ORIGINAL

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646

06

17 April 2004

Chairman Marc Spitzer
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Environmental Portfolio Standar
Docket No. RE-00000C-00-0377

Re: EPS Change Workshop 3, held 16 April 2004 at ACC Offices, Tucson, Arizona.

I would like to provide you a copy of my presentation at this workshop. Your questions were sincerely missed.

The presentation indicates, we must continue, with vigor, the EPS program but shift interest, from directly supporting centralized utilities to support individual decentralized installations. The utilities have failed with less than 200 homes tied to the grid in Arizona and less than 10 MW of total solar power.

The solar industry is mature, and can easily achieve the goals outlined in the paper. We need several **thousand of MW** of solar and renewable power, not tens, which is beyond the vision; foresight and business plan capabilities of APS and TEP. APS has even requested an additional $40-70 million more to achieve the 2007 EPS percentage of 1.1% with 60% solar.

The **solar** electric and heating goals can easily reach **3,000+ MW**, with another **2,000+ MW** of generation avoided by aggressive, digitally controlled, metering systems using DSM. We should be able to achieve these goals in a much shorter timeframe.

I would like to add an additional **recommendation** to shift from "EPS Percentages" to MegaWatts (MWs) of electric energy, which permits coherence with the Western Governors Association goals.

The article referenced in the paper is attached. The use of modern two-way, power-line meters and a "box" at each user were the major capital costs. Note in the article, second page:

> "FPL ultimately selected the two-way power-line communication system. The utility made this decision, even though it had higher capital costs, because it offered significantly lower operations and maintenance costs that more than offset the higher capital costs."

The $2+ billion saved with fewer power plants was additional savings.

A discussion on Maine's 30% renewables goal was valuable. The half (15%) attributed to "co-generation" is an excellent way to increase electrical generation capabilities. Boiler-driven steam turbines, at coal-fueled power plants, are fairly inefficient, averaging between 30-35% efficiency with gas turbines a bit higher. The laws of thermodynamics are impossible to modify, but mature state of the art co-generation additions can boost these efficiencies for steam to over 60% and for natural gas turbines to 75% or higher. This means, that for each BTU of energy consumed, 75% BTUs of equivalent electrical power results.

Co-generation should be encouraged also in Arizona. We do not have any Co-Generation goals in the EPS process. Since EPS is a "renewable" program, and Co-Gen is really an improvement in "efficiency" program, why not have both? The Commission should start requiring higher and higher efficiency for turbine-driven generation devices. Why not have a program where all steam turbines have

an average efficiency rating of 40% by a certain date, rated at 50% five years later, rate at 60% five-years after that and that gas turbines average rating be 50% by a certain date, rated at 60% five years later, and 70% five years after than. This would permit the utilities time to establish a plant replacement cycle with increasing efficient turbines. Funding should in rate cases.

Please free to call or request additional information as this topic or additional information about the recommendations, as this topic is critical for our long-term reliable, efficient, cost-effective electricity.

Sincerely,

Marshall Magruder

Marshall Magruder
(520) 398-8587 marshall@magruder.org

Cc: Mr. Ray Williamson, Workshop Chairman

Attachments:

1. Marshall Magruder letter to the EPS Change Workshop Three of 16 April 2004.
2. *Transmission & Distribution World,* "Mega Load Management System Pays Dividends – FPL and customers benefit from demand-side management program. Customers are paid to participate, while utility meets peak load without resorting to new generation", February 2004. (www.tdworld.com)

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646

April 16, 2004

BEFORE THE ARIZONA CORPORATION COMMISSION

Chairman Marc Spitzer
Commissioner William A. Mundell
Commissioner Jeff Hatch-Miller
Commissioner Mike Gleason
Commissioner Kristin Mayes
EPS Workshop Chairman Ray T. Williamson
1200 West Washington Street, Phoenix, AZ 85700

Re: Environmental Portfolio Standard Change Workshop 3, "Notice of Special Open Meeting" Agenda for April 16, 2004

Summary. This letter provides public comments for the issues listed in the referent Agenda:

1. Portfolio Percentage

- ***Whether or not Arizona can and should increase its commitment to renewable energy by increasing the portfolio percentage?***

The present EPS percentage of 1.1% is much less adjacent states and the national average for states with an EPS or equivalent renewable energy standard. The highest is Maine at 30%. The Governor of California is pushing for 33%. The need to more diverse, distributed, and renewable energy is well documented and is essential for future growth in the Great State of Arizona.[1]

The present 0.8% to 1.1% portfolio standard encourages instead of discouraging, further development of non-renewable energy fuel sources, namely coal and natural gas generation plants.

Recommend the portfolio percentage be gradually increased to 15% over a period fourteen years as follows:

- In **2008**, to increase from **1.1% to 2.0%.**
- In **2009**, to increase from **2.0% to 3.0%** and, then **1.0% annually** through **2021 to 15.0%.**

The A.A.C. R14-2-1618B.3 EPS process has to be modified, staring in 2008, with monetary bonus incentives developed when accomplishments exceed and penalties for failure to achieve the standard.

2. Expiration Date

- ***Elimination of the Environmental Portfolio Standard expiration date?***

[1] See *Cost, Benefits, and Impacts of the Arizona Environmental Portfolio Standard,* by the ACC Cost Evaluation Working Group, June 30, 2003, with benefits discussed in Section IV and Appendix 2.

The present expiration date impedes the utility industry to invest in long-term projects to support this program or to leverage their EPS funds to capitalized additional benefits for its customers.

Recommend the expiration date be changed to **2025**, and automatically renewed, unless contested, for an additional five-years in 2015 and 2020, thus extending to **2035**. This should permit confidence and reduce financial long-term risks due to possible reduction of this program.

3. Technology & Mix

- ***Consideration of inclusion of new and emerging technologies as part of the review of the appropriate resource mixes.***

The long-term future of energy solutions appears to be mostly hydrogen-centric oriented; however, there are many implementation steps that may impede this energy source. Other technologies, involving known and unknown solutions, need to be considered. The only technological solutions that should not be considered involve coal, natural gas, or nuclear energy sources.

Recommend no restrictions be placed the technology mix.

- ***Allocation of funding among various technologies.***

Arizona, by all measures, is the best state for solar energy. The average home receives eight times is energy demands on its roof. The utility infrastructure is minimized for solar electricity generation systems. The utility infrastructure does provide a backup power source, and is necessary when a solar system does not have a storage capability. In addition to electricity generation, solar hot water heaters, can reduce between 20-35% of the average home's energy needs, and needs to be encouraged due to the rapid return on investment for homeowners.

Recommend the present 60% or greater allocation towards solar energy devices is continued with additional interest towards solar water heaters. It is further recommended that the following goals be established:

By **2012**, over **500,000 solar water-heating systems** are installed in Arizona
By **2017**, over **1,000,000 solar water-heating systems** are installed in Arizona
By **2021**, over **2,000,000 solar water-heating systems** are installed in Arizona
[This can reduce demand by 500 MW, at least one 500 MW powerplant]

By **2012**, over **100,000 solar electricity generation systems** are installed in Arizona
By **2017**, over **500,000 solar electricity generation systems** are installed in Arizona
By **2021**, over **1,000,000 solar electricity generation systems** are installed in Arizona.
[This can reduce demand at least 2,000 MW or five 400 MW powerplants, siting, transmission lines, with pollution health threats and save over $2 billion in capital expenses with reduce O&M]

- ***Review of whether the approach of static percentages is still justified and if so, whether those percentages should be reconfigured, in the phase-in section of the rules in A.A.C. R14-2-1618B.3.***

See above for phase in dates, which need to be allocated to service areas, based of its customers, by rate category. If an utility fails to meet its quota, then if will have its rates reduced by the percentage it failed to make its quota, if it exceeds its percentage by 2%, for the above dates, then for every additional two percent above its "quota" percent, it will be given a 1% bonus for next five

years. This pertains to both solar water heating and solar electricity generation systems, by customer categories such as residential, business, industrial and municipal streetlights.

Example, in 2017, the utility service area should have 10% solar water-heaters, 5% electricity generation systems and 11% had solar water-heating systems, and 9% had electricity generation systems. There would be a 2% increase in electricity rates, as water heaters were 11-10, less than 2% or no impact and solar electric systems were 3% above goal, thus allowing a 0.5 % automatic rate increase for five years (next EPS goal line) as profit for achieving the goal.

4. Funding Issues

- ***A discussion of increasing the Environmental Portfolio Standard funding levels.***

The present system of funding does not encourage distributed generation nor does the EPS funding scheme encourage residential, business, or industrial customers to invest in ownership of energy generation devices. The primary benefactors are the utilities, who have demonstrated this by large, centralized, solar "power plants" from their century of such experiences. The paradigm shift and transformation of this industry towards renewable, distributed energy sources has not been accepted by the major utilities in Arizona. For example, TEP has less than 100 photovoltaic systems (total 160 kW in TEP's areas of responsibility while is has used EPS funds primarily for its single 3,800 kW "solar plant".

Recommend funding shift from the utilities to ratepayers after 2008. The EPS surcharge should aid both initial investment and operations. Initial investment incentives include tax credits and other incentives, such as in the following Arizona legislature bills, which have passed the House and are waiting approval by the Senate:

AB2613 Increases solar energy credits to $5000 for individuals and to $25,000 for businesses
AB2526 Provides property tax reductions for businesses with over 10% solar energy devices
Ab2527 Provides for solar and renewable energy sources for Arizona schools
AB2528 Requires energy audits every 12-years for state buildings and cost/benefits analyses.

Recommend the Commission encourage the Arizona Senate to strongly consider passage of all four of these to provide ratepayer tax credits, conserve Arizona school operations and maintenance funds, promote business usage of solar energy devices, and audit all Arizona state buildings. These bills incentivize capital investment for all customer categories throughout the state, including schools and state-operated facilities.

Recommend true net metering be required throughout the state for renewable energy generation, whenever the fuel source is other than coal, natural gas, or any petroleum product and the fuel is compliant with all environmental regulations, such as clean air and water statutes. True net metering will benefit the small-distributed generation system owners by having the utility purchase, at its retail rate for that customer category, and sell at the same monetary value. NO additional surcharges will be permitted for systems smaller than 50 kW.

- ***Whether or not Arizona can and should increase its commitment to renewable energy by increasing the surcharge?***

The state should increase its commitment to renewable energy; however, increasing the EPS surcharge will not incentivize the required direction needed to make advances in renewable energy. The proposed AB2613 tax credit incentive, plus potential federal tax credits, should motivate most new homeowners and businesses that incorporation of both solar water-heating and electricity

generation during initial construction is when such investments are best made. Carrying the cost in one's mortgage with lower utility bills for decades is another monetary incentive.

Recommend shifting funding emphasis of the EPS surcharge towards customer installations. As shown in various reports, the utilities centralized "solar" power plants and other means will never achieve meaningful results necessary to achieve the above EPS percentages. In view of a decrease in new utility infrastructure requirements, extensive savings in capital investments will result.

Recommend that monetary incentives be developed for customer installations to account for the numerous other incentives used in the utility industry including interest-free loans, guaranteed ROI, tax credits, valuations at 25% market value for property tax that are not available to residential, business, industrial or governmental customers. Such incentives could be to establish low-interest EPS loan programs, low down payments, customer and contractor training and educational programs, bulk-purchases, and many others. The Commission could use the utility or another entity to manage these incentives.

Recommend utilities be required to leverage all EPS funds, with at least a 1:5 ratio of EPS funds received to long-term loans. With this program continuing for decades, this will permit payback over the life-cycle of EPS energy devices. These public service utilities will monitor all renewable energy projects in its service area for compliance with the appropriate IEEE or other design standards to ensure conformance with standard interconnection devices.

Recommend the ACC Staff establish standard distributed generation interconnections for use by all utilities throughout the state. Such interconnection standards are critical for builders, electricity industry workers, utilities, and are necessary to facilitate all renewable additions to the state's energy grid. Further, the ACC Staff should establish a simple, one-step process for interconnecting to promote interoperability and facilitate distributed generation.

- ***Restoration of Demand Side Management funding.***

A Demand Side Management (DSM) program has one goal: to reduce demand, primarily shift demand from "peak" to "off-peak" hours. DSM is NOT a conservation program nor is DSM an efficiency program. These two are very important but are not realistic candidates for DSM funding.

There are many ways to accomplish DSM. A recent article[2] indicated that 7/8th of the customer's volunteered to have a load management system, installed on their distribution panel, which permitted to utility to remotely control (1) air conditioning, (2) electric hot water heaters, and (3) pool equipment. The two-way control system even permitted an over-ride capability, which was used about 1.5%. For this, a customer credit of $6.00 for controlling air conditioners (up to five consecutive minutes off) and $3.50 for water heaters was shown on each month's bill. What were the resultant benefits for the utility? It **avoided building 10 new 400 MW power plants to "clip" peak loads**. There were NO other incentives provided by the State Utility Commission, such as DSM funding, because the utility made money by saving capital investment with this program.

The overall result of DSM will be fewer power plants, less transmission line requirements, and similar results found by the ESP program.

---

[2] See *Transmission & Distribution World*, February 2004, "Mega Load Management System Pays Dividends: FPL and customers benefit for demand-side management program. Customers are paid to participate, while the utility meets peak load without resorting to new generation," by Michael Andreolas, FPL, pp. 33 to 37. Copy provided to Mr. Ernest Johnson, Utility Division Director during EPS Workshop Number 1.

Further, APS has a digital meter program which shows current usage. This is similar to the current miles/gallon meter in hybrid automobiles. Such modern, digital meters can show actual cost and total usage and cost since reset. This enhances conservation and energy efficiency while augmenting the above load management program.

A review of Semi-Annual DSM Reports in 2000 and 2001 submitted by Citizens, showed nearly non-compliance with "demand side management" since only bill fillers and a few energy audits were accomplished for over $200,000 in return. At that time, filings and data requests strongly recommended careful auditing of DSM program for real reductions in demand. Billing fillers are not DSM.

Recommend utilities strongly consider replace all analog meters with two-way digital meters on a long-term program; say ten years, with capital costs recovered during routine rate cases. With such meters, then aggressive DSM, energy efficiency, and conservation programs can be initiated, such as the one described above.

Recommend, when and if an RTO is established in or for Arizona, a continuously updated web-based display be developed that shows actual and forecast demand conditions. Use of current demand date should give the public awareness of the current status of the Arizona electricity system. The California ISO display at http://www.caiso.com/outlook.html (and its details at lower pages) will be essential for conservation and DSM.

Recommend DSM funding be only used to pay for achieving demand reductions in actual, measured loads. The scheme discussed below, provides incentive to flatten the demand curve. Measured monthly loading spread, for this purpose, will be determined by (1) Monthly Average Peak (max) Load determined by summing each day's Peak hourly demand, (2) Monthly Average Minimum Load determined by summing each day's Minimum hourly load, (3) Monthly Demand Spread as the difference between (1) and (2); (4) Ratio of this year's Peak-Min Demand Spread to the same month Peak-Min Demand Spread for that month of the prior year. If the ratio is less than 1.00, the Peak Demand Spread has been reduced, and if higher, Peak Demand Spread has increased.

For a monetary incentive, the rates can be increased 50% of a Demand Spread reduction, but increase by the ratio of any increase, during next rate case. Example: (from 1) Peak Daily Average 110 MW, (from 2) Minimum Daily Average was 62 MW. Difference (from 3) is 48 MW. Prior year was 50 MW. Ratio (from 4) is 48/50 = 96%. A 2% positive rate adjustment is credited for DSM consideration during next rate case. If the Ratio was 1.04, then a 4% rate debit adjustment could be made. The Commission would have an objective measure for DSM.

Recommend no additional funding be dedicated to DSM. If DSM funding is returned, recommend the ACC Staff or an outside contractor (under a performance incentive contract) monitors careful audits of all DSM expenditures.

Sincerely,

Marshall Magruder
520.398.8587
marshall@magruder.org

Mega Load Management System Pays Dividends

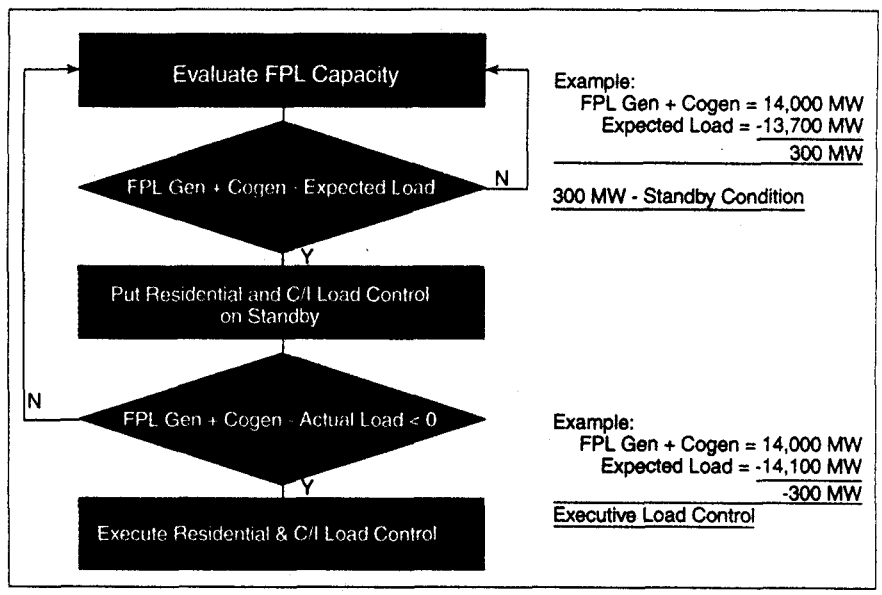
FPL and customers benefit from demand-side management program. Customers are paid to participate, while the utility meets peak load without resorting to new generation.

By Michael Andreolas, Florida Power & Light Co.

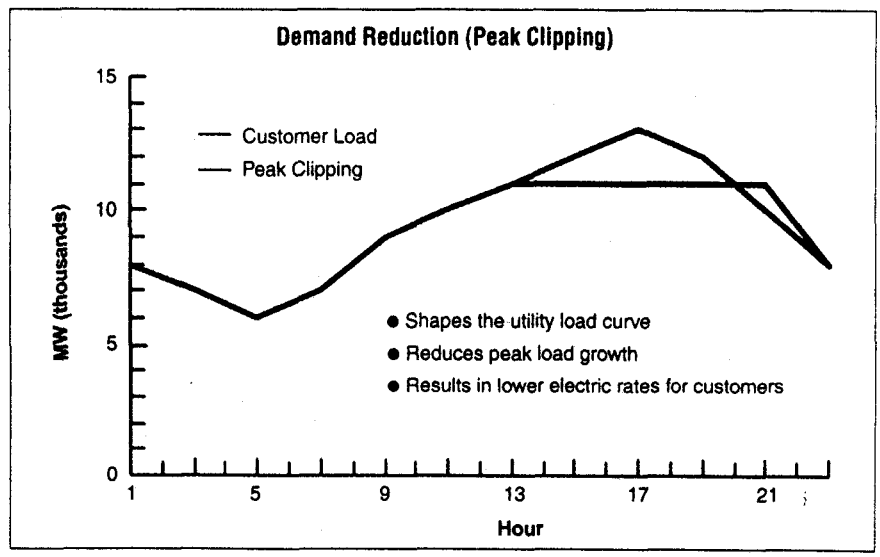
In the early 1980s, the Florida Public Service Commission (PSC) mandated that Florida-based utilities implement demand-side management (DSM) programs in response to the energy crisis. As a result, Florida Power & Light Co. (FPL; Miami, Florida, U.S.) developed several conservation programs for customers. In conjunction, FPL evaluated many load-management systems (LMS) to complement the existing DSM conservation measures. The LMS technology was particularly evaluated regarding the communications methods used by each system. The three basic modes of communications, each of which embraces a whole different class of systems, include power-line carrier, telephone and radio.

FPL's Program Development & Management (PDM) department analyzed different load-control technologies and assessed their performance using the following considerations:

- Information rate
- Message reliability
- Noise and EMF immunity
- Environmental effects
- Flexibility and expandability of the system
- Hardware reliability and security
- Regulatory agency acceptance
- Legal authorization and protection of frequencies
- Safety to the general public
- Technical competency required of the utility operating personnel
- Ease of installation, operation and maintenance (O&M)
- Life of equipment.



The Capacity Shortage Flowchart shows the decision process to initiate load control.



A demand-side management program enables a utility to dip peaks.

FPL ultimately selected a two-way power-line communications system. The utility made this decision, even though it had higher capital costs, because it offered significantly lower operations and maintenance costs that more than offset the higher capital costs.

FPL ultimately selected a two-way power-line communications system. The utility made this decision, even though it had higher capital costs, because it offered significantly lower operations and maintenance (O&M) costs that more than offset the higher capital costs. The O&M savings was particularly important in regards to being able to locate failed equipment. Detection of failures can be performed remotely, which avoids expensive infield "searches" for non-operational equipment. In addition, the selected LMS system has the ability to perform capacitor bank switching.

Guaranteeing Success

PDM conducted several other studies to determine the most effective approach required to ensure a successful program:

- *Marketing Communications.* PDM used several approaches, including a door-to-door campaign, telemarketing and, in some cases, a full-scale media program to encourage participation. Although the effects of each type of marketing were uncertain, it was clear that, in combination, these aggressive efforts would have an impact on the participation level.
- *Customer Incentives.* PDM evaluated and compared a monthly bill credit to implicit incentives, such as varying rate options, spot pricing and a time-of-use rate. Clearly, cash incentives were the winner because customers jumped at the opportunity to receive a monthly credit on their electric bill.
- *Effects of Control.* A storage water-heating program, for example, can be controlled unnoticed by the customer most of the time. Other programs, such as cycling off air conditioners, have a more direct impact on customers' service.
- *Customers' Attitudes.* Based on studies, it was clear that people's attitude toward the utility, energy use and other basic factors strongly influence whether or not they will participate in load management or DSM programs in general.

It is particularly useful to view the electric utility as a business with a market structure in both the production and sales area. The production side of planning is broken down into areas related to capacity and cost alternatives. The sale side of the business can be viewed as based on the regulatory setting, market share and diversification.

Once these parameters are identified and ranked, generic load shape changing objectives are selected. Load shape objectives include: peak clipping, valley filling, load shifting, conservation and freeing peak capacity to permit strategic load growth.

From a utility's point of view, a reliable LMS is required to reduce increased peak capacity. DSM and load control, in particular, allow the utility to obtain an optimum balance of centralized and decentralized energy technologies while integrating them throughout the service territory. It allows the utility to establish a reliable and predictable supply of power to its customers, based on thorough knowledge of their characteristics and needs.

A System that Delivers

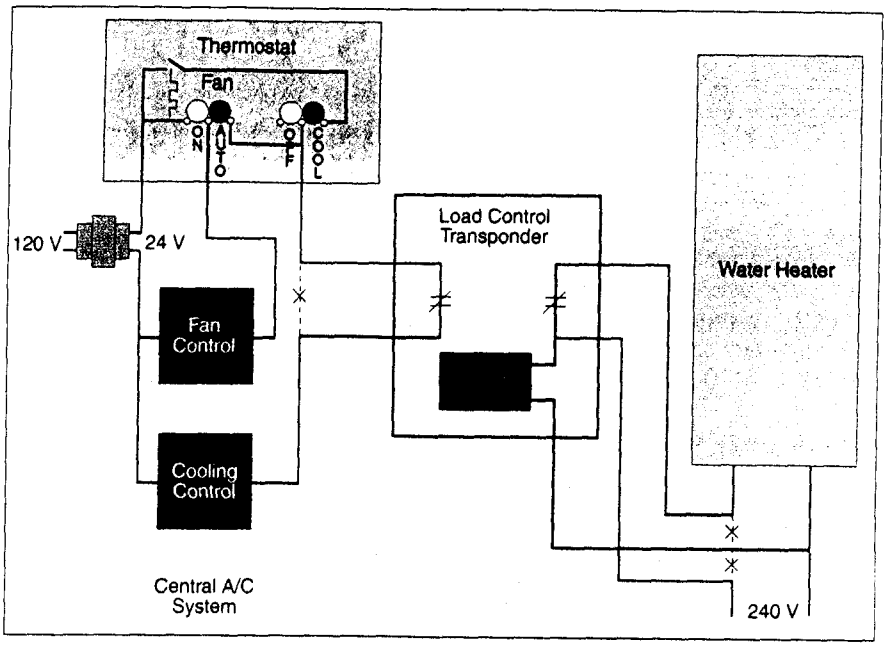
Of all the systems considered, FPL selected a power-line frequency system because of the many control strategies and the ability of a two-way communications feature. As a result, FPL installed the largest LMS in the world. This system uses more than 816,000 load-control transponders connecting more than 712,000 users. The LMS uses the Two-Way Automatic Control System (TWACS) from Distribution Control Systems Inc. (DCSI; St. Louis, Missouri, U.S.). Not only does the system provide FPL with an efficient energy management tool, but it also serves as a cost-effective alternative to building generating plants and distribution

grids. This system is an attractive economic alternative when compared to the total cost of adding new base-load power-generating equipment, such as combined cycle units.

FPL's regulatory filings with the PSC have consistently shown that the economic costs of building and operating these types of new generating units are at least 20% to 30% higher than the cost of installing and operating the DMS program.

From the operational point of view, FPL's load-management experience has been positive. The load-management program is an effective and reliable tool to reduce peak demand. However, maintaining an infrastructure to support implementation and handle customer inquiries is essential. Having load-control support groups in customer service and the field area has proved to be valuable as well as required.

Once the LMS field equipment is installed in the customer's home, about 1.5% of these customers generate calls. These calls can be as simple as adding additional appliances to the load-control program or eliminating the customers' perception that their participating appliances failed because of the installed LMS equipment. Employees who are trained regarding LMS—including a basic electrical knowledge of air-conditioning, water heaters and pool pump operation/wiring—help reduce customer drop-outs and ensure continued customer participation.



A typical demand-side management customer circuit schematic.

Putting the Program into Action

Historically, FPL has only implemented load control when the system load was anticipated to dip into the capacity reserve margin, which is generally unusual. Currently, load control is implemented on average about three to four times a year—two times in the summer and approximately twice in the winter. It took about five years to develop and implement the use of the LMS as it operates today, recognizing the benefits of having additional power generation during peak demand periods. Over the years, FPL learned that through the spring and fall shoulder months, the LMS system serves as a valuable tool during power-plant maintenance or in situations caused by force majeure.

FPL believes it is vital to establish a smart balance of when to initiate load control to successfully manage a program that is beneficial to both the utility and the customer. Additionally, because a load-management program involves customers, use of the system is influenced by behavioral as well as technological considerations. Making the system as invisible as possible to customers is key. To achieve this, FPL generally avoids using load management to curtail air-conditioning loads.

Rather, it primarily controls water heaters and pool pumps, unless capacity needs are critical. However, on a monthly basis, the LMS performs a 15-minute control on water heaters and pool pumps year-round. This maintains a balance between every business unit involved during an actual load-control event. Communication of the load-control event also is tested via the LMS by pager, e-mail and cell phone activation.

Using a portfolio of DSM programs, including interruptible rates for large power customers and a predominantly residential load-control program, FPL and its customers have successfully reduced demand for energy by 3463 MW. This reduction has allowed FPL to avoid building approximately 10 new 400-MW power plants. Of that total, 1000 MW of peak demand savings can be directly attributed to FPL's LMS. This not only has prevented blackouts, but it also allowed FPL to sell energy to other utilities within Florida when they needed additional power to meet their capacity needs.

The application of load management requires that customers give the utility permission to control their appliances. FPL pays residential customers incentives of $6 for controlling air conditioning and $3.50 for water heaters per month. Incentives are a major contributor to the ongoing cost of load-control programs. Currently, FPL is evaluating a reduction in the incentives it pays to customers to increase the long-term cost-effectiveness of the program.

Although it is important for electric utilities to adopt DSM programs, the need to evaluate program costs and benefits is an ongoing consideration. Long-term cost savings can only be met through careful planning and efficient testing, as well as prompt implementation of studies and the evaluation of resulting data. For FPL, it must evaluate the cost savings annually and submit its report to the PSC. Therefore, the process is designed to assess both short- and long-term goals.

Reaping the Rewards

Overall, FPL's customers have benefited from the load-control program because of its contribution in allowing FPL to maintain a quality, reliable and predictable supply of power generation during peak demand periods. In addition, saving customers money through lower electric rates by not building additional power plants combined with the benefits obtained by the utility, FPL's load-control program continues to be a premier offering for its customers.

Michael Andreolas, program manager of Florida Power & Light Co.'s load control program, has been working with FPL for 28 years. During program development, he designed the first set of installation and monitoring specifications for the load control equipment installed in customer homes. Currently, he is responsible for the purchase and installation of transponders/substation equipment, sales lead generation, contractor/inspector training, and field activities/support. Through his efforts, FPL has successfully launched load-control programs in both the residential and commercial sectors that have more than 700,000 active participants. Andreolas, who holds a BS degree in engineering technology from Florida International University, also has experience in residential and commercial field areas, distribution services, and in the Energy Conservation Department (DSM).

Michael_Andreolas@fpl.com