BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission Review of Numeric Conservation Goals Florida Power & Light Company	))))	DOCKET NO. 080407-EG
In re: Commission Review of Numeric Conservation Goals Progress Energy, Florida, Inc.	))))	DOCKET NO. 080408-EG
In re: Commission Review of Numeric Conservation Goals Tampa Electric Company	))))	DOCKET NO. 080409-EG
In re: Commission Review of Numeric Conservation Goals Gulf Power Company	))))	DOCKET NO. 080410-EG
In re: Commission Review of Numeric Conservation Goals Florida Public Utilities Company	))))	DOCKET NO. 080411-EG
In re: Commission Review of Numeric Conservation Goals Orlando Utilities Commission	))))	DOCKET NO. 080412-EG
In re: Commission Review of Numeric Conservation Goals Jacksonville Electric Authority	))))	DOCKET NO. 080413-EG

DIRECT TESTIMONY AND EXHIBIT OF:

WILLIAM STEINHURST

Q. Please state your name and occupation.

A. My name is William Steinhurst, and I am a Senior Consultant with Synapse Energy Economics (Synapse), which is headquartered in Cambridge, Massachusetts. My business address is 45 State Street, #394, Montpelier, Vermont 05602.

Q. On whose behalf did you prepare this prefiled testimony?

A. I prepared this testimony on behalf of the SACE-NRDC.

Q. Please summarize your qualifications.

A. I have over twenty-five years' experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, the California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, the Delaware Public Utilities Commission, the Regulatory Assistance Project, the National Association of Regulatory Utility Commissioners, the National Regulatory Research Institute, AARP, the Union of Concerned Scientists, the Northern Forest Council, the Nova Scotia Utility and Review Board, the U.S. EPA, the Conservation Law Foundation, the Sierra Club, the Oklahoma Sustainability Network, Illinois Energy Office, the Massachusetts Executive Office of Energy Resources, the James River Corporation, and the Newfoundland Department of Natural Resources.

I hold a B.A. in Physics from Wesleyan University, and an M.S. in Statistics and Ph.D. in Mechanical Engineering from the University of Vermont.

Q. Please summarize any prior experience working on energy efficiency.

A. I have testified as an expert witness in approximately 30 cases on topics including utility rates and ratemaking policy, prudence reviews, integrated resource planning, demand side management policy and program design, utility financings, regulatory enforcement, green marketing, power purchases, statistical analysis, and decision analysis. I have been a frequent witness in legislative hearings and represented the State of Vermont, the Delaware Public Utilities Commission Staff, and several other groups in numerous collaborative settlement processes addressing energy efficiency, resource planning and distributed resources.

I was the lead author or co-author of Vermont's long-term energy plans for 1983, 1988, and 1991, as well as the 1998 report *Fueling Vermont's Future: Comprehensive Energy Plan and Greenhouse Gas Action Plan*, as well as Synapse's study *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*. I was recently commissioned by the National Regulatory Research Institute to write *Electricity at a Glance*, a primer on the industry for new public utility commissioners, which included coverage of energy efficiency programs.

Q. Have you previously testified before the Florida Public Service Commission? ("the Commission" or "PSC")?

A. No.

Q. Please summarize your testimony.

A. I respond to and provide recommendations for certain items in the April 14, 2009, Staff Proposed Issues List ("Staff Issues List"). I also recommend for the Commission's consideration several aspects of good program design and implementation that should be taken into account in goal setting and elsewhere.

My recommendations are made in light of my understanding of Florida Statute and the recent FEECA bill (Fla. St. §§ 366.80-85, 403.519) and how they would be applied by an expert in utility resource planning and are guided by its statement of the Florida Legislature's policy, which reads in relevant part:

> 377.601. Legislative intent
>
> * * *
>
> (2) It is the policy of the State of Florida to:
> (a) Develop and promote the effective use of energy in the state, and discourage all forms of energy waste, and recognize and address the potential of global climate change wherever possible.
> (b) Play a leading role in developing and instituting energy management programs aimed at promoting energy conservation, energy security, and the reduction of greenhouse gas emissions.

Q. How is your testimony organized?

A. I address, in order, several of the issues listed in the Staff Issues List. Following that, I discuss several aspects of good program design and implementation and how they should be taken into account in goal setting in this proceeding.

ISSUE 2: **Did the Company provide an adequate assessment of the achievable potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems?**

Q. Do you have any concerns about the manner in which utility avoided cost estimates for energy and deferred capacity were prepared?

A. Several. Below, I discuss some of the ways in which avoided cost estimates ought to be done. NRDC-SACE witness Mosenthal discusses how DSM potential screening should be done. However, it is very hard to determine specifics on what was done by the FEECA utilities. Little relevant quantitative information was provided by most of the FEECA utilities in their direct case. Certain discovery responses that may be relevant to this question were received just before the deadline for filing this testimony, and we have not yet been able to review those responses. I may need to provide updated testimony once we have reviewed that data.

Q. Is it appropriate to accord DSM and demand-side renewables zero capacity value prior to the date of the next needed generation unit?

A. Not necessarily. First of all, there may be value in pure demand reductions, especially ones that are dispatchable or remotely controllable or ones that have a high coincidence with system peaks, even if the generation system is relative to the required level of reserves. Benefits in that situation can include extra on-peak T&D loss reductions, longer life for transformers and other T&D equipment as well as generators dispatched for spinning reserve, ancillary services value delivered, reduced clearing prices for ancillary services, and the ability to make off-system sales of firm capacity to neighboring utilities or regions. Air quality may be improved due to reduced operation of comparatively inefficient peakers or older, dirtier cycling plants to meet reserve requirements or super-peak loads; those air quality benefits are likely to accrue during hours when air quality is at its poorest and may be assigned some quantitative value due to freed up air permits or allowances, reduced constraints on economic development by industries that are subject to air quality regulation, or other public benefits. In addition, there may be situations where additional capacity can contribute to increased reliability of the system, both from a generation adequacy point of view and a T&D constraint perspective, locally or regionally. Such increased reliability can be of value to consumers, even if hard to quantify.

If Florida is growing quickly, now or after recovery from the recession, someone will probably need capacity.[1] There is likely to exist at least an informal bilateral market for capacity during the initial years of a given DSM measure's life, and imports from outside Florida are projected to be substantial.[2] Therefore, it is not plausible to assume zero avoided capacity value for even the early years of DSM measures. Furthermore, discounting "Uncertain Resources," i.e., unsited utility or merchant generation, the Commission's target reserve margin will not be met as early as 2010, supporting that conclusion.[3] One of the FEECA utilities, Gulf Power, is a member of the Southern Company System, which has an automatic mechanism in their system agreement for "capacity equalization" in which companies compensate each other for capacity deficits and surpluses. This mechanism may create a non-zero value for avoided capacity in every year, both for Gulf Power and for any FEECA utility within transmission distance of it.

[1] The 2008 FRCC load forecast calls for 2.1% per year demand growth between 2008 and 2017.
[2] The FRCC projected firm interregional purchases for 2008 of 2,448 MW, decreasing by 2017 to 846 MW, which is still a substantial opportunity for avoiding capacity needs.
[3] NERC 2008 report at 84.

I recommend that the Commission require the FEECA utilities to account for the value of the sales of surplus capacity and all other products or resources freed up by DSM in both the near term and the long term. If they are really claiming ZERO avoided capacity cost for some period, then they should be required to demonstrate that they have "gone to the market" with capacity for sale in an manner verifiably designed and executed to maximize the value of capacity for sale, and that no one was interested.

Q. Does the avoided cost method used by the FEECA utilities appear to properly preserve the capacity value associated with DSM that was approved in a previous FEECA goal-setting proceeding and relied upon in subsequent resource plans and need determination proceedings?

A. No, it appears that the proposed new goals for 2010-2014 are based on a zero or near-zero capacity value for the early years of their measure life. In contrast, when goals were set for that time period in the 2004 FEECA goal-setting proceeding, programs implemented in those years were assumed to contribute to the forecast capacity need of each utility.

For example, in the Standard Offer Contract filed by FPL on May 20, 2008, the Company's Avoided Unit has an in-service date of June 1, 2014. Under that contract, the capacity value is approximately zero until June 1, 2014.

Consider a hypothetical energy efficiency measure with a measure life of four years, installed at two locations on June 1, 2012 and June 1, 2014. The measure installed on June 1, 2014 would have approximately twice the capacity value than the measure installed on June 1, 2012 since it would receive capacity value credit for the full four years of its measure life rather than only the final two years of its measure life.

However, in the previous 2004 goal-setting proceeding, FPL appears to have relied upon an Avoided Unit with an in-service date of June 1, 2007 (Petition for Approval of Florida Power & Light Company's Standard Offer Contract, December 5, 2003, Docket 031093). This proceeding would also have covered the two hypothetical measures I described above, but would have assigned them each an approximately equal avoided capacity cost value since they would both have been installed after the effective date of the in-service date of the Avoided Unit.

The current effective goals for FPL and the other utilities are based in part on the avoided capacity values utilized in the 2004 proceeding. Subsequently, FPL and other FEECA utilities filed resource plans and petitions for determination of need that relied, in part, upon meeting those goals and installing that capacity.

In this proceeding, the FEECA utilities propose to reduce their goals for the five year period based, in part, on a method of analysis that includes approximately zero capacity value for several years until the utility's next Avoided Unit in-service date is reached. Yet measures implemented during this time period, at least up to the levels anticipated in the utilities' existing resource plans, obviously do have capacity value since that capacity has been relied upon in the resource plans and the utilizes have already or will soon avoid the need to build, purchase or otherwise obtain alternate capacity to meet forecast capacity needs.

Given this apparent change, I recommend that the Commission require the utilities to justify their method for valuing avoided capacity cost during the first five years of the plan and explain why it does not reflect the value that was attributed to meeting the goals in the prior FEECA goal-setting proceeding. There may be some need to update these values to place them in a consistent analytic framework (e.g., taking inflation into account).

Q. In identifying the avoided generation unit benefit, do the utilities ever consider the potential to avoid or delay, in whole or in part, the construction of a nuclear unit?

A. I cannot determine what the utilities actually do from the materials they filed. However, it appears based on Wilson's testimony that the utilities have never incorporated the capacity value of any nuclear plants, including nuclear plants that are merely proposed, in determining the avoided cost of capacity for DSM screening.

Even if a nuclear unit were actually under construction, there is, until quite far along, a large "to-go" cost that could be avoidable. Failure to cancel a unit that could be avoided by DSM less expensive than that remaining "to-go" cost would constitute imprudent management. Allowing in the avoided cost calculation for the possibility of canceling a nuclear construction project is quite reasonable.

Even big supply side resources can be avoided or deferred by small DSM. First, aggressive implementation of many small DSM measures can, taken together, amount to a large block of avoided demand. Second, because load forecasts and resource needs are not known with certainty, it is possible that a small amount of DSM delivered could allow deferral of a large unit on a statistical basis. Also, if Florida looks at avoided costs on a utility-specific basis, a particular utility's DSM achievement could quite reasonably allow it to have a smaller share in a nuclear construction project (initially, or by selling an interest in an underway project).[4]

Q. Were the baseline assumptions used by the utilities (growth rates, capital costs, fuel costs, etc.) appropriate? Were the sensitivity analyses useful in identifying the impact of varying these parameters on the total economic potential?

A. I was unable to determine from the materials filed by the utilities whether those assumptions and analyses were appropriate. Certain discovery responses that may be relevant to this question were received just before the deadline for filing this testimony, and we have not yet been able to review those responses. I may need to provide updated testimony after reviewing that data.

Q. Are there other shortcomings in the way the FEECA utilities handled other benefits of DSM or externalities in establishing the benefits of energy efficiency?

A. Yes. I discuss carbon externalities below in my response to Issue 5. In addition to the non-electric benefits mentioned earlier in my response to this Issue 2, I would like to describe three other problems with the FEECA utilities' handling of the benefits of DSM and demand-side renewables.

The first is the potential for energy efficiency and demand-side to delay or moderate constraints on Florida's economy. It is my understanding that Florida does not have major problems today with levels of criteria pollutants (under the Clean Air Act Amendments or CAA). However, if a situation were to develop where one or more of those pollutants was out of compliance or was expected to become out of compliance, there are provisions in the CAA that could limit commercial or industrial development in

[4] For further discussion of these points, see, for example, http://www.synapse-energy.com/Downloads/SynapseReport.2005-09.UNFCCC.Using-Electric-System-Operating-Margins-and-Build-Margins-.05-031.pdf at 11-13.

the affected regions of the state or require expensive retrofits of fossil fueled power plants to come back into compliance. Energy efficiency measures and programs would then become the Florida economy's first line of defense. This may be a hypothetical at this point, but I recommend that the Commission consider such benefits in exercising its discretion in setting goals for utility energy efficiency and demand-side renewables.

Second, there are significant benefits from DSM for at-risk citizens. By at-risk, I mean limited-income, elderly, disabled and ill residential customers and small businesses. To the extent that utility energy efficiency programs deliver bill reductions to at-risk residential customers, they will benefit from both more affordable heating and cooling of their residences and more disposable income for food, medicine and other expenses that support well-being. (This applies to institutional customers serving such populations as well, including nursing homes and hospitals.) The Commission should take that into account in setting goals and should disregard any claims that utility energy efficiency programs cannot benefit those customers because they are renters, live in manufactured housing or other justifications. Programs can be fielded that are feasible for those customers and attractive to them. There are also secondary benefits that flow to the State and all taxpayers (and ratepayers) from those benefits. For example, increased well-being, more comfortable living environments, and more disposable income available for medical care and other expenses can reduce the burden on public assistance of all kinds and health care systems, including shifting of costs to other payers.

Third, energy conservation programs provide additional benefits by acting as a hedge against volatile market prices for power and generating fuels. Utilities often invest in relatively high cost resources to ensure system reliability and reduce the risk of being required to make expensive market power purchases. The premium price associated with these investments can be thought of as hedging against the uncertainty in the supply and demand forecast.

The most sophisticated treatment of this issue that I am aware of is the resource planning process used by the Northwest Power and Conservation Council. The NWPCC considers nine sources of uncertainty in its resource planning model for the Fifth Power Plan, and may add three additional sources of uncertainty to its Sixth Power Plan model. The sources of uncertainty considered in that plan are:

- Load requirements
- Gas price
- Hydrogeneration
- Electricity price
- Forced outage rates
- Aluminum price (may be dropped in Sixth Power Plan)
- Carbon allowance price
- Production tax credits
- Renewable energy credit (green tag value)
- Power plant construction costs (may be added in Sixth Power Plan)
- Technology availability
- Conservation costs

The NWPCC resource plan includes options to install various energy resources, including new power plant construction and new conservation and demand response measure installation. The decision to move forward with a power plant entails certain construction, operation and retirement risks, which may be matched with the plant costs and benefits. Variation of the sources of uncertainty listed above affect the magnitude of the risks, costs and benefits.

The NWPCC planning process considers a wide range of plant build options (“plans”) as well as variations in the sources of uncertainty listed above. Modeling conducted for the plan demonstrates that resources used to minimize the risk of cost spikes by definition cost more than their expected value. The premium price for these resources, whether they are peaking plants or energy conservation resources, is necessary to reduce potential price volatility.

In a study of the hedging value of energy conservation, the NWPCC found that under least cost planning the effect of energy conservation is to defer single cycle combustion turbines. The study indicates that this is counter to traditional uses of low-capital cost resources for risk management (e.g., combustion turbines) rather than high-capital cost resources (e.g., conservation). The study indicates that the advantage of conservation is that it delivers energy savings value to the system under any scenario, while a combustion turbine only delivers value if it is actually needed. For this reason, conservation has a quantifiably lower premium cost associated with reducing system cost risk, and is thus the hedging instrument of choice in the NWPCC.

The NWPCC estimated that the risk premium represented by a combustion turbine unit is about 90% of total cost, in comparison to lost opportunity conservation (e.g., new construction or replace on burnout measures) with a premium cost of 40% of total cost and discretionary conservation with almost no premium cost. The discounted risk premium available from conservation measures was estimated with a conservation cost of $50 per MWh, which is higher than typical conservation measure costs.

In summary, the NWPCC has demonstrated the value of its policies to reduce system cost risk by accelerating investment in energy efficiency programs.

It is interesting to note that FPL makes a quite similar point in its Need Study for the Turkey Point nuclear units in the section titled "Discussing the Hedge Provided by Fuel Diversity." The study states, "Because the price of nuclear fuel has been and is projected to remain relatively stable, and because changes in nuclear fuel prices are not directly linked to changes in the prices of natural gas and fuel oil, having a fuel diverse portfolio that includes significant contributions from nuclear fuel helps dampen the effect of volatility in natural gas prices. For this reason the addition of Turkey Point 6 & 7 will help dampen the volatility in system fuel costs and make the cost of electricity more stable and predictable." (FPL, "Need Study for Electrical Power, Docket No. 070650-EI, p. 33) Considering that the price of "energy efficiency fuel" is almost always zero, it is evident that it would offer an even greater hedge value than nuclear fuel can offer to dampen the volatility in system fuel costs.

Q. Overall, how does the method used by Florida utilities compare with methods for establishing the value of energy efficiency in other jurisdictions?

A. The FEECA utilities took advantage of certain economies of scale and scope by working together with Itron. However, the way in which this was done has led to numerous concerns outlined here and in the testimony of other NRDC-SACE witnesses. I recommend the approach used by the New England ISO. The electric and gas utilities, together with relevant state agencies and various intervenor organizations, work together to calculate consistent avoided costs for electricity and gas on a regional basis. This is done every two years, and the various program administrators in their DSM plan filings use the results.[5]

Benefits of the AESC approach include: consistency between electric and gas avoided costs, consistency across utilities (results are not identical, but are consistent with differences driven by real differences in portfolios and load shapes), cost efficiency (in that there is one big model and process rather than several), transparency (anyone can participate in the AESC study group and assumptions and results are discussed openly and documents are posted to a project-specific website), and buy-in (at the end the groups seem to be in reasonable agreement, perhaps not as to every detail, but as a general matter leading all groups to accept the results).

Q. Are there other system benefits to energy efficiency that were not considered, for example the insurance (or hedging) value of energy efficiency against fuel cost spikes?

A. I was not able to determine from the FEECA utilities' Testimony or information available through the Collaborative process whether other system benefits were considered. Discovery responses that may be relevant to this question were received just before the deadline for filing this testimony, and we have not yet been able to review those responses. Accordingly, I may need to provide updated testimony once we have reviewed that data.

However, the Commission should understand that there are a number of benefits that accrue to states that pursue energy efficiency programs. Aside from energy and

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[5] *See*, for example, http://www.synapse-energy.com/Downloads/SynapseReport.2007-08.AESC.Avoided-Energy-Supply-Costs-2007.07-019.pdf. The 2009 AESC study is nearing completion, but not yet available.

capacity cost savings and avoided CO_2 costs, these benefits include non-electric benefits such as water and heating fuel savings, lower prices due to the demand-reduction-induced price effect (DRIPE), economic stimulus, job creation, risk reduction, and energy security. DRIPE benefits are being scrutinized by an increasing number of jurisdictions, including most of the New England states, the NY State Energy Research and Development Authority (NYSERDA). New England, New York, Illinois, and Oklahoma regulators, among many others, consider energy security, job creation and economic stimulus benefits. Jurisdictions that rely on risk reduction benefits are discussed below in this testimony. The *NAPEE* discusses job creation, economic development benefits, and risk reduction; it also places water savings, other fuel savings and environmental benefits explicitly as part of the TRC.[6]

Many electric efficiency measures also deliver non-electric benefits. Insulation and air sealing measures not only save on air conditioning costs in the summer months, but also save the customer money on heating fuels. High efficiency clothes washers use less water and impose smaller burdens on sewage treatment plants than standard, top-load models. LED exit signs and long lasting fluorescents reduce the maintenance cost of changing light bulbs and reduce air conditioning requirements.

Reductions in the quantity of energy and capacity that customers will need in the future due to efficiency and/or demand response programs result in lower prices for electric energy and capacity in wholesale markets. Lower demand means that the wholesale markets do not need to purchase the next most expensive unit. This benefit from utility energy efficiency programs reducing market prices is referred to as the Demand-Reduction-Induced Price Effect (DRIPE) and helps all customers, not just

[6] *NAPEE*, Chapter 6, generally, and especially p. 6-22.

participants. It can also reduce the price of natural gas for all gas consumers, not just utilities. The electric market clearing price benefit during peak hours can be much higher, and also has a dampening impact on price volatility. DRIPE impacts are significant in absolute dollar terms, since very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Moreover, consideration of DRIPE impacts can also increase the cost-effectiveness of peak-focused EE measures on the order of 15% to 20%, because the estimated absolute dollar benefits of DRIPE are being attributed to a relatively small quantity of reductions in energy.

The economic stimulus provided by energy efficiency occurs, in part, through a reduced dependence on imported fossil fuels and an increased focus on development of in-state solutions. Local resources are used to manufacture, construct or install, and operate energy efficiency technologies, thereby creating direct local jobs. As a result, energy efficiency can provide new sources of income for those who work in struggling industries.

Energy efficiency creates both direct and indirect jobs. Because the focus of the effort is not simply in manufacturing, but also in R&D, service and installation, these are well-paying, skilled positions that are not easily outsourced to other states and countries. Direct jobs result from the use of local skilled workers in the development, manufacture, construction, installation and operation and maintenance of energy efficiency technologies. Indirect jobs result from development of energy efficiency technologies as the payment of wages and purchase of goods and services in the economy results in additional job creation as workers and firms supplying goods and services to the energy efficiency industry, in turn, make purchases from the local economy. In addition, as energy efficiency reduces energy bills, businesses and households gain increased discretionary income which becomes available to purchase goods and services or for investment. This drives jobs in those markets and investment areas.

Energy efficiency reduces risks associated with fuel price volatility, unanticipated capital cost increases, more stringent regulations, fossil fuel supply shortages, and climate change. The highly volatile nature of natural gas prices has been a primary driver of more volatile electricity rates. This situation is unlikely to change in the near future, no matter which type of new supply is developed and brought into service.

Another risk avoided by energy efficiency deals with the long development timelines and inflexibility associated with conventional generation (compared to the short lead time and maneuverability of energy efficiency programs) exposes these resources to longer-term increases in the cost of labor and materials – unanticipated cost increases which increase the risk of disallowance and stranded costs and many other potential changes in the economy that can invalidate the planning assumptions originally used to justify them. It can take more than a decade before new coal and nuclear plants are operational. Conversely, energy efficiency is more nimble and less risky, both financially and environmentally. Aggressive energy efficiency eliminates the risk associated with committing to huge investments a decade or more before they will be needed.

Other downsides faced by fossil fuel plants include longer-term supply concerns due to finite supply and transportation bottlenecks. Recent issues with transporting coal have caused some existing coal plants to buy supplies at higher prices on the spot market in order to meet electricity demand. Energy efficiency is not subject to supply and transportation constraints that impact fossil fuels.

Fossil fuel plants are often sited at sea level or along rivers because they require large amounts of cooling water. Risk factors such as sea level rise, storm surges, and drought, which have become more frequent due to climate change, pose concern, as do risks of thermal and other forms of pollution of marine and estuarine habitats. Implementation of energy efficiency reduces greenhouse gas emissions, which reduces the risk of adverse effects from climate change without adding other risk factors.

Energy efficiency reduces competition between states for fuels to support electricity production, competition between states for electricity imports, and dependence on imported oil for electricity production. Oil prices have spiked above $135 per barrel and, long term, will continue to rise due to a number of factors including diminishing supply, increased demand in many countries and additional costs associated with safeguarding supplies located in countries suffering from economic, social and political instability. This cost increase makes increased reliance on oil unlikely. Energy efficiency can help states meet future demand increases and reduce dependence on out-of-state or overseas resources.

Early adoption of energy efficiency policies could help states garner additional allowances (i.e., funds) as part of any national greenhouse gas programs that are enacted by Congress. Following the trend established by the Regional Greenhouse Gas Initiative (RGGI), global warming bills introduced in Congress have tended to include provisions to auction allowances, rather than to give them away free to sources, but also to provide additional allowance allocations to (1) utilities and states that take early action by establishing binding greenhouse gas reduction targets, (2) utilities and states reducing greenhouse gas emissions and (3) states with more aggressive greenhouse gas reduction targets than equivalent Federal programs.

Issue 4. Do the Company's proposed goals adequately reflect the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions, pursuant to Section 366.82(3)(b), F.S.?

Q. Do you have an opinion on this issue?

A. Yes, I do. The FEECA utilities' proposed goals do not adequately reflect the costs and benefits of utility energy efficiency to the general body of ratepayers as a whole. In part, this goes back to the concerns raised in response to Issue 2. Further, the new FEECA legislation requires (explicitly or through broad policy statements) inclusion in cost-effectiveness testing of benefits that are not reflected in the utility studies and goals.

Q. Do the utilities' goals flow from a complete and appropriate estimate of the technical potential for energy efficiency in Florida?

A. Not entirely. As explained by NRDC-SACE witness Wilson in his prefiled testimony, the overall technical potential should be increased by at least 8%, from 34% to 42% statewide due to a short list of very specific omissions.

> A reasonable estimate of the additional technical potential that the Commission might reasonably add to the findings of the technical potential study is 12,700 GWh, including 3,400 GWh savings from the excluded end-use sectors and 10,600 GWh from the overlooked measures, of potential energy savings. This represents an increase of approximately 8%, or a total statewide technical potential of 42% rather than the 34% reported by Itron.

Q. Do the utilities' goals flow from a complete and appropriate estimate of the economically achievable potential for energy efficiency in Florida?

A. No, they do not. In addition to an underestimate in the technical potential—the starting point for further analysis—of at least 8%, there a number of other errors and omissions were made. NRDC-SACE witness Mosenthal sums up his investigation of the achievable potential studies this way:

> The result of the achievable potential analysis on its face is simply not a credible estimate of the maximum amount of DSM resources that could be captured cost-effectively in Florida.

Among the errors and omissions Mr. Mosenthal identified in his review are:

- unreasonable assumptions and criteria;
- a flawed understanding of the principals of integrated resource planning and the language of the new Statute;
- unreasonably low penetration rates for energy saving measures;
- inaccurate cost-effectiveness analysis; and
- failure to consider new and innovative program strategies that could result in much higher penetration of cost-effective efficiency and demand resources

So, overall, given the shortcomings identified by those witnesses and in my own testimony, one must conclude that

(1) the benefits of avoided energy and capacity including, but not limited to, carbon emissions,

(2) the technical potential (which would certainly increase with a fuller assessment of the benefits of utility energy efficiency), and

(3) the achievable potential (which, again, would certainly increase with a fuller assessment of the benefits of utility energy efficiency and the technical potential), as estimated by the utilities do not amount to a complete and appropriate estimate of the economically achievable potential for energy efficiency in Florida.

<u>ISSUE 5</u>: Do the Company's proposed goals adequately reflect the costs imposed by state and federal regulations on the emission of greenhouse gases, pursuant to Section 366.82(3)(d), F.S?

Q. Do you have an opinion on this issue?

A. I do. In summary, the answer is "no."

Q. Please give an example.

A. Per the testimony provided by JEA witness Kushner (at page 6), CO_2 allowance prices are not included in the fuel price forecast. Witness Kushner also testified that such prices are included in the sensitivity analyses. See Kushner Exhibit BEK-2, page 1 of 1, which provides CO_2 allowance price assumptions. The data contained in this Exhibit are from EIA's input to S 2191 (Lieberman-Warner).

Q. Do the data provided by witness Kushner (and also mentioned by other FEECA witnesses) adequately address the requirements of Section 366.82(3)(d) of the Florida Statutes?

A. As I understand them, in part yes and in part no. The data provided by witness Kushner and other FEECA witnesses address potential federal legislation. Florida also has state requirements to develop regulations to limit greenhouse gas emissions. Also, the data cited by witness Kushner and other FEECA witnesses are taken from US Senate bill 2191, also referred to as the Lieberman-Warner bill, which is from 2007 and now obsolete.

Q. Did any other FEECA utility witnesses rely on that data?

A. Apparently. TECO witness Bryant also mentions the CO_2 price per ton range used for federal legislation. Bryant direct prefiled at 33.

Q. Leaving aside for a moment the numerical values adopted by FEECA utility witnesses, how were the values applied to reflect those costs in their proposed goals or measure screening?

A. It appears that at least some of the FEECA utilities merely ran additional sensitivity scenarios reflecting certain low and high carbon costs. *See*, for example, Kushner direct prefiled at 6. Likewise, it appears that those sensitivity scenarios had no effect on some of the FEECA utilities' proposed DSM goals. *See*, for example, Bryant direct prefiled at 37, lines 5–17. Gulf Power's witness Floyd, on the other hand, states that that company included a "mid-range" value of $20 per ton (2014 dollars, escalating thereafter at an unstated rate) and FPL witness Sims states that his company used a "base case" value of $14 in 2013 rising to $23 in 2018 (both nominal dollars). Sims Exh.-SRS-7.

I consider those values to be at the extreme low end of the reasonable range of estimates and inappropriate as a basis for meeting the requirement to adequately address the requirements of Section 366.82(3)(d) of the Florida Statutes.

Q. Please explain.

A. I will first address federal legislation to limit greenhouse gas emissions, and later focus on Florida's state efforts to reduce such emissions.

With respect to federal legislation, the data from S 2191 are now two years old and were based upon legislative objectives that have since become more comprehensive and more stringent. Recent bills introduced during 2009, notably Waxman-Markey, reflect deeper GHG reductions. The utilities high price assumption reference is based on federal legislation that would prohibit or severely restrict the use of international offsets.

This outcome is not likely. The Waxman-Markey bill provides for a 50/50 split between domestic and international offsets, and would permit the quantity of international offsets to increase, if sufficient domestic offsets were not available. We would expect the effect of allowing offsets to be used, and to increase the percentage of international offsets if insufficient domestic offsets are not available, will be to keep allowance prices below the high price assumptions used by the utilities in their assessment of federal greenhouse gas legislation. On the other hand, the utilities' low and mid-range CO_2 allowance prices are below the ranges I would recommend.

Q. Can you give us some examples of CO_2 allowance prices used in utility resource planning?

A. Yes. In its 2005 Integrated Resource Plan, Avista used a range from $7 to $25/ton for the 2010 planning year and from $15 and $62/ton for the 2023 planning year. Portland General Electric and Pacificorp adopted a range of $0 to $55 beginning in 2003 and 2004, respectively. Idaho Power adopted a range of $0 to $61 starting in 2008. Northwest Energy adopted a range of $15 to $41 starting in 2005. (I would not consider $0 to be a credible low case value at this time.) Those values are all in 2005 dollars.[7]

The California PUC requires that regulated utility IRPs include carbon adder of $8/ton CO2, escalating at 5% per year as of 2005.[8] The Oregon PUC has adopted a range from $0 to about $85 (levelized 2013-2030 in 2007 dollars). Other PUCs have adopted ranges from the teens to $35–$45 (also levelized 2013-2030 in 2007 dollars).[9]

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[7] David Schlissel, Lucy Johnston, Bruce Biewald, David White, Ezra Hausman, Chris James, and Jeremy Fisher, *Synapse 2008 CO2 Price Forecasts*, at 21. Available at http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf

[8] CPUC Decision 05-04-024

[9] Schlissel, et al., op. cit.

Various analyses of a number of proposed federal climate change laws indicate early year costs of nearly $10 to over $60, with the 2018 range going from just over $10 to about $90 with all the analyses rising steadily thereafter (in 2007 dollars).[10] The U.S. Department of Energy has recently issued estimates with a low-range value of $2, a mid-range value of $33 and a high-range value of $80, escalating at 3% per year.[11]

Q. Do you have recommendations for what CO_2 allowance prices the utilities should use for planning utility energy efficiency programs and goal setting?

A. Yes. I recommend that, at a minimum, the Commission require the use of allowance prices with a low-case allowance price of $15 per ton, a mid- or base-case allowance price of $30 per ton, and a high-case allowance price of $78 per ton (all levelized over the period 2013-2030, in 2007 dollars). I believe that a reasonable figure for the *long-run* marginal cost of carbon emissions is around $80 (in 2008 dollars, about $78 in 2007 dollars) and recommend that the Commission require high case analysis reflecting that price be analyzed and considered in permanent goal setting.

Q. What are the potential effects from using those allowance prices?

A. There are two main benefits. First, those allowance prices will better reflect the environmental and public health externalities associated with the combustion of fossil fuels. Second, including a CO_2 allowance price enables more cost-effective energy efficiency measures to be adopted and increases the potential to develop additional renewable energy resources.

I believe the recommended mid-range allowance price forecast is close to what greenhouse gas allowances will initially sell for in a federal program and much more

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[10] Ibid., Fig. 5.
[11] U.S. DOE, *Energy Conservation Program: Energy Conservation Standards and Test Procedures for General Service Fluorescent Lamps and Incandescent Reflector Lamps*, pp. 14-15.

realistically reflects current expectation than the utility witnesses' assumptions would, even if they had allowed those prices to influence their proposed goals. At the same time, I believe using unrealistically high allowance prices, like those included in the utilities' high price assumptions, do a disservice by overstating the potential costs of a federal program.

Q. Did the FEECA utilities address the potential for state regulation of greenhouse gases in Florida?

A. None of the utilities testimony or CO_2 allowance price assumptions includes an analysis of state level GHG regulation.

Q. What state level regulations or programs have been announced or considered in Florida?

A. Governor Crist's Executive Order 07-127, as I understand it, requires the Florida DEP to develop a cap and trade program with the following GHG reduction requirements: by 2017, reduce GHG emissions to 2000 levels; by 2025 reduce GHG emissions to 1990 levels, and by 2050, reduce GHG emissions to 20% of 1990 levels. The October 15, 2008, report from the Governor's Action Team on Energy and Climate Change recommended that these regulations first focus on the electric sector.[12] The Florida Department of Environmental Protection has undertaken a rulemaking pursuant to legislative authority to develop GHG reduction rules in 2008. (http://www.dep.state.fl.us/air/rules/ghg/electric.htm)

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[12] *Florida's Energy and Climate Change Action Plan*, Ch. 4. http://www.flclimatechange.us/ewebeditpro/items/O12F20142.PDF

Q. What would be the effect of Florida adopting regulations to reduce greenhouse gas emissions, independently or through joining a regional program such as RGGI or WCI?

A. One effect relevant to setting goals for utility energy efficiency programs that could arise would be that in-state fossil fueled generators would have to procure adequate CO_2 allowances to cover their annual emissions. Generators with higher CO_2 emissions per MWh would have higher costs of generation than those with lower or no CO_2 per MWh. These higher costs would then enable more cost-effective energy efficiency programs to be adopted, and they would also help to enable development of demand-side and commercial or industrial scale renewable generation.

<u>ISSUE 7</u> What cost-effectiveness test or tests should the Commission use to set goals, pursuant to Section 366.82, F.S.?

Q. What new statutory language has Florida enacted regarding appropriate tests for cost-benefit analysis of utility energy efficiency?

A. As explained by NRDC-SACE witness Wilson, the 2008 Energy Act amended Fla. Stat. § 366.82(3) provides that in establishing goals for utility energy efficiency, the Legislature now requires that the Commission consider:

a) The costs and benefits to customers participating in the measure.

b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

c) The need for incentives to promote both customer-owned and utility-owned energy efficiency and demand-side renewable energy systems.

d) The costs imposed by state and federal regulations on the emission of greenhouse gases.

§ 366.82(3), Fla. Stat. 2008

Of these four provisions, subdivision (b) is the one that, on its own terms, bears on the proper test for the cost-effectiveness of such programs.

Q. In that subdivision (b), what is your understanding of how "costs and benefits" and "to the general body of ratepayers" are applied in practice by experts in DSM program design and implementation?

A. In practice, that phrase "costs and benefits" is used by experts in the field to mean the net present value of the difference in whole-life (or life-cycle) utility cost of service with and without a measure, program or other resource. The phrase "to the general body of ratepayers" is applied to mean the cost of service for the entire body of ratepayers, as a whole, including all the system-wide costs and benefits of the measure, program or other resources.

Q. Is the TRC Test consistent with the manner in which experts in the field would apply the phrase "costs and benefits to the general body of ratepayers as a whole"?

A. Yes.

Q. Is it reasonable to interpret that language as consistent with, requiring the use of, or allowing the use of either the RIM Test for the purpose of deciding whether a given program, measure or other resource is cost effective?

A. No.

Q. Have you reviewed the testimony that Mr. Ralph Cavanagh is submitting in this proceeding?

A. I have and I agree with Mr. Cavanagh's conclusion that, as a matter both of my understanding of the language of the amended FEECA statute and as a matter of sound policy, the TRC test—not the RIM test—should be used when setting goals.

Q. As a policy matter, what cost-benefit test do you recommend for DSM screening, taking into consideration the public interest and the potential impact on economic development?

A. I recommend use of the TRC for program design, goal setting, field screening, and program evaluation. The public interest favors that choice for many reasons, not the least of which is that no other test will lead to resource choices that deliver least cost service to ratepayers. Economic development and the desire for a sound State economy also favor that choice for several reasons including green jobs, said by many to be the likely cutting edge of the future U.S. economy, reduced price volatility, more predictable bills and rates for businesses, and greater economic multipliers for EE (and RE) than for traditional generation).

ISSUE 8: What residential summer and winter megawatt (MW) and annual Gigawatt-hour (GWh) goals should be established for the period 2010-2019?

Q. Do you have a recommendation on this issue?

A. Yes, I do. My quantitative recommendations are provided in Exh. WS-1, together with my recommendations for the commercial/industrial goals, and are explained in my response to Issue 9, below.

ISSUE 9: **What commercial/industrial summer and winter megawatt (MW) and annual Gigawatt hour (GWh) goals should be established for the period 2010-2019?**

Q. Do you have a recommendation on this issue?

A. Yes, I do. My quantitative recommendations are provided in Exh. WS-1 together with my recommendations for the residential goals, and are explained below.

Q. What annual energy DSM savings goals do you recommend to the Commission?

A. As I understand it, Florida law establishes that it is State policy to "[p]lay a leading role in developing and instituting energy management programs aimed at promoting energy conservation, energy security, and the reduction of greenhouse gas emissions." Fla. St. § 377.601(2)(b). In my opinion as an expert on utility resource planning, to do so Florida's electric utilities will need to be among the leading electric utilities in the nation in terms of savings from their energy efficiency and peak demand reduction programs. That will not happen, in my opinion, unless the Commission establishes savings goals for the utilities that match those achieved by the leading utilities in the nation. The "leading electric utilities in the country" run DSM programs that save the equivalent of on the order of 1.0 percent of electricity sales each year."[13] In fact, as explained by other NRDC-SACE witnesses, a number of the leading DSM program administrators consistently save in excess of 1.0% per year. The same reports indicate a

[13] *National Action Plan for Energy Efficiency (NAPEE)*, p. ES-4. This conclusion is also supported by the Western Governors' Association Clean and Diversified Energy Initiative in its *Energy Efficiency Task Force Report*, p. 55 (Jan. 2006), available at http://www.westgov.org/wga/initiatives/cdeac/Energy%20Efficiency-full.pdf.

consensus that the cost of saved energy for those leading DSM programs is on the order of $0.02-0.03/kWh (utility plus participant costs)..[14]

One logical conclusion is that the Commission should set savings goals of no less than 1.0% per year, and I recommend that the Commission set savings goals at that level for annual electric energy sales for the years 2010 through 2019. However, I recommend that the Commission do so on an interim basis for both the residential and commercial sectors. In my response to Issue 12, given below in this testimony, I explain what I mean by setting goals on an interim basis and how the Commission should go about establishing permanent goals. Below, I address ramp up issues and my recommended goals for utilities during ramp up years.

Q. Do you have a recommendation regarding winter and summer peak demand savings?

A. Yes, I do. The FEECA utilities have various demand response and load control initiatives in place or proposed. My recommendation with respect to winter and summer peak demand savings goals is to set the goals at the sum of (a) the peak demand savings impact for each season from the utility energy efficiency programs needed to deliver my recommended electric energy savings goal of 1% per year, plus (b) the additional peak demand savings impact for each season from each utility's demand response and load control initiatives in place or proposed (as approved by the Commission). Since the seasonal peak demand impacts delivered by the utility energy efficiency programs needed to deliver an electric energy savings goal of 1% per year will depend critically on the specific measures deployed, it will only be possible to determine the appropriate goals for

[14] *Id.*

peak demand savings after the Commission has a better idea of the peak demand savings impact of a 1% energy savings goal.

Q. Have your prepared specific numeric savings goals that you recommend to the Commission?

A. Yes. After taking into account the known errors in the utilities' analyses identified by myself, Mr. Mosenthal and Mr. Wilson, and taking into account correct application of the TRC test, it is my expert opinion that the actual achievable potential should be well in excess of 10% of retail sales. Accordingly, as I recommended in an earlier answer, the Commission should be confident that it may adopt an across the board interim goal of 1% per year for each utility and each category of savings with certain adjustments explained below. In Exh. WS-1, provide filled out numeric goal tables for each electric utility that prefiled proposed savings goals for itself in this proceeding.

The tables in Exh. WS-1 are formatted in the manner requested under Issues #8 and #9 in the Staff Issues List with one modification. Because I based my numeric goals on data from the FEECA utility *Ten Year Site Plans*, and because those plans do not disaggregate seasonal peak demands by customer class in the way that the Staff Issues List does, I was only able to provide aggregate seasonal peak demand savings goals.

Since FPUC does not file a *Ten Year Site Plan*, I was unable to develop specific numerical goals for that utility, although I do recommend the same 1% per year electric energy savings target apply to FPUC.

In addition, as explained in the immediately preceding answer, it is possible to give only illustrative goals for peak demand savings. Therefore, and purely for illustrative purposes, I have calculated the numerical peak demand savings goals from my electric energy interim savings goals as if the peak demand savings were strictly proportional to the energy savings, i.e., 1% per year.

Q. Please explain how you prepared the recommended numeric goals set out in Exh. WS-1.

A. In absence of correct analysis from utilities, I recommended in an earlier answer that Commission adopt an across the board interim goal of 1% per year for each utility and each category of savings. The tables in Exh. WS-1 represent an annual savings goal of 1% of a given utility's forecasted energy, summer peak demand or winter peak demand, as the case may be, for the given customer category. Again, the record supports goals of at least 1%, but because of the errors in the utility analysis, I recommend that 1% be adopted as interim goals. I explain further what I mean by setting goals on an interim basis and how the Commission should go about establishing permanent goals in my response to Issue 12, given below in this testimony. Because the most recent *Ten Year Site Plans*, provide forecasts only through 2018, it was necessary to extrapolate goals for 2019. I adopted forecast values for 2019 electric energy sales and peak demands equal to the 2018 company forecasts plus a percentage increase over 2018 at the same rate as the increase from 2017 to 2018 in those forecasts.

Q. How do you recommend the Commission address ramp up issues in setting goals for utility energy efficiency?

A. Time is of the essence in this matter. Every day programs are not in place and fully ramped up, efficiency savings that would have lasted for years are lost. Further, there is not reason the FEECA utilities cannot quickly ramp up to aggressive implementation. Furthermore, the faster and more aggressively programs are scaled up, the lower I would expect their cost of saved energy to be—a goal all stakeholders should share. Utilities new to DSM can ramp up programs quickly to substantial impacts. For example, in 2007, the third year of its DSM program, the Arizona Public Service Company achieved annual energy savings equivalent to 0.89% of retail electricity sales (ramping up from 0.09% in 2005, and 0.37% in 2006).[15]

Q. So, do you have recommendations for adjusting your 1% per year savings goals during ramp up?

A. Yes, I do. I have separate recommendations for the smaller FEECA utilities and for the larger ones. I consider OUC, FPUC and JEA to be smaller utilities for this purpose.

The larger utilities reported savings to EIA in 2007 of between 0.11% and 0.2% of retail sales. Taking into account that baseline, I recommend a three-year ramp up schedule for interim savings goals of 0.33% in year one, 0.66% in year two, and 1.00% in year three and thereafter.

Of the three smaller FEECA utilities, two reported savings of 0.10% or less in 2007. (OUC did not report.) Taking that and their size into account, I recommend a four-year ramp up schedule for interim savings goals of 0.25% in year one, 0.50% in year two, 0.75% in year three, and 1.00% in year four and thereafter.

These ramp up schedules are reflected in the illustrative numeric goals in my Exh. WS-1, except that, as mentioned above, I have not prepared a schedule for FPUC.

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[15] Arizona Public Service Company's response to Western Resource Advocates First Set of Data Requests, Arizona Corporation Commission Docket No. E-01345A-08-0172, August 4, 2008.

Q. How do those recommendations relate to the utilities' prefiled studies and their claims about achievable potential?

A. Obviously, my recommended goals are larger than the utilities' recommended goals. After ramp up, my recommendations are 1% of annual sales, while the FEECA utilities recommended goals average less that one-tenth of that. My recommendation results in a cumulative 10-year savings on the order of 9% of retail sales. NRDC-SACE witness Wilson concludes that the technical potential for Florida might reasonably be estimated as 42%, nearly five times my recommendation. NRDC-SACE witness Mosenthal observes that a ratio of achievable potential to technical potential of about 60% is "fairly typical." Applying that ratio to a technical potential of 42% gives an estimate of achievable potential equal to about 25% of load, nearly triple my recommendation. As for the utilities' claims about achievable potential, FPL's estimate of achievable potential is under 1% of load, no more than a ninth of my recommendations.

While that may seem like a large difference, it is easily accounted for by the many errors in the analysis of achievable potential conducted by those utilities. Those errors are discussed elsewhere in my testimony and that of the other NRDC-SACE witnesses. Not the least of those errors was their use of the RIM test and the fallacious decision to arbitrarily exclude any measures or programs with a short participant payback If we compare my recommended goals to the results of the Itron technical potential studies, a different picture emerges. In any event, annual savings goals of 1% of energy sales or peak demand are entirely reasonable given past experience and fully justified under Florida's State policy

<u>ISSUE 10</u>: In addition to the MW and GWh goals established in Issues 7 and 8, should the Commission establish separate goals for demand-side renewable energy systems?

Q. Was the solar PV economic/achievable analysis was done correctly?

A. No. For this measure, I have prepared an illustrative cost-benefit analysis under the TRC and Participant tests using information from FEECA utility witnesses and other sources. The analysis was done for 2010 installation and 2015 installation. It showed that demand-side PV did not pass the TRC, but was close to passing the Participant Test in 2010 and passed it easily in 2015. I would note that if the Florida State incentives available for PV are counted as a reduction to the capital cost of PV units—an assumption that is not normally made in the TRC—the technology does pass the TRC. Due to time constraints, it was necessary to perform this analysis with highly preliminary "placeholder" inputs, especially for avoided costs. Even so, the finding that the Participant Test is passed with zero or a very small utility incentive, taken together with the emphasis recent Florida statute places on setting goals for demand-side PV, suggests that there are policy considerations that support special consideration for this emerging resource. Certainly, it would be beneficial for the Commission to require the FEECA utilities to undertake a fresh assessment of the market potential for demand-side PV. Alternatively, a small goal now to build infrastructure and public awareness for future full deployment could be deemed reasonable, given the language of Fl. Sta. 377.601(2)(h)(i), which says that State policy is to "Encourage the research, development, demonstration, and application of alternative energy resources, particularly renewable energy resources."

Q. What recommendations do the FEECA utilities offer in regard to separate goals for demand-side renewable energy systems?

A. In their testimony, each utility representative recommends that the Commission should not establish separate goals.

Q. And what do you recommend?

A. I recommend that the Commission set separate MW and GWh goals for demand-side renewables. These goals can be consistent with Florida's renewable energy resources, and ramp up over time as experience is gained and more technologies become cost effective.

Given the policy goals of FEECA, the Commission should do what it can (I'm not a lawyer) to make this a priority in this proceeding if for no other reason than the long term market transformation benefits that would flow from highlighting this demand-side renewable technology. A separate goal would ensure that the utilities and the Commission attend to this specific legislative policy goal and provide a forum for continuous improvement in that area.

<u>ISSUE 11</u>: In addition to the MW and GWh goals established in Issues 7 and 8, should the Commission establish additional goals for efficiency improvements in generation, transmission, and distribution?

Q. Do you recommend that the Commission establish savings goals for these categories?

A. Increasing generating plant efficiency and reducing T&D losses can be particularly valuable as all customers benefit directly. They are especially low risk resource options in general because an improvement to an existing facility is typically less onerous and chancy to permit and requires less capital than building a new resource. Further, there would likely be shorter lead times and less planning risk.

However, I recommend that the Commission defer this issue briefly for later proceedings in this docket (or another one, such as the next *Ten Year Site Plan* review, if preferred) to allow time for the utilities to perform technical and economic potential studies for efficiency improvements at their existing power plants and in their existing T&D systems. I recommend that the Commission set a date certain by which the utilities will provide that information for review.

Ideally, each utility should plan and conduct a comprehensive study evaluating options for improving generator efficiency and transmission and distribution system efficiency. The studies should also identify any environmental regulations that might be triggered as a result of the efficiency improvements (e.g., New Source Review), estimate the cost of compliance with those regulations above and beyond the costs directly associated with the efficiency improvements, and the benefits to the public associated with those additional costs of compliance with environmental regulations.

Based on the findings of that study, it should then implement a program to bring its generators and T&D system to the level of efficiency that is optimal on a present value of life cycle societal cost basis within a reasonable period of time. These studies and action plans should be reviewed and updated at reasonable intervals and could form the basis for Commission goals in these areas. Finally, each utility should implement a program, as part of its IRP, to maintain generation and T&D efficiency improvements on an ongoing basis. As many of the subject facilities would affect more than one utility, close cooperation among them should be required for these studies.

To give some sense of the range of options, I will list some of the T&D system efficiency measures that are likely to offer benefits as a result of circuit-by-circuit and system-as-a-whole potential study. At a minimum, evaluations should assess the economics and technical feasibility of the following measures:

- Strategic placement and control of reactive power devices;
- Distribution circuit reconfiguration;
- Installation of distribution automation to control reactive power, feeder configuration, phase balancing, and peak loads;
- Re-conducting lines to larger-sized conductors;
- Replacement of conventional silicon steel core transformers with high efficiency silicon steel transformers or amorphous metal core transformers;
- Conservation voltage regulation;
- Increasing distribution system voltage levels;
- Implementation of a distribution transformer load management (DTLM) program
- Implementation of T&D Equipment Selection and Utilization Standards based on life-cycle cost analysis to ensure that all transformer and capacitor selection and purchase decisions fully reflect the TRC of projected capacity and energy losses

over the equipment lifetime with due regard for expected loadings and duty cycles and a program to inventory transformers in use and on hand to match transformer loss characteristics with customer load factors, as well as an ongoing system to monitor and adjust transformer loading for optimal economic benefit.

<u>ISSUE 11 (Second mention)</u>: In addition to the MW and GWh goals established in Issues 7 and 8, should the Commission establish separate goals for residential and commercial/industrial customer participation in utility energy audit programs for the period 2010-2019?

Q. What is your recommendation regarding this issue?

A. This question suggests the Commission might consider adoption of certain goals that address what would typically be considered an output measurement, not a measurement of results. In the field of program evaluation, several kinds of program evaluation are identified. These types of evaluation include process, input (resource usage), output (service delivery), result (outcome), and cost-effectiveness evaluation. Each has its place in a sound evaluation process. Each has an important place in sound monitoring, verification and evaluation (MV&E) of utility efficiency programs; for example, process evaluation can be especially useful during program startup or after program modification, both to ensure that hard-to-reach customer groups are being recruited and served in ways that work for them and to identify promptly any practices and procedures that are not working optimally so that they may be corrected quickly.

Normally, I recommend that regulators set binding goals mainly for results, with process, output and other types of evaluation provided for management and regulatory review. However, Fla. St. § 366.82(11) specifically calls (1) for the Commission to require that utilities deliver energy audits and (2) for utilities to report “actual results” after each six-month period. That statute also requires consideration of "the difference, if any, between actual and projected results . . . be taken into account in succeeding periods.” To me, as an expert in utility resource planning, this language implies the prior existence of goals for this output measurement (required audits). Given this, I recommend that the Commission set goals for delivery of audits. Since the technologies and human resources required for a useful audit of dwellings differs significantly from those required for auditing commercial facilities, especially large ones, I do recommend that the Commission set goals separately for residential and commercial energy audits.

I also recommend that the Commission bear in mind that for utility energy audits to provide any useful benefit to ratepayers, those audits must result in actual measures being implemented and savings delivered. Going through the motions of doing audits is not enough. Further, the work of recruiting a customer, performing an energy audit for that customer, and providing the customer with recommendations and the education and explanations needed to understand and act on those recommendations is a substantial investment. So, utility energy audits must result in useful recommendations that customers can and will implement. That, in turn, requires that a comprehensive suite of measures, programs and customer incentives that are attractive to customers back up the audits. In addition, an energy audit can maximize benefits to ratepayers, the utility, and society only if it is designed and implemented to be comprehensive, by which I mean that the audit and the supporting programs ensure that all cost-effective measures are identified, , requires follow through from audits must maximize measures are identified, offered and encouraged, without any arbitrary restrictions. One example of such an arbitrary restriction is a limitation on the number of instances of a given measure (e.g., CFLs) may be offered. Another is loading the field screening of measures with allocations of A&G, marketing and audit expenses that are already sunk costs.

For those reasons, and since, as I understand it, utility energy audits are now required by Florida law, I recommend that the Commission go beyond simply setting goals for the two customer groups and direct utilities to (1) ensure that audits are designed maximize acceptance of audits and recommendations by each customer group, including hard-to-reach customers, (2) provide audit customers with recommendations and the education and explanations that enable them to understand and act on those recommendation, support those audits with a comprehensive suite of measures, programs and customer incentives that are attractive to customers, (4) design and implement audits in a manner that ensures that all cost-effective measures are identified, offered and encouraged, (4) perform program design and field screening without any arbitrary restrictions on the number and type of measures offered, and (5) perform program design and field screening in a manner that does not include in the cost of incremental measures any allocation of A&G, marketing and audit expenses, or other costs that are sunk at the time of delivering the audit recommendations to the customer.

Q. This issue, as posed, does not request recommendations for specific audit delivery goals. Do you have any recommendations for how such goals should be set?

A. Setting such goals is a difficult task for a regulator, but it should be addressed in a thoughtful manner. I recommend that the Commission set goals for the pace of audit delivery that are sufficient to fully utilize any available efficiency program resources—

that is, to keep the "pipeline full" for efficiency service delivery programs. As programs are fielded and resources allocated to them, the pace of audit delivery can be adjusted to suit those programs and resources.

<u>ISSUE 12</u>: Should this docket be closed?

Q. Do you have any advice on this question?

A. I understand this as mainly a legal question, but I do recommend that the Commission keep in mind from the testimony provided by NRDC and SACE certain practical implications that would follow from making that decision.

The bottom line conclusion from the testimony of NRDC's and SACE'S witnesses is that the studies of efficiency and customer-side renewables potential provided by the utilities greatly underestimate the achievable potential. Based on our review of these studies, it is clear that it is possible to achieve at least 1% annual energy efficiency gains after a brief ramp up period. This conclusion is further supported by my experience with other potential studies, none of which indicated less than 10% achievable potential for energy efficiency over ten years. However, because of the lack of transparency in the economic and achievable potential study, it is possible that more aggressive goals could be supported.

Accordingly, the studies are an inadequate basis to set final ten-year goals. These erroneous studies put the Commission in a difficult position. As I understand them, Florida statutes require the Commission to set savings goals for the utilities' energy efficiency and customer-side renewable programs, but the utilities have given the

Commission such inadequate information and process that they cannot form a basis for further action. The phrase “bricks without straw” comes to mind.

Of course, as I understand it, the Commission cannot avoid setting goals this year, so I recommend that the Commission set interim goals of 1% per year for utility energy efficiency savings, as indicated above in response to Staff Issues #8 and #9 (modified for the brief ramp up period I recommend). I also recommend one type of demand-side renewable generation goal in response to Staff Issue #10.

However, I recommend that the Commission adopt those as interim goals and keep this proceeding open (or initiate a new one) for the following purposes: (1) to require the utilities to perform a review of the technical potential study to address issues identified in this proceeding and a report providing a revised technical potential study; (2) to require the utilities to conduct a full, properly documented and fully transparent revisiting of the economic and achievable potential studies to correct the errors and omissions described by NRDC’s and SACE’s witnesses; (3) to receive and provide an opportunity for review those new studies, with Commission funding for independent expert review of the studies; and (4) to set refined permanent goals for energy efficiency savings and demand-side renewable generation.

I am not an expert in Florida’s administrative procedures or its public participation regulations, but I would encourage the Commission to direct these studies and reviews in a manner that provides other stakeholders (not simply my clients) a role in commenting on the study as it proceeds. For example, a number of states use a special master, hearing officer, or other state-appointed official to lead the process of developing the final set of recommendations, rather than relying on the utilities to propose and putting the burden of rebuttal on third parties without access to ratepayer-funded research and litigation resources.

I understand that under my proposed approach, there might be a situation where it would not be appropriate to hold a utility fully accountable for meeting the interim goals due to differences between them and the final goals, but stress that a utility should so be excused *if and only if* the Commission's final goals for it are lower than its interim goals *and* the utility's achievements are consistent with those final goals.

Other Items for Consideration

Q. On the Staff Issues List, Issues #8 and #9 requested proposed goals for both energy consumption and peak load by season. Are those the only goals called for in the FEECA? If not what other goals should the Commission consider adopting?

A. The subdivision of FEECA (Fla. St. § 366.82(2)) that directs the Commission to adopt goals for energy efficiency reads as follows:

> (2) The commission shall adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems, specifically including goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption, to reduce the growth rates of weather-sensitive peak demand, and to encourage development of demand-side renewable energy resources. The commission may allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base.

It is noteworthy that the statute calls for goals designed "reduce and control the growth rates of electric consumption" and "to reduce the growth rates of weather-sensitive peak demand." Clearly, the former calls for setting goals for energy savings measured in terms of GWh per year of consumption. The latter charge requires a bit more thought. It calls for reduction in the growth rates of weather-sensitive peak demand. On its face this means goals for the reduction of the demand attributable to certain specific end uses, such as air conditioning, space heating, swimming pool heating, commercial space conditioning, and certain other commercial end uses, whose usage or performance depend on ambient temperature, humidity, wind speed and so on.[16]

The Commission may wish to set specific goals for reducing the peak load from those weather sensitive end uses or it may prefer to set overall peak demand goals. If the Commission wishes do so *and* adopts my recommendation to hold subsequent proceedings in this docket (see response to Issue 12 below in this testimony), I recommend that it defer setting goals for weather sensitive end uses to that proceeding and direct utilities to identify and add to their revised studies any additional end uses and measures that exist for such end uses.

Q. So, with respect to energy goals and peak demand goals, are both equally important? And how should the Commission address differing levels of achievement by utilities across those goals?

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[16] While I will not go into detail here, it is worth noting that certain aspects of supply-side electricity consumption have a weather-sensitive peak demand. Some examples are in the T&D sector, such as the energy consumed by the fans that cool large transformer and the increase in resistance of wires as the ambient temperature rises. In the generation sector, some parasitic loads at generating stations increase with ambient air temperature, and the overall thermal cycle efficiency of many types of non-renewable generators declines with higher ambient air or water temperatures.

A. Both kinds of goal have important impacts on the public interest, but I recommend the Commission pay the most attention to utility performance against the Commission's energy goals if there is ever a tension between the two kinds of performance. By statute, reducing CO_2 emissions is a policy goal of the State of Florida. For a given fuel mix, CO_2 emissions from the electric industry are primarily driven by the quantity of electric energy produced. Therefore, mitigation of GHG emissions is best addressed through energy goals, rather than demand goals.

Q. You and other NRDC-SACE witness have recommended the Commission require use of the TRC test for screening DSM resources. Do you recommend any adjustments to that test?

A. Yes, I recommend three adjustments to the TRC test.

The first has to do with the inclusion of values for carbon costs in the avoided cost of energy and capacity to be used in design, field screening and evaluation of utility energy efficiency programs and in goal setting. I have recommended specific numeric values for that adjustment elsewhere in this testimony.

Second, I recommend an adder of 10% to the avoided cost of transmission and distribution, reserves and ancillary services within the TRC calculation to represent the non-energy benefits of avoiding those requirements, such as land use impacts. I recommend that the Commission direct that these adjustments be applied in addition to the other quantifiable benefits from DSM, and that they be used when calculating TRC values for specific DSM measures and programs in both program design and field screening, as well as for goal setting, for program evaluation and for evaluating the cost-effectiveness of the overall portfolio of a utility's DSM programs. This is comparable to the way external costs of supply-side resources are recognized, for example, in Vermont.[17]

Third, I recommend that the costs of DSM measures and programs be reduced by 10% prior to being used in the TRC calculation to reflect their lower risk compared to supply-side alternatives. In parallel to my first adjustment, I recommend that the Commission direct that this adjustment be applied as a reduction to the sum of the costs of DSM, and that it be used when calculating TRC values for specific DSM measures and programs in both program design and field screening, as well as for goal setting, for program evaluation and for evaluating the cost-effectiveness of the overall portfolio of a utility's DSM programs.

Q. What is the basis for your recommendation of a 10% reduction to DSM program and measure costs to represent non-energy benefits of DSM in measure and program screening and evaluation?

A. I have discussed the risk avoidance benefits and hedging benefits of utility energy efficiency programs relative to supply-side resources elsewhere in this testimony. Here, I will only discuss one additional perspective on this matter.

DSM programs may not always be 100% successful, but compared to supply-side resources they offer immense risk reduction benefits for ratepayers and utility shareholders, alike. For example, energy efficiency can help reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid

[17] This percentage adder approach to factoring environmental costs into resource evaluation was widely used in the 1990s and usually applied equally to avoided costs of generation and T&D. *See*, for example, Vt. Public Service Board Final Order in Docket 5270, 1990; S. Stoft, J. Eto and S. Kito, *DSM Shareholder Incentives: Current Designs and Economic Theory*, Lawrence Berkely Laboratories, 1995. More recently in the western states, the emphasis for generation externalities has been on pricing carbon emissions, but the percentage adder approach remains valid for non-generation avoided costs that impose external costs on society in areas of land use, habitat intrusion, scenic and tourism effect, and so on.

the costs of unanticipated increases in future fuel prices. As discussed by NRDC-SACE witness Wilson in his prefiled testimony, FPL has claimed in its nuclear plant need determination that fuel diversity is desirable, particularly when it reduces rate sensitivity to fuel costs. Generally, energy efficiency has zero sensitivity to fuel costs making it superior to nuclear generation in that regard.

Energy efficiency can also reduce the risks associated with environmental impacts, by reducing a utility's environmental impacts and helping utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO_2 regulation. Energy efficiency can improve the overall reliability of the electricity system by reducing peak demand at those times when reliability is most at risk and by slowing the rate of growth of electricity peak and energy demands and giving utilities more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply.[18] In addition, energy efficiency can be generally less risky than supply-side alternatives because DSM programs are modular and easily adjustable as circumstances change, plus each measure installed delivers benefits beginning immediately, unlike power plants that deliver no benefits at all unless and until they are completely built; uncertainties in load forecasts, capital costs of new generation, permitting delays and so on are types of planning risk that burden supply-side options but not DSM resources.

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[18] Steven Nadel, Fred Gordon and Chris Neme, *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*: ACEEE 2000, http://www.aceee.org/pubs/u008.htm; Regulatory Assistance Project, *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, prepared for the National Association of Regulatory Utility Commissioners, June 2001.

I consider a 10% downward adjustment to DSM costs a reasonable proxy for the cost of those risks.[19] Ten percent is a commonly use contingency reserve for major construction projects and, so, is a reasonable proxy for at least one of the many risks borne by supply-side resources and not by DSM programs. (Some generation-related projects, such as nuclear decommissioning projects) are planned with contingency factors of 25% or more.)

Q. You have advocated here for several Commission actions, but then recommended that those actions be deferred to a later proceeding in this docket or another. Why is that?

A. Time is of the essence; prompt action is required of all involved—utilities, interveners, Commission—because of looming new generation investments.[20] However, the current recession gives Florida some chance of avoiding the creation of lost opportunities by having new construction/remodeling programs out the door by winter 09. Even though Florida is a leader in the area of building codes utility electric efficiency

[19] There are various ways of treating these risk reduction benefits in resource selection. To minimize the regulatory burden, I have proposed the simplest of those: application of a percentage discount to the cost of DSM. That is the approach utilized in Vermont since 1990. Vt. PSB Final Order in Docket 5270. More complicated methods for addressing this issue are widely used by firms of all kinds in their internal planning. Roschelle, A., Steinhurst, W., Peterson, P., & Biewald, B. (2004). *Long Term Power Contracts: The Art of the Deal*. Public Utilities Fortnightly (August), 56-74. One of those methods is the use of risk-adjusted discount rates. *See,*for example, Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans,* LBNL-58450, available at http://eetd.lbl.gov/EA/EMP. ("Increasingly, analysts are calling attention to the benefits of renewable energy as a hedge against electricity sector risks. In particular, renewable energy may be viewed as a valuable contributor to a generation portfolio due to its ability to mitigate natural gas price risk and the risk of future environmental regulations, most notably the risk of future carbon regulation (see, e.g., Wiser et al. 2005; Bolinger et al. 2005; Wiser et al. 2004; Awerbuch 1993, 2003; Hoff 1997; Cavanagh et al. 1993).") The complex Monte Carlo analyses that form the basis of the Northwest Power and Conservation Council discussed elsewhere in this testimony are another approach to the same problem. These methods have much to recommend them in terms of objectivity and transparency and have been used in Washington, Nevada, California, Idaho and other jurisdictions, but their adoption would require the Commission to first undertake a lengthy proceeding to determine the risk tolerance of ratepayers, which is one reason I have recommended a streamlined approach.

[20] *See,* for example, FPL 2009-2018 *Ten-Year Power Plan Site Plan,* pp. 7 ff.

programs can procure DSM resources well above the levels of efficiency in building codes.

Q. Do you have any other recommendations in regard to energy efficiency programs?

A. Yes, I have two. The first highlights the importance of avoiding the creation of lost opportunities in the course of delivering utility energy efficiency programs and explains some of the standards that the Commission should impose to prevent that outcome. The second relates to provision of energy efficiency services to certain hard-to-reach customer groups and explains some of the standards that the Commission should impose to ensure equitable treatment of those customers and to avoid losing out on the efficiency savings available in their homes and businesses.

Q. Please explain your first additional recommendation.

A. Utility energy efficiency programs, as for any other utility expenditure or investment, should be prudently managed and deliver least cost service. Two important policies are necessary to ensure that outcome.

First, utility energy efficiency programs should be designed and implemented to minimize "lost opportunities." Lost opportunities occur when efficiency measures are not installed when it is most cost-effective to do so (e.g., the construction of a new building or facility, building renovations, and the purchase of new appliances or equipment).

Second, programs should be designed and implemented to minimize "cream skimming." Cream skimming occurs when only the most cost-effective efficiency measures are installed, even though additional, higher-cost measures would be cost effective. Cream skimming can lead to lost opportunities, because revisiting a customer to install the remaining measures may involve prohibitive transaction costs.

While this is not a program design proceeding, I bring this issue to the Commission's attention because of one of the decision rules adopted by FEECA utilities—their omission of measures with participant paybacks of less than two years. The two-year payback criterion for screening measures has the potential to create lost opportunities. Once the overhead has been spent to enroll a customer in an audit or custom measure program or otherwise, deliberately omitting any cost effective measure prevents least cost resource acquisition and is, therefore, imprudent management, as well as contrary to Florida's least cost service policy. Adoption by the utilities of such an arbitrary and self-defeating policy suggests to me that the Commission would be wise to take the precaution of explicitly requiring that utility energy efficiency programs be designed and delivered in a manner that prevents cream skimming or the creation of lost opportunities. I also recommend that the Commission establish goals that are based on potential studies not tainted with such errors and require that utility energy efficiency programs (1) adhere to comprehensive approaches that improve energy efficiency of entire buildings or industrial processes, rather then just address single measures or technologies, and (2) include a full menu of services, including incentives, marketing, training, technical assistance, and education on a number of end use applications (such as lighting, appliances, HVAC systems, and improvements to the building envelope)..

Q. Please explain your second additional recommendation.

A. Equity demands proper treatment of hard-to-reach customers, including those on limited incomes, small businesses, and others. Specifically, the Commission should require that utility energy efficiency programs (or additional, special programs) be designed such customers be designed and implemented so as to ensure that such customers' needs are met in ways the work for them, not the average customer. Comments in the testimony of FEECA utilities in this proceeding indicate a lack of sensitivity to this requirement and lead me to spell out in some detail here the policy on hard to reach customers that I recommend the Commission adopt and require utilities to follow in their energy efficiency programs. The Commission should also establish goals that are based on potential studies not tainted with such errors.

Q. What do you mean by "hard-to-reach" customers?

A. By hard-to-reach customers I mean:

(1) Residential electricity users who rent their residences from persons other than kin (defined in a manner appropriate to Florida law and society), trusts operated by and for the benefit of the users, or the users' legal guardians,

(2) Commercial electricity users who rent their business property from persons other than the users' owners, parent companies, subsidiaries of their parent companies, their own subsidiaries, or trusts operated by and for the benefit of the same;

(3) Residential or commercial electricity users who traditionally fail to engage in energy efficiency or demand response programs because of one or more severe barriers beyond those experienced by average residential or commercial customers in a utility's service area.

By "barrier," I mean any physical or non-physical necessity, obligation, condition, constraint, or requisite that obstructs or impedes electricity user participation in energy efficiency or demand response programs. Barriers may include but are not limited to language, physical or mental disability, educational attainment, utility meter type, economic status, property status, or geography.

Q. Policy do you recommend to the Commission in regard to utility energy efficiency programs for hard-to-reach customers?

A. I recommend that the Commission policy be that utilities are required to address programs for limited-income customers and hard-to-reach customers so as to assure proportionate energy efficiency programs are deployed in these customer groups despite higher barriers to energy efficiency investments. The Commission may wish to allow programs targeted to low-income or hard-to-reach customers to meet lower threshold cost-effectiveness results than other programs or be enhanced in other ways to ensure that those customers are not left out.

Q. Please summarize the key conclusions in your testimony.

A. Certainly. The FEECA utilities' analysis of technical and achievable DSM potential is woefully inadequate and fails to comply with Florida statutes as an expert working in the field of utility resource planning would understand them. The Commission should reject the FEECA utilities' proposed goals and adopt the interim percentage savings I recommend in this testimony. In view of the many flaws in those utility analyses, the Commission should undertake a more reasoned and consistent potential study and economic analysis across the jurisdictional utilities before setting any final goals. The Commission should ensure that the statutory change in cost-benefit test definitions enacted recently is adhered to by the utilities. The Commission should act in its goal setting and oversight of utility energy efficiency programs and expenditures with a clear understanding that the roles of demand-side renewable energy and customer incentives in the goals require discreet and specific analysis.

Among the bases for those conclusions and recommendations are the demonstrated underestimate of the technical potential by at least 8%, illogical and totally improper use of the Participant Cost Test, utility reliance on the RIM test in the face of clear direction from the Legislature to the contrary, and the imposition of arbitrary and pointless restrictions on measures with less than a 2 year payback. For the Commission to take final action on DSM goal setting on such a flimsy foundation would be a huge and possibly irreparable disservice to the people of Florida.

Q. Does that conclude your testimony at this time?

A. Yes.

Load Forecast by Florida Utilities

Note: 2019 values for energy consumption and peak are the corresponding 2018 value incremented by the ratio of the 2018 value to the 2017 value.

FPL

	Forecast of RCI Energy Consumption (GWh)			Forecat of Peak Demand (MW)		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	52,041	44,878	3,584	21,124	20,031	2008/2009
2010	51,427	45,417	3,606	21,147	18,790	2009/2010
2011	51,654	46,620	3,656	21,368	19,120	2010/2011
2012	52,438	48,460	3,690	21,933	19,710	2011/2012
2013	52,639	49,537	3,687	22,249	20,098	2012/2013
2014	52,818	51,273	3,676	23,533	21,154	2013/2014
2015	53,087	52,822	3,662	24,142	21,882	2014/2015
2016	53,614	54,515	3,645	24,772	22,396	2015/2016
2017	54,249	56,233	3,631	25,401	22,912	2016/2017
2018	55,175	58,198	3,622	26,143	23,466	2017/2018
2019	56,117	60,232	3,613	26,907	24,033	2018/2019

Source: Schedule 2.1, 2.2, 3.1, and 3.2

Progress Energy

	Forecast of RCI Energy Consumption			Forecat of Peak Demand		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	19,641	11,811	3,890	10,825	12,108	2008/2009
2010	19,563	11,921	3,930	10,844	12,246	2009/2010
2011	20,023	12,243	4,108	11,008	12,457	2010/2011
2012	20,725	12,535	4,265	11,388	12,895	2011/2012
2013	21,184	12,720	4,565	11,685	13,285	2012/2013
2014	21,523	12,909	4,564	11,728	13,254	2013/2014
2015	21,689	13,037	4,492	11,965	13,553	2014/2015
2016	21,968	13,276	4,271	12,160	13,810	2015/2016
2017	22,478	13,528	4,281	12,383	14,096	2016/2017
2018	23,005	13,788	4,295	12,600	14,372	2017/2018
2019	23,544	14,053	4,309	12,821	14,643	2018/2019

TECO

	Forecast of RCI Energy Consumption			Forecat of Peak Demand		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	9,088	6,711	2,392	4,524	5,037	2008/2009
2010	9,276	6,845	2,401	4,613	5,115	2009/2010
2011	9,508	6,968	2,411	4,635	5,208	2010/2011
2012	9,737	7,124	2,419	4,729	5,234	2011/2012
2013	9,974	7,290	2,428	4,815	5,321	2012/2013
2014	10,225	7,457	2,438	4,904	5,411	2013/2014
2015	10,487	7,629	2,446	5,009	5,519	2014/2015
2016	10,755	7,804	2,457	5,116	5,629	2015/2016
2017	11,040	7,987	2,469	5,151	5,743	2016/2017
2018	11,339	8,159	2,480	5,266	5,785	2017/2018
2019	11,646	8,335	2,491	5,384	5,827	2018/2019

Gulf Power

	Forecast of RCI Energy Consumption			Forecat of Peak Demand		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	5,676	3,962	2,147	2,970	2,759	2008/2009
2010	5,842	4,054	2,183	3,040	2,856	2009/2010
2011	6,063	4,213	2,195	3,132	2,953	2010/2011
2012	6,243	4,336	2,185	3,180	3,036	2011/2012
2013	6,423	4,457	2,172	3,252	3,121	2012/2013
2014	6,579	4,560	2,162	3,320	3,183	2013/2014
2015	6,737	4,663	2,150	3,391	3,242	2014/2015
2016	6,934	4,797	2,137	3,446	3,325	2015/2016
2017	7,161	4,960	2,130	3,536	3,426	2016/2017
2018	7,392	5,125	2,141	3,632	3,505	2017/2018
2019	7,630	5,295	2,152	3,731	3,586	2018/2019

OUC

	Forecast of RCI Energy Consumption			Forecat of Peak Demand		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	2,303	388	3,374	1,232		2008/2009
2010	2,320	399	3,401	1,304	1,238	2009/2010

2011	2,352	403	3,457	1,324	1,254	2010/2011
2012	2,433	409	3,543	1,358	1,285	2011/2012
2013	2,508	417	3,625	1,397	1,321	2012/2013
2014	2,584	425	3,710	1,436	1,360	2013/2014
2015	2,662	434	3,805	1,475	1,399	2014/2015
2016	2,746	440	3,883	1,513	1,438	2015/2016
2017	2,833	446	3,962	1,551	1,476	2016/2017
2018	2,925	452	4,037	1,590	1,514	2017/2018
2019	3,020	458	4,113	1,630	1,553	2018/2019

JEA

	Forecast of RCI Energy Consumption			Forecat of Peak Demand		Winter Season
	Residential	Commercial	Industrial	summer peak	winter peak	
2009	5,486	1,388	5,908	2,917	3,039	2008/2009
2010	5,474	1,385	5,896	2,954	3,022	2009/2010
2011	5,525	1,398	5,951	2,973	3,058	2010/2011
2012	5,581	1,412	6,011	3,047	3,138	2011/2012
2013	5,657	1,431	6,093	3,109	3,122	2012/2013
2014	5,735	1,451	6,177	3,179	3,174	2013/2014
2015	5,834	1,476	6,283	3,244	3,218	2014/2015
2016	5,946	1,504	6,405	3,340	3,287	2015/2016
2017	6,064	1,534	6,531	3,417	3,367	2016/2017
2018	6,194	1,567	6,672	3,498	3,480	2017/2018
2019	6,327	1,601	6,816	3,581	3,597	2018/2019

DSM goal | 1.00% | % increment per year (except ramp-up years as shown as BOLD in table)

Cumulative DSM Goal in % of Annual Sales and Peak

Large utilities	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	0.33%	0.66%	1.66%	2.66%	3.66%	4.66%	5.66%	6.66%	7.66%	8.66%	9.66%
Commercial (GWh)	0.33%	0.66%	1.66%	2.66%	3.66%	4.66%	5.66%	6.66%	7.66%	8.66%	9.66%
Industrial (GWh)	0.33%	0.66%	1.66%	2.66%	3.66%	4.66%	5.66%	6.66%	7.66%	8.66%	9.66%
Total summer peak (MW)	0.33%	0.66%	1.66%	2.66%	3.66%	4.66%	5.66%	6.66%	7.66%	8.66%	9.66%
Total winter peak (MW)	0.33%	0.66%	1.66%	2.66%	3.66%	4.66%	5.66%	6.66%	7.66%	8.66%	9.66%

Small Utilities	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	0.25%	0.50%	0.75%	1.75%	2.75%	3.75%	4.75%	5.75%	6.75%	7.75%	8.75%
Commercial (GWh)	0.25%	0.50%	0.75%	1.75%	2.75%	3.75%	4.75%	5.75%	6.75%	7.75%	8.75%
Industrial (GWh)	0.25%	0.50%	0.75%	1.75%	2.75%	3.75%	4.75%	5.75%	6.75%	7.75%	8.75%
Total summer peak (MW)	0.25%	0.50%	0.75%	1.75%	2.75%	3.75%	4.75%	5.75%	6.75%	7.75%	8.75%
Total winter peak (MW)	0.25%	0.50%	0.75%	1.75%	2.75%	3.75%	4.75%	5.75%	6.75%	7.75%	8.75%

FPL

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	52,041	51,427	51,654	52,438	52,639	52,818	53,087	53,614	54,249	55,175	56,117
Commercial (GWh)	44,878	45,417	46,620	48,460	49,537	51,273	52,822	54,515	56,233	58,198	60,232
Industrial (GWh)	3,584	3,606	3,656	3,690	3,687	3,676	3,662	3,645	3,631	3,622	3,613

Total summer peak (MW)	21,124	21,147	21,368	21,933	22,249	23,533	24,142	24,772	25,401	26,143	26,907
Total winter peak (MW)	20,031	18,790	19,120	19,710	20,098	21,154	21,882	22,396	22,912	23,466	24,033

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	172	339	857	1,395	1,927	2,461	3,005	3,571	4,155	4,778	5,421
Commercial (GWh)	148	300	774	1,289	1,813	2,389	2,990	3,631	4,307	5,040	5,818
Industrial (GWh)	12	24	61	98	135	171	207	243	278	314	349
Total summer peak (MW)	70	140	355	583	814	1,097	1,366	1,650	1,946	2,264	2,634
Total winter peak (MW)	66	124	317	524	736	986	1,239	1,492	1,755	2,032	2,353

Progress Energy

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	19,641	19,563	20,023	20,725	21,184	21,523	21,689	21,968	22,478	23,005	23,544
Commercial (GWh)	11,811	11,921	12,243	12,535	12,720	12,909	13,037	13,276	13,528	13,788	14,053
Industrial (GWh)	3,890	3,930	4,108	4,265	4,565	4,564	4,492	4,271	4,281	4,295	4,309
Total summer peak (MW)	10,825	10,844	11,008	11,388	11,685	11,728	11,965	12,160	12,383	12,600	14,372
Total winter peak (MW)	12,108	12,246	12,457	12,895	13,285	13,254	13,553	13,810	14,096	14,372	14,643

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	65	129	332	551	775	1,003	1,228	1,463	1,722	1,992	2,274

Commercial (GWh)	39	79	203	333	466	602	738	884	1,036	1,194	1,358
Industrial (GWh)	13	26	68	113	167	213	254	284	328	372	416
Total summer peak (MW)	36	72	183	303	428	547	677	810	949	1,091	1,255
Total winter peak (MW)	40	81	207	343	486	618	767	920	1,080	1,245	1,415

TECO

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	9,088	9,276	9,508	9,737	9,974	10,225	10,487	10,755	11,040	11,339	11,646
Commercial (GWh)	6,711	6,845	6,968	7,124	7,290	7,457	7,629	7,804	7,987	8,159	8,335
Industrial (GWh)	2,392	2,401	2,411	2,419	2,428	2,438	2,446	2,457	2,469	2,480	2,491
Total summer peak (MW)	4,524	4,613	4,635	4,729	4,815	4,904	5,009	5,116	5,151	5,266	5,384
Total winter peak (MW)	5,037	5,115	5,208	5,234	5,321	5,411	5,519	5,629	5,743	5,785	5,827

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	30	61	158	259	365	476	594	716	846	982	1,125
Commercial (GWh)	22	45	116	189	267	347	432	520	612	707	805
Industrial (GWh)	8	16	40	64	89	114	138	164	189	215	241
Total summer peak (MW)	15	30	77	126	176	229	284	341	395	456	520
Total winter peak (MW)	17	34	86	139	195	252	312	375	440	501	563

Gulf Power

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	5,676	5,842	6,063	6,243	6,423	6,579	6,737	6,934	7,161	7,392	7,630
Commercial (GWh)	3,962	4,054	4,213	4,336	4,457	4,560	4,663	4,797	4,960	5,125	5,295
Industrial (GWh)	2,147	2,183	2,195	2,185	2,172	2,162	2,150	2,137	2,130	2,141	2,152
Total summer peak (MW)	2,970	3,040	3,132	3,180	3,252	3,320	3,391	3,446	3,536	3,632	3,731
Total winter peak (MW)	2,759	2,856	2,953	3,036	3,121	3,183	3,242	3,325	3,426	3,505	3,586

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	19	39	101	166	235	307	381	462	549	640	737
Commercial (GWh)	13	27	70	115	163	212	264	319	380	444	511
Industrial (GWh)	7	14	36	58	79	101	122	142	163	185	208
Total summer peak (MW)	10	20	52	85	119	155	192	230	271	315	360
Total winter peak (MW)	9	19	49	81	114	148	183	221	262	304	346

OUC

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019

Residential (GWh)	2,303	2,320	2,352	2,433	2,508	2,584	2,662	2,746	2,833	2,925	3,020
Commercial (GWh)	388	399	403	409	417	425	434	440	446	452	458
Industrial (GWh)	3,374	3,401	3,457	3,543	3,625	3,710	3,805	3,883	3,962	4,037	4,113
Total summer peak (MW)	1,232	1,304	1,324	1,358	1,397	1,436	1,475	1,513	1,551	1,590	1,630
Total winter peak (MW)		1,238	1,254	1,285	1,321	1,360	1,399	1,438	1,476	1,514	1,553

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	6	12	18	43	69	97	126	158	191	227	264
Commercial (GWh)	1	2	3	7	11	16	21	25	30	35	40
Industrial (GWh)	8	17	26	62	100	139	181	223	267	313	360
Total summer peak (MW)	3	7	10	24	38	54	70	87	105	123	143
Total winter peak (MW)	0	6	9	22	36	51	66	83	100	117	136

JEA

Load Forecast

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	5,486	5,474	5,525	5,581	5,657	5,735	5,834	5,946	6,064	6,194	6,327
Commercial (GWh)	1,388	1,385	1,398	1,412	1,431	1,451	1,476	1,504	1,534	1,567	1,601
Industrial (GWh)	5,908	5,896	5,951	6,011	6,093	6,177	6,283	6,405	6,531	6,672	6,816
Total summer peak (MW)	2,917	2,954	2,973	3,047	3,109	3,179	3,244	3,340	3,417	3,498	3,581
Total winter peak (MW)	3,039	3,022	3,058	3,138	3,122	3,174	3,218	3,287	3,367	3,480	3,597

Proposed DSM Goal

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential (GWh)	14	27	41	98	156	215	277	342	409	480	554
Commercial (GWh)	3	7	10	25	39	54	70	86	104	121	140
Industrial (GWh)	15	29	45	105	168	232	298	368	441	517	596
Total summer peak (MW)	7	15	22	53	85	119	154	192	231	271	313
Total winter peak (MW)	8	15	23	55	86	119	153	189	227	270	315