of Florida's electric utilities. At the workshop, the staff issued an extensive data request to the utilities seeking to reconstruct more completely the events of the Christmas weekend. This data was received on January 17, 1990.

The report which follows is an analysis of the utility data from which certain observations have been drawn. Our intent is to identify potential areas of improved performance which may be practiced during future cold weather emergencies. In preparing this report, it is not staff's intent to cast blame or directly address the prudence of actions taken, or not taken, by utilities prior to and during the Christmas emergency. Staff is of the opinion that any such issues of prudence should be addressed in other docketed proceedings before the Commission.

OVERVIEW

The cold weather which gripped Florida during the Christmas holidays did not affect Florida alone. For at least a week prior to December 23, weather services tracked the arctic cold front as it moved from the Mid-West to the South-East. As the storm proceeded along its southeasterly route, record low temperatures were recorded in 30 states. The severity and duration of the bitter cold caused widespread disruptions in the supply of all types of heating fuel nationwide. The supply of fuel oil, natural gas, and bottled gas was particularly affected in northern states. Frozen well fields in Louisiana and Texas and the diversion of some natural gas supplies to northern states resulted in curtailments to non-firm industrial gas users throughout the Southeast. Natural gas supplies to Florida's utilities were curtailed beginning Friday, December 22, and were not restored until Tuesday, December 26. Firm gas deliveries to residential customers in peninsular Florida remained uninterrupted throughout the cold weather. Some disruptions to firm gas deliveries were experienced in panhandle Florida, however. See Attachment 1. Electric generating capacity reserve margins were stretched to their limits. In Florida and Texas customer demand exceeded available generation supplies resulting in widespread rotating blackouts of firm customer load.

Much was known about the magnitude and direction of the storm. What was not as clear was how far south it would travel and how long it would linger before dissipating. Weather service reports were monitored daily by Florida's electric utilities. Then, on the morning of Thursday, December 21, confirmation that the cold would settle into Florida was received. At 6:15 a.m. on Thursday, the National Weather Service issued a Cold Weather Alert affecting all of peninsular Florida and the Keys.

The Cold Weather Alert warned of "very cold arctic air covering the Peninsula and Keys Saturday (December 23) and Sunday (December 24) with only a slight moderation Christmas Monday (December 25)". The bulletin went on to state: "A hard freeze likely north all three mornings...Freezing temperatures into central Saturday...Coldest statewide Sunday morning with hard freeze extending to central and near freezing temperatures to southeast coast." See Attachment 2.

With confirmation of the storms' approach, Florida's electric utilities finalized their cold weather preparations. Fuel supplies were reviewed and spot purchases of fuel oil were made to supplement inventories at generating plants normally fueled by non-firm gas. Maintenance schedules and generation availability status were reviewed. Attempts were made to expedite repairs at generating plants (Manatee 2 (790 MW) and Martin 1 (790 MW)) and to reactivate cold stand-by units (Larsen 7 (51.2 MW) and Larsen 6 (24.6 MW)) where possible. The early stages of each utility's capacity shortfall plans were initiated. Contacts with the press were initiated on Thursday and Friday, December 21 and 22, and media spots appealing for conservation were requested. Interruptible and curtailable customers were notified and curtailments to these non-firm service customers began on Saturday, December 23.

On Friday evening, December 22, snow and sleet began to fall and accumulate in north Florida. By Saturday, the "White Christmas" being experienced by north Floridians had extended into central Florida. Tampa, Port Richey, and

Sarasota reported sitings of scattered snowfall. Snow flurries were also experienced in Brevard County on the east coast. Bitter cold temperatures had moved into south Florida. Below-freezing temperatures were reported beginning 1 a.m. Sunday, December 24, in all of the state's 67 counties except for Dade, Collier and Monroe. As is illustrated by the following temperature readings experienced throughout the state, the cold weather came to Florida and stayed. See Illustration 1.

STATE OF FLORIDA
DAILY MORNING TEMPERATURES

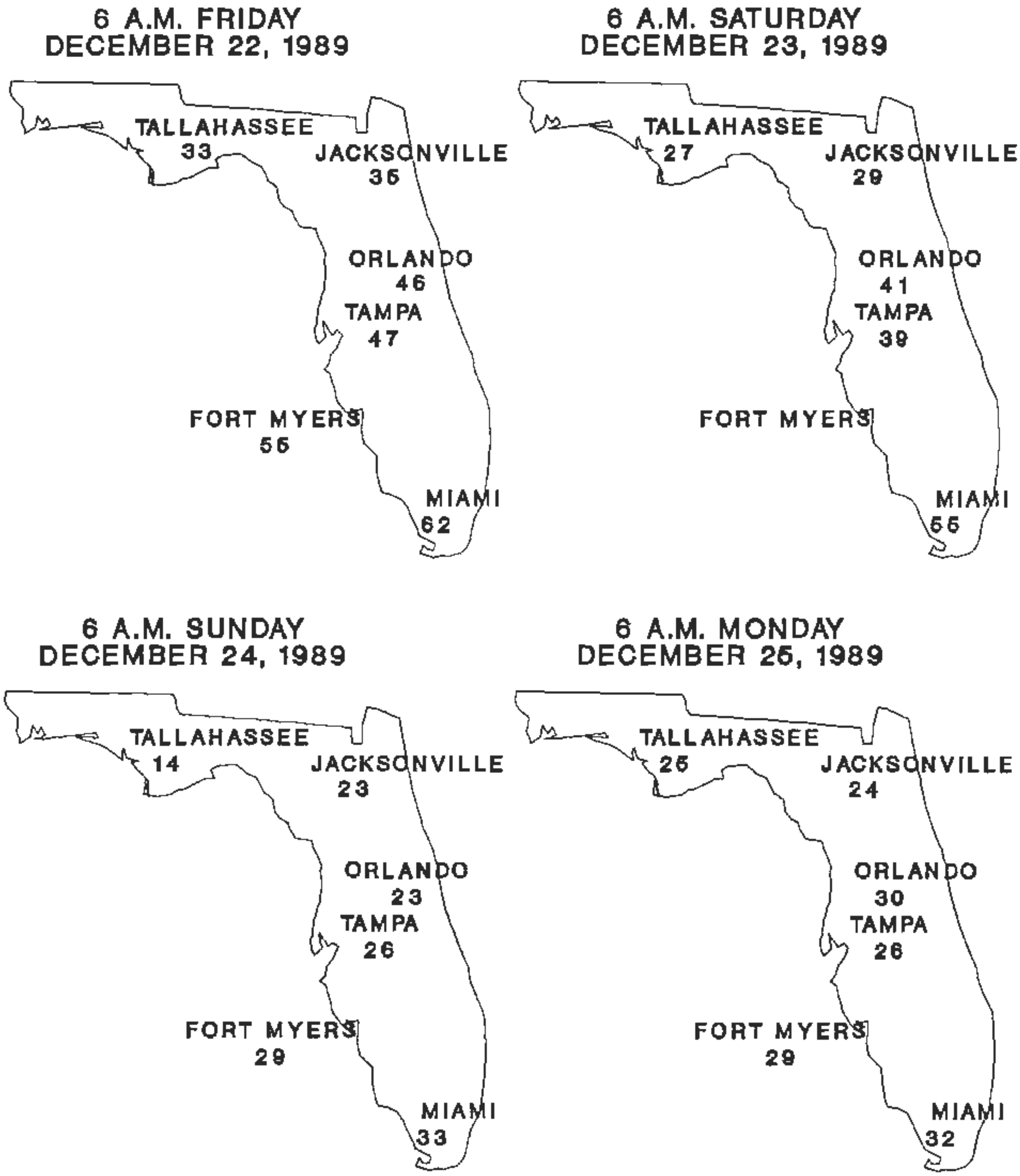


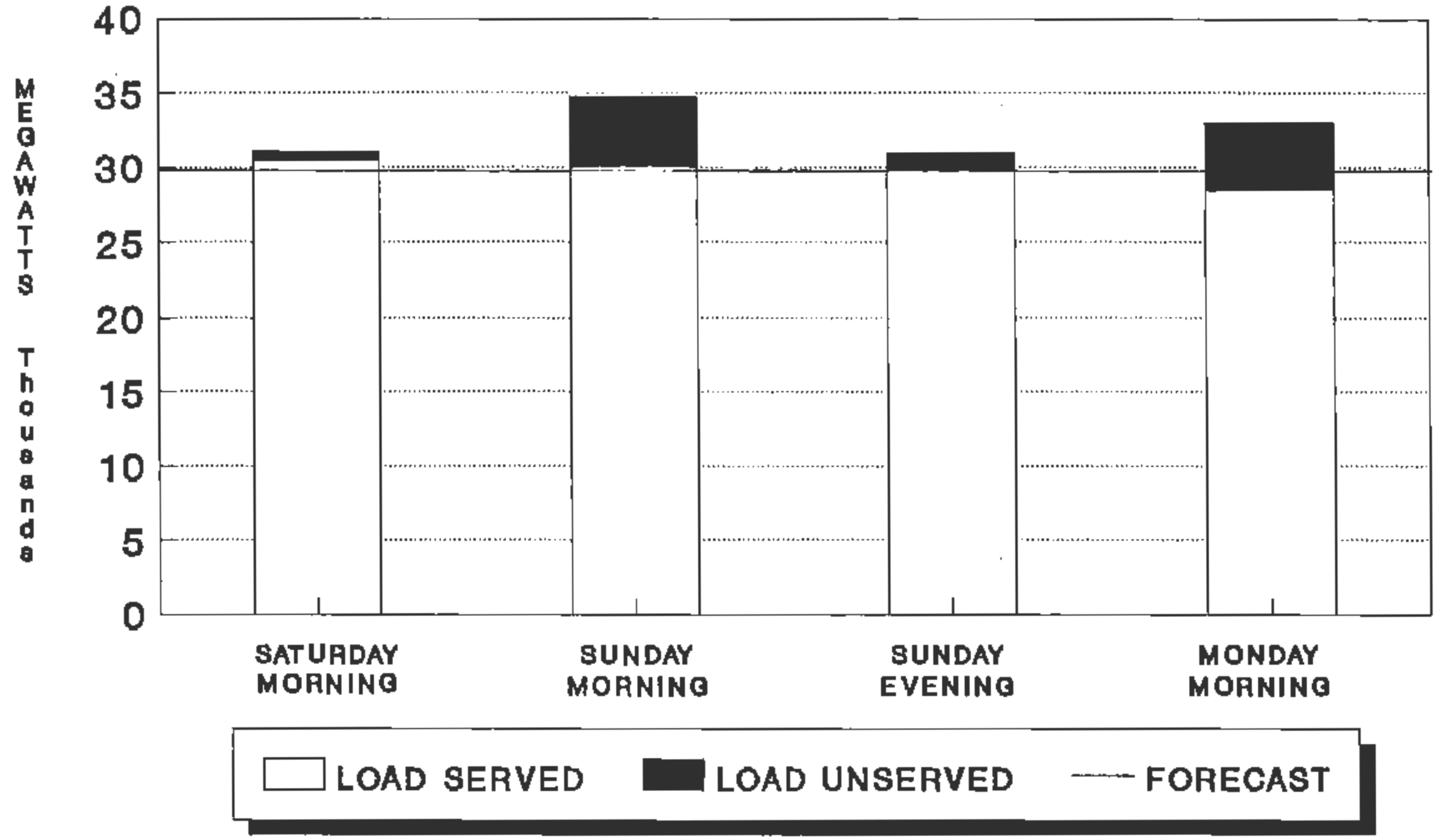
Illustration 1

With these record low temperatures, Florida's electric utilities experienced record high demands for electricity. According to the forecasts contained in the 1989 Ten Year Site Plans, Florida's utilities projected a statewide non-coincident firm peak demand of 29,752 MW for the winter of 1989/90. On Saturday evening, December 23, however, as the cold weather settled into the state, a peak demand of 31,074 MW was experienced. Of this, 569 MW of firm load was not served. By Sunday morning, December 24, statewide demand had grown to 34,776 MW, 4,744 MW of which was not served. As daytime temperatures warmed slightly on Sunday, Sunday evenings' peak decreased to 30,999 MW; 1,283 MW was not served. By Monday morning, Christmas day, peak demand had increased again to 32,986 MW; 4,472 MW was not served. Because peak demand exceeded total generating and purchased power capacity, rotating blackouts were initiated during each of these periods. Prior to initiating rotating blackouts, non-firm customer loads, such as interruptible, curtailable, and load management, were curtailed (up to 1,495 MW statewide). Public appeals were made for voluntary conservation. Finally, firm load was shed through system wide brownouts (voltage reductions) and rotating blackouts.

During the periods of rotating blackouts, service was rotated among customers for periods of up to 5 to 8 hours. Although many of these planned interruptions were limited to 15 to 30 minutes per customer per hour, many customers were affected by more than one rotation. In some parts of the state (most notably in the TECO service area), customers experienced outage times of up to 2 hours. At various times throughout the weekend, rotating blackouts affected customers from Jacksonville to Key West. It is estimated that up to 1 million Florida residences were affected at some time during the Christmas weekend. See Illustration 2.

Illustration 2

STATE OF FLORIDA
PEAK ELECTRICAL DEMAND



SATURDAY-MONDAY DECEMBER 23-25, 1989

In addition to the planned rotating blackouts, many customers experienced unplanned service outages. These outages occurred as individual distribution lines (serving 1,000 customers or more) and individual distribution transformers (serving one to several customers) were overloaded and tripped out of service. According to the utility data, over 4,000 unplanned outages to distribution lines and transformers occurred statewide over the Christmas holidays. Restoration times for these outages ranged from less than one minute to over 27 hours. The average outage time appears to have been approximately 3 hours. In the TECO service territory alone, approximately 31,520 customers were affected by such unplanned outages. (TECO was one of the few utilities which reported the number of customers affected by unplanned outages, other utility data is expressed in terms of total KVA load served)

While some of these outages were due to non-weather related causes (e.g., trees, animals, automobile accidents, equipment age and malfunction), the vast majority appear to have been caused by overloads and other weather related factors. Many of these outages occurred to circuits returning to service after a planned rotation by the utility. In such cases the surge of electrical load which occurred after an extended interruption of home heating equipment overwhelmed the distribution equipment (cold load start-up). As a consequence, protective fuses tripped and, in some extreme cases, distribution lines melted in half and transformers were destroyed. Many customers recovering from the inconvenience of a short rotating outage were then subjected to the misery of a long extended forced outage.

PENINSULAR FLORIDA UTILITIES

On Thursday, December 21, Florida Power Corporation (FPC) employees met with a writer from the Tampa Tribune to discuss the need for voluntary customer conservation during the cold weather. On Friday, December 22, in anticipation of a tight energy supply and the likely use of load management over the weekend, FPC contacted the St. Petersburg Times, Tampa Tribune, Orlando Sentinel, and the Associated Press and United Press International. Nevertheless, written media coverage does not appear to have begun until Saturday morning, December 23.

On Saturday, December 23, three Tampa Bay television stations were contacted by FPC and asked to broadcast messages asking for conservation and warning of the potential for rolling blackouts. However, FPC did not request television stations to "crawl" blackout information across the bottom of television screens until after rolling blackouts had begun at about 6:0D p.m.

As temperatures dropped Saturday evening, electrical loads increased rapidly. Starting around 6:00 p.m. and continuing until 10:11 p.m., FPC was forced to initiate rolling blackouts (maximum 400 MW firm load shed at 6:00 p.m.). Prior to the rolling blackouts, FPC had curtailed all its interruptible and curtailable load (approximately 300 MW), initiated its residential load management program (approximately 500 MW), and initiated a system wide voltage reduction (approximately 100 MW). Also, FPC was receiving firm purchased power from the Southern Company (up to 590 MW), as-available energy from Qualifying Facilities (up to 157 MW), and emergency assistance from several other peninsular Florida utilities during this period. It simply was not enough to avoid the rolling blackouts.

From Saturday evening until about 1:00 p.m. Monday, December 25, media contacts were virtually ongoing. In addition to the "crawling" blackout alerts on television, FPC requested the media to run stories carrying specific energy conservation recommendations. These included recommendations to lower thermostats, avoid unnecessary clothes washing and drying, turn off non-essential lights, and plan to delay Christmas cooking until noon or later. Nevertheless, additional rolling blackouts were initiated Sunday morning, December 24, from 5:15 a.m. to 1:00 p.m. (maximum 1200 MW firm load shed at 8:00 a.m.) and Monday morning, December 25, from 7:20 a.m. to 9:46 a.m. (maximum 815 MW firm load shed at 8:00 a.m.). See Appendix A.

Tampa Electric Company (TECO) began notifying the news media on Friday, December 22, of the possibility of blackouts expected to occur on Sunday morning, December 24. The company's largest generating unit, Big Bend 4 (439 MW), was out of service because of damage caused by a fire in its scrubber system caused by a welding accident. Gannon 6 (358 MW), the company's second largest generating unit, was also out of service undergoing repairs to its generator. Finally, the peaking unit at the Big Bend Plant, Big Bend CT (80 MW), was out of service due to a damaged rotor. This represented approximately 30 percent of TECO's total system generation out of service for repairs (877 MW out of 2906 MW total).

On Saturday afternoon, TECO's Corporate Communications Department prepared and released to the media (newspapers, radio, and TV) a message warning of the "strong possibility" of rotating blackouts during the Sunday morning peak. Customers were requested to curtail all unnecessary use of electricity. Also on Saturday afternoon, TECO contacted local television stations and requested "videofont crawls" to interrupt programming and warn of impending blackouts and urge for conservation. Early Saturday evening, local television and radio stations were contacted a second time. Media contacts intensified and became around-the clock for the next three days.

On Saturday evening at 6:00 p.m., TECO curtailed service to its interruptible customers (up to 165 MW). Beginning on Sunday morning, TECO began morning and evening interruptions of its residential load management customers (up to 235 MW). These interruptions to non-firm customers continued through Monday, December 25.

At 6:00 a.m. Sunday morning, December 24, TECO initiated rolling blackouts of firm customer load. These continued until 2:00 p.m. (maximum 1094 MW firm load shed at 11:00 a.m.). Rolling blackouts were again initiated at 6:00 p.m. and continued until 2:00 a.m. Monday, December 25 (maximum 883 MW firm load shed at 9:00 p.m.). Rolling blackouts were initiated for a third time at 8:00 a.m. Monday, December 25, and continued until 11:00 a.m. (maximum 925 MW firm load shed at 10:00 a.m.). See Appendix C.

Florida Power & Light (FPL) finalized its preparations for public appeals for conservation on Friday, December 22. On Friday, FPL's Corporate Communications provided informational materials to each FPL division, including a Customer Information System (CIS) message, a media statement and tips for customer energy conservation. A public appeal message was provided with the request that it be held in case it was needed. Throughout the day Friday, FPL Corporate Communications and division managers responded to periodic weather-related questions using the media statement.

At about 4:00 p.m. Saturday, December 23, FPL's Power Supply advised Corporate Communications and the divisions of the need for public appeal. Media contacts were initiated prior to the evening broadcasts and before the print media's deadlines for Sunday morning papers.

At 6:00 a.m. Sunday, December 23, FPL Corporate Communications was notified by FPL Power Supply that rotating blackouts would be initiated. Corporate Communications was activated at 7:00 a.m. Between 7 and 9 a.m., Corporate Communications provided live and taped radio interviews to local (Miami) and statewide (AP-radio) radio stations. A news statement was sent to all divisions for their use locally. By 2:00 p.m. a complete media information package was provided to each division, along with procedures for their use through Tuesday, December 26. The package included a news release, radio "actuality" and television "crawl" messages, an updated public appeal message, and a special commercial and industrial customer appeal message. FPL estimates it provided information to 300 media representatives from December 22-26. This includes multiple contacts with news media in the service territory over the four-day period.

FPL initiated rotating blackouts from 6:08 a.m. to 11:30 a.m. Sunday, December 24. At their peak, a maximum of 1,600 MW of firm load was shed. Rotating blackouts were repeated Sunday night from 6:09 p.m. to 6:15 p.m. (maximum 200 MW firm load shed) and from 8:18 p.m. to 10:17 p.m. (maximum 500 MW firm load shed). On Monday morning, December 25, as the cold weather settled into south Florida, FPL was forced to interrupt a maximum of 2,800 MW of firm load from 4:57 a.m. to 11:14 a.m.

Prior to initiating rotating blackouts to firm customer load, FPL contacted its curtailable customers and initiated curtailments to its Commercial/Industrial and Residential Load Management customers. FPL estimates a reduction in load of 125 MW to 185 MW starting 6:00 a.m., Sunday, December 25 as a result of curtailments to these non-firm customers. See Appendix B.

Seminole Electric Cooperative (Seminole) is a rural electric cooperative that supplies electric generation, purchased power, and transmission to its 11 member distribution rural electric cooperatives in peninsular Florida. During a capacity shortfall emergency, Seminole is responsible for communicating the nature and severity of the pending emergency to its members and advising them of the amount of load each is required to shed. Since the individual members provide direct service to the ultimate consumers, the member coops are responsible for determining the actual distribution feeders which will be interrupted, the frequency of rotation, and the utilization of load management as a part of the load control strategy. The individual members are also responsible for making contacts with the local media and local authorities.

During capacity shortfall emergencies, Seminole communicates with its members through pre-formatted and free-formatted messages sent from the Seminole Energy Management Control Center to each of the 11 member cooperatives. Three different alert levels are communicated to the member systems relating to the severity of the risk of load shed. These are:

Code Green	Normal operation. No load shed required.
Code Blue	Generation or transmission capacity shortage could occur within 48 hours and manual load shedding may be necessary. Review feeder rotation procedures and insure that personnel will be available if needed.
Code Yellow	Generation or transmission capacity shortage is imminent. Have personnel stand by at SCADA console or in substations to implement manual load shedding when requested by Seminole System Coordinator.
Code Red	Generation or transmission capacity shortage is in

effect. Reduce load through any of the available, accepted methods. Maintain continuous load reduction of at least this amount until further notice from Seminole System Operator. (Note: The amount of load to be reduced is specified by Seminole. For example, Red 5: reduce load 5%, Red 10: reduce load 10%, etc.)

Seminole activated its emergency warning system on Thursday, December 21, 1989. At 8:17 a.m. on Thursday, Seminole requested that each of its members review the Seminole/Member Emergency Coordination Practice #3001.010, pertaining to emergency load shedding. This message was repeated on Friday morning, December 22. On Friday afternoon, at 4:09 p.m., Seminole sent a Code Blue message to its members warning of the possible need for manual load shedding within 48 hours. A Code Yellow alert, putting the member systems on the ready, was issued at 5:59 p.m. on Saturday, December 23. Four minutes later, at 6:03 p.m., a Code Red 2 message was sent initiating a 2% (32MW) systemwide load shed. Individual members complied and approximately 32 MW was shed from about 6 p.m. to 10:15 p.m. On Sunday morning, December 24, a Code Red load shed was again initiated from about 4:00 a.m. to 1:00 p.m. resulting in rotating blackouts on member systems affecting up to 665 MW of firm load. On Sunday evening, approximately 39 MW of firm load was shed from about 9:00 p.m. to 10:00 p.m. Rotating blackouts were also initiated on Monday, December 25, affecting up to 117 MW from about 5:00 a.m. to 11:00 a.m.

Seminole serves up to 1214 MW of its members' load requirements from generation that Seminole owns. The balance of the member systems' peak load requirements are purchased under partial requirements and reserve contracts with other utilities, principally Florida Power Corporation (FPC) and Florida Power & Light (FPL). As such, there are three different load shed scenarios potentially faced by Seminole during a capacity shortfall emergency. They are (1) load shed as required for the loss of Seminole generation, (2) load shed as required of Seminole as a firm purchaser of power from FPC while they are shedding load, and (3) load shed as required of Seminole as a firm purchaser of power from FPL while they are shedding load. Each of the periods during which Seminole curtailed firm load involved some combination of these three scenarios. The rotating blackouts on the Seminole system which occurred on Saturday morning were in support of FPC's load shed requirements. Those which occurred on Sunday morning were due to the forced outage of Seminole Unit 2 (640 MW) and also in support of FPC's load shed requirements. The rotating blackouts which occurred on Sunday evening were in support of FPL's load shed requirements. On Monday morning, rotating blackouts were initiated by Seminole in support of both FPC and FPL's load shed requirements.

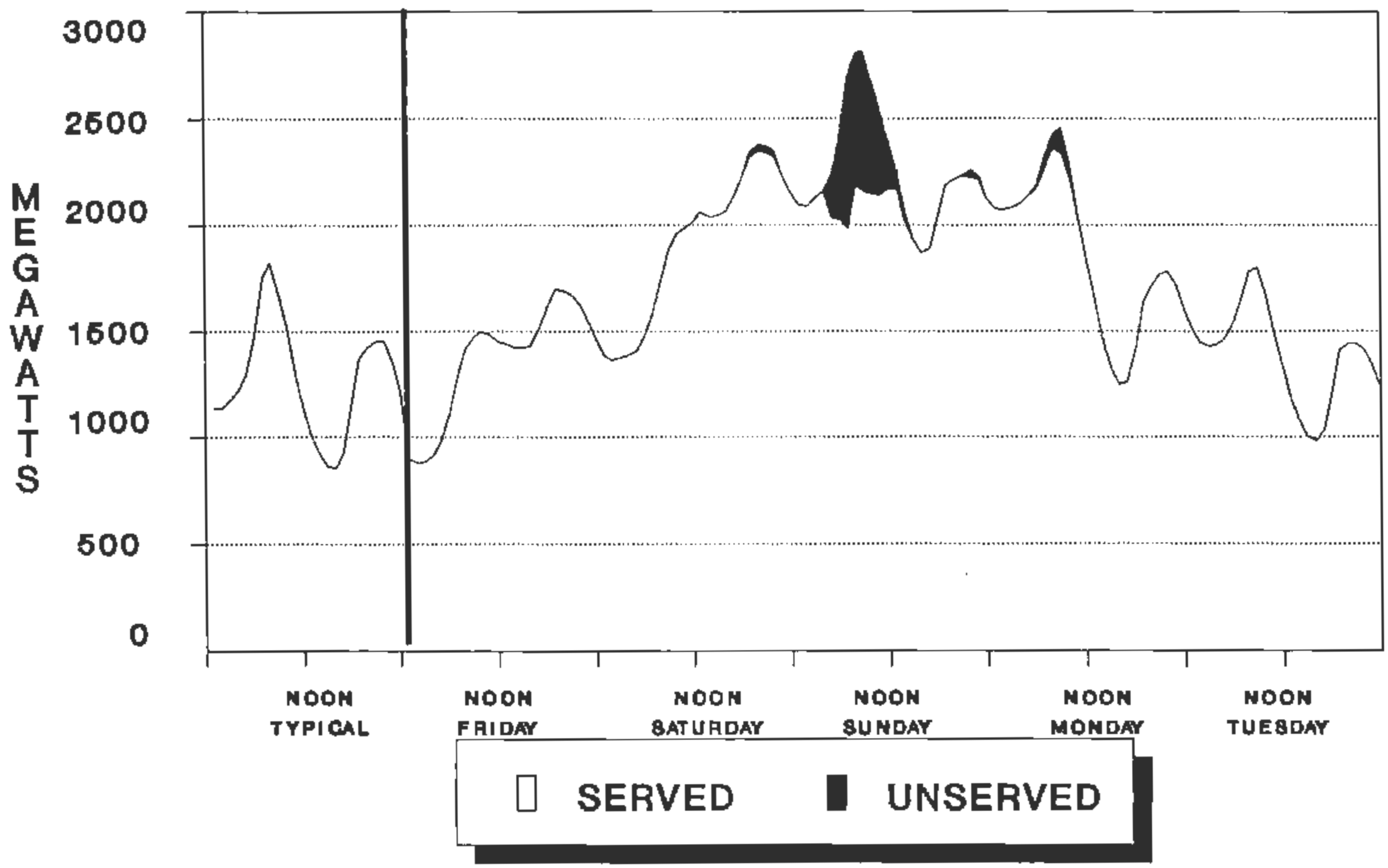
Although Seminole's members do not serve any interruptible or curtailable customers, they do have a total of from 50 to 70 MW of capacity in residential load management. This load management was used by Seminole on the morning of Saturday, December 23 for peak reduction. During the rotating outage periods, however, when Seminole was required to shed more load than load management could provide, the decision as to the use of load management as a part of the overall reduction strategy was left to the individual member systems. See Appendix E.

As a point of interest, the territories served by Seminoles' 11 member systems cover much of peninsular Florida, extending from the Appalachicola River to Nassau County, west to east, and from the Georgia/Florida border to Hendry county, north to south. Also, Seminole's member systems serve predominantly residential customers. Because of this geography and customer makeup, Seminole's electrical load profile for December 23-25, 1989 is highly representative of the load conditions which were experienced throughout peninsular Florida over the Christmas holidays. See Illustration 3.

Illustration 3

SEMINOLE ELECTRIC COOPERATIVE

ACTUAL SYSTEM LOAD



DECEMBER 22 - DECEMBER 26, 1989

DECEMBER 14, 1989 - TYPICAL WINTER DAY

Illustration 3 compares the hourly average peak demand placed on Seminole's system during the Christmas holidays to the hourly peak demands experienced on a more typical winter day, December 14, 1989. As is shown in the left window of Illustration 3, on a typical winter day, night time electrical loads gradually decline as people sleep and home heating thermostats are set to lower temperatures. In the morning, as people awake, kick off the warm bed-covers and feel the early morning chill, they react by turning up the heat in their homes. Since most home heating in Florida is done with electricity (74.2%), this results in a very high morning peak demand on the electric system. Normally, this morning peak demand is of relatively short duration. As the sun warms the outdoor air, houses warm up, and home heating systems begin to cycle and do not have to work as hard. By mid-afternoon, electrical demands have declined significantly. In the late afternoon, this cycle reverses itself. As the sun sets and outdoor air temperatures fall, heating systems begin to kick in, and the demand for electricity rapidly increases. This results in an early evening electrical peak which, again, is normally dramatic but of short duration.

The righthand portion of Illustration 3 plots the hourly average peak electrical demand experienced by Seminole from Friday through Tuesday, December 22-26, 1989. As temperatures fell on Saturday morning, they continued to decline Saturday afternoon and on into Saturday evening. Home heating equipment continued operating throughout the day driving electrical demand with it. After a brief respite Saturday night as people slept, heating demand and, with it, electrical demand soared on Sunday morning. As the cold temperatures stabilized on Sunday, electrical load gradually began to decline, in its cyclic pattern, until warming temperatures occurred by midday Monday. Because of the sustained low temperatures which occurred over the Christmas holidays, instead of serving "spiked" peaks of relatively short duration, Florida's utilities were faced with ever growing periods of peak demand.

There are a total of 32 municipal electric utilities which operate in peninsular Florida. These utilities and the rotating blackouts initiated by them during the Christmas weekend are listed below. See Appendices G through S.

Generating Municipal Systems

	Initiated Rotating Blackouts
Fort Pierce Utilities Authority	No
Gainesville Regional Utilities	No
City of Homestead	No
Jacksonville Electric Authority	Yes
City of Key West	Yes
City of Kissimmee	Yes
City of Lakeland	Yes
Lake Worth Utilities Commission	No
Utilities Commission of New Smyrna Beach	Yes
Orlando Utilities Commission	Yes
Reedy Creek Utilities	No
City of St. Cloud	Yes
Sebring Utilities Commission	Yes
City of Starke	No
City of Tallahassee	No
City of Vero Beach	No

Nongenerating Municipal Systems

	Power Supplier	Initiated Rotating Blackouts
Alachua	Gainesville Regional Utilities	No
Bartow	FPC	No
Bushnell	FMPA All Requirements Project	No
Clewiston	FPL	No
Fort Meade	FPL	No
Green Cove Springs	FMPA All Requirements Project	No
Havana	FPC	No
Jacksonville Beach	FMPA All Requirements Project	No
Leesburg	FMPA All Requirements Project	No
Moore Haven	Glades Electric Coop	No
Mount Dora	FMPA/FPC	No
Newberry	FMPA/FPC	No
Ocala	FMPA All Requirements Project	No
Wauchula	FPC	No
Williston	FPC	No

PANHANDLE FLORIDA UTILITIES

Gulf Power Company did not initiate any rotating blackouts during the Christmas weekend. The Southern system, of which Gulf Power is a member, was in a selling mode throughout the period of December 23-25, 1989. During peak load periods on all three days, Gulf Power purchased power from the pool. Also throughout this period the Southern system was selling at least 3400 MW to peninsular Florida utilities, which is the maximum capacity that can reliably be transmitted into peninsular Florida. Had additional transmission capacity been available in Florida, Southern estimates that they could have delivered a minimum of an additional 800 MW to peninsular Florida before reaching transmission constraints within the Southern system. Additional generating capacity was available on the Southern system throughout the Christmas weekend.

Since Gulf Power and the Southern system had sufficient generating capacity to serve load during the Christmas weekend, no emergency conservation announcements to the public were made. Although Gulf did have scattered unplanned distribution outages, fewer than 5 percent of the company's customers were affected. On December 23, at 8:45 p.m., one substation transformer was interrupted for 11 minutes and was restored when a faulted 155 KV transmission line section was isolated.

Alabama Electric Cooperative (AEC) is a rural electric cooperative which supplies generation, purchased power, and transmission to 4 member distribution rural electric cooperative in Panhandle Florida. Neither AEC nor its member systems initiated any rotating blackouts during the Christmas holidays.

OBSERVATIONS AND RECOMMENDATIONS

EMERGENCY PREPAREDNESS

Recommendation: The Commission should issue a PAA order requiring Florida's electric utilities to prepare a specific cold weather emergency plan for the State of Florida. The development of these plans should be coordinated by the Florida Electric Power Coordinating Group (FCG) in concert with the Public Service Commission, the Governor's Energy Office, and the Department of Consumer Affairs/Division of Emergency Management. The final Statewide plan should be codified through Commission rulemaking and included in the State of Florida Peace Time Emergency Plan.

Discussion: Each electric utility in Florida has an emergency plan or emergency operating procedures in place which address actions to be taken in a capacity shortfall emergency. However, these plans and procedures appear to place more emphasis on managing generation resources and curtailing load during an emergency rather than managing customer demand through public awareness prior to an emergency. It is clear that utility efforts to forewarn the public of pending blackouts during the Christmas holidays were largely ineffective.

Although existing capacity shortfall plans call for public announcements and appeals for conservation as soon as an emergency appears imminent, they lack sufficient detail about how, when, and how urgently these announcements should be made. Little distinction is made between a cold weather emergency and other types of capacity shortfall emergencies, such as sustained hot weather, hurricane, or fuel shortages. No distinction is made for emergencies which occur during holidays as opposed to normal working days. Procedures for contacting other emergency officials during the course of a capacity shortfall emergency are vague and inconsistent from utility to utility. While utility functions such as generation and transmission system operating procedures appear to be coordinated statewide, there does not appear to be the same level of coordination between utilities and state and local emergency personnel during a cold weather emergency.

We believe that a specific cold weather emergency plan is needed for the State of Florida. Such a plan should begin with individual utility plans. Significant enhancements to existing utility capacity shortfall plans and procedures are needed to specifically address actions to be taken in a cold weather emergency. Particular emphasis is needed in the areas of public communications prior to and during a cold weather emergency and communication, coordination, and cooperation with local and state emergency officials. Finally, a Statewide Cold Weather Emergency Plan is needed to ensure consistency among the individual utility plans and to establish paths of communication and coordination between utilities and state and local officials during a cold weather emergency.

Recommendation: In developing the Statewide Cold Weather Emergency Plan, utilities should establish more effective means of communicating with the public prior to and during a cold weather emergency.

Discussion: In fairness to the utilities, existing emergency procedures were followed during the recent holiday crisis. Despite attempts to communicate with the public prior to initiating widespread rotating blackouts, however, the public simply did not get the message. In many instances, they either were not alerted in sufficient time or not alerted with sufficient urgency to take meaningful action to mitigate the impact of the rolling blackouts which occurred during the Christmas holidays.

Clearly, the first element of a Statewide Cold Weather Emergency Plan must focus on the early identification of any cold weather threat to electric service in Florida. Most, if not all, utilities in Florida subscribe to the broadcast services of the National Weather Service and therefore know when threatening weather is approaching Florida. Generally, it appears that cold weather alerts from the National Weather Service can be expected at least 48 hours in advance of a storm's approach. (See Attachment 2) This leaves precious little time for utilities to prepare "custom-made" announcements and press packages. Consideration should be given to the development of "precanned" radio, television, and print media spots which can be left on file with local and statewide media networks. These may be updated and augmented as necessary as the threat of a cold weather emergency becomes more certain. To ensure the timely and uncensored release of these public announcements, media spots should be prepaid and published or broadcast on demand. Because of the likelihood of short lead times, emphasis should be placed on "live" media formats such as television and radio. Scrolling text at the bottom of television screens seems particularly effective.

The Statewide and individual utility plans should contain consistent, stepwise progressive levels of alert which escalate in their gravity as weather conditions worsen. For example, a Phase 1 Alert might communicate the approach of a severe cold weather front and trigger the release of initial conservation messages through the press. As the cold weather materializes, the urgency of conservation messages would be stepped up and the possibility of rotating blackouts emphasized. Local and state emergency facilities and personnel would be placed in a state of readiness. Instructions on what to do in the event of a blackout would be released, including emergency phone numbers for the utility and for local authorities. At Phase 3, when rotating blackouts are imminent, radio and television stations should be alive with blackout announcements and "scrolling" messages. By now all emergency services should have been fully activated and phone lines open to handle the inquiries from the public. By Phase 4, the actual curtailment and rotation of electric service, conservation pleas should continue to be broadcast and emergency services and contacts clearly made known.

The point of this example is not to predetermine or dictate the exact content of a Statewide Cold Weather Emergency Plan. Rather, it is intended to emphasize the need for preplanned, coordinated communication between utilities and their customers and utilities and local and state emergency personnel during a cold weather emergency. Only through this high level of communication and cooperation can the chaos, confusion and, ultimately, anger and dissatisfaction which occurred during the recent "Cold and Dark" Christmas be avoided.

Recommendation: In developing the Statewide Cold Weather Emergency Plan, utilities should establish uniform guidelines and priorities for interrupting firm customer load.

Discussion: The firm load rotation schemes currently employed by most of Florida's electric utilities differentiate only between critical loads and non-critical loads. Staff observes that a third distinction for "priority" loads may be appropriate. Critical loads are generally defined as facilities which serve the public health and welfare. Examples are hospitals, emergency medical centers, police and fire protection, and critical water and wastewater facilities. Priority loads are generally defined as individuals with special health related needs. These may range from a life support system in the home to the special heating requirements of the elderly or infirmed. Non-critical loads are generally defined as the remaining population of firm service customers.

The distinction between and treatment of "critical" loads and "priority" loads during a period of firm load shedding is not consistent from utility to utility. This should be addressed in the development of a Statewide Cold Weather Emergency Plan. Generally, the staff believes that critical loads which serve to protect the public health and welfare should not be included in utility rotation schemes. We also believe that individuals with special medical requirements such as life support systems should be given special consideration in utility rotation schemes. However, there is a need to balance the special requirements of individuals with the need to protect the long term integrity of the bulk power supply in Florida and to minimize electric service disruptions to the public as a whole. It seems prudent that electrical service to customers depending on life support systems in the home should not be intentionally interrupted unless absolutely necessary. If such loads are to be subjected to rotating blackouts, utilities should be required to establish procedures to identify each customer with special in-house medical equipment and ensure that they are warned of an impending emergency which may affect their electric service. It should also be determined whether these customers have access to a back-up power supply in the home or to appropriate public health facilities. Special consideration should also be given in each utility's load shedding scheme to minimize the frequency and duration of interruptions to "priority" customers.

Recommendation: Utilities should review the adequacy of the current telephone systems and procedures for responding to trouble calls from consumers during emergencies.

Discussion: As rotating blackouts were initiated statewide, utility switchboards were swamped by calls from consumers. While the utilities called in additional personnel to man the phones, there simply were not enough phone lines to handle the onslaught of calls. This also appears to have been exasperated by poor communication with other emergency personnel such as fire and police who had nothing to tell people who called them other than to refer them to the electric utility.

Utilities should evaluate the adequacy of their existing telephone systems and procedures. Technology in the telecommunications industry has improved significantly in the last few years, and equipment appears to be available in today's marketplace which may be better suited to handle the volume of calls utilities experienced during the Christmas emergency. Utilities should also review procedures which require live operators to answer trouble calls. While under normal circumstances human interaction may be preferred from a customer relations viewpoint, during an emergency it is more important that the phone be answered, even if by a recording, and that the caller's information be imparted, even if it is to a recording device. Utilities should consider using recordings to intercept phone calls that cannot be answered due to volume. These recordings could advise customers of the general state of affairs during an emergency and give instructions to either continue holding or leave a brief and concise message indicating the problem they are experiencing.

CONSERVATION

Recommendation: Utilities should enhance current public education programs to better inform customers of the benefits of conservation in mitigating the adverse affects of cold weather.

Discussion: It is obvious from the actions of consumers during the Christmas cold weather emergency that utilities have not been entirely successful in their efforts to educate the public. The numerous incidents of overloaded distribution lines and transformers which occurred as service was restored to homes after controlled feeder rotations is indicative of the lack of public understanding of how the electric system works and why. Electric distribution systems are designed to withstand a certain amount of simultaneous peak loading. Normally, however, some amount of diversity exists among the major home appliances, such as heating equipment, being served by a distribution circuit. During the extended cold weather that Florida experienced over the Christmas weekend, there was very little diversity in electrical home heating loads. Under more "normal" cold weather conditions, while a certain amount of circuit overloading might be expected, on the whole the distribution systems of the utilities would probably have held up. With home heating interrupted during rotating blackouts, however, heat loss from homes was accelerated. As service was restored, home heating systems all came on at once operating at full blast. The resulting surge placed on the electrical system quickly overloaded distribution circuits and in some cases actually melted distribution lines and destroyed neighborhood transformers. The consequences were extremely long outage times. Phone lines were jammed with outage reports and utilities scrambled to route trouble crews to affected areas. Much of this might have been avoided had consumers been better informed as to what to expect and what to do during extreme weather conditions. Such simple advice as: "Turn down thermostats, wear warm clothing, and if the power does go out, turn off all electrical heating loads until a few minutes after service is restored so you can be sure to have heat again." would suffice.

Too often, utility informational advertising appears aimed more at "image" enhancement or "load" building than at promoting cost-effective conservation. As the saying goes: "The best offense is a good defense". An informed public, knowledgeable in the ways of energy conservation, is perhaps the most valuable resource available to utilities faced with generation and distribution equipment stretched to their limits. Systematic and continuous consumer education on the effects of severe weather on weather sensitive loads in Florida is of paramount importance.

Recommendation: Utilities should continue to implement all cost-effective conservation programs, including those that promote the cost-effective use of natural gas in the residential sector to moderate Florida's dependence on electric heating.

Discussion: According to 1986 end use statistics compiled by the staff, 74.2 percent of all home heating in Florida is done with electricity. Only

8.4 percent of home heating is done with natural gas. Because of this reliance on electricity for home heating, Florida is particularly exposed to the surge and overload conditions experienced on local distribution facilities and the peak demands placed on generating equipment during severe cold weather like that which occurred over the Christmas holidays.

Natural gas is a clean, efficient and, in many instances, a cost-effective alternative to the use of electricity for home heating. According to a study prepared for the Commission by Howard Kuhns in 1982, from central Florida through north Florida, natural gas heating during the winter coupled with high efficiency air conditioning equipment for use during the summer appears to be the most cost effective approach to home climate control. (See Attachment 3) If these results continue to be valid, and staff believes that they are, it would appear prudent for Florida's electric utilities to consider the role natural gas usage might play in mitigating the volatility of winter electrical peaks in Florida. Where natural gas is available for use in residential subdivisions, electric utilities should include natural gas use in their conservation plans where such is a cost effective means of reducing peak demand and the need to construct expensive new power plants.

The topic of electric utilities promoting the cost-effective use of natural gas is currently being pursued in Docket No. 890737-PU, Implementation of Section 366.80-.85, F.S., Conservation Activities of Electric and Natural Gas Utilities. In this docket, the Commision has ordered electric and gas utilities to develop and file cost-effective conservation programs for the

Commission's review and adoption. Electric utilities have been asked to develop cost-effective programs which promote the use of natural gas or explain why such programs cannot be developed. In response, the electric utilities have challenged the Commission's authority to require them to promote the use of natural gas. The electrics contend that this is contrary to the Florida Energy Efficiency and Conservation Act, Sections 366.80-.85, Florida Statutes, and that the Commission's order violates their First Amendment rights to freedom of speech. Legal briefs have been filed and the Commission is scheduled to consider these arguments at the February 6, 1990 Agenda.

Recommendation: Utilities should work in concert with the Commission and the Department of Community Affairs to review the Florida Building Code and the practice of using electric strip heating in Florida homes.

Discussion: As has been stated, a total of 74.2 percent of all Florida homes are heated with electricity. Of the homes heated electrically, 77.2 percent use electric resistance strip heat. In this type of heating electric current is run through a high resistance wire and the friction caused by the impeded electrons heats the wire. A fan is then used to blow air over the heated wire thereby circulating the warmed air and heating the home.

Electric strip heating is the most inefficient means of heating a home. Electric heat pumps and natural gas heating systems, for example, are two to three times as efficient as electric strip heat. But because of its low installed cost, the use of electric strip heat is widespread throughout Florida. With the adoption of the 1986 revisions to the Florida Building Code, significant restrictions have been placed on the use of electric strip heat in new homes located in north Florida and, to some extent, central Florida. However, electric strip heat is still widely used in new homes in south Florida. Also, a large percentage of existing homes throughout Florida continue to rely on electric strip heat. For example, in panhandle Florida approximately 57 percent of existing homes use electric strip heat.

Because of this high saturation, staff believes that utilities should continue to pursue cost-effective alternatives to electric strip heat in their service areas. Further, the Florida Building Code should be reviewed to determine whether a more aggressive stance may be taken with respect to the development and enforcement of building standards applicable to new construction, with focus on south Florida, and retrofit applications to existing homes throughout Florida.

GENERATING UNIT PERFORMANCE

Recommendation: The operating performance of the investor-owned utility generating units during the Christmas cold weather emergency should be reviewed further as part of the Commission's Generating Performance Incentive Factor (GPIF) review in the Fuel and Purchased Power Cost Recovery Clause proceedings.

Discussion: According to statistics provided by the utilities in the 1989 Planning Hearing 20 Year Plan, as of December 1, 1989, the State had access to a total of 33,973 MW of generating capacity, 2,400 MW of firm purchased power from the Southern Company, and 247 MW of generation by Qualifying Facilities, for a total of 36,620 MW capacity. Based on the forecasted winter peak of 29,752 MW, Florida utilities had a planned reserve margin of 23 percent. However, during the Christmas weekend an average of 7,900 MW of capacity was unavailable to serve peak load. Based on utility filings, approximately 3,566 MW of generation was unavailable prior to and during the Christmas weekend due to planned or forced maintenance. Therefore, it appears that approximately 4,333 MW of generation was affected by unplanned outages or deratings during the Christmas weekend. Because of the number of outages, staff has not been able to meaningfully analyze each of these outages in this report. As such, we suggest that these outages be reviewed in further detail in the Fuel Adjustment proceedings. The following recommendations highlight some of staff's concerns in this area.

Recommendation: Utilities should review their power plant winterization plans and procedures to determine whether critical control lines can be better insulated to protect them from freezing conditions.

Discussion: A number of generating plant outages and deratings which occurred during the extended cold weather occurred when boiler feedwater sensing lines and other critical water lines froze within the plant. This occurred at the JEA/FPL St. Johns Units 1 and 2 (1248 MW), FPL's Martin 1 (790 MW) and Sanford 3 (139 MW), Seminole's Unit 2 (640 MW), and Lakeland/Orlando McIntosh 3 (340 MW). Winterization plans and procedures should be reviewed at each of these facilities.

3157

Recommendation: Utilities should review power plants which use light oil as a primary fuel or back-up fuel during curtailments of natural gas to determine if existing fuel filter systems are adequately designed to ensure uninterrupted fuel flow during cold weather.

Discussion: A number of generating plant outages and deratings which occurred during the extended cold weather occurred when oil fuel filters became clogged and the unit had to be taken off-line to clear or replace the filters. This occurred at FPC's Debary P6 (55 MW), Intercession City P1 (57 MW) and P3 (57 MW), and Suwannee P2 (65 MW); FPL's Port Everglades and Fort Lauderdale Gas Turbines (1458 MW); Kissimmee's Diesel Unit 16 (2 MW), and Orlando's Indian River CTA (96 MW).

1790

Fuel delivery systems at these plants should be reviewed to determine whether design improvements can be made to improve the reliability of fuel delivery from fuel storage tanks to the power plant. Dual fuel lines and filters should be installed where practicable.

Recommendation: Utilities should pursue alternate fuel capabilities at generating plants which currently burn only natural gas which is subject to curtailment during cold weather.

Discussion: Because of home heating requirements in the rest of the nation during the Christmas holidays, non-firm gas deliveries to Florida power plants were curtailed from Friday, December 22, until Tuesday, December 26, 1989. At many of the generating plants in Florida which burn natural gas as a primary fuel, light oil is used as a back up. However, due to current environmental constraints, the use of light oil is not permitted at some plants. As a consequence, when non-firm natural gas supplies were curtailed on Friday, December 22, the following generating plants were shut down: FPL's Cutler 5 (68 MW) and Cutler 6 (131 MW); Gainesville's Deerhaven GT 1 (18 MW) and GT2 (18 MW); and Tallahassee's Purdom GT 1 (12 MW) and GT 2 (12 MW).

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Utilities should investigate the possibilitiy of obtaining environmental waivers to burn light oil at these facilities during capacity shortfall emergencies. Additionally, pressure should be brought to bear on the Federal Energy Regulatory Commission to expedite their review and approval of the

Phase 2 expansion of the Florida Gas Transmission (FGT) pipeline in Florida. Estimates from FGT are that had this additional capacity been available during the Christmas holidays, Florida utilities could have contracted for adequate supplies of firm gas and transported it into Florida. The curtailments which occurred at Florida power plants would then not have been necessary. See Attachment 4.

Recommendation: Utilities should review their plans for the reactivation of generating units currently on extended reserve cold stand-by.

Discussion: During the Christmas cold weather the following generating units were on extended reserve cold stand-by: FPL's Riviera 2 (71 MW); TECO's Hookers Point 1-5 (206 MW); Jacksonville's Southside 1-3 (107 MW) and Northside 2 (262 MW); Lakeland's Larsen 4-7 (119 MW) and Larsen GT 1-3 (39 MW); and Tallahassee's Purdom 1-4 (32 MW). On Saturday, December 23, the City of Lakeland was able to return Larsen 7 (51 MW) to service, and on Sunday, December 24, Larsen 6 (25 MW) was returned to service. 912

Current utility plans call for most of the units on extended reserve cold standby to be returned to service during the early to mid 1990's. These units were placed on cold standby because of the high cost of oil and because of adequate reserve margins at the time. In light of the capacity shortfalls which were experienced during the Christmas weekend, these plans should be revisited. Where practicable, cold standby units should be returned to service earlier, or their status should be enhanced from a state of "cold" standby to "hot" standby.

Recommendation: The outages which occurred at the Turkey Point 3 and 4 nuclear units should be reviewed in more detail in the Fuel Adjustment Clause.

Discussion: Turkey Point 4 (688 MW) tripped off line at 11:14 p.m. on Saturday, December 23 as a result of a short circuit which occurred in control circuits to the unit's main steam isolation valve. The problem was found to be due to corrosion of terminal boards which control the unit's main steam isolation valve. The unit was not returned to service until 6:50 a.m. Thursday, December 28. Because of the forced outage experienced at Turkey Point 4, FPL decided for safety reasons to shut down and inspect Turkey Point 3. Turkey Point 3 (688 MW) was taken off line at 1:36 a.m. on Monday, December 25. During the safety inspection which ensued, similar corrosion of the terminal boards controlling the main steam isolation valve were detected. It was determined, however, that the unit could be returned to service and it was brought back on line at 8:52 a.m. on Monday, December 25.

The reason for the corrosion found in the terminal boxes at both units is not known at this time. The Nuclear Regulatory Commission (NRC) is investigating the problem. The Commission should monitor the review by the NRC and address any issues of prudence which may arise from it in the Fuel Adjustment Clause.

NATURAL GAS SUPPLIES

Recommendation: The Commission should encourage the Federal Energy Regulatory Commission to expedite its review and approval of the Florida Gas Transmission (FGT) Settlement Docket on the issue of open access and allow the Phase II expansion of the FGT pipeline into Florida to proceed.

Discussion: FGT's open access docket and the expansion of the FGT pipeline has been in litigation before the FERC for about three years. The parties have agreed on most issues. All that remains is for FERC to hear and resolve some minor rate structure issues and update their Environmental Impact Assessment. The Florida Commission has intervened in the docket. We should encourage FERC to expedite their review.

The Phase II expansion will increase natural gas supplies in Florida by approximately 100 MMCF per day. Under the FGT open access settlement agreement, Florida utilities would be able to contract for firm gas in the field and transport that gas to power plants in the state without the constant threat of interruption. It appears that gas supplies were available during the Christmas cold weather emergency, and had Florida had the pipeline capacity to transport it, Florida Power & Light, and perhaps other Florida utilities, would not have suffered interruptions to their gas-fired power plants during the Christmas holidays.

GENERATION AND TRANSMISSION PLANNING

Recommendation: Utilities should reflect the impact of the cold weather experienced during the Christmas holidays in their load and energy forecasts and generation and transmission expansion plans.

Discussion: The Commission opened Docket No. 890779-EU in June 1989 to investigate the adequacy of the electrical transmission grid in north Florida. This docket was originally opened to determine whether additional transmission capacity was needed to avoid transmission bottlenecks projected to occur in north Florida in the mid 1990's. The effects of the rotating blackouts which occurred during December 23-25, 1989 should also be considered in this docket.

Specifically, the Southern companies has stated that during the cold weather emergency experienced in peninsular Florida, the Southern system had generating capacity to sell in addition to the 3400 MW already being sold to peninsular Florida utilities. Southern estimates that had additional transmission capacity been available in Florida, Southern could have sold an additional 800 MW to peninsular Florida before encountering transmission limitations on the Southern system. Therefore, one issue that needs to be addressed in Docket 890779-EU is whether additional transmission lines should be built by peninsular Florida utilities to take advantage of emergency power purchases from the Southern system during times of capacity shortfall in the state.

The Commission has also opened Docket No. 900004-EU and 900004-EU-A as part of our ongoing planning hearings to review the long range load and energy forecasts and generation and transmission plans of the utilities in Florida. The effects of the December 23-25, 1989 cold weather should be taken into consideration in the utility plans and forecasts to determine the need for base load, intermediate, and peaking capacity in Florida.

Attachment I

FLORIDA PUBLIC SERVICE COMMISSION

Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32399-0850

M E M O R A N D U M

December 26, 1989

TO : JOE JENKINS, DIRECTOR OF ELECTRIC AND GAS

FROM: JOE McCORMICK, CHIEF OF GAS REGULATION

RE : GAS UTILITY OPERATIONS DURING CHIRISTMAS 1989 COLD WEATHER

Despite supply curtailment by Florida Gas Transmission, the gas industry had only minor disruptions of firm service during the last few days of cold weather. Those were caused, almost entirely, by rolling brownouts of the electric utilities.

Interruptible customers were curtailed from late Friday through today because of the freezing of wells in southern Texas and in Louisiana. This problem affected the whole nation, not just Florida. Here, the citrus industry was hit hardest by curtailment. Because of the freeze, they are processing 24 hours a day and have had to use more expensive backup fuel.

Curtailment was not a capacity problem, but a short term supply problem caused by extreme weather conditions in the gas fields. As temperatures in the gas fields come back up and frozen wells begin flowing, full service is being restored. Priority 5, which includes much of the citrus service was coming back on at noon today. Lower priorities will come back on as soon as gas is available.

For firm gas customers, electric utilities' rolling brownouts affected the operation of gas furnaces. Problems were of two types: 1) Electric controls on gas furnaces cause them to stop running when the power goes off. They all come back on at once when electricity is restored. In some areas where power was off for a fairly long time, all gas furnaces coming back on at once drew down the gas pressure in distribution mains, causing a few customers to lose service. Sixteen customers in Brevard County and two in Orlando had to have relight service. 2) Some furnaces have safety features that require manual reset when electricity has been disrupted. This entailed service calls by the gas company to get the furnace running, again. St. Joe Natural Gas Company's reported this problem in its service area.

cc: Bob Trapp, Assistant Director, Division of Electric & Gas
Bureau of Gas Regulation

FLORIDA PUBLIC SERVICE COMMISSION

Fletcher Building
101 East Gaines Street
Tallahassee, Florida 32399-0850

MEMORANDUM

January 22, 1990

TO : JOE JENKINS, DIRECTOR OF ELECTRIC AND GAS

FROM: JOE McCORMICK, CHIEF OF GAS REGULATION JM

RE : NORTHWEST FLORIDA GAS OUTAGES - CHRISTMAS 1989

Panhandle gas utilities supplied by United Gas Pipeline did experience service interruptions over Christmas. Each of the four utilities contacted lost some firm customers due to a large pressure drop on United's system. This was reported to be due, in part, to some of United's large direct service interruptible customers not curtailing load quickly enough when asked to do so by United. After that, United was not able to "catch up" and get the system back up to adequate operating pressure through the weekend.

The City of Milton is at the end of a United line and had the greatest problem from low pressure. They lost service to 329 houses in the Cape Hart housing area, which I understand is off-base military housing. Service was lost due to low pressure from 1:30 - 5:30 p.m Saturday, December 23 and again from 10:00 p.m. to 2:30 a.m. Saturday night/Sunday morning. Sunday, December 24, from 5:00 to 10:00 a.m. the area was off due to complete loss of pressure.

Energy Services of Pensacola reported that they curtailed interruptible customers about 3:00 p.m., Friday. Sunday, United called to say they were losing pressure at Milton. A pressure drop on ESP's feeds from United then caused ESP to lose about 240 customers during the day Sunday, December 24. ESP reported that no customers were lost, other than during the day Sunday.

Escambia County Utilities Authority lost individual customers for a few hours at a time from Friday through Sunday. When United began to lose pressure, ECUA began to supplement natural gas with propane-air mixture. Some farm taps, small regulator stations serving some individual customers, froze up. In each case, once the farm tap was thawed, service was restored.

Okaloosa County Gas District reported that Whiting Field voluntarily cut back its load and Eglund AFB cut its system over to backup fuel. As a result, Okaloosa did not lose any firm customers.

The investor-owned gas utilities, West Florida Natural Gas and St. Joe Natural Gas are served by Florida Gas Transmission. They had no losses, other than those associated with electric blackouts.

cc: Bob Trapp, Assistant Director, Division of Electric & Gas
Bureau of Gas Regulation

Cold Weather

NNNN
TTAA00 KMIA 211117
FLZ005>023-212315-

FLORIDA EXCEPT NORTHWEST EXTENDED FORECAST
NATIONAL WEATHER SERVICE MIAMI FL
615 AM EST THU DEC 21 1989

.SATURDAY THROUGH CHRISTMAS MONDAY

VERY COLD ARCTIC AIR WILL COVER THE PENINSULA AND KEYS SATURDAY AND SUNDAY WITH ONLY A SLIGHT MODERATION CHRISTMAS MONDAY. FAIR AND QUITE COLD THROUGHOUT THE PERIOD EXCEPT BECOMING CLOUDY SOUTHEAST COAST AND KEYS CHRISTMAS. QUITE WINDY SATURDAY AND SUNDAY. A HARD FREEZE LIKELY NORTH ALL THREE MORNINGS... FREEZING TEMPERATURES INTO CENTRAL SATURDAY...COLDEST STATEWIDE SUNDAY MORNING WITH HARD FREEZE EXTENDING TO CENTRAL AND NEAR FREEZING TEMPERATURES TO SOUTHEAST COAST.

LOWS ALL THREE MORNINGS IN THE TEENS NORTH...LOW TO MID 20S CENTRAL AND UPPER 20S TO LOWER 30S SOUTH EXCEPT NEAR 40 SOUTHEAST COAST SATURDAY AND MONDAY AND IN THE 50S KEYS. HIGHS...NORTH IN THE 30S SATURDAY AND 40S SUNDAY AND CHRISTMAS...CENTRAL 40S SATURDAY AND 50S SUNDAY AND CHRISTMAS...SOUTH 50S SATURDAY AND SUNDAY AND 60S MONDAY...KEYS NEAR 60 SATURDAY AND 60S SUNDAY AND MONDAY.

$$

Alert

SPECIAL WEATHER STATEMENT
NATIONAL WEATHER SERVICE MIAMI FL
1100 AM EST THU DEC 21 1989

...ARCTIC AIR TO COVER FLORIDA OVER THE HOLIDAY WEEKEND...

.L INDICATIONS ARE STILL THAT THE RECORD BREAKING ARCTIC AIR MOVING INTO THE SOUTH TODAY AND TONIGHT WILL COVER FLORIDA OVER THE HOLIDAY WEEKEND.

AT THE CURRENT TIME MINIMUM TEMPERATURES ARE FORECAST TO BE IN THE TEENS OVER MUCH OF NORTH FLORIDA SATURDAY AND SUNDAY MORNING WITH TEMPERATURES IN THE 20S OVER CENTRAL FLORIDA AND 30S OVER SOUTH FLORIDA EXCEPT 40S UPPER KEYS TO 50S LOWER KEYS. DAYTIME TEMPERATURES SATURDAY WILL NOT RISE MUCH ABOVE FREEZING IN THE EXTREME NORTH AND BE MOSTLY IN THE 40S TO 50S ELSEWHERE. TEMPERATURES WILL BE A LITTLE WARMER ON CHRISTMAS BUT STILL WELL BELOW NORMAL.

THE ARCTIC AIR WILL BE ACCOMPANIED BY STRONG WINDS ON SATURDAY AND SUNDAY PRODUCING WIND CHILLS SELDOM EXPERIENCED IN FLORIDA. DEPENDING ON THE EXACT TRACK OF THE CENTER OF THE LARGE SURFACE HIGH PRESSURE AREA TEMPERATURES COULD APPROACH THE RECORD BREAKING TEMPERATURES WHICH OCCURRED AROUND CHRISTMAS OF 1983.

ALL FLORIDA RESIDENTS SHOULD BE THINKING ABOUT PRECAUTIONS TO TAKE FOR THESE RATHER EXTREME CONDITIONS. RESIDENTS OF SOUTH FLORIDA WHO WILL BE TRAVELING UPSTATE FOR THE WEEKEND SHOULD BE PREPARED FOR CONDITIONS EXPECTED THERE.

...COLD WEATHER PRECAUTIONS FOR FLORIDIANS...

1. LOCAL PUBLIC OFFICIALS AND VOLUNTEER AGENCIES SHOULD PREPARE SHELTERS FOR PEOPLE WHO MAY NEED SHELTERING DURING THESE SEVERE CONDITIONS.

WRAP EXPOSED WATER PIPES IN THOSE AREAS WHERE THE TEMPERATURES ARE FORECAST TO BE WELL BELOW FREEZING FOR SEVERAL HOURS.

3. CHECK THE COOLANT SYSTEM OF AUTOMOBILES AND TRUCKS FOR SUFFICIENT ANTIFREEZE TO PROTECT THEIR ENGINES AND COOLANT SYSTEM WHERE WELL BELOW FREEZING TEMPERATURES ARE EXPECTED.

4. ANYONE PLANNING OUTDOOR ACTIVITIES SHOULD CONSULT THE LATEST FORECASTS BEFORE VENTURING OUT. TOGETHER WITH THE LOW TEMPERATURES THE STRONG WINDS WILL CAUSE WIND CHILLS WHICH COULD PRODUCE HYPOTHERMIA IF TOO MUCH TIME IS SPENT OUT WITHOUT ADEQUATE PROTECTION.

5. CHECK HEATERS FOR SUFFICIENT VENTILATION AND KEEP FLAMMABLE MATERIAL AWAY FROM OPEN FLAMES. MANY DEATHS OCCUR IN THE SOUTH...INCLUDING FLORIDA...DURING COLD WEATHER OUTBREAKS BECAUSE OF INSUFFICIENT VENTILATION OR FAULTY HEATERS LEADING TO FIRES OR CARBON MONOXIDE POISONING.

6. IN ADDITION TO AGRICULTURAL INTERESTS HOMEOWNERS SHOULD BE PREPARED TO PROTECT TENDER PLANTS AND TREES.

7. HOUSEHOLD PETS SHOULD BE BROUGHT INDOORS AND LIVESTOCK AND OTHER ANIMALS SHOULD BE PROPERLY PROTECTED FOR THE EXPECTED CONDITIONS.

ADDITIONAL STATEMENTS WILL BE ISSUED BY LOCAL NATIONAL WEATHER SERVICE OFFICES AS THE COLD AIR PUSHES INTO FLORIDA TONIGHT AND FRIDAY.

REVISED
TECHNICAL REPORT
ON
RESIDENTIAL ENERGY CONSUMPTION AND PEAK DEMAND
CAUSED BY
THREE MAJOR SYSTEMS
AIR CONDITIONING, CENTRAL HEATING AND WATER HEATING

PREPARED FOR
THE FLORIDA PUBLIC SERVICE COMMISSION
JOSEPH CRESSE, CHAIRMAN
GERALD. L. (JERRY) GUNTER
SUSAN WAGNER LEISNER
JOHN R. MARKS, III
KATIE NICHOLS

BY HOWARD KUHNS, CONSULTING ENGINEER
8895 NORTH MILITARY TRAIL
BUILDING D, SUITE 201
PALM BEACH GARDENS, FLORIDA 33410

JANUARY, 1982

T A B L E   O F   C O N T E N T S

Preface

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II. Air Conditioning and Heating Energy Consumption

III. Air Conditioning and Heating Peak Demand

IV. Water Heating

A P P E N D I C E S

A. Background for Energy Calculations

B. Example Economic Case

C. Example Demand Points Calculation

D. Future Residential Construction

E. Florida Model Energy Code For Building Construction

PREFACE

THE ISSUE AT HAND

During the next 15 years, 3 million new homes will be established in Florida. These new homes will require the construction of additional power plants, at great expense. Should the needs for additional electrical generation be met solely by adding new plants, or should part of the requirements be met through energy conservation? If each new home is built better, the kilowattt hours of energy and the kilowatts of peak demand can be reduced substantially. This study indicates that the Florida consumer will be better off to have a better home.

The Florida Energy Code offers the most viable and effective mechanism to bring about these improvements to new homes.

The effects will be far reaching, because the benefits of energy conservation in buildings grow exponentially. Small improvements placed in each new building will continue to save energy and yield peak reductions for the life of the building and the life of the system. At the same time, the number of new buildings grows each year. Over a period of years, the resulting benefits become large. Increasing prices for energy add to the process.

As one example, consider how much energy and expenditure can be avoided if 70% of the new homes built in Florida between 1982 and 1997 possess air conditioning systems with efficiency ratios of 9.5 instead of 7.5 and these homes use 75% of the energy shown in chapter 2 of the report. The next table depicts how many kilowattt hours will not be consumed and how much money will not be spent.

YEAR	CUMULATIVE NUMBER OF NEW HOMES 100%	MILLIONS OF KWH NOT USED EACH YEAR 70% *	MILLIONS OF DOLLARS NOT SPENT EACH YEAR (70%)*	MILLIONS OF DOLLARS NOT SPENT CUMULATIVE
1982	174,600	218	$ 14	$ 14
1983	349,000	437	32	46
1984	524,000	655	52	98
1985	698,000	874	76	174
1986	873,000	1,092	111	285
1987	1,047,000	1,310	133	418
1988	1,222,000	1,529	167	585
1989	1,397,000	1,736	204	789
1990	1,571,000	1,957	243	1,032
1991	1,746,000	2,184	286	1,318
1992	1,921,000	2,402	324	1,642
1993	2,096,000	2,621	382	2,024
1994	2,270,000	2,838	435	2,459
1995	2,445,000	3,056	490	2,949
1996	2,619,000	3,275	550	3,499
1997	2,794,000	3,493	612	4,111
TOTALS		29,677	$ 4,111.0	

* 70% of the residences are shown instead of 100%, because the energy code can not be expected to be applied to all residences.

It can be seen, that if air conditioners are improved by the one step shown, citizens of Florida will forego the use of almost 30 billion kilowatt hours and will not spend 4.1 billion dollars on this energy, during the next 15 years.

In a similar manner, peak demand and resultant construction of power plants can be dramatically affected. Chapter 3 of the report shows that, during the next 10 years, a half million kilowatts of peak demand can be avoided by building homes with 10% lower peaks demands.

C H A P T E R I
SCOPE, ORGANIZATION, AND EXECUTIVE SUMMARY, COORDINATION WITH OTHER MEASURES, THEORIES, IMPLEMENTATION

SCOPE

The purpose of this study is to calculate the cost effectiveness to the Florida consumer of the three largest residential energy consuming systems and to calculate the peak demand loads for these systems.

The study can then be used as a basis to modify the Florida Model Energy Code for Building Construction, and as a basis for further studies to establish demand reduction and energy reduction programs.

The configurations studied include:

New Residences: This report applies only to new residences. Some of this data can be applied to existing residences, but must be done so with care. For example, an existing house constructed before the energy code would be expected to consume more energy than shown herein. Generally, the cost of replacing an existing air conditioner with an upgraded model would cost more for an existing house than the upgrade costs shown here.

Climate Zones: The state is divided into three climate zones which are designated North, Central and South. Section 3 of the Energy Code lists the counties included in North (1, 2 and 3), Central (4,5 and 6) and South (7,8 and 9) zones. Weather data for Jacksonville, Tampa and Miami was utilized.

Systems: The systems studied are systems commonly constructed as part of a residence, including central air conditioning, central heating, and water heating.

Air conditioners studied are all electrical, air cooled, under 65,000 BTUH, with air duct systems.

Central heating systems include electrical resistance strips, air cooled heat pumps, and natural gas furnaces. All share the air conditioning duct system.

Water heating systems include electrical resistance, solar with resistance supplement, heat recovery units which reclaim heat from air conditioning, dedicated heat pumps, and natural gas.

Residential Configurations: Five types of residences are analyzed:

800 square foot single family
1600 square foot single family
2400 square foot single family
1600 square foot multi-family
600 square foot mobile home

Appendix A shows house plans and statistics for these residences.

ORGANIZATION AND APPROACH

This report is organized into four chapters and five appendices.

Chapter I contains the Scope, Organization, and the Executive Summary.

Chapter II contains the analysis of air conditioning and heating systems energy consumption.

Chapter III shows a method of limiting peak demand in new construction. The method is a "points" method which can be incorporated into the Energy Code.

Chapter IV covers water heating data.

Appendix A describes the assumptions which were used for the energy calculations.

Appendix B contains an example case of the five year economic analysis.

Appendix C takes the reader through an example peak points calculation.

Appendix D projects construction trends and shows the predictions used in the chapters.

Appendix E is a copy of the 1980 Energy Code now in effect.

EXECUTIVE SUMMARY

The target year is 1982. This will be the first year in which new and higher requirements can be put forth in the Energy

Code. Therefore, the five and ten year durations used as the bases for calculations, begin with 1982.

This report contains information which can be used to calculate cost effectiveness under any conditions of amortization period, interest rate, etc. However, three scenarios have been calculated herein and are based on the benefits and costs for 5 and 10 year periods; showing accumulation of annual costs and a present worth scenario for 10 years. The building industry views 5 years as a criteria because the average Florida resident relocates in 5 years.

AIR CONDITIONING AND CENTRAL HEATING:

The analysis shown in Chapter II was used to generate the bar graphs I-A through I-O, I-AA through I-OO, and I-<u>AA</u> through I-<u>OO</u>. These graphs depict the five year and ten year accumulated savings or loss for the North, Central and South zones, for the five residence configurations and for 100% usage and 50% energy usage.

The solid black bars depict savings or losses as a result of the Florida citizen making full use (100%) of the air conditioning and heating systems. Similarly, the cross hatched bars show savings or losses resulting from 50% usage.

The degree of use is all-important when considering cost effectiveness. For example, the most cost effective system for a person who runs the air conditioner constantly will be a high efficiency unit. On the other hand, someone who rarely uses air conditioning or who has an unusually efficient structure will be better off, financially, with a low efficiency system.

The bars on the graphs show 100% and 50% usage of the systems. The condition which should be used as a basis for Code minimum requirements will be between 50% and 100%. The recommendations herein are based on the midpoint of 75%.

On each graph, the first three sets of bars are for systems with electric strip heating and air conditioning efficiencies of 8.5, 10.0, and 11.5.

The next two sets are for heat pumps which have efficiencies of 6.8 and 8.5 in the cooling mode and COPS of 2.3 and 2.6 in the heating mode.

The last three sets are for natural gas heating and air conditioning efficiencies of 6.8, 8.5, and 10.0.

The observations and recommendations are based on embedded kilowatt hour costs. Power plant construction deferrals, which come about because of peak demand reductions will be presented in a separate report.

NORTH FLORIDA OBSERVATIONS: (Refer to graphs I-A through E, I-AA through I-EE and I-AA through I-EE.

Because of the high heating loads in the north, the gas heating bars show highest savings in all residences. Heat pumps are significantly cost effective in all the single family houses, but show a loss for multi-family. The low efficiency 6.8 heat pump is more cost effective than the higher 8.5.

Heat strips are least cost effective. In North Florida, small houses have high percentages of heat strips. DVCA statistics show the following percentages.

1981-- NORTH FLORIDA
NEW HEATING SYSTEMS BY PERCENT

RESIDENCE SIZE	STRIPS	H. PUMP	GAS
Less than 1200 SF	54%	28%	18%
1200-1600 SF	32	50	18
1600-2000 SF	27	56	17
Over 2000 SF	12	78	09

(Mobile homes excluded)

It can be seen that, for small homes, present construction practices result in three times as many inefficient strips as efficient gas systems. The larger homes which are occupied by more affluent citizens have six times as many heat pumps as resistance strips.

The inefficiency of strips cannot be compensated in the North by high efficiencies on the cooling side.

In every case examined, resistance strips are the least beneficial mode of heating.

On the air conditioning side, heat pumps with the low efficiency rating of 6.8 are more cost effective than the higher ratings. This may change in future if the costs for higher efficiency equipment come down.

Mobile homes are a special case. Energy consumption levels are so low that improvements in efficiencies (beyond EER= 6.8) cannot be justified. Keep in mind that new mobile homes are being considered here which meet HUD requirements for insulation. Many existing mobile homes were built without insulation and are unusually inefficient.

CENTRAL FLORIDA OBSERVATIONS: (Refer to graphs I-F through J, I-FF through JJ, and I-FF through I-JJ.)

In Central Florida, heating considerations are so relevant that gas systems offer the best return. Gas systems with air conditioning EERs of 8.5 to 10.0 are most beneficial.

Straight cool systems with resistance strips are the next most effective configuration with EERs of 8.5 to 10.0.

Heat pumps are cost effective with an EER of 6.8.

Mobile homes are a special case. Improvements in equipment efficiencies cannot be justified.

SOUTH FLORIDA OBSERVATIONS: (Refer to graphs I-K through O, I-KK through OO and I-KK through I-OO.)

In South Florida, gas systems are cost effective in single family homes, but represent a loss in the multi-family model.

Straight cool systems with resistive strip heating are the most effective, with an EER of 10.0.

Heat pumps are not a good buy in any case studied.

Mobile homes again are a special case with no equipment upgrading justified.

WATER HEATING OBSERVATIONS: (Refer to tables IV-C through IV-H)

The tables show the 5 and 10 year costs of water heating. Systems are listed in order, from highest costs to lowest:

1. Electrical resistance
2. Dedicated heat pump
3. Heat recovery unit on air conditioner
4. Heat recovery unit on heat pump
5. Solar with supplementary resistance
6. Natural gas

In North Florida, solar is less effective than a heat recovery unit on a heat pump.

RECOMMENDATIONS FOR THE ENERGY CODE:

AIR CONDITIONING:

In order to comply with the legislative mandate to set code minimum efficiencies at the point most cost effective for Florida citizens, the Energy Code minimums must be raised to an EER (or SEER) of 10 for straight cool systems. It is recommended that the following schedule be set.

EQUIPMENT DESCRIPTION STRAIGHT COOL	EFFECTIVE DATES 1982 EER or SEER	 1984 EER or SEER
Air cooled split system,	8.5	10.0
Air cooled package system	8.0	9.5

Before 1984, a study must be conducted to determine requirements for latent heat capacities. Air conditioners with EERs over 9.5 may not have adequate capacity to remove moisture and lower the humidity to comfortable levels. The minimum capacities must, therefore, be determined and placed in the code.

RESISTANCE HEAT STRIPS:

Resistance strips should be disallowed in North Florida, except with heat pumps. In South and Central Florida, resistance strips are economical for the consumer based on embedded kilowatt energy costs. Reductions in strips may be justified on the basis of deferred power plant construction. (Report supplement)

HEAT PUMPS:

Heat pumps with an EER of 6.8 are beneficial in North and Central Florida, but cannot be justified in South Florida on the basis of embedded costs to the consumer.

The prescriptive measures recommended are:

1. Limit sizes of supplementary electrical heat strips in North and Central Florida to one kilowatt per ton.
2. In South Florida zones 8 and 9, supplementary heat strips would not be installed, except in cases where health requirements dictate otherwise.
3. Supplementary heat strips are to be operated with an outdoor thermostat.

GAS HEATING:

Natural gas is not universally available, so the Code cannot set prescriptive minimums. However, the literature and seminars produced in conjunction with the Code should show the benefits and costs of gas.

POINT SYSTEM:

It is recommended that the base point requirement in the Code be changed from 100 points to 85 points in order to maintain good construction practices for the envelope.

WATER HEATING:

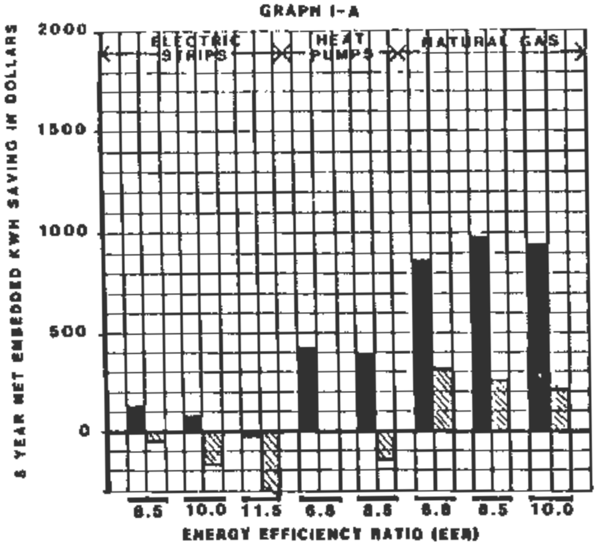
It is recommended that electrical resistance water heating be disallowed, effective 1981, except supplementary to other systems.

Dedicated heat pumps are to be added to the Code, Section 9, to receive credit points. (Present plans call for this.)

Heat recovery units for heat pump applications are to be added to Section 9.

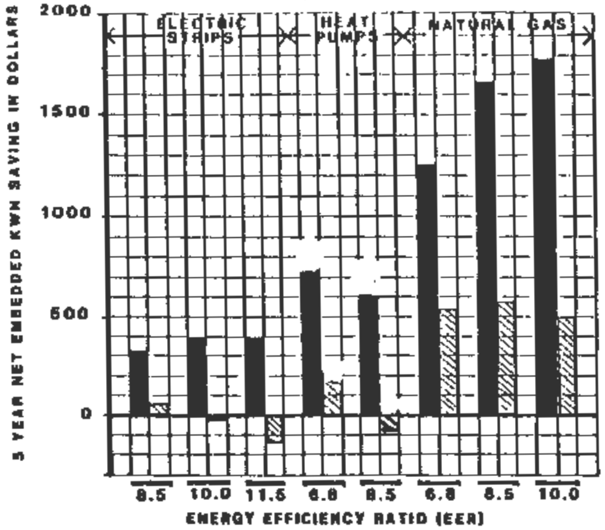
Energy Code literature and seminars are recommended to have additional benefit-cost data.

GRAPH I-A



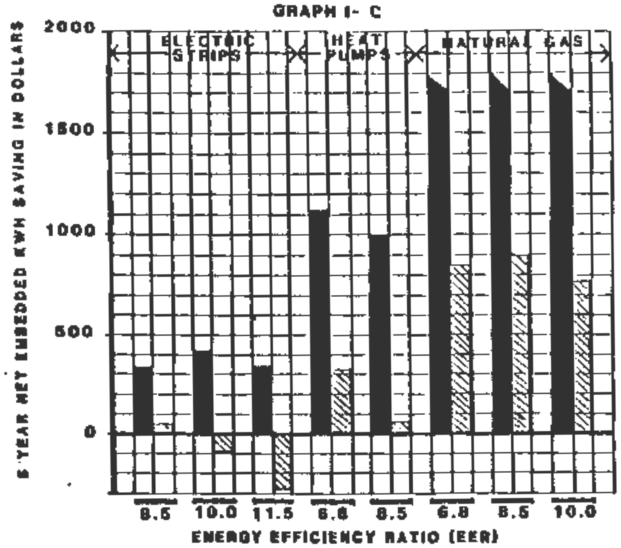
800 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I-B



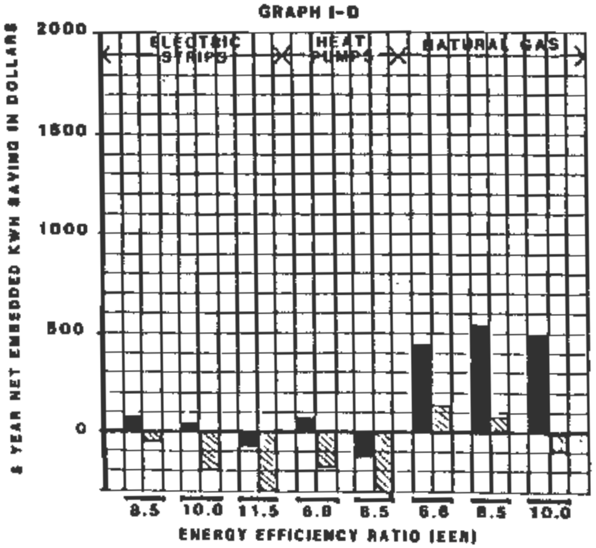
1600 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I- C



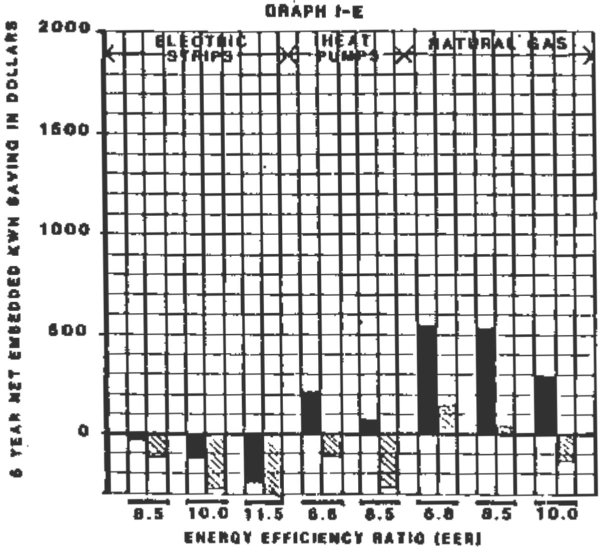
2400 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I-D



MULTIFAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I-E



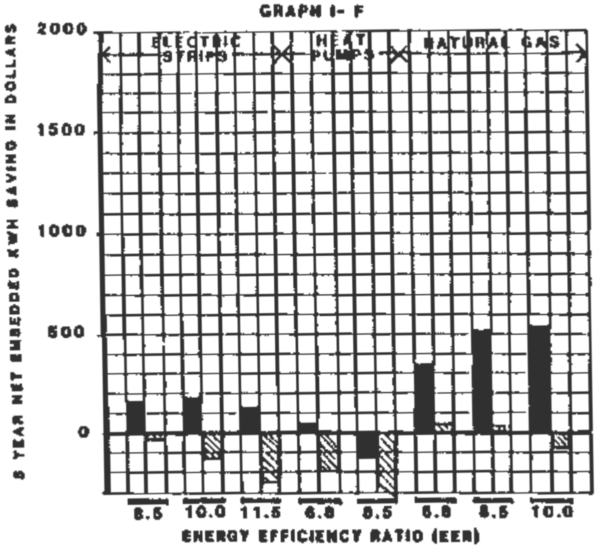
MOBILE HOME
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

F I V E Y E A R A N A L Y S I S

NORTH FLORIDA

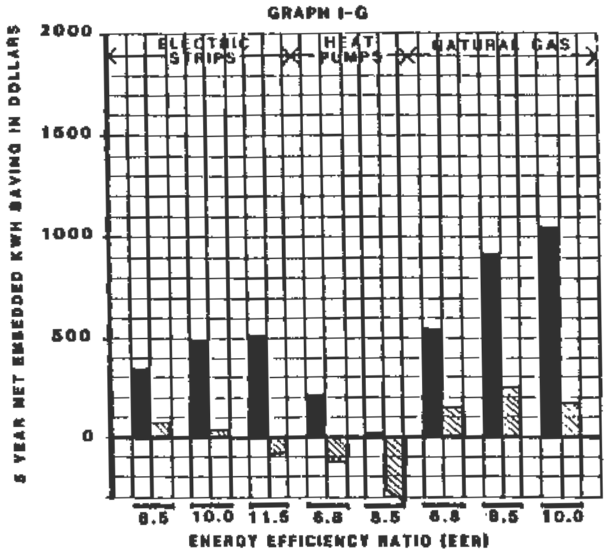
SOLID BARS INDICATE
100% USAGE

CROSS HATCHED BARS
INDICATE 50% USAGE



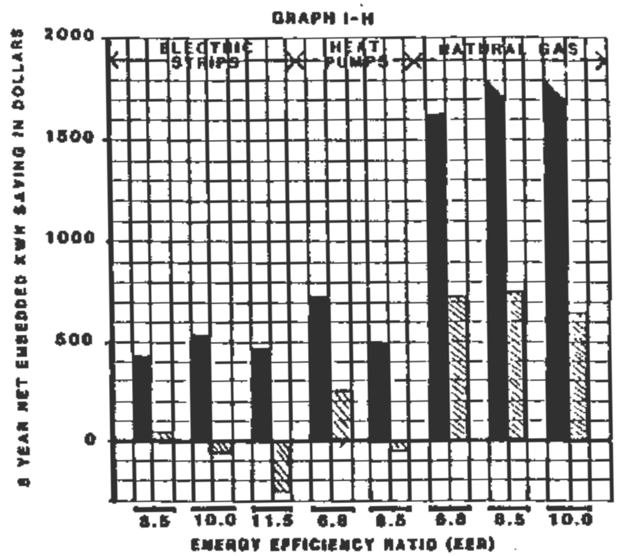
800 SF SINGLE FAMILY
CENTRAL FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



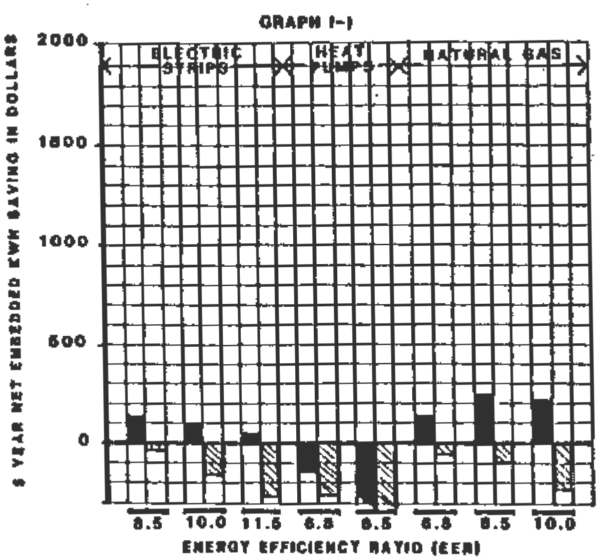
1600 SF SINGLE FAMILY
CENTRAL FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



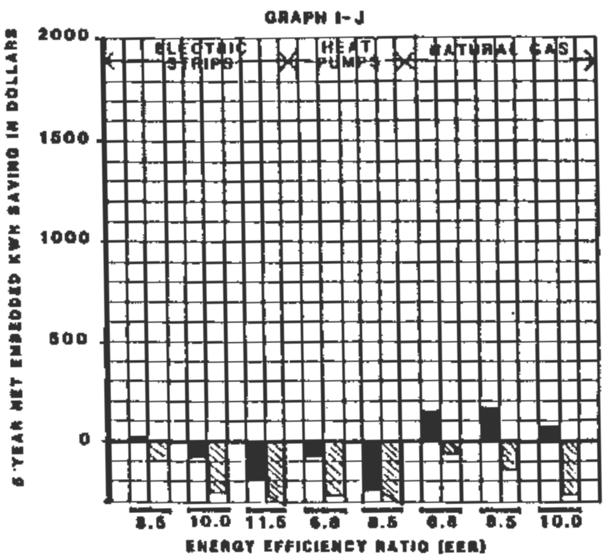
2400 SF SINGLE FAMILY
CENTRAL FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



MULTIFAMILY
CENTRAL FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



MOBILE HOME
CENTRAL FLORIDA

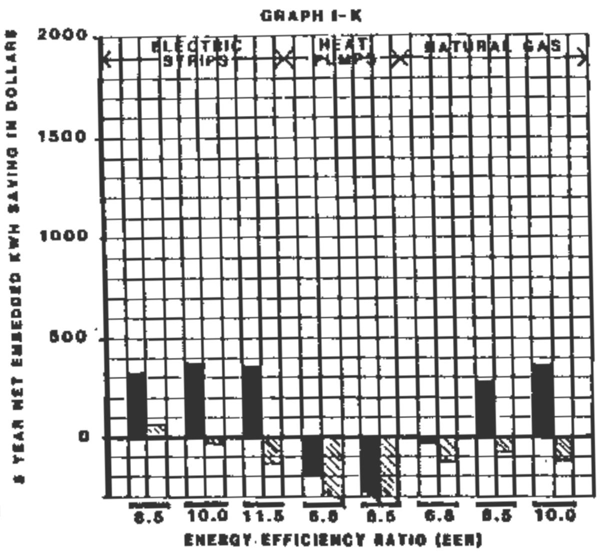
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

F I V E Y E A R A N A L Y S I S

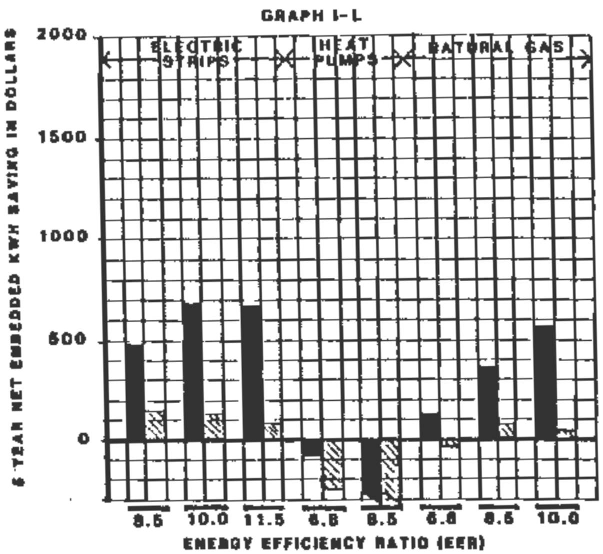
CENTRAL FLORIDA

SOLID BARS INDICATE
100% USAGE

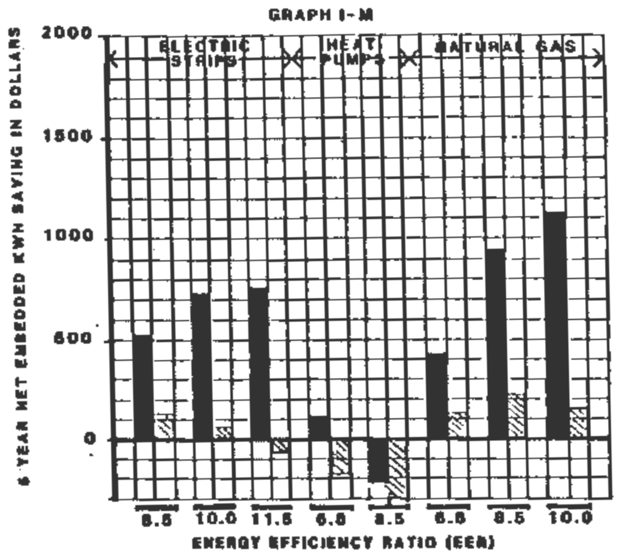
CROSS HATCHED BARS
INDICATE 50% USAGE



800 SF SINGLE FAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



1600 SF SINGLE FAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



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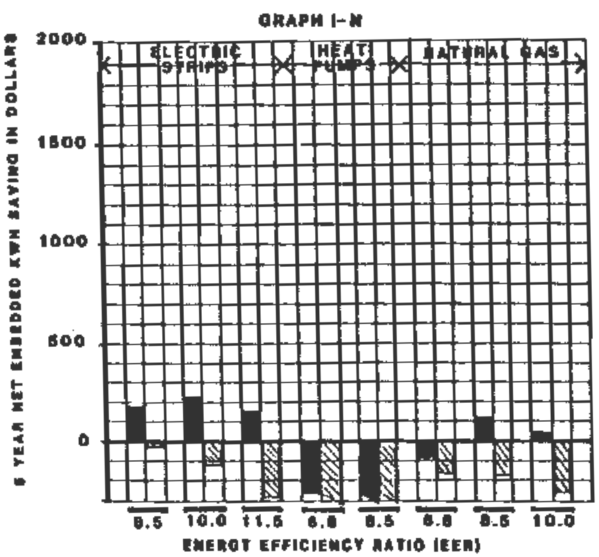
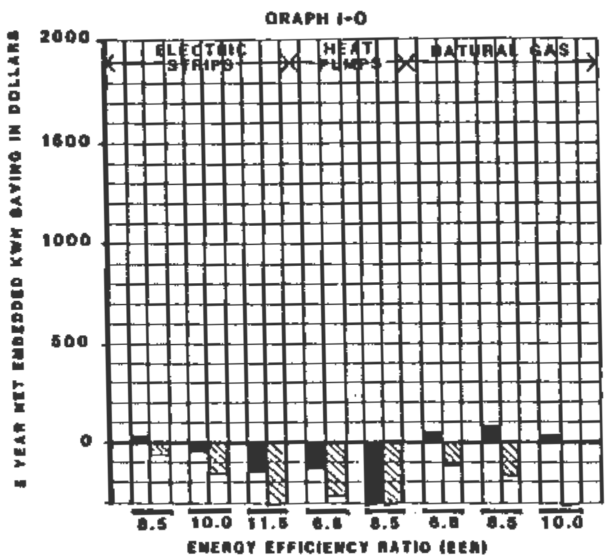
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



MULTIFAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



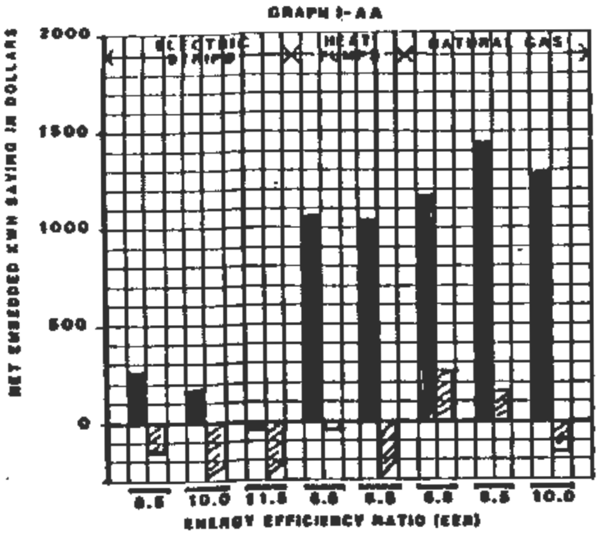
MOBILE HOME
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

F I V E Y E A R A N A L Y S I S

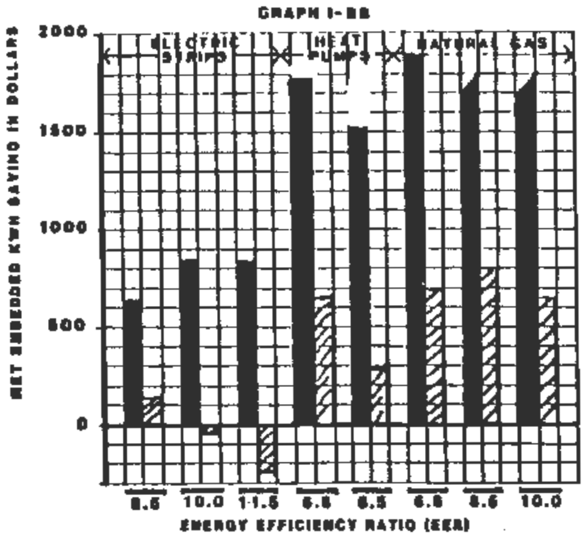
SOUTH FLORIDA

SOLID BARS INDICATE 100% USAGE

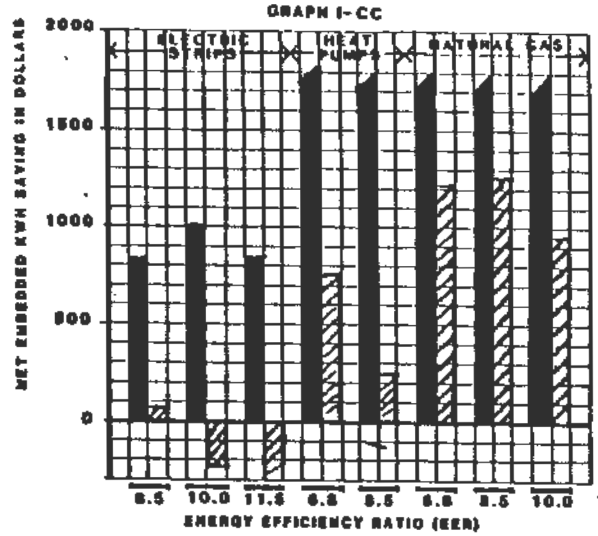
CROSS HATCHED BARS INDICATE 50% USAGE



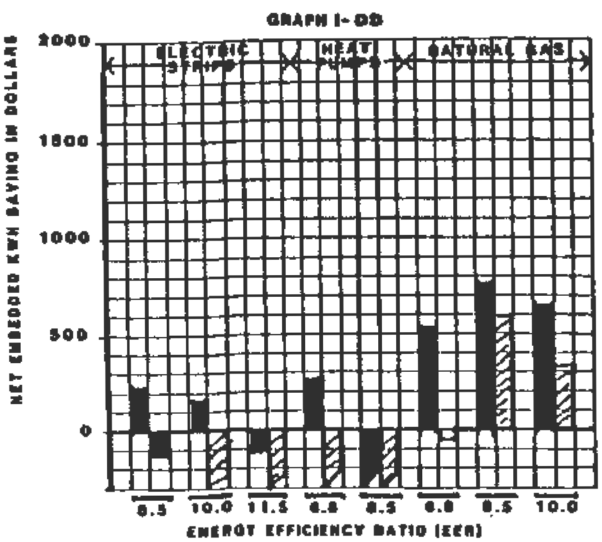
800 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



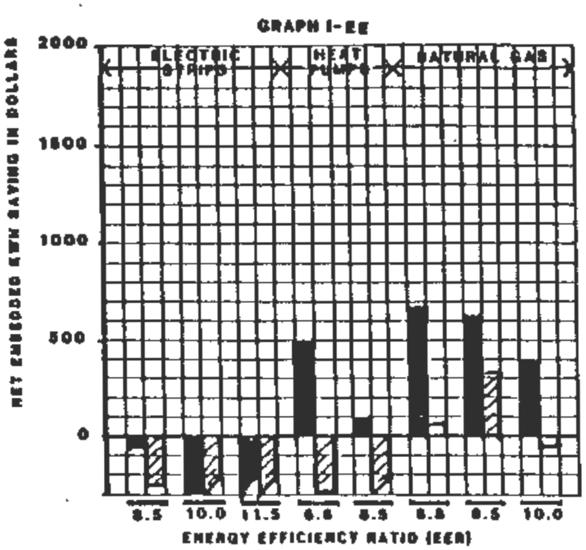
1600 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



2400 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



MULTIFAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS



MOBILE HOME
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

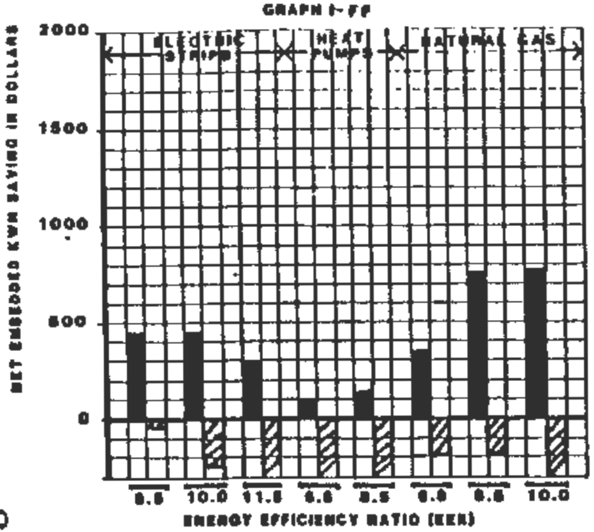
TEN YEAR ANALYSIS

NORTH FLORIDA

SOLID BARS INDICATE
100% USAGE

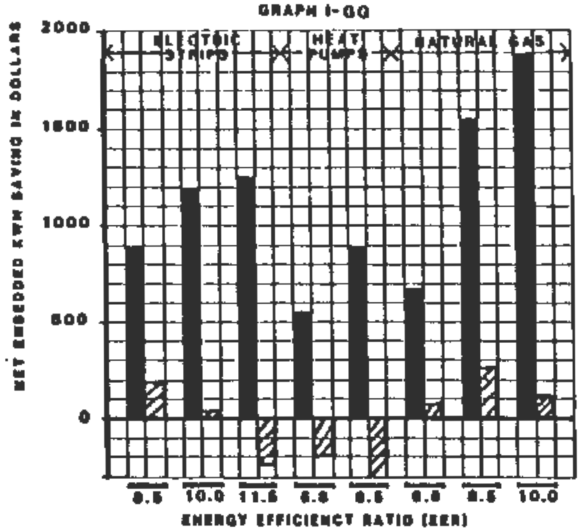
CROSS HATCHED BARS
INDICATE 50% USAGE

GRAPH I-FF



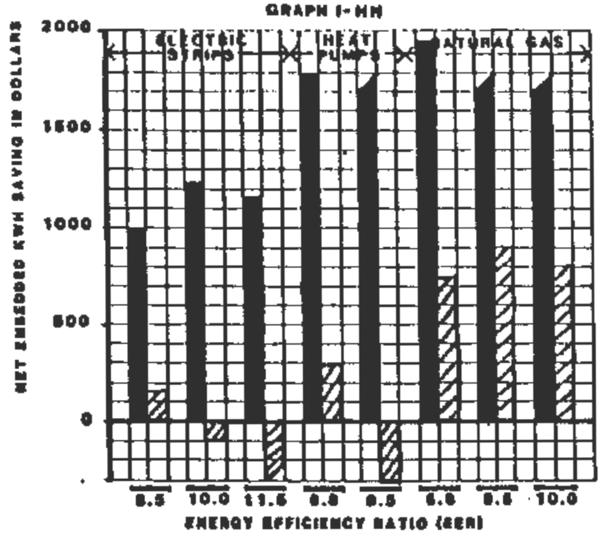
800 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-GG



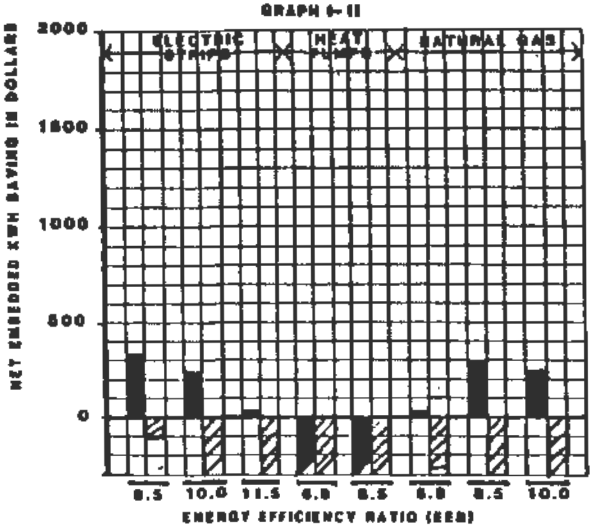
1600 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-HH



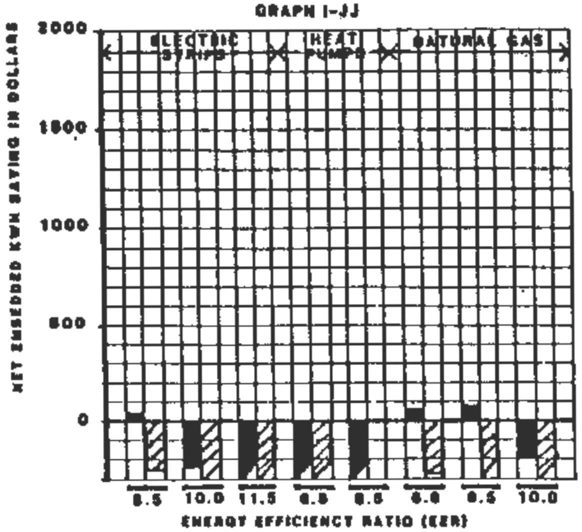
2400 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-II



MULTIFAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-JJ



MOBILE HOME
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

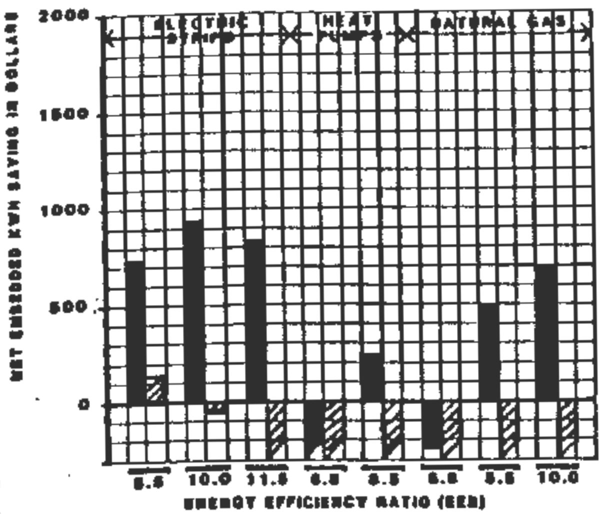
TEN YEAR ANALYSIS

CENTRAL FLORIDA

SOLID BARS INDICATE
100% USAGE

CROSS HATCHED BARS
INDICATE 50% USAGE

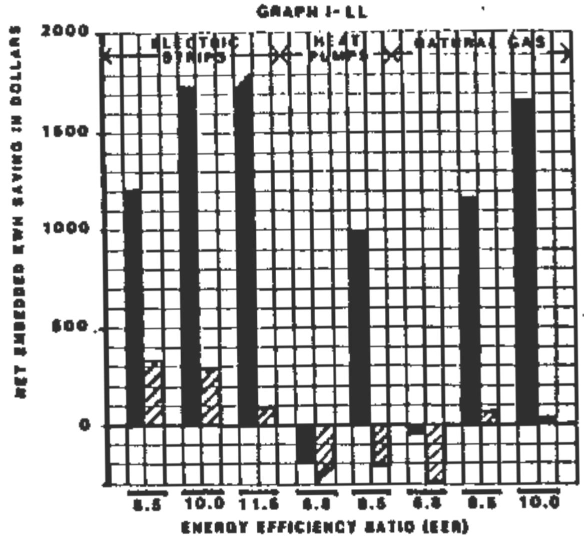
GRAPH I-KK



800 SF SINGLE FAMILY
SOUTH FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

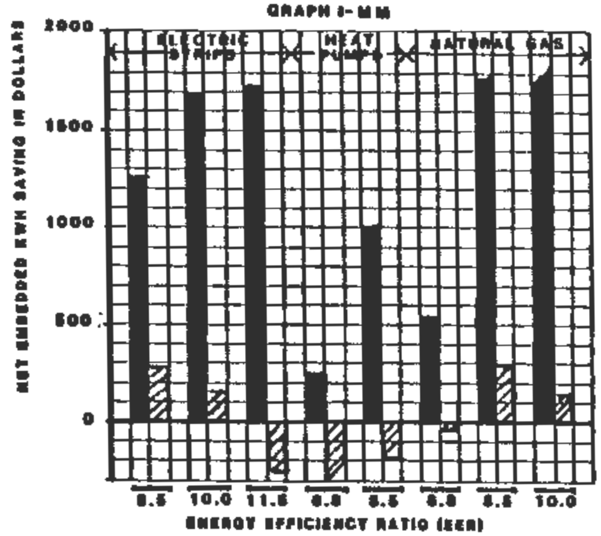
GRAPH I-LL



1600 SF SINGLE FAMILY
SOUTH FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

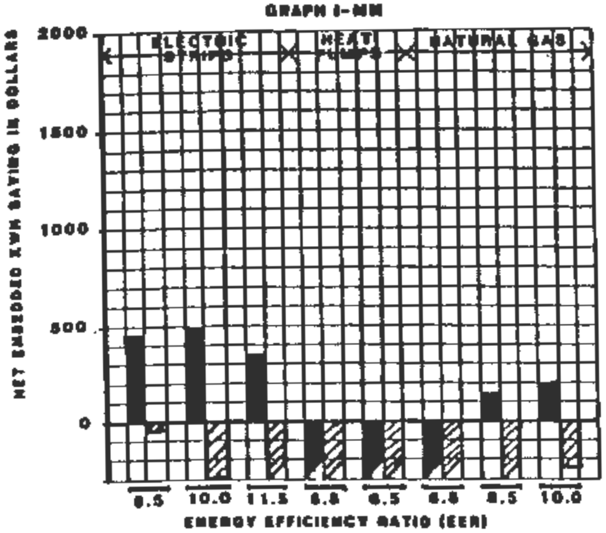
GRAPH I-MM



2400 SF SINGLE FAMILY
SOUTH FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

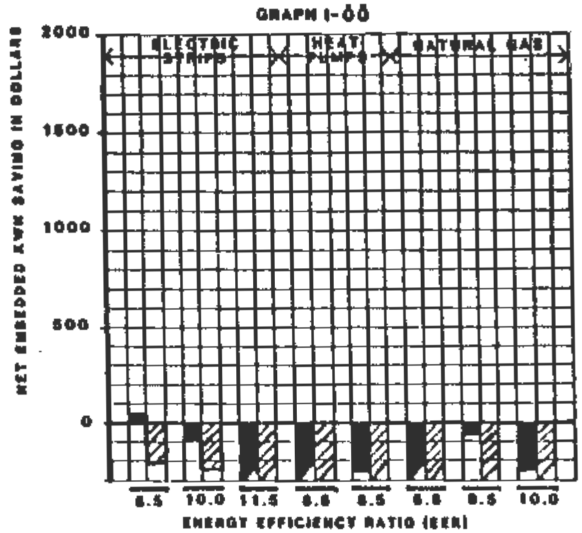
GRAPH I-NN



MULTIFAMILY
SOUTH FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-OO



MOBILE HOME
SOUTH FLORIDA

BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

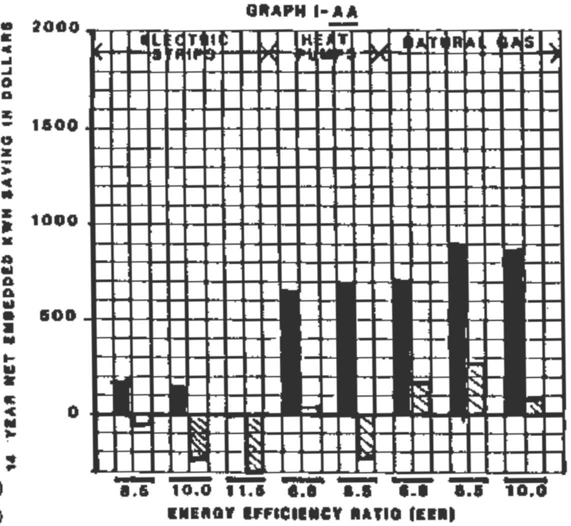
T E N Y E A R A N A L Y S I S

SOUTH FLORIDA

SOLID BARS INDICATE 100% USAGE

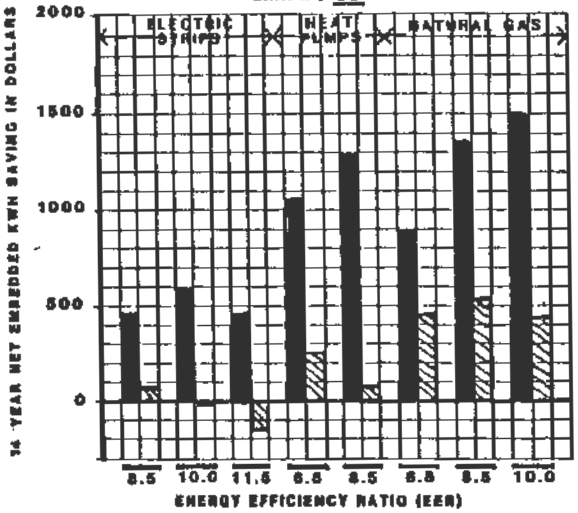
CROSS HATCHED BARS INDICATE 50% USAGE

GRAPH I-AA



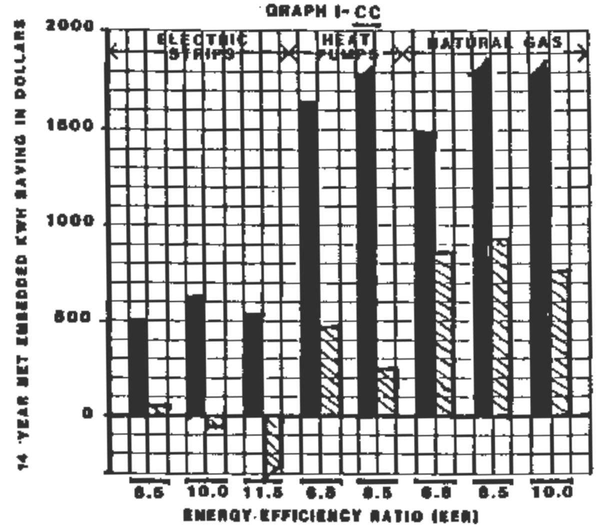
800 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-BB



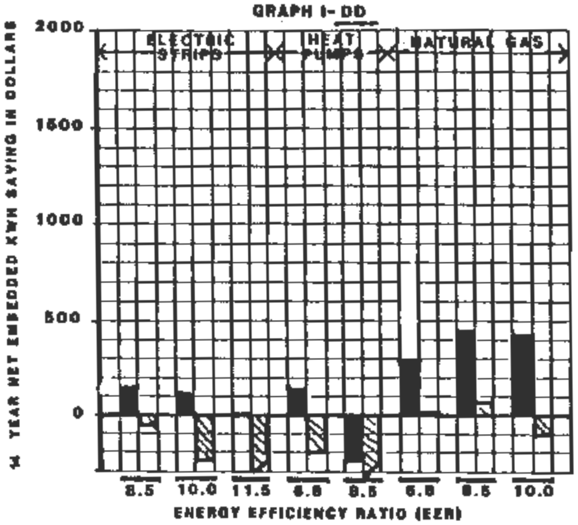
1600 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-CC



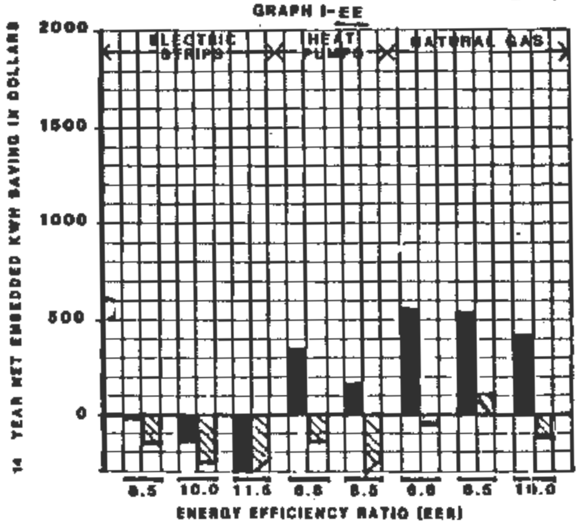
2400 SF SINGLE FAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-DD



MULTIFAMILY
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

GRAPH I-EE



MOBILE HOME
NORTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER=6.8 AND RESISTANCE STRIPS

PRESENT VALUE ANALYSIS

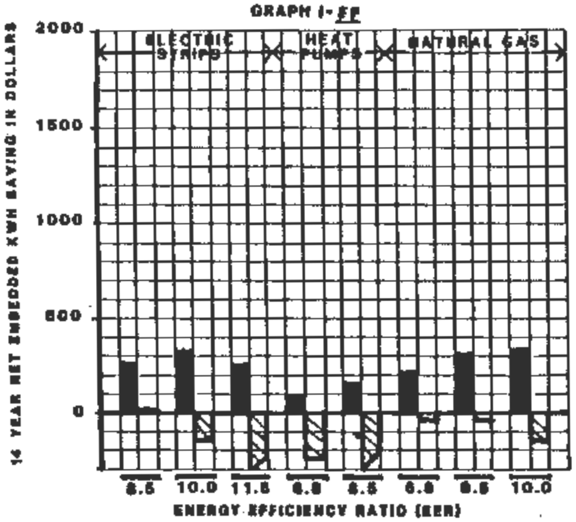
TEN YEARS

NORTH FLORIDA

SOLID BARS INDICATE
100% USAGE

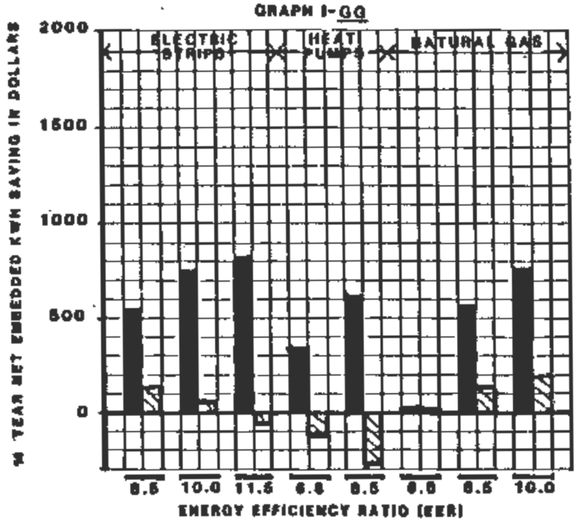
CROSS HATCHED BARS
INDICATE 50% USAGE

GRAPH I-FF



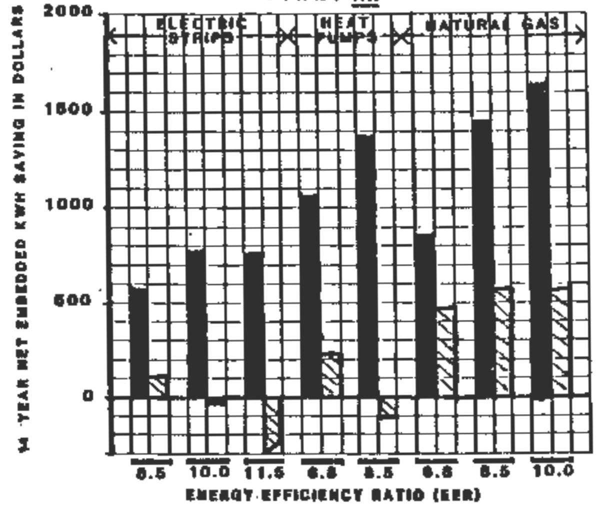
800 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I-GG



1600 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

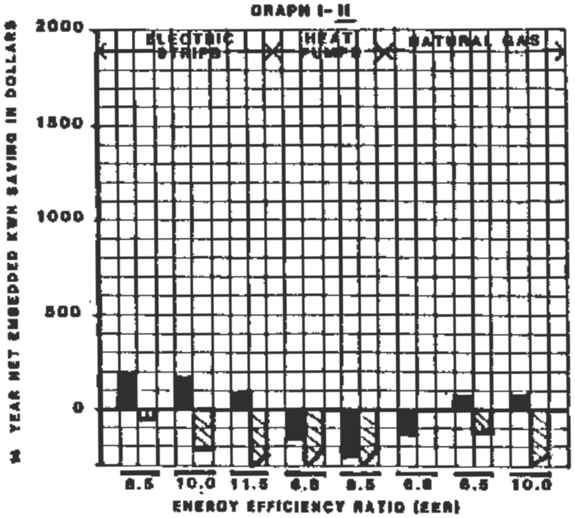
GRAPH I-HH



2400 SF SINGLE FAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

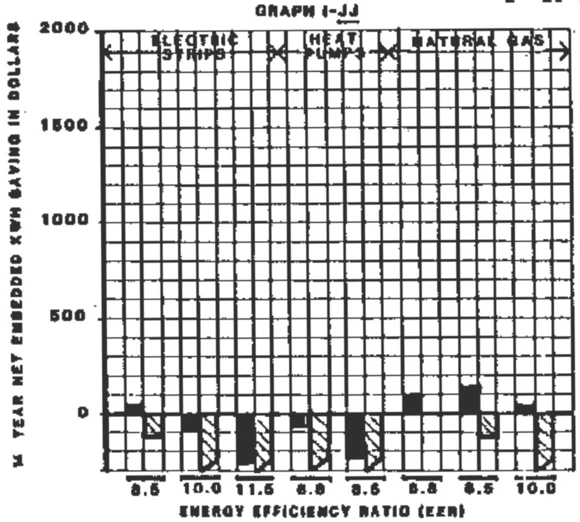
70 I-15

GRAPH I-II



MULTIFAMILY
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

GRAPH I-JJ



MOBILE HOME
CENTRAL FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

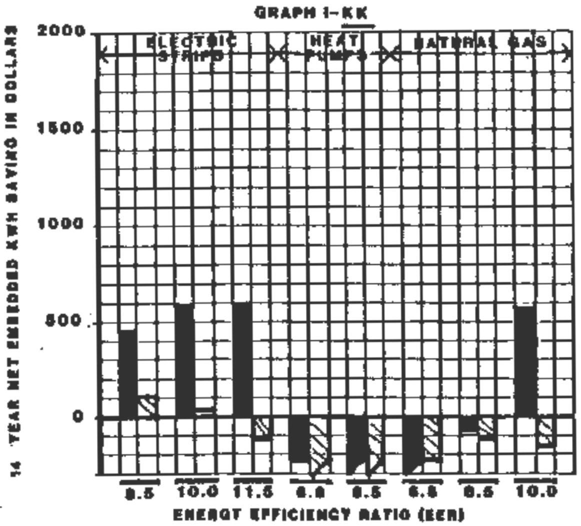
P R E S E N T   V A L U E   A N A L Y S I S

T E N   Y E A R S

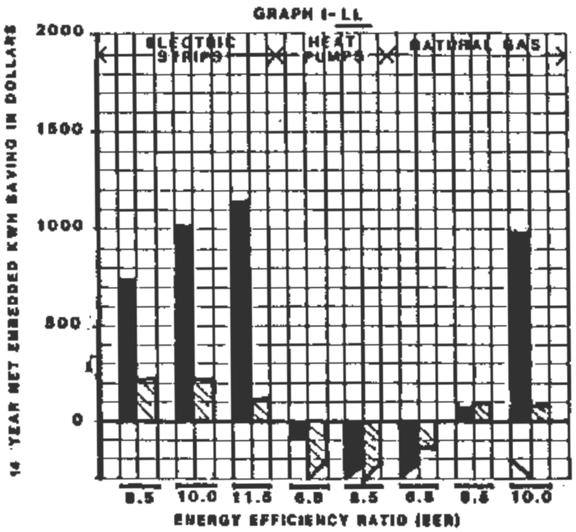
CENTRAL FLORIDA

SOLID BARS INDICATE
100% USAGE

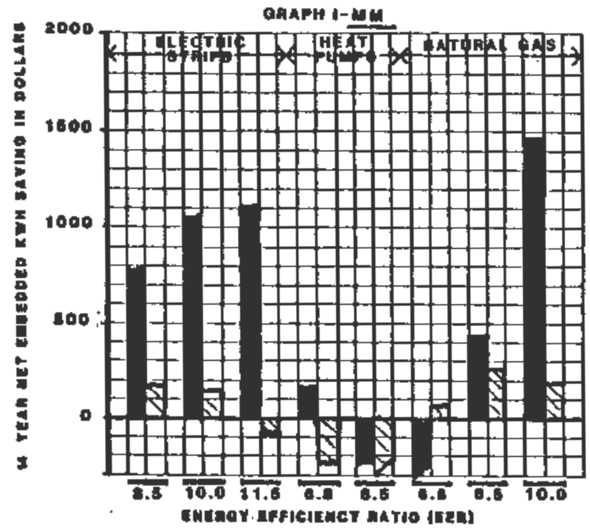
CROSS HATCHED BARS
INDICATE 50% USAGE



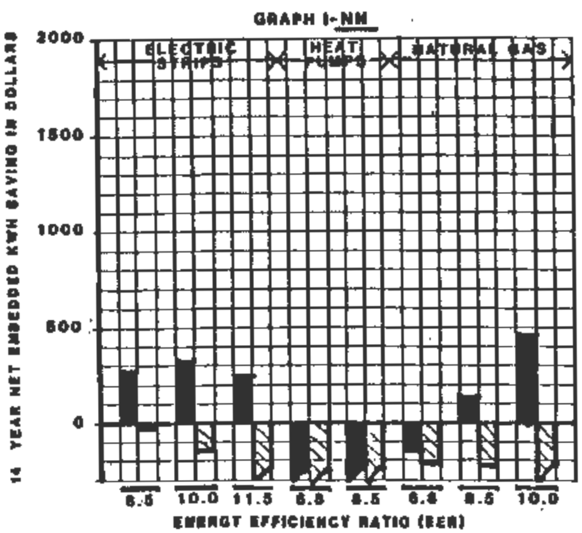
800 SF SINGLE FAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



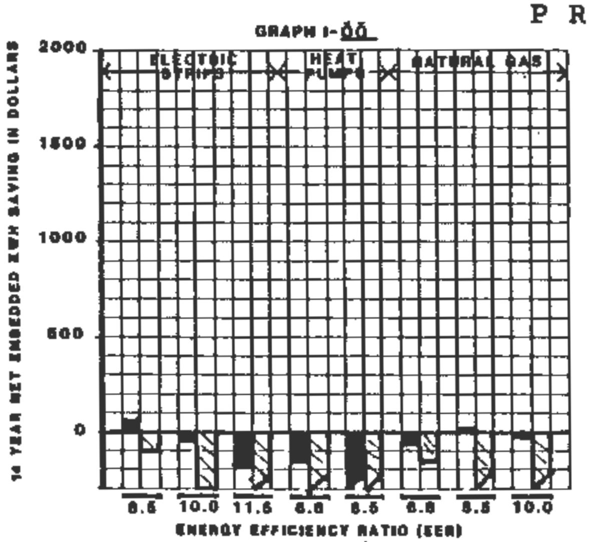
1600 SF SINGLE FAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



2400 SF SINGLE FAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



MULTIFAMILY
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS



MOBILE HOME
SOUTH FLORIDA
BASE CASE: STRAIGHT COOL WITH EER-6.8 AND RESISTANCE STRIPS

PRESENT VALUE ANALYSIS

TEN YEARS

SOUTH FLORIDA

SOLID BARS INDICATE
100% USAGE

CROSS HATCHED BARS
INDICATE 50% USAGE

COORDINATION WITH OTHER MEASURES

The energy code can be used to benefit the people of Florida. However, the program will not succeed in full measure if other programs are not carried forth at the same time. Specifically, programs for demand metering, time of use metering, and demand control must be continued.

It is absolutely essential that these programs not be put forth without the code program. These programs do not make better buildings. It is more beneficial to the typical Florida citizen to live in a home which peaks out with fewer kilowatts than to call upon that citizen to undergo control of peak loads.

After the buildings are constructed with low peak and energy characteristics, other programs can be put into effect to bring about a second level of improvements.

THEORIES

Every study of this kind generates theories which are not in the domain of the study, and which deserve further analysis. The following theories have evolved from this study.

1. Peak demand will become more exaggerated in the future because, as the price of energy grows higher, people conserve and this conservation is taken from the base, not the peak. The result is that peaks (especially winter peaks) will increase at rates faster than the growth of the base load. This phenomenon is expected to accelerate in future years at a rate higher than in the past.

The need is clear for extensive demand reduction measures and accelerated programs to provide peaking generation.

2. Winter visitors contribute extensively to south and central Florida winter peak conditions. At the same time, because their air conditioning and heating systems are used so little, it is difficult to obtain personal dollar benefits from improvements in efficiencies.

3. People who live in small apartments and homes are those with the lower incomes. Small dwellings are equipped with the least efficient systems. Therefore, lower income people have the greatest need for governmental participation in construction via the energy code.

4. Air conditioning and heating system oversizing causes about 6% unnecessary consumption of residential energy in Florida. In addition, the oversized equipment costs more and provides less comfort. This is an area where the "free market" process can bring benefits through a program starting with research and ending with an outreach program to encourage voluntary size reductions.

IMPLEMENTATION

Following is a list of tasks to implement the recommendations of the report. In addition, studies and programs are listed which are not part of the report but which should be put forth to improve Florida buildings.

1. Modify the energy code for December 31, 1981 issuance. Recommendations similar to those contained in the report will be incorporated. This task is to be accomplished by DVCA.

2. Complete the service availability charge. If a charge is to be placed on new homes which do not possess efficient air conditioning, heating, and water heating systems prior to meter installation, a program for inspection must be instituted. The meter installers, who will to inspect the equipment for compliance must be properly trained. The DVCA can take part by having manufacturers place stickers on complying equipment at the factories.

If the service availability charge is dropped, it is recommended that the sticker program and the meter installer inspection be put into effect, anyway. The outstanding problem now with the energy code is the difficulty of implementation. We estimate that only 50% of the residences now being constructed comply with the code. This percentage can be raised appreciably by expanding the DVCA educational and promotional programs. It will also be helped by the meter installer inspections.

Municipal utilities and REA cooperatives should be brought into the inspection program.

3. During the coming year, the energy code must be improved to reduce peak demand and save energy to the next level of cost effectiveness. DVCA is now in the process of preparing a plan.

4. Approximately 4 million Florida homes were built before the energy code. These existing homes are generally inefficient. Many have no insulation. Almost all have inefficient systems. It is cost effective to the consumer to change out much of the equipment. In this age of high interest rates, most home owners are reluctant to spend the money for improvements and landlords have no incentive to change equipment. A successful program for existing homes should be initiated which would include a method of calculating the EPI (similar to the EPA for automobiles) for existing homes. The program would audit all homes in Florida.

Such a program must include a plan to simplify the job for the homeowner and provide low interest rates for the improvement. Most importantly, the savings generated by the improvements would be applied directly, resulting in no increase in utility bills for consumers. A mini-study should be put forward to determine the exact degree of benefits to be derived by mass retrofitting of residential buildings.

5. At the very least, existing home EPI points should be disclosed at the time of sale of the residence.

6. Non-residential buildings need to be studied for opportunities for peak demand reductions. The code now does not address itself to peak demand. A study should be put forth for non-residential buildings, because there is a vast source of untapped energy and demand resources available.

Traditionally, non-residential buildings have been designed without any regard for peak demand limitations or reductions. Most commercial and institutional buildings possess cost effective opportunities for demand reductions. In spite of widespread use of demand meters, there is now little incentive in the building industry to design buildings and systems to avoid peaking loads.

The energy code has a new section which shows the person designing the building where energy is being spent. This section can also incorporate a calculation of the peak demand and show the causes which create the peak. Incentives can be added to put into the design of the building those features which reduce peaks.

For example, most commercial buildings in Florida do not require winter heating during the day, but must be heated in the morning to get started. This causes a load during the power company peak period. The code can be used to encourage peak load reductions by setting up incentives for preheating buildings prior to the morning peak period. If such a code incentive is coupled with a rate incentive, the result will be reduced peaks and more productive electric utility operations.

Almost every building on line now wastes 10% to 50% of its energy because designs were made in an era when energy conservation was not an issue. The most sophisticated members of the construction and building management industries do not understand how energy is spent in their buildings. Millions of dollars have been spent in areas that provided little or no improvements. The DVCA possesses the nucleus of the staff necessary to bring about meaningful advancements.

CHAPTER II
AIR CONDITIONING AND HEATING SYSTEM ENERGY CONSUMED

The energy consumed by five types of residences was calculated using methods and assumptions described in Appendix A. This chapter is set up in four parts. In the first part, energy consumption figures are presented for the five configurations. The second part shows the costs of improvements in equipment efficiencies. The third part tabulates the cost differences for improvements, along with the improvements in kilowatt hours and the improvements in peak demand. The fourth part shows the net savings and losses resulting from the improvements for a five year period, a 10 year period, and a present value analysis (10 years).

For North Florida, Central Florida, and South Florida the kilowatt hours consumed are shown in the following three tables. Air conditioning energy is listed for four EERs (Energy Efficiency Ratios). Heating energy is listed for electric resistance heat strips, and heat pumps with three COPs (Coefficients of Performance).

TABLE II - A

NORTH FLORIDA--AIR CONDITIONING--KWH

EER	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
6.8	3,913	6,614	7,801	3,936	2,375
8.5	3,130	5,291	6,241	3,149	1,900
10.0	2,661	4,498	5,305	2,676	1,614
11.5	2,314	3,913	4,615	2,329	1,404

NORTH FLORIDA--HEATING--KWH

COP	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
STRIP	4,955	6,519	9,300	2,966	3,566
2.3	2,790	3,680	5,280	1,720	1,879
2.6	2,522	3,290	4,628	1,575	1,657
2.8	2,316	3,030	4,285	1,473	1,491

(North Florida and Central Florida heat pumps have supplementary resistance strips.)

TABLE II - B

CENTRAL FLORIDA--AIR CONDITIONING--KWH

EER	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
6.8	4,849	7,400	8,605	4,354	2,636
8.5	3,879	5,920	7,315	3,701	2,241
10.0	3,298	5,032	5,851	2,961	1,792
11.5	2,868	4,376	5,091	2,576	1,560

CENTRAL FLORIDA--HEATING--KWH

COP	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
STRIP	2,595	3,391	6,717	1,542	1,890
2.3	1,401	1,828	3,654	883	996
2.6	1,268	1,653	3,305	774	878
2.8	1,167	1,521	3,060	717	791

TABLE II - C

SOUTH FLORIDA --AIR CONDITIONING--KWH

EER	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
6.8	6,402	8,930	10,143	5,108	2,975
8.5	5,121	7,144	8,114	4,086	2,380
10.0	4,353	6,070	6,898	3,473	2,023
11.5	3,788	5,284	6,001	3,022	1,760

SOUTH FLORIDA --HEATING--KWH

COP	HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
STRIP	1,070	1,486	2,746	664	1,411
2.3	466	673	1,267	303	645
2.6	404	607	1,129	269	575
2.8	381	526	979	233	499

Miami heat pumps have no supplementary heat strips.

The table below shows the differences in cost for air conditioning and heating systems. Notice that only the differences are shown. For example, an air conditioner (straight cool) rated at 1.5 tons and an SEER of 8.5 will cost $274 more than a unit with an SEER of 6.8.

AIR CONDITIONING AND HEATING SYSTEM COST DIFFERENCES

TONS	EER				
	6.8SC-8.5SC	8.5SC-10SC	10SC-11.5SC	6.8SC-6.8HP	8.5SC-8.5G
1.5	$ 274	$ 290	$ 300	$ 572	$ 163
3	286	300	310	550	120
4	374	400	450	640	93

The next table shows averaged cost differences for four sizes of air conditioners and five ranges of systems.

SC=Straight cool with heat strips
HP=Heat pump with supplementary strips
G=Natural gas furnace with straight cool-includes pilotless ignition, auto vent damper, piping & venting.

The following three tables summarize costs, and energy and peak demand savings.

TABLE II - D

NORTH FLORIDA
FIRST COST DIFFERENCES/KWH ENERGY SAVED/KW DEMAND SAVED *

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	274	286	374	286	274
	KWH	783	1323	1560	787	475
	KW	0.48	0.84	1.22	0.84	0.51
8.5 SC--10 SC	$	290	300	400	300	290
	KWH	469	794	936	473	286
	KW	0.29	0.51	0.73	0.51	0.30
10 SC--11.5 SC	$	300	310	450	310	300
	KWH	347	587	692	347	210
	KW	0.27	0.48	0.69	0.48	0.29
HEATING						
6.8 SC--6.8 HP COP=2.3	$	572	550	640	550	572
	KWH	2165	2839	4020	1246	1607
	KW	1.65	3.00	4.31	2.91	2.35
2.3 HP--2.6 HP EER=8.5	$	280	350	490	350	280
	KWH	268	390	652	145	222
	KW	0.17	0.31	0.46	0.31	0.25
8.5 SC--8.5 GAS	$	348	305	272	305	348
	KWH	na	na	na	na	na
	KW	5.38	9.72	14.03	9.48	7.65

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

* KW demand numbers are for individual residences.

TABLE II - E

CENTRAL FLORIDA--FIRST COST DIFFERENCES/KWH ENERGY SAVED/KW DEMAND SAVED *

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONED						
6.8 SC--8.5 SC	$	274	286	374	286	274
	KWH	970	1480	1721	871	528
	KW	0.47	0.97	1.44	0.93	0.48
8.5 SC--10 SC	$	290	300	400	300	290
	KWH	581	888	1033	522	310
	KW	0.28	0.58	0.87	0.56	0.29
10 SC--11.5 SC	$	300	310	450	310	300
	KWH	430	656	763	387	232
	KW	0.21	0.43	0.64	0.41	0.21
HEATING						
6.8 SC--6.8 HP COP=2.3	$	572	550	640	550	572
	KWH	1194	1563	3063	659	894
	KW	1.66	2.84	4.09	2.18	2.00
2.3 HP--2.6 HP EER=8.5	$	280	350	490	350	280
	KWH	133	175	349	109	118
	KW	0.17	0.30	0.43	0.21	0.20
8.5 SC--8.5 GAS	$	348	305	272	305	348
	KWH	na	na	na	na	na
	KW	5.38	9.22	13.3	7.06	6.51

Heat pumps have supplementary heat strips which are a maximum of 35% of the design heat load.

* KW demand numbers are for individual residences.

TABLE II - F

SOUTH FLORIDA --FIRST COST DIFFERENCES/KWH ENERGY SAVED/KW DEMAND SAVED *

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	274	286	374	286	274
	KWH	1281	1786	2029	1022	595
	KW	0.47	0.97	1.44	0.85	0.48
8.5 SC--10 SC	$	290	300	400	300	290
	KWH	768	1074	1217	613	357
	KW	0.28	0.58	0.87	0.51	0.29
10 SC--11.5 SC	$	300	310	450	310	300
	KWH	565	786	900	453	264
	KW	0.21	0.43	0.64	0.38	0.21
HEATING						
6.8 SC--6.8 HP	$	572	550	640	550	572
COP=2.3	KWH	604	813	1479	361	766
(no strips)	KW	1.67	3.42	5.90	2.86	1.19
2.3 HP--2.6 HP	$	280	350	490	350	280
EER=8.5	KWH	60	64	138	34	70
	KW	0.16	0.33	0.57	0.28	0.12
8.5 SC--8.5 GAS	$	348	305	272	305	348
	KWH	na	na	na	na	na
	KW	3.30	6.76	11.65	5.65	2.35

* KW demand numbers are for individual residences.

The next three tables describe the financial saving to the consumer for five years of operation. The numbers are based on the consumer in the 25% tax bracket, paying a 15% mortgage for 30 years, with 2% property taxes. Energy costs are $0.065 per kilowatt hour for the first year of 1982, rising linearly to $ 0.1165 in 1989. The three numbers shown for each entry are energy costs saved, costs of ownership, and the difference which is the savings or loss. Parentheses are used to highlight conditions that represent a loss to the consumer.

These tables contain only energy cost-benefit data with embedded peak demand allocations. (No marginal allocations are shown for peak demand improvements).

Gas prices are shown averaged over next 5 years as: $0.619/THERM.

Refer to Appendix B for example analysis.

TABLE II-G
100% USAGE
NORTH FLORIDA--FIVE YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	313	528	622	314	189
	$	205	217	284	217	205
	$	108	311	338	97	(16)
8.5 SC--10 SC	$	187	317	374	189	114
	$	219	228	304	228	219
	$	(32)	89	70	(39)	(105)
10 SC--11.5 SC	$	138	234	276	139	84
	$	228	236	342	258	228
	$	(90)	(2)	(66)	(119)	(144)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	864	1133	1604	497	642
	$	434	418	486	418	434
	$	430	715	1118	79	208
2.3 HP--2.6 HP EER=8.5	$	106	155	260	58	89
	$	213	267	372	267	213
	$	(107)	(112)	(112)	(209)	(124)
8.5 SC--8.5 GAS	$	1152	1512	2160	688	828
	$	264	232	207	232	264
	$	888	1280	1953	456	564

Heat pumps have supplementary heat strips sized at 35%.

TABLE II - H
100% USAGE
CENTRAL FLORIDA--FIVE YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	387	591	687	348	211
	$	205	217	284	217	205
	$	182	374	403	131	6
8.5 SC--10 SC	$	232	355	412	208	124
	$	219	228	304	228	219
	$	13	127	108	(20)	(95)
10 SC--11.5 SC	$	172	262	305	154	93
	$	228	235	342	235	228
	$	(56)	27	(37)	(81)	(135)
HEATING						
6.8 SC--6.8 HP	$	476	624	1225	263	356
COP= 2.3	$	434	418	486	418	434
	$	42	206	739	(155)	(78)
2.3 HP--2.6 HP	$	53	70	140	44	47
EER=8.5	$	213	266	372	266	213
	$	(160)	(196)	(232)	(222)	(166)
8.5 SC--8.5 GAS	$	599	787	1640	355	436
		264	232	207	232	264
	$	335	555	1433	123	172

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - I

100% USAGE

SOUTH FLORIDA --FIVE YEAR ENERGY BENEFIT-COST TABLE

SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	511	713	810	408	237
	$	205	217	283	217	205
	$	306	496	527	191	32
8.5 SC--10 SC	$	307	428	486	245	142
	$	219	228	304	228	219
	$	88	200	182	17	(77)
10 SC--11.5 SC	$	225	314	359	181	106
	$	228	236	342	236	228
	$	(3)	78	17	(55)	(122)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	241	324	590	144	306
	$	434	418	486	418	434
	$	(193)	(94)	104	(274)	(128)
2.3 HP--2.6 HP EER=8.5	$	24	26	55	14	28
	$	213	267	372	267	213
	$	(189)	(241)	(317)	(253)	(185)
8.5 SC--8.5 GAS	$	248	342	634	153	324
	$	264	232	207	232	264
	$	(16)	110	427	(79)	60

Heat pumps have no supplementary heat strips.

The next three tables show benefits and costs similar to the last three, but it is assumed that consumption will be 50% of the numbers shown in tables II-A, II-B and II-C.

TABLE II-J
50% USAGE
NORTH FLORIDA--FIVE YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	156	264	311	157	95
	$	205	217	284	217	205
	$	(48)	47	27	(60)	(110)
8.5 SC--10 SC	$	94	158	187	94	57
	$	219	228	304	228	219
	$	(125)	(69)	(117)	(134)	(162)
10 SC--11.5 SC	$	69	117	138	69	42
	$	228	236	342	258	228
	$	(159)	(119)	(204)	(189)	(186)
HEATING						
6.8 SC--6.8 HP	$	432	566	802	248	321
COP= 2.3	$	434	418	486	418	434
	$	(2)	148	316	(170)	(113)
2.3 HP--2.6 HP	$	53	78	130	29	45
EER=8.5	$	213	267	372	267	213
	$	(160)	(189)	(242)	(238)	(168)
8.5 SC--8.5 GAS	$	576	756	1080	344	414
	$	264	232	207	232	264
	$	312	524	873	112	150

Heat pumps have supplementary heat strips sized at 35%.

TABLE II - K
50% USAGE
CENTRAL FLORIDA--FIVE YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	194	296	344	174	105
	$	205	217	284	217	205
	$	(11)	79	60	(43)	(100)
8.5 SC--10 SC	$	116	178	206	104	62
	$	219	228	304	228	219
	$	(103)	(50)	(98)	(124)	(151)
10 SC--11.5 SC	$	86	131	152	77	47
	$	228	235	342	235	228
	$	(142)	(104)	(190)	(158)	(181)
HEATING						
6.8 SC--6.8 HP	$	238	312	613	131	178
COP= 2.3	$	434	418	486	418	434
	$	(196)	(106)	127	(287)	(256)
2.3 HP--2.6 HP	$	27	35	70	22	23
EER=8.5	$	213	266	372	266	213
	$	(186)	(231)	(302)	(244)	(190)
8.5 SC--8.5 GAS	$	300	394	820	178	218
		264	232	207	232	264
	$	36	162	613	(54)	(46)

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - L
50% USAGE
SOUTH FLORIDA --FIVE YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	256	357	405	204	118
	$	205	217	283	217	205
	$	51	140	122	(13)	(87)
8.5 SC--10 SC	$	153	214	243	122	71
	$	219	228	304	228	219
	$	(66)	(14)	(61)	(106)	(148)
10 SC--11.5 SC	$	112	157	180	90	53
	$	228	236	342	236	228
	$	(116)	(79)	(162)	(146)	(175)
HEATING						
6.8 SC--6.8 HP	$	120	162	295	72	153
COP= 2.3	$	434	418	486	418	434
	$	(314)	(256)	(191)	(346)	(281)
2.3 HP--2.6 HP	$	12	13	28	7	14
EER=8.5	$	213	267	372	267	213
	$	(201)	(254)	(344)	(260)	(199)
8.5 SC--8.5 GAS	$	124	171	317	76	162
	$	264	232	207	232	264
	$	(140)	(61)	110	(156)	(102)

Heat pumps have no supplementary heat strips.

The next three tables show benefits and costs of air conditioning and heating systems based on life-of-equipment durations of 10 years and 100% usage. Energy costs are $ 1.15/therm for gas and $ 0.097/KWH for electricity.

TABLE II-M
100% USAGE
NORTH FLORIDA-TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	760	1283	1513	763	461
	$	506	529	691	529	506
	$	254	754	822	234	(45)
8.5 SC--10 SC	$	454	770	908	459	277
	$	536	555	740	555	536
	$	(82)	215	168	(96)	(259)
10 SC--11.5 SC	$	336	569	671	337	204
	$	555	574	832	574	555
	$	(219)	(5)	(161)	(237)	(351)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	2100	2753	3899	1209	1559
	$	1058	948	1184	948	1058
	$	1042	1805	2715	261	501
2.3 HP--2.6 HP EER=8.5	$	260	378	632	141	215
	$	518	648	906	648	518
	$	(258)	(270)	(274)	(507)	(303)
8.5 SC--8.5 GAS	$	1833	2472	3441	1097	1319
	$	644	564	503	564	644
	$	1189	1908	2938	533	675

TABLE II - N

100% USAGE

CENTRAL FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE

SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	941	1436	1669	845	512
	$	506	529	691	529	506
	$	435	907	978	316	6
8.5 SC--10 SC	$	563	861	1002	506	301
	$	536	555	740	555	536
	$	27	306	262	(49)	(235)
10 SC--11.5 SC	$	417	636	740	375	225
	$	555	574	832	574	555
	$	(138)	62	(92)	(199)	(330)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	1158	1516	2971	533	555
	$	1058	948	1184	948	1058
	$	100	568	1787	(415)	(503)
2.3 HP--2.6 HP EER=8.5	$	129	170	339	106	114
	$	518	648	906	648	518
	$	(389)	(478)	(567)	(542)	(404)
8.5 SC--8.5 GAS	$	960	1254	2485	570	699
	$	644	564	503	564	644
	$	316	690	1982	6	55

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - O
100% USAGE
SOUTH FLORIDA --TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	1243	1732	1968	991	577
	$	506	529	691	529	506
	$	737	1203	1277	462	71
8.5 SC--10 SC	$	745	1042	1180	594	346
	$	536	555	740	555	536
	$	209	487	440	39	(190)
10 SC--11.5 SC	$	548	762	873	439	256
	$	555	574	832	574	555
	$	(7)	188	41	(135)	(299)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	586	789	1434	350	743
	$	1058	948	1184	948	1058
	$	(472)	(159)	250	(598)	(315)
2.3 HP--2.6 HP EER=8.5	$	58	62	134	33	68
	$	518	648	906	648	518
	$	(460)	(586)	(772)	(615)	(450)
8.5 SC--8.5 GAS	$	396	550	1016	246	522
	$	644	564	503	564	644
	$	(248)	(14)	513	(318)	(122)

Heat pumps have no supplementary heat strips.

The next three tables show benefits and costs similar to the last three, but it is assumed that consumption will be 50% of the numbers shown in tables II-M, II-N and II-O.

TABLE II-P
50% USAGE
NORTH FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	380	642	756	381	230
	$	506	529	691	529	506
	$	(126)	113	65	(148)	(276)
8.5 SC--10 SC	$	227	385	454	230	138
	$	536	555	740	555	536
	$	(309)	(170)	(286)	(325)	(398)
10 SC--11.5 SC	$	168	284	336	168	102
	$	555	574	832	574	555
	$	(387)	(290)	(496)	(406)	(453)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	1050	1376	1949	603	780
	$	1058	948	1184	948	1058
	$	(8)	(428)	765	(345)	(278)
2.3 HP--2.6 HP EER=8.5	$	130	189	316	70	108
	$	518	648	906	648	518
	$	(388)	(459)	(590)	(578)	(410)
8.5 SC--8.5 GAS	$	916	1236	1720	548	660
	$	644	564	503	564	644
	$	272	672	1217	(16)	16

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - Q

50% USAGE

CENTRAL FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE

SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	471	718	834	423	256
	$	506	529	691	529	506
	$	(35)	189	143	(106)	(250)
8.5 SC--10 SC	$	281	430	501	253	151
	$	536	555	740	555	536
	$	(255)	(125)	(239)	(302)	(385)
10 SC--11.5 SC	$	208	318	370	188	112
	$	555	574	832	574	555
	$	(347)	(256)	(462)	(386)	(443)
HEATING						
6.8 SC--6.8 HP	$	579	758	1485	267	278
COP= 2.3	$	1058	948	1184	948	1058
	$	(479)	(190)	301	(681)	(780)
2.3 HP--2.6 HP	$	65	85	170	53	57
EER=8.5	$	518	648	906	648	518
	$	(453)	(563)	(736)	(595)	(461)
8.5 SC--8.5 GAS	$	480	627	1242	285	350
	$	644	564	503	564	644
	$	(164)	63	739	(279)	(294)

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - R

50% USAGE

SOUTH FLORIDA --TEN YEAR ENERGY BENEFIT-COST TABLE

SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	621	866	984	496	288
	$	506	529	691	529	506
	$	115	337	293	(33)	(218)
8.5 SC--10 SC	$	372	521	590	297	173
	$	536	555	740	555	536
	$	(164)	(34)	(150)	(258)	(363)
10 SC--11.5 SC	$	274	381	436	220	128
	$	555	574	832	574	555
	$	(281)	(193)	(396)	(354)	(427)
HEATING						
6.8 SC--6.8 HP	$	293	394	717	175	372
COP= 2.3	$	1058	948	1184	948	1058
	$	(765)	(554)	(467)	(773)	(686)
2.3 HP--2.6 HP	$	29	31	67	17	34
EER=8.5	$	518	648	906	648	518
	$	(489)	(617)	(839)	(631)	(484)
8.5 SC--8.5 GAS	$	198	275	508	123	261
	$	644	564	503	564	644
	$	(446)	(289)	5	(441)	(383)

Heat pumps have no supplementary heat strips.

The next three tables show present value benefits and costs of air conditioning and heating systems based on life-of-equipment durations of 10 years and 100% usage.

TABLE II-S
PRESENT VALUE - 100% USAGE
NORTH FLORIDA-TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	445	752	887	448	270
	$	273	292	382	292	273
	$	172	460	505	156	(3)
8.5 SC--10 SC	$	267	451	532	269	163
	$	296	306	408	306	296
	$	(29)	145	124	(37)	(133)
10 SC--11.5 SC	$	197	336	393	197	119
	$	306	316	459	316	306
	$	(109)	20	(66)	(119)	(187)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	1230	1613	2284	708	913
	$	583	561	653	561	583
	$	647	1052	1631	147	330
2.3 HP--2.6 HP EER=8.5	$	152	222	371	82	126
	$	286	357	499	357	286
	$	(134)	(135)	(128)	(567)	(160)
8.5 SC--8.5 GAS	$	1254	1672	2384	761	911
	$	354	311	277	311	354
	$	900	1361	2107	450	557

TABLE II - T
PRESENT VALUE - 100% USAGE
CENTRAL FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	551	841	978	494	301
	$	273	292	382	292	273
	$	278	549	596	202	28
8.5 SC--10 SC	$	330	505	587	297	176
	$	296	306	408	306	296
	$	34	199	179	(9)	(120)
10 SC--11.5 SC	$	244	373	434	220	132
	$	306	316	459	316	306
	$	(62)	57	(25)	(96)	(174)
HEATING						
6.8 SC--6.8 HP	$	679	888	1740	375	508
COP= 2.3	$	583	561	653	561	583
	$	96	327	1087	(186)	(75)
2.3 HP--2.6 HP	$	76	99	198	62	67
EER=8.5	$	286	357	499	357	286
	$	(210)	(258)	(301)	(295)	(219)
8.5 SC--8.5 GAS	$	661	871	1732	396	483
	$	354	311	277	311	354
	$	307	560	1455	85	129

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - U
PRESENT VALUE - 100% USAGE
SOUTH FLORIDA --TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	732	1015	1153	581	338
	$	273	292	382	292	273
	$	459	723	771	289	65
8.5 SC--10 SC	$	436	610	692	348	203
	$	296	306	408	306	296
	$	140	304	284	42	(93)
10 SC--11.5 SC	$	321	447	511	257	150
	$	306	316	459	316	306
	$	15	131	52	(59)	(156)
HEATING						
6.8 SC--6.8 HP	$	343	462	841	205	435
COP= 2.3	$	583	561	653	561	583
	$	(240)	(99)	188	(356)	(148)
2.3 HP--2.6 HP	$	34	36	78	19	40
EER=8.5	$	286	357	499	357	286
	$	(252)	(321)	(421)	(338)	(246)
8.5 SC--8.5 GAS	$	271	381	706	169	358
	$	354	311	277	311	354
	$	(83)	70	429	142	4

Heat pumps have no supplementary heat strips.

The next three tables show present value benefits and costs similar to the last three, but it is assumed that consumption will be 50% of the numbers shown in tables II-S, II-T and II-U.

TABLE II-V
PRESENT VALUE - 50% USAGE
NORTH FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVING OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	222	376	443	224	135
	$	273	292	382	292	273
	$	(51)	84	61	(68)	(138)
8.5 SC--10 SC	$	133	225	266	134	81
	$	296	306	408	306	296
	$	(163)	(81)	(142)	(172)	(215)
10 SC--11.5 SC	$	98	168	196	98	59
	$	306	316	459	316	306
	$	(208)	(148)	(263)	(218)	(247)
HEATING						
6.8 SC--6.8 HP	$	615	806	1142	354	456
COP= 2.3	$	583	561	653	561	583
	$	32	245	489	(207)	(127)
2.3 HP--2.6 HP	$	76	111	185	41	63
EER=8.5	$	286	357	499	357	286
	$	(210)	(246)	(314)	(316)	(223)
8.5 SC--8.5 GAS	$	627	836	1192	381	456
	$	354	311	277	311	354
	$	273	525	915	70	102

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - W
PRESENT VALUE - 50% USAGE
CENTRAL FLORIDA--TEN YEAR ENERGY BENEFIT-COST TABLE
SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	275	420	489	247	150
	$	273	292	382	292	273
	$	2	128	107	(45)	(123)
8.5 SC--10 SC	$	165	252	293	148	88
	$	296	306	408	306	296
	$	(131)	(54)	(115)	(158)	(208)
10 SC--11.5 SC	$	122	186	117	110	66
	$	306	316	459	316	306
	$	(184)	(130)	(342)	(206)	(240)
HEATING						
6.8 SC--6.8 HP COP= 2.3	$	339	444	870	187	254
	$	583	561	653	561	583
	$	(244)	(117)	217	(374)	(329)
2.3 HP--2.6 HP EER=8.5	$	38	49	99	31	33
	$	286	357	499	357	286
	$	(248)	(308)	(400)	(326)	(253)
8.5 SC--8.5 GAS	$	331	436	866	198	242
	$	354	311	277	311	354
	$	(23)	125	589	(113)	(112)

Heat pumps have supplementary heat strips sized at 35% of the design winter load.

TABLE II - X

PRESENT VALUE - 50% USAGE

SOUTH FLORIDA --TEN YEAR ENERGY BENEFIT-COST TABLE

SAVINGS IN DOLLARS/COSTS IN DOLLARS/NET SAVINGS OR LOSS

		HOUSE 800 SF	HOUSE 1600 SF	HOUSE 2400 SF	MULTI-FAMILY	MOBILE HOME
AIR CONDITIONING						
6.8 SC--8.5 SC	$	386	507	576	290	169
	$	273	292	382	292	273
	$	113	215	194	(2)	(104)
8.5 SC--10 SC	$	218	305	346	174	101
	$	296	306	408	306	296
	$	(78)	(1)	(62)	(132)	(195)
10 SC--11.5 SC	$	160	223	255	128	75
	$	306	316	459	316	306
	$	(146)	(93)	(204)	(188)	(231)
HEATING						
6.8 SC--6.8 HP	$	176	231	420	102	217
COP= 2.3	$	583	561	653	561	583
	$	(407)	(330)	(233)	(459)	(366)
2.3 HP--2.6 HP	$	17	18	39	9	20
EER=8.5	$	286	357	499	357	286
	$	(269)	(339)	(460)	(348)	(266)
8.5 SC--8.5 GAS	$	136	190	353	85	179
	$	354	311	277	311	354
	$	(218)	(121)	76	(226)	(175)

Heat pumps have no supplementary heat strips.

CHAPTER III
PEAK DEMAND REDUCTION

The energy code now addresses energy in kilowatt hours only. To comply with the code, every residence must have 100 points or fewer EPI (Energy Point Index) as calculated using the method described in Section 9 of the Code (see Appendix E).

The existing code does not address the peak demand condition. This chapter investigates procedures which can be incorporated into Section 9 of the code for the purpose of achieving reductions in peak demand.

This chapter is divided into three parts.

Part 1 describes a method of obtaining peak demand reductions by setting forth a calculation for each residence which is similar in format to the existing Section 9 energy point calculation.

Part 2 presents a comparison of the energy point calculation and the peak point calculation. On the summer side, the energy point calculation causes improvements in residences that are so like the peak calculation improvements that, for the sake of simplicity, it is recommended that the code be stepped down for energy to obtain reductions in summer peaks.

Part 3 shows the probable state-wide effect of peak reductions, using the code.

PART 1 PEAK POINTS METHOD

The method calls for a calculation for each residence to be submitted when applying for a building permit. The residence must have 100 points or less for the winter peak index (WPI) and, if used, 100 or less for the summer peak index (SPI). The points have been developed to be proportional to the peak load for the residence.

For example, two residences of the same size with 100 points and 90 points can be expected to have peak loads of approximately 10% in difference.

The state has been divided into three climate zones which form three weather "bands"--north, central, and south. Calculations for these zones are based on weather in Jacksonville, Orlando, and Miami. Figures III-A, III-B, and III-C show the calculation method proposed for the three zones.

The figures show the factors which will result in a peak demand reduction of 10% below present construction. The percentage can be changed by putting in different factors or by changing the maximum points for compliance. For purposes of explanation, consider the south zone table III-C. Calculations are made in three steps. First, the energy element ratios are calculated (wall, roof, glass, etc.). Secondly, the summer point index is calculated. Thirdly, the winter point index is calculated.

The element ratios are simply the areas of the elements divided by the area of conditioned floor space. If the residence has 1200 square feet of wall area and 1000 square feet of floor area, the wall ratio will be 1.20.

The second step is to calculate the summer peak index, and in so doing, the designer will be seeing the features of the residence which make up the peak.

Multipliers are selected from the right hand side of figure III-C which apply to the elements. Consider two examples. Clear glass, single pane (one thickness) with a north facing exposure has a multiplier of 340. A wall which has R3 insulation will have a multiplier of 15.

The calculations are made in the bottom section to arrive at the summer point index. A full example calculation is worked out in Appendix C.

The final step is to calculate the heating point index by performing the calculations shown on the left side of the figure III-C.

Several outstanding features need to be explained. These calculations do not require any information to be taken from the plans beyond what is now required for a section 9 calculation.

The procedures shown can be incorporated onto the section 9 form, so no additional forms will be required.

Following is a list of elements and their relative influence on peaks, for typical homes.

In the winter, the selection of the heating system is the predominant matter. If oil or gas heat is chosen, the winter points become zero. The selection of a heat pump with no resistance heat back up is the next best low point choice. Heat pumps can result in differences of over 40 points. Resistance heat is the highest point item, because less heat is produced for each kilowatt-hour of energy expended than any other system shown.

The structural elements are listed with approximate contributions to peaks:

	Winter	Summer
Glass windows and doors	40%	65%
Roof	30%	10%
Walls	20%	15%
Doors	10%	10%

PART 2 COMPARISON OF PEAK POINTS WITH ENERGY POINTS

The existing energy point method can be used to reduce peak demand. For example, the summer energy points can be reduced by 5% by reducing the amount of glass by 10%. At the same time, the 10% glass reduction will cause a 5.4% reduction in peak.

The following table shows 10% improvement in major construction features and the resulting peak and energy point improvements, for summer conditions.

SUMMER--SOUTH FLORIDA

IMPROVEMENT	EFFECTS ON DEMAND POINTS		EFFECTS ON ENERGY POINTS	
REDUCE GLASS 10%	REDUCE	5.4%	REDUCE	5.0%
ADD 10% INSULATION				
WALLS	REDUCE	0.6	REDUCE	1.4
ROOF	REDUCE	0.3	REDUCE	0.6
ADD 10% TO A/C EER	REDUCE	9.1	REDUCE	7.2
MOVE A/C DUCTS INSIDE	REDUCE	15.0	REDUCE	12.0

It is apparent, that summer peak points and energy consumption points run closely parallel. Any improvement for energy will result in a like improvement for peak demand. Clearly, it is not necessary to incorporate into the code a calculation for energy and demand.

The existing calculation for energy can do the job for peak demand also. If the code is taken farther to reduce energy by setting lower EPI requirements for energy, the summer peaks will undergo a similar reduction.

This is not the case for winter. The following table shows the relationship.

WINTER - SOUTH FLORIDA

IMPROVEMENT	EFFECTS ON			
	DEMAND POINTS		ENERGY POINTS	
REDUCE GLASS 10%	REDUCE	2.1	REDUCE	0.3
ADD 10% INSULATION				
WALLS	REDUCE	0.6	REDUCE	0.2
ROOF		1.0		0.3
IMPROVE HEATING EFF. 10%	REDUCE	9.1	REDUCE	2.3
MOVE AIR DUCTS INSIDE	REDUCE	15.0	REDUCE	3.0
GAS COMFORT HEAT	REDUCE	100.0	REDUCE	10.0
CHANGE STRIPS TO H. PUMP	REDUCE	60.0	REDUCE	12.0
SOLAR COMFORT HEATING (50%)	REDUCE	0.0	REDUCE	10.0

The most significant reductions in peak demand can be obtained by improvements in the heating system. Therefore, it is recommended that the peak point system for winter only be incorporated into the energy code.

As explained earlier, the points shown in figures III-A, III-B, and III-C are specifically based on a 10% reduction in peak demand. This percentage was selected for purposes of explanation.

PART 3 STATEWIDE WINTER PEAK REDUCTIONS

This subchapter shows one scenario to predict the effect of winter demand reductions in each of the three climate zones and for the state as a whole.

Keep in mind that we are looking at future construction, not existing buildings. Mobile homes are not included.

The steps followed are:
1. Calculate the number of residences to be built, classified by size and climate zone. (Refer to Appendix D).
2. Calculate the winter peak demand of each size residence in kilowatts for each climate zone.
3. Calculate total peak demand for each climate zone and the state.
4. Calculate a 10% reduction. (The percentage is chosen for explanation purposes only).

Other scenarios can be selected and calculated using the method.

PART 3 STATEWIDE EFFECT OF WINTER DEMAND LIMITING

Residences constructed with heating systems other than resistance strips will comply. Therefore, only the following numbers of residences will be affected.

ANNUAL NEW RESIDENCES WITH
ELECTRICAL RESISTANCE HEATING SYSTEMS

CLIMATE ZONE	--------SINGLE 800 SF	FAMILY 1600 SF	--------- 2400 SF	MULTI-FAMILY
NORTH	2,700	2,700	300	5,400
CENTRAL	8,000	10,000	2,100	20,400
SOUTH	6,100	14,000	8,500	32,500
TOTALS	16,800	26,700	10,900	58,300

TOTAL FOR THE STATE........112,700

Winter peaks for residences by types are:

INDIVIDUAL RESIDENCE WINTER PEAKS (KILOWATTS)

CLIMATE ZONE	--------SINGLE 800 SF	FAMILY 1600 SF	--------- 2400 SF	MULTI-FAMILY
NORTH	5.38	9.72	14.03	9.48
CENTRAL	5.38	9.22	13.30	7.06
SOUTH	3.30	6.76	11.65	5.65

(See tables II-D, II-E and II-F)

The statewide annual increases in peak demand conditions are shown in the following table.

STATEWIDE RESIDENTIAL ANNUAL NEW PEAK (KW)

CLIMATE ZONE	--------SINGLE 800 SF	FAMILY 1600 SF	--------- 2400 SF	MULTI-FAMILY
NORTH	14,500	26,200	4,200	51,200
CENTRAL	43,000	92,200	27,900	144,000
SOUTH	20,100	94,600	127,000	183,600
TOTALS	208,100	213,000	159,100	378,800

TOTAL FOR STATE............ 959,000 KILOWATTS FOR ONE YEAR.

In a ten year period 9.6 million kilowatts of new installed heat strip peak load will come on line. Applying a coincidence factor of 50%, shows 4.8 million.

If winter peaks were reduced by 10%, the saving thus achieved will be 0.48 million kilowatts.

CHAPTER IV
WATER HEATING

This chapter shows energy and peak demand data for residential water heating systems.

For energy calculations, the following occupancies and rates of consumption were assumed.

TYPE RESIDENCE	NUMBER OF PEOPLE	GALLONS PER DAY
800 sf single family	2	40
1600 sf single family	4	70
2400 sf single family	5	85
Multi-family	2	40
Mobile home	2	40

The next table shows the first costs, federal tax rebates, and 5 year and 10 year summations of down payment plus annual payments.
The 5 and 10 year calculations are based on the same assumptions of interest and taxes shown in Appendix B.

The benefits and costs in this chapter are not incremental costs.

Solar system configurations are:
2 People - 17 SF high performance collector- 40 gal. storage.
4 People - 34 SF high performance collector- 60 gal. storage.
5 People - 51 SF high performance collector- 80 gal. storage.

All configurations include costs of tanks and electrical circuits.

TABLE IV-A

COST DATA
FIRST COSTS/TAX REBATE/FIVE YEAR COSTS/TEN YEAR COSTS

SYSTEM		800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
RESISTANCE				
incl. elec.	FC $	260	310	310
circuit	TR $	0	0	0
	5Y $	198	236	236
	10Y $	364	435	435
SOLAR				
incl. tank	FC $	1235	1885	2275
& wiring	TR $	494	754	910
	5Y $	466	711	858
	10Y $	1030	1573	1898
AC. HRU				
incl. tank	FC $	660	710	710
	TR $	0	0	0
	5Y $	502	539	539
	10Y $	925	996	996
H.P. HRU				
	FC $	660	710	710
	TR $	0	0	0
	5Y $	502	539	539
	10Y $	925	996	996
D. HEAT PUMP				
	FC $	1235	1235	1235
	TR $	0	0	0
	5Y $	939	939	939
	10Y $	1733	1733	1733
GAS				
	FC $	315	360	360
	TR $	0	0	0
	5Y $	239	274	274
	10Y $	442	505	505

Note: All systems include tank and wiring.

Energy consumption figures in kilowatt hours are shown in the following table for the three climate zones and the five types of systems which utilize electricity for fundamental or supplementary heat.

TABLE IV-B

ANNUAL ENERGY CONSUMPTION KILOWATT HOURS
ELECTRIC RESISTANCE/SOLAR SYSTEM/A-C
HEAT RECOVERY UNIT/HEAT PUMP HEAT
RECOVERY UNIT/DEDICATED HEAT PUMP

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
NORTH				
	RESISTANCE	2094	3589	4188
	SOLAR	440	1405	1871
	A.C., HRU	1268	2173	2537
	H.P., HRU	855	1417	1821
	D. HEAT PUMP	1047	1795	2094
CENTRAL				
	RESISTANCE	1896	3375	3938
	SOLAR	221	679	847
	A.C., HRU	1033	1840	2148
	H.P., HRU	675	1350	1500
	D. HEAT PUMP	948	1688	1969
SOUTH				
	RESISTANCE	1874	3351	3910
	SOLAR	219	674	840
	A.C., HRU	750	1341	1564
	H.P.	598	1125	1273
	D. HEAT PUMP	937	1676	1955

The next three tables are for the three climate zones and show the systems overall 5 year costs which include ownership plus energy.

TABLE IV-C

5 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
NORTH				
	RESISTANCE	$ 198	$ 236	$ 236
		$ 836	1432	1672
		$ 1034	1668	1908
	SOLAR	$ 466	$ 711	$ 858
		$ 176	561	747
		$ 642	1278	1605
	A.C., HRU	$ 502	$ 539	$ 539
		$ 506	868	1012
		$ 1008	1407	1551
	H.P., HRU	$ 502	$ 539	$ 539
		$ 341	566	727
		$ 843	1105	1266
	D. HEAT PUMP	$ 939	$ 939	$ 939
		$ 418	717	836
		$ 1357	1656	1775
	GAS	$ 239	$ 274	$ 274
		$ 356	611	713
		$ 595	885	987

TABLE IV-D

5 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
CENTRAL				
	RESISTANCE	$ 198	$ 236	$ 236
		$ 756	1347	1572
		$ 954	1583	1808
	SOLAR	$ 466	$ 711	$ 858
		$ 88	271	338
		$ 554	982	1196
	A.C., HRU	$ 502	$ 539	$ 539
		$ 412	735	858
		$ 914	1274	1397
	H.P., HRU	$ 502	$ 539	$ 539
		$ 269	529	599
		$ 771	1068	1138
	D. HEAT PUMP	$ 939	$ 939	$ 939
		$ 378	674	786
		$ 1317	1613	1725
	GAS	$ 239	$ 274	$ 274
		$ 333	574	670
		$ 572	848	944

TABLE IV-E

5 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
SOUTH				
	RESISTANCE	$ 198	$ 236	$ 236
		$ 748	1338	1561
		$ 946	1574	1797
	SOLAR	$ 466	$ 711	$ 858
		$ 87	269	335
		$ 553	980	1193
	A.C., HRU	$ 502	$ 539	$ 539
		$ 299	535	624
		$ 801	1074	1163
	H.P., HRU	$ 502	$ 539	$ 539
		$ 239	449	508
		$ 741	988	1047
	D. HEAT PUMP	$ 939	$ 939	$ 939
		$ 374	669	780
		$ 1313	1608	1719
	GAS	$ 239	$ 274	$ 274
		$ 319	570	665
		$ 558	844	939

The next three tables are for the three climate zones and show the systems overall 10 year costs which include ownership plus energy.

TABLE IV-F

10 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
NORTH				
	RESISTANCE	$ 364	$ 435	$ 435
		$ 2031	3481	4497
		$ 2395	3916	4932
	SOLAR	$ 1030	$ 1573	$ 1898
		$ 426	1362	1814
		$ 1456	2935	3712
	A.C., HRU	$ 925	$ 996	$ 996
		$ 1229	2107	2460
		$ 2154	3103	3456
	H.P., HRU	$ 925	$ 996	$ 996
		$ 829	1374	1766
		$ 1754	2370	2762
	D. HEAT PUMP	$ 1733	$ 1733	$ 1733
		$ 1015	1741	2031
		$ 2748	3474	3765
	GAS	$ 442	$ 505	$ 505
		$ 816	1400	1633
		$ 1258	1905	2138

TABLE IV-G
10 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
CENTRAL				
	RESISTANCE	$ 364	$ 435	$ 435
		$ 1839	3272	3819
		$ 2203	3708	4254
	SOLAR	$ 1030	$ 1573	$ 1898
		$ 214	659	821
		$ 1244	2232	2719
	A.C., HRU	$ 925	$ 996	$ 996
		$ 1002	1784	2083
		$ 1927	2780	3079
	H.P., HRU	$ 925	$ 996	$ 996
		$ 655	1310	1455
		$ 1580	2306	2451
	D. HEAT PUMP	$ 1733	$ 1733	$ 1733
		$ 919	1637	1910
		$ 2652	3370	3643
	GAS	$ 442	$ 505	$ 505
		$ 743	1323	1543
		$ 1185	1828	2049

TABLE IV-H

10 YEAR COST OF OWNERSHIP PLUS COST OF ENERGY

CLIMATE ZONE	SYSTEM	800 SF HOUSE MULTI-FAMILY MOBILE HOME	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
SOUTH				
	RESISTANCE	$ 364	$ 435	$ 435
		$ 1817	3250	3793
		$ 2181	3685	4227
	SOLAR	$ 1030	$ 1573	$ 1898
		$ 212	653	814
		$ 1242	2226	2712
	A.C., HRU	$ 925	$ 996	$ 996
		$ 727	1301	1517
		$ 1652	2297	2513
	H.P., HRU	$ 925	$ 996	$ 996
		$ 580	1091	1234
		$ 1505	2087	2230
	D. HEAT PUMP	$ 1733	$ 1733	$ 1733
		$ 908	1625	1896
		$ 2641	3358	3629
	GAS	$ 442	$ 505	$ 505
		$ 365	653	762
		$ 807	1158	1267

Following are peak demand kilowatts for each type of system.

INDIVIDUAL WATER HEATER PEAK DEMAND IN KILOWATTS

SYSTEM TYPE	800 SF MULTI-FAMILY MOBILE HOMES	1600 SF SINGLE FAMILY	2400 SF SINGLE FAMILY
RESISTANCE	4.5 KW	4.5 KW	4.5 KW
SOLAR	4.5	4.5	4.5
HRU	4.5	4.5	4.5
D.HEAT PUMP	1.2	1.2	1.2
GAS	0	0	0

Electric resistance water heaters are considered on an electric system wide basis to be 0.40 kilowatts in summer and 0.80 kilowatts in winter.

APPENDIX A
BACKGROUND FOR ENERGY CALCULATIONS

Five types of residential buildings are analyzed for energy consumption. They are classified as:

Single Family House, 800 square feet of conditioned floor
Single Family House, 1600 square feet of conditioned floor
Single Family House, 2400 square feet of conditioned floor
Multifamily apartment, 1600 square feet
Mobile Home, 600 square feet

Figures A-1 through A-5 show the floor plans and outline descriptions of construction features. In addition, the following conditions were programmed:

	NORTH	CENTRAL	SOUTH
Glass area as % of floor area	14-15	15-16	17-18
Infiltration avg. air change/hr	0.5	0.5	0.5
Weather cities	Jack'vle	Tampa	Miami
Wall construction	Frame	CBS	CBS
Summer thermostat settings	78F	78F	78F
Winter thermostat settings	70F	70F	75F

People 800 SF=2 1600 SF=4 2400 SF=5 Multifamily=2
Mobile home=2

Method of analysis: The EP computer program was used. It is owned by the Energy Management Service of Portland, Oregon. The program calculates 8760 hourly energy points. The EP program is a highly developed energy analysis program.

The equipment performance equations used were taken from the DOE 2.1 computer program. Performance points for systems by Lennox, General Electric, Weatherking, and York were plotted against the DOE curves to determine suitability of the curves.

Four air conditioning companies were invited to run their own parallel analysis on the same building configurations. General Electric and Lennox submitted supporting data, which was of great value.

Life Style Considerations:

Energy consumption is greatly affected by "life style". Florida citizens consume energy with thousands of variations and patterns, making it difficult to predict typical consumption with accuracy.

The kilowatt hour figures shown in these tables reflect the consumption that can be expected in residences which fully air condition during the summer and fully heat during the winter. Therefore, these numbers can be considered to represent the upper level of energy consumption. Most life style variations in practice are expected to cause deductions from these numbers. The most relevant variations will be:

1. Abstinence of the use of air conditioning and heating systems. Depending on the location, 5% to 14% of the residences in Florida do not air condition at all.

2. Differences in thermostat settings. The calculations are based on 78F summer and 70F or 75F winter settings. Variations from these settings can readily result in 10% differences in consumption.

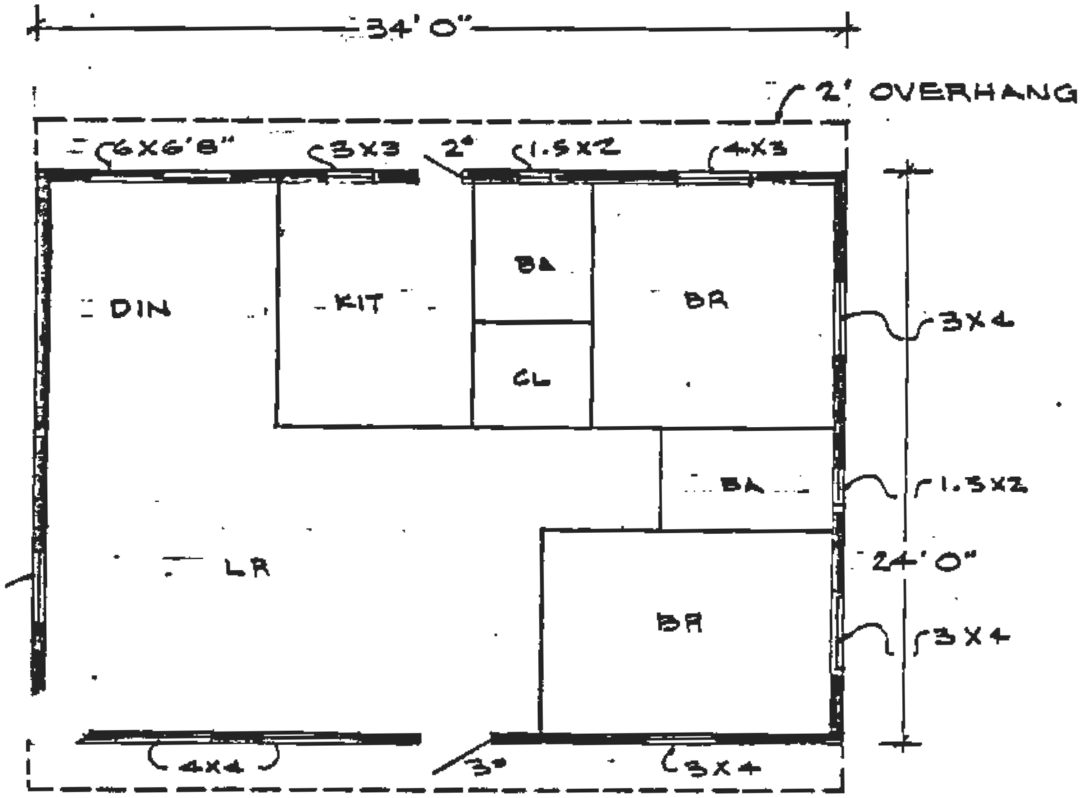
3. Window management. A citizen who conscientiously pulls draperies or shades closed to save energy can readily reduce consumption 5% to 10% in the summner. The energy figures shown herein are based on conscientious window management.

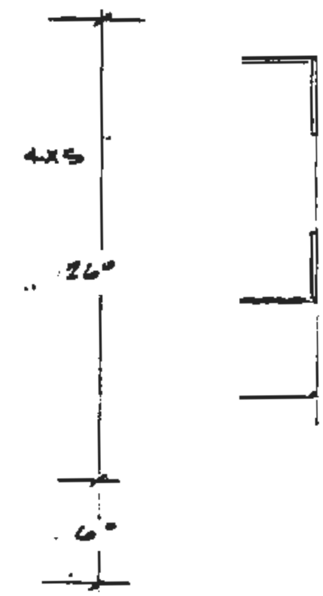
4. Infiltration. The admittance of outside air to the conditioned space by leakage through the structure and by opening and closing doors commonly accounts for much of the air conditioning energy required for a residence. Life style, in turn, affects infiltration. A family who opens doors frequently and allows the doors to stand open unnecessarily will readily consume 20%.

5. Maintenance. Air conditioning and heating systems are not unreasonably difficult to maintain. However, consultation with contractors indicates that, generally, maintenance of residential systems is poor and this results in rapid degradation of equipment efficiency. Coming years are assuredly to bring increased fuel costs and increasing awareness on the part of our people of the importance of cleaning air filters, checking refrigerant, cleaning coils, and repairing duct work.

FIGURE A-1

816 SF HOUSE





P S C - CODE
TYPICAL HOUSE 816 SQUARE FEET
****

GROSS DIMENSIONS: 24' X 34'
WALLS: ZONES 123: FRAME R11
ZONES 4-9: CBS R3
CEILING: DRY WALL R19
ROOF: GABLED WITH ATTIC
OVERHANGS: 2' ON NORTH & SOUTH
0' ON EAST AND WEST (GABLE ENDS)
AREAS: FLOOR 816
GROSS WALL 928
GLASS 148
DOORS TWO AT 20 & 15
TYPICAL GLASS CONFIGURATION:
WINDOW 4' 0" HIGH WITH 1' 4" WALL ABOVE
SLIDING GLASS DOOR 6' X 6' 8"
BATHROOMS 2' HIGH
SLAB ON GRADE
NO PATIO OR CARPORT

APPENDIX B
EXAMPLE BENEFIT-COST ANALYSIS FOR AIR CONDITIONING

This example analyzes the costs and benefits of installing a 1.5 ton air conditioner in an 800 square foot single family home in South Florida rated with an EER of 8.5 instead of the present code minimum of 6.8.

The higher EER air conditioner will cost more to install, but will have less expensive operating costs because it will produce the same cooling while consuming fewer kilowatt hours of energy.

In addition, the higher EER unit will present fewer watts of peak demand, causing a reduced summer peaking requirement on the electric utility system.

The analysis includes:

> The energy improvement over a 5 year period, using energy costs with embedded peak demand costs.

BASE CONDITIONS

Homeowner's mortgage: 30 years at 15% interest, down payment= 20%

Electric rate of $ 0.06519 per KWH for the first year, increasing to .09451 in 5 years.

Homeowner's tax rate = 25%. For all house sizes irrespective of observation that purchasers of larger houses may be in higher tax bracket.

EXAMPLE ASSUMPTIONS

Climate: South Florida (Miami)
House: 800 square feet of air conditioned floor space, single family CBS house. Refer to Appendix A for further details.

Air conditioning figures (1.5 ton):

EER	KWH PER YEAR	EQUIPMENT COST DIFFERENCE	DESIGN LOAD BTUH	PEAK KW
6.8	6,402	$ 274	18,400	2.70
8.5	-5,121			-2.23
Reductions	1,281			0.47

FIVE YEAR CALCULATIONS

YEAR	ELEC. RATE $/KWH	KWH SAVED	ENERGY $ SAVED	PEAK KW SAVED*
1	.06519	1,281	$ 84	0.33
2	.07252	1,281	93	0.33
3	.07985	1,281	102	0.33
4	.08718	1,281	112	0.33
5	.09451	1,281	120	0.33
Total savings		6,405	$ 511	

* System peak demand saving = (0.47 KW) (0.70) = 0.33

Calculate homeowner's costs.
Down payment: 20% of $ 274 = $ 54.80
Amount put on mortgage = $ 274 - 54.80 = $ 219.20
Annual cost = (mortgage) (capital recovery factor)
= ($ 219.20) (0.15230) = $ 33.38 per year

Account for tax deduction for interest:

YEAR	INTEREST	25% TAX DEDUCTION
1	$ 32.88	$ 8.22
2	32.80	8.20
3	32.72	8.18
4	32.62	8.15
5	32.50	8.12

Property tax = 2% ($ 274) = $ 5.48
This is tax exempt. However, the exemption is rarely applied for.

Benefit - cost summary:

YEAR	ENERGY $ SAVED		MORTGAGE AND DOWN PAYMENT		TAX DED'N		PROPERTY TAX		ANNUAL NET SAVED
1	$ 84		$ 88		$ 8		$ 5		$ (1)
2	93		33		8		5		62
3	102		33		8		5		71
4	112		33		8		5		81
5	121		33		8		5		90
	$ 511	-	$ 220	+	$ 40	-	$ 25	=	$ 306

Total 5 year saving is $ 306.

TEN YEAR PRESENT VALUE CALCULATIONS

The following example shows the same house conditions calculated to determine the present value of benefits and costs. This calculation uses embedded energy costs.

ASSUMPTIONS

A. PHYSICAL

1. South Florida (Miami) Location
2. 800 square feet of air-conditioned floor space, single family CBS house (Refer to Appendix A for further details.)
3. 1.5 ton central ducted air-conditioner
4. Improvement is a change from 6.8 EER to 8.5 EER

B. FINANCIAL

1. \$274 Increased Equipment Cost
2. Increase in down payment of 20% x \$274 = \$54.80
3. Increased amount on mortgage is \$274 - \$54.80 = \$219.20
4. 5% increased maintenance cost of 0.05 (\$247) = \$13.70 for years five to ten; zero maintenance cost for years zero through four.
5. Salvage and incremental equipment renewal costs not considered.
6. Principal and Interest payment schedule

Year	Principal	Interest	Total(a)
1	\$0.50	\$32.88	\$33.38
2	0.58	32.80	33.38
3	0.66	32.72	33.38
4	0.76	32.62	33.38
5	0.87	32.51	33.38
6	1.01	32.37	33.38
7	1.16	32.22	33.38
8	1.33	32.05	33.38
9	1.53	31.85	33.38
10	1.76	31.62	33.38

(a) Using 0.15230 capital recovery factor at 15% for 30 years.

7. Increased Property Tax (2%) on increased $274 valuation is $5 per year (More efficient equipment is exempt from property tax; however, the exemption is rarely applied for).
8. Homeowner 25% income tax rate
9. 10% Present Worth Discount Rate

COST-EFFECTIVE TO CONSUMER CALCULATIONS

SAVINGS				COSTS				
Year	KWH	$/KWH	Annual	Mortgage and Down Payment	Property Tax	Income Tax Deduction	Increased Maintenance	Annual
1	1,281	.06519	$84	$88	$5	$9(a)	$ 0	$84
2	1,281	.07252	93	33	5	9	0	29
3	1,281	.07985	102	33	5	9	0	29
4	1,281	.08718	112	33	5	9	0	29
5	1,281	.09451	120	33	5	9	14	43
6	1,281	.10184	130	33	5	9	14	43
7	1,281	.10917	140	33	5	9	14	43
8	1,281	.11650	149	33	5	9	14	43
9	1,281	.12382	159	33	5	9	14	43
10	1,281	.13116	168	33	5	9	14	43

(a) $9.50 rounded to $9.00 instead of $10.00

				NET SAVINGS	
Year	Savings	Costs	Net	Present Value (10%)	Cumulative Present Valu
1	$84	$84	$ 0	$0	$ 0
2	93	29	64	53	53
3	102	29	73	55	108
4	112	29	83	57	165
5	120	43	77	48	213
6	130	43	87	49	262
7	140	43	97	50	312
8	149	43	106	50	362
9	159	43	116	49	411
10	168	43	125	48	459

APPENDIX C
EXAMPLE PEAK CALCULATION

Following is an example of the calculation for peaking condition based on the 10% reduction figures shown in Figure III A.
The residence features are:

Single family house in South Florida.
Floor area (conditioned area/ slab on grade)....1600 sf
Glass areas north..........134
east 20
south..........100
west 33
Overhangs......none
Walls concrete block with insulation R6 area.....1169 sf
Ceiling insulation R19...........................1600 sf
Straight cool air conditioner with SEER=7.0
Heating system resistance strips, central COP=1.0
Ductwork is in the attic

Refer to Figure C-A which shows the calculation sheet.

Calculate the glass, wall and roof ratios by dividing areas by the floor area. The wall ratio is 1169 / 1600 = 0.73.
Calculate the roof ratio 1600 / 1600 = 1.0.
Calculate glass ratios 134 / 1600 = .084   20 / 1600 = .012
100 / 1600 = .063   33 / 1600 = .021

Do the summer calculation. Circle the glass type and orientations. Circle the wall and roof multipliers which apply to R3 walls and R19 roof. Circle the air conditioning multiplier for the SEER of 7.0 Circle the duct multiplier of 1.15 since the ductwork is in the attic.

Move the ratios down to the calculation section .084 , .012 , .063 , etc. Move the multipliers down to the calculation section 340, 340, 340, 460, 11, 13, etc. Multiply the ratios by the multipliers .084 x 340 = 28.6, .012 x 340 = 4.1, etc.

Add up the points in the right hand column. The subtotal of 84.8 is obtained.

Multiply by the duct multiplier of 1.15 to get the second subtotal of 97.5.

Multiply by the air conditioner multiplier of 1.0 to get the summer point index of 97.5. Since this is less than 100 the house complies for summer peaking.

Perform the winter calculation using the same approach as the summer. The index shown is 95.4, which meets the requirements. The designer can improve the house to comply by several methods:

Change to double pane glass	WPI = 88.5
Change wall insulation to R11	93.9
Change roof insulation to R30	90.4
Move ductwork inside	83.0
Change the heating system to heat pump	57.2

All of the data used in this calculation is already required for the section 9 calculation.

A P P E N D I X   D

FUTURE RESIDENTIAL CONSTRUCTION

In order to determine the effects of air conditioning, heating, and water heating on a statewide basis and on the basis of the three climate zones, a projection of the number of residential units to be placed or constructed is needed. In addition, it is necessary to break down the statistics for homes heated with heat strips, gas and heat pumps.

Data was obtained from census figures, energy code statistics, utility company publications, and the Department of Veteran and Community Affairs.

The following table shows the housing inventory shown by 1980 census figures.

1980 NUMBER OF RESIDENCES IN FLORIDA BY TYPE

CLIMATE ZONE	SINGLE FAMILY	MULTI-FAMILY	MOBILE HOME
NORTH	480,000	275,000	105,000
CENTRAL	1,021,000	584,000	224,000
SOUTH	916,000	525,000	201,000
TOTALS	2,417,000	1,384,000	530,000

TOTAL FOR THE STATE........4,329,000

The next table shows the 1980-1981 numbers of new residences established in Florida by type. It is assumed that, each year from 1980 through 1992, these numbers of new residences will be placed or constructed in Florida.

1980 TO 1992 NUMBERS OF NEW RESIDENCES PER YEAR

CLIMATE ZONE	SINGLE FAMILY 800 SF	SINGLE FAMILY 1600 SF	SINGLE FAMILY 2400 SF	MULTI-FAMILY	MOBILE HOME
NORTH	5,000	9,000	2,700	18,300	9,600
CENTRAL	9,900	19,000	6,300	38,800	20,400
SOUTH	7,300	15,000	9,400	34,900	18,200
TOTALS		83,600		92,000	48,200

TOTAL FOR THE STATE........223,800

The next three tables show the new residences established each year by types of heating systems. It is assumed that 1981 trends will continue.

1980 TO 1992 ANNUAL NEW RESIDENCES WITH ELECTRICAL RESISTANCE HEATING SYSTEMS

CLIMATE ZONE	SINGLE FAMILY 800 SF	SINGLE FAMILY 1600 SF	SINGLE FAMILY 2400 SF	MULTI-FAMILY
NORTH	2,700	2,700	300	5,400
CENTRAL	8,000	10,000	2,100	20,400
SOUTH	6,100	14,000	8,500	32,500
TOTALS	16,800	26,700	10,900	58,300

TOTAL FOR THE STATE........112,700

1980 TO 1992 ANNUAL NEW RESIDENCES WITH HEAT PUMPS

CLIMATE ZONE	SINGLE FAMILY 800 SF	SINGLE FAMILY 1600 SF	SINGLE FAMILY 2400 SF	MULTI-FAMILY
NORTH	1,400	4,700	2,100	9,500
CENTRAL	1,400	6,500	4,000	13,300
SOUTH	1,200	900	800	2,100
TOTALS	4,000	12,100	6,900	25,000

TOTAL FOR THE STATE........48,000

1980 TO 1992 ANNUAL NEW RESIDENCES WITH GAS HEATING

CLIMATE ZONE	SINGLE FAMILY 800 SF	SINGLE FAMILY 1600 SF	SINGLE FAMILY 2400 SF	MULTI-FAMILY
NORTH	900	1,600	300	3,200
CENTRAL	400	2,400	100	5,000
SOUTH	100	100	0	200
TOTALS	1,400	4,100	400	8,400

TOTAL FOR THE STATE........ 5,900

Attachment 4

Inter-Office Correspondence

FPL

To: W. G. Walker, III Date: January 25, 1990

From: Mario Villar Department: Regulatory Affairs

Subject: **Meeting with Florida Gas Transmission**

On January 18, 1990, I attended a meeting between our Fuel Resources department and Florida Gas Transmission. Among the subjects discussed were the Christmas cold weather spell and the status of the FGT Settlement Docket at FERC. The following is a summary of our discussions.

Christmas Cold Weather Spell

FGT purchases gas supplies based on projected demand on its system. However, due to the current interruptible nature of contracts with various large customers, such as FPL, a portion of FGT's own contracts for gas supplies or transportation are themselves interruptible contracts with gas suppliers and other pipelines. During the winter FGT normally contracts with others for a maximum of 520-550 MMCF per day of firm gas supplies, out of a total pipeline capacity of 825 MMCF per day. This includes about 200 MMCF per day projected for FPL's interruptible P-10 supplies.

During the Christmas cold spell, FGT experienced a series of supply interruptions which resulted in the pipeline stabilizing at about 450 MMCF per day. This was due to cut-off of interruptible contracts for either gas or transportation and well freeze-offs (best guess is 50-75 MMCF for well freezing). As a result, FPL received no gas during the holiday period cold spell.

Once the FGT open-access settlement is approved at FERC, FGT can provide firm sales and/or transportation service to those customers which have committed to buy or transport gas. The settlement has fully allocated the FGT pipeline capacity throughout its customer base. Equally important, approval of the settlement will allow the Phase II expansion of the FGT pipeline, thus increasing the gas supply capability in the State by 100 MMCF per day. While this will not totally eliminate the possibility of curtailment or interruption of gas supplies, the firmness of the contracts and the increased pipeline capacity will tend to significantly reduce curtailment.

Had the FGT settlement been in effect during the Christmas cold spell, the State of Florida would have, in all likelihood, received close to the 825 MMCF per day pipeline capacity as a result of firm contracts. The increased gas availability would have also allowed FPL to generate with gas, thus alleviating the rolling blackout situation experienced during this period.

Form 1008 (Stocked) Rev. 5/89

W. G. Walker, III
Page two
January 25, 1990

FERC Docket Status

FGT stated that the FERC Staff had requested data to update its Environmental Impact Assessment. That data request was completed and filed the week before so that Staff could now start its final review. Should FGT see no action from Staff by mid-February, they intend to file a motion to expedite. They would like FPL and other customers to support them at that time. If all goes well, they expect an order in June or July.

As you know, we met with Fuel Resources subsequent to that meeting and discussed alternative courses of action for FPL. It was agreed that FERC Staff progress on this docket should be monitored and that FPL should pursue alternative methods of encouraging an expedited FERC review. At this time we will be developing, with Fuel Resources, a draft of a letter that could be sent to FERC expressing our concern over the status of the settlement in light of our recent cold weather experience in Florida.

MV:vlf

cc: W. H. Brunetti

APPENDICES

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Appendix A

FLORIDA POWER CORPORATION

FLORIDA POWER CORPORATION

Forecasted Peak Load: (1989 Ten Year Site Plan)	6,034 MW firm load
Actual Peak Load:	
Saturday, December 23:	Evening
	6,494 MW firm load served 500 MW firm load unserved 6,994 MW total firm load
Sunday, December 24:	Morning
	6,416 MW firm load served 1,283 MW firm load unserved 7,699 MW total firm load
	Evening
	6,505 MW firm load served 100 MW firm load unserved 6,605 MW total firm load
Monday, December 25:	Morning
	6,280 MW firm load served 706 MW firm load unserved 6,986 MW total firm load
Total System Generating Capacity:	6,611 MW
Scheduled Maintenance:	560 MW

Crystal River 1 (400 MW) began its scheduled outage on October 21, 1989. It was originally scheduled to return to service by December 7, 1989. However, during the early stages of the outage, the intermediate pressure turbine shell was found to be warped. Both the upper and lower halves of the turbine shell were removed and shipped to the General Electric Company in Jacksonville, Florida for repair. The unit is currently scheduled to return to service during the week of January 15, 1990.

Suwannee River 3 (84 MW) began a planned turbine maintenance outage on November 4, 1989. The unit was originally scheduled to return to service December 15, 1989. The high, intermediate, and low pressure rotors were all sent to General Electric in Jacksonville, Florida for repairs. Originally, only the first stage blades were to be replaced. However, upon inspection it was but found that three additional stages also needed to be replaced. The additional blades were not available and had to be manufactured. The unit is currently scheduled to return to service during the week of January 15, 1990.

Turner 4 (76 MW) began a planned turbine maintenance outage on September 30, 1989. Originally two turbine stages were to be replaced. However, after inspection, it was found that two additional stages needed to be replaced. the turbine rotor was sent to Wisconsin where the additional stages were to be manufactured. The unit is expected to return to service during the week of January 22, 1990.

Generating Unit Forced Outages:

Saturday, December 23:

As of 8:00:

Bartow 3 (220 MW) limited to 190 MW , high temperature on generator extraction line

Suwannee P1 (65 MW) limited to 33 MW, B-side forced out; cracks found in 5th stage compressor blades

Morning (12:01 a.m. to 12:00 p.m.)

Crystal River 4 (750 MW) limited to 690 MW from 3:00 a.m. to 6:00 a.m., to clear pulverizers of wet coal

Turner 3 (75 MW) limited to 40 MW from 7:00 a.m. to 10:00 a.m., problems with an air heater. Unit forced off line at 11:00 a.m.

Afternoon (12:01 p.m.to 6:00 p.m.)

Bartow 3 (220 MW) limited to 178 MW due to economizer leak at 2:00 p.m. This condition remained throughout the rest of the day.

Turner 3 (75 MW) came back on-line at 1:45 p.m. The unit was limited to 49 MW due to air heater problems.

Evening (6:01 to 12:00 a.m.)

Crystal River 2 (476 MW) reduced load to approximately 390 MW at 10:00 p.m. to minimize condenser Delta T (environmental restrictions)

Turner P3 (75 MW) reduced to 60 MW at 10:45 p.m. to correct temperature differential across the turbine.

Turner P4 (75 MW) reduced to 20 MW at 10:45 p.m. to correct temperature differential across the turbine.

Sunday, December 24

Morning (12:01 a.m. to 12:00 p.m.)

Bartow 1 (115 MW) experienced a salt leak and was limited to 55 MW from 1:00 a.m. to 3:05 a.m.

Bartow 3 (220 MW) experienced backpressure problems between 8:00 a.m. and 10:00 a.m. and was limited to 140 MW. Then was limited to 178 MW due to the economizer leak.

Crystal River 2 (476 MW) was limited to 390 MW between 1:00 a.m. and 6:00 a.m. to minimize condenser Delta T (environmental restriction).

Bartow P3 (53 MW) tripped off-line between 10:00 and 11:00 a.m. due to atomizing air line leak.

Bartow P4 (53 MW) tripped on generator differential and vibration between 10:00 a.m. and 12:00 p.m.

Debary P6 (55 MW) came off-line at 12:27 a.m. to repair oil filter. Was back on line at 1:45.

Turner P3 (75 MW) at 60 MW between 1:00 and 5:00 a.m. to correct temperature differential across turbine. Unit tripped off-line at 8:21 a.m. due to exhaust temperature spread differential.

Turner P4 (75 MW) at 20 MW between 1:00 and 5:00 a.m. to correct temperature differential across turbine.

Afternoon (12:01 p.m. to 6:00 p.m.)

Anclote 2 (515 MW) lost a flame and dropped to 311 MW between 1:31 and 4:00 p.m.

Crystal River 2 (476 MW) reduced load at 2:10 to minimize condenser Delta T (environmental restriction).

Crystal River 4 (750 MW) lost a coal feeder and dropped to 709 MW between 3:37 and 5:00 p.m.

Debary P1 (55 MW) tripped off-line from 1:00 to 6:00 p.m. due to air in fuel lines.

Turner P3 (75 MW) back on line at 3:00 p.m.

Evening (6:01 p.m. to 12:00 a.m.)

Crystal River 2 (476 MW) at reduced load through 8:40 p.m. (environmental restriction). Then was requested to come to full load.

Turner 3 (75 MW) tripped off line at 12:00 a.m. due to transmission line problems.

Debary P2 (55 MW) and Debary P6 (55 MW) tripped off-line at 12:00 a.m. due to transmission line problems.

Turner P3 (75 MW) and Turner P4 (75 MW) tripped off-line at 12:00 a.m. due to transmission line problems.

Sunday, December 25

Morning (12:01 a.m. to 12:00 p.m.)

Bartow 3 (220 MW) developed a salt leak and was limited to 92 MW between 5:30 and 8:33 a.m. Other hours were limited to 178 MW due to economizer leak.

Crystal River 2 (476 MW) was limited all day due to unit control computer failure and wet coal. Stayed between 213-414 MW.

Crystal River 4 (750 MW) had a blockage in a coal feeder and was limited to 650 MW from 11:00 a.m. to 12:00 p.m.

Turner 3 (75 MW) off-line all day due to a blown fuse in station service transformer when transmission lines crossed on December 24. Could not maintain drum level. Had to drain boiler and let it cool before refilling for start-up.

Intercession City P1 (57 MW) and P3 (57 MW) both tripped at 8:33 due to clogged fuel filters. Came back on-line at 8:40 a.m. but were limited to half load until 8:00.

Suwannee P2 (65 MW) tripped at 7:18 a.m. due to clogged fuel filter. Came back on line by 8:00 a.m.

Afternoon (12:01 p.m. to 6:00 p.m.)

Intercession City P1 (57 MW) and P3 (57 MW) both became available for full load at 1:27 p.m.

Evening (6:01 p.m. to 12:00 p.m.)

Crystal River 2 (476 MW) began reducing load at 10:00 p.m. to 210 MW for condenser maintenance.

Crystal River 4 (750 MW) had a coal mill fire at 6:40 p.m. and reduced load to 642 MW. Available for full load at 7:30 p.m.

Purchased Power:

Saturday, December 23

Southern	13,407 MWH (up to 590 MW) from 12:00 a.m. to 12:00 a.m. Schedule ASSD, assured
FPL	102 MWH (up to 24 MW) from 10:00 a.m. to 5:00 p.m. Schedule B for D, emergency maintenance
Orlando	562 MWH (up to 120 MW) from 12:00 p.m. to 7:00 p.m. Schedule B, emergency maintenance
Tallahassee	1084 MWH (up to 100 MW) from 12:00 p.m. to 12:00 a.m. Schedule B, emergency maintenance
FPL	2062 MWH (up to 522 MW) from 4:00 p.m. to 12:00 a.m. Schedule B, emergency maintenance
JEA	391 MWH (up to 144 MW) from 7:00 p.m. to 12:00 a.m. Schedule A, emergency

Sunday, December 24

Southern	14,160 MWH (590 MW) from 12:00 a.m. to 12:00 a.m. Schedule ASSD, assured
Tallahassee	2,637 MWH (up to 140 MW) from 12:00 a.m. to 12:00 a.m. Schedule B, emergency maintenance
FPL	1,828 MWH (up to 467 MW) from 12:00 a.m. to 5:00 a.m. Schedule B for D, emergency maintenance
JEA	647 MWH (up to 180 MW) from 12:00 A.M. to 6:00 a.m. Schedule A, emergency
Orlando	25 MWH (up to 18 MW) from 2:00 p.m. to 4:00 Schedule B, emergency maintenance
FPL	265 MWH (up to 64 MW) from 6:00 p.m. to 12:00 a.m.

Monday, December 25

Southern	14,160 MWH (590 MW) from 12:00 a.m. to 12:00 a.m. Schedule ASSD, assured
Tallahassee	1,668 MWH (up to 150 MW) from 12:00 a.m. to 12:00 p.m. Schedule B, emergency maintenance
Gainesville	103 MWH (up to 30 MW) from 7:00 a.m. to 11:00 a.m. Schedule A, emergency

Cogeneration:

The only Qualifying Facilities that are telemetered are Pinellas County Resource Recovery, Florida Crushed Stone and Bay County. The nameplate capacity of these Qualifying Facilities is 213.8 MW total. The maximum output deliverable to FPC is 181 MW total. During the three day period from Saturday, December 23 through Monday, December 25, these QFs delivered an average of 148.8 MW (82.2% overall capacity factor based on net deliverable capacity).

Actual generation from the smaller QFs will not be available until their meters are read.

Saturday, December 23

Pinellas County Resource Recovery	1,012 MWH (up to 51 MW) 12:00 a.m. to 12:00 a.m.
Florida Crushed Stone	2,384 MWH (up to 101 MW) 12:00 a.m. to 12:00 a.m.
Bay County Resource Recovery	115 MWH (up to 5 MW) 12:00 a.m. to 12:00 a.m.

Sunday, December 24

Pinellas County Resource Recovery	1,236 MWH (up to 55 MW) 12:00 a.m. to 12:00 a.m.
Fla. Crushed Stone	2,286 MWH (up to 101 MW) 12:00 a.m. to 12:00 a.m.
Bay County Resource Recovery	24 MWH (1 MW) 12:00 a.m. to 12:00 a.m.

Monday, December 25

Pinellas County Resource Recovery	1,321 MWH (up to 57 MW) 12:00 a.m. to 12:00 a.m.
Fla. Crushed Stone	2,311 MWH (up to 99 MW) 12:00 a.m. to 12:00 a.m.
Bay County Resource Recovery	24 MWH (1 MW) 12:00 a.m. to 12:00 a.m.

Interruptible and Curtailable Load

All interruptible customers were at zero load and all curtailable customers were at their contract demand by 4:00 p.m. Saturday, December 23. This resulted in a load reduction of approximately 300 MW.

Rate provisions for interruptible customers allows them to buy emergency power when available. Once emergency power is not available, they must go to zero load. Curtailable customers are notified they must reduce load to their contract demand.

Load Management

FPC has 270,884 participating customers on their load management program. The approximate demand reduction at 8:00 a.m when the temperature is 32-33 degrees Fahrenheit is 500 MW.

Saturday, December 23: 12:21 a.m. to 11:55 p.m.

Sunday, December 24:	1:45 a.m. to 3:05 p.m.
	5:00 a.m. to 2:19 p.m.
	5:42 p.m. to 12:00 a.m.
Monday, December 25:	12:01 a.m. to 3:00 a.m.
	4:45 a.m. to 10:45 a.m.

Public Announcements:

Public announcements made prior to the Christmas weekend were made orally to the media. The gist of these announcements was that customers should conserve due to the cold weather. Specifically, on Thursday, December 21, Florida Power Corporation employees met Tampa Tribune writer Phil Willon, which resulted in a feature story which ran on Saturday, December 23. Another version of the story ran on Sunday, December 24.

In anticipation of a tight energy supply for the weekend and the likely use of load management over the weekend, on Friday, December 22, the St. Petersburg Times, Tampa Tribune and the Orlando Sentinel, Associated Press and United Press International were contacted.

On Saturday, December 23, three Tampa Bay television stations were contacted and asked to broadcast messages concerning conservation and the potential for rolling blackouts on Sunday. As there was no advance warning of the large Saturday night load, only after rolling blackouts had begun at about 6:00 p.m. Saturday, December 23, were television stations asked to "crawl" blackout information across the bottom of television screens. In addition, the media was requested to run stories carrying specific energy conservation recommendations. Recommendations included lower thermostat, avoid unnecessary clothes washing and drying, turn off non-essential lights, plan to delay Christmas cooking until noon or later. From this point until approximately 1:00 p.m. Monday, December 25, media contacts were virtually ongoing.

Voltage Reductions

When this program is activated, the distribution bus voltages are reduced by 2.5 percent. This results in an estimated 100 MW demand reduction over FPC's system. During the Christmas emergency, system wide voltage reductions were implemented as follows:

Saturday, December 23: 11:21 a.m. to 11:55 p.m.

Sunday, December 24:	1:45 a.m. to 3:05 a.m.
	5:00 a.m. to 2:19 p.m.
	5:42 p.m. to 12:00 a.m.

Monday, December 25: 12:01 a.m. to 3:00 a.m.
4:45 a.m. to 10:45 a.m.

Rotating Blackouts:

SATURDAY 12/23/89		SUNDAY 12/24/89		MONDAY 12/25/89	
TIME	MW	TIME	MW	TIME	MW
6:00 p.m.	400	5:15 a.m.	150	7:20 a.m.	215
8:00 p.m.	350	6:00 a.m.	250	7:32 a.m.	315
8:40 p.m.	300	6:40 a.m.	200	7:40 a.m.	365
8:52 p.m.	250	7:00 a.m.	400	7:48 a.m.	465
10:05 p.m.	200	7:10 a.m.	500	7:55 a.m.	615
10:08 p.m.	100	7:15 a.m.	600	7:57 a.m.	715
10:11 p.m.	0	7:20 a.m.	800	8:00 a.m.	815
		7:26 a.m.	900	8:09 a.m.	790
		7:40 a.m.	1050	8:10 a.m.	740
		8:00 a.m.	1200	8:11 a.m.	640
		8:50 a.m.	1100	8:16 a.m.	590
		9:20 a.m.	1150	8:27 a.m.	550
		10:37 a.m.	1000	8:53 a.m.	500
		11:15 a.m.	900	9:03 a.m.	450
		11:30 a.m.	800	9:15 a.m.	400
		11:45 a.m.	700	9:20 a.m.	350
		12:05 p.m.	600	9:23 a.m.	250
		12:22 p.m.	500	9:35 a.m.	200
		12:31 p.m.	400	9:42 a.m.	150
		12:43 p.m.	150	9:46 a.m.	0
		1:00 p.m.	0		

Critical Loads

FPC has 734 distribution feeders, with 143 identified as serving critical loads. Generally, these include hospitals, police and fire stations, nursing homes, and water and waste water treatment facilities.

During the Christmas weekend, FPC interrupted 22 critical loads as part of their rotating outage plan. The majority of these customers had on-site backup generation. Each critical feeder was interupted an average of 6 times for 22 minutes. The minimum outage was 2 minutes, the maximum, 36 minutes.

Unplanned Distribution Outages

Total System

Total of 974 outage incidents.
748 due to overloads (i.e. tripped fuses and circuit breakers).
226 due to equipment failure (i.e. damaged transformers, cables, and lines)
Average outage time was 3 hours 30 minutes, ranging from a minimum of less than a minute to a maximum of 23 hours 39 minutes.

Appendix B

FLORIDA POWER & LIGHT COMPANY

FLORIDA POWER & LIGHT

Forecasted Peak Load: (1989 Ten Year Site Plan)	13,794 MW

Actual Peak Load:

Saturday, December 23:	Evening	
	12,969 MW	firm load served
Sunday, December 24:	Morning	
	13,986 MW	firm load served
	1,600 MW	firm load unserved
	15,586 MW	Total firm load
	Evening	
	13,988 MW	firm load served
	200 MW	firm load unserved
	14,188 MW	Total firm load
Monday, December 25:	Morning	
	12,772 MW	firm load served
	2,700 MW	firm load unserved
	15,472 MW	Total firm load

Total System Generating Capacity: 14,105 MW

Excludes Riviera 2 (71 MW) which is on Long Term Reserve Shutdown. Plans are to return Riviera to service by 1993.

Scheduled Maintenance: 1,240 MW

Port Everglades 4 (369 MW) was removed from service for major overhaul on September 8, 1989. Unit is scheduled to return on line April 15, 1990 and resume normal operation by April 21, 1990. Due to the extensive work involved in the overhaul it was not possible to return the unit to service.

Manatee 2 (790 MW) was removed from service for overhaul on October 12, 1989. Unit is scheduled to return on line January 5, 1990 and resume normal operation by January 9, 1990. Discussions were conducted with plant management by both Power Resources management and System Operations management prior to December 22, 1989. Even the most ambitious schedule could not return the unit prior to December 27, 1989. Unit actually returned January 5 and was released for normal operation on January 9.

Martin 1 (790 MW) was removed from service for overhaul on October 30, 1989. Unit was scheduled to return on line December 23, 1989 and resume normal operation by December 31, 1989. Discussions with the plant management resulted in an around the clock effort which successfully returned the unit to service on December 22, almost full load for December 24 and full load for December 25.

Port Everglade CT 1 (40.5 MW) and Ft. Lauderdale CT 16 (40.5 MW) were on major overhaul and re-assembly could not be accomplished by December 24, 1989.

Generating Unit Forced Outages:

Turkey Point 4 (Rated 688 MW)	Limited from: To: Rated/Limit: Reason:	12/19/89 12/23/89 - 11:14 p.m. 688/320 MW Condenser leak in "A" water box
Cutler 5 (Rated 68 MW)	Unavailable 12/22/89 - 12/28/89 due to no gas available to run the "Gas Only" unit	
Cutler #6 (Rated 131 MW)	Unavailable 12/22/89 - 12/28/89 due to no gas available to run the "Gas Only" unit	
Martin 1 (Rated 790 MW)	Limited from: To: Rate/Limit: Reason:	12/22/89 - 12:47 p.m. 12/23/89 - 11:00 p.m. 790/slowly increased load until chemistry cleared Boiler chemistry after overhaul
JEA/FPL St. Johns River Power Park 1 (FPL Share - 125 MW)	Off: On: Reason:	12/22/89 - 7:03 p.m. 12/22/89 - 8:55 p.m. Drum level sensing line frozen
Manatee 1 (Rated 790 MW)	Off: On: Reason:	12/22/89 - 10:40 p.m. 12/23/89 - 2:58 p.m. Poor boiler chemistry due to acid leak into condensate system
Port Everglades and Fort Lauderdale Gas Turbines (Rated 1458 MW)	Performance during the entire period 12/23/89 to 12/27/89 was approximately 60% of rated capability due to the lack of natural gas fuel resulting in the running on liquid fuel. Clogged fuel filters and other fuel pressure problems resulted in intermittent unavailability.	

JEA/FPL St. Johns River Power Park 1 (FPL Share - 125 MW)	Off: On: Reason:	12/23/89 - 10:38 a.m. 12/23/89 - 6:02 p.m. Drum level sensing line frozen
JEA/FPL St. Johns River Power Park 2 (FPL Share - 125 MW)	Off: On: Reason:	12/23/89 - 11:44 a.m. 12/23/89 - 3:13 p.m. Orum level sensing line frozen
Putnam 2 (Rated 234MW)	Limited from: To: Rate/Limit: Reason:	12/23/89 - 6:44 p.m. 12/24/89 - 3:00 p.m. 234/120 MW Fire on insulation due to a fuel line leak on one of the turbine units. Turbine back on line 09:52, increased to full load by 15:00
Turkey Point 4 (Rated 688 MW)	Off: On: Reason:	12/23/89 - 11:14 p.m. 12/28/89 - 6:50 a.m. Corrosion of terminal boards on main steam isolation valve
JEA/FPL St. Johns River Power Park 2 (FPL Share - 125 MW)	Off: On: Reason:	12/23/89 - 11:57 p.m. 12/24/89 - 1:30 a.m. Drum level sensing line frozen
Martin 1 (Rated 790 MW)	Off: On: Reason:	12/24/89 - 5:19 a.m. 12/24/89 - 6:42 a.m. Frozen drum level sensing line
St. Lucie 1 (Rated 860 MW)	Limited from: To: Rate/limit: Reason:	12/24/89 - 6:20 a.m. 12/24/89 - 2:54 p.m. 860/776 MW Frozen sensing line on 1A feed pump
Martin 1 (Rated 790 MW)	Off: On: Reason:	12/24/89 - 10:35 a.m. 12/24/89 - 11:10 a.m. Boiler feed pump trip-invertor malfunction
Manatee 1 (Rated 790 MW)	Off: On: Reason:	12/24/89 - 8:12 p.m. 12/27/89 - 4:08 p.m. Water wall tube leaks (5)

Turkey Point 3 (Rated 688 MW)	Off: On: Limited until: Reason:	12/25/89 - 1:36 a.m. 12/25/89 - 8:52 a.m. 12/25/89 - 9:28 p.m. Going to 100% power Safety related shutdown found corrosion (similar to what caused unit #4 to trip) of terminal boards on main steam isolation valve
Sanford 3 (Rated 139 MW)	Limited from: To: Rate/Limit:	12/25/89 - 4:05 a.m. 12/25/89 - 7:15 a.m. Frozen acid and caustic lines in water plant resulting in low condensate
JEA/FPL St. Johns River Power Park 1 (FPL Share - 125 MW)	Limited from: To: Rate/Limit: Reason:	12/25/89 - 9:41 a.m. 12/25/89 - 3:00 p.m. 125/85 MW Main transformer overheating
Cape Canaveral 2 (Rated 370 MW)	Limited from: To: Rate/Limit: Reason:	12/25/89 - 12:27 p.m. 12/25/89 - 4:15 p.m. 370/180 MW Travelling screen sheared a pin due to a heavy run of fish from cold weather, condenser tube leak 14:30 - 16:15
Martin 1 (Rated 790 MW)	Limited from: To: Rate/limit: Reason:	12/25/89 - 2:43 p.m. 12/25/89 - 6:00 p.m. 790/463 MW Boiler feed pump starting problems
Martin 1 (Rated 790 MW)	Off: On: Reason:	12/26/89 - 1:57 a.m. 12/26/89 - 4:41 a.m. Feed pump control circuit ground
Sanford 3 (Rated 139 MW)	Limited from: To: Rate/Limit: Reason:	12/26/89 - 4:14 p.m. 12/26/89 - 4:58 p.m. 139/50 MW Boiler control problems

UNIT PERFORMANCE DURING FEEDER ROTATION

UNIT	CONT. CAPAB MW	12/24/89 0700 MWH	0800 MWH	0900 MWH	1000 MWH	1100 MWH	1200 MWH	1900 MWH	2100 MWH	2200 MWH	2300 MWH	12/25/89 0600 MWH	0700 MWH	0800 MWH	0900 MWH	1000 MWH	1100 MWH	(NOTE 1) 1200 MWH	AVERAGE GEN (NOTE 1) MWH.	HOURLY MAXIMUM GENER MWH	HOURLY MINIMUM GENER MWH	AVG GEN/ CONT CAPAB %	DELTA MW FROM CONT CAP AVG-CONT
TF#1	370	384	384	384	384	383	384	383	387	388	388	386	387	385	386	385	385	385	385	388	383	104.10	15
TF#2	370	383	383	382	382	382	383	385	387	385	386	384	383	383	383	383	383	385	384	387	382	103.67	14
FL#4	138	138	138	136	137	138	137	138	139	138	138	136	138	137	136	134	139	139	137	139	134	99.50	-1
FL#5	138	139	138	140	138	138	139	139	140	141	140	140	140	140	139	136	141	140	139	141	136	100.91	1
PE#1	205	207	207	206	207	206	206	208	209	209	209	207	208	207	208	206	208	207	207	209	206	101.16	2
PE#2	205	211	211	211	210	209	211	211	213	212	212	211	211	210	211	211	211	211	211	213	209	102.93	6
PE#3	369	383	382	383	380	382	380	384	384	384	385	384	384	382	383	382	380	382	383	385	380	103.69	14
PE#4			OVERHAUL																				
RV#3	274	286	286	283	284	283	283	289	292	290	290	288	285	286	285	286	283	286	286	292	283	104.45	12
RV#4	274	279	275	256	259	256	268	280	283	281	281	279	275	277	275	275	275	274	273	283	256	99.77	-1
MR#1	790	50	486	760	764	448	342	754	750	760	758	834	830	830	832	830	832	816	679	834	50	85.92	-111
MR#2	790	844	840	842	842	840	840	844	844	844	844	844	842	842	838	838	838	820	842	844	838	106.53	52
CC#1	370	383	383	383	380	382	382	384	385	386	386	384	385	383	384	383	383	383	384	386	380	103.65	14
CC#2	370	388	390	388	390	387	388	392	392	392	391	389	388	389	388	388	388	387	389	392	387	105.20	19
SN#3	139	146	146	152	152	152	154	149	151	152	151	36	33	64	124	149	151	146	129	154	33	92.72	-10
SN#4	366	358	368	374	374	374	375	376	380	379	378	378	378	376	375	374	378	368	375	380	358	102.41	9
SN#5	366	374	378	378	377	378	377	379	383	383	381	382	381	382	381	380	382	374	380	383	374	103.76	14
FM#1	138	147	147	146	147	151	153	154	155	154	156	153	154	154	153	153	152	149	152	156	146	110.01	14
FM#2	370	376	387	387	385	386	386	384	385	384	383	383	382	381	382	381	380	378	383	387	376	103.58	13
MT#1	790	828	824	824	822	824	822	830	172	0	0	0	0	0	0	-4	0	0	371	830	-4	47.01	-419
MT#2			OVERHAUL																				
PN#1	234	221	225	223	223	223	220	220	184	226	220	223	210	210	211	208	210	208	216	226	184	92.33	-18
PN#2	234	82	84	82	84	135	146	200	170	205	204	199	105	104	103	105	104	104	132	205	82	56.41	-102
CU#5			NOT AVAILABLE DUE TO CURTAILMENT OF GAS FUEL SUPPLY													-1							
CU#6			NOT AVAILABLE DUE TO CURTAILMENT OF GAS FUEL SUPPLY																				
SUBTOTAL	7300	6607	7062	7320	7321	7057	6976	7483	6785	6693	6681	6620	6499	6522	6577	6584	6603	6542	6837	7483	5573	93.66	-463
TP#3	688	696	695	695	695	695	695	689	705	706	707	0	0	0	7	80	122	131	449	707	0	65.29	-239
TP#4	688	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	-688
SL#1	860	778	788	803	806	808	814	871	872	871	872	871	870	867	867	867	867	868	843	872	778	98.05	-17
SL#2	860	865	863	862	858	854	857	863	865	867	865	861	861	858	859	858	856	859	861	867	854	100.09	1
SUBTOTAL	3096	2339	2346	2360	2359	2357	2366	2423	2442	2444	2444	1732	1731	1725	1733	1805	1845	1858	2153	2444	1632	69.55	-943
FLGT 1	486	246	222	240	320	326	298	188	190	204	202	226	160	140	184	170	180	100	219	326	140	44.96	-268
FLGT 2	445	376	374	374	370	370	360	338	366	358	358	307	317	346	346	332	340	225	352	376	307	79.10	-93
PEGT	445	238	244	328	332	360	354	354	344	338	338	326	338	334	308	293	266	200	318	360	238	71.56	-127
FMGT	756	714	708	708	696	668	668	649	720	736	738	744	744	742	738	733	714	666	714	744	649	94.41	-42
SUBTOTAL	2132	1574	1548	1650	1718	1724	1680	1529	1620	1636	1636	1603	1559	1562	1576	1528	1500	1191	1603	1806	1334	75.17	-529
DIESEL	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	88.89	-1
TOTAL GEN	12537	10528	10964	11338	11406	11146	11030	11443	10855	10781	10769	9963	9797	9817	9894	9925	9956	9599	10601	11741	8547	84.56	-1936

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Question No. 1a, Attachment No. 2
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UNIT PERFORMANCE DURING FEEDER ROTATION

UNIT	CONT. CAPAB MW	12/24/89 0700 MWH	0800 MWH	0900 MWH	1000 MWH	1100 MWH	1200 MWH	1900 MWH	2100 MWH	2200 MWH	2300 MWH	12/25/89 0600 MWH	0700 MWH	0800 MWH	0900 MWH	1000 MWH	1100 MWH	(NOTE 1) 1200 MWH	AVERAGE GEN (NOTE 1) MWH	HOURLY MAXIMUM GENER MWH	HOURLY MINIMUM GENER MWH	AVG GEN/ CONT CAPAB %	DELTA MW FROM CONT CAP AVG-CONT
TOTAL GEN	12537	10528	10964	11338	11406	11146	11030	11443	10855	10781	10769	9963	9797	9817	9894	9925	9956	9599	10601	11741	8547	84.56	-1936
COGEN (2)	183	74	71	74	78	80	78	77	72	80	81	95	71	70	61	54	48	51	73	95	48	39.67	-111
SJRPP	624	520	542	567	592	602	610	598	590	597	603	622	622	628	629	612	431	429	585	629	431	93.80	-39
SOCO	2067	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2067	2067	2067	2067	2067	2067	2067	2041	2067	2025	98.73	-26
NET INTERCHANGE(3)		178	173	173	170	168	184	201	175	95	64	159	60	-72	-74	-204	-133	-98	82				
INADVERTANT (3)		-6	-14	-84	-55	-201	-19	-46	-280	-52	-9	-30	-58	25	-47	-201	-86	-3	-73				
TOTAL INTERCHANGE		2447	2479	2577	2580	2740	2548	2545	2792	2659	2654	2655	2758	2812	2878	3138	2765	2648	2689			93.56	
TOTAL LOAD SERVED	15411	12975	13443	13915	13986	13886	13578	13988	13647	13440	13423	12618	12555	12629	12772	13063	12721	12247	13290			86.23	
MAX FEEDER ROTATION		500	1300	1600	1600	1500	1200	200	500	500	200	1100	1700	2800	2700	1900	1800	500	1271	2800	200		

NOTES:

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(1) DATA FOR HOUR ENDING 1200 12/25 NOT INCLUDED IN AVERAGE STATISTICS BECAUSE FEEDER ROTATION ENDED EARLY IN THE HOUR AS LOAD FELL OFF RAPIDLY (OUTPUT FOR THE HOUR LIMITED BY LOAD RATHER THAN CAPABILITY).

(2) COGENERATION CONTINUOUS CAPABILITY BASED ON ESTIMATED MAXIMUM OUTPUT DELIVERABLE TO FPL FROM EACH FACILITY. TOTAL NAMEPLATE RATINGS FOR THESE FACILITIES IS 244.6 MW. THE PALM BEACH RESOURCE RECOVERY FACILITY (RATED 61.2 MW NAMEPLATE, 55 MW EXPECTED) WAS TAKEN OFF LINE 12/5 FOR A TEN DAY OUTAGE. BY LETTER DATED 12/20, THE OPERATORS NOTIFIED FPL THAT THE OUTAGE HAD BEEN EXTENDED "FOR SEVERAL WEEKS" DUE TO UNANTICIPATED OFFSITE REPAIRS. THE AVERAGE OUTPUT OF THE REMAINING FACILITIES DURING THE FEEDER ROTATION HOURS WAS 75.78% OF EXPECTED CAPACITY (39.67% OF NAMEPLATE CAPACITY).

(3) INTERCHANGE ACCOUNTING RECORDS FLOWS OUT OF THE SYSTEM AS POSITIVE AND FLOWS INTO THE SYSTEM AS NEGATIVE ( ). INTERCHANGE SALES DURING THESE HOURS WERE LIMITED TO THE TRANSFER OF ST. LUCIE PLANT OUTPUT OWNED BY OTHERS AND PARTIAL REQUIREMENTS WHOLESALE ENERGY. THESE TRANSACTIONS WERE OFFSET BY EMERGENCY ENERGY PURCHASES ON 12/25.

Purchased Power:

The majority of power purchased was the result of firm capacity contracts with the Southern Companies and the Jacksonville Electric Authority's portion of the St. Johns River Power Park coal units. Capacity from Southern was not curtailed at all during the period. Florida/Southern interconnections were loaded to reliability limits throughout all periods of rotating feeder outages. Output from the St. John's units was not at full capacity for the entire period; however, the units operated at a 84% capacity factor for the period December 22-26 and at 94% capacity factor during periods of rotating feeder outages.

Saturday, December 23

Southern	49,608 MWH (up to 2,067 MW) from 12:00 a.m. to 12:00 p.m. Schedule UPS, unit power sales
Jacksonville	5,107 MWH (up to 373 MW) 12:00 a.m. to 12:00 p.m. St. Johns River Power Park
Orlando	53 MWH (up to 53 MW) from 3:00 a.m. to4:00 a.m. Schedule C, economy
Gainesville	10 MWH (up to 10 MW) from 4:00 a.m. to 5:00 a.m. Schedule C, economy
Southern	92 MWH (up to 75 MW) 4:00 p.m. to 6:00 p.m. Schedule C, economy
Homestead	1 MWH (up to 1 MW) from 6:00 p.m. to 7:00 p.m. Schedule C, economy

Sunday, December 24

Jacksonville	7,413 MWH (up to 368 MW) 12:00 a.m. to 12:00 a.m. St. Johns River Power Park
Southern	28,225 MWH (up to 2,025 MW) from 12:00 a.m. to 1:00 p.m. Schedule UPS, unit power sales
Southern	20,462 MWH (up to 2,025 MW) from 1:00 p.m. to 12:00 a.m. Schedule R, economic replacement for UPS
Jacksonville	259 MWH (up to 131 MW) 8:45 p.m. to 11:00 p.m. Schedule A, emergency
Homestead	6 MWH (up to 3 MW) from 9:00 p.m. to 11:00 p.m. Schedule A, emergency

Monday, December 25

Southern	38,941 MWH (up to 1820 MW) 12:00 a.m. to 12:00 a.m. Schedule UPS, unit power sales
Southern	10,667 MWH (up to 850 MW) 12:00 a.m. to 12:00 a.m. Schedule R, economic replacement for UPS
Jacksonville	5,719 MWH (up to 249 MW) 12:00 a.m. to 12:00 a.m. St. Johns River Power Park
Jacksonville	1,421 MWH (up to 300 MW) 12:00 a.m. to 12:00 p.m. Schedule A, emergency

Monday, December 25 (Continued)

Sebring	5 MWH (up to 5 MW) from 1:00 p.m. to 2:00 p.m. Schedule C, economy
Gainesville	25 MWH (up to 25 MW) from 1:00 p.m. to 2:00 p.m. Schedule C, economy
Southern	471 MWH (up to 225 MW) 5:00 p.m. to 8:00 p.m. Schedule C, economy
Sebring	23 MWH (up to 11 MW) 9:00 p.m. to 12:00 a.m. Schedule C, economy
Orlando	37 MWH (up to 37 MW) from 11:00 p.m. to 12:00 p.m. Schedule A, emergency

Cogeneration

The nameplate capacity of the Qualifying Facilities which sell as-available energy to FPL is 244.6 MW. The maximum output deliverable to FPL is 183 MW. During the periods on Saturday, December 24 and Sunday, December 25 in which FPL was experiencing rotating blackouts, QFs delivered an average of 73 MW (39.67% overall capacity factor based on net deliverable capacity).

Qualifying Facilities were called several times to request their maximum availability and to alert them as-available energy pricing would be based on gas-turbine costs for much of the holiday period.

During this period, the Palm Beach County Resource Recovery facility (61.2 MW) was shut down for major maintenance. On Christmas morning, however, employees of this facility indicated that they would "wrap up their work for the day to conserve energy."

The Metro-Dade Resource Recovery facility (56 MW) was operating on two of their three boilers during this emergency period. The third boiler was under repair.

The Royster-Mulberry facility (12 MW), which is in TECO's service territory but sells as-available energy to FPL, indicated that they were tripped off line early Sunday morning, December 24, and were unable to obtain power from TECO to restart the facility.

Interruptible and Commercial/Industrial Load Management:

Sunday, December 24	6:00 a.m. to 10:00 a.m.	75 MW reduction
	11:30 a.m. to 12:00 a.m.	74 MW reduction
Monday, December 25	12:00 a.m. to 11:00 a.m.	74 MW reduction
	5:00 p.m. to 12:00 a.m.	76 MW reduction
Tuesday, December 26	12:00 a.m. to 11:00 a.m.	76 MW reduction

Note: The contracted demand reduction capability from these options is approximately 100 MW. The reductions shown for the above time periods represent load that otherwise would have been on during the holiday weekend. These reductions are comprised of both actual demand reductions during interruption periods plus participants' decisions not to operate based at least in part on FPL's notice on December 22, 1989 concerning the likelihood of interruption over the holiday weekend. The remaining portion (approximately 25 MW) of the 100 MW capability represents load that was not on solely due to the holiday weekend operating schedules of participants (i.e., the notice of potential interruption did not affect these participants' prior decision not to operate on these days.) In summary, none of the 100 MW load needed to be served due to a combination of load management and the participants' holiday weekend operating schedules.

Curtailable:

Sunday, December 24	6:00 a.m. to 12:00 a.m.	30-90 MW reduction
Monday, December 25	12:00 a.m. to 1:00 p.m. 5:00 p.m. to 12:00 a.m.	30-75 MW reduction 30-75 MW reduction
Tuesday, December 26	12:00 a.m. to 9:30 a.m.	30-110 MW reduction

Note: The estimated demand reduction is a range of demands that represents what FPL believes was actually reduced over various periods of the curtailment, given that it was a weekend, holiday, and at very early and late times of the day. Of the 160 curtailable customers, there are some who would normally be down on Sundays, and on Christmas day, or at least during some of the curtailment hours. A better estimate of the avoided load from curtailable rate customers will be developed when the monthly billing cycle data is available.

Residential Load Management

Sunday, December 24	6:00 a.m. to 10:00 a.m.	20 MW reduction
Monday, December 25	6:00 a.m. to 10:00 a.m.	20 MW reduction
Tuesday, December 26	6:00 a.m. to 9:30 a.m.	20 MW reduction

Public Announcements:

Friday, December 22

Corporate Communications provided informational materials to each FPL division, including a Customer Information System (CIS) message, a media statement and tips for customer energy conservation. A public appeal message also was provided with the request that it be held in case it was needed. Corporate Communications and division managers responded to periodic weather-related questions throughout the day using the media statement.

Saturday, December 23

At about 4:00 p.m. Power Supply advised Corporate Communications and the divisions of the need for public appeal. Media contacts were initiated by Corporate Communications and the divisions prior to the evening broadcasts and before the print media's deadlines for Sunday morning papers.

The following media outlets were contacted: Wire services--Associated Press (AP), United Press International (UPI); major daily newspapers--Miami Herald, Ft. Lauderdale Sun-Sentinel, Palm Beach Post, Orlando Sentinel, Daytona Beach News Journal, Florida Today, Ft. Myers News Press, Sarasota Herald Tribune; radio/television stations--WINK, WSPB, WKXY, WKZM, WRBQ, WSVN, WPLG, WCIX, WTVJ, WXLT and Storer Cable.

Sunday, December 24

Corporate Communications was notified by Power Supply at 6:00 A.M. that rolling blackouts would be initiated. Corporate Communications was activated at 7:00 a.m. Between 7:00 and 9:00 a.m., Corporate Communications provided live and taped radio interviews to WINZ (Miami, all news), WFLA and AP-radio (statewide) using initial press statement.

The 8:30 a.m. news statement was sent to all divisions for their use locally and was used for media callouts and responses to inquiries.

By 2:00 p.m. a complete media information package was provided to each division, along with media procedures for use through Tuesday, December 26. The package included a news release, radio "actuality", television "crawl" message, and updated public appeal message and a special commercial and industrial customer appeal message. See Attachment D.

The package was issued to the wire services (AP and UPI), major print and broadcast media throughout FPL's service territory.

Monday & Tuesday, December 25 & 26

Corporate Communications continued providing updates and responding to media calls as outlined in the memorandum issued December 24.

FPL estimates it provided information to 300 media representatives from December 22-26. This count includes multiple contacts with news media in the service territory over the four-day period.

Voltage Reductions and Rotating Service Outages:

Saturday, December 23

No voltage reductions or firm load shed.

Sunday, December 24

6:08 a.m. to 11:30 a.m.	1,600 MW maximum firm load shed 753 feeders affected 2-3 rotations per feeder 7-20 minute outages during each rotation
6:09 p.m. to 6:15 p.m.	200 MW maximum firm load shed 26 feeders affected 1 rotation per feeder 5-6 minute outages during each rotation
8:18 p.m. to 10:17 p.m.	500 MW maximum firm load shed 353 feeders affected 1 rotation per feeder 4-16 minute outages during each rotation

Monday, December 25

4:57 a.m. to 11:14 a.m.	2,800 MW maximum firm load shed 753 feeders affected 5-6 rotations per feeder 1-20 minute outages during each rotation

Unplanned Distribution Outages:

Total of 662 outages
458 weather related (blown fuses, damaged transformers, line overloads)
204 non-weather related (tree, salt corrosion, animals, other natural causes)
Average outage time was 3 hours 4 minutes, ranging from a minimum of 1 minute to a maximum of 27 hours 21 minutes.

Critical Loads

FPL has a total of 1,842 feeders currently in service; 55 of these feeders serve critical loads, 391 serve priority loads.

FPL defines "critical" customers as those who must not be selected for either underfrequency or manual tripping during capacity shortfall situations. Critical customers were subjected to service interruptions not initiated by FPL during the emergency. Listed below are the critical customers which were subjected to service interruptions during the emergency:

Customer	Date, Time & Length of Outage	Cause	Action Taken
Civil Defense	12/26-05:37 120 minutes	Fuse Switch Failed	Replaced Lateral Switch
Hospital	12/24-09:43 127 minutes	Wire Down	Replaced Insulator & Wire
Sewage Plant	12/25-20:58 15 minutes	Car Hit Pole	Isolated feeder and repaired cross-arm
Sewage Plant	12/23-00:06 24 minutes	Car Hit Pole	Splinted pole for temporary repair
Sewage Plant	12/23-19:14 171 minutes	Wire Down	Replaced Wire
Sewage Plant	12/26-08:03 102 minutes	U/G Cable Failed	Cable Repaired

FPL has a second category of customers defined as "priority" customers. These have been identified as important for public safety, medical care or vital public services such as water plants and sewage facilities, etc. Although "priority" loads may be interrupted during capacity shortfall emergencies, every effort is made to expedite restoration of service following such emergencies.

Priority customers were interrupted as part of FPL's rotation plan during the Christmas weekend. Each was interrupted 4 times on December 25 and 6 times on December 26 for an average of 20 minutes per interruption.

Appendix C

TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC COMPANY

Forecasted Peak Load: (1989 Ten Year Site Plan)	2,573 MW
Actual Peak Load:	
Saturday, December 23:	Evening 2,942 MW firm load served 0 MW firm load unserved 2,942 MW Total firm load
Sunday, December 24:	Morning 2,040 MW firm load served 1,016 MW firm load unserved 3,056 MW Total firm load Evening 2,122 MW firm load served 847 MW firm load unserved 2,969 MW Total firm load
Monday, December 25:	Morning 2,164 MW firm load served 852 MW firm load unserved 3,016 MW Total firm load

NOTE: The forecasted planning peak for firm load is a 60 minute net integrated total firm load of 2,403 MW. For the purposes of this report, TECO reported instantaneous peak load data. Therefore their forecasted 2,403 MW of firm load at peak translates to a gross instantaneous total peak of approximately 2,573 MW.

Total System Generating Capacity: 2,906 MW

Excludes Hookers Point Station (206 MW) which is on Long Term Reserve Shutdown. The Hookers Point Station is expected to be returned to service as follows: HP3-4 (74 MW) by 1/91, HP5 (68 MW) by 1/92, and HP1-2 (64 MW) by 1/93.

Scheduled Maintenance: 877 MW

Big Bend 4 (439 MW) was removed from service for a planned outage on November 10, 1989. The unit was originally scheduled to return to service on December 14, 1989; however, the unit was forced out of service beyond this time due to a fire in scrubber absorber tower "A". The fire resulted from welding work being performed by a contractor. The unit returned to service January 10, 1990. The unit could not have been returned to service prior to the emergency.

Gannon 6 (358 MW) was removed from service for a planned outage on September 16, 1989. The unit was scheduled to return to service on December 15, 1989, but was forced out of service beyond this time due to a generator starter coil failure. The failure occurred after maintenance work was performed by the manufacturer and the unit was restarted. At present, the unit is estimated to return to service by July 1, 1990. The unit cannot be returned to service prior to this time.

Big Bend CT (80 MW) was removed from service due to an outage caused by rotor damage. It was returned to service on January 17,1990. The unit could not be returned to service prior to this time.

Generating Unit Forced Outages

Gannon 5 (217 MW) — 6:51 p.m. Friday, December 22 to 3:49 a.m. Saturday, December 23
Status: Off-line
Reason: Air preheater failed

Gannon 5 (217 MW) — 1:30 p.m. to 3:57 p.m. Saturday, December 23
Status: Limited
Reason: Condenser Tube Salt Leak

Gannon 1 (103 MW) — 12:40 p.m. to 1:55 p.m. Monday, December 25,
Status: Limited
Reason: Clean shells and debris from condenser

Gannon 2 (108 MW) — 4:55 p.m. to 5:34 p.m. Monday, December 25
Status: Limited
Reason: Clean shells and debris from condenser

Gannon 2 (108 MW) — 11:25 p.m. Monday, December 25 to 12:20 a.m. Tuesday December 26
Status: Limited
Reason: Clean shells and debris from condenser

Purchased Power:

Saturday, December 23

Orlando — 1,835 MWH (up to 155 MW) from 12:00 a.m. to 1:00 p.m.
Schedule A, emergency

FPL — 180 MWH (45 MW) from 12:00 a.m. to 4:00 a.m.
Schedule B, emergency maintenance

FPL	590 MWH (up to 210 MW) from 12:00 a.m. to 4:00 a.m. Schedule A, emergency
FPL	10,622 MWH (up to 905 MW) from 7:00 a.m. to 12:00 a.m. Schedule B, emergency maintenance
Orlando	215 MWH (up to 80 MW) from 1:00 p.m. to 3:00 p.m. Schedule B, emergency maintenance

Sunday, December 24

FPL	2,132 MWH (up to 525 MW) from 12:00 a.m. to 5:00 a.m. Schedule B, emergency maintenance
Seminole	35 MWH (up to 35 MW) from 4:00 a.m. to 5:00 a.m. Schedule A, emergency
Orlando	17 MWH (up to 20 MW) from 5:00 a.m. to 5:50 a.m. Schedule B, emergency maintenance
Orlando	51 MWH (up to 65 MW) from 2:00 p.m. to 3:15 p.m. Schedule B, emergency maintenance
Jacksonville	210 MWH (up to 80 MW) from 2:00 p.m. to 5:00 p.m. Schedule B, emergency maintenance
FPL	998 MWH (up to 380 MW) from 2:30 p.m. to 6:00 p.m. Schedule B, emergency maintenance
Jacksonville	227 MWH (up to 265 MW) from 10:30 p.m. to 12:00 a.m. Schedule B, emergency maintenance

Monday, December 25

Jacksonville	3,314 MWH (up to 400 MW) from 12:00 a.m. to 2:00 p.m. Schedule B, emergency maintenance
FPC	500 MWH (up to 200 MW) from 1:00 a.m. to 5:00 a.m. Schedule B, emergency maintenance
Orlando	120 MWH (up to 60 MW) from 2:00 a.m. to 4:30 a.m. Schedule B, emergency maintenance
Tallahassee	138 MWH (up to 130 MW) from 11:30 a.m. to 12:35 p.m. Schedule B, emergency maintenance
FPC	38 MWH (up to 150 MW) from 12:00 p.m. to 12:15 p.m. Schedule B, emergency maintenance

Cogeneration:

Saturday, December 23

TECO has firm capacity and energy contracts with three Qualifying Facilities (QFs). They are Conserv, Hillsborough County Resource Recovery Facility, and the City of Tampa. The nameplate capacity of these QFs is 64 MW. The maximum output deliverable to TECO is 41.2 MW. During the three day period of Saturday, December 23 through Monday, December 25, these QF's delivered an average of 32.3 MW (78.5%) overall capacity factor based on net deliverable capacity.

The remaining Qualifying Facilities on TECO's system are primarily self service QFs which sell surplus as-available energy to TECO. These are Royster, which also sells wheeled as-available energy to FPL, Gardinier, New Wales, Ridgewood, and CNT Phosphate. While the nameplate capacity of these QFs is 167.3 MW, the maximum output deliverable to TECO varies. From Saturday through Monday, December 23-25, these QFs delivered an average of 21.2 MW.

Hills. County	648 MWH (up to 28 MW)	12:00 a.m. to 12:00 a.m.
City of Tampa	284 MWH (up to 16 MW)	12:00 a.m. to 12:00 a.m.
Royster	128 MWH (up to 10 MW)	12:00 a.m. to 11:00 p.m.
Gardinier	54 MWH (up to 3 MW)	12:00 a.m. to 11:00 p.m.
New Wales	4 MWH (up to 2 MW)	12:00 a.m. to 3:00 a.m.
Conserv	2 MWH (up to 1 MW)	1:00 a.m. to 3:00 a.m.
Conserv	27 MWH (up to 3 MW)	4:00 a.m. to 12:00 a.m.
New Wales	62 MWH (up to 6 MW)	4:00 a.m. to 12:00 a.m.
Ridgewood	35 MWH (up to 8 MW)	7:00 p.m. to 12:00 a.m.
CNT Phosphate	21 MWH (up to 7 MW)	8:00 p.m. to 12:00 a.m.

Wheeled to FPL:

Royster	111 MWH (up to 5 MW)	12:00 a.m. to 12:00 a.m.

<u>Sunday, December 24</u>

Hills. County	484 MWH (up to 28 MW)	12:00 a.m. to 12:00 a.m.
City of Tampa	209 MWH (up to 12 MW)	12:00 a.m. to 12:00 a.m.
Conserv	90 MWH (up to 8 MW)	12:00 a.m. to 12:00 a.m.
New Wales	82 MWH (up to 8 MW)	12:00 a.m. to 12:00 a.m.
CNT Phosphate	145 MWH (up to 9 MW)	12:00 a.m. to 12:00 a.m.
Gardinier	87 MWH (up to 10 MW)	12:00 a.m. to 5:00 p.m.
Ridgewood	49 MWH (up to 13 MW)	12:00 a.m. to 6:00 a.m.
Ridgewood	112 MWH (up to 18 MW)	1:00 p.m. to 12:00 a.m.

Wheeled to FPL:

Royster	23 MWH (up to 4 MW)	12:00 a.m. to 6:00 a.m.

<u>Monday, December 25</u>

Hills. County	193 MWH (up to 14 MW)	12:00 a.m. to 12:00 a.m.
City of Tampa	299 MWH (up to 16 MW)	12:00 a.m. to 12:00 a.m.
Conserv	91 MWH (up to 6 MW)	12:00 a.m. to 12:00 a.m.
New Wales	86 MWH (up to 6 MW)	12:00 a.m. to 12:00 a.m.
Ridgewood	306 MWH (up to 20 MW)	12:00 a.m. to 11:00 p.m.
CNT Phosphate	85 MWH (up to 8 MW)	12:00 a.m. to 10:00 p.m.
Gardinier	133 MWH (up to 13 MW)	6:00 a.m. to 12:00 a.m.

During the cogeneration rule hearings, some comments were made regarding the delivery of cogenerated power during the December 22-26, 1989 emergency. The Commission asked that the company respond to these comments. Their response follows.

"During the December 22-26, 1989 time period, Tampa Electric experienced record power demands caused by extreme weather conditions that not only covered our service area but blanketed the entire state. During that time period the company made every effort to get the most out of its available generators and to purchase power from other sources. During the most critical time periods, purchased power was not available from other utilities because of record demands and capacity shortfalls on their systems. Throughout this time period Tampa Electric purchased power from its cogeneration customers. The company's objectives throughout this critical time were to find ways to improve our capacity situation and, during times of capacity shortfall, to manage the shortfall through the rotation of firm load circuit's without jeopardizing service to critical loads. Tampa Electric is aware of two types of comments that have been made regarding the acceptance of cogeneration power.

One general comment was that the utilities turned down power from some cogenerators. (See attached letter from Royster).

The company is aware of a couple of instances during the emergency period where cogeneration units tripped off line and then requested power to help them start up again. When cogenerators are not exporting power, they purchase their power, such as start up power which can be several magawatts for several hours, under interruptible rates. These requests for start up power came at some very critical times in the firm load curtailment rotation process. The maximum rotation with the available circuits was underway and if any additional power was needed it appeared it would have to be taken away from critical circuits. The request for cogeneration start up power were not fulfilled, therefore, until the company, although still rotating circuits, was out of the risk of having to rotate critical circuits. Start-up power was then provided for the cogenerators to come on line.

A second more specific comment regarding the acceptance of cogeneration power was made by an IMC Representative. The statement by IMC was that an additional one-half to one megawatt was offered to Tampa Electric and that Tampa Electric responded that each party should take care of itself. (See attached letter from IMC).

A more detailed description of these communications is required.

Friday December 22, 1989 at 1:59 pm an IMC Representative contacted the Tampa Electric dispatch supervisor. The call was made as a result of an earlier notice by Tampa Electric to IMC's Interruptible Load Mining Operations requesting a shut down of those operations. IMC was looking for estimates of when the power supply situation would be most critical" "to use as guidelines for adjusting material supply into their plant and power out. Tampa Electric advised that there was a lot of uncertainty because of the large demands in the state and questions as to the availability of purchased power. It was noted that the loss of one or two large operating generators in the state could severely change things. In response to IMC, Tampa Electric indicted that it would prefer to receive export power from IMC and that would also provide IMC more stability. It appeared to Tampa Electric that IMC needed to balance the flow of raw material into its plant that came from the mining operations that are on the interruptible rate and the processing plant power needs. If they generated too much (by exporting more) they could run out of material because of interruptions on the interruptible rate; if they generated too little they would not be able to export power to Tampa Electric. The IMC Representative concluded that it would be best to stay in the power export mode, but without getting carried away, and would try to do this until the cold front passed. Tampa Electric agreed and noted that this approach would be the most helpful to both IMC and to Tampa Electric."

IMC FERTILIZER, INC.

January 4, 1990

RECEIVED
FLORIDA PUBLIC SERVICE COMM.
JAN 8 1990
ELECTRIC AND GAS

Mr. James Dean
Chief, System Planning and Conservation Bureau
Electric & Gas Department
Florida Public Service Commission
101 East Gaines Street
Tallahassee, Florida 32301

Dear Mr. Dean:

Mr. Richard Zambo has informed me that you would be interested in our experience during the extremely cold spell on Christmas weekend. I understand our experience is not unlike that of other cogenerators served by Tampa Electric.

On the afternoon of Friday, December 29, Mr. G. D. Loughrie, the operating manager in the area that includes our cogeneration system, learned that Tampa Electric anticipated shortages to occur during the expected cold weather. He immediately called the chief dispatcher, his usual contact at Tampa Electric, and offered to take whatever measures would be available to him to maximize our export of electricity during that period. In relating the conversation to me on the following Wednesday (12/27), Mr. Loughrie expressed surprise at the dispatcher's response. He neither accepted or rejected Mr. Loughrie's offer but appeared to be totally disinterested. Finally, after Mr. Loughrie persisted in offering to maximize our export, the dispatcher responded in words to the effect, "You go ahead and generate to take care of your own needs. We will generate to take care of ours"! During the four day period, December 23, 24, 25 and 26, we exported an average of 3.5 MW. If Tampa Electric had given us reason to believe that it would be useful, we could have taken the steps Mr. Loughrie referred to, perhaps even adjusting our production schedules, and we might have been able to export an additional 0.5 to 1 megawatt to help our neighbors. This is not much when compared to the total shortfall but, at an estimated 5 KW peak per household, this would have kept the heat and lights on in 100 to 200 houses.

I believe that it would he totally unfair to imply from this action (or lack of action) on the part of the dispatcher that either he or Tampa Electric is so adamantly opposed to cogeneration that they would deliberately sacrifice the comfort and risk the health of their own ratepayers rather than accept the benefits of cogeneration. I do think, however, that this demonstrates that

IMC Fertilizer, Inc., New Wales Operations, P.O. Box 1035, Mulberry, Florida 33860, (813) 428-2531

the employees of Tampa Electric, and probably of all the other IOU's in Florida, still do not have any appreciation of the value of cogeneration. When faced with the shortage of their own generation, they do not think of the cogenerators as a source of electricity, even when directly confronted with the opportunity as Tampa Electric's dispatcher was. They were like a drowning man looking for a rescue boat and completely ignoring the floating life preserver within reach because he can't think of anything but a boat being able to float.

Perhaps, with the leadership of the Public Service Commission Staff, the IOU's might learn the lesson from the Christmas weekend that cogeneration is a source of electricity that can and should be taken seriously.

Very truly yours,

D. E. Hirsch
Director Technical Services

DEH/bs
015/#027

cc: R. A. Zambo, Attorney at Law
G. D. Loughrie

January 9, 1990

RECEIVED
FLORIDA PUBLIC SERVICE COMM.

JAN 12 1990

Royster Company
P.O. Drawer 797
Mulberry, Florida 33860
(813) 425-1176

Royster

Mr. Jim Dean, Staff
Florida Public Service Commission ELECTRIC AND GAS
101 East Gaines Street
Fletcher Building
Tallahassee, Florida 32301-8153

Dear Mr. Dean:

This letter is to provide the Commission with information which may be useful in the investigation of the circumstances which prevailed during the period December 23 through December 26, 1989 relating to the problems which occurred with the electric utilities shortfall of capacity during that period.

The Royster Company, as you know, is a Qualified Facility Cogenerator which routinely generates sufficient power for its own use and exports some excess power. Experience during December was that the generator had produced approximately 16 MW with an export of 4-5 MW up to the period in question.

During the early morning hours of December 24, mechanical problems had forced a shutdown in the Sulfuric Acid Plant, which is the production unit which supplies the waste heat for the generator. At the time that we were prepared to re-start the plant we were unable to get approval from Tampa Electric, our supplying utility, to do so. Our plant remained shutdown through the entire period, and beyond.

Although we are on the interruptible, standby rate schedule SBI-3, and as such are susceptible to curtailment, had we been allowed to use approximately 6 MW of power for 1 to 2 hours during the period 6 a.m. of the 24th until 6 p.m. of the 25th we could have started the plant and generator and subsequently supplied at least the excess of 4-5 MW which we had been supplying. Under the dire circumstances which prevailed, it would seem that this alternative would have been much preferred to the option of maintaining our plant in a shutdown condition.

Not knowing all of the details of the utilities problems may result in an oversimplification of the situation. It would appear however that a better utilization of our cogeneration capability could have been made during this period of extreme power shortfall.

Sincerely,

T. R. Schmalz, P.E.
Manager of Engineering & Environmental Services

TRS:sk

cc: G. L. Dahms, Gen. Mg.

Interruptible and Curtailable Load:

Saturday, December 23:	6:00 p.m. to 12:00 a.m. 9 MW to 185 MW reduction
Sunday, December 24:	12:00 a.m. to 12:00 a.m. 12 MW to 60 MW reduction
Monday, December 25:	12:00 a.m. to 12:00 a.m. 10 MW to 111 MW reduction

Note: All interruptible customers were interrupted. Range of MW reduction takes into account the planned reductions in interruptible load by customers for the holiday weekend.

Load Management:

Saturday, December 23:	None.
Sunday, December 24:	8:00 a.m. to 11:00 a.m. 180 MW reduction
	7:00 p.m. to 10:00 p.m. 90 MW reduction
Monday, December 25:	5:00 a.m. to 7:00 a.m. 190 MW reduction
	7:00 a.m. to 8:00 a.m. 235 MW reduction
	12:00 p.m. to 3:00 p.m. 50 MW reduction

Public Announcements:

Friday, December 22, 1989

On Friday, December 22, 1989, Tampa Electric informed the Tampa Tribune that there was a possibility of blackouts, but not likely until Sunday morning, December 24. Radio station Q105 was also told on Friday, December 22, 1989, that the situation was tight and Tampa Electric urged customers to conserve. The following initial warning message was used:

Initial Warning/Conservation Message: 12/22 - 12/23, 1989

"Due to severe cold weather and record demands for electricity throughout the southeast, Tampa Electric is asking Customers to voluntarily reduce use of electricity to avoid the need for rotating blackouts of residential neighborhoods.

Tampa Electric will implement its Prime Time load management program and will take other steps to deal with the situation.

We expect 6 a.m. to 11 a.m. Sunday (Dec. 24) to be the most critical period and we're asking Customers to turn off water heaters and all unnecessary appliances, and to set thermostats back about 10 degrees.

If rotating blackouts are necessary, they are not at this time expected to last for more than 15 - 30 minutes. We will regularly update the news media about the status of the emergency program and any changes or variations in the plan.

While Tampa Electric will have extra Customer Service people on hand throughout the period, we do ask that Customers wait at least 30 minutes before calling about an outage.

Electric utilities throughout the state are working together in an effort to meet the record demands during the severe cold weather, but curtailments may be needed on the Tampa electric system and elsewhere . . . if demand overwhelms available supply."

Saturday, December 23, 1989

On Saturday afternoon, Tampa Electric's Corporate Communications Department developed the following message guidance for immediate use:

"Although we appear to be OK tonight (Saturday), there is a strong possibility that we will have to curtail electricity tomorrow morning when we reach our peak. If we do have to do that, it will come only after we have attempted to purchase power, interrupt our interruptible Customers, and sought relief from Prime Time Customers.

Our emergency program will consist of rotating blackouts of power, affecting groups of Customers, and as those groups rotate out of the blackout, another group would be rotated into the blackout.

We ask all our Customers to do their utmost to curtail all unnecessary use of electricity. Specific conservation information also given: lower thermostats, etc."

On Saturday afternoon, Tampa Electric contacted TV stations - channels 8, 10 and 13 - to ask for videofont crawls on TV stations to interrupt programming and warn of impending blackouts and urge conservation.

Tampa Electric also contacted radio stations WFLA, Q105, WTKN, WSUN and WQYK. Attempts were made to contact WTOG and WDAE, but no response was received. The Tampa Tribune, St. Pete Times, and Lakeland Ledger were contacted. Attempts were also made to contact the Winter Haven News Chief, but received no response.

Early Saturday evening, Tampa Electric contacted the following broadcast media a second time: WFLA (Channel 8), WTVT (Channel 13), WTSP (Channel 10) and radio stations WRBQ (Q105) and WFLA.

Media contacts by Tampa Electric intensified and became around-the-clock for the next three days.

Sunday, December 24

5:15 a.m. Tampa Electric began renotifying media that curtailments had begun. Continuous media contact continued. The conservation and crisis messages in effect were as follows:

Conservation Message: 12/24 - 12/25, 1989

> "Because of record Customer demand for power as a result of the severe freeze affecting the entire southeast, Tampa Electric has been forced to implement an emergency load curtailment program in our service area.
>
> The program involves interrupting (blacking out) electric service to a portion of our Customers, on a rotating basis.
>
> In order to minimize the risks of load curtailment, Customers are asked to conserve electricity through every available means: for example, set thermostat settings as many as 10 degrees lower than would normally be the case; compensate by wearing extra clothing; if you can, turn off water heaters until just prior to the time you would need the water; disconnect exterior Christmas lights and turn off any other lights, appliances or equipment which either are not in use or not vital at the time."

Crisis Message: 12/24 - 12/25, 1989

> "Tampa Electric again has been forced to implement load curtailment involving rotating electric power blackouts throughout our service area. (Then give appropriate estimates for duration and intensity)."

This is an emergency program that we and most other utilities in Florida have enacted in order to protect the integrity of the state's electric system. Not to do so would overload the system in a way that could black out the state of Florida.

We are experiencing a record demand from our Customers beyond anything we could have adequately planned. The levels appear to be in a range we would not have forecast until 1995. So this is truly an unprecedented, weather-related event.

It is important that Customers who do have power conserve electricity as much as possible, so that we can minimize the inconvenience of load curtailment imposed on our other Customers. (Cite conservation examples)

We have all available personnel working hard and around-the-clock to restore service as fast as possible. Our phone lines are jammed, however. It appears that some Customers who have lost power for reasons other than curtailment cannot get through to our Cust. Inquiry department, because Customers who have been curtailed have literally overwhelmed the system.

We're asking curtailed Customers to please not call our service lines, in the hope that will free space for Customers with specific weather-related outages. Curtailed customers are likely to experience episodes of power gain and power loss, varying in intensity, on an intermittent basis every few hours. Customers affected by spot or system outages have had much longer outages with no relief and are not being curtailed.

Those numbers to call are 223-0800 and 228-4111."

In the early afternoon, the news media were notified of a 4 p.m. news conference which included Tampa Electric, Florida Power and the Florida Coordinating Group. This news conference was held for one hour beginning at 4 p.m.

6 p.m. - Tampa Electric spokesman was live on Channel 8 with top local story. Tampa Electric's spokesman opened newscasts on both Channels 10 and 13 at 11 p.m.

Monday, December 25

Media contacts continue virtually around-the-clock. Tampa Electric spokesmen logged several hours live on WFLA during the emergency. More than 250 interviews and media information requests were handled by Tampa Electric Corporate Communications throughout the emergency.

Voltage Reductions and Rotating Service Outages:

Saturday, December 23: None.

Sunday, December 24:	6:00 a.m.	613 MW firm load shed
	7:00 a.m.	906 MW firm load shed
	8:00 a.m.	927 MW firm load shed
	9:00 a.m.	1016 MW firm load shed
	10:00 a.m.	888 MW firm load shed
	11:00 a.m.	1094 MW firm load shed
	12:00 p.m.	847 MW firm load shed
	1:00 p.m.	876 MW firm load shed
	2:00 p.m.	580 MW firm load shed
	6:00 p.m.	551 MW firm load shed
	7:00 p.m.	835 MW firm load shed
	8:00 p.m.	843 MW firm load shed
	9:00 p.m.	883 MW firm load shed
	10:00 p.m.	819 MW firm load shed
	11:00 p.m.	806 MW firm load shed
	12:00 a.m.	717 MW firm load shed
Monday, December 25:	1:00 a.m.	559 MW firm load shed
	2:00 a.m.	383 MW firm load shed
	8:00 a.m.	910 MW firm load shed
	9:00 a.m.	852 MW firm load shed
	10:00 a.m.	925 MW firm load shed
	11:00 a.m.	630 MW firm load shed

Unplanned Distribution Outages:

Distribution Circuit Outages

Total of 30 outages affecting 20 different circuits.
All due to overloading. Average outage time was 1 hour 25 minutes, ranging from a minimum of less than one minute to a maximum of 19 hours 39 minutes. Approximately 20,852 customers affected.

Outages Involving Poles and Wires

Total of 82 outages.
16 due to weather/load, 50 due to equipment failure, 16 due to other causes (tree, vehicle strike, etc.). Average outage time was 4 hours 13 minutes, ranging from a minimum of less than one minute to a maximum of 14 hours 3 minutes. Approximately 512 customers affected.

Primary Line Fuse Trips

Total of 71 outages.
58 due to weather/load, 7 due to equipment failure, 6 due to other causes. Average outage time was 3 hours 37 minutes, ranging from a minimum of 6 minutes to a maximum of 22 hours 32 minutes. Approximately 3,687 customers affected.

Transformer Outages

Total of 950 outages.
904 due to weather/load, 32 due to equipment failure, 14 due to other causes. Average outage time was 3 hours 27 minutes, ranging from a minimum of 4 minutes to a maximum of 22 hours 35 minutes. Approximately 6,469 customers affected.

Critical Loads

TECO has 587 distribution feeders on its system, with 143 identified as serving critical loads. 15 of the feeders serving critical loads were interrupted during firm load curtailments an average of 9 times each for an average 48 minutes duration.

Appendix D

FLORIDA PUBLIC UTILITIES

FLORIDA PUBLIC UTILITIES COMPANY

Forecasted Peak Load:

Fernandina Beach:	42 MW
Marianna:	40 MW

Actual Peak Load:

Fernandina Beach:	71 MW
Marianna:	51 MW

Total System Generating Capacity: 100 KW

Scheduled Maintenance: None

Generating Unit Forced Outages: None

Purchased Power:

FPUC purchased power as usual from JEA and Gulf during this period.

Cogeneration

None

Interruptible and Curtailable Load

None

Load Management

None

Public Announcements:

None

Voltage Reductions and Rotating Service Outages:

None

Unplanned Distribution Outages:

Reported 2 unplanned distribution outages, each lasting 2 hours.

Critical Loads

No critical loads experienced planned interruptions during this period.

SEMINOLE ELECTRIC COOPERATIVE

SEMINOLE ELECTRIC COOPERATIVE

Forecasted Peak Load: (1989 10 Year Site Plan)	2,246 MW
Actual Peak Load:	
Saturday, December 23:	Evening
	2,347 MW firm load served
	32 MW firm load unserved
	2,379 MW total firm load
Sunday, December 24:	Morning
	2,152 MW firm load served
	665 MW firm load unserved
	2,817 MW total firm load
	Evening
	2,223 MW firm load served
	39 MW firm load unserved
	2,262 MW total firm load
Monday, December 25:	Morning
	2,343 MW firm load served
	117 MW firm load unserved
	2,460 MW total firm load
Total System Generating Capacity:	1,294 MW
Scheduled Maintenance:	None

Generating Unit Forced Outages:

Sunday, December 24

3:25 a.m.	Seminole Unit 2 (640 MW) Frozen steam pressure indication line
9:55 a.m.	Unit startup; ran at reduced capacity throughout the day due to frozen coal in silos.

Monday, December 25:

4:00 p.m.	Seminole Unit 2 back to full capacity

Purchased Power:

Saturday, December 23:

FPC	28 MWH from 12:00 a.m. to 12:00 p.m. Reserve Capacity purchase

Sunday, December 24:

FPL	92 MWH (up to 74 MW) from 3:00 to 6:00 a.m. Reserve Capacity purchase
JEA	276 MWH (up to 170 MW) from 3:00 to 6:00 a.m. Reserve Capacity purchase 25 MWH from 7:00 to 8:00 a.m. Reserve Capacity purchase 2,245 MWH (up to 200 MW) from 9:00 a.m. to 9:00 p.m. Reserve Capacity purchase
FPC	46 MWH (up to 23 MW) from 3:00 to 5:00 a.m. Schedule H 27 MWH from 8:00 to 9:00 p.m. Schedule H
TAL	80 MWH (up to 20 MW) from 12:00 to 5:00 p.m. Reserve Capacity purchase
Gainesville	395 MWH (up to 50 MW) from 12:00 p.m. to 12:00 a.m. Reserve Capacity purchase
OUC	43 MWH (up to 40 MW) from 4:00 to 6:00 a.m. Reserve capacity purchase
TECO	36 MWH (up to 33 MW) from 4:00 to 6:00 a.m. Reserve capacity purchase

Monday, December 25:

JEA	4 MWH from 12:00 to 1:00 a.m. Reserve capacity purchase
TAL	43 MWH (up to 32 MW) from 1:00 to 3:00 p.m. Reserve capacity purchase

Gainesville	275 MWH (up to 40 MW) from 12:00 to 11:00 a.m. Reserve capacity purchase
OUC	10 MWH (up to 9 MW) from 12:00 to 3:00 p.m. Reserve capacity purchase

Note: Seminole reports occasional resales of purchased power during this period. On Sunday, December 24, 337 MWH (up to 75 MW) was resold to Orlando from 5:00 p.m. to 11:00 p.m. and 265 MWH (up to 64 MW) was resold to FPC. On Monday, December 25, 25 MWH (up to 23 MW) was resold to Orlando from 9:00 a.m. to 11:00 a.m.

Cogeneration: None

Interruptible and Curtailable Load:

SEC's member cooperatives have no interruptible or curtailable load on their systems.

Load Management:

SEC estimates that it had 50-70 MW of capacity in load management during the December 23-25 peak load periods. Load management was used by SEC on the morning of Saturday, December 23 for peak reduction. During the rotating outage periods, however, when Seminole was required to shed more load than load management could provide, the decision as to the use of load management as a part of the overall reduction strategy was left to the individual member system's discretion.

Public Announcements:

Seminole implemented its SECI/Member Emergency Coordination procedure on Thursday, December 21 in anticipation of the approaching cold weather. Messages are sent from SEC's Energy Management Control Center to each of the 11 member cooperatives. The specific messages during the Christmas outage period consisted of periodic status reports and alert levels and, ultimately, load shed requests and restoration authorizations. See the following list for all member notifications.

SEMINOLE ELECTRIC COOPERATIVE INCORPORATED

Issue Date	Page 1 of 3
Approved By	Number 3001.010

Subject	Section
SECI/MEMBER EMERGENCY COORDINATION	OPERATIONS

Purpose: To provide a reliable and efficient mechanism for exchange of information between Seminole and its Members during emergency conditions associated with electrical operation.

Scope: Any operational emergency which requires coordinated action by Seminole and its Members will require action hereunder. The affected operational emergency conditions requiring such action are listed as follows:

Generation or Transmission Capacity Shortage
Underfrequency Relay Operations

*State-wide energy shortage due to fuel unavailability is excluded here and covered separately under the Fuel Emergency Plan

Notification: In order to facilitate the initiation of action under the above emergency conditions in an efficient manner and in order to avoid confusion or misunderstanding, a series of action requests have been designated. Such action requests will be communicated to each Member system through the most expeditious communication means available for use. Such communication channels now and in the future may be telephone, SCADA (through local RTU at Member headquarters), SECI printer (associated with future SECI Energy Management System), etc.

The definitions of such action requests are as follows:

Condition	Code	Action Request Description
1	Green	Normal operation - No load shed required.
1	Blue	Generation or transmission capacity shortage could occur within 48 hours and manual load shedding may be necessary. Review feeder rotation procedures and insure that personnel will be available if needed.
1	Yellow	Generation or transmission capacity shortage is imminent. Have personnel stand by at SCADA console or in substations to implement manual load shedding when requested by SECI System Coordinator. No Members load should be shed under 1-Yellow.

Condition	Code	Action Request Description
1	Red 5	Generation or transmission capacity shortage is in effect and load shedding must begin. Reduce load through any of the available, accepted methods in an amount equal to 5% of the current estimated load level, i.e.: If estimated total load is 100MW, reduce load by 5MW. Maintain continuous load reduction of at least this amount until further notice from SECI System Coordinator.
1	Red 10	Reduce load by 10% (Example: Total reduction = 10MW)
1	Red 15	Reduce load by 15% (Example: Total reduction = 15MW)
1	Red 20	Reduce load by 20% (Example: Total reduction = 20MW)
1	Red 30	Reduce load by 30%
1	Red 40	Reduce load by 40%
1	Red 50	Reduce load by 50%
1	Red 60	Reduce load by 60%
1	Red 70	Reduce load by 70%
1	Red 80	Reduce load by 80%
1	Red 90	Reduce load by 90%
1	Red 100	Disconnect all load

Note: Load restoration requests will take above form as well. Restoration will occur by moving backwards through the above steps.

MEMBER NOTIFICATIONS

RELATED TO DEC. 23-25 CAPACITY SHORTAGE

DATE	TIME	MESSAGE
Thursday 12/21/89	0817	Co-op Summary Report
		Requested members review SECI/Member Emergency Coordination Practice #3001.010 (Emergency Load Shedding).
Friday 12/22/89	0812	Co-op Summary Report
		Same message as on Thursday 12/21/89.
Friday 12/22/89	1609	Message to all Member Systems.
		Condition 1, Code Blue with standard explanation.
Saturday 12/23/89	1731	Message to all Member Systems.
		System load at 2211 and climbing.
Saturday 12/23/89	1759	Message to FPC Member Systems.
		Condition 1, Code yellow.
Saturday 12/23/89	1803	Message to FPC Member Systems.
		Condition 1, Code red 2. (2%) Shed 32 MW in FPC area.
Saturday 12/23/89	2215	Message to FPC Member Systems.
		Condition 1, Code Red 0. (0%) Return to normal.
Sunday 12/24/89	0307	Message to all Member Systems.
		Condition 1, Code yellow. Shedding possible as early as 0500.
Sunday 12/24/89	0338	Message to all Member Systems.
		Condition 1, Code Red 10 (10%) - Seminole 2 tripped.

Sunday 12/24/89	0427	Message to all Member Systems. Condition 1, Code Red 20. (20%)
Sunday 12/24/89	0527	Message to all Member Systems. Condition 1, Code Red 25. (25%)
Sunday 12/24/89	0625	Message to all Member Systems. Condition 1, Code Red 30. (30%)
Sunday 12/24/89	0950	Message to all Member Systems. Requested verification of load shed.
Sunday 12/24/89	0958	Message to all Member Systems. Seminole 2 on-line at 0955.
Sunday 12/24/89	1019	Message to all Member Systems. Condition 1, Code Red 25 (25%)
Sunday 12/24/89	1042	Message to all Member Systems. Condition 1, Code Red 20 (20%)
Sunday 12/24/89	1114	Message to all Member Systems. Condition 1, Code Red 15. (15%)
Sunday 12/24/89	1156	Message to all Member Systems. Condition 1, Code Red 10. (10%)
Sunday 12/24/89	1215	Message to all Member Systems. Condition 1, Code Red 5. (5%)
Sunday 12/24/89	1300	Message to all Member Systems. All load restored.
Sunday 12/24/89	1720	Message to all Member Systems. Expect to load shed between 1830 and 2130.
Sunday 12/24/89	1733	Message to all Member Systems. Same as previous message.

Sunday 12/24/89	2016	Message to all Member Systems. Manatee 1 trip - standby for load shed.
Sunday 12/24/89	2109	Message to FP&L Member Systems. Condition 1, Code Red 5. (5%)
Sunday 12/24/89	2223	Message to FP&L Member Systems. All load restored.
Sunday 12/24/89	2232	Message to FP&L Member Systems. Repeat last message.
Monday 12/25/89	0509	Message to FP&L Member Systems. Reduce FP&L load by 17 MW (5%).
Monday 12/25/89	0612	Message to FP&L Member Systems. Maintain 5% in FP&L area-Standby for load management.
Monday 12/25/89	0717	Message to FP&L Member Systems nd L.M. Step Scheduler. Implement 100% Load Management.
Monday 12/25/89	0730-0930	Messages to FPC Member Systems. Several load shed requests in FPC area up to 70MW during peak.
Monday 12/25/89	0935	Message to all Member Systems. Discontinue feeder rotation but maintain L.M.
Monday 12/25/89	1022	Message to all Member Systems and L.M. Step Scheduler. Discontinue L.M. in FPC area - maintain in FP&L.
Monday 12/25/89	1206	Message to all Member Systems. There should be no load shed or load management in effect.

The individual member cooperatives are responsible for notifying their member consumers of possible emergency situations. All cooperatives but Okefonoke Rural Electric Cooperative and Peace River Electric Cooperative made public appeals for conservation from their consumers.

Central Florida Electric Cooperative:

Contacted radio station in Levy, Gilchrist, and Dixie Counties, Saturday morning, December 23. Released information to inform their members that power outages were occurring and instructing them on how to report outages. Repeated blackout and conservation messages on Saturday and Sunday evenings and Monday morning.

Clay Electric Cooperative:

Issued a press release Saturday afternoon, December 23 informing the public that "hundreds of customers" were already without power and listing telephone numbers to report outages. Lake Sunday morning, December 24, Clay issued a second release advising of rotating outages and requesting conservation. These reports were sent to all mewspapers, radio and television stations in their service area.

Glades Electric Cooperative:

Glades issued a release on Saturday morning, December 23, advising their members of current outages, possible rolling outages, and requesting conservation. Two radio stations in their service territory broadcast this information round the clock from December 23-25.

Lee County Electric Cooperative:

Lee requested conservation of their members through conversation with news personnel.

Sumter Electric Cooperative

Contacted media Saturday, December 23, 3:00 p.m., advising of system-wide emergency situation. Called all area newspapers, radio and television stations through Monday providing updates and requesting conservation.

Suwannee Valley Electric Cooperative:

Contacted local radio station as soon as SVEC knew load shed would be required. News bulletins were broadcast hourly during the time SVEC was under the shedding requirement.

Talquin Electric Cooperative:

TEC called for conservation Saturday evening, December 23. On Sunday morning, December 24, the coop announced rotating outages; that afternoon and evening, requested conservation again. Broadcasts were made via local radio and television.

Tri County Electric Cooperative:

Made appeals for conservation via local radio and television beginning Saturday evening, December 23, through Monday.

Withlacoochee River ELectric Cooperative:

Released information on Sunday, December 24, requesting conservation and advising of rotating outages.

Voltage Reductions and Rotating Service Outages:

Seminole's combined member systems operate approximately 700 distribution feeders. Each of the 11 member cooperatives has made its own designation of critical versus non-critical feeder load. For some member systems, the rural service configuration offers little flexibility to segregate the critical from the non-critical loads while still leaving enough non-critical load to accomplish the required load reduction.

There are three load shed scenarios which include (1) load shed for loss of SEC generation, (2) load shed as required of SEC as a firm purchaser of power from FPC while such company was shedding load, and (3) load shed as required of SEC as a firm purchaser of power from FPL while such company was shedding load.

Saturday, December 23:	6:00 p.m.	32 MW firm load shed
	7:00 p.m.	32 MW firm load shed
	8:00 p.m.	32 MW firm load shed
	9:00 p.m.	32 MW firm load shed

Curtailments during this period were in support of FPC's load shed requirement.

Sunday, December 24:	4:00 a.m.	200 MW firm load shed
	5:00 a.m.	398 MW firm load shed
	6:00 a.m.	706 MW firm load shed
	7:00 a.m.	626 MW firm load shed
	8:00 a.m.	665 MW firm load shed
	9:00 a.m.	534 MW firm load shed
	10:00 a.m.	400 MW firm load shed
	11:00 a.m.	232 MW firm load shed
	12:00 p.m.	94 MW firm load shed
	1:00 p.m.	41 MW firm load shed

Curtailments during this period were due to the unscheduled outage of Seminole Unit 2 and in support of FPC's load shed requirement.

	9:00 p.m.	39 MW firm load shed
	10:00 p.m.	20 MW firm load shed

Curtailments during this period were in support of FPL's load shed requirement.

Monday, December 25:	5:00 a.m.	17 MW firm load shed
	6:00 a.m.	65 MW firm load shed
	7:00 a.m.	68 MW firm load shed
	8:00 a.m.	117 MW firm load shed
	9:00 a.m.	69 MW firm load shed
	10:00 a.m.	23 MW firm load shed
	11:00 a.m.	12 MW firm load shed

This curtailment was in support of both FPC's and FPL's load shed requirements.

Unplanned Distribution Outages:

Central Florida Electric Cooperative:

Reported 117 unplanned feeder interruptions.

Clay Electric Cooperative:

Reported 52 unplanned feeder interruptions averaging 3 hours duration. The minimum outage was 26 minutes; the maximum, 9 hours.

Glades Electric Cooperative:

Reported some unplanned feeder interruptions, with a maximum of 8 hours duration.

Lee County Electric Cooperative:

Reported 428 unplanned feeder interruptions. The maximum interruption was 11 hours.

Okefenoke Rural Electric Membership Cooperative:

No service interruptions.

Peace River Electric Cooperative:

Reported 22 unplanned feeder interruptions averaging 1 hour 54 minutes each. The minimum interruption was 30 minutes; the maximum, 6 hours.

Sumter Electric Cooperative:

Reported 4 unplanned feeder interruptions, averaging 3 hours duration. The minimum outage was 1 hour 36 minutes; the maximum, 4 hours.

Suwannee Valley Electric Cooperative:

Reported 2 unplanned feeder interruptions.

Talquin Electric Cooperative:

Reported 54 unplanned feeder interruptions, averaging 1 hour 30 minutes duration. The minimum outage was 17 minutes; the maximum, 6 hours 10 minutes.

Tri County Electric Cooperative:

Reported 19 unplanned feeder interruptions, averaging 1 hour 27 minutes. The minimum outage was 15 minutes; the maximum, 5 hours 5 minutes.

Withlacoochee River Electric Cooperative:

Reported 103 feeder interruptions, averaging 3 hours 53 minutes duration. The minimum outage was 36 minutes; the maximum, 21 hours 40 minutes.

Appendix F

FLORIDA KEYS ELECTRIC COOPERATIVE

FLORIDA KEYS ELECTRIC COOPERATIVE

Forecasted Peak Load: (1989 Ten Year Site Plan) — 125 MW firm load

Actual Peak Load: — 100 MW firm load served

Total System Generating Capacity: — 14.1 MW

Scheduled Maintenance: — None

Generating Unit Forced Outages: — None

Purchased Power:

Power was purchased as usual from FPL.

Cogeneration:

None

Interruptible and Curtailable Load

None

Load Management

None

Public Announcements:

None

Distribution Outages

FKEC has 12 distribution feeders. 2 of which are identified as serving critical loads. Neither was interrupted during this period. There were 33 interruptions averaging 30 minutes duration; the minimum outage was 11 minutes; the maximum, 1 hour 22 minutes.

Appendix G

FORT PIERCE UTILITIES AUTHORITY

FORT PIERCE UTILITIES AUTHORITY

Forecasted Peak Load: 114 MW

Actual Peak Load:

Saturday, December 23:	Evening	
	111 MW	firm load served
	0 MW	firm load served
	111 MW	Total firm load
Sunday, December 24:	Morning	
	115 MW	firm load served
	0 MW	firm load unserved
	115 MW	Total firm load
	Evening	
	105 MW	firm load served
	0 MW	firm load unserved
	105 MW	Total firm load
Monday, December 25:	Morning	
	106 MW	firm load served
	0 MW	firm load unserved
	106 MW	Total firm load

Total System Generating Capacity: 141.1 MW

Scheduled Maintenance: 49.5 MW

King 6 (16.5 MW) out of service since 8/18/86.
King 7 (33 MW) out of service since 1/27/88.

Generating Unit Forced Outages: None

Purchased Power:

Saturday, December 23

None

Sunday, December 24

None.

Monday, December 25

JEA	9 MWH
GVL	167 MWH
SEC	51 MWH
TAL	60 MWH

Cogeneration

None

Interruptible and Curtailable Load

None

Load Management

None

Public Announcements: None.

Voltage Reductions and Rotating Service Outages:

Sunday, December 24 - Monday, December 25

During system peaks, the water and wastewater plants went to back-up generation, and voltage was reduced by 3%.

Unplanned Distribution Outages:

The utility reported 67 trouble calls over the weekend.

GAINESVILLE REGIONAL UTILITIES

GAINESVILLE REGIONAL UTILITIES

Forecasted Peak Load: (1989 Ten Year Site Plan)	263 MW
Actual Peak Load:	
Saturday, December 23:	Evening
	269 MW firm load served
	0 MW firm load unserved
	269 MW total firm load
Sunday, December 24:	Morning
	263 MW firm load served
	0 MW firm load unserved
	263 MW total firm load
	Evening
	235 MW firm load served
	0 MW firm load unserved
	235 MW total firm load
Monday, December 25:	Morning
	245 MW firm load served
	0 MW firm load unserved
	245 MW total firm load
Total System Generating Capacity:	458.5 MW
Scheduled Maintenance:	48 MW

J.R. Kelly Unit 8 was removed from service on November 3, 1989 for scheduled maintenance and was expected back in service on December 31, 1989.

Generating Unit Forced Outages:

Saturday, December 23

12:00 a.m.	Deerhaven Gas Turbine 1 18 MW Natural gas curtailment Unit unavailable for service
12:00 a.m.	Deerhaven Gas Turbine 2 18 MW Natural gas curtailment Unit unavailable for service

Sunday, December 24

Deerhaven Gas Turbine 1 18 MW
Natural gas curtailment
Unit unavailable for service

Deerhaven Gas Turbine 2 18 MW
Natural gas curtailment
Unit unavailable for service

Monday, December 25:

Deerhaven Gas Turbine 1 18 MW
Natural gas curtailment
Unit unavailable for service

Deerhaven Gas Turbine 2 18 MW
Natural gas curtailment
Unit unavailable for service

Tuesday, December 26:

4:00 p.m. Deerhaven Gas Turbine 1 18 MW
Natural gas service restored
Unit available for service

4:00 p.m. Deerhaven Gas Turbine 2 18 MW
Natural gas service restored
Unit available for service

Purchased Power: None

Cogeneration: None

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

Gainesville Regional Utilities made verbal announcements twice daily, beginning Saturday, December 23, to all broadcast media. This included information requested by the media as well as that information described in the GRU Disaster Preparedness Plan, page 21-1, Public Relations Procedure.

Voltage Reductions and Rotating Service Outages:

Gainesville Regional Utilities serves 50 distribution feeders on its system and has identified 13 of these as serving critical load. At no time during the report period was it necessary for GRU to resort to its rotation plan in order to reduce load levels or maintain transmission voltages.

Unplanned Distribution Outages

Most of GRU's reported service outages were seemingly unrelated to the cold weather and of a routine nature. They reported 49 interruptions averaging 1 hour 8 minutes duration. The minimum outage was 1 minute; the maximum 8 hours 21 minutes.

Appendix I

JACKSONVILLE ELECTRIC AUTHORITY

JACKSONVILLE ELECTRIC AUTHORITY

Forecasted Peak Load: 1,700 MW

Actual Peak Load:

Saturday, December 23:	Evening	
	1,984 MW	firm load served
	0 MW	firm load unserved
	1,984 MW	total firm load
Sunday, December 24:	Morning	
	2,005 MW	firm load served
	45 MW	firm load unserved
	2,050 MW	total firm load
	Evening	
	1,771 MW	firm load served
	0 MW	firm load unserved
	1,771 MW	total firm load
Monday, December 25:	Morning	
	1,831 MW	firm load served
	0 MW	firm load unserved
	1,831 MW	total firm load

Total System Generating Capacity: 2,274 MW

Excludes Southside Stations 1, 2, and 3 (107 MW), Kennedy Station 8 (46 MW), and Northside Station 2 (262 MW), which are in long-term cold shutdown.

Scheduled Maintenance: 262 MW

Northside Station 1 (262 MW) was on forced outage from November 30 to December 28 due to a failed generator exciter.

Generating Unit Forced Outages:

Friday, December 22:

7:01 p.m.	St. Johns River Power Park Unit 1 (660 MW) Flame scanner failure
10:55 p.m.	Returned to service

Saturday, December 23:

1:20 a.m.	Northside Station Unit 1 (275 MW) Boiler tube leak
7:46 a.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
10:31 a.m.	Returned to service
10:38 a.m.	St. Johns River Power Park Unit 1 (660 MW) Frozen boiler control
6:02 p.m.	Returned to service
11:44 a.m.	St Johns River Power Park Unit 2 (660 MW) Frozen boiler control
3:14 p.m.	Returned to service
11:59 a.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
1:50 a.m.	Returned to service
12:10 p.m.	Northside Station combustion turbine Unit 3 (62 MW) Low voltage
12:50 p.m.	Returned to service
12:10 p.m.	Northside Station combustion turbine Unit 4 (62 MW) Low voltage
12:50 p.m.	Returned to service
3:01 p.m.	Kennedy Station combustion turbine Unit 4 (63 MW) Low cooler temperature
4:10 p.m.	Returned to service
3:39 p.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
4:38 p.m.	Returned to service
8:03 p.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Instruments and controls failure
8:54 p.m.	Returned to service
11:18 p.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
11:56 p.m.	St. Johns River Power Park Unit 2 (660 MW) Circulating water pump

Sunday, December 24:

12:15 a.m.	Kennedy Station combustion turbine Unit 6 returned to service

1:30 a.m.	St. Johns River Power Park Unit 2 returned to service
1:55 a.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
2:34 a.m.	Returned to service
7:02 a.m.	Kennedy Station combustion turbine Unit 6 (63 MW) Computer failure
7:40 a.m.	Returned to service
6:21 p.m.	Northside Station Unit 1 returned to service

<u>Monday, December 25:</u>

6:38 a.m.	Kennedy Station combustion turbine Unit 5 (63 MW) Computer failure
7:37 a.m.	Returned to service
10:51 a.m.	Kennedy Station combustion turbine Unit 5 (63 MW) Computer failure
11:29 a.m.	Returned to service
11:40 a.m.	Northside Station combustion turbine Unit 3 (62 MW) High exhaust temperature
12:30 p.m.	Returned to service
9:00 p.m.	Kennedy Station combustion turbine Unit 5 (63 MW) Computer failure

<u>Tuesday, December 26:</u>

1:00 p.m.	Kennedy Station combustion turbine Unit 5 returned to service

<u>Purchased Power:</u>

<u>Saturday, December 23</u>

Southern	9,912 MWH Unit Power Sales
Southern	5,275 MWH emergency purchases
FPL	8,008 MWH firm purchases
Ft. Pierce	65 MWH
Gainesville	215 MWH
Homestead	27 MWH
Lake Worth	20 MWH
Orlando	117 MWH
Sebring	4 MWH
Seminole	260 MWH
Tallahassee	160 MWH

NOTE: (All Municipal purchases above were either economy, emergency, assured or short term firm.)

Sunday, December 24

Southern	9,912 MWH Unit Power Sales
Southern	7,016 MWH emergency purchases

Monday, December 25

Southern	8,441 MWH Unit Power Sales
Southern	5,524 MWH emergency purchases

Cogeneration:

Saturday, December 23

Jefferson Smurfit 6 MWH

Sunday, December 24

Jefferson Smurfit 1 MWH

Monday, December 25

Jefferson Smurfit 4 MWH

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

Electronic and Print Media Appeals for Voluntary Curtailment of Non-Essential Electric Usage

Saturday, December 23:

12:25 p.m.	WJXT-TV 4
12:35 p.m.	WTLV-TV 12
12:45 p.m.	WJKS-TV 7
12:55 p.m.	WPDQ Radio

1:00 p.m.	WOKV Radio
1:10 p.m.	WAYR Radio
1:15 p.m.	WAPE Radio
1:20 p.m.	WQIK Radio
2:55 p.m.	Florida Times-Union
5:30 p.m.	WJXT-TV 4 -- Live telephone interview on conservation and restoration efforts
6:00 p.m.	WTLV-TV 12 -- Live telephone interview on conservation and restoration efforts
6:20 p.m.	WPDQ Radio interview

Sunday, December 24:

7:15 a.m.	WJXT-TV 4
7:25 a.m.	WTLV-TV 12
7:35 a.m.	WJKS-TV 17
7:40 a.m.	WAPE Radio
7:45 a.m.	WPDQ Radio
7:50 a.m.	WOKV Radio
7:55 a.m.	WQIK Radio
12:00 p.m.	WTLV-TV 12 -- Live telephone interview on conservation and restoration efforts
2:00 p.m.	WJXT-TV 4 -- Videotaped interview on conservation and restoration efforts
2:30 p.m.	WJXT-TV 4 -- Live telephone interview on conservation and restoration efforts
3:00 p.m.	Florida Times-Union
4:00 p.m.	Florida Times-Union
6:00 p.m.	WTLV-TV 12 -- Live telephone interview on conservation and restoration efforts
10:30 p.m.	WJXT-TV 4
10:35 p.m.	WTLV-TV 12

Monday, December 25:

7:35 a.m.	WJXT-TV 4
7:41 a.m.	WTLV-TV 12
7:50 a.m.	WJKS-TV 17
8:00 a.m.	WPDQ Radio
8:05 a.m.	WOKV Radio
8:10 a.m.	WAPE Radio
8:20 a.m.	WQIK Radio

Electronic and Print Media Termination of Appeals for Voluntary Curtailment of Non-Essential Electric Usage

Monday, December 25:

11:00 a.m.	WJXT-TV 4
11:10 a.m.	WTLV-TV 12
11:15 a.m.	WJKS-TV 17

11:20 a.m.	WPDQ Radio
11:25 a.m.	WOKV Radio
11:30 a.m.	WAPE Radio
11:35 a.m.	WQIK Radio
1:30 p.m.	WTLV-TV 12 -- Videotaped interview on conservation and restoration efforts
3:45 p.m.	Florida Times-Union
4:00 p.m.	WTLV-TV 12
4:15 p.m.	WJKS-TV 17
4:30 p.m.	WJXT-TV 4

Voltage Reductions and Rotating Service Outages:

Saturday, December 23

12:14 p.m.	St. Johns River Power Park 1 & 2 (1200 MW) trips off line 211 MW of firm load shed approximately 50,000 customers affected public appeals for conservation
12:44 p.m.	firm service restored

Sunday, December 24

	public appeals for conservation 5% voltage reduction system wide
6:56 a.m.	45 MW of firm load shed approximately 290,000 customers affected
9:28 a.m.	firm service restored
10:03 a.m.	22 MW of firm load shed approximately 145,000 customers affected
10:30 a.m.	Firm service restored

As part of the Company's rotation plan, JEA interrupted 30 feeders only once for less than thirty minutes on December, 23, 1989, 12:14 p.m.. Three of the feeder breakers failed to successfully close back in when commanded which resulted in extended outages (maximum outage of 5 hours, 29 minutes) to those three feeders.

Unplanned Distribution Interruptions:

JEA reported 627 unplanned distribution outages during the period. The minimum outage was less than 30 minutes; the maximum, 36 hours.

Critical Loads:

JEA has 216 distribution feeders, 59 of which are identified as serving critical loads. None were interrupted during this period.

Appendix J

CITY OF KEY WEST

CITY OF KEY WEST

Forecasted Peak Load: 63 MW
(10 Year Site Plan)

Actual Peak Load:

Saturday, December 23:	Evening	
	63 MW	firm load served
	0 MW	firm load unserved
	63 MW	total firm load
Sunday, December 24:	Morning	
	46 MW	firm load served
	14 MW	firm load unserved
	60 MW	total firm load
	Evening	
	52 MW	firm load served
	24 MW	firm load unserved
	76 MW	total firm load
Monday, December 25:	Morning	
	73 MW	firm load served
	0 MW	firm load unserved
	73 MW	total firm load

Total System Generating Capacity: 93 MW

Excludes KWSP Unit 5 (15 MW) which has been unavailable since 11/5/87 due to a fire. Big Pine PD1, which will be unavailable until 4/30/91.

Scheduled Maintenance:

Stock Island Steam Plant unit 6 (35 MW) off line for overhaul 11/29/89. Expected in service 2/1/90.

Generating Unit Forced Outages:

Sunday, December 24

	KWSP Unit 3 (15 MW) Unavailable Salt leaks in condenser
4:40 a.m.	GT unit trip off-line Low megavars
5:10 a.m.	Unit on-line
6:40 p.m.	GT unit 1 trip off-line Low fuel pressure
7:10 p.m.	Unit on-line

Monday, December 25

	KWSP Unit 3 (15 MW) Unavailable Salt leaks in condenser
1:36 p.m.	SIPD #2 tripped off-line Low cooling water Unavailable through December 26

Purchased Power:

Saturday, December 23

FPL	601 MWH (up to 35 MW), Schedule ST	12:00 a.m. to 12:00 a.m.
OUC	285 MWH (up to 12 MW), Stanton	12:00 a.m. to 12:00 a.m.

Sunday, December 24

FPL	108 MWH (up to 28 MW), Schedule ST	12:00 a.m. to 7:00 a.m.
	264 MWH (up to 35 MW), Schedule ST	11:00 a.m. to 9:00 p.m.
	53 MWH (up to 35 MW), Schedule ST	11:00 p.m. to 12:00 p.m.
OUC	285 MWH (up to 12 MW), Stanton	12:00 a.m. to 12:00 a.m.

Monday, December 25

FPL	82 MWH (up to 29 MW), Schedule ST	12:00 a.m. to 5:00 a.m.
	382 MWH (up to 35 MW), Schedule ST	12:00 p.m. to 12:00 a.m.
OUC	285 MWH (up to 12 MW), Stanton	12:00 a.m. to 12:00 a.m.
Gainesville	20 MWH (up to 18 MW)	8:00 p.m. to 10:00 p.m.
Sebring	6 MWH	8:00 p.m. to 9:00 p.m.

Cogeneration:

Saturday, December 23

Metro Key West	3.5 KWH supplied 12:00 a.m. to 3:00 a.m.

Sunday, December 24

Metro Key West	4.4 KWH supplied 12:00 a.m. to 4:00 a.m.

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

The utility's public information officer contacted the five local radio stations at 7:00 a.m., Sunday, December 24, before the outages began requesting conservation. At 8:00 a.m., the following announcement was released to the radio stations:

> "City Electric System has cut electricity to the following areas ...Electricity consumers in those areas can expect to remain without power for about one hour.
>
> Again, City Electric System is asking everyone to curtail energy usage today. Conserving electricity can help prevent further outages. Outages are occurring as a result of the tremendous loads placed on the System due to the record low temperatures. The cold temperatures throughout the state are affecting City Electric System's access to purchased power."

By 9:15 a.m., outages were occurring so quickly that releases about specific area outages were not feasible. So, the following release was read to the radio stations.

> "City Electric System will be rotating outages this morning due to the record low temperatures throughout the state, which have placed tremendous demands on utilities."

"When your power goes out, you can expect to be without power for about one hour. Please continue to conserve electricity to prevent extended outages."

Radio stations were contacted again Sunday (12/24) afternoon. The public information officer informed each station that City Electric System was going to rotate outages again from about 6 p.m. until about 9 p.m. And that in all likelihood rotating outages would occur Christmas Day morning.

Christmas Day radio stations were contacted at about 6:30 a.m. They were informed that rotating outages would take place again from about 7:00 a.m. until noon.

The following statement was read to each station--one recorded the statement and used it once every half hour between 7:15 and 11:00. The other stations did make announcements about once every 45 minutes.

"City Electric System will rotate power outages again this morning. Record low temperatures throughout the state have placed tremendous demands on utilities. Utilities, unable to meet the demands have been forced to rotate outages.

When your power goes off you can expect to be without power for about one hour.

You can help by flipping off the 240 volt breakers in your fuse box when your power goes out. Wait about half an hour after your power is restored before flipping them back on. This will protect the System from overloads and protect you from extended outages.

If you leave your home, please be very careful driving because traffic lights may be out too.

And please, do not call City Electric System unless it's an emergency -- we know that you re without power. An emergency includes sparking or arcing on lines outside your home or your neighbors have power, but you don't."

As a follow-up to the Christmas outages, City Electric System is sending out a consumer newsletter that explains what happened and how consumers can cope with outages in the future.

Voltage Reductions and Rotating Service Outages:

The City implemented a rotating outage plan on Sunday morning and Monday morning, with an average interruption time of 2 hours 25 minutes over the two-day period.

Unplanned Distribution Outages

The City reported 25 unplanned distribution outages, averaging 3 hours 35 minutes duration. The minimum outage was 27 minutes; the maximum, 8 hours 33 minutes.

Critical Loads:

The City has 25 distribution feeders with 3 identified as serving critical load. None were interrupted during this period.

Appendix K

CITY OF KISSIMMEE UTILITY AUTHORITY

KISSIMMEE UTILITY AUTHORITY

Forecasted Peak Load: 180 MW

Actual Peak Load:

Saturday, December 23: Evening

171 MW	firm load served
10 MW	firm load unserved
181 MW	total firm load

Sunday, December 24: Morning

169 MW	firm load served
10 MW	firm load unserved
179 MW	total firm load

Evening

158 MW	firm load served
12 MW	firm load unserved
170 MW	total firm load

Monday, December 25: Morning

172 MW	firm load served
15 MW	firm load unserved
187 MW	total firm load

Total System Generating Capacity: 106.4 MW

Scheduled Maintenance: 13 MW

Steam turbine Unit 22 (8 MW) and Diesel Units 9 (3 MW) and 11 (2 MW), which were unavailable during this period.

Generating Unit Forced Outages:

Saturday, December 23

3:00 a.m.	Gas turbine unavailable
	Natural gas curtailment
10:30 p.m.	Unit available

3:00 a.m.	Steam turbine unit 23 unavailable Natural gas curtailment
10:30 p.m.	Unit available

Sunday, December 24

Gas turbine ran at reduced capacity (14 MW) after FGT released some natural gas to KUA.

7:36 a.m.	Diesel unit 17 Change pilot fuel pump
8:01 a.m.	Unit available
8:06 a.m.	Diesel unit 16 Change oil strainer
8:35 a.m.	Unit available
9:45 a.m.	Diesel unit 14 Fuel leak
10:11 a.m.	Unit available

Monday, December 25:

2:30 a.m.	Entire plant tripped off-line BH 20 opened
4:30 a.m.	Plant back on line

Gas turbine ran at reduced capacity (14 MW) after FGT released some natural gas to KUA.

9:40 a.m.	Diesel unit 8 Fuel leak, cylinder no. 5
10:38 a.m.	Unit available

Purchased Power:

Saturday, December 23:

OUC	1,497 MWH (up to 95 MW), 12:00 a.m. to 12:00 a.m.
TECO	345 MWH (up to 15 MW), 12:00 a.m. to 12:00 a.m.
FPC	109 MWH (up to 24 MW), 10:00 a.m. to 5:00 p.m.
Homestead	5 MW, 8:00 p.m. to 9:00 p.m. 4 MW, 10:00 p.m. to 11:00 p.m.

Sunday, December 24:

Homestead	296 MWH (up to 19 MW), 12:00 a.m. to 12:00 a.m.

Gainesville	10 MWH (up to 9 MW), 12:00 a.m. to 2:00 a.m. 86 MWH (up to 41 MW), 4:00 a.m. to 8:00 a.m. 222 MWH (up to 47 MW), 9:00 a.m. to 5:00 p.m.
TECO	346 MWH (up to 15 MW), 12:00 a.m. to 12:00 p.m.
FPL	131 MWH (up to 41 MW), 1:00 a.m. to 5:00 a.m.
OUC	156 MWH (up to 20 MW), 6:00 a.m. to 4:00 p.m. 34 MWH (up to 20 MW), 7:00 p.m. to 11:00 p.m.
Tallahassee	46 MWH (up to 19 MW), 1:00 p.m. to 4:00 p.m.
JEA	257 MWH (up to 24 MW), 1:00 p.m. to 12:00 a.m.

Monday, December 25:

OUC	166 MWH (up to 30 MW), 12:00 a.m. to 6:00 a.m. 652 MWH (up to 70 MW), 7:00 a.m. to 12:00 a.m.
Homestead	198 MWH (up to 18 MW), 12:00 a.m. to 3:00 p.m.
JEA	96 MWH (up to 24 MW), 12:00 a.m. to 5:00 a.m.
Tallahassee	271 MWH (up to 20 MW), 12:00 a.m. to 3:00 p.m.
TECO	346 MWH (up to 15 MW), 12:00 a.m. to 12:00 a.m.
FPC	100 MWH (up to 25 MW), 2:00 p.m. to 7:00 p.m.

Cogeneration: None

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

A request was made at 11:30 a.m., Sunday, December 24, to radio stations WFIV (Kissimmee), WPCV (Orlando), and STAR 101 FM (Orlando), to broadcast the following announcement: Kissimmee Utility Authority is experiencing power shortages and rotating blackouts. Please turn off all unnecessary equipment.

At 5:30 p.m., Sunday, December 24, the same message was phoned to the Orlando Sentinel newspaper.

Voltage Reductions and Rotating Service Outages:

KUA has 21 distribution feeders on its system, with 2 identified as serving critical loads. Fourteen of those feeders were cycled many times from 9:00 p.m. Saturday, December 23, until 10:00 Monday, December 25. Each was cut off for 15 minutes and then left on for one hour if the utility could leave them on that long.

Critical Loads Affected:

Both West feeder, serving Humana Hospital, and Donegan feeder, serving the Osceola County Prison, were part of the utility's rotating outages. Although Humana Hospital has back-up generation on-site, it was not operational during this period.

Unplanned Distribution Outages

The Boggy Creek feeder was off at 5:00 p.m. Saturday for approximately 5 hours due to a burned out primary. The North BVL feeder lost approximately 80% of the load from 5:00 p.m. Saturday to 5:00 a.m. Sunday due to a burned out junction box. Numerous other feeders tripped due to phase imbalance and overload. The ground overcurrent relays were turned off and the feeders sectionalized to restore the power.

Appendix L

CITY OF LAKELAND

CITY OF LAKELAND

Forecasted Peak Load: 439 MW firm load
(1989 Ten Year Site Plan)

Actual Peak Load:

Saturday, December 23: Evening

535 MW firm load served
27 MW firm load unserved
562 MW Total firm load

Sunday, December 24: Morning

537 MW firm load served
57.7 MW firm load unserved
594.7 MW Total firm load

Evening

475 MW firm load served
27 MW firm load unserved
502 MW Total firm load

Monday, December 25: Morning

508 MW firm load served
23 MW firm load unserved
531 MW Total firm load

Total System Generating Capacity: 481.5 MW

Larsen steam units 4, 5, 6 & 7 (119.1 MW) and Larsen gas turbines 1, 2, & 3 (39 MW) are on extended cold standby and are not included in this total. Unit 7 (51.2 MW) was returned to service on Saturday, December 23 and Unit 6 (24.6 MW) was returned to service on Sunday, December 24.

Scheduled Maintenance: 86 MW

McIntosh 1 (86 MW) out of service due to turbine overhaul started October 1, 1989.

Generating Unit Forced Outages:

Saturday, December 23

7:05 a.m.	McIntosh 2 (118 MW) derated to 90 MW due to failure of #3 oil burner to light
8:00 a.m	Larsen 7 (51.2 MW) derated to 48 MW, low oxygen in combustion air with fans wide open
9:05 a.m.	McIntosh 3 (204/340 MW) derated to 300 MW due to compartment 34 being out of service for instrument department check of primary air flow problem
10:48 a.m.	McIntosh GT (39 MW) tripped, power supply or thermocouple grounded
8:00 p.m.	Larsen 4 (19.4 MW) derated to 17.5 MW, feedwater pump #1 failed, switched to feedwater pump #2 which will only carry 17.5 MW
12:15 p.m.	McIntosh GT returned to service
12:53 p.m.	Larsen GT 2 (13 MW) failed to start, cold water in diesel starter block.
3:00 p.m.	McIntosh 2 returned to full load
11:41 p.m.	McIntosh 3 returned to full load
11:50 p.m.	McIntosh 3 tripped
11:58 p.m.	McIntosh 2 derated to 90 MW to replace #1 burner flame scanner

Sunday, December 24

12:36 a.m.	McIntosh 3 on
12:40 a.m.	McIntosh 3 tripped
1:16 a.m.	McIntosh 3 on
1:50 a.m.	McIntosh 3 tripped
2:17 a.m.	McIntosh 3 on but limited to 200 MW due to frozen coal in compartment 33 and 34
2:30 a.m.	McIntosh 2 returned to full load
10:04 a.m.	McIntosh 3 tripped, feedwater flow meter frozen due to failed heat strips on sensing line from feedwater flow transmitter. Many problems from frozen lines throughout plant delayed unit coming back on line
4:43 p.m.	McIntosh 3 returned to service but load limited to 200 MW due to frozen coal in silos and feeder pipes causing "no coal on belt" trips.
5:00 p.m.	Larsen 7 (51.2 MW), derated to 40 MW, leak on southwest lower water wall distribution header
10:45 p.m.	Larsen 5 (23.9 MW) derated to 21 MW, to burn clinker off tube wall

Monday, December 25

3:05 a.m.	Larsen 5 returned to full load
4:50 a.m.	Larsen 5 derated to 23 MW, could not maintain D.A. level, valve stuck half open, trash in strainer
7:25 a.m.	Larsen 5 returned to full load

Notes:
Reported generating unit capacities are net winter ratings.
Lakeland, OUC, and FMPA are members of the Florida Municipal Power Pool. While each utility is responsible for the operation and maintenance of their own generation, the output of the units is centrally dispatched by OUC.
McIntosh 3 (340 MW) is jointly owned by OUC (136) and the City of Lakeland (204 MW).

Purchased Power:

The City of Lakeland is a member of the Florida Municipal Power Pool, with generating resources dispatched by OUC (see OUC summary of purchased power).

Cogeneration:

None.

Interruptible and Curtailable Load:

None.

Load Management:

Sunday, December 24	6:00 a.m. to 10:00 a.m. 7 MW water heating load spread over 71 distribution feeders

Use of load management was stopped during the rotating outages to take advantage of the built in 30 minute delay on restoration of water heater load on the cycled circuits. A decision was made not to impose cold water on customers on top of rotating blackouts.

Public Announcements:

A press release was prepared for Friday December 22. However, this release was inadvertently mailed rather than hand delivered and did not reach the targeted news media until Tuesday, December 26.

Phone contacts were made with radio stations WONN-AM/WPCV-FM Sunday morning, December 24, when rotating outages were forced by lost generation. Other local stations could not be reached at the time. WONN/WPCV made conservation pleas and reported the problems the system was experiencing from 11:05 a.m. until 5:05 p.m. in the stations normal hourly news broadcast on Sunday and from 7:05 a.m. until 5:05 p.m. on Monday. The Manager of Systems Operations was in contact with them through the period by telephone to keep them updated on the situation and also gave the station suggestions to broadcast for demand reduction. The Mayor of Lakeland also called the local radio stations and asked them to broadcast similar information. It is estimated that demand was reduced by approximately 5 MW in response to the broadcasts for conservation.

Voltage Reductions and Rotating Service Outages:

Saturday, December 23

6:00 a.m. system wide voltage reduction initiated (approximately 17 MW)
8:05 a.m. normal voltage restored
8:35 p.m. system wide voltage reductions initiated (approximately 27 MW)

Sunday, December 24	7:00 a.m.	26.7 MW total firm load shed
	8:00 a.m.	57.7 MW total firm load shed
	9:00 a.m.	53.85 MW total firm load shed
	10:00 a.m.	33.95 MW total firm load shed
	11:00 a.m.	107 MW total firm load shed
	12:00 p.m.	129.8 MW total firm load shed
	1:00 p.m.	64.2 MW total firm load shed
	4:00 p.m.	66.9 MW total firm load shed
	5:00 p.m	35.4 MW total firm load shed
	6:00 p.m.	38.05 MW total firm load shed
	7:00 p.m.	85.2 MW total firm load shed
	8:00 p.m.	54.3 MW total firm load shed
	11:10 p.m.	normal voltage restored
Monday, December 25	8:00 a.m.	23 MW total firm load shed

Note:
Unless otherwise noted, firm load shed reported is for the hour ending.
Planned outage time for circuits on rotation was 20 minutes or less in order to avoid problems with cold load pick-up. However, actual outage times ranged from a minimum of 2 minutes to a maximum of 194 minutes with an average of 27 minutes.

Unplanned Distribution Outages:

Sunday, December 24

Subtransmission Outages: 64 minute and a 6 minute outage to a double circuit line Sunday morning

Feeder/Lateral Outages:	<u>78 total outage incidents</u> 39 tripped line fuses 9 cable failure/downed lines 4 tree or animal damage 13 other utility equipment problems 13 problems with customer equipment outage times ranging from 2 minutes to 19 hours
Transformer Outages:	<u>121 total outage incidents</u> 71 transformer failures 38 tripped fuses 5 cable failure/downed lines 4 tree damage 2 other utility equipment problems 1 human error outage times ranging from 20 minutes to 30.6 hours

Critical Loads Affected:

The City has 71 distribution feeders on its system, with 7 identified as serving critical loads. Two of those feeders, serving the water/wastewater plant and the City distribution warehouse, were interrupted as part of the rotting outages.

LAKE WORTH UTILITIES AUTHORITY

CITY OF LAKE WORTH UTILITIES

Forecasted Peak Load: 88 MW

Actual Peak Load:

Saturday, December 23: Evening

68 MW	firm load served
0 MW	firm load unserved
68 MW	total firm load

Sunday, December 24: Morning

82 MW	firm load served
0 MW	firm load unserved
82 MW	total firm load

Evening

79 MW	firm load served
0 MW	firm load unserved
79 MW	total firm load

Monday, December 25: Morning

80 MW	firm load served
0 MW	firm load unserved
80 MW	total firm load

Total System Generating Capacity: 129.7 MW

Scheduled Maintenance: 64 MW

Steam Unit No. 4 (33 MW), removed from service 6/22/89 for extensive overhaul. Gas Turbine Unit No. 1 (31 MW), removed from service 4/25/89 for exhaust stack reconstruction.

Generating Unit Forced Outages:

Monday, December 25

8:05 a.m.	Steam turbine Unit No. 1 Oil burner problem
9:00 a.m.	Unit available

Purchased Power:

Saturday, December 23

FMPA 636 MWH (up to 19 MW), 12:00 a.m. to 12:00 a.m.

Sunday, December 24

FMPA 675 MWH (up to 19 MW), 12:00 a.m. to 12:00 a.m.

Monday, December 25

FMPA 675 MWH (up to 19 MW), 12:00 a.m. to 12:00 a.m.

Cogeneration: None

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

The City of Lake Worth is a 12 square mile area surrounded by FPL's service area. The same media serving FPL's customers also service CLWU customers. The City felt that any public appeal on their part would be redundant and therefore made no announcements of their own.

Voltage Reductions and Rotating Service Outages:

The City has 43 distribution feeders, 16 of which are identified as serving critical loads. Rotating service outages were not instituted during this period. The City believes that voltage reduction significantly reduced the forecasted peaks.

Critical Loads Affected:

No critical loads were affected.

Unplanned Distribution Outages

The City reported 32 unplanned distribution outages of varying lengths of time (none longer than 3 hours; most less than 1 hour).

Appendix N

CITY OF NEW SMYRNA BEACH UTILITIES COMMISSION

CITY OF NEW SMYRNA BEACH

Forecasted Peak Load: 75.2 MW
(1989 Ten Year Site Plan)

Actual Peak Load:

Saturday, December 23:	Evening	
	78.2	MW firm load
Sunday, December 24:	Morning	
	39.2	MW firm load served
	*31.9	MW firm load unserved
	71.1	MW Total firm load
	Evening	
	53.8	MW firm load served
	*17.9	MW firm load unserved
	71.7	MW Total firm load
Monday, December 25:	Morning	
	39.2	MW firm load served
	*33.6	MW firm load unserved
	72.8	MW Total firm load

NOTE: *Not provided by the City of New Smyrna Beach. Estimated by staff based on system load before and after rolling blackouts.

Total System Generating Capacity: 24 MW

Scheduled Maintenance: 4 MW

Smith Street 6 (2 MW) out of service since August 21, 1987 due to major mechanical malfunction, scheduled to return to service June, 1990.
8 Swoope 4 (2 MW) out of service since December 13, 1989 due to cylinder liner problems, scheduled to return to service January 17, 1990.

Generating Unit Forced Outages:

Beginning at 2:00 a.m. December 23 natural gas supply was curtailed for 83 hours on Swoope 2 (0.9 MW) and Swoope 3 (2 MW). These units are dual fired and were switched to burn light oil during this period.

From 5:50 a.m. to 6:45 a.m., on December 24, Swoope 3 (2 MW) tripped off line due to a radiator fan motor breaker action.

Smith Street 3 (0.84 MW) was limited to 0.75 MW throughout the emergency due to environmental limits on exhaust stack opacity.

Purchased Power:

Saturday, December 23

FPL	207	MWH from 12:00 a.m. to 12:00 a.m. Schedule PR-3, partial requirements
FPL	429	MWH from 12:00 a.m. to 12:00 a.m. Schedule ST, partial requirements
TECO	230	MWH from 12:00 a.m. to 12:00 a.m. Schedule D, maintenance
FPL	45	MWH from 3:00 p.m. to 12:00 a.m. Schedule B, emergency maintenance
Homestead	10	MWH from 5:00 p.m. to 8:00 p.m. Schedule C, economy
Homestead	8	MWH from 9:00 p.m. to 11:00 p.m. Schedule C economy

Sunday, December 24

FPL	256	MWH from 12:00 a.m. to 12:00 a.m. Schedule PR-3, partial requirements
FPL	36	MWH from 12:00 a.m. to 7:00 a.m. Schedule ST, partial requirements
TECO	49	MWH from 12:00 a.m. to 6:00 a.m. Schedule D, maintenance
Homestead	7	MWH from 5:00 a.m. to 7:00 a.m. Schedule C, economy
Homestead	50	MWH from 7:00 a.m. to 4:00 p.m. Schedule B, emergency maintenance
FPL	193	MWH from 11:00 a.m. to 9:00 p.m. Schedule ST, partial requirements
JEA	15	MWH from 11:00 a.m. to 12:00 p.m. Schedule A, emergency
JEA	27	MWH from 1:00 p.m. to 4:00 p.m. Schedule A, emergency
TECO	15	MWH from 4:00 p.m. to 6:00 p.m. Schedule D, maintenance
JEA	80	MWH from 7:00 p.m. to 12:00 a.m. Schedule A, emergency
FPL	40	MWH from 10:00 p.m. to 12:00 a.m. Schedule ST, partial requirements

Monday, December 25

FPL	255	MWH from 12:00 a.m. to 12:00 a.m. Schedule PR-3, partial requirements
Sebring	3	MWH from 12:00 a.m. to 1:00 a.m. Schedule C, economy
FPL	115	MWH from 12:00 a.m. to 5:00 a.m. Schedule ST, partial requirements
JEA	92	MWH from 12:00 a.m. to 2:00 p.m. Schedule A, emergency
Gainesville	5	MWH from 5:00 a.m. to 6:00 a.m. Schedule C, economy
Lake Worth	4	MWH from 6:00 a.m. to 7:00 a.m. Schedule C, economy
Gainesville	5	MWH from 7:00 a.m. to 8:00 a.m. Schedule C, economy

Orlando	19	MWH from 11:00 a.m. to 2:00 p.m. Schedule B, emergency maintenance
TECO	113	MWH from 12:00 p.m. to 12:00 a.m. Schedule D, maintenance
Homestead	5	MWH from 12:00 p.m. to 1:00 p.m. Schedule B, emergency maintenance
FPL	208	MWH from 1:00 p.m. to 12:00 a.m. Schedule ST, partial requirements

Cogeneration:

None.

Interruptible and Curtailable Load:

None.

Load Management:

The City of New Symrna Beach has approximately 3 MW of water heater and heating load on its direct Load Management Program. These loads were interrupted at various times throughout December 23-25, 1989. Peak interruptions occurred on Saturday, December 23 as follows.

Saturday, December 23

5:00 p.m. to 10:10 p.m.	hot water heater load interrupted
5:00 p.m. to 11:45 p.m.	heating load interrupted

Public Announcements:

The Utilities Commission released a public announcement on December 21 warning its customers of extreme cold temperatures expected to occur over the Christmas holidays. The public announcement was hand delivered to local radio, television, and newspaper offices. The content of the announcement pertaining to electric service states:

> "Customers are requested to set heating system thermostats at 68 degrees or lower and to avoid all but the most essential use of electrical appliances between the hours of 7:00 a.m. and 10:00 a.m. until the weather becomes warmer."
>
> "Although the Commission expects adequate generating resources to be available to meet the expected load, these measures will reduce peak demand on the Utilities Commission's electric system and help to assure continued delivery of electric service to everyone. Any customers experiencing interruptions in electric service are requested to call the Commission's 24-hour emergency trouble service at 427-1366."

"The residential load management system will be operating and participating customers may experience brief interruptions in heating and water heating systems during this time. Some individuals will be more comfortable wearing a sweater or jacket indoors while thermostats are turned down."

On Saturday evening, December 23, the news media (newspapers, radio, and television) was contacted by telephone of impending rotating blackouts expected at approximately 6:00 a.m. on December 24, 1989.

Voltage Reductions and Rotating Service Outages:

On Saturday, December 24 emergency generators were started at the Commission's Glencoe Water Treatment Plant and the North Causeway Pollution Control Plant. Firm service was also curtailed to the Fish Memorial Hospital which operated on emergency generators.

Pollution Control Plant (370 KW):	from 6:20 a.m. December 24 thru 10:20 a.m. December 26
Water Treatment Plant (190 KW):	from 6:30 a.m. December 24 thru 10:30 a.m. December 26
Fish Memorial Hospital (720 KW):	from 5:30 a.m. December 24 thru 1:30 p.m. December 24 from 5:30 a.m. December 25 thru 2:00 p.m. December 25

Rotating feeder outages affecting up to 46% of total customers during the peak period were experienced as follows:

Saturday, December 23

No firm load shed.

Sunday, December 24

6:05 a.m. to 11:53 a.m. 6:15 p.m. to 11:00 p.m.	30 minute rotating outages affecting 6 of 18 total circuits.

Sunday, December 24

4:28 a.m. to 1:02 p.m.	15 minute rotating outages affecting 13 of 18 total circuits.

Unplanned Distribution Outages:

Saturday, December 23

Lost one regulator at Substation 4 resulting in a brief outage to by-pass regulator. Switched phases with lateral tap in Oliver Estates to balance station.

Sunday, December 24

Replaced 8 distribution transformers (15 KVA to 37.5 KVA) resulting in outage times of 3 to 5 hours to individual residences.

Critical Loads Affected:

The City has 18 distribution feeders on its system, with 4 identified as serving critical load. These were unaffected during this period.

Appendix O

ORLANDO UTILITIES COMMISSION

ORLANDO UTILITIES COMMISSION

Forecasted Peak Load: 729 MW
(1989 10 Year Site Plan)

Actual Peak Load:

Saturday, December 23: Evening

789 MW firm load served
0 MW firm load served
789 MW Total firm load

Sunday, December 24: Morning

801 MW firm load served
0 MW firm load unserved
801 MW Total firm load

Evening

701 MW firm load served
0 MW firm load unserved
701 MW Total firm load

Monday, December 25: Morning

702 MW firm load served
0 MW firm load unserved
702 MW Total firm load

Total System Generating Capacity: 1210 MW

Scheduled Maintenance: none

Generating Unit Forced Outages

Saturday, December 23

11:50 a.m.	Indian River CTA (46.8/96 MW) failed to start
12:15 p.m.	Indian River CTA on
11:50 p.m.	McIntosh 3 (136/340 MW) tripped, loss of stator cooling water flow due to frozen sensing line

Sunday, December 24

12:36 a.m.	McIntosh 3 on
12:40 a.m.	McIntosh 3 tripped
1:16 a.m.	McIntosh 3 on
1:50 a.m.	McIntosh 3 tripped
2:17 a.m.	McIntosh 3 on but limited to 200 MW due to boiler chemistry
10:01 a.m.	McIntosh 3 tripped, feedwater flow meter frozen
11:17 a.m.	Indian River CTA tripped, plugged fuel filters
11:55 a.m.	Indian River CTA on
12:36 a.m.	Indian River CTA tripped, plugged fuel filters
1:00 p.m.	Indian River CTA on
3:22 p.m.	Indian River 3 (321 MW) off due to tube leak
5:59 p.m.	Indian River CTA tripped, plugged fuel filters
6:29 p.m.	Indian River CTA on
6:33 p.m.	Indian River CTA tripped, plugged fuel filters
9:17 p.m.	Indian River CTA on
9:44 p.m.	Indian River CTB (46.8/96 MW) tripped due to fuel transfer
9:45 p.m.	McIntosh 3 returned to full load
10:18 p.m.	Indian River CTB on

Monday, December 25

7:42 a.m.	Indian River 3 on but limited to 200 MW

Tuesday, December 26

10:00 a.m.	Stanton 1 (299/436 MW) tripped due to air controller
1:05 a.m.	Stanton 1 on
9:11 a.m.	Indian River 3 off for maintenance of tube leak

Notes:
Reported generating unit capacities are net winter ratings.
Lakeland, OUC, and FMPA are members of the Florida Municipal Power Pool. While each utility is responsible for the operation and maintenance of their own generation, the output of the units is centrally dispatched by OUC.
McIntosh 3 (340 MW) is jointly owned by OUC (136) and the City of Lakeland (204 MW).
Stanton 1 (436 MW) is jointly owned by OUC (299 MW), the City of Kissimmee (21 MW) and the Florida Municipal Power Agency (116 MW)
Indian River CT A & B (96 MW each) are jointly owned by OUC (46.8 MW each) and the City of Kissimmee and FMPA (49.2 MW each).

Purchased Power:

Saturday, December 23

None

Sunday, December 24

Gainesville	120 MWH from 12:00 a.m. to 4:00 a.m. Schedule A, emergency
Seminole	63 MWH from 1:00 a.m. to 4:00 p.m. Schedule M, maintenance
Jacksonville	344 MWH from 3:00 p.m. to 10:00 p.m. Schedule A, emergency
FPL	84 MWH from 4:00 p.m. to 5:00 p.m. Schedule A, emergency
Gainesville	87 MWH from 4:00 p.m. to 6:00 p.m. Schedule A, emergency
Seminole	324 MWH from 5:00 p.m. to 11:00 p.m. Schedule M, maintenance

Monday, December 25

Seminole	24 MWH from 9:00 a.m. to 10:00 a.m. Schedule A, emergency
Seminole	7 MWH from 5:00 p.m. to 6:00 p.m. Schedule C, economy
Gainesville	35 MWH from 5:00 p.m. to 8:00 p.m. Schedule C, economy

Cogeneration

None

Interruptible and Curtailable Load

None

Load Management

None

Public Announcements:

The only time that OUC contacted the media was after Indian River 3 was taken off line due to a steam leak at 3:22 p.m. on Sunday, December 24. At this time the three television stations and radio stations were told that rolling outages might occur and that OUC requests that customers cut unnecessary use, lower thermostats and turn off Christmas lights. Customer Service Dispatch has a hot line with the fire department and a direct line with the police department. They were in constant contact with both during the Christmas emergency.

Voltage Reductions and Rotating Service Outages:

Saturday, December 23

No voltage reductions or firm load shed

Sunday, December 24

5:58 p.m.	10 MW of firm load shed (10 minute cycles affecting 5964 total customers)
6:27 p.m.	firm service restored

Monday, December 25

No voltage reductions or firm load shed

Unplanned Distribution Outages:

Saturday, December 23

6:54 p.m. to 11:57 p.m.	Feeder circuit #4-32, 1258 customers Underground cable splice failure (not weather related)
7:56 p.m. to 9:03 p.m.	Feeder circuit #6-24, 1071 customers Automobile striking pole (not weather related)

No critical loads affected.

SEBRING UTILITIES COMMISSION

SEBRING UTILITIES COMMISSION

Forecasted Peak Load: 67 MW

Actual Peak Load:

Saturday, December 23: Evening

53 MW firm load served
0 MW firm load unserved
53 MW total firm load

Sunday, December 24: Morning

67 MW firm load served
5 MW firm load unserved
72 MW total firm load

Evening

52 MW firm load served
0 MW firm load unserved
52 MW total firm load

Monday, December 25: Morning

57 MW firm load served
0 MW firm load unserved
57 MW total firm load

Total System Generating Capacity: 70 MW

Scheduled Maintenance: None

Generating Unit Forced Outages:

Saturday, December 23

5:00 a.m. Dinner Lake plant (11 MW)
Natural gas curtailment
Switched over to oil, ran at reduced output (8.2 MW) during peak hours due to fuel oil pressure problems and frozen controls on deareator.

Sunday, December 24

1:00 p.m.	Modified fuel pumps on Dinner Lake plant Unit available for full output

Purchased Power:

No power purchases were available during period Friday, December 22, through 10:00 a.m., Tuesday, December 26. Sebring was a seller during this time.

Cogeneration: None

Interruptible and Curtailable Load:

None

Load Management:

None

Public Announcements:

None

Voltage Reductions and Rotating Service Outages:

SUC has 14 distribution feeders on its system, with 6 identified as serving critical loads. Four of those feeders were cycled three to four times from 8:08 a.m. to 10:41 a.m., Sunday, December 24. The average interruption was 10 minutes.

Critical Loads Affected:

Feeder No. 43, serving Highlands County Emergency Center and SUC Well No. 4, was part of the utility's rotating outages. The Emergency Center has on-site back-up generation, which was used during the period.

Unplanned Distribution Outages

SUC reported 23 unplanned distribution outages, averaging 2 hours 36 minutes duration. The minimum interruption was 20 minutes; the maximum, 6 hours 5 minutes.

CITY OF TALLAHASSEE

CITY OF TALLAHASSEE

Forecasted Peak Load: 379 MW

Actual Peak Load:

Saturday, December 23:	Evening	
	361 MW	firm load served
	0 MW	firm load unserved
	361 MW	total firm load
Sunday, December 24:	Morning	
	401 MW	firm load served
	0 MW	firm load unserved
	401 MW	total firm load
	Evening	
	324 MW	firm load served
	0 MW	firm load unserved
	324 MW	total firm load
Monday, December 25:	Morning	
	323 MW	firm load served
	0 MW	firm load unserved
	323 MW	total firm load

Total System Generating Capacity: 512 MW

Excludes Purdom Units 1-4 (28 MW total), which are on extended cold standby.

Scheduled Maintenance: None

Generating Unit Forced Outages:

Friday, December 22:

	Corn Hyrdo Units 1, 2, 3 11 MW Limited to 4 MW due to water rate of flow
12:00 a.m.	Purdom Unit 7 50 MW Gland seal leak
12:00 p.m.	Unit available for service

10:00 p.m. Purdom Gas Turbine 1 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

10:00 p.m. Purdom Gas Turbine 2 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Saturday, December 23

Corn Hyrdo Units 1, 2, 3 11 MW
Limited to 4 MW due to water rate of flow

Purdom Gas Turbine 1 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Purdom Gas Turbine 2 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

11:30 a.m. Hopkins Unit 1 14 MW
Battery problem
6:00 p.m. Unit available for service

12:00 a.m. Purdom Unit 7 50 MW
Limited to 35 MW due to burner problems
6:00 p.m. Unit released to full capability

Sunday, December 24

Corn Hyrdo Units 1, 2, 3 11 MW
Limited to 4 MW due to water rate of flow

Purdom Gas Turbine 1 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Purdom Gas Turbine 2 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Monday, December 25:

Corn Hyrdo Units 1, 2, 3 11 MW
Limited to 4 MW due to water rate of flow

Purdom Gas Turbine 1 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Purdom Gas Turbine 2 12 MW
Natural gas curtailment; environmental permit restriction on fuel oil use.
Unit unavailable for service

Tuesday, December 26:

Corn Hyrdo Units 1, 2, 3 11 MW
Limited to 4 MW due to water rate of flow

8:00 a.m. Purdom Gas Turbine 1 12 MW
Natural gas service restored
Unit available for service

8:00 a.m. Purdom Gas Turbine 2 12 MW
Natural gas service restored
Unit available for service

Purchased Power:

Saturday, December 23

Southern 75 MW Schedule E Purchase (Usual purchase amount is 50 MW, but the City exercised its option for an additional 25 MW purchase.)

Sunday, December 24

Southern 75 MW Schedule E Purchase (Usual purchase amount is 50 MW, but the City exercised its option for an additional 25 MW purchase.)

Monday, December 25

Southern 75 MW Schedule E Purchase (Usual purchase amount is 50 MW, but the City exercised its option for an additional 25 MW purchase.)

Cogeneration:

None.

Interruptible and Curtailable Load:

None.

Load Management:

None.

Public Announcements:

The City of Tallahassee did not make any Public Service announcements requesting conservation during the Christmas holidays.

Voltage Reductions and Rotating Service Outages:

The City of Tallahassee serves 100 distribution feeders on its system and has identified 14 of these as serving critical load. The City was not required to interrupt any distribution circuit or shed any customer load during this period.

Unplanned Distribution Outages

Note: Most of the City's reported service outages were seemingly unrelated to the cold weather and of a routine nature (downed limbs, squirrels on the lines). However, the City reported 22 unplanned feeder interruptions, averaging 2 hours duration. The minimum outage was 20 minutes; the maximum, 6 hours.

Critical Loads Affected

None

CITY OF VERO BEACH

CITY OF VERO BEACH

Forecasted Peak Load: (1989 10 Year Site Plan)	138 MW

Actual Peak Load:

Saturday, December 23:	Evening
	120 MW firm load served
	0 MW firm load served
	120 MW Total firm load
Sunday, December 24:	Morning
	142 MW firm load served
	0 MW firm load unserved
	142 MW Total firm load
	Evening
	136 MW firm load served
	0 MW firm load unserved
	136 MW Total firm load
Monday, December 25:	Morning
	136 MW firm load served
	0 MW firm load unserved
	136 MW Total firm load

Total System Generating Capacity: 130 MW

Scheduled Maintenance: 16.5 MW

Unit No. 2 (16.5 MW) was removed from service 12/3/89 due to seizure of rotating element. Due back 1/19/90.

Generating Unit Forced Outages: None

Purchased Power:

Saturday, December 23

OUC	19 MWH from 12:00 a.m. to 12:00 p.m.
FPL	11 MWH from 12:00 a.m. to 12:00 p.m.
FPL	4 MWH from 12:00 a.m. to 12:00 p.m., partial requirements

Sunday, December 24

Unclear from responses.

Cogeneration

None

Interruptible and Curtailable Load

None

Load Management

None

Public Announcements: None.

Voltage Reductions and Rotating Service Outages:

None

Unplanned Distribution Outages:

Reported 15 unplanned distribution outages, averaging 2 hours 25 minutes duration. The minimum interruption was 25 minutes, the maximum 5 hours 50 minutes.

Critical Loads Affected:

The City has 32 distribution feeders on its system, with 11 identified as serving critical load. Five of those feeders experienced unplanned interruptions (hospital, fire station, ambulance station) during this period with a minimum duration of 25 minutes and maximum fo 5 hours 50 minutes.

FLORIDA MUNICIPAL POWER AGENCY

FLORIDA MUNICIPAL POWER AGENCY

Forecasted Peak Load: (10 Year Site Plan)	356 MW	
Saturday, December 23:	Evening	
	448 MW	firm load served
	0 MW	firm load unserved
	448 MW	total firm load
Sunday, December 24:	Morning	
	455 MW	firm load served
	0 MW	firm load unserved
	455 MW	total firm load
	Evening	
	381 MW	firm load served
	0 MW	firm load unserved
	381 MW	total firm load
Monday, December 25:	Morning	
	400 MW	firm load served
	0 MW	firm load unserved
	400 MW	total firm load

The Florida Municipal Power Agency is a wholesale supplier of electricity to five member systems through its All-Requirements Project. The participating members are:

City of Bushnell
City of Green Cove Springs
City of Jacksonville Beach
City of Leesburg
City of Ocala

Purchased Power:

Saturday, December 23

FPC 2,636 MWH (up to 126 MW), Partial Requirements
12:00 a.m. to 12:00 a.m.

FPL — 480 MWH (up to 20 MW), Partial Requirements for Jacksonville Beach
12:00 a.m. to 12:00 a.m.

96 MWH (up to 4 MW), Partial Requirements for Green Cove Springs
12:00 a.m. to 12:00 a.m.

Gainesville — 720 MWH (up to 30 MW), Schedule D
12:00 a.m. to 12:00 a.m.

Lake Worth — 255 MWH (up to 15 MW), capacity and energy purchase
12:00 a.m. to 12:00 a.m.

Sebring — 70 MWH (up to 10 MW), capacity and energy purchase
6:00 a.m. to 2:00 p.m.
45 MWH (up to 10 MW), capacity and energy purchase
3:00 p.m. to 9:00 p.m.

TECO — 480 MWH (up to 20 MW), Schedule D
12:00 a.m. to 12:00 a.m.

<u>Sunday, December 24</u>

FPC — 2,755 MWH (up to 126 MW), partial requirements
12:00 a.m. to 12:00 a.m.
3 MWH, Schedule H
8:00 p.m. to 9:00 p.m.

FPL — 513 MWH (up to 27 MW), partial requirements for Jacksonville Beach
12:00 a.m. to 12:00 a.m.
101 MWH (up to 5 MW), partial requirements for Green Cove Springs
12:00 a.m. to 12:00 a.m.

Gainesville — 720 MWH (up to 30 MW), Schedule D
12:00 a.m. to 12:00 a.m.

Lake Worth — 335 MWH (up to 15 MW), capacity and energy purchase
12:00 a.m. to 12:00 a.m.

Sebring — 5 MWH, capacity and energy purchase
3:00 a.m. to 4:00 a.m.
96 MWH (up to 10 MW), capacity and energy
11:00 a.m. to 12:00 a.m.
7 MWH (up to 4 MW), Schedule A
4:00 p.m. to 6:00 p.m.

TECO — 480 MWH (up to 20 MW), Schedule D
12:00 a.m. to 12:00 a.m.

Monday, December 25

FPC	2,830 MWH (up to 126 MW), partial requirements 12:00 a.m. to 12:00 a.m.
FPL	346 MWH (up to 27 MW), partial requirements for Jacksonville Beach 12:00 a.m. to 3:00 p.m. 162 MWH (up to 27 MW), partial requirements for Jacksonville Beach 6:00 p.m. to 12:00 a.m. 70 MWH (up to 6 MW), partial requirements for Green Cove Springs 12:00 a.m. to 2:00 p.m. 36 MWH (up to 6 MW), partial requirements for Green Cove Springs 6:00 p.m. to 12:00 a.m.
Gainesville	720 MWH (up to 30 MW), Schedule D 12:00 a.m. to 12:00 a.m.
Lake Worth	262 MWH (up to 20 MW), capacity and energy purchase 12:00 a.m. to 12:00 a.m.
Sebring	66 MWH (up to 10 MW), capacity and energy purchase 12:00 a.m. to 7:00 a.m. 141 MWH (up to 10 MW), capacity and energy purchase 9;00 a.m. to 12:00 a.m.
TECO	480 MWH (up to 20 MW), Schedule D 12:00 a.m. to 12:00 a.m.

Public Announcements:

City of Leesburg

CATV crawl on Weather Channel 12/23/89, 8:00 p.m. through 12/25/89, 8:00 a.m. continuously every 5 minutes:

> "Due to power overload City of Leesburg requests that all customers turn off Christmas lights, hot water heaters, and lower thermostat 2 degrees to conserve electricity -- Thanks."

WLBE 790 AM Radio was given the same announcement and was asked to announce it every chance possible.

City of Jacksonville Beach

ABC, CBS and NBC affiliates in Jacksonville ran public service announcements regarding conservation at the utility's request.

GULF POWER COMPANY

GULF POWER COMPANY

Forecasted Peak Load: (1989 Ten Year Site Plan)	1,577 MW

Actual Peak Load:

Saturday, December 23:	Evening
	1,813 MW firm load served
	0 MW firm load unserved
	1,813 MW total firm load
Sunday, December 24:	Morning
	1,804 MW firm load served
	0 MW firm load unserved
	1,804 MW total firm load
	Evening
	1,459 MW firm load served
	0 MW firm load unserved
	1,459 MW total firm load
Monday, December 25:	Morning
	1,407 MW firm load served
	0 MW firm load unserved
	1,407 MW total firm load

Total System Generating Capacity: 2,315 MW

Scheduled Maintenance: 346.5 MW

Christ 5 (89 MW) was removed from service on October 14, 1989 to perform a scheduled major turbine inspection. The unit was scheduled to return to service on January 12, 1990.

Daniel 1 (257.5 MW) was removed from service on December 2, 1989 to conduct planned full maintenance. An attempt was made but too much work remained to bring the unit back on line during the Christmas weekend. The unit was returned to service on January 12, 1990.

Generating Unit Forced Outages:

Daniel 2 (256.8 MW)	11:34 a.m. to 5:34 p.m. Saturday, December 23 245 MW reduction Condenser vacuum pump problem

Smith 1 (165.4 MW)	12:35 p.m. to 3:00 p.m. Saturday, December 23 11 MW reduction Condenser tube leak
Smith 1 (165.4 MW)	3:00 p.m. to 5:00 p.m. Saturday, December 23 102 MW reduction Condenser tube leak

Purchased Power:

The Southern system, of which Gulf is a member, was in a selling mode during the December 23-25, 1989 period. Throughout this period the Southern system was selling at least 3400 MW to peninsular Florida utilities, which is the maximum capacity which can reliably be transmitted into peninsular Florida. Had additional transmission capacity been available in Florida, Southern could have delivered a minimum of an additional 800 MW to peninsular Florida before reaching transmission constraints within the Southern system. Additional generating capacity was available throughout the period.

Cogeneration:

Gulf Power received up to 5 MW of generation from the Bay County Resource Recovery Facility (13.8 MW gross) during the period of December 23-25, 1989. This was wheeled to Florida Power Corporation pursuant to contract.

Interruptible and Curtailable Load

None.

Load Management

None.

Public Announcements:

None. Since Gulf and the Southern system had sufficient generating capacity to serve firm load, there was no need for emergency conservation announcements during this period.

Voltage Reductions and Rotating Service Outages:

None.

Unplanned Distribution Outages

Although Gulf did have scattered unplanned distribution outages, fewer than 5 percent of the Company's were without electricity during the extreme temperature conditions.

On the transmission system, one substation transformer was interrupted on December 23 at 8:45 p.m. for 11 minutes and was restored by isolating a faulted 155 KV line section.

Critical Loads Affected

Gulf has 240 distribution feeders on its system, with 127 identified as serving critical loads. None were reported to have been interrupted during this period.

ALABAMA ELECTRIC COOPERATIVE

ALABAMA ELECTRIC COOPERATIVE

Peak Load Forecast: 180 MW

Actual Peak Load: 230 MW

AEC is a generation and transmission cooperative, serving the following Panhandle Florida distribution cooperatives:

Escambia River Electric Cooperative
Gulf Coast Electric Cooperative
Choctawhatchee Electric Cooperative
West Florida Electrtic Cooperative

None of the member utilities interrupted circuits as part of a rotating outage plan. There were minimal outages caused by overload, unbalanced load condition and in one case a tree limb on a line. AEC reported sufficient energy, capacity and transmission to serve its members and their customers during this period.

Attachment 2

Utility Characteristics									RESIDENTIAL				COMMERCIAL			INDUSTRIAL			TRANSPORTATION			TOTAL		
									Revenues	Sales	Customers		Revenues	Sales	Customers	Revenues	Sales	Customers	Revenues	Sales	Customers	Revenues	Sales	Customers
Data Year	Utility Number	Utility Name	Part	Service Type	Data Type O = Observed I = Imputed	State	Ownership	BA Code	Thousand Dollars	Megawatthours	Count	Average Monthly Bill Per Customer	Thousand Dollars	Megawatthours	Count	Thousand Dollars	Megawatthours	Count	Thousand Dollars	Megawatt hours	Count	Thousand Dollars	Megawatthours	Count
2020	195	Alabama Power Co	A	Bundled	O	AL	Investor Owned	SOCO	2,379,707.4	17,620,060	1,295,794	153.04	1,535,783.5	12,599,224	202,791	1,297,459.4	20,383,787	6,159	.	.	.	5,212,950.3	50,603,071	1,504,744
2020	733	Appalachian Power Co	A	Bundled	O	WV	Investor Owned	PJM	621,183.0	4,887,948	354,340	146.09	292,716.0	3,078,799	66,462	261,608.0	3,915,282	2,248	0.0	0	0	1,175,507.0	11,882,029	423,050
2020	6455	Duke Energy Florida, LLC	A	Bundled	O	FL	Investor Owned	FPC	2,895,724.9	21,458,693	1,655,304	145.78	1,421,070.4	14,624,126	206,498	247,131.4	3,147,394	1,999	0.0	0	0	4,563,926.7	39,230,213	1,863,801
2020	17539	Dominion Energy South Carolina, Inc	A	Bundled	O	SC	Investor Owned	SCEG	1,126,473.0	8,372,815	653,376	143.67	801,652.7	7,614,583	104,345	341,649.0	5,273,958	774	0.0	0	0	2,269,774.7	21,261,356	758,495
2020	803	Arizona Public Service Co	A	Bundled	O	AZ	Investor Owned	AZPS	1,953,176.3	14,747,876	1,150,194	141.51	1,317,102.6	12,347,971	135,278	168,994.8	2,248,560	3,231	.	.	.	3,439,273.7	29,344,407	1,288,703
2020	14328	Pacific Gas & Electric Co.	A	Bundled	O	CA	Investor Owned	CISO	3,522,035.0	14,895,194	2,122,790	138.26	2,348,449.0	9,286,320	249,054	2,480,918.0	12,052,437	91,487	0.0	0	0	8,351,402.0	36,233,951	2,463,331
2020	19876	Virginia Electric & Power Co	A	Bundled	O	VA	Investor Owned	PJM	3,619,141.5	29,714,756	2,277,356	132.43	3,146,828.4	42,538,628	261,660	314,821.2	5,273,671	557	14,431.2	164,460	1	7,095,222.3	77,691,515	2,539,574
2020	7140	Georgia Power Co	A	Bundled	O	GA	Investor Owned	SOCO	3,446,630.6	27,828,611	2,277,256	126.13	2,970,653.3	30,804,771	326,502	1,185,631.8	22,040,396	10,672	7,584.1	140,609	1	7,610,499.8	80,814,387	2,614,431
2020	55937	Entergy Texas Inc.	A	Bundled	O	TX	Investor Owned	MISO	607,906.8	6,145,701	410,753	123.33	353,075.8	4,646,083	52,318	369,344.4	7,884,794	5,678	.	.	.	1,330,327.0	18,676,578	468,749
2020	9324	Indiana Michigan Power Co	A	Bundled	O	IN	Investor Owned	PJM	608,037.0	4,267,535	411,748	123.06	414,474.0	3,791,762	55,184	478,503.0	6,461,278	4,060	0.0	0	0	1,501,014.0	14,520,575	470,992
2020	9417	Interstate Power and Light Co	A	Bundled	O	IA	Investor Owned	MISO	601,867.0	3,622,771	407,849	122.98	486,708.0	3,869,362	85,271	487,797.0	6,372,272	1,432	0.0	0	0	1,576,372.0	13,864,405	494,552
2020	3046	Duke Energy Progress - (NC)	A	Bundled	O	NC	Investor Owned	CPLE	1,813,755.8	15,727,252	1,236,396	122.25	1,148,127.0	12,755,572	208,523	508,171.2	7,814,712	3,406	.	.	.	3,470,054.0	36,297,536	1,448,325
2020	6452	Florida Power & Light Co	A	Bundled	O	FL	Investor Owned	FPL	6,665,244.0	63,817,760	4,548,301	122.12	3,805,456.0	46,652,403	576,651	177,675.0	3,123,005	11,999	5,427.0	70,830	1	10,653,802.0	113,663,998	5,136,952
2020	5416	Duke Energy Carolinas, LLC	A	Bundled	O	SC	Investor Owned	DUK	758,277.1	6,604,246	517,863	122.02	483,056.2	5,218,274	98,406	464,196.7	8,191,318	1,505	0.0	0	0	1,705,530.0	20,013,838	617,774
2020	18454	Tampa Electric Co	A	Bundled	O	FL	Investor Owned	TEC	1,020,010.2	10,121,922	698,493	121.69	673,229.0	7,941,137	86,146	133,200.3	1,890,671	1,408	.	.	.	1,826,439.5	19,953,730	786,047
2020	10171	Kentucky Utilities Co	A	Bundled	O	KY	Investor Owned	LGEE	632,661.0	5,968,339	438,537	120.22	545,413.9	5,176,314	92,843	357,943.1	5,662,888	1,737	.	.	.	1,536,018.0	16,807,541	533,117
2020	733	Appalachian Power Co	A	Bundled	O	VA	Investor Owned	PJM	651,825.0	6,027,445	456,500	118.99	302,655.0	3,559,229	78,599	301,987.0	4,625,700	1,956	0.0	0	0	1,256,467.0	14,212,374	537,055
2020	15470	Duke Energy Indiana, LLC	A	Bundled	O	IN	Investor Owned	MISO	1,060,491.7	9,081,648	745,027	118.62	738,298.3	7,668,161	104,280	680,290.0	9,573,093	2,697	0.0	0	0	2,479,080.0	26,322,902	852,004
2020	13407	Nevada Power Co	A	Bundled	O	NV	Investor Owned	NEVP	1,217,594.0	10,476,628	855,549	118.60	413,940.0	4,734,638	110,308	368,290.0	4,928,833	1,549	350.0	3,960	1	2,000,174.0	20,144,059	967,407
2020	814	Entergy Arkansas LLC	A	Bundled	O	AR	Investor Owned	MISO	838,064.7	7,583,717	598,506	116.69	482,495.4	5,578,749	96,291	460,448.5	7,585,640	23,481	5.5	39	1	1,781,014.1	20,748,145	718,279
2020	5109	DTE Electric Company	A	Bundled	O	MI	Investor Owned	MISO	2,825,425.8	16,315,340	2,019,921	116.57	1,797,578.8	15,864,385	205,836	591,774.3	8,445,654	741	468.7	4,116	2	5,215,247.6	40,629,495	2,226,500
2020	12685	Entergy Mississippi LLC	A	Bundled	O	MS	Investor Owned	MISO	523,378.5	5,378,310	379,705	114.87	437,830.6	4,680,646	70,172	145,100.3	2,342,917	3,620	.	.	.	1,106,309.4	12,401,873	453,497
2020	14006	Ohio Power Co	A	Bundled	O	OH	Investor Owned	PJM	1,155,379.0	9,149,236	839,613	114.67	209,567.0	1,845,661	80,558	30,231.0	310,092	3,598	0.0	0	0	1,395,177.0	11,304,989	923,769
2020	11241	Entergy Louisiana LLC	A	Bundled	O	LA	Investor Owned	MISO	1,260,496.3	13,771,171	946,440	110.99	948,395.4	11,244,437	140,927	1,306,968.6	28,880,742	10,882	.	.	.	3,515,860.3	53,896,350	1,098,249
2020	17609	Southern California Edison Co	A	Bundled	O	CA	Investor Owned	CISO	4,478,159.0	24,584,033	3,432,735	108.71	4,436,658.0	29,507,958	463,981	589,544.0	4,753,779	25,104	.	.	.	9,504,361.0	58,845,770	3,921,820
2020	1167	Baltimore Gas & Electric Co	A	Bundled	O	MD	Investor Owned	PJM	1,185,560.2	9,787,118	916,333	107.82	288,494.6	2,485,487	68,327	12,172.8	109,921	3,322	0.0	0	0	1,486,227.6	12,382,526	987,982
2020	16609	San Diego Gas & Electric Co	A	Bundled	O	CA	Investor Owned	CISO	1,685,162.5	6,606,155	1,311,290	107.09	1,408,326.2	5,903,249	153,144	358,553.4	1,841,889	392	8,799.3	46,822	5	3,460,841.4	14,398,115	1,464,831
2020	19436	Union Electric Co - (MO)	A	Bundled	O	MO	Investor Owned	MISO	1,371,554.3	13,250,393	1,071,999	106.62	1,040,748.6	13,174,534	159,512	261,052.4	4,157,495	3,754	1,485.7	19,465	1	2,674,841.0	30,601,887	1,235,266
2020	4254	Consumers Energy Co	A	Bundled	O	MI	Investor Owned	MISO	2,078,770.9	13,331,252	1,630,424	106.25	1,465,706.9	11,162,631	223,900	573,306.6	6,952,357	1,348	.	.	.	4,117,784.4	31,446,240	1,855,672
2020	13756	Northern Indiana Pub Serv Co	A	Bundled	O	IN	Investor Owned	MISO	527,788.3	3,483,963	418,871	105.00	494,069.9	3,638,022	58,158	415,370.3	7,480,320	2,154	1,838.7	18,001	1	1,439,067.2	14,620,306	479,184
2020	20847	Wisconsin Electric Power Co	A	Bundled	O	WI	Investor Owned	MISO	1,289,134.8	8,239,413	1,024,922	104.82	975,671.5	8,348,941	119,434	527,276.7	6,422,913	623	141.0	963	2	2,792,224.0	23,012,230	1,144,981
2020	9273	Indianapolis Power & Light Co	A	Bundled	O	IN	Investor Owned	MISO	566,273.0	5,003,327	450,244	104.81	223,905.0	1,702,005	54,092	509,752.0	5,987,895	5,574	0.0	0	0	1,299,930.0	12,693,227	509,910
2020	5416	Duke Energy Carolinas, LLC	A	Bundled	O	NC	Investor Owned	DUK	2,234,440.0	21,558,142	1,788,300	104.12	1,746,260.0	22,707,156	291,484	671,499.3	11,421,625	4,595	1,236.3	16,124	1	4,653,435.6	55,703,047	2,084,380
2020	15248	Portland General Electric Co	A	Bundled	O	OR	Investor Owned	PGE	969,909.4	7,756,251	791,119	102.17	600,678.1	6,151,752	106,162	228,617.9	3,505,703	4,321	907.9	10,097	1	1,800,113.3	17,423,803	901,603
2020	12796	Monongahela Power Co	A	Bundled	O	WV	Investor Owned	PJM	405,268.4	3,626,669	333,844	101.16	245,740.5	2,648,838	53,107	349,742.3	5,816,469	6,836	0.0	0	0	1,000,751.2	12,091,976	393,787

2020	4226	Consolidated Edison Co-NY Inc	A	Bundled	O	NY	Investor Owned	NYIS	2,904,629.0	11,107,429	2,402,283	100.76	1,891,211.0	9,382,313	425,378	8,223.0	52,790	46	413.0	1,527	2	4,804,476.0	20,544,059	2,827,709
2020	15477	Public Service Elec & Gas Co	A	Bundled	O	NJ	Investor Owned	PJM	2,140,181.0	12,404,427	1,783,500	100.00	1,030,812.0	8,227,000	243,026	72,947.0	1,116,277	6,531	8,733.0	88,174	1	3,252,673.0	21,835,878	2,033,058
2020	15474	Public Service Co of Oklahoma	A	Bundled	O	OK	Investor Owned	SWPP	579,751.0	6,116,579	483,536	99.92	386,464.2	5,872,283	72,286	221,249.6	5,713,383	6,796	0.0	0	0	1,187,464.8	17,702,245	562,618
2020	17718	Southwestern Public Service Co	A	Bundled	O	TX	Investor Owned	SWPP	256,877.8	2,562,133	214,908	99.61	230,882.9	3,343,412	57,811	260,269.7	7,381,412	150	0.0	0	0	748,030.4	13,286,957	272,869
2020	14063	Oklahoma Gas & Electric Co	A	Bundled	O	OK	Investor Owned	SWPP	809,627.5	8,742,115	679,548	99.29	603,197.7	8,405,475	105,868	319,752.5	7,442,630	9,372	0.0	0	0	1,732,577.7	24,590,220	794,788
2020	14354	PacifiCorp	A	Bundled	O	OR	Investor Owned	PACW	620,141.9	5,759,839	524,689	98.49	483,434.8	5,388,670	70,093	139,033.2	1,829,442	9,172	1,514.6	15,509	1	1,244,124.5	12,993,460	603,955
2020	14940	PECO Energy Co	A	Bundled	O	PA	Investor Owned	PJM	1,247,729.0	9,875,262	1,086,552	95.69	211,811.0	2,177,907	92,827	34,494.0	618,835	348	0.0	0	0	1,494,034.0	12,672,004	1,179,727
2020	15500	Puget Sound Energy Inc	A	Bundled	O	WA	Investor Owned	PSEI	1,186,013.5	10,976,067	1,039,596	95.07	809,277.8	8,011,605	138,583	101,566.7	1,095,916	3,289	452.1	4,634	1	2,097,310.1	20,088,222	1,181,469
2020	9191	Idaho Power Co	A	Bundled	O	ID	Investor Owned	IPCO	532,085.4	5,280,429	470,804	94.18	282,097.0	3,861,432	70,150	314,528.1	5,018,314	19,440	0.0	0	0	1,128,710.5	14,160,175	560,394
2020	13781	Northern States Power Co - Minnesota	A	Bundled	O	MN	Investor Owned	MISO	1,241,194.9	9,033,597	1,171,591	88.28	1,268,029.0	12,082,902	141,360	558,613.2	7,004,313	502	1,919.4	20,410	1	3,069,756.5	28,141,222	1,313,454
2020	12341	MidAmerican Energy Co	A	Bundled	O	IA	Investor Owned	MISO	618,793.1	5,986,935	604,126	85.36	371,366.4	4,565,657	98,781	767,145.5	13,872,083	1,653	.	.	.	1,757,305.0	24,424,675	704,560
2020	13573	Niagara Mohawk Power Corp.	A	Bundled	O	NY	Investor Owned	NYIS	1,302,047.7	10,300,885	1,307,935	82.96	287,242.2	3,339,925	112,928	46,599.9	941,761	568	0.0	0	0	1,635,889.8	14,582,571	1,421,431
2020	4110	Commonwealth Edison Co	A	Bundled	O	IL	Investor Owned	PJM	2,547,676.2	19,250,047	2,637,056	80.51	786,494.6	7,841,717	215,127	54,721.4	858,862	174	0.0	0	0	3,388,892.2	27,950,626	2,852,357
2020	14354	PacifiCorp	A	Bundled	O	UT	Investor Owned	PACE	823,432.9	7,687,775	856,983	80.07	716,780.5	8,836,864	93,306	474,838.4	8,276,695	8,050	5,262.8	49,213	1	2,020,314.6	24,850,547	958,340
2020	15466	Public Service Co of Colorado	A	Bundled	O	CO	Investor Owned	PSCO	1,145,077.1	9,992,279	1,298,707	73.48	1,240,861.1	12,463,353	218,890	409,534.2	6,298,197	322	8,126.4	94,079	1	2,803,598.8	28,847,908	1,517,920

Attachment 3

QUESTION No. 1:
Please describe whether and to what extent FPL has identified any inaccuracies in customer bills attributable to the integration of Gulf Power customers into the FPL billing system.

RESPONSE:
FPL's customer accounts in Northwest Florida are billed under the Customer Account Management Systems (CAMS), which is separate from FPL's legacy billing system. When NextEra Energy acquired Gulf Power, the acquisition did not include a Customer Information Systems (CIS) solution. CAMS was piloted in 2019 and implemented in 2020 as the new billing system for Gulf customers. Gulf Power customers are now FPL Northwest Florida customers and continue to be billed through CAMS.

In January of 2022, FPL implemented new Commission-approved rates for all FPL customers, including FPL Northwest Florida. The alignment of different rate structures was complex and involved multiple teams of employees and months of preparation to ensure the transition would occur as smoothly as possible. The company supplemented existing controls with additional proactive measures, such as statement validation processes and comparing our bill calculation to an external bill calculator, to provide more comprehensive billing validations. Specific testing efforts were heavily focused on verifying billing and statement accuracy. Processes are in place to validate billing accuracy through a comprehensive quality bill check process that samples and analyzes customer accounts across all rates on every billing day for accuracy. In addition, the system automatically monitors all bills for potential irregularities and automatically holds atypical bills for manual review.

As with any significant tariff change, a relatively small number of billing exceptions were expected. In this instance, less than 0.5% of all customer bills needed to be addressed. The integration team performed extensive validations and customer statement reviews to ensure minimal impact to customers. For each mitigated exception, customers have been issued corrected statements as applicable. While we have seen and addressed isolated issues that have been traced to human error or cosmetic aspects of the customer experience, we have not identified any systemic concerns.

FPL investigates all customer-initiated billing inquiries and continues to conduct proactive measures to improve the customer experience as outlined above. Dedicated teams remain in place to efficiently address any issues that arise. We also continue to improve the customer experience for non-essential offerings (e.g. better explanation of what online projected bill estimates represent), and we continue to work with FPL Northwest Florida customers who received higher-than-expected bills following the cold weather and implementation of new rates in early 2022.

QUESTION No. 2:
Has FPL identified any discrepancies between data shown on customer bills, including electricity consumption, and data provided on FPL's online customer platforms, including through its website and app, during the period December 1, 2021 – March 1, 2022? If so, please describe and explain any such discrepancies.

RESPONSE:
FPL has not identified any discrepancies between data shown on customer bills, including electricity consumption, and actual bills available on FPL's online or app-based customer platforms for the period of December 1, 2021 – March 1, 2022. Customer bills and data on FPL's online customer platforms are consistent as of the time the bill is issued. Any adjustments made to the customer's account after the bill is issued (e.g., fees, credits, payments, partial payments, etc.) are reflected online and will not be reflected until the customer's next bill statement.

FPL's online platforms have a tool to show a customer their projected bill amount. FPL is aware of concerns expressed by several FPL NW customers regarding the Projected Bill data that they can view online. The Projected Bill amount tool assumes that the customer's consumption during the remaining days in the billing cycle will be consistent with the average daily consumption for the measured usage for the prior days in the customer's current billing cycle. The Projected Bill amount can change if customers alter their energy usage. The projected bill amount includes base charges and charges related to taxes but does not include additional programs and miscellaneous services.

QUESTION No. 3:
Please provide the number of meter tests requested and completed in the northwest service area during the period December 1, 2021 – March 1, 2022 and summarize the results of the completed tests.

RESPONSE:
In the FPL northwest service area during the period of December 1, 2021 – March 1, 2022, the Company received requests for 160 meter tests and completed 157 meter tests. The three meter tests not completed were due to access issues. All 157 meters tested within the allowable tolerance of plus or minus 2.0%. Although all the meters tested within the 2% FPSC standard, two meters were changed because they did not meet FPL's stringent internal standards of plus or minus 0.5%. Of the 157 meters tested, 152 were for residential customers and 5 were commercial customers.

QUESTION No. 4:
Please explain the extent to which weather conditions in the northwest service area during the period December 1, 2021 – March 1, 2022 impacted customer electricity consumption?

RESPONSE:
The FPL northwest service area experienced multiple cold weather days during the December 1, 2021 – March 1, 2022 timeframe, most of which were in the month of January 2022. As shown in Table 1 below, there was a significant increase in electricity consumption by FPL customers in the northwest service area in January 2022, including an approximate 30% increase in electric consumption for residential customers when compared to December 2021. This is consistent with historical customer usage patterns in FPL's Northwest Florida service area, as historically consumption in January is greater than December. Please see Table 2 for daily low, high and average temperatures as measured at the Pensacola weather station during the requested date range.

Table 1:

FPL Delivered Sales by Customer Class - Northwest Florida

		Residential & Home Business	Commercial	Industrial	Street and Highway Light	Total
Year	**Month**	**Total Tariff (kWh)**	**Total Tariff (kWh)**	**Total Tariff (kWh)**	**Total Tariff (kWh)**	**Total Tariff (kWh)**
2021	**Dec**	379,143,316	253,780,048	120,367,185	2,610,312	755,900,861
2022	**Jan**	492,995,195	366,527,139	65,031,805	2,961,194	927,515,333
2022	**Feb**	376,270,820	198,116,164	169,535,118	2,601,483	746,523,585

Table 2:

Temp. °F	Min	Max	Avg
12/01/21	45	70	58
12/02/21	50	77	63
12/03/21	58	74	65
12/04/21	53	76	64
12/05/21	55	74	65
12/06/21	64	78	70
12/07/21	59	66	63
12/08/21	51	72	62
12/09/21	50	73	63
12/10/21	72	79	75
12/11/21	57	78	72
12/12/21	50	62	54
12/13/21	50	69	60
12/14/21	56	72	63
12/15/21	56	71	62
12/16/21	60	72	66
12/17/21	67	72	69
12/18/21	69	77	74
12/19/21	47	69	59
12/20/21	45	53	49
12/21/21	46	54	50
12/22/21	41	64	51
12/23/21	36	62	50
12/24/21	44	71	58
12/25/21	59	76	68
12/26/21	63	79	69
12/27/21	66	77	71
12/28/21	70	78	73
12/29/21	72	79	75
12/30/21	74	80	76
12/31/21	72	78	75

Temp. °F	Min	Max	Avg
01/01/22	73	79	75
01/02/22	40	76	67
01/03/22	35	48	39
01/04/22	34	53	43
01/05/22	43	63	55
01/06/22	45	73	61
01/07/22	39	57	47
01/08/22	44	66	55
01/09/22	60	74	67
01/10/22	44	64	54
01/11/22	39	58	48
01/12/22	40	60	49
01/13/22	40	68	54
01/14/22	43	68	55
01/15/22	49	65	58
01/16/22	38	51	43
01/17/22	38	59	46
01/18/22	35	56	47
01/19/22	46	67	59
01/20/22	40	66	54
01/21/22	35	39	37
01/22/22	35	53	43
01/23/22	29	52	41
01/24/22	37	59	49
01/25/22	47	52	50
01/26/22	42	60	49
01/27/22	40	65	50
01/28/22	40	54	48
01/29/22	32	50	40
01/30/22	36	62	51
01/31/22	48	66	56

Temp. °F	Min	Max	Avg
02/01/22	52	66	59
02/02/22	61	66	63
02/03/22	67	72	70
02/04/22	37	66	47
02/05/22	34	53	42
02/06/22	35	60	47
02/07/22	44	49	46
02/08/22	41	61	49
02/09/22	35	63	50
02/10/22	44	69	56
02/11/22	42	64	54
02/12/22	51	67	59
02/13/22	41	56	48
02/14/22	35	62	49
02/15/22	38	64	52
02/16/22	48	69	61
02/17/22	63	75	69
02/18/22	43	72	55
02/19/22	39	64	50
02/20/22	46	64	55
02/21/22	55	68	62
02/22/22	65	74	69
02/23/22	65	73	68
02/24/22	67	75	69
02/25/22	52	79	66
02/26/22	49	76	61
02/27/22	51	68	58
02/28/22	48	67	57
03/01/22	49	72	59

[i] For instance, in January 2022 there were 13 days with a low temperature of 39 degrees or lower, as measured at the Pensacola weather station. By comparison, December 2021 only had 1 such day.

QUESTION No. 5:
Please identify the date(s) disconnections for non-payment and late payment charges were suspended due to the Covid-19 pandemic, and the date(s) disconnections for non- payment and late payment charges were reinstituted for customers in the northwest service area?

RESPONSE:
Disconnections for non-payments in the northwest service area were suspended due to Covid-19 on March 16, 2020 and resumed on November 20, 2020. Please note that collection activities were already suspended prior to this period on January 13, 2020 in advance of the CAMS system implementation.

Late payment charges were not billed throughout 2020 and 2021 in the former Gulf Power service territory as this service charge was not part of Gulf Power's tariff. Following the effective date of the rate case tariff, the first instance of billed late payment charges for FPL-NW customers occurred on January 10, 2022. As a courtesy, customers who contacted the care center were able to request a waiver of two late payment charges. This process to waive late payment charges is ongoing.

QUESTION No. 6:
Please describe any payment extension plans that were available to customers during the period December 1, 2021 – March 1, 2022. If any such plans were available during this period, provide the number of customers (residential and commercial/industrial) who were under a payment arrangement?

RESPONSE:
FPL has historically offered risk-based system generated payment extension (PEXT) options. In addition to these regular PEXT offerings, other payment extension options include circumstances such as Assist Commitment deferrals when an agency commits to a low-income assist payment, Medical Essential Services special arrangements, and revenue protection billing special installment arrangements.

Following the COVID-19 pandemic, FPL expanded the payment extension offerings to include an extended hardship option. This special installment-based payment extension applies to eligible customers who express a hardship to the agent and do not qualify for the standard PEXT.

Also, for the FPL-NW region, the customer is offered an installment-based hardship payment extension. Although the agents encourage the customers to make a payment on their account to lower their balance, no payment is required to setup the extension. The maximum extension allowed is three monthly installments which is billed and due with the following regular monthly bill statements.

The table below contains the total volume of payment extensions granted for the period requested.

Payment Extensions Volume Granted

Dec-2021	467
Jan-2022	732
Feb-2022	1,082

Note: The FPL-NW data during this period is reflective of the suspension of disconnections beginning on 12/17/21 through 01/18/22 due to tariff alignment system work resulting in a lower volume of requested extensions.

QUESTION No. 7:
Please provide the number of disconnections for non-payment for each month of the period December 1, 2021 – March 1, 2022?

RESPONSE:
The table below contains the total volume of disconnections for non-payment transactions for the period requested.

Disconnections for non-payment

Dec-2021	2,906
Jan-2022	3,657
Feb-2022	7,930

Note: The FPL NW data during this period is reflective of the suspension of disconnections beginning on 12/17/21 through 01/18/22 due to tariff alignment system work. Additionally, a total of 13 days at the FPL NW region were impacted by cold temperatures with disconnections for non-payment suspended during the period.

QUESTION No. 8:
Please explain whether and to what extent the number of callers to FPL's customer service center has changed during the period December 1, 2021 – March 1, 2022, compared to December 1, 2020 – March 1, 2021?

RESPONSE:
The number of callers to FPL NW's customer service center has decreased by 8% during the period of December 1, 2021 – March 1, 2022, compared to December 1, 2020 – March 1, 2021.

QUESTION No. 9:
Please explain whether and to what extent the wait time experienced by callers to speak to an FPL customer service agent or operator has changed during the period December 1, 2021 – March 1, 2022, compared to December 1, 2020 – March 1, 2021?

RESPONSE:
The average wait time experienced by callers to speak to an FPL NW agent has decreased by 38% (average wait time decreased from 155 seconds to 97 seconds) during the period December 1, 2021 – March 1, 2022, compared to December 1, 2020 – March 1, 2021.

Attachment 4

Power Delivery Winterization Update

Power Delivery has completed detailed analysis of system capacity and philosophy for extreme winter scenarios

Executive Summary

- **Transmission and Distribution detailed system analysis yielded overall reduction in extreme winter mitigation costs from original estimate**
  - Five year execution plan - $467MM (2022-27)
- **Aligning operating and design philosophies between FPL and Gulf provide both operational efficiencies and reliability benefits**
- **Distribution system review highlighted opportunities for alignment and upgrades - $353MM**
  - Feeder and Lateral operating philosophy alignment
  - Field transformer loading philosophy alignment and upgrades
- **Transmission system review highlighted opportunities for alignment and upgrades - $114MM**
  - Power Transformer emergency ratings alignment
  - Regulator/Reactor upgrades
  - Transmission Line Upgrades

Power Delivery has completed detailed analysis of system capacity and philosophy for extreme winter scenarios

Executive Summary

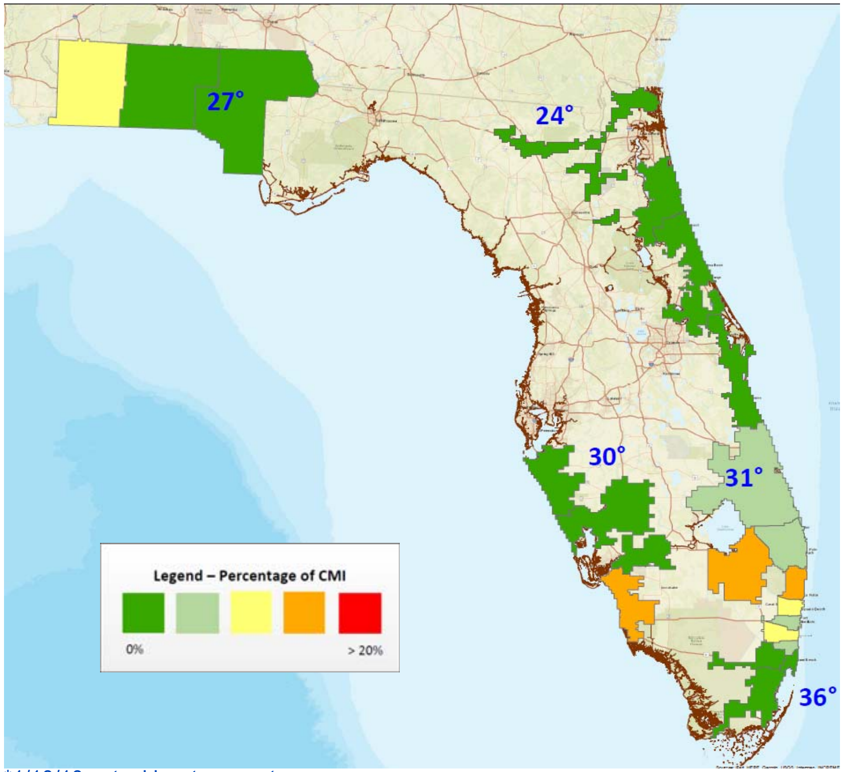
- **After internal capital adjustments no incremental increase required for Winterization in Power Delivery, however requires year over year budget shifts**
  - Options available to recover via SPP or include in base rates

Power Delivery analyzed impact from January 2010[1] with current design and cold weather operating philosophy

January 2010 Reliability Impact

- **Major reliability impact due to temperatures below average for a prolonged period**
  - Record – 5 days of high temperatures below 60 deg
  - Avg 12-day temp – 49.9°F
- **Largest reliability impacts regionalized for both FPL and Gulf Power**
  - South of Lake Okeechobee (FPL)
  - West (Pensacola – Gulf)
- **System performance, operating, and design philosophies reviewed from the meter to the substation**

CMI by Region



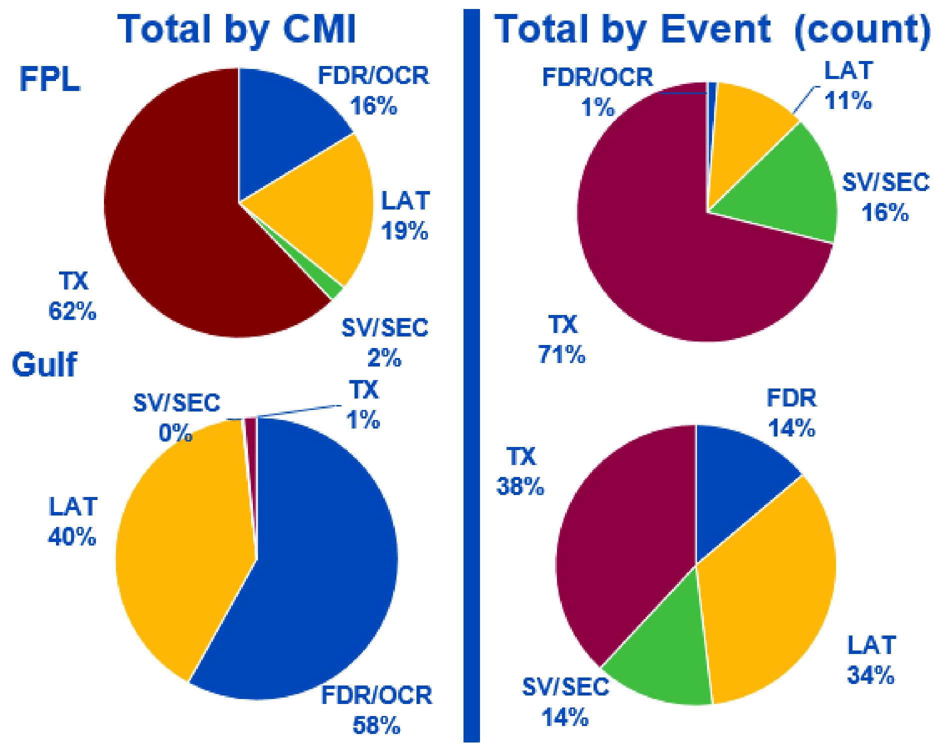
*1/10/10 actual low temperatures

1) 1989 detailed reliability information unavailable, 2010 impacts utilized as baseline for extreme cold-weather impact

Gulf and FPL's systems both had significant reliability impact, but responded differently to the event

2010 Review

- **Significant CMI events for both operating companies**
- **Primary reliability drivers differed by company**
  - FPL – Field Transformers (underground)
  - Gulf – OH Feeders
- **Low temperature conditions emphasis for evaluation**
  - Cold load pickup
  - Overload



Both FPL and Gulf saw major outlier events in January 2010

The 2010 winter reliability event impacted both FPL and Gulf's distribution system requiring review of philosophies

Distribution

- **Meter to transformer (secondary) – no change to philosophy**
- **Field Transformers – address reliability impacts at FPL**
  - Align initial loading and replacement criteria
  - 6,000 field transformers at FPL - $33MM
- **Laterals – address overload scenarios at Gulf Power**
  - Accelerate completion of ALS installation at Gulf Power - $6MM incremental 2022, reduce $3MM/yr. 2023-24
  - Align lateral loading and fusing philosophies with FPL
  - Legacy system addressed by SSUP and CEMI programs
- **Feeders**
  - Align design and operating philosophies between FPL and Gulf
  - 87 Feeders, 9 Substations at Gulf - $284MM
  - 11 Feeders, 1 Substation at FPL - $36MM

Distribution upgrades require $353MM to mitigate forecasted winter conditions

FPL

The 2010 winter reliability event proved little impact due to transmission/substation facilities

Transmission/Substation

- **Due to cold weather load forecast – portions of the transmission system must be addressed**
- **Transmission**
  - 36 miles of transmission upgraded at a cost of $75MM – FPL only
- **Substation Power Transformers**
  - Align FPL and Gulf emergency rating philosophy
    - -- Increase Gulf capacity from 130% to 150% in winter
  - FPL total substation transformer capacity is ~ 56,000MVA, 4 transformers to be upgraded - $8MM
  - Gulf total substation transformer capacity is ~3,100 MVA, 12 transformers to be upgraded - $28MM
- **Substation Regulators and Reactors**
  - Cold weather load exceeds current capability on 90 regulators and 9 reactors - $3M

Transmission/Substation upgrades require $114MM to mitigate forecasted winter conditions

FPL

Power Delivery Winterization detailed evaluation resulted in a cost reduction from $1,039MM to $467MM

	Revised Forecast	FPL		Gulf		Total Cost
Substation Transformers	Replace/Install 16 transformers – align philosophy	4	$8MM	12	$28MM	$36MM
Substation Equipment	Replace 90 Regulators and 9 Reactors	66 Regulators 9 Reactors	$2.25MM	24 Regulators	$0.75MM	$3MM
New Feeders	Build 98 new feeders – align philosophy	11	$20MM	87	$140MM	$160MM
New Substations[1]	Build 10 new substations	1	$16MM	9	$144MM	$160MM
Field Transformers	Replace 6,000 transformers – FPL only	6,000	$33MM	0	0	$33MM
Transmission	Upgrade 36 miles of transmission line	36	$75MM	0	0	$75MM
Laterals	Accelerate ALS program at Gulf from YE 2024 to YE 2022	0	0	Incremental 2022	$6MM	$6MM incremental 2022, reduction 2023-24
Total		$154.25MM		$312.75MM		$467MM

- **Prior Estimated Costs**
  - Gulf: $305MM - $610MM
  - FPL: $344MM - $429MM
  - Total: $649MM - $1,039MM

Alignment of philosophies and detailed system review reduced estimated costs to $467MM, a significant reduction from original estimate

1) New Substations required in support of new feeder construction

A portion of plan may be recoverable by SPP as currently defined

Clause/Base Split

	Revised Forecast	SPP* Units	SPP Cost	Base Units	Base Cost	Total Cost
Substation Transformers	Replace/Install 16 transformers – align philosophy	16	$36MM			$36MM
Substation Equipment	Replace 90 Regulators and 9 Reactors	60	$1.9MM	30/9	$1.1MM	$3MM
New Feeders	Build 98 new feeders – align philosophy			98	$160MM	$160MM
New Substations	Build 10 new substations			10	$160MM	$160MM
Field Transformers	Replace 6,000 transformers – FPL only	4500	$24.7MM	1500	$8.3MM	$33MM
Transmission	Upgrade 36 miles of transmission line	36	$75MM			$75MM
Laterals	Accelerate ALS program at Gulf from YE 2024 to YE 2022			1	$6MM incremental 2022	$6MM incremental 2022, reduction 2023-24
Total		$137.6MM		$329.4MM		$467MM

*Requires 2023 SPP filing
Note: 2022 SPP Filing is complete, no new items included into 2022 SPP budget

- **Already included in SPP filing**
  - Feeder Hardening – 6 feeders at Gulf YE 2022
  - Power Transformers – 1 Increased Capacity – Philips Inlet (Gulf)

FPL

After internal capital adjustments, no incremental increase is required for winterization, year over year shift only

Winterization/SR 80/SR 70 Preliminary Capital - Yearly

	Items	# of Items	2022 ($MM)	2023 ($MM)	2024 ($MM)	2025 ($MM)	2026 ($MM)	2027 ($MM)	Capital Total
	Winterization		$ 15.4	$ 83.0	$ 132.2	$ 124.4	$ 80.0	$ 32.0	$ 467.0
FPL	New Substations	1		$ 16.0					$ 16.0
FPL	New Feeders	11		$ 9.0	$ 11.0				$ 20.0
FPL	Sub Power Transformers - Replacements	4		$ 4.0	$ 4.0				$ 8.0
FPL	Voltage Regulators - 3 per item	22	$ 0.7	$ 0.8	$ 0.7				$ 2.1
FPL	Reactors - 3 per item	3	$ 0.2						$ 0.2
FPL	Distribution Padmount Transformers	4000	$ 5.5	$ 5.5	$ 11.0				$ 22.0
FPL	Distribution Aerial Transformers	2000	$ 2.8	$ 4.1	$ 4.1				$ 11.0
FPL	Transmission Improvements			$ 21.0	$ 35.0	$ 19.0			$ 75.0
Gulf	New Substations	9			$ 32.0	$ 64.0	$ 48.0		$ 144.0
Gulf	New Feeders	87		$ 16.0	$ 28.0	$ 32.0	$ 32.0	$ 32.0	$ 140.0
Gulf	Sub Power Transformers - Increase Capacities	9		$ 7.3	$ 7.3	$ 7.4			$ 22.0
Gulf	Sub Power Transformers - Replacements	3		$ 2.0	$ 2.0	$ 2.0			$ 6.0
Gulf	Voltage Regulators - 3 per item	8	$ 0.3	$ 0.3	$ 0.2				$ 0.8
Gulf	ALS		$ 6.0	$ (3.0)	$ (3.0)				$ -
	State Road 80 Rebuild Project		$ 3.0	$ 144.0	$ 223.0	$ 7.0			$ 377.0
	State Road 70 Rebuild Project		$ 1.0	$ 1.0	$ 2.0	$ 27.0	$ 206.0	$ 97.0	$ 334.0
	Total - Winterization, SR70, SR80		$ 19.4	$ 228.0	$ 357.2	$ 158.4	$ 286.0	$ 129.0	$ 1,178.0
	500 kV Loop (AFUDC)				$ (445.4)	$ (506.7)	$ (535.2)		$ (1,487.3)
	Gulf Power - Major Projects Budget			$ (90.0)					$ (90.0)
	Totals - Winterization/SR80/SR70 incl. Project adjustments		**$ 19.4**	**$ 138.0**	**$ (88.2)**	**$ (348.3)**	**$ (249.2)**	**$ 129.0**	**$ (399.3)**
	Total Estimated Clause (SPP)			**$ (45.0)**	**$ (64.2)**	**$ (28.4)**	**$ -**	**$ -**	**$ (137.6)**
	Total Estimated Base		**$19.4**	**$93.0**	**($152.4)**	**($376.7)**	**($249.2)**	**$129.0**	**($536.9)**

Capital budget shift from 2025 into 2023 and 2027 will allow existing budget to self-cover winterization

FPL

Plan execution requires modification to Power Delivery core practices

Next Steps

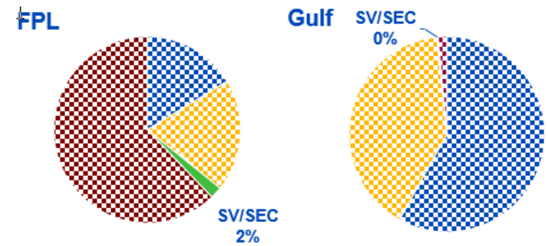
- **Modify Power Delivery annual system planning process to include extreme winter scenarios**
- **Adjust system standards and design criteria – change management process**
  - Engineering workshops
  - Documentation
- **Review reliability impacts related to new feeder construction**
  - 3 – 5 min reduction in SAIDI for Gulf Region

Appendix

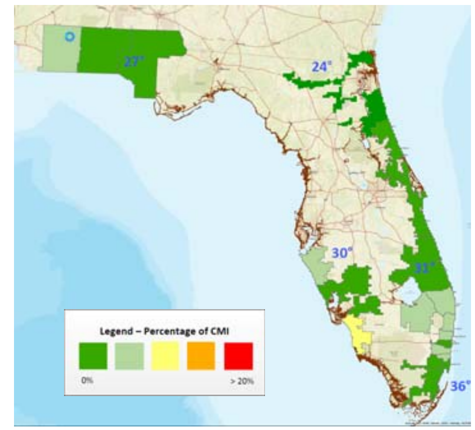
OH/UG Service Standards are aligned between Gulf and FPL

Meter to Transformer

- **Gulf and FPL services are sized to meet the capability of home electrical panels**
- **Review of January 2010 proved limited overall impact - ~1% of total**
  - Primary impacts driven by legacy conductors smaller than current design guidelines
  - Splices/connectors primary failure points
- **Legacy conductor continues to be inherent risk and will be addressed by SSUP program**
  - Small wire services
  - Open wire secondary

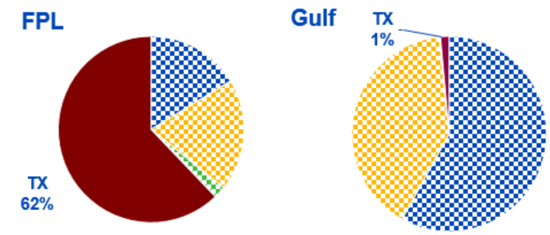


Service CMI



No recommended changes to service philosophy or mitigations required

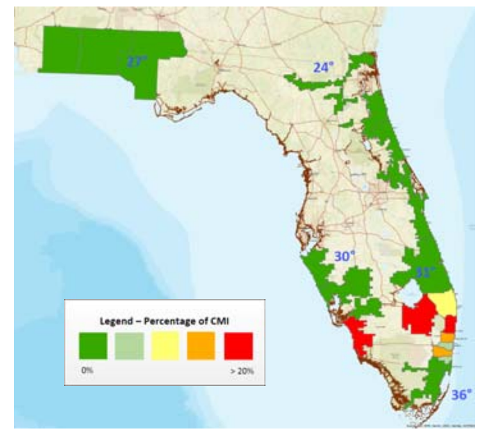
Field transformer outages drove overall reliability impact during January 2010's winter event for FPL



Field Transformers

- **Largest CMI contributor for FPL in 2010 – Underground units**
  - Failures primarily due to loading impacts
- **Regionalized impacts observed south of Lake Okeechobee**
  - Increased population (load) during winter in south – "Snowbirds"
  - More diversity in non-electric heating sources north of Lake (gas, fireplaces, etc.) – reduced loads
- **Recommendations:**
  - Align FPL and Gulf philosophies
  - Proactive replacement of 6,000 units - $33.0MM

Transformer CMI



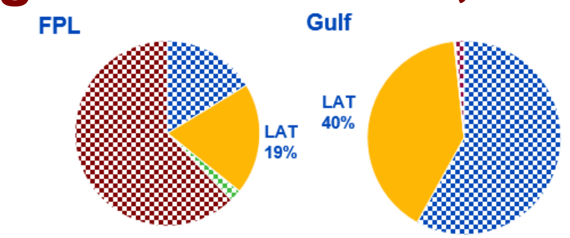
	FPL Existing		Gulf Existing		Proposed	
	Summer	Winter	Summer	Winter	Summer	Winter
Initial Loading	120%	200%	125%	140%	100%	120%
Changeout Loading	200%	200%	160%	180%	160%	180%

1) Level 2 chargers can add 3-7kW per home, estimated 2 homes/transformer (33% adoption on avg.) up to 14kW (15.5kVA)

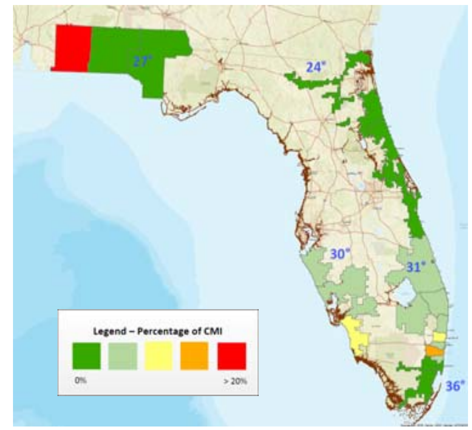
While lateral outages were an impact during the 2010 event, programs exist to mitigate exposure

Laterals

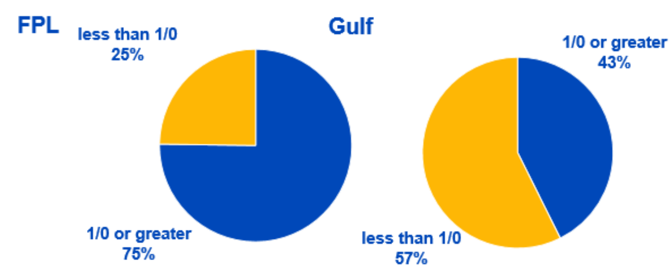
- **During the January 2010 event, lateral outages were a challenge for both Gulf and FPL**
  - 40% total CMI – Gulf, 20% total CMI – FPL
  - Overload – Gulf, Equipment Failure – FPL
    - -- Both main causes primarily on legacy "small wire" (conductor < 1/0)
    - -- Undersized fuse sizing drove outages at Gulf
- **Existing programs will address small wire/ legacy fuse sizing concerns**
  - ALS – minimize fusing variety, eliminate cold load pickup/overload, align fusing standards
    - -- Gulf planned completion YE 2024
  - SSUP – eliminate legacy OH laterals
  - CEMI – reactive program – problem laterals



Lateral CMI

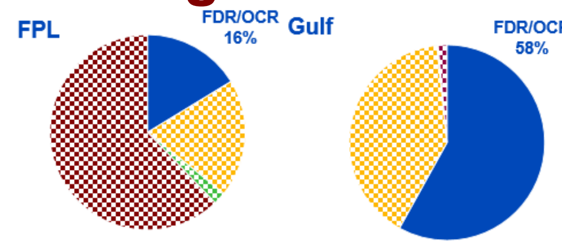


Legacy Conductor



Gulf's ALS deployment can be accelerated from YE 2024 to YE 2022 for additional $6MM incremental

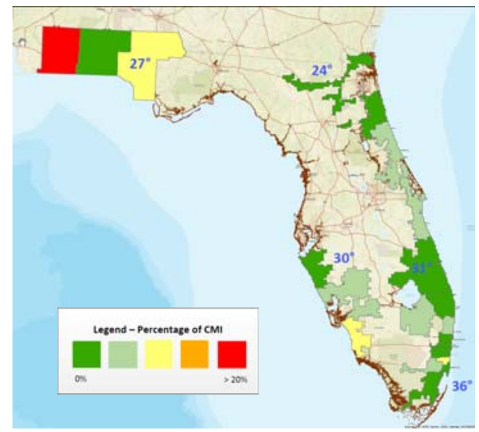
Review of 2010's winter event proved Feeder outages were a large impact at Gulf due to overload



Feeders

- **Feeder performance differed between FPL and Gulf during the January 2010 event**
  - Gulf – ~60% CMI, FPL – ~20% CMI
  - Gulf – overload, FPL – equipment failure
- **Alignment of philosophies for winter loading of feeders will mitigate previous overload scenarios at Gulf Power**
  - 720A (840A emergency), part of yearly planning and system expansion process
  - Mitigate cold load pickup/overload scenarios
- **Reviewing forecasted loads/alignment criteria**
  - FPL – 11 new feeders
    1 new substation – $36MM
  - Gulf – 87 new feeders
    9 new substations - $284MM

Feeder CMI



	FPL Existing		Gulf Existing		Proposed	
	Summer	Winter	Summer	Winter	Summer	Winter
Loading Criteria	600A	720A	600A	N/A	600A	720A
Construction (future alignment)	568 (600A)		795 (900A)		568	

Winterization efforts will require a $320MM investment over the next five (5) years to reduce feeder loading

Team Recommendations differ from original estimates due to deeper analysis of philosophies and system capabilities and updated forecast information

Summary of Recommendations

	FPL	Gulf
Meter to Transformer	No recommended actions – maintain aligned philosophy	
Field Transformers	Change initial and change-out (capacity upgrade) criterial to align with Gulf: Initial: 100%/120%, Changeout 160%/180% (Summer/Winter) Replace 6,000 units with forecasted overload	Reduce initial loading criteria to align FPL and Gulf philosophies – 100%/120% (Summer/Winter)
Laterals	No recommended changes	Align philosophies with FPL – lateral fusing and standards guideline, accelerate ALS deployment
Feeders	No changes to philosophy – build 11 feeders	Address legacy feeders (pre-2017 philosophy), build 87 feeders
Regulators/Reactors	Replace 66 regulators, 9 reactors that are forecasted to exceed rated capabilities	Replace 24 regulators,that are forecasted to exceed rated capabilities
Substation Transformers	Replace 4 Power Transformers	Adopt FPL emergency rating philosophy (130% Summer, 150% Winter), Add 9 Transformers, Replace 3
Substations	1 New Substation	9 New Substations
Transmission	Upgrade ampacity on 6 Transmission Lines/Sections (~36 miles)	No recommended actions – Gulf transmission capable for forecasted loads

Reductions in estimated new substations and substation transformers reduces previously estimated overall costs

Attachment 5

FPL

Planning for Severe Winter Peak Loads:

A Presentation to the FPSC Staff

Integrated Resource Planning

November 23, 2021

DRAFT – Discussion of Work in Progress

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- Executive Summary
- Background
- High Winter Load Forecasts
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Executive Summary

- **Both FPL's 2020 and 2021 Ten-Year Site Plan (TYSP) resource plans show Winter reserve margins that exceed 20% during their 10-year reporting periods, but which also show declining Winter reserves over the 10 years**
- **This trend was recognized by FPL prior to the February 2021 extreme Winter cold front in Texas and neighboring states**
- **These two factors prompted FPL to review its projected ability to meet a very cold Winter event with the resource plan presented in FPL's 2021 TYSP**
- **There have been three severe cold events in FPL's service territory over the past 45 years: 1977, 1989, and 2010** (of these three events, the 1989 event impacted FPL's customers the most)
- **As part of its review, FPL examined 3 potential very cold load forecast scenarios:**
  - A forecast based on 2010 actual temperatures
  - A forecast based on 1989 actual temperatures
  - An "extreme" forecast w/ temperatures ~ 10 degrees colder than in 1989

Executive Summary (Continued)

- **FPL conducted Winter analyses** (using the 1989 Actual temperatures to develop the primary forecast) **and focused on two periods: (i) 2022-2025, and (ii) 2022-2030**
- **The analyses projected that, with this Winter peak forecast, FPL would not be able to serve all customers in any year in 2022-2030 with the 2021 TYSP resource plan**
- **The analyses then examined what additional resources would be needed to allow FPL to serve all customers w/ this forecast, along with the projected CPVRR costs**
- **Two approaches were used:**
  - The 1st approach meets the LOLP criterion all years even with the higher Winter load forecast
  - The 2nd approach uses another quantitative approach that examines projected hourly MWh load not served each year with this Winter forecast

Based on results of these analyses, FPL is making certain resource changes, and is also planning to change its Winter load forecast; all of these changes will be reflected in FPL's 2022 TYSP

Executive Summary (Continued)

- **The changes that FPL is making in regard to its 2022 TYSP include:**
  - Winterization enhancements to the fossil & nuclear generation fleets
  - Acquire 315 MW of PPAs for the Winter of 2021/2022
  - Retain Manatee 1 & 2 through 2030 for use only with very cold Winter conditions
  - Install ~ 790 MW of Winter only generation capacity upgrades over several years
  - Conduct pilot testing of ITRON RIVA meters in 2022 to – among other objectives - evaluate increasing feeder rotation capability
  - Use a 1989 Actual temperature-based load forecast for January only, with a P50 forecast for all other months in its IRP work
- **Then, using the new Winter forecast and these resource changes, perform optimization analyses with the AURORA model that seeks to eliminate or reduce projected customer outages during very cold Winter events**

FPL seeks to inform the FPSC Staff of these changes prior to filing its 2022 TYSP and discuss any questions/concerns the Staff may have

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FPL has projected declining Winter total reserve margins in both its 2020 and 2021 TYSP resource plans

Projected Winter Total Reserve Margins (%) (using a P50 forecast for Winter Peaks)

	2020 TYSP	2021 TYSP
2022	41.3%	40.7%
2023	46.0%	44.0%
2024	39.5%	35.8%
2025	39.1%	34.0%
2026	38.5%	32.2%
2027	37.0%	30.6%
2028	35.9%	28.6%
2029	36.1%	28.0%
2030	- -	27.8%

The primary changes in the 2021 TYSP vs the 2020 TYSP are: (i) forecasted higher Winter load, and (ii) reduced unit upgrades

These projected Winter reserve margin values all exceed the minimum 20% total reserve margin criterion, but show a trend of declining Winter reserves over the 10-year periods

In February 2021, Texas experienced a Winter storm of unprecedent severity

2021 Texas Record Cold

- **Record-setting, multiple day sub-freezing temperatures across Texas**
  - A similar cold weather event occurred in Texas in 2011
- **Approximately 48.6% of generation (52,300 MW) was unavailable**
  - Majority of unit issues associated with fossil generation and fuel supply
  - "Winterization" of plants a central issue
- **Customer outages were implemented to prevent statewide blackouts**
  - Maximum at one time of ~ 20,000 MW (4 to 4.5 MM customers) load unserved with ~ 10,000 to 12,000 MW shed on average
  - Outages lasted for three days
- **In addition, a number of customer outages were "non-surgical"**
  - Critical accounts, including natural gas pumping stations, were among those experiencing outages

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As a result of this event, FERC issued a report with a series of recommendations for improving reliability under severe weather events *(one of which, # 9, addressed resource planning)*

FERC Recommendation # 9

"Planning Coordinators should reconsider some of the inputs to their publicly-reported winter season anticipated reserve margin calculations for their respective BA footprints so that the reported reserve margins will better predict the reserve levels that the BAs could experience during winter peak conditions" (emphasis added)

BA= Balancing Authority

NERC: February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, September 23, 2021

FPL is planning changes such as this in its IRP work regarding being able to meet very cold Winter loads

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In the past 45 years there have been three major cold weather events in Florida (1977, 1989, and 2010)

Florida Cold Fronts

- **January 2010 event characterized by a cold front the week before, temperatures staying cool for the next several days, and then a deep arctic front on January 9th**
  - Peak demand of 24,486 MW (FPL's 2009 TYSP P50 forecasted Winter load for 2010 was ~ 18,800)
  - Very cold temperatures throughout the state (Miami was 35 degrees), Skies overcast, event affected all entities in Florida and in the SE US, limiting purchases or imports
- **December 1989 event was during the Christmas holiday**
  - Temperatures in Miami appear to be approximately 5 degrees colder than in 2010, also with overcast skies: Southeast US also experienced very high loads limiting Florida imports
- **January 1977 event - - "the day it snowed in Miami"**
  - Similar to the 1989 event in terms of temperatures

Of these three events, 1989 had the most severe impact on FPL's customers who experienced rotating outages over a two-day period

In order to analyze the impact of a future very cold Winter event, 3 new forecasts were developed largely based on these historical Winter events

3 New Winter Peak Forecasts

- **A P50 Winter forecast has typically been used in FPL's IRP work** (which is based on a system average temperature of ~ 39 degrees F)
- **Three new Winter peak forecasts were developed for these analyses:**
  1) **A "2010 Actual temperature" forecast** (w/ a system average temperature of ~ 33 degrees F.)
  2) **A "1989 Actual temperature" forecast** (w/ a system average temperature of ~ 29 degrees F.)
  3) **An "Extreme" forecast** (w/ a system average temperature of ~ 19 degrees F.)

The intent was to develop forecasts for Winter conditions that FPL had already experienced, plus a "Texas-like" extreme cold weather event

All three of the new load forecasts were developed using a similar methodology

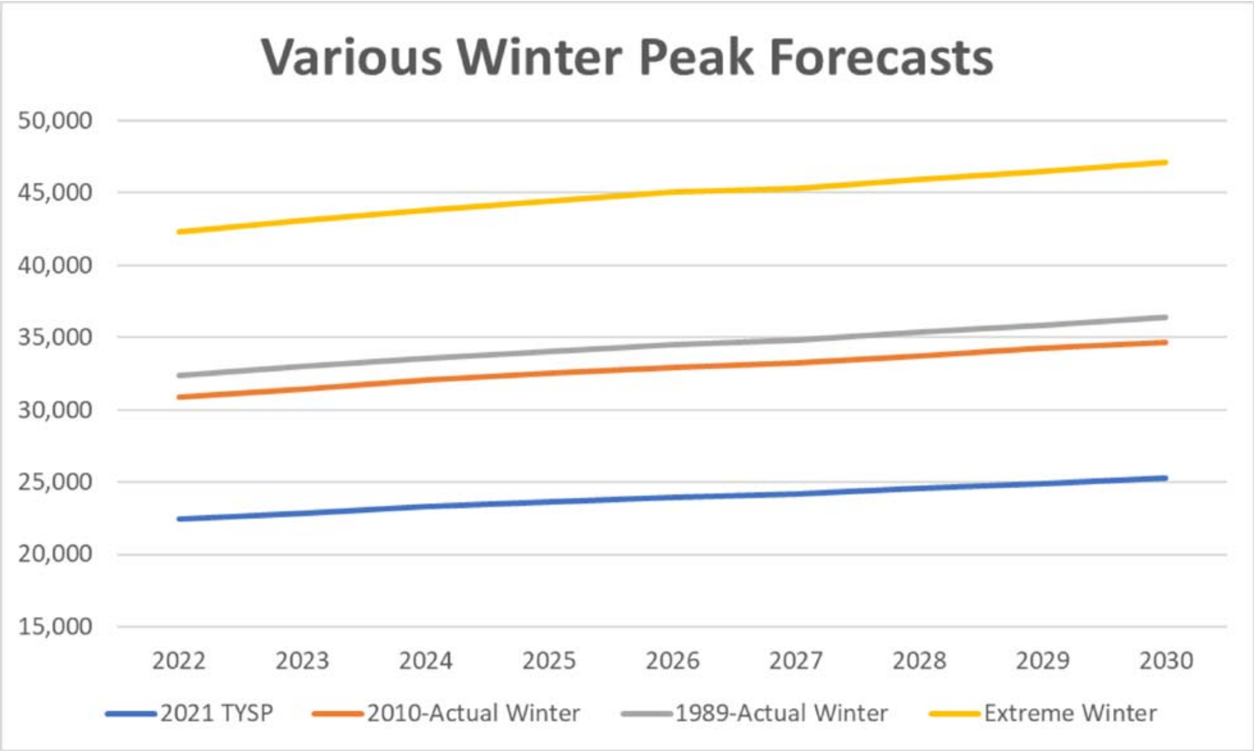
How the New Winter Peak Forecasts Were Developed

- **The first two forecasts were based on the actual temperatures experienced during the 2010 and 1989 cold fronts**
- **The third forecast used temperatures that were 10 degrees colder than experienced during the 1989 event**
- **The hourly daily pattern for the three forecasts were based on the 2010 event** (accurate hourly loads for the 1989 event were not available due to the rotating outages)
- **All load forecasting parameters** (such as number of customers, etc.)**, other than temperatures, were unchanged from the P50 Winter forecast developed for the 2021 TYSP**

All three new forecasts resulted in peak loads that were significantly higher than with the current P50 forecast (see next slide)

Each of the 3 new Winter forecasts have peaks that are at least 40% higher than the P50 2021 TYSP forecast

New Winter Forecasts vs 2021 TYSP Forecast



About 88% higher than 2021 TYSP

About 40-44% higher than 2021 TYSP

2021 TYSP

See Appendix for table showing annual MW values for each forecast

FPL selected the 1989 Actual (temperature) forecast as the focus of its preliminary analyses

Why the 1989 Actual Forecast Was the Focus of FPL's Analyses

- **Comparing the 2010 Actual forecast vs the 1989-Actual forecast showed that the 1989 Actual forecast's peak load was ~ 1,600 MW higher than the 2010 Actual forecast** *(and FPL had already experienced the colder temperatures associated with the 1989-Actual forecast)*
- **Preliminary analyses using the Extreme forecast resulted in projections of massive problems in meeting customer load** *(see the Appendix for the results for the years 2025 & 2030)*
  - However, this extreme load in Florida was viewed as very unlikely
  - In addition, the projected amount of load unable to be served in those years exceeds 12,000 MW, thus making it very expensive to attempt to prepare for such a load

For these reasons, FPL's focus in its preliminary analyses was the 1989 Actual forecast

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Using the 1989 Actual as the primary forecast, FPL undertook preliminary analyses of its ability to serve all customers

FPL's Preliminary Winter Analyses*

- **These analyses first concentrated on the near-term (2022-2025) period**
  - The analyses identified whether FPL would be able to serve all customer load in this period
- **The analyses then proceeded to analyze the longer-term (2022-2030) period**
  - This portion of the study used the same approach as was used for the near-term period
  - The additional MW needed to be able to meet the unserved load for all years were identified and resource plans that include these additional MW were analyzed

**These analyses are preliminary for two reasons: (i) the resource plan shown in the 2021 TYSP was used, and (ii) forecasts & other data from the 2021 TYSP were also used*

FPL's primary objective in undertaking the analyses was to determine how many additional resources would be needed to serve all customer load if a 1989 Actual Winter load occurred

FPL performed reliability analyses using 2 approaches, then performed economic analyses

FPL's Winter Study Methodology

- **Approach # 1 (LOLP): (w/ the TIGER model)**
  - Determine the projected LOLP with the 1989 Actual forecast using the 2021 TYSP resource plan
  - Then determine how many additional MW would be needed to lower each year's LOLP below the 0.1 criterion
- **Approach # 2 (Hourly): (w/ an alternate quantitative approach)**
  - Examine hourly loads and capabilities to determine hourly unserved energy plus projections of customer outages
  - Then determine how many additional MW would be needed each year to serve the projected unserved energy
- **Then, for both approaches, use the AURORA model to determine the projected CPVRR costs of resource plans based on each approach vs the 2021 TYSP resource plan**

FPL also performed reliability analyses using the 2010-temperature and the Extreme forecasts (These results are shown in the Appendix)

FPL

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Approach # 1 first examined the projected LOLP values for each year using the TIGER model

Annual LOLP Results with the TIGER Model 1989 Actual Winter Forecast: 2022-2025

Assumptions	Case 1: w/ 1989-Actual Forecast & Revised LC
2021 TYSP resource plan with 1989-Actual Load Forecast	X
LC - Use Summer MW values as a proxy for LC capabilities w/ very cold temps	X
Projected Annual LOLP	
2022	5.486
2023	4.092
2024	5.871
2025	6.537

LOLP criterion is a maximum of 0.1 day per year

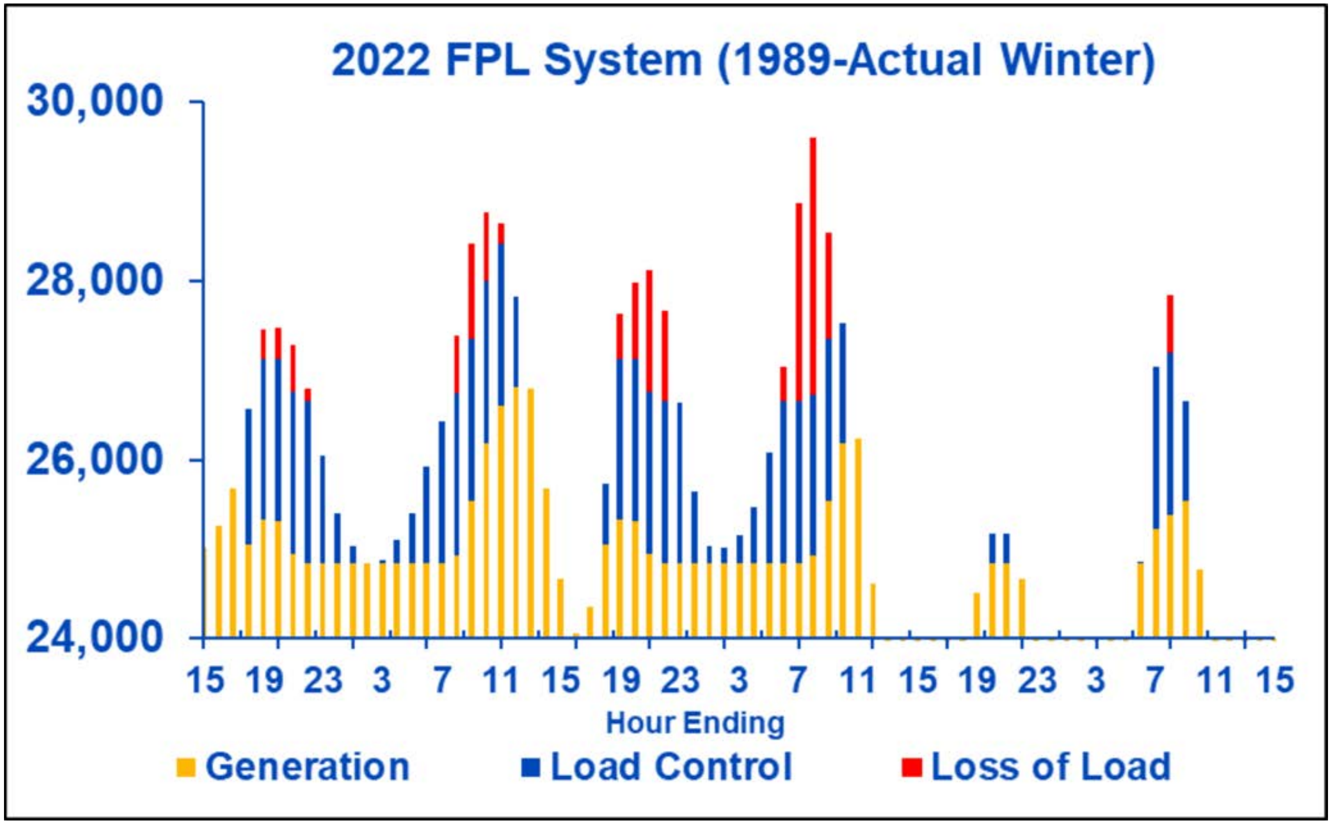
This analysis assumed the 2021 TYSP resource plan w/ no additional generation resources

The LOLP criterion is projected to be violated in each year of the 2022-2025 period w/ the 1989 Actual forecast

FPL

Approach # 2 examined hourly loads and capabilities & confirmed the projected inability to serve all load in 2022

Projected Loss of Load Based on 1989 Actual Forecast For the Year 2022 (FPL Only)



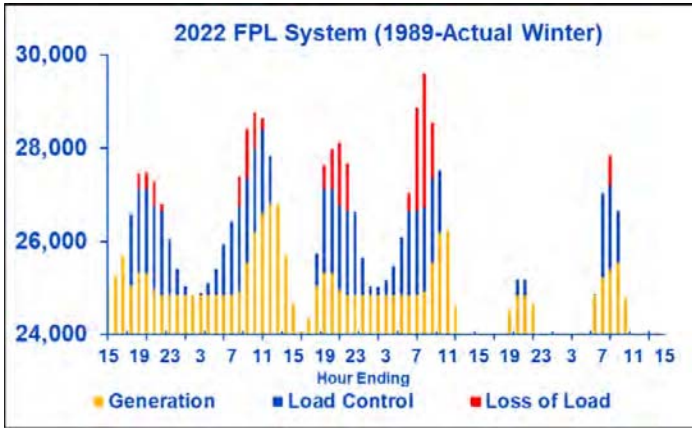
These preliminary analyses assumed the 2021 TYSP resource plan w/ no additional resources

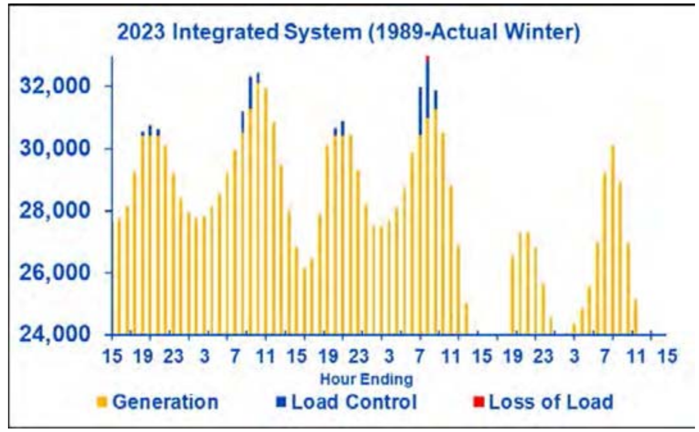
Note: At this point in the analyses using Approach # 2, **no generation forced outages** are assumed

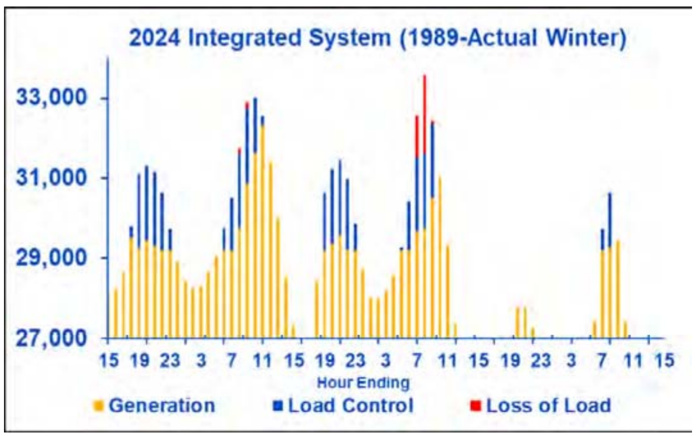
The loss of load projected for 2022 is ~ 2,400 MW at the worst hour and 15,000 MWh of unserved energy over the 3 days

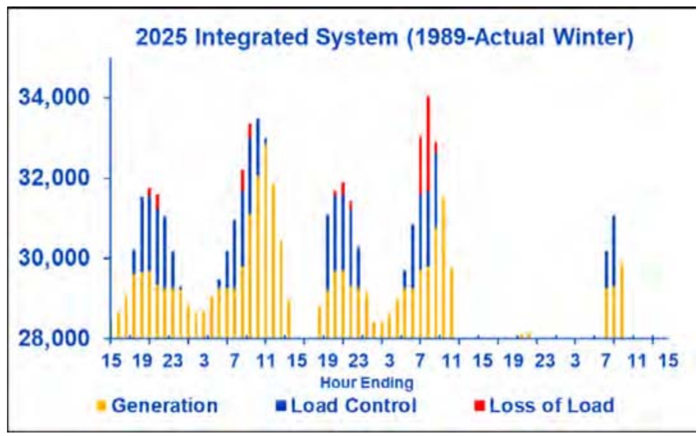
Projections improve for 2023 (due to the integration of FPL & Gulf and Dania Beach), **but problems are again projected for 2024 & 2025**

Projected Loss of Load based on 1989 Actual Forecast For the Years 2022-2025









These preliminary analyses assumed the 2021 TYSP resource plan w/ no additional resources (and **no generation forced outages**)

DRAFT – Discussion of Work in Progress

The projected unserved energy values were converted to outage times for the subset of customers whose feeders can be rotated

Projected Customer Outages Over the 3-Day Period
(assuming no addl. resources & no generation forced outages)

Number of Rotation Eligible Customers* = 3,500,000

	2022	2023	2024	2025
Assumed Generation Forced Outages (MW)	**0**	**0**	**0**	**0**
Shortage in Peak Hour (MW)	2,402	168	1,971	2,484
Total Loss of Load over the cold-front period (MWh)	15,027	168	3,382	6,295
# of Customer Outages (30 minutes each)	3,005,400	33,600	676,400	1,259,000
# of Outages per Rotation Eligible Customer	0.86	0.01	0.19	0.36

*"Rotation eligible" customers are customers who are served by feeders that can be switched off in extreme conditions (*i.e.*, feeders which do not have any identified critical customers such as hospitals and police stations). Currently, there are ~ 3.5 million such customers on FPL's system.

The next slide shows how these outage projections change if 1,000 MW or 2,000 MW of generation forced outages are assumed

The condensed table below shows how projected outage times increase if generation forced outages are assumed

Projected Customer Outages: 2022-2025

(assumes no addl. resource & 3 levels of generation forced outages)

Number of Rotation Eligible Customers* = 3,500,000

	2022	2023	2024	2025
Assumed Generation Forced Outages (MW)	**0**	**0**	**0**	**0**
# of Customer Outages (30 minutes each)	3,005,400	33,600	676,400	1,259,000
# of Outages per Rotation Eligible Customer	0.86	0.01	0.19	0.36
Assumed Generation Forced Outages (MW)	**1,000**	**1,000**	**1,000**	**1,000**
# of Customer Outages (30 minutes each)	7,480,120	281,573	3,485,036	4,805,329
# of Outages per Rotation Eligible Customer	2.14	0.08	1.00	1.37
Assumed Generation Forced Outages (MW)	**2,000**	**2,000**	**2,000**	**2,000**
# of Customer Outages (30 minutes each)	14,447,062	1,187,254	7,645,237	9,350,204
# of Outages per Rotation Eligible Customer	4.13	0.34	2.18	2.67

Note: the derivation of the 1,000 MW and 2,000 MW forced outage assumptions is discussed in the Appendix

The projected number of outages increases significantly if non-zero generation forced outages are assumed

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To address these projected impacts, FPL is currently enhancing the "winterization" of its fossil and nuclear generation fleets

Generation Winterization Efforts

- **Each year FPL's power plants execute a winterization preventive maintenance process to verify physical plant readiness for Winter operations, including insulation condition assessment & operator refresher training**

- **These efforts are now being enhanced by activities that include the following:**
  - Heat tracing & insulation on critical piping
  - Insulation and/or heated enclosures for critical equipment that could result in mis-operation if frozen
  - Shelters for critical valves that could be exposed to freezing rain
  - Wind barriers for critical valves

A 1/01/2022 completion of this work is projected for the 4 nuclear units plus the Sanford, Okeechobee, Cape Canaveral, Manatee, & West County plants. Others to be completed by 5/01/2022

FPL is also planning for adequate fuel supply w/ very cold Winter events & for potential gas supply interruptions

Fuel Supply Planning Efforts

- **Regarding natural gas use and supply, FPL:**
  - Consumes ~ 1.8 million MMBTU/day of natural gas on average
  - Has more than 2.6 million MMBTU/day of firm gas transportation capacity across 3 delivery pipelines, plus ~ 0.6 million MMBTU/day of additional firm gas transportation capacity on several upstream pipelines that provide access to additional natural gas supply points
  - Has ~ 5 million MMBTU of gas storage capacity in Mississippi & Alabama

- **Regarding distillate fuel oil for back up fuel:**
  - ~ 65% of FPL's CC & CT generation can use distillate fuel oil
  - FPL will store sufficient distillate to allow ~ 80 continuous hours of full load operation for ~ 13,000 MW of CC & CT generation, and uses multiple fuel oil suppliers for potential resupply of stored fuel

In addition, several near-term generation enhancements are underway

Near-Term Capacity Increases That Can Help Address Projected Loss-of-Load Thru 2025

1) **Short-term capacity purchases for the 2021 – 2022 Winter months only totaling ~ 315 MW**

2) **2) Winter upgrades to CC units over several years (no Summer MW increases):**
   - Adds up to ~ 790 MW of Winter (only) capacity *(MW value subject to change)*

3) **Retaining the Manatee 1 & 2 units for limited operation only during high Winter load periods** (see next slide)
   - Retain ~ 1,600 MW of Winter (only) capacity

In the analyses that followed, FPL assumed that each of these near-term resources were added

The Manatee 1 and 2 units will be available for use only during forecasted very cold Winter events

Manatee 1 and 2 units in Inactive Reserve-Winter Capable" Status

- **System operators typically plan for high Winter peak loads several days before occurrence, thus allowing advance warning regarding the need for the Manatee units to be operational**

- **When a very cold front is forecast, personnel will be transferred from other plants to Manatee for the duration of the high load period** (the Manatee units will be unmanned by operators at all other times)

- **Retaining the capability to utilize Manatee in this way will add about 1,600 MW of Winter peak capability that can run on oil** (thus preserving the ability of the rest of the fossil generation system to utilize all available natural gas)

FPL currently plans to maintain the Inactive Reserve-Winter Capable status for Manatee 1 & 2 through 2030

With Approach # 1, the LOLP criterion is still not projected to be met even after these near-term resources are added

Annual LOLP Results with the TIGER Model 1989 Actual Winter Forecast: 2022-2025

Assumptions	Case 1: w/ 1989-Actual Forecast & Revised LC	Case 2: Case 1 plus near-term resource additions
2021 TYSP resource plan with 1989-Actual Load Forecast	X	X
LC - Use Summer MW values as a proxy for LC capabilities w/ very cold temps	X	X
Short Term Winter 2022 PPAs (315 MW)		X
Winter Upgrades (794 MW)		X
Manatee 1 & 2 Retained - Winter Capacity Only (1,600 MW)		X
Projected Annual LOLP		
2022	5.486	2.416
2023	4.092	1.690
2024	5.871	2.493
2025	6.537	3.939

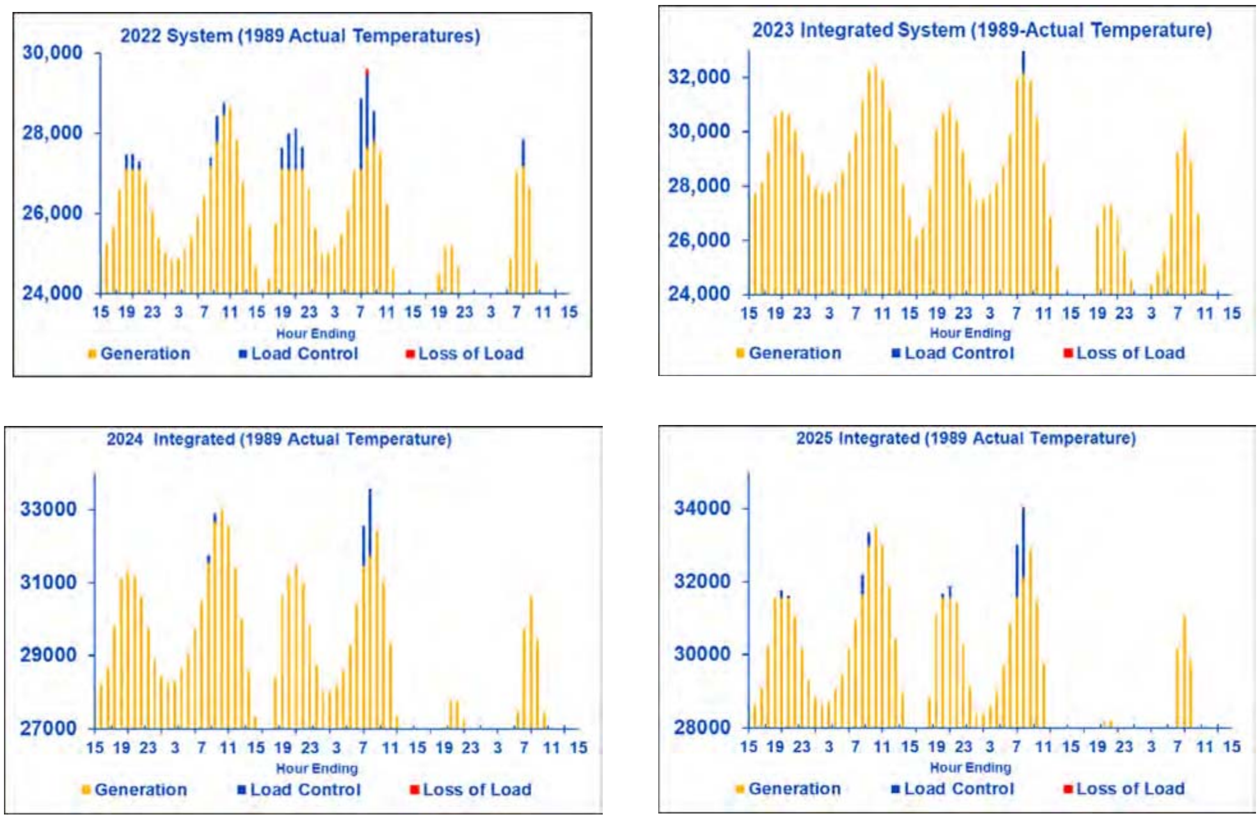
LOLP criterion is a maximum of 0.1 day per year

This analysis assumed the 2021 TYSP resource plan w/ no additional resources except for the near-term resources

Additional resources would be needed to meet the LOLP criterion in the near-term with Approach # 1

With Approach # 2, most of the problems are addressed by the near-term additions (assuming no forced outages)

Projected loss of load based on 1989 Actual Forecast 2022- 2025 (with near-term resource additions)



These preliminary analyses assumed the 2021 TYSP resource plan w/ the near-term additional resources (and **no generation forced outages**)

The previously projected inability to meet load is now addressed for 2023 & 2024 (w/ small amount of projected loss of load for one hour in 2022 and 2025)

DRAFT – Discussion of Work in Progress

The table below shows revised customer outage projections assuming the near-term additions are in place

Projected Customer Outages: 2022-2025
(assumes near-term additions & 3 levels of generation forced outages)

Number of Rotation Eligible Customers* = 3,500,000

	2022	2023	2024	2025
Assumed Generation Forced Outages (MW)	**0**	**0**	**0**	**0**
# of Customer Outages (30 minutes each)	30,869	0	0	10,320
# of Outages per Rotation Eligible Customer	0.01	0.00	0.00	0.00
Assumed Generation Forced Outages (MW)	**1,000**	**1,000**	**1,000**	**1,000**
# of Customer Outages (30 minutes each)	328,745	0	123,577	210,320
# of Outages per Rotation Eligible Customer	0.09	0.00	0.04	0.06
Assumed Generation Forced Outages (MW)	**2,000**	**2,000**	**2,000**	**2,000**
# of Customer Outages (30 minutes each)	2,056,570	8,496	458,939	629,124
# of Outages per Rotation Eligible Customer	0.59	0.00	0.13	0.18

The near-term additions are projected to significantly reduce the number of customer outages (for example, from ~ 9.43 million to ~ 630,000 in 2025 assuming 2,000 MW of generation forced outages)

With a 1989 Actual Winter occurrence , FPL projects problems in being able to meet load in 2022 through 2025

Summary of Results from Near-Term Analyses: 2022-2025

- **Using a 1989 Actual temperature forecast for Winter peak load, and assuming no changes to FPL's 2021 TYSP resource plan, FPL is projected to not be able to meet customer load under either an LOLP perspective or an hourly perspective in any of these 4 years**

- **Assuming the winterization efforts for generation and fuel supply, plus the addition of the previously described 3 types of near-term resource additions** (310 MW of PPAs for 2021/2022, ~ 790 MW of Winter upgrades, and retaining Manatee 1 & 2's 1,600 MW for use in very cold Winter conditions only), the results improve, but the projected problems are not eliminated:
  - Projected LOLP values are reduced by (roughly) a factor of 2
  - The hourly analysis shows customer outages are projected to still occur, but to a lesser degree

FPL's analyses then expanded to examine the years 2026 through 2030

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With Approach # 1, the projected LOLP values get worse as the years 2026 thru 2030 are accounted for

Annual LOLP Results with the TIGER Model 1989 Actual Winter Forecast: 2022-2030

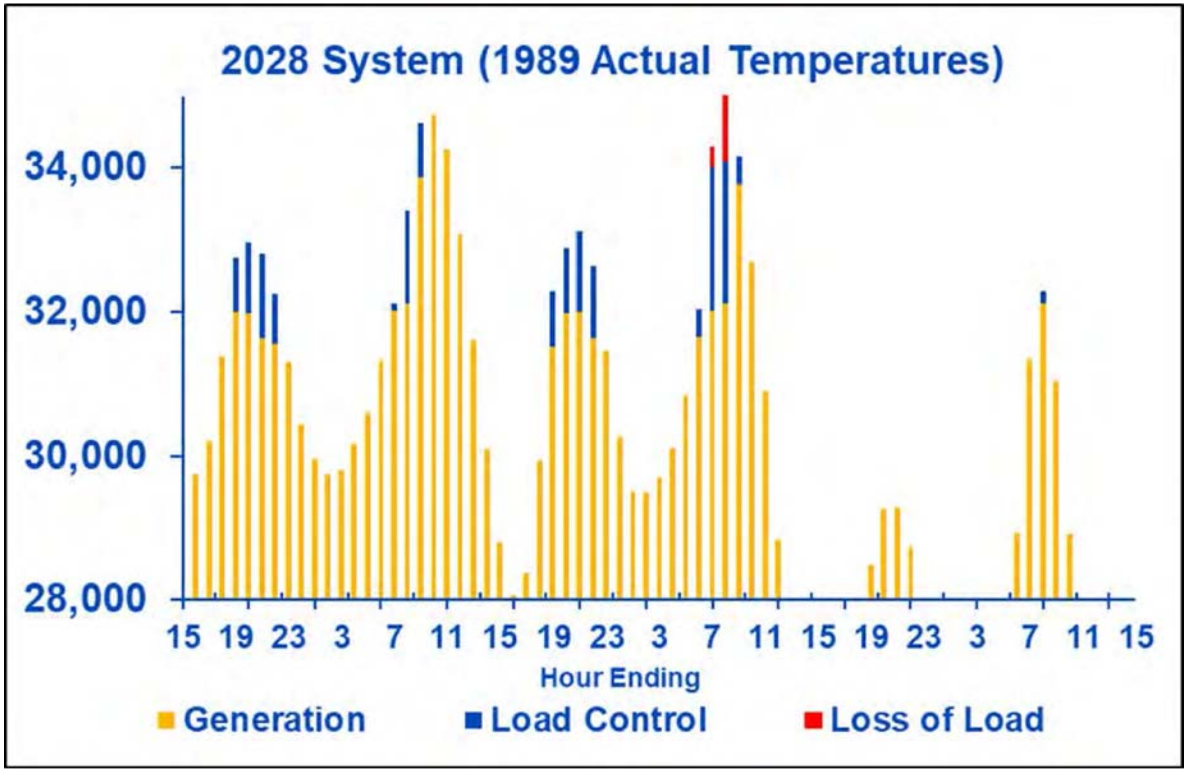
Assumptions	Case 1: w/ 1989-Actual Forecast & Revised LC	Case 2: Case 1 plus near-term resource additions
2021 TYSP resource plan with 1989-Actual Load Forecast	X	X
LC - Use Summer MW values as a proxy for LC capabilities w/ very cold temps	X	X
Short Term Winter 2022 PPAs (315 MW)		X
Winter Upgrades (794 MW)		X
Manatee 1 & 2 Retained - Winter Capacity Only (1,600 MW)		X
Projected Annual LOLP		
2022	5.486	2.416
2023	4.092	1.690
2024	5.871	2.493
2025	6.537	3.939
2026	6.529	3.915
2027	7.032	4.862
2028	7.293	5.428
2029	7.204	5.257
2030	7.090	5.155

LOLP criterion is a maximum of 0.10 day per year

Includes the near-term resource additions previously discussed

Approach # 2 again projects an inability to meet all load in the 2026-2030 period (the graph below shows the results for 2028 only)

Projected Loss of Load based on 1989 Actual Forecast For the Year 2028



These preliminary analyses assumed the 2021 TYSP resource plan w/ near-term resource additions <u>and **no generation forced outages**</u>

The next slide examines projected customer outages with the same 3 generation forced outage levels used earlier

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Approach # 2 again quantified the amount of expected unserved energy and resulting customer impacts

Projected Customer Outages: 2026-2030
(includes the near-term resources & 3 levels of generation forced outages)

Number of Rotation Eligible Customers* = 3,500,000

	2026	2027	2028	2029	2030
Assumed Generation Forced Outages (MW)	**0**	**0**	**0**	**0**	**0**
# of Customer Outages (30 minutes each)	78,092	153,304	309,295	374,445	402,861
# of Outages per Rotation Eligible Customer	0.02	0.04	0.09	0.11	0.12
Assumed Generation Forced Outages (MW)	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**
# of Customer Outages (30 minutes each)	363,871	513,441	802,024	1,090,181	1,967,514
# of Outages per Rotation Eligible Customer	0.10	0.15	0.23	0.31	0.56
Assumed Generation Forced Outages (MW)	**2,000**	**2,000**	**2,000**	**2,000**	**2,000**
# of Customer Outages (30 minutes each)	1,109,847	2,043,446	3,645,483	4,660,002	5,522,585
# of Outages per Rotation Eligible Customer	0.32	0.58	1.04	1.33	1.58

Even with the near-term additions, significant numbers of customer outages are still projected in the 2026 thru 2030 time period – additional resources will be needed to address this

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The next step was to determine how many MW of new resources are needed to meet the LOLP criterion each year

Approach # 1: Resource MW Needed Thru 2030

- **Although the TIGER model is often used to project LOLP values for a given resource plan, it can also be used to determine how many MW of new resources would need to be added to a resource plan to allow that plan to meet the LOLP criterion**
- **Assuming no new resources can be added until 2023, the TIGER results call for 6,000 MW of additional resources** (beyond the 2021 TYSP plan plus near-term resources) **thru 2030 as follows:**

Year	Addl. MW Needed	Resulting LOLP
2023	2,200	0.098
2024	1,200	0.090
2025	1,300	0.098
2026	100	0.087
2027	700	0.091
2028	500	0.097
2029	0	0.082
2030	0	0.076
Total =	6,000	

LOLP values are lower in 2029 & 2030 due to the addition of batteries (300 MW in 2029 and another 400 MW in 2030) in the 2021 TYSP resource plan

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Also with Approach # 2, the next step was to determine how many MW of new resources are needed

Approach # 2: Resource MW Needed thru 2030

Using the previously introduced forced outage values (1,000 MW & 2,000 MW) **for each year, the projected amounts of incremental MW (beyond the near-term additions) that were projected to allow FPL to serve the previously determined unserved load are shown in the tables below:**

1,000 MW out	
Year	**Addl. MW Needed**
2024	1,400
2025	0
2026	100
2027	300
2028	500
2029	200
2030	100
Total =	2,600

2,000 MW out	
Year	**Addl. MW Needed**
2024	2,400
2025	0
2026	0
2027	400
2028	500
2029	300
2030	500
Total =	4,100

For both approaches, the AURORA model was then used to project the CPVRR cost impact of these additional resources

AURORA Modeling Approach

- **The P50 load forecast for each year used in the 2021 TYSP work was modified by substituting the 1989-Actual forecast for January only** (with no changes to other 11 months)
- **The following assumptions for resource options were used:**
  - All resource additions in the 2021 TYSP were assumed as a "given"
  - The near-term resource additions were also assumed as a "given"
  - The additional needed MW developed in each approach were assumed (for purposes of this analysis only) to be 4-hour batteries and these were also a "given" (later optimization analyses will determine the best resource(s) to add)
- **AURORA then developed a new "re-optimized" resource plan for each approach for 2031-on to account for the impact of the new resources on the number and timing of 2031-on filler units**

A comparison of the new plan for each approach, versus the 2021 TYSP resource plan, are presented on the next slides

The resulting resource plan for Approach # 1 is shown below

Comparison of "New" Resource Plan vs 2021 TYSP Plan: Resource Additions, Summer RM, & CPVRR Costs

2021 TYSP Resource Plan			Resource Plan with Additional Batteries to Meet LOLP Criterion	
Year	Resource Additions	Summer RM%	Resource Additions	Summer RM%
2022	596 MW Solar	25.5	596 MW Solar	25.5
2023	745 MW Solar	21.6	745 MW Solar **22 x 100 MW Battery**	26.9
2024	894 MW Solar	20.02	894 MW Solar **12 x 100 MW Battery**	27.3
2025	894 MW Solar	20.07	894 MW Solar **13 x 100 MW Battery**	29.3
2026	969 MW Solar	20.0	969 MW Solar **1 x 100 MW Battery**	29.3
2027	969 MW Solar	20.0	969 MW Solar **7 x 100 MW Battery**	30.2
2028	1,192 MW Solar	20.0	1,192 MW Solar **5 x 100 MW Battery**	30.8
2029	1,192 MW Solar 3 x 100 MW Battery	20.0	1,192 MW Solar 3 x 100 MW Battery	30.6
2030	1,192 MW Solar 4 x 100 MW Battery	20.0	1,192 MW Solar 4 x 100 MW Battery	30.4
	Solar MW Additions thru 2030 =	5,513	Solar MW Additions thru 2030 =	5,513
	Storage MW Additions thru 2030 =	700	Storage MW Additions thru 2030 =	6,700
	CPVRR $ millions thru 2068 =	82,026	CPVRR $ millions thru 2068 =	85,990
	CPVRR Difference (millions) =		**3,964**	

Battery additions shown in **bold black font** have been added to address the 1989-Actual Winter load

The two new resource plans for Approach # 2 are shown on the following slides

The resulting resource plan for Approach # 2 (assuming 1,000 MW of forced outages) is shown below

Comparison of "New" Resource Plan vs 2021 TYSP Plan: Resource Additions, Summer RM, & CPVRR Costs

	2021 TYSP Resource Plan		Resource Plan with Add'l Batteries to Meet Load with 1,000 MW of Forced Outages	
Year	Resource Additions	Summer RM%	Resource Additions	Summer RM%
2022	596 MW Solar	25.5	596 MW Solar	25.5
2023	745 MW Solar	21.6	745 MW Solar	21.6
2024	894 MW Solar	20.0	894 MW Solar **14 x 100 MW Battery**	23.7
2025	894 MW Solar	20.1	894 MW Solar	23.7
2026	969 MW Solar	20.0	969 MW Solar **1 x 100 MW Battery**	23.8
2027	969 MW Solar	20.0	969 MW Solar **3 x 100 MW Battery**	24.3
2028	1,192 MW Solar	20.0	1,192 MW Solar **5 x 100 MW Battery**	25.2
2029	1,192 MW Solar 3 x 100 MW Battery	20.0	1,192 MW Solar 3 x 100 MW Battery **2 x 100 MW Battery**	25.6
2030	1,192 MW Solar 4 x 100 MW Battery	20.0	1,192 MW Solar 4 x 100 MW Battery **1 x 100 MW Battery**	25.4
	Solar MW Additions Thru 2030 =	5,513	Solar MW Additions Thru 2030 =	5,513
	Storage MW Additions Thru 2030 =	700	Storage MW Additions Thru 2030 =	3,300
	Total CPVRR ($Millions):	82,026	Total CPVRR ($Millions):	83,443
	CPVRR Difference ($Millions) =		**1,417**	

Battery additions shown in **bold black font** have been added to address the 1989-Actual Winter load

DRAFT – Discussion of Work in Progress

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The resulting resource plan for Approach # 2 (assuming 2,000 MW of forced outages) is shown below

Comparison of "New" Resource Plan vs 2021 TYSP Plan: Resource Additions, Summer RM, & CPVRR Costs

	2021 TYSP Resource Plan		Resource Plan with Add'l Batteries to Meet Load with 2,000 MW of Forced Outages	
Year	Resource Additions	Summer RM%	Resource Additions	Summer RM%
2022	596 MW Solar	25.5	596 MW Solar	25.5
2023	745 MW Solar	21.6	745 MW Solar	21.6
2024	894 MW Solar	20.0	894 MW Solar **24 x 100 MW Battery**	25.6
2025	894 MW Solar	20.1	894 MW Solar	25.6
2026	969 MW Solar	20.0	969 MW Solar	25.5
2027	969 MW Solar	20.0	969 MW Solar **4 x 100 MW Battery**	26.1
2028	1,192 MW Solar	20.0	1,192 MW Solar **5 x 100 MW Battery**	26.8
2029	1,192 MW Solar 3 x 100 MW Battery	20.0	1,192 MW Solar 3 x 100 MW Battery **3 x 100 MW Battery**	27.2
2030	1,192 MW Solar 4 x 100 MW Battery	20.0	1,192 MW Solar 4 x 100 MW Battery **5 x 100 MW Battery**	27.7
	Solar MW Additions Thru 2030 =	5,513	Solar MW Additions Thru 2030 =	5,513
	Storage MW Additions Thru 2030 =	700	Storage MW Additions Thru 2030 =	4,800
	Total CPVRR ($Millions):	82,026	Total CPVRR ($Millions):	84,302
	CPVRR Difference ($Millions) =		2,276	

Battery additions shown in **bold black font** have been added to address the 1989-Actual Winter load

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Another option is under consideration: utilizing new smart meter technology to increase the number of rotation eligible customers

Overview of Smart Meters in FPL and Gulf

- **FPL's legacy service area is served by ITRON smart meters**
  - Current meters have only limited ability to communicate with each other leaving feeder rotation as the only practical way to currently deal with a situation in which firm load is greater than available generation
- **Gulf's legacy area is served by ~ 480,000 Sensus smart meters**
  - Only ~ 60,000 Sensus meters are capable of remote disconnect
- **Advanced smart meters now offer a number of advantages including** (but not limited to)**:**
  - Enhanced storm restoration capability, particularly in Gulf's area, thru ability to "ping" meters to identify if premise is receiving electric service
  - Future capability to communicate with specific appliances in homes (in conjunction with smart electric panels)
  - Enhanced ability for ITRON's RIVA meters to communicate meter-to-meter, thus moving away from the current capability in which FPL can only send the same signal sent to all meters on a specific feeder

FPL will be conducting pilot testing of the ITRON RIVA meters in 2022

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FPL is making certain changes regarding resources, and planning to use a 1989 Actual Winter load forecast, in its 2022 IRP work that will be reflected in its 2022 TYSP

Changes

- **FPL is proceeding with the following resource changes and/or enhancements to better enable FPL to serve customers during very cold Winter events:**
  - Winterization enhancements to the fossil and nuclear generation fleets (see Appendix for more information)
  - Acquire the 315 MW of PPAs for the Winter of 2021/2022
  - Retain Manatee 1 & 2 through 2030 for use only with very cold events
  - Install ~ 790 MW of Winter only generation capacity upgrades (over several years)
  - Conduct pilot testing of ITRON RIVA meters in 2022 to – among other objectives – evaluate increasing feeder rotation capability
- **In addition, FPL is planning to use a 1989 Actual temperature-based load forecast for Winter in its IRP work:**
  - Use a 1989 Actual forecast for January only, and the same P50 forecast for all other months

With these changes to resources and the forecast, perform resource planning to address both Summer & Winter peaks

Changes (Continued)

- **In regard to Summer load, perform analyses of resource plans that meet the 20% total reserve margin and 10% generation reserve margin criteria** (business as usual)
- **In regard to the 1989 Actual Winter load forecast, perform analyses based on Approach # 2 that seeks to eliminate or reduce customer outages assuming a specific forced outage MW level** (that has yet to be determined)
- **The AURORA optimization model will be used in these analyses**
- **The resource planning work is just beginning**

FPL seeks to inform the FPSC Staff of these changes prior to filing its 2022 TYSP and discuss any questions/concerns the Staff may have

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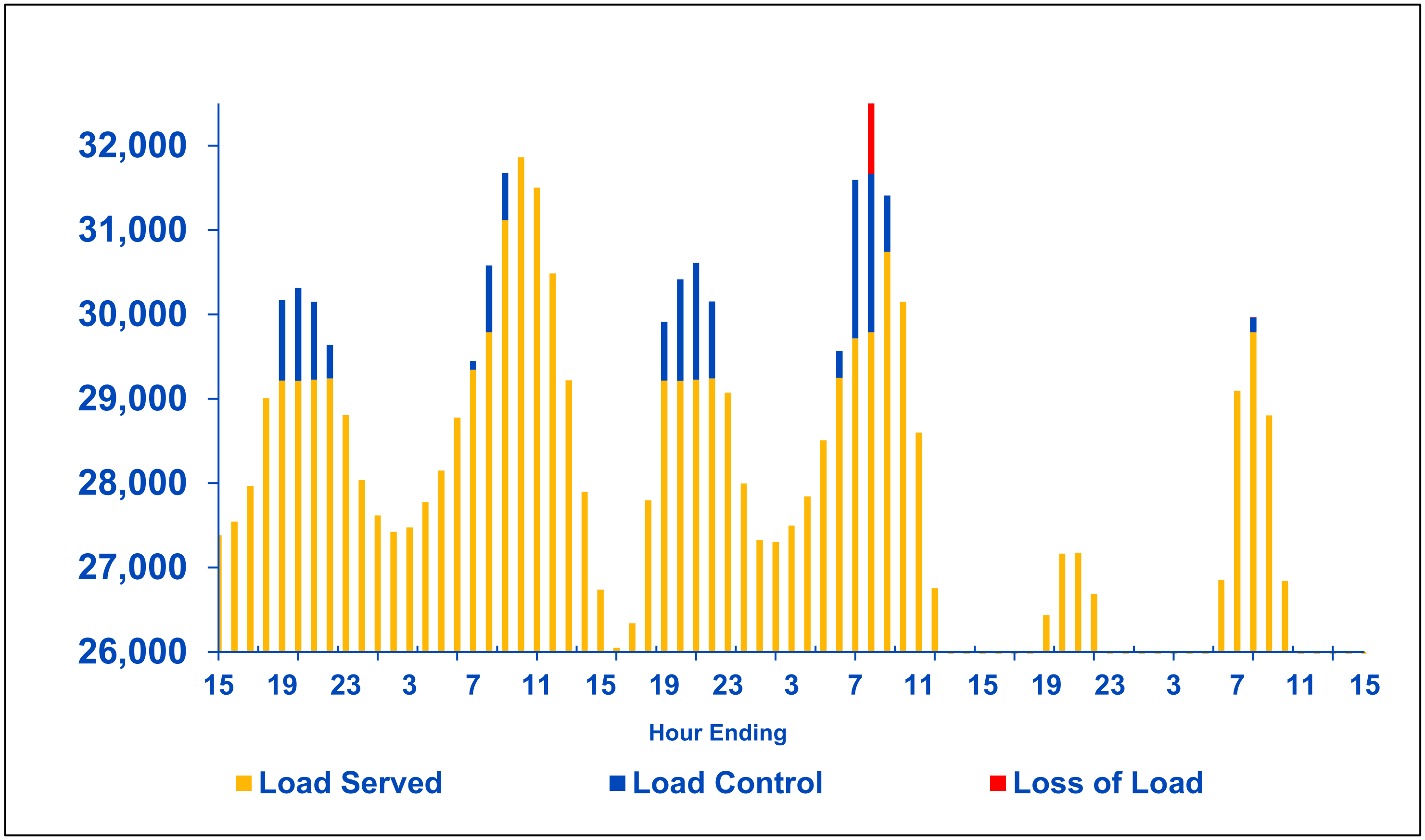
Winter Peak Forecasts (MW)

Winter Peak MW Forecasts

Year	2021 TYSP (P50)	2010-Actual	1989-Actual	Extreme Winter
2022	22,461	30,909	32,388	42,310
2023	22,869	31,475	32,978	43,079
2024	23,287	32,047	33,574	43,851
2025	23,624	32,507	34,053	44,470
2026	23,957	32,961	34,525	45,080
2027	24,199	33,285	34,861	45,344
2028	24,552	33,758	35,354	45,930
2029	24,916	34,246	35,861	46,521
2030	25,289	34,739	36,372	47,101

Hourly projections with the 2010 Actual Winter forecast in 2025 are shown below

High Load Hours w/ 2010 Actual Load: 2025

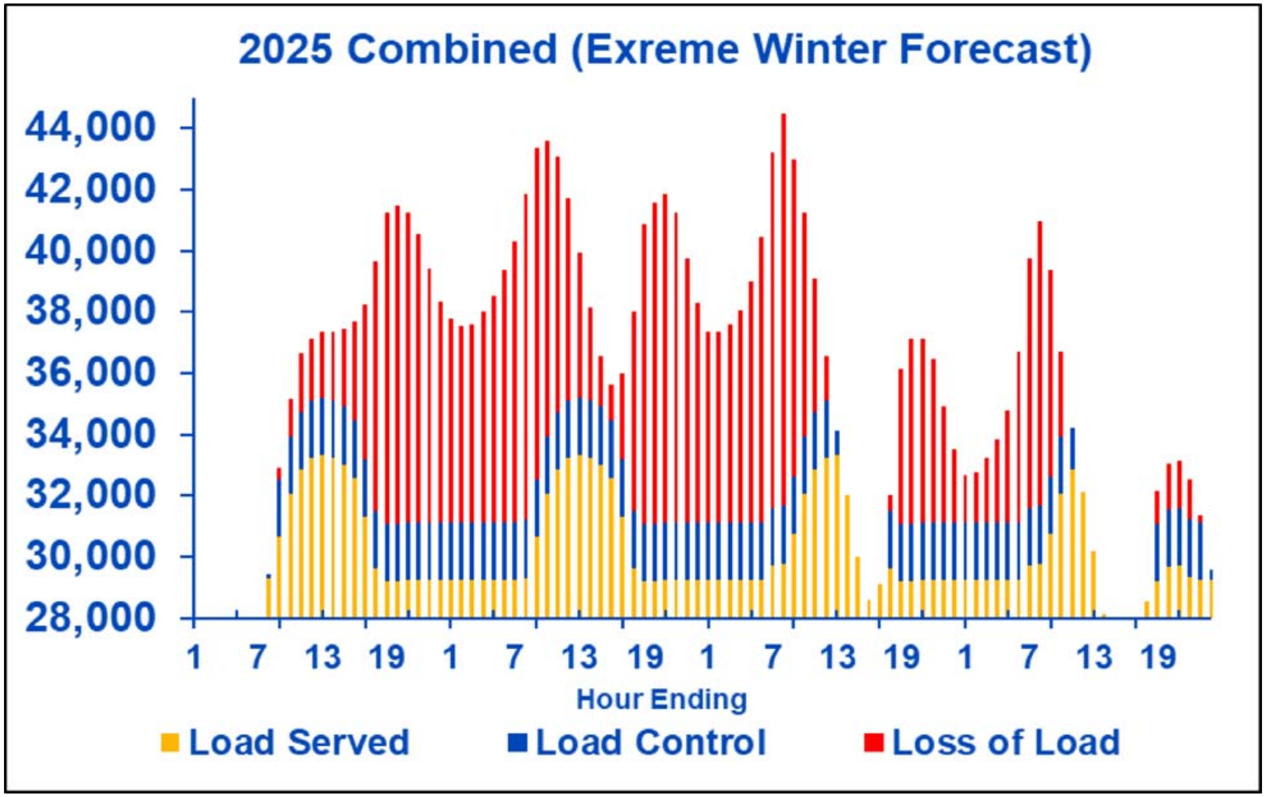


These preliminary analyses assumed the 2021 TYSP resource plan w/ no additional resources (and **no generation forced outages**)

In a scenario with 1,000 MW out, 7 additional hours are projected to lose load

Hourly projections with the Extreme Winter forecast in 2025 are shown below

High Load Hours w/ Extreme Winter Forecast: 2025



Maximum load not served is 12,800 MW

These preliminary analyses assumed the 2021 TYSP resource plan w/ no additional resources (and **no generation forced outages**)

Projections for these 96 hours are: (i) LC is used for 78 hours and (ii) load is not served in 74 hours

Two projections of "expected" values for generation forced outages were developed for use with Approach # 2

"Expected" Values for Generation Forced Outage MW

- **The first projection was based on the value that FPL's System Operations group uses in planning annual maintenance schedules**
  - This projection is based an assumption of having largest nuclear unit (St. Lucie 2) out, plus other fossil generation capacity out
  - For Winter, this total value is ~ 1,975 MW (which is slightly greater than the size of FPL's largest unit, Ft. Myers 2)
- **A second projection was based on a MW-weighted forced outage value for the generation fleet**
  - Each unit's Winter MW value was multiplied by that unit's FOR (for example, a 1,000 MW unit with a FOR of 3% would yield an expected forced outage value of 30 MW for that unit)
  - The values for each unit were developed, then summed, to derive a fleet projection of ~ 1,000 MW

As a result, the analyses used two forced outage values: 1,000 MW and 2,000 MW

FPL