BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	DOCKET NO. 130199-EI
In re: Commission review of numeric conservation goals (Duke Energy Florida, Inc.).	DOCKET NO. 130200-EI
In re: Commission review of numeric conservation goals (Tampa Electric Company).	DOCKET NO. 130201-EI
In re: Commission review of numeric conservation goals (Gulf Power Company).	DOCKET NO. 130202-EI
In re: Commission review of numeric conservation goals (JEA).	DOCKET NO. 130203-EM
In re: Commission review of numeric conservation goals (Orlando Utilities Commission).	DOCKET NO. 130204-EM
In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	DOCKET NO. 130205-EI Filed: May 19, 2014

Direct Testimony of Tim Woolf

On Behalf of the Sierra Club

On the Topic of Setting Goals for Increasing the Efficiency of Energy Consumption and Increasing the Development of Demand-Side Renewable Energy Systems

May 19, 2014

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including economic and technical assessments of energy resources; electricity market modeling and assessment; integrated resource planning; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the US Environmental Protection Agency, the US Department of Energy, the US Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over twenty-five professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity, I was responsible for overseeing a considerable expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of DPU's energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; the review of smart grid pilot programs; and the review and approval of long-term contracts for renewable power. I also oversaw a variety of other DPU dockets, including several electric and gas rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the

Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Master's Degree in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a Bachelor of Science Degree in Mechanical Engineering and a Bachelor of Arts Degree in English from Tufts University.

Q. Please describe your professional experience as it relates to energy efficiency policies and programs.

A. Energy efficiency policies and programs have been at the core of my professional career. While at the Massachusetts DPU, I played a leading role in updating the Department's energy efficiency guidelines, in reviewing and approving the 2010-2012 three-year energy efficiency plans, in reviewing and approving energy efficiency annual reports, in leading a working group on rate and bill impacts, and advocating for the New England wholesale electricity market to include energy efficiency. I also co-chaired the Working Group on Utility Motivation as part of the State Energy Efficiency Action Network sponsored by the US Department of Energy and the US Environmental Protection Agency.

As a consultant, my work has encompassed all aspects of energy efficiency program design and implementation, including cost-benefit analyses, avoided costs, program budgeting, program assessment, utility financial incentives and other relevant regulatory policies. I am currently the lead technical consultant for the National Efficiency Screening Project. In addition, I recently completed three national studies on demand resource cost-effectiveness, including one for the US Department of Energy and the Federal Regulatory Commission. I have reviewed and critiqued utility energy efficiency policies and programs throughout the US, and I have testified on these issues in British Columbia, Colorado, Delaware, Kentucky, Massachusetts, Minnesota, Nevada, Nova Scotia, Québec, and Rhode Island. I have also represented clients on several energy efficiency collaboratives, where policies and programs were discussed and negotiated among a variety of stakeholders. I work for a variety of clients on energy efficiency

issues, including consumer advocates, environmental advocates, regulatory commissions and the US Department of Energy.

Q. On whose behalf are you testifying in this case?

A. I am testifying on Sierra Club's behalf.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the goals of the electric utilities that are subject to the Florida Energy Efficiency and Conservation Act (the Utilities). I focus on Florida Power & Light Company (FPL) and Duke Energy Florida, Inc. (DEF), because they serve such a large portion of Florida's electricity demand. However, many of my findings and recommendations can and should be applied to all of the Utilities.

Also, much of my testimony addresses the Utilities' energy efficiency and load management programs. I also address demand-side renewable resources, primarily in Section 7. Throughout my testimony, I refer to the energy efficiency and load management programs as demand-side management (DSM), and I refer to the customer-sited renewable resources as demand-side renewables. I do not address supply-side efficiency goals.

Q. Have you previously testified before this Commission?

A. No.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

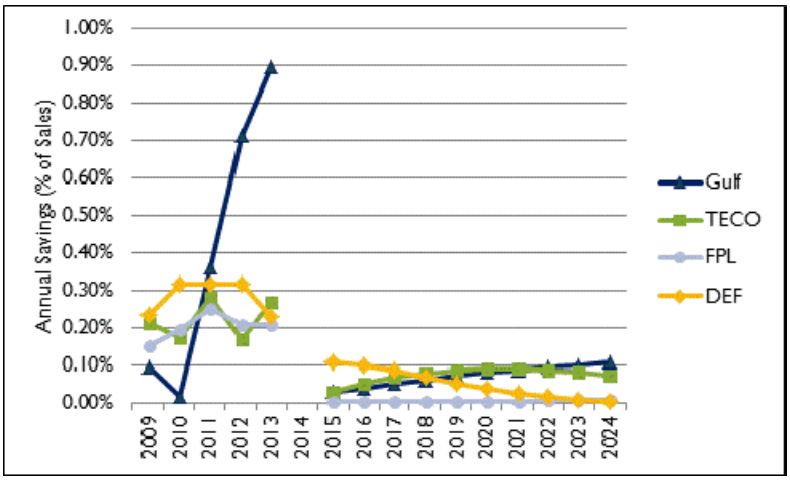
Q. Please summarize your primary conclusions.

A. My primary conclusions are summarized below. Additional details and citations are provided in the main body of my testimony.

<u>The Utilities DSM Goals Are Extremely Low</u>

By any measure the Utilities' proposed DSM goals are extremely low. Figure 2.1 compares the DSM goals proposed by FPL, DEF, Tampa Electric Company (TECO) and Gulf Power Company (Gulf) to these utilities' DSM savings in recent years.

Figure 2.1 Historic Savings and Proposed Energy Goals



As Figure 2.1 shows, the proposed goals depart dramatically from past DSM savings levels. For example, FPL achieved 214 GWh savings in 2013, but proposes to save 2.4 GWh in 2015. In other words, *FPL's proposed goals are one hundred times less than what FPL achieved in 2013*—a drop that my analysis below shows is entirely unwarranted.

The Utilities' historic DSM savings are well below industry practices in most other states. In 2011 over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, several states saved over 1.0 percent of retail sales. If the Commission were to accept FPL's proposed DSM goals, then FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country.

Figure 2.1 also shows that these four utilities propose very different DSM goals over the relevant ten-year period, from 2015 to 2024: DEF's goals, like FPL's, decline to almost nothing, while Gulf and TECO's goals increase modestly. This raises the question of why DEF would have such a dramatic decline in its goals, while other utilities are able to increase their goals over the same period.

These proposed DSM goals are not low because the DSM opportunities are not available or are not cost-effective—as the Utilities claims. The proposed goals are also not low because the Utilities have already achieved most of the DSM potential that is available,

or that new building codes and appliance standards are going to eliminate DSM opportunities—as the Utilities claim.

These goals are extremely low because the Utilities have skewed the analysis by applying overly narrow definitions of cost-effectiveness, thereby significantly understating the value of DSM programs—the lowest-cost, lowest-risk resource. In addition, the Utilities' resource planning processes[1] contain fundamental flaws, leading to results that are not credible, that understate the value of DSM, and ultimately do not provide the Commission with the information necessary to set goals pursuant to FEECA.

The Utilities' DSM Screening Practices Understate the Value of DSM

The Utilities try to define cost-effectiveness in ways that understate the value of DSM. As a result, the Utilities' DSM screening practices are incorrect, misleading, and should not be used for the purpose of setting DSM goals. In particular:

- The Utilities' definition of cost-effectiveness does not take into consideration "the costs and benefits to the general body of ratepayers as a whole," as required by Section 366.82(3), Florida Statutes (F.S.).
- The Utilities ultimately only apply one DSM screening test—the Rate Impact Measure (RIM) test. Despite references to other tests, the Utilities use the RIM test as the sole criterion for proposing DSM goals. The RIM test should not be used to determine DSM cost-effectiveness. It has been rejected by essentially every state except Florida. There are better ways to address the important issue of DSM rate impacts.
- The Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, the Utilities significantly overstate their estimates of lost revenues—the key additional cost included in the RIM test.

[1] I use the terms resource planning processes and resource planning practices interchangeably to mean the Utilities' analytic methodology for resource planning.

- The Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by Section 366.82(3)(d). The Utilities also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

The Utilities' Resource Planning Practices are Fundamentally Flawed

In my 30 years of experience in reviewing and regulating DSM plans and integrated resource plans, I have never seen such opaque, convoluted, and misguided resource screening practices. In particular, the Utilities' attempt to incorporate DSM into their resource planning suffers from the following flaws:

- The Utilities' technical potential estimates significantly understate the full technical potential for DSM in Florida by ignoring several efficiency technologies, and by applying an overly-stringent free-rider screen.

- FPL and DEF undervalue DSM by conducting two economic screens. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and "optimized" with supply-side resources.

- FPL's resource planning understates DSM capacity (i.e., MW) benefits by freezing in place several new generation options, including new combustion turbines and the Turkey Point Units 6 and 7. Thus, FPL ignores the potential for DSM measures to postpone, reduce or avoid these expensive new capacity requirements, and fails to account for key benefits of DSM.

- FPL's resource planning understates DSM energy (i.e., MWh) benefits by assuming that DSM measures can only be installed for meeting reliability needs. This simplistic assumption dramatically understates another key benefit of DSM.

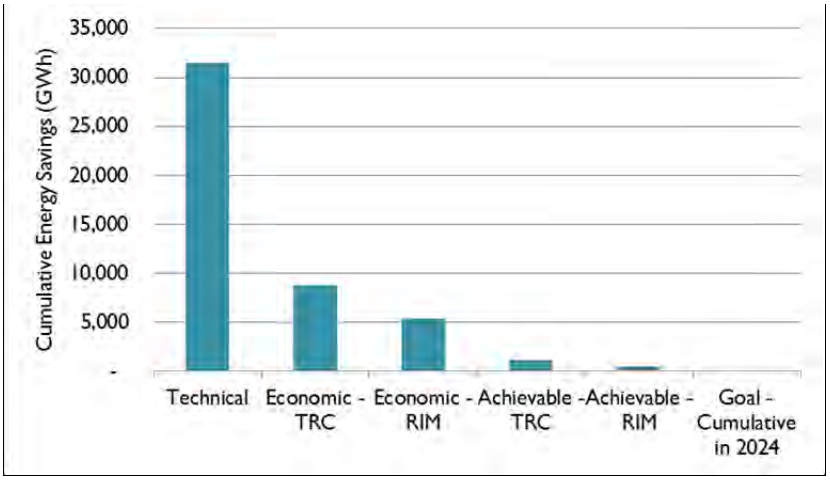
- The Utilities' resource planning is unnecessarily complex and opaque. FPL claims that its complicated process is necessary to understand the economic impacts of DSM, but in fact FPL's process obscures and understates DSM benefits.

Consequently, the output of the process provides no meaningful information regarding the real value and implications of DSM.

The practices listed above conflict with the standard industry resource planning practices.[2] So much so that the results of the Utilities' aberrant practices are not credible and the Commission should not use them to set goals here.

Figure 2.2 shows the results of FPL's technical, economic and achievable estimates, demonstrating how a dramatic reduction in DSM potential occurs at each step. At the final step, due to FPL's incorrect practice of considering DSM only when it is needed to meet reliability needs (in MW), FPL eliminates nearly all potential DSM from its proposed goals—this is not a credible result.

Figure 2.2 FPL Efficiency Savings at Various Screening Levels (GWh)



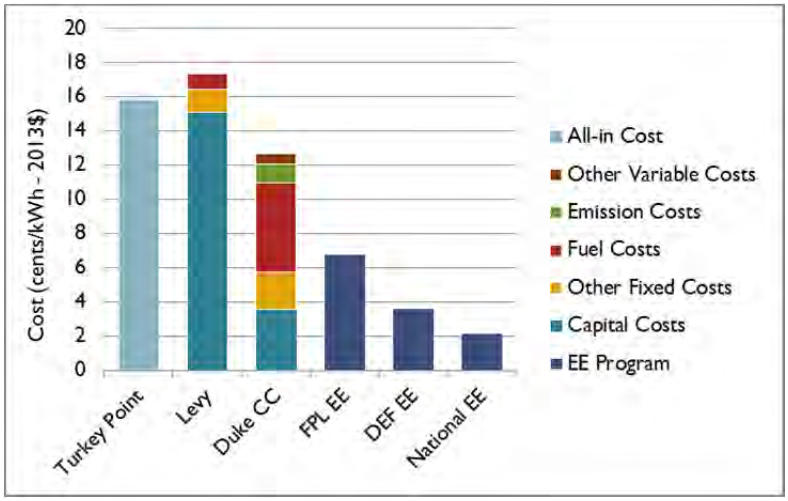
DSM costs significantly less than supply-side alternatives. Therefore, DSM can significantly reduce utility system costs and customer bills, a key fact that risks being obscured by the Utilities' incorrect analysis.

Figure 2.3 compares the levelized cost of saved energy from DSM to the levelized costs of the proposed Turkey Point and Levy nuclear facilities, and the estimated costs of the

[2] See, e.g., Synapse Energy Economics, *Best Practices in Electric Utility Integrate Resource Planning*, prepared for the Regulatory Assistance Project, 2013.

combined-cycle gas facility used by DEF in its resource planning process.[3] DSM is the clear winner, costing significantly less than alternative resources, contrary to what the Utilities try to argue by citing their flawed resource planning processes. Moreover, DSM helps mitigate the significant risks associated with these, more expensive supply-side resources.[4]

Figure 2.3 Cost of Generation Technologies versus the Cost of Saved Energy



Higher DSM Goals Would Lead to a Better Balancing of Costs and Rates

One of the key objectives in setting DSM goals is to strike the proper balance between reduced costs and the potential for increased rates. Striking this balance requires a much better assessment of rate impacts than the RIM test provides (even when correctly applied). It requires a reasonable assessment of (a) the potential rate impacts of the DSM proposed goals; (b) the potential for reducing customer costs and customer bills; and (c) the customer participation rates in the DSM programs. My analysis shows that:

- The rate impacts of the Utilities' proposed DSM goals will be so low as to be unnoticeable, and higher DSM goals would lead to very small rate impacts, if any.

[3] Levelized costs are the constant unit cost (in $/MWh) that, if incurred over a pre-determined period would have the same net present value as the stream of annual costs incurred over the same period.

[4] Ceres, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, prepared by Ron Binz, Rich Sedano, Denise Furey, Dan Mullen, April 2012.

- Higher DSM goals would result in reduced costs, and therefore reduced bills.
- Higher DSM goals would result in greater DSM program participation, further offsetting any increase in rates that might occur as a result of DSM programs.

The Utilities Understate the Potential Value of Demand-Side Renewables

The Utilities significantly understate the potential value of demand-side renewable resources by not accounting for recent and anticipated cost trends in the PV industry; overstating customers' ability and interest in installing PV systems without utility support; and by omitting the avoided cost of GHG emissions.

Q. Please summarize your primary recommendations.

A. My primary recommendations are summarized below. Additional details are provided in the main body of my testimony.

DSM Goals. The Commission should set DSM goals[5] for the Utilities as follows:

- Energy (GWh) Savings. Each Utility should be required to achieve annual efficiency savings equal to one percent of retail sales by 2019.
- Capacity (MW) savings. Each utility should be required to achieve capacity savings such that the ratio of capacity-to-energy savings is consistent with the ratios that were achieved by the Companies in recent years. This will maintain the current balance between energy and capacity savings of the DSM programs.[6]

Demand-Side Renewables. The Commission should require the Utilities to continue to provide PV programs to their customers, with some modifications to the current programs as outlined below. The Commission should open a separate docket to investigate appropriate goals for customer-sited renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar photovoltaic (PV) systems.

[5] These goals do not include savings from demand-side renewable resources.

[6] This recommendation is not meant to suggest that the current balance between capacity and energy savings is ideal. It is merely meant to prevent the balance from becoming any worse.

Regulatory Support. The Commission should open a generic docket to investigate opportunities to establish a revenue decoupling mechanism to help remove the Utilities' financial disincentive to advance DSM. That docket should also investigate opportunities to establish shareholder performance incentives to help provide positive financial incentives for the Utilities to implement successful DSM programs.

Future DSM Screening. For future DSM planning and goal-setting purposes, the Commission should: (a) clarify that the RIM test should not be used for screening DSM programs; (b) clarify that a proper application of the TRC test should include the customer incentive provided by a utility, and participant non-energy benefits; (c) require reasonable estimates of GHG compliance costs be used in the base case analysis; and (d) present the results of the Utility Cost test for consideration by the Commission.

Future Resource Planning. For future DSM planning and goal-setting purposes, the Commission should require the Utilities to conduct resource planning processes that provide meaningful information for the purpose of setting DSM goals. In particular, the resource planning process should: (a) comport with standard industry resource planning practices; (b) be transparent with regard to decision-making processes, the results and interpretation of the results; (c) use the present value of revenue requirements as the primary criterion for selecting among different resource plans; (d) analyze numerous plans to optimize the combination of demand-side and supply-side resources; and (e) use reasonable estimates of free-rider impacts from measurement and verification studies, and not the overly simplistic payback criterion.

3. DEMAND-SIDE MANAGEMENT COST-EFFECTIVENESS TESTS

Q. Why is cost-effectiveness so important in setting goals DSM goals?

A. DSM is by far the lowest-cost resource available to meet customer needs. Efficiency resources reduce electric system costs and thereby reduce average customer bills. These cost- and bill-impacts are precisely what an economic regulator like the Commission oversees with the help of cost-effectiveness tests. When applied correctly, the tests can substantiate whether a particular resource or portfolio of resources is cost-effective.

DSM goal-setting is no exception. Notably, at least once every five years, FEECA requires the Commission to avail itself of the best available information regarding the cost-effectiveness of potential DSM, demand response, and demand-side renewable energy resources to set DSM goals. *See* Sections 366.81, 366.82(3)(a)-(d), (5)(b), F.S. Moreover, each year, the Utilities are required to provide the Commission with evidence of "lowest cost possible" planned energy, including the resources covered by DSM goals. *See* Rule 25-22.072, F.A.C. (incorporating by reference Form PSC/RAD 43-E (11/97)).

In setting DSM goals, the Commission must not lose sight of the fact that DSM can significantly reduce utility and customer costs. If DSM cost-effectiveness analyses are not properly defined or conducted, then the Utilities may implement an inappropriate amount of DSM, and their customers will pay more—potentially a lot more—than necessary for electricity services.

Q. Have the Utilities properly evaluated the cost-effectiveness of DSM in setting their DSM goals?

A. No. The Utilities' proposed DSM goals are way too low because the Utilities' cost-effectiveness screening is fundamentally flawed in ways that significantly understate the cost-effectiveness of DSM programs.

Q. Please describe how the remainder of this section is organized.

A. Since the DSM cost-effectiveness tests are so important to setting DSM goals, I dedicate a large portion of my testimony to them. First, I describe a national effort that provides useful guidance on the very issues of cost-effectiveness in these dockets. Second, I describe how cost-effectiveness is defined in Florida based on FEECA and the Commission's implementing regulations and orders. Third, I discuss my concerns with the way that the Utilities have defined and used cost-effectiveness tests for setting their DSM goals. Finally, I discuss several important benefits that the Utilities have omitted from their screening tests, particularly greenhouse gas (GHG) regulatory compliance costs and non-energy benefits associated with DSM programs.

The National Efficiency Screening Project

Q. What is the National Efficiency Screening Project?

A. The National Efficiency Screening Project (NESP) was recently formed to provide guidance on ways to improve efficiency screening practices. The NESP Team published a set of principles and recommendations for how states should reconsider and potentially modify their efficiency screening practices.[7] One of NESP's key recommendations is that each state should apply a framework—the Resource Value Framework (RVF)—to identify the most appropriate costs and benefits to consider when screening DSM programs. I will describe RVF and its relevance to the Utilities' DSM goals below.

Q. What is the NESP Team?

A. The NESP Team is led by a steering committee who oversees the entire initiative. I am a member of this steering committee, as the lead technical consultant. The NESP Team also includes project advisors, who assist in developing and refining NESP's key principles and recommendations. The project advisors are nationally-recognized energy efficiency experts who help capture perspectives from across the country. Finally, NESP project members, representing many organizations that support the NESP principles and recommendations, advance national and state campaigns to improve energy efficiency screening. The individuals and organizations that comprise the NESP Team are listed in the NESP Recommendations document cited above.

Q. What are the key elements of the Resource Value Framework?

A. The RVF includes several principles that each state should apply when designing its energy efficiency screening test:

- The Public Interest. The ultimate objective of efficiency screening is to determine whether a particular energy efficiency program, or portfolio of programs, is in the public interest.

[7] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening* (March 2014), available at http://www.nhpci.org/projects/costbenefittesting.html.

- Energy Policy Goals. Efficiency screening practices should account for the energy policy goals of each state, as articulated in legislation, commission orders, regulations, guidelines and other policy directives. These policy goals provide guidance as to which efficiency programs are in the public interest.

- Symmetry. Efficiency screening practices should ensure that tests are applied symmetrically, where both relevant costs and relevant benefits are included in the screening analysis. For example, a state that chooses to include participant costs in its screening test should also include participant benefits, including non-energy benefits, otherwise the test will be skewed against energy efficiency resources.

- Hard-to-Quantify Benefits. Efficiency screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify and monetize. Several methods are available to approximate the magnitude of relevant benefits, as described below.

- Transparency. Efficiency program administrators should use a standard template to explicitly identify their state's energy policy goals and to document their assumptions and methodologies.

- Applicability to all resources. In general, these principles should be applied to all types of electric and gas utility resources; both demand-side and supply-side resources.

Q. Does the NESP Recommendations document provide any guidance on how the standard screening tests should be defined?

A. Yes. While all states use one or more of the standard "tests" described in the California Standard Practice Manual as the foundation for their own efficiency screening practices, states differ in their definitions of these tests. Figure 3.1 presents the definitions of the standard screening tests, based on the most recent literature on this topic and the NESP recommendations. I will return to Figure 3.1 when I discuss the Utilities' definitions of cost-effectiveness below.

Figure 3.1. Components of the Standard Cost-Effectiveness Tests

	Participant Test	RIM Test	Utility Test	TRC Test	Societal Test
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Avoided Energy Costs	---	Yes	Yes	Yes	Yes
Avoided Capacity Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (utility perspective)	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (participant perspective)	Yes	---	---	Yes	Yes
Non-Energy Benefits (societal perspective)	---	---	---	---	Yes
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Lost Revenues Associated with Fixed Costs	---	Yes	---	---	---

Q. Is the Resource Value Framework a new screening test for states to consider?

A. No. It is a framework—a set of principles and recommendations—that provides guidance for each state in designing and implementing its energy efficiency screening process. The Resource Value Framework is designed to provide each state with flexibility to ensure that its screening practices meet its own needs and interests.

One of the key concepts in the RVF is that states do not need to be confined to the strict definition of the standard screening tests described in the California Standard Practice Manual. The RVF includes the key principles that each state should incorporate into its efficiency screening practices to ensure consistency between its energy efficiency programs and energy policy goals. In other words, each state's screening test should be based on its own legislation, regulations and commission orders. While this may seem like an obvious recommendation, some states apply efficiency screening tests that are not consistent with their own regulatory standards and energy policy goals. In fact, this is one

of the fundamental problems with the Utilities' DSM screening practices—they conflict with FEECA standards and policy goals.

Q. Does the NESP Recommendations document provide any guidance on efficiency screening tests that should not be used?

A. Yes, the NESP Recommendations document clearly recommends against the RIM test's use for screening energy efficiency programs, for reasons that I will describe below. Instead, states should use other analyses, and apply other considerations to address concerns about rate impacts from energy efficiency programs. Florida is no exception.

Q. Based on your work with the National Efficiency Screening Project, what lessons does it offer to Florida?

A. Contrary to perhaps the most fundamental NESP recommendation, the Utilities try to define cost-effectiveness and conduct resource screening in ways that conflict with FEECA and the related Commission regulations and decision-making precedents.

Another key NESP recommendation is that the RIM test should not be used for screening DSM measures. Contrary to this recommendation, the Utilities rely almost entirely on the RIM test in their definitions of cost-effectiveness, and in their resource planning process.

Another key NESP recommendation is that a utility's DSM screening assumptions, methodologies and practices should be transparent, so that regulators and other stakeholders can draw meaningful conclusions from them. The Utilities resource planning process is anything but transparent; it is convoluted, overly-complex, not well explained, and lacking in the information that the Commission ultimately needs to set DSM goals. To make matters worse, the Utilities present the results of their resource planning analyses in ways that are unnecessarily confusing and even misleading.

In sum, the Utilities' DSM screening practices are out of synch with standard industry practices, and do not even come close to meeting evolving industry "best practices." I elaborate on all of these points below.

The Definition of Cost-Effectiveness in Florida

Q. How is DSM cost-effectiveness defined in FEECA?

A. The Florida Energy Efficiency and Conservation Act focuses on cost-effectiveness, starting with the very first sentence in the Act, which states: "[t]he Legislature finds and declares that it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. This language is especially important in this goal-setting docket, not only because it requires that demand-side conservation systems (i.e., DSM programs) be cost-effective, but also because it places the concept of cost-effectiveness in the context of protecting the health, prosperity and general welfare of the state and its citizens.

FEECA provides further guidance on how to assess cost-effectiveness. Section 366.82(3), F.S., states that in developing DSM goals the Commission shall take into consideration:

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 DSM and demand-side renewable energy systems.

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

Q. How is DSM cost-effectiveness defined in the Commission's regulations?

A. Rule 25-17.008, F.A.C., sets out in detail the methodologies and tests for estimating efficiency program cost-effectiveness. In particular, the Rule identifies the minimum filing requirements for utilities reporting cost-effectiveness data, and the Rule refers to the Commission's Cost-Effectiveness Manual.[8] That Manual requires that cost-effectiveness analyses be conducted using three tests: the Participants test, the RIM test, and the Total Resource Cost (TRC) test.

[8] Florida Public Service Commission, *Cost-Effectiveness Manual For Demand-Side Management Programs and Self-Service Wheeling Proposals,* July 17, 1991.

In its FEECA Annual Report, the Commission provides the following definitions of these DSM cost-effectiveness tests:

- Participants test. The Participants test analyzes costs and benefits from a program participant's point of view and ignores the impact on the utility and other ratepayers not participating in the program. The costs customers pay for equipment and maintenance are considered under the Participants test. Benefits considered in the test include incentives that are paid by the utility to the customers and a reduction in customer bills.

- RIM test. The RIM test includes the costs associated with incentive payments to participants and decreased revenues to the utility which typically must be recovered from the general body of ratepayers at the time of a rate case. In particular, the RIM test is designed to ensure that all ratepayers, not just the program's participants, will benefit from a proposed DSM program. A DSM program that passes the RIM test ensures that all customer rates are lower than they otherwise would have been without the DSM program.

- TRC test. The TRC test measures the overall economic efficiency of a DSM program from a social perspective. This test measures the net costs of a DSM program based on its total costs, including both the participant's and the utility's costs. Unlike the RIM test, customer incentives and decreased revenues are not included as costs in the TRC test; instead, these factors are treated as transfer payments among ratepayers. Moreover, certain external costs and benefits such as environmental impacts are appropriate for inclusion under the TRC test.

FPSC, *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act*, (Feb. 2014), at 15, *available at* http://www.psc.state.fl.us/publications/pdf/electricgas/FEECA2014.pdf ("2014 FEECA Report").

Q. How did the Commission address DSM cost-effectiveness in the last DSM goal-setting case?

A. The Commission found that the TRC test (or, the e-TRC test) should be used to set DSM goals, and that consideration should be given to the impacts—especially the rate impacts—of efficiency programs on non-participants. In particular, the Commission found that:

> . . . consideration of both the RIM and TRC tests is necessary to fulfill the requirements of Section 366.82(3)(b), F.S. Both RIM and TRC tests address costs and benefits beyond those associated solely with the program participant. By having RIM and TRC results, we can evaluate the most cost-effective way to balance the goals of deferring capacity and capturing energy savings while minimizing rate impacts to all customers.

Order No. PSC-09-0855-FOF-EG, at 15. The utilities proposed DSM goals that were based on the E-RIM test, which is an enhanced version of the RIM test including avoided carbon compliance costs. The Commission rejected this approach and approved DSM goals based upon the unconstrained E-TRC test, which is an enhanced version of the TRC test including avoided carbon compliance costs. *Id*.

With regard to rate impact considerations, the Commission found that:

> Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in the monthly utility bill. Since participation in DSM programs is voluntary and this Commission is unable to control the amount of electricity each household consumes, we should ensure the lowest possible overall rates to meet the needs of all customers.

Id. at 26.

Q. How has the Commission addressed DSM cost-effectiveness issues in more recent orders?

A. After the Commission set the 2009 DSM goals, the Utilities' filed DSM Plans that described their proposals to meet those goals. The Commission approved the proposed DSM Plans of TECO, JEA, Orlando Utilities Commission (OUC) and Florida Public

Utilities Company (FPUC) in 2010, and the proposed DSM Plan of Gulf in 2011. *See* 2014 FEECA Report, at 17-18 (citing relevant orders).

However, the Commission modified the proposed DSM Plans proposed by FPL and DEF. The Commission found that their proposed DSM Plans would result in an increase to the average residential customer's monthly bill that would "constitute an undue rate impact on customers." Order No. PSC-11-0346-PAA-EG, at p. 4 (FPL); Order No. PSC-11-0347-PAA-EG, at 5, 6 (DEF, then Progress Energy Florida, Inc.). Consequently, the Commission directed FPL and DEF to modify their DSM plans to continue their existing programs, finding that the rate impacts of those programs were "relatively minor." Order No. PSC-11-0346-PAA-EG, at 5; Order No. PSC-11-0347-PAA-EG, at 7.

The Utilities' Definition of Cost-Effectiveness

Q. How have the Utilities defined cost-effectiveness?

A. FPL uses four tests in its preliminary screening of DSM: the Participants test; the preliminary RIM test, the preliminary TRC test; and the "years-to-payback test, using a two-year criterion. Direct Testimony of Witness Sim, Document No. 01476-14, at 23. DEF uses the Participant, TRC, and the RIM tests in its preliminary screening of DSM. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 27.

However, both FPL and DEF ultimately use the RIM test in determining their DSM goals.

Q. Please summarize your concerns with the Utilities' definitions of cost-effectiveness.

A. I summarize several concerns here, and address each of them in more detail in the following subsections.

First and foremost, the Utilities' definitions are not in compliance with either the overall intent of FEECA or the specific requirements of FEECA. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. The Utilities' cost-effectiveness analyses do not meet this overall goal. FEECA also requires that in establishing the DSM goals, the

Commission should take into consideration "the costs and benefits to customers participating in the measure" and "the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions." Section 366.82(3), F.S. Again, the Utilities definition of cost-effectiveness does not comply with this requirement.

Second, the Utilities ultimately only rely on one test to propose goals: the RIM test. Despite the appearance of modeling and analyzing several different tests, they use the RIM test as the sole criterion for making the final decision in setting DSM goals. The RIM Test should never be used to determine DSM cost-effectiveness; there are better ways to address the important issue of DSM rate impacts.

Third, the Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, their estimates of lost revenues —the key additional cost included in the RIM test—are significantly overstated. Furthermore, the Utilities present the results of the RIM Test in misleading ways, dramatically overstating the extent to which customers will experience higher rates.

Fourth, the Utilities misrepresent (or misunderstand) the proper definition of the TRC test, by asserting that this test does not account for the incentive payments that the utility provides to the participating customer. Accordingly, they have incorrectly dismissed the TRC test as not in compliance with FEECA, when in fact it is the one test that is most in compliance with FEECA.

Fifth, the Utilities ignore one of the most useful screening tests available: the Utility Cost test. This test is especially helpful for determining the economic impact on all customers as a whole, and for providing useful information regarding rate and bill impacts.

Sixth, the Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by FEECA in Section 366.82(3)(d), F.S. They also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

Finally, the Utilities apply fundamentally flawed resource planning practices to further analyze the potential role of DSM programs in meeting resource planning needs. This exacerbates and adds to the problems outlined above. I address these problems in more detail in Section 4.

In sum, the Utilities' misuse of DSM cost-effectiveness tests, combined with their flawed efficiency screening process, lead to results that are so defective as to make them meaningless. The Utilities' analyses ultimately obscure the basic fundamental fact that DSM programs offer tremendous benefits to customers because they cost significantly less than supply-side alternatives. I offer some alternative economic analysis in Section 5 to expand upon and clarify this critical point.

The Rate Impact Measure Test Can Lead to Perverse Outcomes

Q. Why do you recommend that the RIM test not be used to evaluate DSM cost-effectiveness?

A. The RIM test should never be used for evaluating DSM cost-effectiveness both on theoretical grounds and for practical reasons. In sum, the logic underlying the RIM test is flawed; it will not result in lowest costs to the utility system or to the utility customer; it can lead to perverse outcomes where significant cost reductions are foregone in order to avoid negligible rate impacts; it is inconsistent with the regulatory treatment of supply-side resources; and (worst of all) it provides no meaningful information for the Utilities or the Commission to use in addressing the key issue of rate and bill impacts.

Q. Why do you say that the underlying logic of the RIM test is flawed?

A. The only difference between the RIM test and the Utility Cost test is the "lost revenues," (i.e., the reduction in the revenues as a result of reduced consumption). If the utility is to be made financially neutral to the impacts of the DSM programs, then the utility should collect that portion of the lost revenues necessary to recover its fixed costs (because fixed costs are not reduced as a result of DSM). If the utility were to recover these lost revenues in rates, then they would result in rate increases.

To understand this issue it is critical to recognize that these lost revenues are the primary reason that long-term rates increase as a result of DSM programs. If it were not for these

lost revenues, then DSM programs would generally cause long-term rates to be *lower than they would be otherwise*, because the benefits of cost-effectiveness DSM outweigh the costs.

It is also critical to recognize that lost revenues are not a "new" cost created by the DSM programs. Lost revenues are simply a result of the need to recover *existing costs spread out over fewer sales*. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important micro-economic principle.

Q. Why do you say that the RIM test will not result in the lowest cost to the utility system or customers?

A. Applying the RIM test to screen efficiency programs will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills on average, should be given priority over minimizing rates. For customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

Q. Why do you say that strict application of the RIM test can lead to perverse outcomes?

A. A strict application of the RIM test can result in the rejection of *significant* reductions in utility system costs to avoid what may be *insignificant* impacts on customers' rates. In fact, this is the outcome of the DEF and FPL reliance on the RIM test to propose DSM goals. As I demonstrate in Section 4, the magnitude of rate impacts that are likely to result from the Utilities' DSM goals are so small as to be unnoticeable, and yet the Utilities use the concept of rate impacts to reject large amounts of DSM measures that

could save customers millions, perhaps billions of dollars. Such a result is clearly not in the best interests of customers overall.

Q. Why do you say that applying the RIM test is inconsistent with the regulatory treatment of supply-side resources?

A. The main goal of the RIM test is to avoid cross-subsidies between customers. In theory, DSM program non-participants may subsidize participants, because the participants may experience reduced bills as a result of reduced electricity consumption, while non-participants may experience increased bills as a result of increased rates. The Utilities claim many times over that they should use their resource planning process to minimize rate impacts, because this will then avoid cross-subsidization. *See, e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 26-28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 7, 15.

While it is important to avoid cross-subsidies where possible, it is also important to recognize that cross-subsidies are endemic to regulated electric utilities. For example:

- When a utility installs a new power plant to meet increasing electricity demands, customers whose electricity demands have not increased in recent years subsidize those customers whose demands have increased.

- When a utility installs a new transmission line to maintain or improve reliability in one part of its service territory, all customers are required to pay for the new transmission line, even though many customers do not experience its benefits.

- When a utility installs distribution systems to serve a newly-developed residential neighborhood or a new industrial park, all customers are required to pay for the new distribution systems, even though many customers do not experience the benefits of them.

- Customers within a rate class that have a high load factor (i.e., high energy consumption relative to peak demand), will subsidize customers in that same rate class with a low load factor, because the cost of power is so much greater during times of peak demand.

Accordingly, DSM should not be held to a standard that cross-subsidization will not be allowed, when that same standard is not applied to supply-side resources. This is especially true given that doing so can lead to perverse outcomes, as described immediately above.

Q. Why do you say that the RIM test provides no meaningful information for addressing the issue of rate and bill impacts?

The RIM test does not provide any information about what actually happens to rates as a result of program implementation. A RIM test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts. What are the implications of DSM plan with a RIM Test benefit-cost ratio of 0.98? How about a benefit-cost ratio of 0.87? How much are customers harmed by these results relative to a positive RIM benefit-cost ratio of 1.2? The RIM Test cannot answer such important questions.

Even worse, the RIM test results can be very misleading. When the RIM test results are put in terms of negative net benefits (the net benefits will be negative for DSM programs that fail the RIM test), it appears as though the DSM programs will be *increasing* costs to customers. However, as described above, the costs that drive the rate impacts under the RIM test are not new, incremental costs associated with the DSM programs. They are *existing costs*, existing fixed costs to be more precise. These are the existing costs that are already in electricity rates. Any rate increase from lost revenues would be a result of recovering those existing fixed costs over fewer sales; not as a result of incurring new costs. In fact, the Utilities present their RIM test results in this misleading way. For example, FPL states that it would have to incur "an additional cost of approximately $296,000,000 in 2015, or of approximately $630,000,000 in 2014" to raise rates enough to cover the TRC 337 MW plan relative to the RIM 337 MW plan. Direct Testimony of Witness SIM, Document No. 01476-14, at 58. This simply is not true. The recovery of

lost revenues does not result in "additional" costs to the utility or to customers. Lost revenues are recovered to help the utility pay for existing fixed costs.

Finally, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and bill impacts of DSM programs. Such information includes the impacts of DSM on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in efficiency programs and thereby experience lower bills.

Q. Are these concerns about the RIM test recognized by other states and other regulatory commissions?

Yes, essentially every state in the country has rejected the use of the RIM test as the primary test to use for determining DSM cost-effectiveness. The Commission should not set efficiency goals based on the outcome of the Utilities' analyses, which are directly in conflict with standard industry practice throughout the US.

Q. So far, you have shown why the RIM test generally should not be used in any state for screening DSM programs. Do you have any particular concerns with the way that the RIM test is calculated and applied by the Utilities in Florida?

A. Yes. The Utilities's methodology significantly overstates the magnitude of the lost revenues, and as a consequence significantly overstates the rate impacts of their DSM proposals. This occurs in two ways.

First, the Utilities use an incorrect methodology for estimating the magnitude of the lost revenues that will impact rates. The Utilities estimate lost revenues on the basis of a projection of total electricity prices. *See, e.g.*, Direct Testimony of Witness Guthrie, Document No. 01497-14, at 38. This is not the correct methodology for estimating lost revenues that will impact rates. The correct methodology is to use a projection of the *fixed components of rates*, not the fixed plus variable components of rates. It is necessary to separate out the portion of rates that represent variable costs, because utilities will be able to reduce variable costs through DSM and therefore will not need to recover any lost revenues associated with those variable costs. The Utilities' assumption that lost revenues should be based on the total electricity rates (fixed and variable components) implies that they will somehow be allowed to increase customer rates for *variable costs that they do*

not incur. That is clearly not how rates are set in Florida, or any state, and should not be the assumption underlying estimates of DSM rate impacts.

Second, the Utilities' methodology for estimating rate impacts is inconsistent with the way that rates are set in Florida. Base rates are only increased at the time of a rate case. Between rate cases, *DSM will not increase rates* because the Utilities' rates will not be adjusted to collect lost revenues of any kind. Eventually with the next rate case, rates will be adjusted based on the most recent sales levels, including savings from DSM up to that point in time. However, the lost revenues that may occur between rate cases are not recovered by the utility, even at the next rate case. For this reason alone, the RIM test results provided by the Utilities are simply wrong—they significantly overstate the extent to which the Florida DSM programs might increase rates.

Each of the two reasons that I just described renders the Utilities' estimates of rate impacts fatally flawed and essentially useless for setting DSM goals. Therefore, I recommend that the Commission completely reject the Utilities' rate impact estimates when setting DSM goals.

Q. Do the Utilities claim that application of the RIM test is consistent with FEECA?

A. Yes. FPL and DEF claim that the Participants test and the RIM test should be used for screening DSM. *See, e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15 ("these two tests capture all of the relevant costs and benefits that should be evaluated when considering an efficiency or load reduction program."). However, the RIM test is much more stringent than the Participants test, and therefore if the two tests are applied together, then the RIM test will be the deciding factor on cost-effectiveness.

Further, FPL proffers that the TRC test "omits the incentive payments made to program participants." *Id*. at 26-27. Based on FPL's misunderstanding that the TRC test omits these incentive payments, FPL essentially rejects the use of the TRC test for screening purposes. Finally, FPL ignores other cost-effectiveness tests that could meet FEECA standards and policy goals.

Q. Do you agree with the Utilities' characterization of these tests?

A. No. The Utilities misinterpret FEECA requirements, and screening test-definitions and implications. Consequently, the Utilities' methodology conflicts with FEECA.

First, the RIM test does not indicate the "cost" impacts on the utility and its customers. As discussed above, it indicates the potential rate impacts on the utility customers (although a not a very useful indication). The distinctive component of the RIM test is the lost revenues, which are not costs associated with DSM. Lost revenues can potentially lead to rate impacts, but they are not cost impacts.

It is important to note that FEECA does not in any way require the minimization of rates as a criterion for setting DSM goals. FEECA is clear about the intent to reduce costs, but does not mention minimization of rates at all.

Second, the Utilities have misinterpreted the definition of the TRC test. FPL and DEF try to argue that the TRC test does not include the incentive payments made to program participants. *See, e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 27; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15-16. In fact, the TRC test does, or should, include these customer incentive payments. The purpose of the TRC test is to include all costs associated with a DSM measure, regardless of who pays them. That is why it is called the "Total Resource Cost" test. Note in Figure 3.1 above, that the customer incentive payment should be included in the TRC test. This is standard industry practice.[9]

In sum, the Utilities rely on a misunderstanding of the definition of the TRC test to reject this test for the purpose of screening DSM measures. However, the TRC test is in fact the best test to indicate the "costs and benefits to the general body of ratepayers as a whole,

[9] It appears as though the Commission is inconsistent on the definition of the TRC test. The 2014 FEECA Report states that the TRC test measures a "DSM program based on its total costs, including both the participant's and the utility's costs." In the next sentence, however, Report states that customer incentives are not included in the TRC test, instead they are treated as "transfer payments" among ratepayers. 2014 FEECA Report, at 15. These two sentences are inconsistent. The first point, about including both the participant's and the utility's costs is the correct definition of the TRC test.

including utility incentives and customer contributions," as required by FEECA. Section 366.82 (3)(b), F.S.

Q. Has the Commission the authority to consider the rate impacts of DSM goals?

A. Yes. Commissions generally have wide discretion to consider many aspects of rates, in many contexts. In previous DSM goal-setting docket, the Commission noted that:

> As specified in Section 366.01, F.S., the regulation of public utilities is declared to be in the public interest. Chapter 366 is to be liberally construed for the protection of the public welfare. Several sections within the Chapter, specifically, Sections 366.03, 366.04, and 366.05, F.S., refer to the powers of the Commission and setting rates that are fair, just and reasonable. The 2008 legislative changes to FEECA did not change our responsibility to set such rates.

Order No. PSC-09-0855-FOF-EG at 25.The concept of setting rates that are "fair, just and reasonable" is widely used in the regulation of the electricity industry. Notably, this standard makes no reference to rate minimization. Rates should be fair, just and reasonable. This requires consideration of, and often a balancing among, several factors beyond rates alone.

Q. Should the Commission consider rate and bill impacts when setting DSM goals?

A. If the rate impacts of DSM goals are of concern, then, yes the Commission should consider implications of rate and bill impacts. However, the RIM test should not be used for this purpose, for the reasons provided above. Instead, rate and bill impacts should be considered using comprehensive, meaningful analyses that provide the utilities and Commissioners with the information necessary to strike the appropriate balance between reduced bills and increased rates. I offer some recommendations on this point in the following subsection.

<u>Rate and Bill Impacts Should be Assessed in Other Ways</u>

Q. How should the Utilities address rate and bill impacts from DSM programs?

A. It is important to recognize that the primary challenge facing the Commission in setting DSM goals is in striking the proper balance between reduced costs and the potential for increased rates. FEECA is clear that the Commission should seek to establish DSM goals

that will reduce costs to the "general body of ratepayers as a whole." Section 366.82(3)(b), F.S. This suggests an emphasis on reduced costs, because ratepayers on average will be better off with reduced costs and reduced bills. In addition, FEECA provides the Commission with the authority to "modify or deny plans that would have an undue impact on the costs passed on to customers." Section 366.82(7), F.S. This language also emphasizes costs over rates.

Nonetheless, the Commission always has the responsibility to consider rate impacts in resource decision-making, and to prevent "undue" rate impacts on customers. Taken together, these considerations indicate that the Commission should not set DSM goals based on rate impacts alone, but should instead strike the proper balance between reduced costs and the potential for increased rates.

Q. What kind of considerations help strike a balance between reduced costs and the potential to increase rates?

A. Three considerations are the most helpful: rate impacts, bill impacts, and DSM program participation rates. Rate impacts, properly estimated, provide an indication of the extent to which rates might increase due to DSM. Bill impacts, properly estimated, provide an indication of the extent to which average customer bills might be reduced due to DSM. Participation rates, properly estimated, provide an indication of the extent to which customers will experience bill reductions or bill increases. Taken together, these three measures indicate the extent to which customers as a whole will benefit from DSM.

Q. How should rate impacts be estimated?

A. Rate impact estimates should account for all factors that impact rates, either positively or negatively. This would include all avoided costs that might exert downward pressure on rates (e.g., generation, transmission, and distribution), including the avoided costs of complying with environmental regulations. Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the Florida ratemaking practices. Rate impacts should be estimated over the long-term, to capture the full period of time over which the efficiency savings will occur. Rate impacts should also

be put into terms that place them in a meaningful context; e.g., in terms of ¢/kWh or percent of total rates.

Q. How should bill impacts be estimated?

A. The bill impacts should build upon the estimates of rate impacts described above. The rate impacts apply to every customer (within the rate class analyzed). Bill impacts, on the other hand, will vary between customers depending upon whether they participate in the DSM programs, and depending upon which DSM program they participate in. Therefore, bill impacts should be estimated separately for each of the types of DSM programs. As with rate impacts, they should be estimated over the long-term, and they should be put into terms that place them in a meaningful context; e.g., in terms of dollars per month, or percent of total bills.

Q. How should program participation rates be estimated?

A. Program participation rates should be estimated by dividing the program participants by the total population of eligible customers, to get a rate in percentage terms. This should be done for each year, and for each program. Participation rates should be compiled across several years to indicate the extent to which customers are participating in the programs over time. To the extent possible, participation in multiple programs and across multiple years should be captured. The long-term program participation rates can be compared with the long-term bill impacts and the long-term rate impacts to get a sense of the extent to which customers are benefiting from the DSM programs.

Q. You recommended that the level of program participation should be considered when deciding whether specific rate impacts are acceptable. Please elaborate on why the level of program participation should be considered when assessing rate impacts of DSM programs.

A. Rate impacts primarily raise the issue of customer equity. Therefore, to assess whether rate impacts—and more importantly, bill impacts—are acceptable and yield equitable outcomes, customer participation rates must be considered. Specifically, program participation rates can reveal the extent to which customers experience bill increases or decreases. If a large portion of customers participate in DSM programs, then the Commission and other stakeholders should be willing to accept relatively higher rate

impacts because many customers will experience net bill reductions and few customers will experience bill increases.

Furthermore, this type of participation information can be very important in reviewing and assessing the Utilities' DSM programs in general. It provides an indication of how successfully each program is pursuing customers, as well as an indication of which types of customers could benefit from future efficiency programs.

Q. Are there actions that the Commission and Utilities can take to increase customer participation in the DSM programs, and thereby mitigate customer equity concerns?

A. Yes. First, the DSM program goals and budgets can be set in a way to increase customer participation. Energy efficiency program goals and budgets could be increased to grow the number of customers that experience bill reductions. This is the exact opposite of approach proffered by the Utilities, which is to reduce DSM program goals and budgets to minimize rate impacts. *In my view, customers overall are better served by a broader application of well-designed, cost-effective DSM programs, because such programs reduce energy system costs and reduce customer bills.*

Q. Is there another approach that the Commission and Utilities can take to maximize customer participation in the DSM programs?

A. Yes. The DSM programs can be designed in a way that encourages as much participation as possible, across as broad a variety of customer types as possible. In particular, DSM programs can be designed to:

- promote all types of efficiency measures that offer cost-effective savings;
- provide all customer types with an opportunity to participate, including hard-to-reach customers such as low-income customers;
- offer efficiency measures that are specifically tailored to many different customer types;
- provide financial and other incentives to overcome the market barriers that prevent customers from participating; and

- identify, target and actively pursue non-participants.

Programs that incorporate these design principles will be more likely to reach a large number of customers, and eventually increase program participation.

Q. Do non-participants experience any benefits of DSM programs?

A. All customers experience the benefits—regardless of whether they participate in the programs. Energy efficiency provides benefits to the entire electricity system, and these benefits are shared by all customers. In particular, DSM can improve system reliability, reduce the need for new generation capacity, reduce planning risk, reduce transmission and distribution costs, reduce the costs of complying with environmental mandates, and reduce reliance upon fossil fuels. Efficiency also results in societal benefits such as local job growth and economic development, reduced environmental impacts and increased economic development. FEECA recognizes this when stating that the Act's intent is to "protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S.

My main point is that concerns about rate impacts are rooted in customer equity issues between participants and non-participants because participants experience direct benefits from DSM (i.e., reduced bills from reduced consumption) that non-participants do not experience. Therefore, when addressing rate impact issues, it is important to fully understand and address this customer equity issue.

The Utilities Do Not Account for the Cost of GHG Regulations

Q. Does FEECA require the Commission to consider the costs of compliance with greenhouse gas regulations?

A. Yes. FEECA requires the Commission to consider, among other things, the "cost imposed by state and federal regulations on the emission of greenhouse gases." Section 366.82(3)(d), F.S.

Q. How should the various efficiency screening tests account for GHG regulatory compliance costs?

A. The cost of complying with current and expected GHG regulations should be included in the TRC test, the Utility Cost test, the Societal Cost test, and in any analyses of rate and

bill impacts. The cost of compliance with any environmental requirements is a cost that will be incurred by utilities and passed on to electricity customers through electricity rates. This compliance cost is therefore an electric system cost, and reducing that cost through DSM is an electricity system benefit. All electricity system costs and benefits should be included in the Utility Cost test, the TRC test, the Societal Cost test, and any analyses of rate and bill impacts.

Note that the cost of complying with environmental regulations are not the same as environmental damage costs (e.g., reduced air quality, damages to lakes and forests, public health impacts). The cost of complying with environmental regulations are an electricity system cost that will be passed on to customers. Environmental damage costs are born by society at large, but do not affect electricity costs or electricity rates.

Q. Why is it so important to account for the cost of compliance with environmental regulations when screening DSM programs?

A. Energy efficiency resources are the most widely available and the lowest-cost option to reduce greenhouse gas pollution and other air pollution. It is important that these low-cost resources be fully utilized to comply with current and future environmental regulations. Otherwise, the costs of complying with such regulations will be greater, and electricity customers will end up paying higher costs than necessary.

Furthermore, DSM offers a set of policy options for reducing GHG pollution that result in *lower bills* for customers, by reducing customer electricity consumption levels. Other GHG pollution reduction options typically result in higher bills for customers.

In sum, it is important to properly account for environmental compliance costs when screening DSM programs because this will minimize future costs to electricity customers.

Q. How should the Utilities account for GHG regulatory compliance costs?

A. The Utilities should apply the best estimate available of the likely costs of complying with state and federal requirements for controlling greenhouse gas pollution during the entire DSM cost-effectiveness study period. Doing so is common practice in the electricity industry. At least 28 utilities have recently used a forecast of CO_2 costs in their planning practices, including utilities in: Arkansas, Arizona, California, Connecticut,

Hawaii, Louisiana, Maine, Massachusetts, Mississippi, South Carolina, New Hampshire, New Mexico, Nevada, North Carolina, Tennessee, Idaho, Indiana, Oklahoma, Oregon, Utah, Vermont, Washington.[10]

Q. How do DEF and FPL account for the cost of complying with GHG regulations when screening efficiency and setting goals?

A. As a part of their resource planning, DEF and FPL have conducted sensitivity analyses where they include CO_2 cost estimates. Both DEF and FPL proffer that adding the CO_2 costs hardly changes the amount of economic or achievable DSM potential, and thus hardly impacts efficiency opportunities or their DSM goals. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 45-46; Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibit HG-14.

Q. Do you agree with FPL's and DEF's conclusion that the cost of complying with GHG regulations will have little impact on their efficiency opportunities?

A. No. This conclusion is counter-intuitive, and highlights just how constraining FPL's and DEF's screening process is. As described in Section 4, FPL's and DEF's resource screening practice suffers from so many flaws and limitations that the results cannot be trusted. Furthermore, FPL's and DEF's resource screening eliminated the majority of DSM measures before CO_2 costs were even considered in the sensitivity analyses. Therefore, I recommend that the Commission give no weight to the results of FPL's and DEF's CO2 sensitivity analyses.

Q. How would the proper accounting of GHG regulatory compliance costs impact the Utilities' cost-effectiveness analyses?

A. The impact would be significant for several reasons. First, properly accounting for GHG regulatory compliance costs would increase the number of DSM measures included in the economic potential and the achievable potential. For example, the consideration of carbon costs was "the primary driver behind why Tampa Electric's energy [GWh] goals

[10] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast*, November 2013, p. 17.

increased over 70 percent" in the last round of goal-setting. *See,* Witness Bryant Deposition Transcript, Hearing Exhibit 4, Item 7, Docket Nos. 080407–080413, at 89.

Second, properly accounting for the value of avoiding GHG compliance costs would decrease the estimated rate impacts of DSM. As described above, complying with an environmental regulation is a cost to the utility system. For any given level of efficiency savings, proper treatment of the value of avoiding GHG compliance costs would indicate lower utility system costs, which would in turn indicate lower rate impacts. In other words, by failing to correctly account for avoided GHG compliance costs in their resource planning, the Utilities omit one of the benefits of DSM that should be included in the RIM test, and thus overstate the rate impacts.

The Utilities Ignore Non-Energy Benefits of Energy Efficiency

Q. What are non-energy benefits of DSM programs?

A. Non-energy benefits are those costs and benefits that are not part of the costs, or the avoided costs, of the energy provided by the utility that funds the efficiency program.[11] There is a wide range of non-energy benefits associated with DSM programs. Non-energy benefits are categorized by the perspective of the party that experiences the impact: the utility, the participant, or society at large.

- Utility non-energy benefits are indirect savings to the utility; savings that will reduce revenue requirements and thus benefit all ratepayers. These include, for example, reduced arrears, reduced bad debt, reduced costs associated with customer disconnection and reconnection.

- Participant non-energy benefits are benefits to DSM program participants. These include, for example, reduced O&M costs, increased safety, improved health, improved productivity in schools and businesses, improved aesthetics and comfort, and water savings. Participants can also experience benefits in terms of "other fuel

[11] Synapse Energy Economics, Inc., "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs," prepared for Regulatory Assistance Project, November 2012, at 3.

savings;" i.e., when gas, oil or other fuels are saved as a result of an electric efficiency program. Participant non-energy benefits can be experienced by all types of customers, but certain non-energy benefits are more significant for low-income programs.

- Societal non-energy benefits are benefits that accrue to society at large, beyond those realized by utilities or program participants. These include, for example, impacts on the environment, economic development, job growth, reduced healthcare costs, and national security benefits.

Q. Are these non-energy benefits relevant to the efficiency screening tests used in Florida?

A. Yes, for three reasons. First, as noted above FEECA requires that utilities implement DSM programs "to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Thus, DSM goals should reflect DSM benefits beyond just those that accrue to the utility system. To do so, non-energy benefits should be included in DSM screening.

Second, as noted above, FEECA requires that in establishing the DSM goals the Commission shall consider "the costs and benefits to customers participating in the measure." Section 366.82(3)(a), F.S. To comply with this directive, participant non-energy benefits should be included in DSM screening.

Third, as indicated in Figure 3.1, participant non-energy benefits are one of the key parts of the TRC test. If these benefits are omitted from the TRC test, then the test will be internally inconsistent and inherently skewed against DSM.

Q. Why would the TRC test be internally inconsistent and skewed against efficiency if participant non-energy benefits are omitted from the TRC test?

A. One of the distinguishing features of the TRC test is that it includes the costs to program participants. When including all participant costs, it is necessary to also include all participant benefits, including both energy benefits and non-energy benefits. Otherwise, the TRC test will include certain costs without considering comparable benefits. This

results in a test that is internally inconsistent, and will provide results that are skewed against DSM programs.

Q. Do other states account for participant non-energy benefits in applying the TRC Test?

A. Yes. States that include participant non-energy benefits in their TRC screening use various methodologies and assumptions to estimate the value of participant non-energy benefits. Some states conduct detailed studies to identify these benefits, and to estimate their monetary value so that the estimates can be included in DSM screening. Other states use "a proxy adder" to increase the utility system benefits by a certain percentage amount, as a rough approximation of non-energy benefits. Still other states conduct sensitivity analyses to indicate the extent to which non-energy benefits might influence DSM cost-effectiveness. In recent years, efficiency industry stakeholders have increasingly strived to properly account for participant non-energy benefits.[12]

Q. What about the uncertainty associated with participant non-energy benefits? Are these benefits certain enough to use when screening DSM programs?

A. While there is some uncertainty regarding the magnitude of some participant non-energy benefits, there is no question that they can be quite large, and that they will have a significant impact on DSM cost-effectiveness under the TRC test. There are several ways to address the uncertainties associated with participant non-energy benefits, and it is better to use an informed estimate of non-energy benefits values than to simply assume that they are equal to zero; a number that we know is wrong. Furthermore, it is important to recognize that there is considerable uncertainty regarding many of the assumptions for the future costs and benefits of demand-side and supply-side resources. There is no reason to hold participant non-energy benefits to a higher standard of certainty than these other costs and benefits.

[12] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, March 2014.

Q. What should the Commission do in this docket to account for participant non-energy benefits?

A. I recommend that the Commission require the Utilities to apply a proxy adder to the efficiency program benefits in the TRC test as an estimate of the participant non-energy benefits. While proxy adders are inherently inexact, it is better to use an informed estimation than to simply assume that the value is zero. Here, I recommend that the Commission require the Utilities to apply the following participant NEB proxy adders: 50 percent for low-income customer programs; 25 percent for residential non-low-income customer programs; and 10 percent for commercial and industrial customer programs. These recommended values are based on my extensive review of non-energy benefits in other states, and are conservative relative to some of the quantified values of non-energy benefits that I am aware of.[13]

If the Commission does not require the Utilities to apply a proxy adder for participant non-energy benefits, the Commission should give less weight to the results of the TRC test and instead give more weight to the results of the Utility Cost test. In the absence of reasonable estimates of participant non-energy benefits, the results of the TRC Test are inherently skewed against DSM, while the Utility Cost Test is not.

At a minimum, the Commission should recognize that TRC results that do not include participant non-energy benefits significantly undervalue the full benefits of the DSM programs. This should at least be a qualitative factor that the Commission considers when setting DSM goals.

[13] Synapse Energy Economics, Inc., *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs*, prepared for Regulatory Assistance Project, November 2012. Synapse Energy Economics, *Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For*, prepared for the National Home Performance Council, July 2012.

4. THE UTILITIES' RESOURCE PLANNING PROCESS

Q. Please provide a summary of the FPL's screening process.

A. FPL provides a relatively detailed description of its screening process, so I will focus on FPL in this Section for this reason. FPL uses a six-step resource planning process to screen DSM and propose DSM goals. Direct Testimony of Witness Sim, Document No. 01476-14, at 15-17, Exhibit SRS-1. To summarize:

- Step 1 develops the DSM Technical Potential. This includes the theoretical full potential for DSM regardless of economic constraints, FPL's resource needs, or customer adoption of efficiency measures. *Id*. at 15.

- Step 2 determines resource needs over the 10-year DSM goal-setting time period. At this point, FPL studies how much capacity (in MW) is needed to meet peak demand requirements, both for a Supply-Only scenario and a With-DSM scenario. *Id*. at 18-22. The results are used in Step 5.

- Step 3 identifies a preliminary DSM Economic Potential via preliminary economic screening that compares DSM options to a single supply-side resource; i.e., without any sort of resource planning analysis. *Id.*at 16. This preliminary economic screening applies the Participants test, the RIM test, the TRC test, and a "years-to-payback" test. *Id.* at 16. At this point, FPL creates two screening "paths." The RIM path analyzes the DSM measures using the RIM test, the Participants Test, and the years-to-payback test. The TRC path analyzes the DSM measures using the TRC test, the Participant test, and the years-to-payback test. *Id*. at 29-30. FPL also conducts several sensitivity analyses, including analyses regarding CO_2 costs, fuel prices, and different levels of years-to-payback. *Id.* at 32-33.

- Step 4 identifies the DSM Achievable Potential. FPL applies an assumption of the "maximum customer incentive level" that it can pay for the DSM measures that passed the economic potential screening above. FPL then estimates the "maximum annual signups" that it could expect from customers based on those customer

incentives. The number of customer signups indicates the extent to which FPL deems DSM savings achievable. *Id*. at 16, 38-39.

- Step 5 develops resource plans (Supply-Only and With-DSM). FPL identifies how many of the DSM measures that passed the Achievable Potential screening above could be used to meet its resource planning needs. The latter only reflect FPL's capacity needs, especially with regard to meeting FPL's 20 percent total reserve margin criterion. *Id.* at 41-42.

- Step 6 analyzes resource plans from both economic and "non-economic" perspectives to select the best resource plan and the accompanying amount of DSM to include in FPL's proposed DSM goals. The economic perspective calculates the levelized system average electric rate for each resource plan. FPL uses this electric rate metric to conduct the economic evaluation of the resource plans and associated amounts of DSM. This metric is also proffered to ensure that there is no cross-subsidization across different groups of customers. *Id*. at 54. The "non-economic" analysis includes two additional "perspectives," including (a) emissions of SO_2, NO_X, and CO_2, and (b) system oil and natural gas usage. *Id*. at 66-67.

Note that the analysis described above is performed for each efficiency measure in isolation. There is no consideration of DSM programs, or the associated technical support, education, marketing, and delivery practices that can be used to implement DSM measures.

Q. Please provide a summary of DEF's resource planning process.

A. DEF performs a resource planning process that is similar to FPL's process. It includes the following key elements:

- DEF conducts a technical potential analysis to identify the amount of DSM and demand-side renewable measures that are theoretically available. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 24.

- DEF conducts a resource planning process, using the Strategist model, to analyze the impacts of DSM from a system resource perspective. DEF develops a Base Case (Supply-Only) plan, and begins economic analysis of DSM measures using the RIM, TRC and Participant tests. *Id*. at 24-27.

- DEF then determines the DSM economic potential, by applying a two-year payback limit for free-ridership, and by performing cost-effectiveness analyses using the RIM and TRC tests. *Id*. at 29-30.

- DEF then sets the DSM achievable potential by applying administrative costs and participant incentives to the economic potential measures. Next, DEF uses a set of "payback acceptance curves" to determine "maximum expected participation rates," and applies a set of "diffusion" curves to determine 10-year participation limits. *Id*. at 31-32.)

- DEF then sets the economic and achievable potentials based on (a) the RIM and Participants tests, and (b) the TRC test. *Id*. at 32-34.

- Finally, DEF conducts sensitivity for fuel prices and free-ridership exclusion periods. *Id*. at 36-37.

Q. Do you have any concerns about the resource planning processes that the FPL and DEF used to set DSM goals?

A. Yes. FPL's and DEF's screening processes suffer from many fundamental flaws. I summarize these flaws below, and elaborate on them in the following subsections.

- The Technical Potential estimates significantly understate the full DSM technical potential in Florida. They exclude many important efficiency measures that are proven to be available, and they continue the Utilities' misguided use of a two-year payback to screen out supposed free-riders.

- FPL and DEF perform two separate economic screening analyses in this process—first, a preliminary screen to determine the economically viable DSM measures, and second, a screen based on resource planning models that supposedly optimize both demand-side and supply-side resources. This results in "double-screening,"

which eliminates a large portion of the DSM measures before they are compared to supply-side resources with the resource planning models.

- FPL and DEF use rate impacts as the primary criterion for resource planning and choosing among resource options. This perpetuates all of the problems with the RIM test that I described above, including the fact that the Utilities' estimates of rate impacts are simply wrong and grossly overstated. Furthermore, FPL's and DEF's own analyses indicate that the rate impacts from the DSM plans that they analyze are likely to be so small as to be unnoticeable.

- FPL incorrectly assumes that DSM can only be implemented if it provides capacity (in terms of MW) that can be used to meet reliability requirements. This ignores DSM's ability to reduce energy costs, and dramatically biases the resource planning process against DSM.

- The FPL's and DEF's resource planning processes do not allow DSM measures the full opportunity to defer new supply-side resources, to reduce the size of new supply-side resources, or to assist with retiring existing, uneconomic supply-side resources. This conflicts with FEECA and gives undue preference to supply-side resources that are "hard-wired" into the system regardless of the amount of DSM savings, including the very expensive and very risky Turkey Point nuclear plant in the case of FPL.

In sum, FPL's and DEF's resource planning processes does not provide the critical information that the Commission needs to set DSM goals pursuant to FEECA. These processes do not provide reasonable estimates of Technical, Economic, or Achievable potential; they do not provide evidence of the extent to which DSM can reduce electricity system costs and therefore reduce customer bills; and they do not provide meaningful information on the extent to which DSM affects the general body of ratepayers as a whole. Ironically, FPL and DEF (erroneously) claim that rate impacts should be the primary criterion for selecting cost-effective DSM, but their own analyses provide almost no useful information that the Commission can use to consider the implications of rate impacts.

1

The Technical Potential Estimates Understate DSM Potential

Q: What kind of technical potential evaluation does FEECA require?

A: Section 366.82(3), F.S., requires the Commission to "evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures." FEECA also requires such evaluation of demand-side renewable energy systems, as discussed in Section 7.

Q: Do you think such an effort is warranted at least every five years?

A: Absolutely. Section 366.82(6), F.S., requires this "full technical potential" evaluation to occur at least every five years, for good reason: Conservation and DSM (together, DSM) are integral parts of a balanced and cost-effective energy system. DSM is particularly valuable in the face of many current challenges for utilities in Florida and many other states, including an over-reliance on generation tied to natural gas (a fuel with notoriously volatile pricing), the need to replace an aging generation fleet, the rising costs and risks of conventional new generation, and the need for transmission and distribution infrastructure upgrades to maintain and expand capacity.

Moreover, rapid changes in the energy sector effectively re-define the regulated energy landscape in intervals even shorter than five years. To meet FEECA's intent to utilize the most efficient and cost-effective DSM programs, the Utilities and the Commission must stay informed of the ongoing research and development regarding these resources, and the potential to include them in Florida's energy system.

Q: Does the evaluation of the full technical potential required by Section 366.82(3), F.S., identify the complete picture of the DSM potential in Florida?

A: No. Technical potential studies by definition do not assess all the implications of DSM. Most importantly, they do not consider the cost-effectiveness of DSM measures; they only measure whether a measure is technically feasible. In addition, they do not consider the likely behavior of customers in response to market changes, pricing signals, and outreach and marketing of efficient products and services. Therefore, to fully capture the potential for DSM in Florida and to best understand the likely costs and benefits to the Utilities' customers, the Commission must also look at the economic and achievable

DSM potential. In fact, the goals proposed by the Utilities are determined by the achievable potential.

Q: Does that mean that the technical potential estimates are irrelevant?

A: No. Each successive estimate of potential is based on the previous one. In other words, the achievable potential is developed based on the results of the economic and technical potential estimates. Therefore, the Commission must verify the completeness and accuracy of every part of the Utilities analysis, from technical potential to achievable potential to the ultimate goal-setting.

Q. Did you review the materials provided by the Utilities regarding their updates of technical DSM potential?

A. Yes, I reviewed the filings by DEF and FPL (Dockets 130199-EI and 130-200-EI, filed on April 2, 2014), as well as their responses to discovery requests by Sierra Club and the Southern Alliance for Clean Energy (SACE). I also reviewed worksheets provided by DEF, FPL, TECO, and Gulf Power that summarize the results of their technical potential updates. These were submitted in advance of the filings as "preliminary drafts" subject to change. I also reviewed a short narrative description of the methodology for updating the 2009 technical potential estimates.

Q. Did you review any other material related to the technical potential estimates?

A. Yes. Because the new estimates are updates of previous estimates from 2009, I also reviewed the potential estimates from the 2009 Technical Potential Study by Itron, Inc. on behalf of the Collaborative comprised of the Utilities (DEF, FPL, TECO, Gulf Power, OUC, and JEA), and the related materials in Dockets No. 080407–080413. In particular, I reviewed critiques of the 2009 Technical Potential Study in Witness Mosenthal's Direct Testimony on behalf of NRDC and SACE, and in Witness Spellman's Direct Testimony on behalf of Staff. Also from those dockets, I reviewed testimony filed by SACE's Witness Wilson and rebuttal testimony filed by Witness Rufo on behalf of the Utilities.

Q. Please summarize the findings of your review of the technical potential.

A. Table 4.1 presents the technical potential by sector as a percentage of sales for that sector, for each of the four utilities named above. These data are drawn from responses provided

by the Utilities on December 6, 2013, to SACE's informal data requests dated November 6, 2013.

Table 4.1 Summary of Technical Potential Estimates

	Technical Potential as % of sales			
Utility	Residential	Commercial	Industrial	Total
DEF	44%	24%	15%	33%
FPL	35%	25%	34%	31%
TECO	36%	33%	14%	32%
Gulf	36%	33%	10%	31%

The Utilities' estimates represent a limited estimate of technical potential, in part because they have omitted relevant measures and relevant energy-consuming sectors and end uses from the analysis. These same problems existed in the 2009 Technical Potential Study, as demonstrated by Witness Mosenthal and Witness Spellman in that docket.

Q. What types of measures have been omitted in these estimates of technical potential?

A. The Utilities overlook various measures and market segments. Here I highlight the key omissions, those that are most likely to represent a substantial amount of potential that is omitted from subsequent analysis of the economic and achievable potential. These including building commissioning and retro-commissioning, new types of LED lighting fixtures, various efficiency measures in data centers, efficiency measures for water and wastewater treatment plants and the agricultural sector, and ultra-low energy buildings such as net zero energy buildings and "Passive Houses." I will explain in detail each of these omissions. Also, because the Utilities' discovery responses list dozens of measures in each of the three sectors, and these measure lists appear to be consistent across the Utilities, my observations and recommendations apply to all of the Utilities.

First, the Utilities omit building commissioning and retro-commissioning in the commercial and industrial sectors. These omitted measures involve targeted efforts by building operation experts to identify operational changes and repairs/adjustments to equipment to realize optimum performance. Typically, these savings opportunities are widespread, inexpensive, and result in substantial savings. Witness Mosenthal noted the

omission of these measures in his 2009 testimony. *See* Document No. 06794-09, at 11. In rebuttal testimony, Witness Rufo claimed that several of the measures included in the technical potential "represent" the potential associated with retro-commissioning. Document No. 07822-09, at 14 . Yet none of the measures described by Witness Rufo address the operational improvements (rather than equipment-based measures) that are a primary result of retro-commissioning activities. While it may be true that the measures offered by Witness Rufo have some overlap with commissioning and retro-commissioning, his testimony does not substantiate that the full technical potential from these activities are included in the Utilities' estimates and updates.

Second, the Utilities appear to omit new types of efficient lighting fixtures for commercial and industrial applications. For instance, from among the most common type of recessed linear fluorescent lighting, the Utilities only include "LED linear tubes." These products were some of the first of their kind on the commercial marketplace, but they have been rapidly eclipsed in performance by newer fixtures that take advantage of LEDs' particular technical characteristics, rather than being limited to the old form-factor and housings of tubular fluorescents. The potential for emerging LED lighting technologies was noted by witnesses, including Witness Spellman in the 2009 goal-setting. *See*. *e.g.*, Witness Spellman Direct Testimony, Document No. 07271-09, at 59. This is another major omission to a technical potential estimate, as there are likely to be LED solutions for virtually every lighting application in commercial and industrial spaces.

Third, the Utilities identify only one data center-related measure, server virtualization. Data centers present openings for significant energy savings because they represent a growing percentage of electricity consumption in many jurisdictions. Therefore, the Utilities should consider other efficiency strategies and technologies ranging from the efficiency of the computing equipment to the power supply and HVAC systems. These represent yet another area where the technical potential likely falls short of the actual opportunity.

Fourth, in 2009, Witness Mosenthal noted the apparent omission of measures specific to water and wastewater treatment plants and to the agricultural sector. The updates do not seem to remedy this omission.

Fifth, in 2009, Witness Wilson, noted that efficient outdoor and street lighting measures were entirely omitted. Yet these measures represent substantial energy consumption, and they are clearly technically feasible. Nonetheless, they are still missing from the Utilities updates.

Last, the updates fail to account for ultra-low energy or net-zero energy buildings. Constructing such new buildings or retrofitting existing buildings to those standards is technically feasible, and thus should be included in the technical potential analysis. For example, an experimental super-energy-efficient residence in Lakeland, Florida demonstrated a 70% to 84% reduction in cooling loads. When the PV electric generation is included during the peak period, the home net demand was only 199 Watts, a 93% reduction in electricity requirements.[14]

Q: Are the Utilities' proposed DSM goals based on their technical potential estimates?

A. Yes, although not directly. The technical potential forms the basis for assessing the economic potential, which in turn forms the basis for the achievable potential. As discussed above in Section 4, the economic and achievable potential estimates are also flawed.

Q: What flaws have you identified in the Utilities' economic potential estimates?

A: The worst flaw is the Utilities' use of the RIM test to determine economic potential, as discussed above in in Section 4. Also problematic are the Utilities': (1) use of a two-year payback to screen efficiency measures for supposed free riders; (2) omission of non-energy benefits; and (3) omission of openings for DSM to replace aging, uneconomic generation. I elaborate on each of these flaws below.

[14] Florida Solar Energy Center (FSEC). "ZEH: Lakeland, Florida."

Q: What is the problem with two-year payback screening?

A: The Utilities screen out any measure from their economic potential estimates if participant payback for that measure is less than two years without incentives. This is a blunt and overly-constrictive way to screen for free riders who would participate in programs without any incentives. As with several other flaws discussed in this testimony, the two-year payback screen was critiqued in the 2009 goal-setting docket. There, Witness Mosenthal described how the use of a two-year simple payback threshold is a critically flawed method to estimate economic potential for several reasons, including (1) inconsistencies between the Utilities' load forecast and the two-year payback method; and (2) the inaccurate assumption that all customers implement efficiency measures with a short payback whether or not the customers know the payback is short. To these, I add that the Utilities' two-year payback screening relies on the incorrect assumption that all customers have ready access to capital sufficient to take advantage of even highly cost-effective efficiency resources.

Q. Please explain these issues in detail.

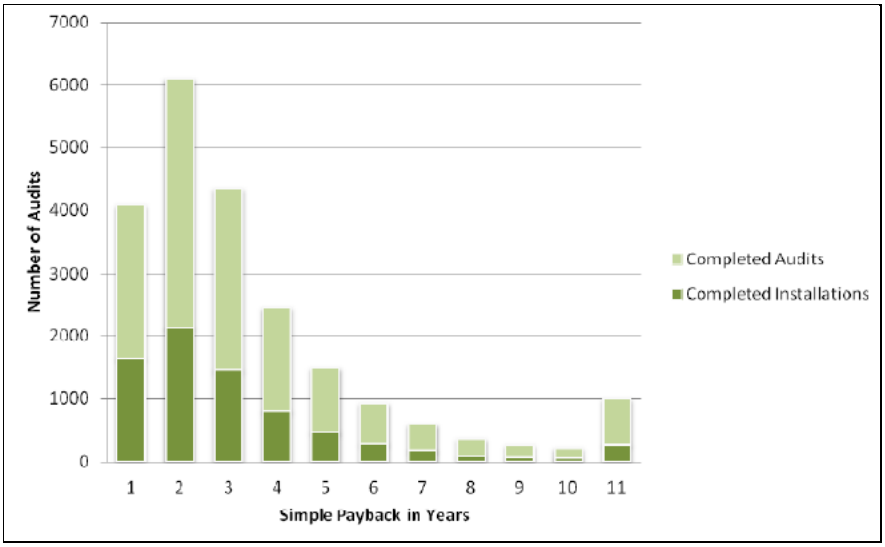
A: First, the Utilities' base load forecast should already include naturally occurring DSM, which is essentially the impact from supposed free riders in an efficiency program. Accordingly, the baseline penetration of such measures that are naturally adopted without incentives should be 100%, and the Utilities' baseline forecast should reflect this. However, the technical and economic potential estimates actually assume some non-zero penetration of these measures, and therefore estimates some non-zero potential which is then removed from the potential estimate. This implies that they are in fact *not* currently installed and *not* reflected in the base load forecast.

Essentially, the Utilities try to "have it both ways" by claiming all these measures would be adopted naturally without incentives, but then the Utilities proceed to estimate DSM potential as though these measures are not adopted without incentives. If the Utilities have not included the impact of naturally occurring efficiency in their load forecast, then it is inappropriate to also omit it from the assessment of potential. That is, it should appear in one of these locations. If it does not, then the utility's need for future capacity

and energy supply is overstated and the ability of efficiency to reduce that need is understated.

Second, the Utilities continue to assume that all customers know and understand the simple payback when buying efficient appliances or equipment. *See, e.g.*, Direct Testimony of Witness Deason, Document No. 01474-14, at 27. There are many customers who do not have time or sufficient understanding to think about whether they can reduce their energy bills and whether or not an initial investment will be recouped. Even when customers do understand that efficiency investments provide a good return on investment, they may not follow through with those investments for myriad reasons. For example, Xcel Minnesota's innovative small business program, One-Stop Efficiency Shop[SM], identified many small business customers who did not adopt DSM even with simple paybacks in the range of 1 to 2 years, as shown in Figure 4.1. More than half of the customers with completed audits did not install DSM measures despite highly favorable returns.

Figure 4.1 Xcel Minnesota One-Stop Shop Audits vs. Installations in 2000 – 2011[15]



Last, even when customers understand the return on their efficiency investment and want to proceed to make that investment, they may not have access to the necessary capital

[15] Kristen Funk, *Small Business Energy Efficiency: Roadmap to Program Design*, Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings, August 2012.

monies. This is particularly true of low-income and fixed-income customers and new home-owners who are fully extended with credit obligations. Utility-sponsored DSM programs can assist with such consumers by offering low or zero interest loans.

In summary, it is clear that assuming that all measures with a two-year simple payback are automatically captured by the marketplace without any intervention is a gross over-simplification that dramatically reduces the achievable potential that utility efficiency programs should be addressing.

Q: Do the Utilities' present any information that supports your contention that not all customers will automatically take advantage of opportunities with a simple payback of less than two years?

A. Yes, the two-year payback threshold conflicts with Itron's 2009 Technical Potential Study, which clearly indicates that far less than 100% of customers will adopt measures with even a better return on investment. For example, DEF applies a payback-acceptance curve to determine maximum expected participation rates by measure. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, at 32. The maximum participation rates are presented in several Excel worksheets that DEF provided in response to Sierra Club's First Set of Interrogatories, No. 1-18. According to those worksheets, the maximum adoption rate for a residential measure with a two-year payback is approximately 42%; for a commercial measure it is just over 30%. Yet the Utilities' screening methodology would assume 100% penetration at two years, without intervention by their efficiency programs. Even at a one-year simple payback, the maximum adoption rates are just 51% for residential customers and 60% for commercial customers, still far below universal acceptance. The Utilities' assumption of maximum adoption rate and free-ridership are therefore internally inconsistent.

Q: Has the Commission expressed any concern with the two-year payback screen?

A: Yes. In the last round of goal-setting, the Commission noted that screen eliminates a substantial amount of potential savings. *See* Order No. PSC-09-0855-FOF-EG, at 9. As a result, the Commission increased the proposal goals for several utilities to account for the potential savings from several residential measures that the Utilities would have eliminated using the two-year payback screen.

Q: Did the Utilities' revise their approach in response to the Commission's Order?

A: No. For example, DEF's filing states that "the first step in the determination of economic potential was to evaluate and account for free-ridership by screening out any measure that had a participant payback of less than two years without a utility incentive." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 29-30.

Q: What is the effect of this approach to assessing free riders?

A: It is significant. For instance, FPL eliminated nearly a quarter of the DSM potential using this screen. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-5 (showing that FPL eschewed 210 measures out of the total of 850 measures based on the two-year payback year screen under the TRC Test).

The Resource Planning Process is Driven Entirely by Rate Impacts

Q. What is the primary criterion that the Utilities use to set their DSM goals?

A. FPL and DEF both set their DSM goals by including only those DSM measures that will not increase electricity rates. FPL calculates a levelized system average electric rate for each resource plan, and then the "rate metric is used as the primary economic basis by which the resource plans, and the amount of DSM in each resource plan, are evaluated." Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF has not identified its primary criterion for selecting DSM. However, DEF's proposed DSM goal is essentially the same as its estimate of achievable potential under the RIM test, indicating that DEF used rate impacts to set its DSM goals. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1 & HG-12.

Q. What is wrong with using rate impacts as the primary criterion to set DSM goals?

A. In Section 3 I describe several fundamental flaws of screening DSM programs with the RIM test; i.e., rate impacts. All of those points are relevant to the Utilities' resource planning process. To summarize:

- Using rate impacts as the primary criterion to select DSM programs conflicts with FEECA's requirements and policy goals.

- Lost revenues are not a "new" cost created by DSM programs; they are instead driven by costs already included in rates. In other words, they are "sunk" costs, and should not be used to determine cost-effectiveness.

- Using rate impacts as the primary criterion to select DSM programs can lead to perverse outcomes; where the opportunity to significantly reduce utility system costs and customer bills may be forgone to avoid a very small increase in rates.

- Using rate impacts as the primary criterion to select DSM programs is inconsistent with the treatment of supply-side resources, which can also lead to cross-subsidization between customers.

- The Utilities calculate rate impacts incorrectly, by estimating lost revenues on the basis of the full electricity rate, as opposed to just the fixed portion of electricity rates. This results in lost revenue estimates that could be more than double what the correct number would be.

- The Utilities calculate rate impacts incorrectly for another reason, by assuming that base rates will increase every year, when in fact base rates only increase at the time of a rate case. Consequently, the Utilities' estimates of rate impacts are grossly overstated.

Furthermore, FPL and DEF's resource planning process is inconsistent with standard industry practice for integrated resource planning. All states that I am aware of that use integrated resource planning practices use the minimization of the present value of revenue requirements as the primary criterion for selecting the preferred resource plan.

Q. Do the Utilities' resource planning processes highlight any additional reasons why rate impacts should not be used as the primary criterion for setting DSM goals?

A. Yes. FPL's own results indicate that the rate impacts of DSM are likely to be very small. Table 4.2 presents the results of FPL's resource planning process, in terms of the levelized system avenge electric rate (cents/kWh). Table 4.2 also presents the difference in levelized average system rates between the Supply Only case and the other cases, as well

as the difference between the RIM 337 MW case and the other cases. Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-11.

Table 4.2 Results of FPL's Resource Planning Process

Resource Plan	Levelized System Average Rate	Difference From Supply Only	Difference from RIM 337 MW
Supply Only	11.7419	0.000%	0.006%
RIM 337MW	11.7412	-0.006%	0.000%
TRC 337 MW	11.7579	0.136%	0.142%
RIM 526 MW	11.7431	0.010%	0.016%
TRC 576 MW	11.7636	0.185%	0.191%

As indicated, there are very small differences in levelized rates between the plans. The levelized rates for the TRC 337 MW plan and the TRC 576 MW plan are only 0.136 percent and 0.185 percent higher than the rate for the Supply Only plan. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described in Section 3. A proper estimate of rate impacts would indicate even lower impacts than the impacts presented in Table 5.1.

Q. Does DEF provide any information on the potential rate impacts of its DSM programs?

A. Only a little. DEF estimates a typical residential customer's rates under the RIM test and the TRC test. The results are summarized in Table 4.3. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-2 & HG-3. I estimate the rate impacts by calculating the percent difference between rates under the RIM the TRC scenarios.

Table 4.3 Residential Customer Rate Estimates

Year	RIM ($/month)	TRC ($/month)	Difference (percent)
2015	1,820	1,829	0.5%
2016	1,802	1,811	0.5%
2017	1,911	1,919	0.4%
2018	1,972	1,980	0.4%
2019	2,103	2,111	0.4%
2020	2,129	2,136	0.3%
2021	2,190	2,195	0.2%
2022	2,235	2,238	0.1%
2023	2,252	2,254	0.1%
2024	2,246	2,247	0.0%

The rate impacts presented in Table 4.3 are relatively small, ranging from 0.5 percent to 0.1 percent. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described above in Section 3. A proper estimate of rate impacts would indicate even lower impacts than those presented in Table 4.3. Further, the DEF rate impacts presented above do not account for the years after 2014, when the DSM installed in this period will continue to result in savings, and will therefore help to lower rates. From a long-term perspective (i.e., over the lives of the efficiency measures), the rate impacts would be significantly lower than those presented in Table 4.3.

Q. What conclusions do you draw from FPL's and DEF's rate impact results?

A. The rate impacts of FPL's and DEF's DSM plans are likely to be very small, so small as to be essentially unnoticeable by most customers. FPL's estimates in particular indicate that the actual rate impacts are likely to be "in the noise." By this I mean that the estimates are likely to be so small that they are within the rounding and uncertainty errors of the resource planning analysis. Therefore, the Commission should give the Utilities' rate impact estimates no weight in setting DSM goals. While the other Utilities provide even less information on rate impacts in their resource planning processes, I expect that the rate impacts from their DSM plans will also be very small, because those plans are of a comparable scale to FPL's and DEF's.

Also, it is helpful to keep these rate impact estimates in perspective. The rate impacts estimated by FPL and DEF, even if they were not overstated, are small relative to the other factors that cause rates to change over time. Rates typically increase by much, much higher amounts after a rate case. It is safe to assume that if FPL completes the construction of Turkey Point Units 6 and 7, rates will need to be increased by much more than the DSM rate impacts estimated by FPL and DEF. However, FPL's resource planning does not capture the potential benefits of postponing Turkey Point Units 6 and 7, as described below, and therefore ignores the potential for DSM programs to help postpone, mitigate or avoid the rate impacts associated with this expensive generation.

FPL and DEF Undervalue DSM by Conducting Two Economic Screens

Q. Please explain what you mean by conducting two economic screens.

A. Both FPL and DEF conduct a screen to determine economic potential, then they conduct a second screen using their resource planning models. FPL describes the first screen as Step 3 of its analysis, where FPL conducts a "preliminary" screening analysis against a single supply-side option, utilizing the Participant test, the RIM test, the TRC test and the "years-to-payback" test. Direct Testimony of Witness Sim, Document No. 01476-14, at16. The second screen occurs during FPL's Step 6, where the resource plans are analyzed from both economic and non-economic perspectives, and where the DSM measures are selected based upon the minimization of levelized rates. Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF explains that its first screen is conducted when each DSM measure is compared to the Base Optimal Supply-Side Plan, to determine sets of cost-effective DSM measures based on the RIM test, the TRC test, and the Participants test. The second screen is conducted when the cost-effective supply-side and demand-side portfolios are "optimized together to formulate integrated resource plans." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 26-27.

Q. Is there any problem with conducting two economic screens in this way?

A. Yes. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and supposedly "optimized" with supply-side resources.[16] This approach is especially problematic if the first screen is unduly constrained, either by using incorrect free-rider assumptions, by using incorrect definitions of the screening tests, or by ignoring some key benefits such as avoided GHG emissions—all of these flaws appear in DEF and FPL's methods. Consequently, when DEF and FPL insert their narrowly-defined set of "cost-effective"

[16] As described in the following subsection, FPL does not actually optimize the combination of supply-side and demand-side options. This, however, does not mitigate the flaws identified in this subsection.

DSM measures into their resource planning process, there are too few DSM measures to meet resource planning needs, and DSM's value is significantly understated.

This practice essentially results in "double-screening" of DSM measures. I am aware of many states that screen DSM using a simple economic screen without resource modeling, and I am aware of many states that screen DSM using a resource planning process, but I am not aware of any states that use both combined. For good reason: doing so severely confines the resource planning process; needlessly complicates DSM screening; and obscures the critical fact that DSM is the lowest-cost, lowest-risk resource.

FPL Significantly Understates Avoided Capacity Benefits

Q. Please summarize how FPL compares DSM measures to supply-side resources.

A. FPL prepares a Supply-Only resource plan, which does not include any new DSM measures after 2014. This plan includes five approved and/or planned change to FPL's generating system, including: (a) retirement of existing Putnam units; (b) the completion of Port Everglades modernization; (c) the removal of existing gas turbines and the addition of 5 new combustion turbines in Broward County; the addition of the firm capacity portion of the EcoGen power purchase agreement; and the addition of Turkey Point Units 6 and 7. Direct Testimony of Witness Sim, Document No. 01476-14, at 21.

In the resource plans that include DSM, FPL includes a 1,269 MW combined cycle unit, as well as various amounts of purchase power agreements. *Id.*, Exhibit SRS-10. These are the resources that are potentially avoidable by DSM measures.

Q. Is this an appropriate way to compare demand-side resources to supply-side resources?

A. No. This methodology significantly understates the potential for DSM to help reduce capacity costs, by fixing the amount of capacity in the system that can be deferred, reduced or avoided by DSM.

First, this methodology freezes in place the five potential changes to FPL's generating system listed above. This means that DSM measures cannot defer, reduce the size of, or avoid several future supply-side resources, such as Turkey Point Unites 6 and 7, or new

combustion turbines. As shown in Sections 2 and 5, DSM costs significantly less than new supply-side resources, and could play a role in deferring, reducing or avoiding new supply-side capacity. The proposed Turkey Point units, in particular, are expected to be very expensive, and involve considerable risks for the FPL's customers. Any opportunity to further delay these units could offer significant benefits to customers. These benefits are not captured in FPL's resource planning process.

Second, the combined cycle unit that FPL used as the potentially avoidable unit was modeled with the fixed size of 1,269 MW. One of the advantages of combined cycle units is that they can be constructed within a wide range of sizes to best match system needs. DSM programs could potentially reduce the size of this unit, thereby saving significant capacity costs. FPL's methodology did not allow for this potential savings opportunity to even be investigated in its resource planning process.

Third, FPL does not even attempt to optimize supply-side capacity options relative to demand-side capacity options. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL does not use its optimization model to identify the best mix of supply-side and demand-side capacity resources. *See* FPL Responses to Sierra Club's Second Set of Interrogatories, Nos. SC-1-31 and SC-1-54. As a result, FPL has not investigated a variety of DSM plans that could potentially reduce utility system costs. This lack of modeling, combined with the first two points above, where FPL considers only a very limited amount of capacity options that can be avoided, demonstrates that FPL has significantly understated the potential for DSM measures to defer, reduce or avoid new capacity resources, thereby understating avoided capacity costs.

FPL's Planning Criteria Ignores Avoided Energy Benefits

Q. How does FPL determine the amount of DSM that should be included in its resource plans and DSM goals?

A. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs, as demonstrated in Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL identifies the amount of capacity needed to meet its 20 percent

reserve margin, either using supply-side or demand-side resources. In the DSM resource plan, FPL assumes the installation of enough DSM to meet any deficiency in the reserve margin, and no more. *Id*. at 41-43. This presumes that DSM measures can only be installed when they are needed for capacity or reliability purposes.

Q. Can DSM measures only be installed when there is a capacity need?

A. No, not at all. FPL ignores the fact that DSM can reduce energy costs, by reducing fuel consumption, even if there is no need for new capacity. FPL thus ignores one of the key benefits of DSM.

Further, FPL's DSM screening practices conflict with standard industry practice, and in fact conflicts with FPL's screening practices for supply-side resources. That is, if energy impacts were ignored on the supply-side, then peaking combustion turbines would be the lowest-cost way to meet future peak demand. Also, there would be no need to build baseload units, such as combined cycle facilities, conventional steam facilities, or nuclear facilities.

Clearly, this is not an appropriate way to plan a utility system. In fact, FPL describes the importance of considering both capacity and energy benefits when developing future resource plans, and states that it is necessary to "capture and accurately compare all of the impacts that competing resource options with different capacity amounts, terms-of-service, heat rates, types of fuel, MW and GWh reduction impacts, and costs will have on FPL's system." Direct Testimony of Witness Sim, Document No. 01476-14, at 43. FPL has failed to do so in its DSM planning, has essentially ignored DMS' energy benefits, and has thus dramatically understated the economic and achievable DSM potential.

<u>The Utilities' Fundamentally-Flawed Resource Planning Eliminates Most DSM</u>

Q. What are the ultimate implications of these flaws in the Utilities' resource planning process, in terms of setting DSM goals?

A. The Utilities' screening process rejects nearly all DSM programs leading to extremely low proposed DSM goals. Figures 4.1 through 4.4 present the bottom-line screening results for FPL and DEF, showing the amount of the technical potential, the economic potential under the RIM and the TRC tests, and the proposed DSM goals. For each

company the first figure is for the energy savings (in terms of GWh), and the second figure is for capacity savings (in terms of MW). As indicated in the figures, the proposed DSM goals are a small fraction of the technical, economic and achievable potential.

Figure 4.1 FPL Efficiency Savings at Various Screening Levels (GWh)[17]

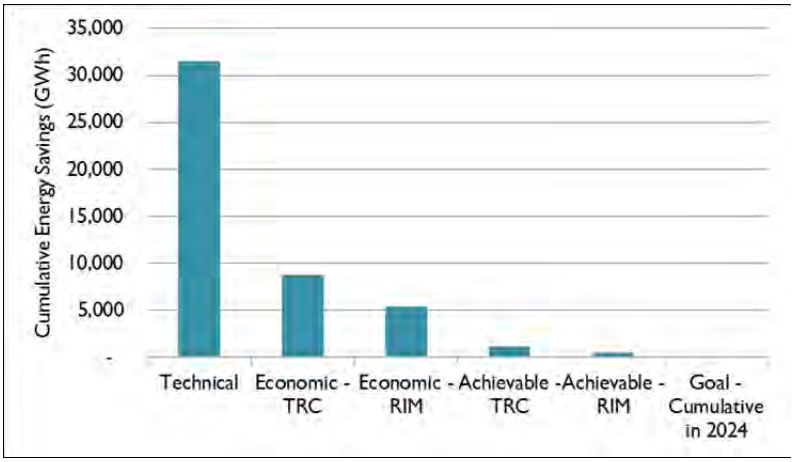
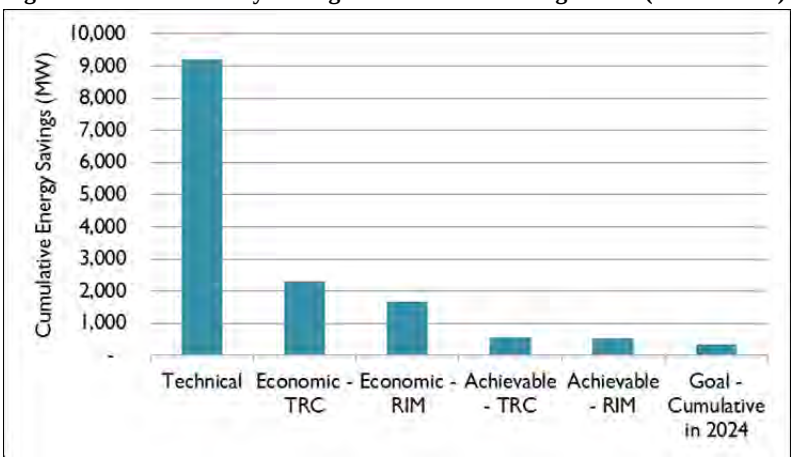


Figure 4.2 FPL Efficiency Savings at Various Screening Levels (Winter MW)[18]



[17] Based on Direct Testimony of Thomas Koch, Document No. 01475-14, Exhibits TRK-4, TRK-5, TRK-6, and TRK-7.
[18] *Id.*

Figure 4.3 DEF Efficiency Savings at Various Screening Levels (GWh)[19]

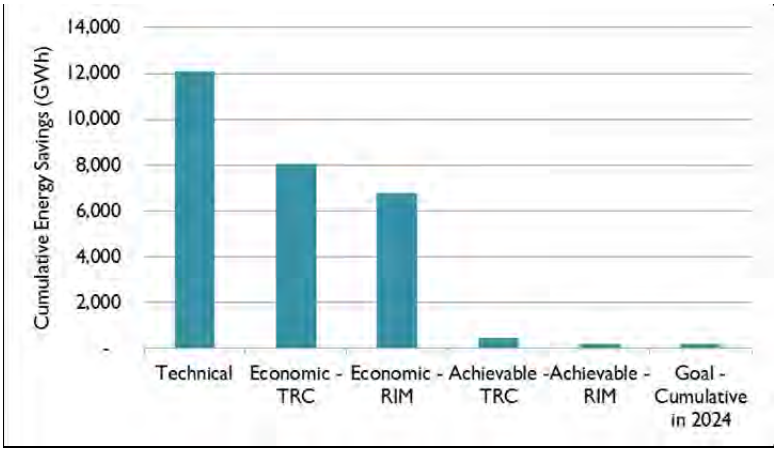
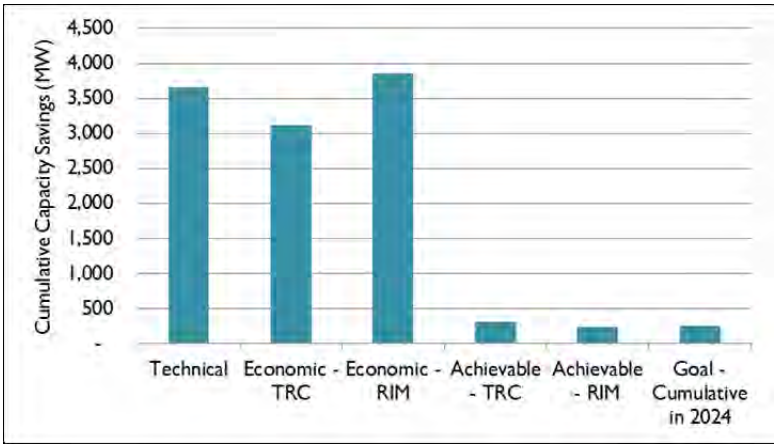


Figure 4.4 DEF Efficiency Savings at Various Screening Levels (Winter MW)[20]



Q. What do these results say about the Utilities' planning analysis?

A. First, recall that the Utilities' technical potential estimates are understated, for the reasons described above. Therefore, the DSM technical potential estimates should be higher than those presented above.

Second, the differences between the technical potential and the economic potential estimates are driven by applying the TRC, RIM and years-to-payback screens. These differences have a dramatic impact on the amount of economic potential, especially for

[19] Based on Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1, HG-5, HG-7, HG-8, HG-12, and HG-13.
[20] *Id.*

FPL. Given the flaws in the Utilities' attempts to use the RIM and TRC tests, as described in Section 3, and that a two-year-payback screen should not be applied at all, the economic potential estimates are clearly too low.

Third, the differences between economic and achievable potential estimates are driven primarily by the Utilities' assumptions regarding maximum incentive amounts and maximum customer signup rates. As described above, these assumptions are overly simplistic and do not account for the many opportunities for the Utilities to promote customer participation through program marketing and delivery options.

Fourth, the differences between FPL's achievable potential estimates and DSM goals are due entirely to FPL's erroneous assumption that DSM can only be implemented for the purposes of meeting reliability requirements. The extent of this limitation is not apparent in the figures above, due to the scale of the vertical axis. FPL's cumulative achievable potential is estimated to be 526 GWh, but FPL has set its DSM goal at only 59 GWh. In other words, FPL has reduced its DSM goals by roughly nine times, because of FPL's incorrect assumption that DSM can only be implemented for the purposes of meeting reliability requirements.

Q. Are there other conclusions that can be drawn from the Utilities' resource planning processes?

A. The Utilities' resource planning process prioritize load management programs (i.e., those that curtail peak demand only), and place little, if any, priority on DSM programs (i.e., those that curtail both energy consumption and peak demand). Specifically, the Utilities' misguided view that DSM can only be implemented to meet reliability requirements strongly favors load management over energy efficiency.

Table 4.3 below provides weighted average summer peak reduction factors for the DSM measures being selected for different potential estimates and scenarios for FPL and DEF. While there are some differences between the Utilities, the Utilities selected resources that offer significantly more peak reduction per MWh energy savings in their achievable potential estimates and proposed goals. For example, FPL's technical potential on average

reduces about 0.3 kW summer peak per MWh energy savings, but FPL's goal is expected to reduce about 5.7 kW summer peak per MWh energy savings.

Table 4.3 Peak Reduction Factor by Scenario for FPL and DEF (kW peak per MWh)

Scenario	FPL	DEF
Technical	0.29	0.30
Economic TRC	0.26	0.39
Economic RIM	0.31	0.57
Achievable TRC	0.53	0.67
Achievable RIM	1.00	1.33
Goal	5.68	1.33

Q. Is there anything wrong with placing a high priority on load management programs?

A. No, not necessarily. Load management programs offer a very low-cost opportunity for the Utilities to reduce demand in the most expensive hours of the year. I encourage the Utilities to maintain, or expand, these programs. My concern is that the Utilities place too much emphasis on load management programs, and not enough emphasis on energy efficiency programs. In doing so, the Utilities are missing the opportunity to significantly reduce electricity costs and to help "protect the health, prosperity and general welfare of the state and its citizens," pursuant to Section 366.81, F.S.

5. THE CENTRAL ISSUE: BALANCING RATE AND BILL IMPACTS

Q. Why is it so important that the Utilities and the Commission strike an appropriate balance between rate impacts and bill impacts?

A. As noted above, this is the primary challenge facing the Commission in setting DSM goals. DSM offers many advantages, with the primary advantage being that DSM reduces utility system costs and thereby reduces customer bills. The one (and only) countervailing consideration is that DSM can potentially increase electricity rates. To understand the implications of rate impacts, it is necessary to consider three important factors: rate impacts, bill impacts, and efficiency program participation rates. Taken together, these three factors indicate the extent to which customers as a whole will benefit from DSM.

Q. Do the Utilities' provide any meaningful information on these three factors in their filings in this docket?

A. No. As described above, the Utilities' analyses of rate impacts are so misguided and replete with flaws that they provide no information that would be useful to the Commission. In fact, the rate impact information that the Utilities provide is very misleading and should be ignored in its entirety. The Utilities' TRC analyses are also flawed, particularly because they ignore several key benefits such as avoided GHG regulatory compliance costs and participant non-energy benefits. Finally, the Utilities do not even provide results for the Utility Costs test, which is the one test that could provide the most information about the impacts on utility revenue requirements and thus the impacts on customer bills.

Q. How, then, do you recommend that the Commission consider the important issues regarding rate impacts and bill impacts?

A. I provide below some high-level information regarding the issues of rate, bills and participants. This information is helpful in illustrating the key tradeoffs that should be considered in setting DSM goals.

DSM Rate Impacts Will be Very Small

Q. How do you recommend that the Commission consider rate impacts associated with the DSM goals?

A. There is very little evidence presented in this case on what the actual rate impacts of the Utilities' DSM goals are likely to be. The Utilities estimates of lost revenues and rate impacts are clearly overstated and therefore unreliable. Even with this caveat, FPL's and DEF's own results suggest that the rate impacts of the DSM plans they have analyzed are likely to be very small, so small as to be unnoticeable by most customers. For these reasons, I recommend that the Commission give very little weight to concerns about the DSM goals discussed in this docket imposing an undue burden on customers as a result of rate impacts.

Q. Has the Commission recently issued an order indicating what an undue rate impact might be?

A. Yes. In Docket No. 1001155-EG, the Commission considered the potential rate impacts of FPL's DSM Plan proposed in that docket. The Commission determined that rate impacts of FPL's proposed DSM plan would cause an undue rate impact on customers. Order No. PSC-11-0346-PAA-EG, at 4. The Commission, therefore, rejected FPL's proposed DSM plan, and required FPL to maintain its existing DSM Plan because its rate impacts were determined to be relatively minor. Order No. PSC-11-0346-PAA-EG, at 5.

Q. How does that precedent impact your assessment of rate impacts here?

A. The Commission's Proposed Agency Action Order in Docket No. 1001155-EG included an estimate of the potential rate impacts of the proposed DSM Plan on a typical residential customer. Those rate impacts were estimated by determining the Energy Conservation Cost Recovery (ECCR) charge needed to support FPL's proposed DSM Plan, and adding those costs to the estimated residential bill. The results indicated that typical residential customer bills could increase in the range of 1.9 – 3.4 percent. Order No. PSC-11-0346-PAA-EG, Table 1.

The methodology used to estimate these rate impacts is very simplistic and does not account for the fact the DSM programs also exert downward pressure on rates. DSM programs reduce generation, transmission, distribution and other costs, which reduces a utility's revenue requirements, which in turn reduces customer rates. These avoided costs are significant and will outweigh the increase in revenue requirements associated with the DSM costs. This downward pressure on rate impacts is not accounted for in the rate impact estimates presented in Order No. PSC-11-0346-PAA-EG.

The downward pressure on rates is especially important in light of the magnitude of rate impacts that result from the installation of baseload power plants. When FPL has a rate case to recover the costs associated with a new power plant, such as Turkey Point Units 6 and 7, there will likely be much higher rate impacts than any impacts associated with DSM programs. DSM can help offset, reduce, defer or even totally avoid some of the rate impacts of large new power plants, but the rate impact estimates presented in Order No.

PSC-11-0346-PAA-EG do not account for any of these benefits. Consequently, they significantly overstate the potential rate impacts from DSM programs, and should not be used in setting DSM goals.

Higher DSM Goals Would Result in Lower Costs and Lower Bills

Q. How do you recommend that the Commission consider bill impacts associated with the DSM goals?

A. As noted above, the Utilities' resource planning process provides little information regarding the extent to which DSM can reduce customer bills. Even worse, the Utilities' overly-complex and overly-constrained screening process actually obscures the undisputable fact that DSM costs significantly less than alternative supply-side resources.

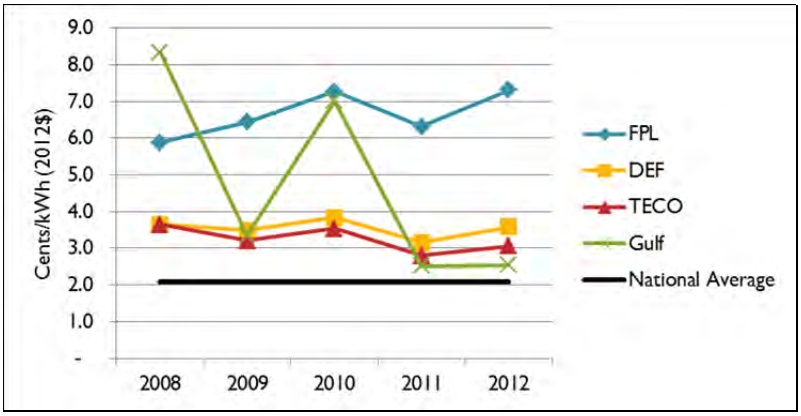
I provide some information below to illustrate this key point. I compare the "cost of saved energy" from DSM programs to the cost of generating energy from alternative sources, in terms of levelized costs.

Q. What is the cost of saved energy from DSM programs?

A. The cost of saved energy (in cents/kWh) is simply a ratio of the cost of implementing DSM programs (in dollars) divided by the energy savings (in GWh). The cost of saved energy can be presented in terms of either annual energy savings, lifetime energy savings, or in terms of levelized lifetime energy savings. I prefer to use levelized lifetime energy savings, because these can then be compared directly to levelized costs of supply-side alternatives.

Figure 5.1 presents the levelized cost of saved energy for the four largest electric utilities in Florida, for 2008 through 2012. It also presents the national average levelized cost of saved energy for 2012, for comparison purposes. As indicated, DEF and TECO have been achieving efficiency savings for roughly 3 to 4 cents/kWh; FPL has been achieving efficiency savings for roughly 6 to 7 cents/kWh; and Gulf's costs have varied considerably over this period.

Figure 5.1. Levelized Cost of Saved Energy: Florida Utilities versus National Average.[21]



Q. What conclusions do you draw from Figure 5.1?

A. First, the DSM programs offered in Florida are considerably more expensive than the national average. I expect this is due more to program design and implementation than it is due to anything unique about Florida.

Second, DEF and TECO have demonstrated that it is possible to implement DSM programs in Florida for roughly 3 to 4 cents/kWh. There is no reason why FPL and the other utilities cannot implement efficiency programs at this level of costs as well.

Third, no matter which utility you look at, DSM is significantly less expensive than supply-side alternatives.

Q. How do you know that DSM is significantly less expensive than supply-side alternatives?

A. Figure 5.2 compares the cost of several generation technologies to the cost of saved energy. The levelized cost of FPL's proposed Turkey Point nuclear unit is estimated by the Company to be roughly 16 cents/kWh.[22] The levelized cost of DEF's proposed Levy nuclear unit is estimated by Synapse Energy Economics to be roughly 17 cents/kWh as a

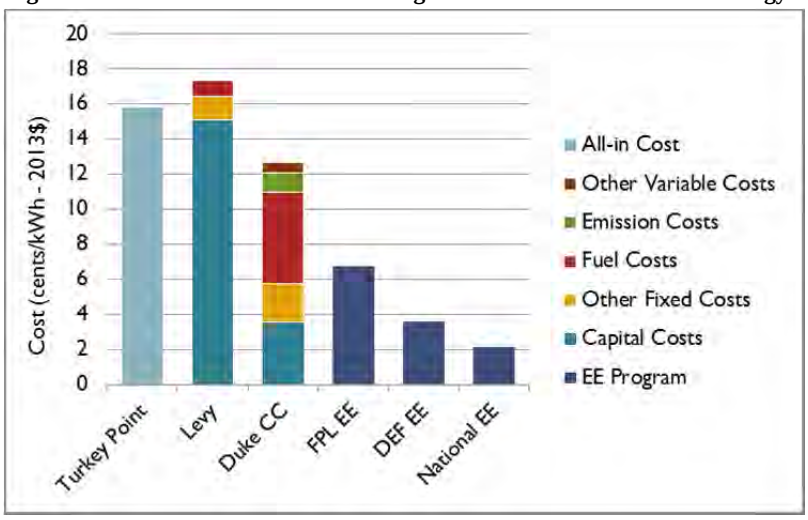
[21] Note that these costs and savings are for the energy efficiency programs offered by the Florida utilities. They do not include the costs or savings for the load management programs, because this metric is much less relevant for programs that have few energy savings.

[22] FPSC, "Hearing Proceedings of Docket No. 130009-EI, Nuclear Cost Recovery Clause" (August 14, 2013), Volume 4, at 821.

mid-point estimate.[23] The DEF CC unit is the cost of a combined cycle unit that DEF used in this docket in its resource planning process.[24] The cost of saved energy values for DEF, FPL and the national average are taken from Figure 5.1.

As indicated in Figure 5.2, the costs of DSM programs are well below those of the supply-side alternatives that those programs could potentially displace. Note that the avoided costs of transmission and distribution associated with the supply-side generation technologies are not included in Figure 5.2, making those resources look less expensive than they really are.[25] Also, note that the DSM programs can help reduce the reserve margin requirements (in MW), and reduce line losses, unlike the supply-side options.

Figure 5.2. Cost of Generation Technologies versus the Cost of Saved Energy



[23] Synapse Energy Economics. "Big Risks, Better Alternatives - An Examination of Two Nuclear Energy Projects in the U.S." October 6, 2011.

[24] The cost estimate is based on the underlying cost assumptions for the "CC2X1 P1 - COMBINED CYCLE" unit provided in Excel file, "Sierra Club ROG 1-13 - Avoided Costs.xlsx" as part of Duke's response to Sierra Club Interrogatory No. 1-13.

[25] According to FPL's response to Sierra Club Interrogatory No. 1-13, the avoided cost of transmission and distribution systems are approximately $150/kW-year and $27/kW-year respectively.

Q. Figure 5.1 presents supply-side and demand-side resource costs in a relatively simple format. Is it not necessary to account for more details of how the two types of resources would affect the utility system, by using resource planning processes?

A. A more detailed resource planning process would provide a better, more comprehensive picture of the costs and benefits of DSM programs in Florida. However, there are two very important conclusions that can be drawn from Figure 5.1, despite its simplicity.

First, DSM programs cost significantly less than supply-side resources. They can cost as little as 2, maybe 4, maybe 6 cents per kWh, while supply-side options cost as much as 12, 16, or even 17 cents/kWh (even before avoided transmission and distribution costs are factored in, or accounting for reserve margin benefits or line loss benefits).

Second, reduced costs from DSM programs will result in reduced customer bills. All of the costs that are shown in Figure 5.1 would eventually be included in a utility's revenue requirements, and passed on to customers. Therefore, the savings resulting from DSM programs would be passed on to customers in the form of lower average customer bills. In fact, the data in Figure 5.1 is the only data presented so far in this docket that provides any indication of how DSM might help reduce customer bills. None of the Utilities' analyses presents information on the impact on customer bills, and yet this is one of the key factors that the Commission should consider in setting DSM goals. I recommend that the Commission consider the information in Figure 5.1 when considering the bill impacts of the proposed DSM goals.

Program Participation Will Mitigate Rate Impacts

Q. Why is it so important to consider program participants, when analyzing rate and bill impacts?

A. Generally speaking, program participants are essentially shielded from the rate impacts of DSM programs; they experience reduced bills as a result of reduced consumption, regardless of any rate increases. Therefore, to the extent that rate impacts appear to be a problem, it is essential to consider the offsetting impact of program participation, in order to understand the extent of the problem.

Q. Do you have any information to offer regarding DSM participation rates?

A. Yes. Figures 5.3 and 5.4 present historic and forecast participation rates for FPL's DSM programs. These are taken from the Company's most recent Annual DSM Report.[26] The participation rates in these figures are based on the number of historic and forecast participants divided by the eligible population of participants. Note that the forecast of participants are based on placeholder goals that FPL was forecasting at the time it prepared the Annual DSM Report. If the Commission were to approve the lower DSM goals proposed by FPL in this docket, then the future participation rates would be much lower than those presented in Figures 6.3 and 6.4.

Figure 5.3. FPL Cumulative Participation Rates – Residential Programs

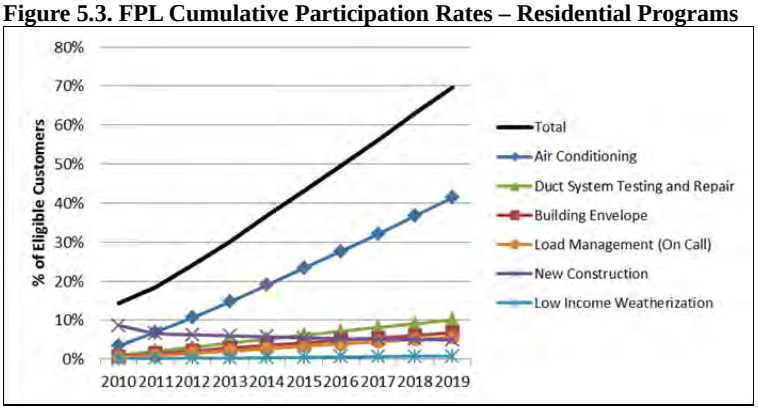
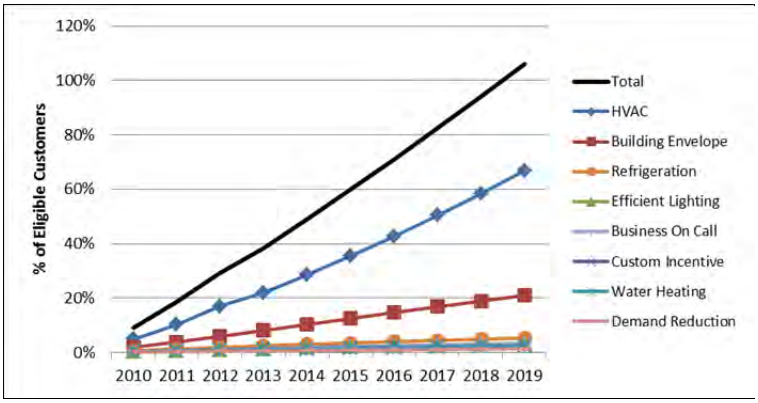


Figure 5.4. FPL Cumulative Participation Rates – Commercial & Industrial Programs



[26] FPL. "2013 Demand Side Management (DSM) Annual Report." February 28, 2014.

Q. What conclusions do you draw from the participation rates presented in Figures 5.3 and 5.4?

A. This information suggests that FPL would be able to serve a significant portion of its residential, commercial and industrial (C&I) customers with DSM programs—if FPL were to continue with the goals it had at the time of the Annual DSM report published in February this year. Roughly 40 percent of residential and 60 percent of C&I customers could be served with air conditioning or HVAC services. Roughly 10 percent of residential and 20 percent of C&I customers could be served with building envelope measures. The total amount of participation could reach up to 70 percent for residential customers, and 100 percent for C&I customers.

In addition, the participation information presented above does not include any of the customer participation that occurred prior to 2010. If this were included in the information presented above, then the cumulative participation rates would be significantly higher.

It is important to note that there are probably instances of multiple participation embedded in the participation rates presented in Figures 6.4 and 6.5. Multiple participation occurs when a single customer participates in more than one program in a single year, or in more than one program across years. Multiple participation is common in DSM programs, and is not discouraged; in fact it is encouraged. I mention this phenomenon to note that in some cases the participation information presented in Figure 5.4 and 6.5 may be somewhat over stated.

In sum, it is safe to conclude that a large portion of FPL's customers has been, or could be, served by the DSM programs. To the extent that there are any significant rate impacts as a result of these programs, they will be offset by efficiency savings for a large portion of customers. This should be a central consideration when setting DSM goals.

A Better Balance Between Reduced Costs Against Increased Rates

Q. Please summarize the conclusions that you draw from the information above regarding rates, bills and participation.

A. There is no question that the Utilities could achieve significantly higher DSM goals, without causing a significant increase in electricity rates. The Utilities' own analysis shows that the rate impacts from higher DSM goals would be so small as to be in "the noise" of the analysis, and this result is from a resource planning process that *overstates* the rate impacts of DSM programs in many ways.

It is also clear that if the Utilities were to adopt significantly higher DSM goals, then customer bills would be reduced significantly. This is the basic conclusion from a straightforward comparison of the costs of supply-side and demand-side resources; unencumbered by opaque, unduly complex and constraining resource planning practices.

Furthermore, the Utilities could provide DSM services to a large portion of their customer base, thereby offsetting any rate impacts that do occur. This could be achieved by maintaining the DSM goals that were previously approved by the Commission in the 2009 goal-setting dockets. Participation could be expanded even further with higher DSM goals.

In sum, this high-level consideration of rate impacts, bill impacts and participation rates indicates that increased DSM goals would lead to greater benefits to "the general body of ratepayers as a whole," consistent with Section 366.82(3)(b), F.S. This is a much better indication of the issues at stake in these dockets than resource planning results presented by the Utilities.

6. ENERGY EFFICIENCY SAVINGS AND GOALS

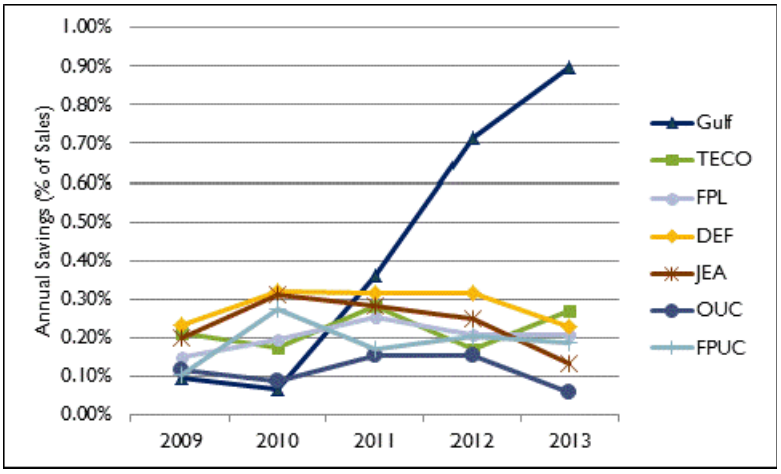
Efficiency Savings in Recent Years

Q. Please summarize the efficiency savings that have been achieved in recent years.

A. Figure 6.1 provides an overview of the energy savings achieved by the FEECA utilities in recent years. The energy savings are presented in terms of annual energy saved as a percent of annual retail sales. This allows for an easy comparison of savings across

utilities of different sizes. It also allows for easy comparison of savings across utilities in different states and regions of the country. As indicated, the Utilities saved roughly 0.1 percent to 0.3 percent of sales in this period, with Gulf achieving higher savings in the later years.

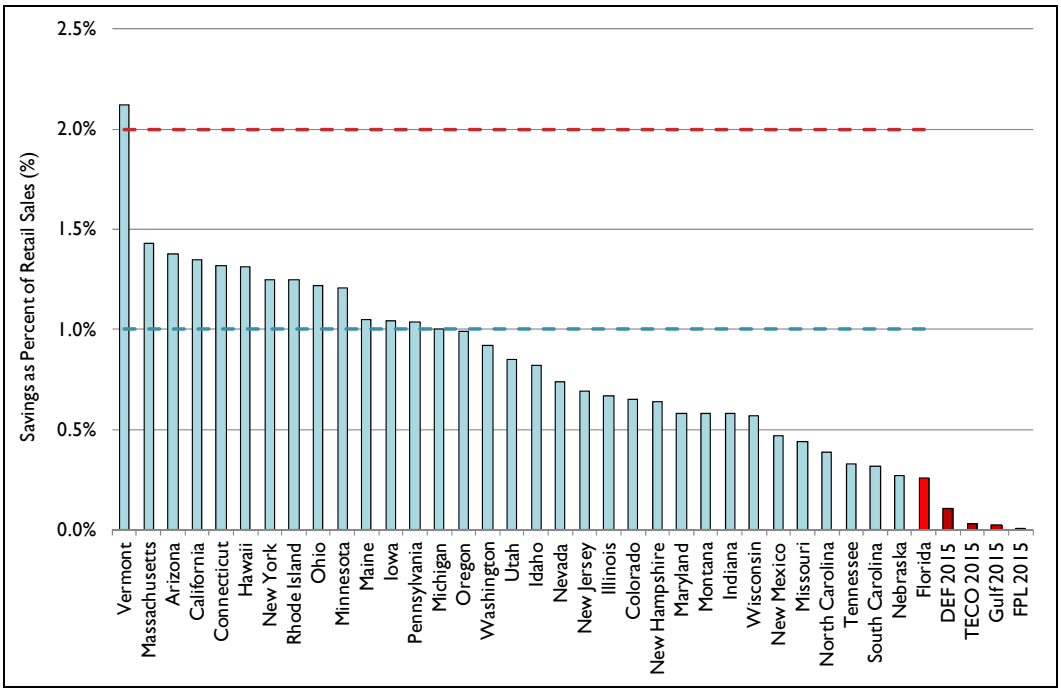
Figure 6.1 Efficiency Savings of Florida Utilities 2008 – 2013



Q. **How do the Utilities' DSM savings in recent years compare with savings by utilities in other states?**

A. Figure 6.2 presents the efficiency savings in 2011 from several states, including Florida, again in terms of percent of retail sales. The savings from all 50 states have been presented in order from the greatest to the lowest savings. To fit the graph onto the page, I have not presented the states that had less energy savings than Florida. As indicated, Florida's 2011 efficiency savings are less than those of 33 other states. Roughly 15 states achieved savings of 1 percent or more, and roughly half of all states achieved savings of 0.5 percent or more. In contrast, Florida saved just about 0.25 percent in 2011. Furthermore, these numbers are a little out of date; I am aware of many states that achieved higher levels of savings in 2012 than in 2011.

Figure 6.2 Efficiency Savings in 2011: Top US States and Florida



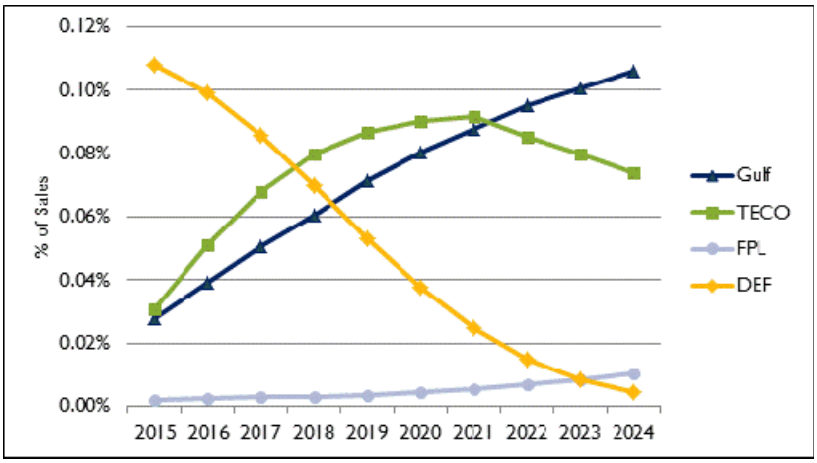
In sum, the Florida utilities are not one of the leading states in terms of delivering DSM savings. Figure 6.2 also presents the proposed 2015 DSM savings goals for the four largest Florida utilities. As indicated, the 2015 DSM goals are well below Florida's 2011 savings, and are well below the historic savings of many other states. I return to this point in the next subsection.

The Utilities' Proposed Efficiency Goals

Q. Please summarize the efficiency goals proposed by the Utilities.

A. Figure 6.3 presents the DSM savings goals proposed by the four largest FEECA utilities. As indicated, DEF's proposed goals start out higher than the others, d then decline significantly during this period. FPL's proposed goals start out much lower than the others and rise slightly during this period. TECO's proposed goals increase significantly at first, then decline in the second half of this period. Finally, Gulf's proposed goals increase significantly throughout this period.

Figure 6.3. Proposed Goals (2015-2024)



Q. How do these proposed goals compare with the amounts of savings achieved by the Utilities in recent years?

A. Figure 6.4 combines the historical savings from Figure 6.1, with the proposed goals presented in Figure 6.3. As indicated, the proposed DSM goals are dramatically lower than the amount of savings achieved in recent years.

Figure 6.4 Historic Savings and Proposed Energy Goals

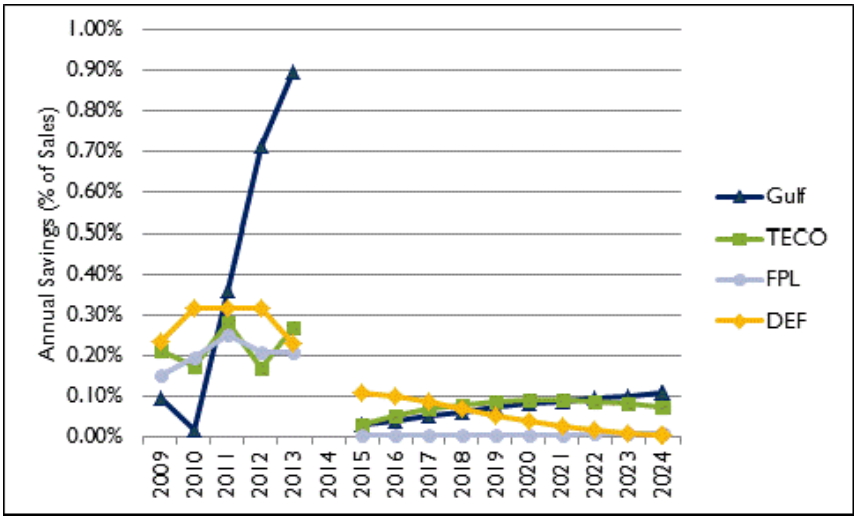


Table 6.1 Historic and Proposed Savings Goals (GWh)

	FPL	DEF	TECO	Gulf
2009	155	88	40	10
2010	204	124	34	8
2011	261	119	52	40
2012	211	115	32	76
2013	214	84	50	95
2014	---	---	---	---
2015	2	40	6	3
2016	3	37	10	4
2017	3	33	13	6
2018	4	27	15	7
2019	4	21	17	8
2020	5	15	18	9
2021	7	10	18	10
2022	8	6	17	11
2023	10	4	16	12
2024	13	2	15	13

Q. Are there any high-level conclusions that can be drawn from the historical and proposed savings levels presented in Figure 6.4?

A. Yes. First, the DSM goals proposed by these four utilities are well below the levels of efficiency savings that they themselves have achieved in recent years. FPL's proposed 2015 goal is less than the company's 2013 savings by a factor of 100. This is a dramatic reduction in DSM goals. DEF's 2015 goal is roughly half of its 2013 savings level. It is also remarkable that FPL is proposing to reduce its DSM goals by so much more than the reductions proposed by the other companies. There is no reason why there should be such striking differences between the goal reductions across the four utilities.

Second, these four utilities (FPL, DEF, TECO, and Gulf) are all proposing inconsistent trends for savings over the DSM goals period. Some propose a dramatic increase over the period, some propose a dramatic decrease over the period, and Gulf proposes both. There

is no logical explanation for such differences in the trends over this period. These Utilities have roughly similar customer bases, and will be exposed to similar efficiency standards and building codes over this period. The differences between the savings trends across the utilities can only be explained by inappropriate assumptions and methodologies, poor planning practices, or some combination of both.

Third, the proposed 2015 goals are dramatically less than the savings achieved by other states, as indicated in Figure 6.2, above. In 2011, over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, and 15 states saved roughly 1.0 percent of retail sales or more. If the Commission were to accept FPL's proposed DSM goals, then *FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country*.

Q. The Utilities have argued that their DSM goals should be lower than in the past, because they have already implemented much of the efficiency savings available in Florida. Do you agree?

A. No. Relative to many other states the Utilities' DSM programs have not achieved large amounts of energy savings in the past. Figure 6.2 illustrates how small the Florida efficiency savings were in 2011 relative to other states. Data from earlier years demonstrate the same point. Relative to the achievements of many other states, the Utilities have left a large portion of the efficiency savings potential in Florida untapped.

In addition, the Utilities' argument is based on a very simplistic understanding of DSM programs, markets and opportunities. The potential for DSM savings is not a stagnant figure, that a utility can pursue for several years and then claim that it has finished the job. Instead, efficiency products are constantly being introduced into the marketplace, creating new opportunities for efficiency savings every year. The recent introduction of LED lighting products is but one example of how new products can create new opportunities for efficiency savings. Furthermore, and more importantly, utility DSM programs should constantly evolve to account for new developments in the market. Utility efficiency programs should constantly be seeking new efficiency measures to promote, considering new marketing and delivery opportunities, and looking for new ways to overcome customer barriers to DSM measures. This is how efficiency programs

are designed in the leading states, and why those states have been able to achieve significantly higher savings than Florida in the past, and plan to achieve higher savings than Florida in the future. I address this point in more detail in the following subsection.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because avoided costs are lower than they have been in the past. Do you agree?

A. No. First, the Utilities have understated avoided costs by not properly accounting for GHG compliance costs and by ignoring participant non-energy benefits. If these costs were properly included in their analysis, then the economic potential for DSM would be higher than indicated by the Utilities.

Second, the Utilities' efficiency programs cost much less than supply-side alternatives, as indicated in Figure 5.1—even under the Utilities' current assumptions of avoided costs. This means there is still lots of room for the efficiency program benefits to exceed the costs, even though avoided costs are less than they were in the past.

Third, this argument would only make sense if the Utilities were implementing the total economic potential for DSM (i.e., all cost-effective energy efficiency), both in the past and proposing to do so going forward. If avoided costs decline for some reason, then the total economic potential for DSM would decline as well. However, the Utilities have not implemented the total economic potential in the past, and they do not propose to implement the total economic potential in the future. Their past savings and future goals are based on implementing the achievable efficiency potential, and only a portion of the achievable efficiency potential at that. This means that there is likely to be a significant amount of efficiency potential that is still available, despite the lower avoided costs.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because new building codes and efficiency standards will diminish the amount of efficiency available. Do you agree?

A. No, not entirely. It is true that increasing building codes and standards will make it more difficult to achieve DSM savings over time. However, this does not mean that the potential for efficiency savings will be reduced by anywhere near the amount indicated by the Utilities' proposed goals.

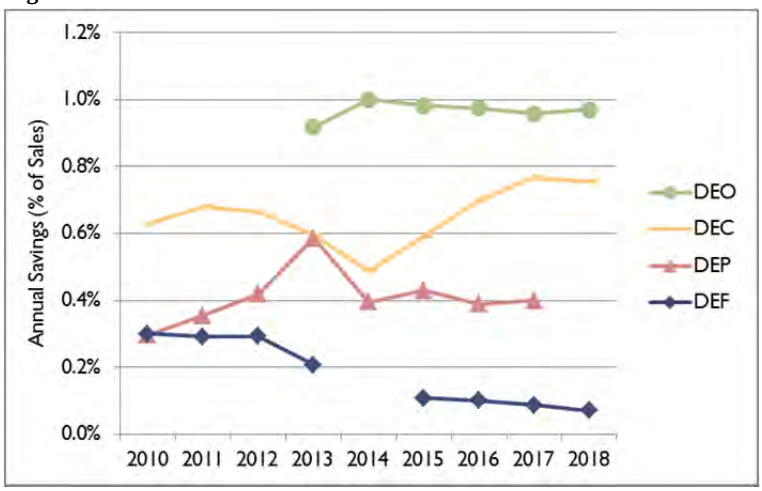
Figure 6.4 shows that some utilities propose future DSM goals that are a small fraction of their recent savings. DEF's proposed DSM goal for 2020 is roughly 15 GWh, which is six times lower than the savings that DEF achieved in 2013. Increasing efficiency standards and building codes will not have such a dramatic effect on the potential efficiency savings available in DEF's service territory. Furthermore, as new efficiency standards begin to take effect, the Utilities should modify their DSM programs to offer additional efficiency measures that are more efficient than the standards. Promoting the purchase of LED lighting products in response to the new federal lighting standards is one example of how utilities in general should respond to the new federal standards. In addition, as efficiency standards are applied to some end-uses (e.g., lighting), utilities should generally place greater emphasis on other types of end-uses where efficiency opportunities still remain.

Efficiency Goals in Florida Relative to Other States

Q. How do DEF's DSM savings goals compare with the efficiency savings of other Duke utilities?

A. Figure 6.5 presents DEF's efficiency savings in recent years, as well as proposed DSM goals, alongside those of Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Duke Energy Ohio (DEO). As indicated, the other Duke companies have already achieved significantly higher levels of efficiency savings than DEF, and have set significantly higher goals for future efficiency savings.

Figure 6.5 Duke Florida Goals Relative to Duke Goals in Other States



Q. What conclusions do you draw from this comparison of efficiency goals across Duke's companies?

A. First, DEF should be able to achieve roughly the same goals as other Duke companies. There is no reason why DEF cannot implement the same types of efficiency programs, offer the same types of efficiency measures, and achieve roughly the same amount of customer participation as other Duke companies. As I describe in more detail below, the differences between these companies is more due to the regulatory environment in each state than the achievable efficiency potential. In addition, DEO, DEC and DEP have all achieved greater savings than DEF in recent years; thus, the goals for these other Duke companies contradict DEF's argument that it has already achieved much of the achievable efficiency potential available in Florida. If that argument were true, then DEO, DEC and DEP could not have saved more energy than DEF in the past and still have higher goals the future.

Furthermore, DEO, DEC and DEP will all be subject to the same federal efficiency standards as DEF; thus the goals of the other Duke companies contradicts DEF's arguments that the achievable potential in Florida is shrinking dramatically due to federal efficiency standards. Finally, even if one were to agree with DEF's arguments that there is less achievable efficiency potential in Florida relative to other states, which I do not, there is no way to justify the magnitude of the difference between DEF's proposed goals, and those of other Duke companies. DEF's proposed efficiency goals are roughly one-tenth the size of DEO's. This means that DEF is proposing to forgo 90 percent of the efficiency savings that DEO is able to achieve. There is no justification for depriving customers of such a large opportunity to reduce system costs and reduce customer bills.

Q. Are you aware of other states in the Southeast that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. I am aware of one state in the Southeast that has recently established significantly higher efficiency goals than those proposed by the Utilities. The Arkansas Public Service Commission recently issued a set of orders that outline several regulatory policies affecting the planning and implementation of DSM programs there. The orders require

several significant changes to these regulatory policies, including the introduction of decoupling, the introduction of shareholder incentives, the requirement to incorporate non-energy benefits into the TRC test, and more. One of the key elements of the recent orders is a set of efficiency goals for the next several years. The Arkansas Commission has required that the electric utilities ramp up their efficiency programs over the next few years, so that they achieve savings equal to 1.0, 1.25 and 1.5 percent by 2014, 2015, and 2016, respectively. I have seen no evidence in this docket indicating that the Florida Commission cannot set comparable goals for the Florida utilities.

Q. Are you aware of other states in the US that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. Yes. I have been involved in three states that have achieved, and plan to continue to achieve, significantly more than what the Utilities are currently achieving or what the Utilities are proposing for their DSM goals.

Massachusetts: In 2012 the Massachusetts program administrators achieved electric efficiency savings equal to 2.1 percent of sales. The energy savings goals that the efficiency program administrators set for the years 2013 to 2015 are 2.50, 2.55 and 2.56 percent of sales each year, respectively. These goals have been approved by the Massachusetts Department of Public Utilities.

Rhode Island: In 2012, the Rhode Island program administrator achieved electric efficiency savings of 1.5 percent of sales. The energy savings goals for 2013 and 2014 are 2.05 and 2.44 percent of sales per year, respectively. These goals were approved by the Rhode Island Public Utilities Commission. The program administrator and other stakeholders are currently proposing energy savings goals for 2015-2016 equal to 2.50, 2.55 and 2.60 percent of sales each year, respectively. These goals have been approved by the Rhode Island Public Utility Commission.

Vermont: As noted above, Vermont has achieved significant energy savings of roughly 2 percent per year on average for the past five years, cumulatively achieving 10 percent savings over those years. The state currently has efficiency savings goals of roughly 2 percent per year for 2012 – 2014. The state is currently in the middle of a planning docket

to set future efficiency savings goals, where the base case proposal is for annual savings goals to of roughly 1.7 percent of retail sales through 2019, 1.4 percent of retail sales through 2026, and 1.3 percent of retail sales through 2033.

Note that all three of these states have been implementing some of the most aggressive and successful efficiency programs in the country for many years. Also, note that the energy savings goals above account for federal efficiency standards, as well as state and local standards and building codes. Even so, *these states are setting DSM goals that are more than 100 hundred times greater than the goals being proposed by the Company in this docket.* There is no justification for such a wide disparity energy efficiency opportunities across these states.

Sierra Club Proposed Efficiency Goals

Q. Does the Sierra Club recommend that the Commission set different DSM goals than the goals proposed by the Utilities?

A. Yes. The Utilities' DSM goals are way too low, for all the reasons outlined above. I recommend that the Commission set significantly higher goals, in order to reduce costs to Florida electricity customers.

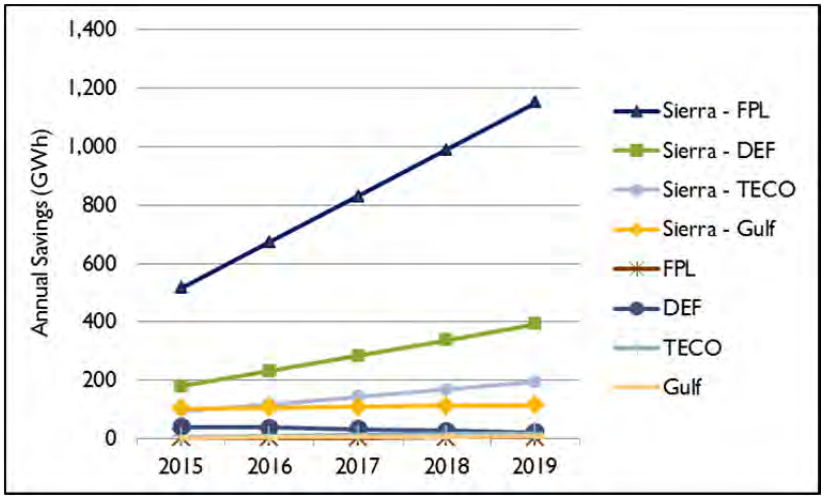
Q. What DSM goals do you recommend for the Florida utilities?

A. I recommend that the Commission set DSM goals such that each of the FEECA utilities will achieve annual efficiency savings equal to one percent of annual retail sales by 2019. These goals are presented in Table 6.2 and Figure 6.6

Table 6.2 Sierra Club DSM Goals (2015-2019) - GWh.

	FPL	DEF	TECO	Gulf
2015	516	180	95	103
2016	673	231	118	106
2017	830	283	143	109
2018	990	337	168	112
2019	1152	394	193	114

Figure 6.6 Sierra Club Goals Relative to Utilities' Goals (2015-2019) – Percent of Sales



Q. Do you recommend that the Commission set goals for capacity savings as well?

A. Yes. It is important that the Commission set goals for both energy (GWh) and capacity (MW) savings. Up until now I have focused on energy savings, as I believe that energy savings are an important indication of the magnitude of a utility's DSM efforts. However, the Commission should set capacity savings as well, as this is different indicator of the magnitude of a utility's DSM efforts.

In fact, it is important for the Commission to consider the ratio of energy savings per capacity savings (MW/GWh), because this provides an indication of the type of programs the Utilities offer—in particular the emphasis that the Utilities are placing on energy efficiency programs relative to load management programs.

Q. Please explain why it is important for the Commission to consider the emphasis that the Utilities are placing on energy efficiency programs versus load management programs when setting DSM goals.

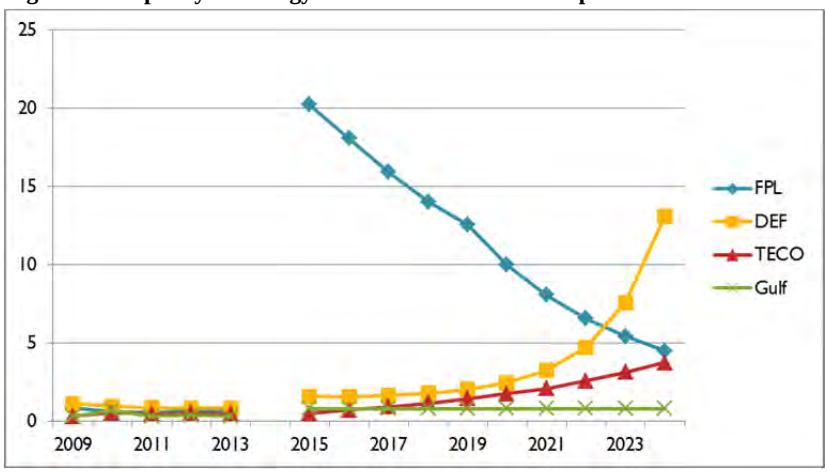
A. Energy efficiency and load management programs both offer benefits to the Utilities and their customers, and the Utilities should offer a proper balance of both types of programs. Load management programs offer some customers the opportunity to reduce their costs in some portions of the year. Energy efficiency programs offer a wider range of opportunities to a wider range of customers, relative to load management programs. Energy efficiency programs also offer customers the potential for reducing their energy consumption by a much greater amount that load management programs. Therefore, if

too much priority is given to load management programs, at the expense of energy efficiency programs, then many customers will be deprived of opportunities to reduce their costs and bills.

Q. Do the Utilities' proposed DSM goals provide a good balance of load management and energy efficiency programs?

A. No. The Utilities have historically placed a much higher emphasis on load management programs and capacity savings than the utilities that I typically work with. More importantly, the Utilities' proposed goals make a dramatic shift toward increased capacity savings and load management, relative to historic programs. This is demonstrated clearly in Figure 6.7, which present capacity-to-energy ratios for the four Utilities, for historic and proposed DSM goals. Note that a higher capacity-to-energy ratio indicates a greater emphasis on load management, relative to energy efficiency.

Figure 6.7 Capacity to Energy Ratios – Historic and Proposed Goals



For some reason that the Company has not explained, FPL's capacity-to-energy ratio is much, much higher than it has been in past years, and is far higher than the other Utilities presented here. FPL's ratio then declines precipitously over the course of the next ten years. The other four utilities start their proposed DSM goals with higher than historic ratios, and then increase them over the course of the period, with DEF's ratios increasing dramatically more than the others.

Q. What conclusions do you draw from the capacity-to-energy ratios presented in Figure 6.7?

A. These capacity-to-energy ratios raise several concerns for the Commission to be aware of. First, these Utilities are clearly planning to make a dramatic shift away from energy efficiency programs toward load management programs. This suggests that they will not be placing much, if any, emphasis on energy efficiency savings, and may therefore deprive customers of large opportunities to reduce costs and bills.

Second, the FPL capacity-to-energy ratios do not make any sense. There is no reason why a utility would make such a major shift toward load management programs in the two years between 2013 and 2015, and then make a shift back away from load management programs. This result suggests that FPL's planning process is flawed, or that the Company is not paying sufficient attention to these important results of its own planning process, or both.

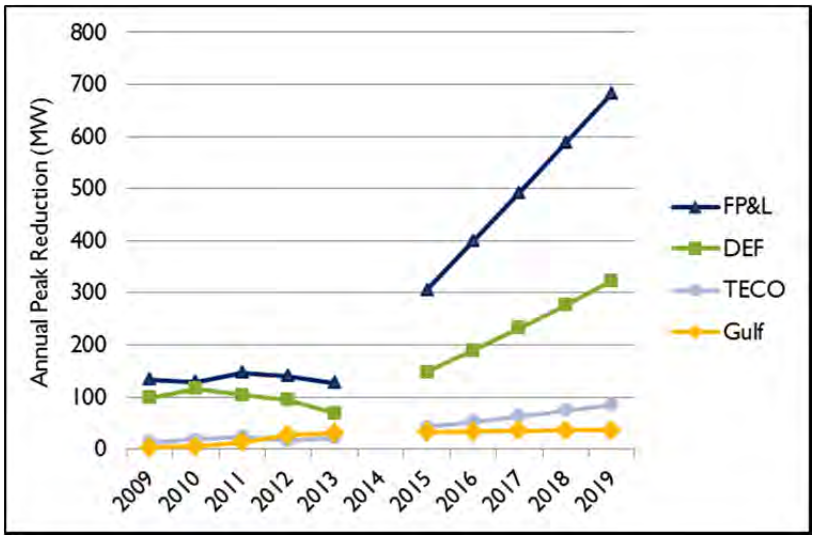
Third, there is a big difference in the ratios across the four Utilities presented in Figure 6.7. There is no good reason for such differences across utilities within the same state. These differences suggest that customers in some of the utilities will not be as well served by the DSM programs as other customers.

Fourth, the Company's do not mention this shift away from energy efficiency programs in their filings. Such an important change in their DSM profiles certainly warrants bringing to the Commission's attention, so that the Commission can make an informed decision on an important shift in DSM priorities and services to customers.

Q. How then have you set capacity DSM goals?

A. I start with the simplistic assumption that the ratio of capacity to energy savings achieved in 2013 is a reasonable balance of energy and capacity savings. I then hold this ratio fixed for the purpose of setting the Sierra Club DSM capacity goals, for each company. I then apply this ratio to the GWh savings of the Sierra Club DSM goals, to back out a capacity goal for each year. The results are provided in Figure 6.8 below.

Figure 6.8 Annual Peak Reduction from DSM – historic and Sierra Club Goals.



Q. Did you rely upon the Utilities' economic analyses or resource planning results in developing the Sierra Club DSM goals?

A. Yes, but only in a limited way. After reviewing the Utilities' economic analyses and resource planning results, I have determined that they suffer from so many fundamental flaws that they are of very limited value for the purpose of setting DSM goals. Even worse, they are misleading in several ways. My reasons for reaching this conclusion are described in detail in Sections 3 and 4 of my testimony.

Q. How then did you develop the Sierra Club DSM goals?

A. These goals are based upon the limited information of value that the Utilities did provide in their analyses in this docket, combined with my extensive knowledge of DSM opportunities, achievements and plans in other states.

As indicated in Section 5 of my testimony, and illustrated in Figure 5.2, there is no question that DSM programs in Florida cost significantly less than supply-side alternatives in Florida, and that increased efficiency savings will result in significantly lower costs to electricity customers.

In addition, I have considered the likely rate impacts of the Utilities' proposed DSM goals, as well as the potential rate impacts of the proposed Sierra Club goals, and it is clear that the average, long-term rate impacts of both sets of goals are likely to be very

low. In the case of the Utilities' proposal, they are likely to be so low as to be "in the noise" of the analysis. The rate impacts of the Sierra Club goals will not be much higher than those of the Utilities' goals.

Furthermore, I have considered the likely customer participation rates that could result from the Utilities' goals, as well as the Sierra Club goals. Under both sets of goals, the Utilities should be able to serve a large portion of customers with efficiency programs, thereby offsetting any increases in rates that might occur. And the Sierra Club's higher goals should result in significantly greater participation levels than the Company's proposed goals, thereby mitigating customer equity and cross-subsidization concerns, and resulting in greater benefits for the "general body of ratepayers as a whole."

As described above, one of the key challenges in setting DSM goals is striking the appropriate balance between reduced costs and increased rates, which requires consideration of rates, bills and customer participation. On these points, the evidence that I present above indicates that the Sierra Club DSM goals strike a good balance and will be in customers' best interest.

Q. How do you know that the Utilities will be able to achieve the Sierra Club's DSM goals ?

A. I am confident that all Florida electric companies have the technical, economic and achievable potential of at least one percent of retail sales, for several reasons. Gulf achieved nearly this level of savings in 2013. If Gulf can achieve this level of savings, there is no reason that the other Utilities cannot. In addition, Duke Energy Ohio has achieved nearly this level of savings, and has goals to achieve one percent savings. If Duke Energy Ohio can achieve savings of one percent by 2014, then surely Duke Energy Florida can achieve similar savings levels by 2019.

Furthermore, I have seen the amounts of efficiency savings that are available in other states, that have been achieved in other states, and that are planned to be achieved in other states. I know the types of efficiency programs, marketing, delivery, customer incentives, and other factors that can be utilized to achieve savings of at least one percent of retail sales. There is no reason that the Utilities cannot achieve savings of at least one

percent of retail sales by 2019, given the levels of savings that have been achieved in other states.

Q. But Florida is a different state from the other states. How can you be sure that the experience in other states is relevant to Florida?

A. First of all, I have worked on the topics of DSM planning and integrated resource planning for most of my 30-year career, and I have addressed these issues in states all across the US, as well as several Canadian provinces. I have prepared many national studies on DSM screening and analysis, including the studies for the National Efficiency Screening Project. I have prepared several regional studies where I estimated the potential for DSM and renewable resources over the long-term horizon; including a study of the Southeast, a study of the Midwest, and a study of the West. I have reviewed state-specific DSM plans and integrated resource plans in many states. In my experience, I have found that most, if not all, states face the same issues, the same barriers, and the roughly same potential for DSM savings. My findings and recommendations are based on my experiences in all of these states and provinces.

Second, the biggest difference between states and provinces affecting the development of DSM programs is the regulatory environment; it is not the customers, or the end-uses, or the climate of the state or province. The regulatory environment is created by legislation, by regulations, and by Commission orders. The legislation in Florida provides as much support for DSM as legislation in many states; this does not pose a barrier to DSM in any way. The Commission's regulations similarly are fairly supportive of DSM relative to other states; they do not pose a barrier to DSM either. The biggest difference between the regulatory environment in Florida and other states is the signals that the Commission sends regarding DSM screening. And the Commission has complete control over the signals that are sent from this point forward. In fact, I believe that given the right regulatory environment, and sufficient time, the Utilities should be able to achieve annual DSM savings of as much as two percent of retail sales. I recommend a DSM goal of one percent of sales by 2019 in this docket to allow time for the Utilities and the relevant trade allies to ramp up to this higher level of DSM savings.

Third, one of the biggest differences between Florida's regulatory environment and those of other states is that many of regulators and other stakeholders, especially those in the leading states, recognize that *well-designed, cost-effective DSM is good for customers*. By this I mean that the advantages that DSM offers customers (i.e., reduced bills, reduced generation costs, reduced transmission and distribution costs, increased reliability, reduced risk, environmental benefits, and more) far outweigh any disadvantages to customers (i.e., very small, if any, increases to long-term average rates). It is ironic, misguided, and very misleading for the Utilities to try to argue that they should limit their DSM goals to protect customers from alleged rate increases or potential cross-subsidization of customers. This implies that cost-effective DSM is somehow bad for customers, when in fact the opposite is true.

Note that while I am representing Sierra Club in this docket, roughly half of all of my clients are either consumer advocates or regulatory commissions. I make similar recommendations for those clients; all on the same concept that well-designed, cost-effective DSM is good for customers.

7. DEMAND-SIDE RENEWABLES

Solar PV Potential

Q. Please briefly describe the results of the technical potential estimates for solar PV by Duke and FPL.

A. As part of this docket, five of the seven utilities subject to FEECA have updated their original technical potential for solar photovoltaic (PV) along with other DSM measures that were estimated by Itron in 2009. The updates for solar PV have been made just to take into account the historical PV projects installed to date since the original study was conducted and the growth of the rooftop areas for additional PV capacity. The results are that Florida utilities still have plenty of PV technical potential. For example, FPL identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. DEF identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. See Tables 7.1 and 7.2, below.

Table 7.1 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[27]

	Summer Peak Capacity MW			Annual Generation GWh		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	14,055	13,815	9	38,136	37,488	27
Duke	5,054	5,000	1	13,737	13,593	6

Table 7.2 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[28]

	Summer Peak Capacity (% of 2012 Peak Demand)			Annual Generation (% of 2012 Sales)		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	66%	64%	0.04%	37%	37%	0.03%
Duke	56%	55%	0.01%	38%	37%	0.02%

Tables 7.1 and 7.2 also show that there have been very little solar PV installations in the Utilities service territories (i.e., cumulative increase of only 0.01% to 0.04% of peak load for the past 4 to 5 years), and the increase in PV capacity due to increased rooftop areas outpaced the capacity additions. This resulted in a slight increase in the total PV capacity potential for 2014 for the two utilities (about 2% increases for FPL and 1% for DEF) when compared with the original estimates made in 2009.

Q. How do the conclusions and methods of the Itron potential study compare with other technical potential estimates you are aware of?

A. Given that not all FEECA utilities have updated their PV potential estimates and new estimates are likely to be very similar to the original estimates based on our review of FPL and DEF's updates, I am comparing the 2009 Itron study results with the results from a recent national solar PV potential study by the National Renewable Energy Laboratory (NREL). For methodologies, Itron made no changes to the original methods

[27] Based on Thomas R. Koch's Exhibit TRK-4 for FPL, Document No. 01475-14, and Helena Guthrie's Exhibit HG-5 for DEF, Document No. 01497-14.
[28] 2012 sales and peak load data for FPL and DEF are from US EIA.

except subtracting the recent solar development and adding new roof space for additional solar.

NREL estimated technical potential of solar PV resources for each state across the United States in 2012 using the geographic information system (GIS). NREL analyzed the technical potential for solar capacity additions across multiple technologies. While Itron only studied the technical potential of rooftop PV installations in the state, NREL examined utility scale PV in both urban and rural settings, in addition to concentrated solar power potential., I will focus on the rooftop PV potential estimates in these two studies.

The conclusions of the NREL study are similar to those of the Itron study: although NREL predicts a higher potential capacity for rooftop solar in Florida, the two studies forecast a similar potential for energy generated through rooftop PV installations in the state. See Table 7.3 below.

Table 7.3 Comparison of Solar PV Potential Results for Florida

	NREL 2012	Itron 2009
GW of potential	49	30
GWh of potential	63,987	69,449
Given state energy consumption	231,210	159,795
Potential as % of Itron consumption assumption	40%	43%
Potential as % of NREL consumption assumption	28%	30%

Similar to the Itron study, the NREL study bases the rooftop PV technical potential calculation on three main variables: available rooftop area; size of the PV module; and the capacity factor for the given region.

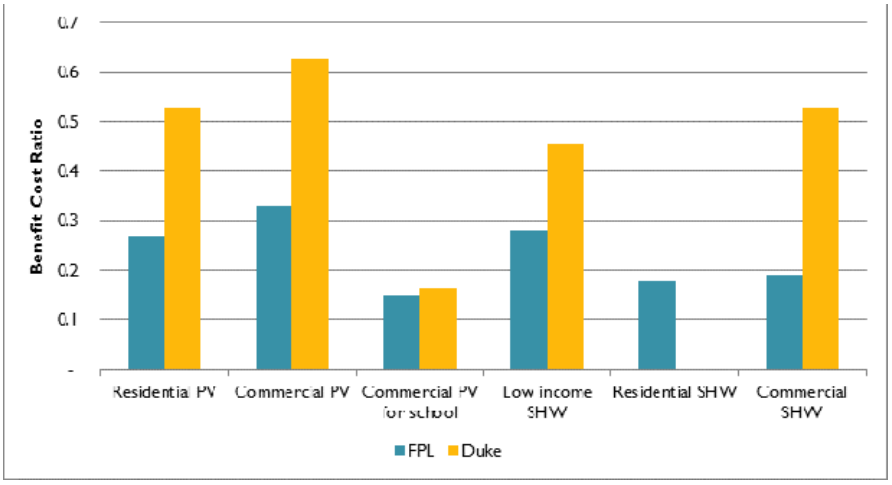
Q. Please briefly describe the results of the achievable potential estimates for solar PV and solar hot water (SHW) by FPL and DEF.

A. DEF and FPL do not provide achievable potential or economic potential for solar resources because their analysis found solar resources are not cost-effective in their jurisdictions.

Q. Please present cost-effectiveness for FPL and DEF's solar pilot programs.

Figure 7.1 presents benefit cost ratios estimated by both companies for their solar PV and solar hot water pilot programs. FPL and DEF proffer that these pilots have benefit cost ratios below 1 under the TRC test.

Figure 7.1 TRC Test Results (Benefit Cost Ratios) of Solar PV Pilot Programs



However, it is highly likely that solar PV and solar hot water could be more cost-effective than the Utilities suggest, as the Utilities do not fully take into account full benefits of demand-side resources and do not assume declining costs of solar PV systems in the future. Secondly, from the utility's perspective using the Utility Cost test, solar PV could be already cost-effective without fully including missed benefits, especially for DEF.

Lastly, note that it is odd that FPL's benefit cost estimates are about half of DEF's estimates for the residential and commercial solar PV pilots. There is a high likelihood that either FPL or DEF are underestimating or overestimating avoided benefits of solar PV systems given that system costs should not differ much between their service territories.

Q. Please explain why the Utilities are not fully taking into account the benefits of solar systems.

A. In a recent meta-analysis of solar PV benefit cost studies, the Rocky Mountain Institute examined 15 studies in detail, and identified that there are numerous benefits of solar PV. This finding indicates that the benefits from solar PV could exceed the costs when

benefits are fully considered. For example, four out of the 15 studies found the benefits of solar PV exceeds 20 cents/kWh, and the two of the studies found benefits exceeding about 30 cents/kWh.

The types of benefits identified in the study are (a) avoided energy, (b) avoided generation, transmission and distribution capacity, (c) avoided grid support services (e.g., reactive supply and voltage control), (d) financial risk hedge (e.g., fuel price hedge and market price response), (e) security risk reduction, (f) environmental benefits (e.g., reduction in CO2 and criteria pollutants and water), and (g) economic development (e.g., jobs and tax revenues). FPL and DEF only include benefits from (a) and (b). While they do include some carbon costs in their sensitivity analysis of DSM measures, as discussed above in Section 3, they underestimate carbon costs for complying with future environmental regulations. Further, the Utilities incorrectly assume zero carbon costs in their base case.

Q. Are the costs assumed by the Utilities reflective of forecasts of future PV costs?

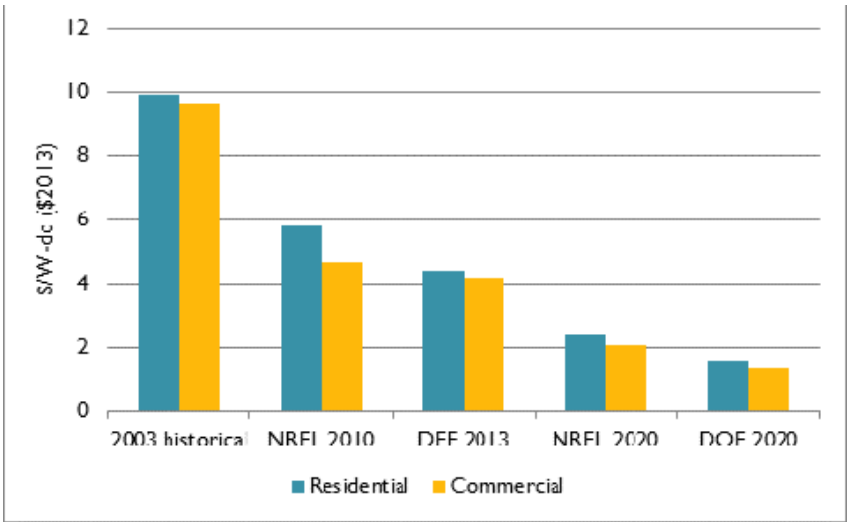
A. No. The Utilities cost-effectiveness results for solar PV are only based on the costs of the current pilot program. *See*, *e.g.*, Direct Testimony of Witness Koch, Document No. 01475-14, at 28–29; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 49 –51. If this is also the case for the formal economic screening, the Utilities are significantly undervaluing the benefits of solar PV for the next decade because price forecasts for PV such those by NREL and US DOE show declining costs.

Q. Please provide solar PV price forecasts by NREL and US DOE and compare them with the current and historical prices.

A. NREL and US DOE have recently developed solar PV price forecasts for the residential and commercial systems. Figure 7.3 provides their price forecasts along with historical prices in 2003, 2010, and 2013. The “DEF 2013” in this figure represents today’s solar PV prices in Florida based on DEF’s data. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 51. Solar PV installed prices have declined by more than half relative to the prices in 2003 as shown in Figure 7.3. Going forward, NREL and

DOE are predicting that solar PV prices will be reduced further by more than half from today's level of $4 per Watt-DC to $2 to $1.5 per Watt-dc levels by 2020.[29]

Figure 7.3 History and Forecast of Installed Costs of Solar PV Systems[30]



US DOE's price forecast represents aggressive price reduction targets under its SunShot Initiative where solar PV prices are reduced by 75% by 2020 from the 2010 levels.[31] In contrast, NREL's price forecast is based on its detailed simulations of silicon module manufacture costs and represents an evolutionary—or business-as-usual—development trajectory for PV prices. NREL indicates that the difference between the evolutionary projections and SunShot targets highlights the need for innovative system designs and installation methods to complement module-level cost reductions.[32]

These low projected installed costs of distributed solar PV systems will result in significantly low levelized costs of solar PV systems by 2020 at levels that are lower than

[29] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012; US DOE. "SunShot Vision Study." February 2012.

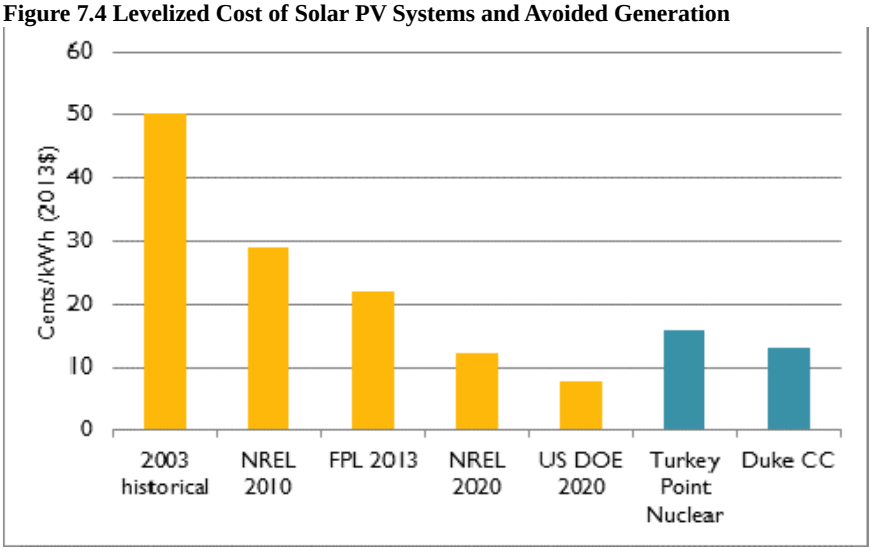
[30] The 2003 historical prices are based on LBNL. "Tracking the Sun VI An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012," July 2013. The "NREL 2010" prices are based on NREL (2012) and represents NREL's simulated historical PV prices used as benchmarking prices to be compared with the NREL's 2020 price forecasts.

[31] US DOE. "SunShot Vision Study." February 2012.

[32] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012.

the levelized costs of new nuclear and natural gas combined cycle power plants as presented in Figure 7.4 below.[33] This means that within the Florida Utilities' 10-year planning horizon solar PV is likely to be cheaper and more cost-effective than the traditional supply-side resource options, even excluding the avoided costs of transmission and distribution systems.

Figure 7.4 Levelized Cost of Solar PV Systems and Avoided Generation



Solar PV Goals

Q. Please describe the solar PV resource goals proposed by Duke and FPL.

A. Both Duke and FPL did not present any goals for solar PV and proposed to discontinue their demand-side solar pilot programs mainly because they found solar pilot programs are not cost-effective, as shown in Figure 7.1**Error! Reference source not found.** above. In addition, DEF's Witness Guthrie and FPL's Witness Koch question whether the programs' rebates are influencing the market to reduce costs or increasing the availability of solar technologies for customers. *See* Document No. 01497-14, at 51; Document No. 01475, at 30. Further, Witness Guthrie tries to cite the competitiveness of the solar market in Florida as another reason for discontinuing solar rebates and the solar pilot programs

[33] The levelized cost of the residential solar systems are estimated based on (a) the installed costs as presented in Figure 7.3, (b) a 20 year economic life, (c) a 19% capacity factor, and (d) a 5% discount rate. The capacity factor was obtained from NREL's PVWatts for Florida. The levelized costs of Turkey Point nuclear power plants and a combined cycle power plant were taken from Figure 6.2 above in my testimony.

Document No. 01497-14, at 50. More specifically, Witness Guthrie states that Florida's solar market has matured significantly over the last five years, and that Florida is "among the most cost competitive states in the U.S." for solar technologies based on a recent report from Green Tech Media and Solar Electric Industries Association. Document No. 01497-14, at 50

Q. Do you agree with FPL and DEF's proposal to discontinue the solar pilot programs?

A. No. I believe it is premature to discontinue the solar pilot programs, and evidence presented by FPL and DEF to support their position is not compelling for the following reasons:

1. FPL and DEF did not provide compelling evidence for their position nor any study to support their positions. Decisions such as those proposed by the Utilities to discontinue the solar pilot should be based on the results of an independent evaluation similar to the evaluation typically conducted for energy efficiency programs.

2. As discussed in Section 3, the Utilities do not properly account for the benefits of reducing GHG emissions, thereby understating the economic value of the solar pilot programs.

3. Promoting customer-side renewable energy meets FEECA requirements and objectives. FEECA's overall goals are to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, FEECA is specifically designed "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id*.

4. Florida has some of the lowest levels of solar PV installations in the country, despite DEF's claim that Florida is among the most-competitive state for solar.

This indicates that there remains considerable opportunity for more solar installations in Florida.

5. Several other states have aggressive solar PV goals in place that are in effect over the next 5 to 10 years.

6. The cost of solar PV is expected to decline further, and to improve cost-effectiveness of solar PV systems.

7. FPL and DEF haven't provided compelling evidence that solar rebates are not influencing the market, and there is possibility that they could enhance or redesign the solar pilots to increase the program's influence on the market.

Q. How much PV capacity Florida has installed to date, and how does it compare with capacity installed in other states?

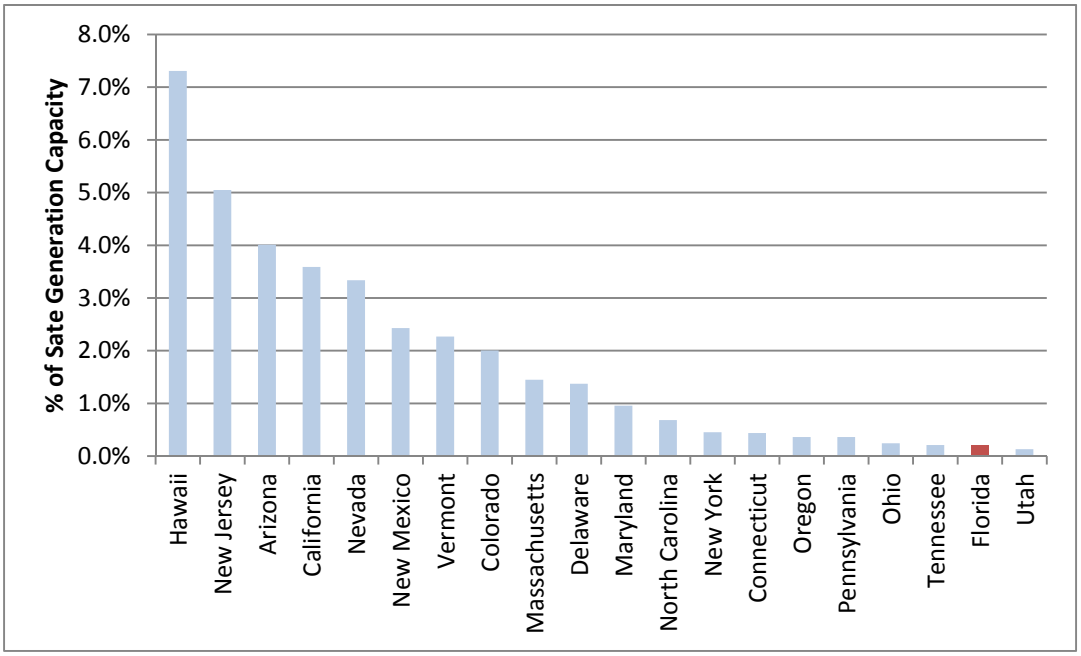
A. Despite the significant amount of solar resource potential in the state and despite DEF's claim that Florida is among the most-competitive state for solar, Florida has installed just about 120 MW of grid connected solar PV as of the end of 2012 according to the Interstate Renewable Energy Council.[34] This ranks Florida 13th in terms of capacity installed in the nation, but ranks 19th in terms of solar PV capacity as a percentage of state total generation. See Table 7.5. As a percentage of state generation capacity, the majority of the top 20 states have installed two to thirty times more solar PV capacity than Florida has installed to date. Note also that more than half of the states with the highest proportion of grid-connected solar photovoltaic capacity to date have less solar resources than Florida. These data imply that Florida's solar market is not competitive, and has not yet matured. Further, the Utilities could and should offer continued, and even more effective support for installations of solar PV.

[34] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013.

Table 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity

Rank	State	Capacity Added in 2012	Cumulative Capacity at the end of 2012	Cumulative Capacity (% of State Generation Capacity)
1	Hawaii	114	200	7.3%
2	New Jersey	391	956	5.1%
3	Arizona	709	1106	4.0%
4	California	983	2559	3.6%
5	Nevada	226	350	3.3%
6	New Mexico	38	203	2.4%
7	Vermont	16	28	2.3%
8	Colorado	103	300	2.0%
9	Massachusetts	123	207	1.5%
10	Delaware	20	46	1.4%
11	Maryland	80	117	1.0%
12	North Carolina	122	208	0.7%
13	New York	56	179	0.5%
14	Connecticut	8	40	0.4%
15	Oregon	21	56	0.4%
16	Pennsylvania	31	164	0.4%
17	Ohio	48	80	0.2%
18	Tennessee	23	45	0.2%
19	Florida	22	117	0.2%
20	Utah	6	10	0.1%

Figure 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity[35]



[35] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013;US Energy Information Administration, "Electricity Power Monthly," Table 6.2A, January 2014,

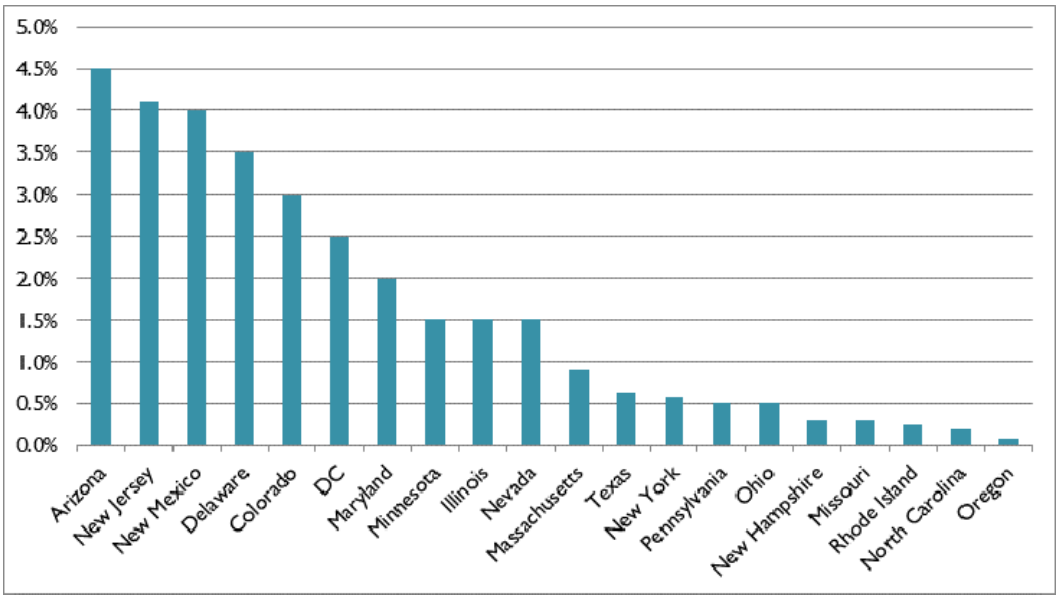
Q. Please describe PV goals established by other states.

A. Across the nation, there are approximately 20 states that require utilities to support the development of solar PV and renewable energy distributed generation systems as part of their renewable energy portfolio standards (RPSs). These states established targets specifically set for promoting either solar system in general (including solar PV and solar hot water), solar PV systems, or distributed generation. **Error! Reference source not found.** 8.6, below, presents a summary of such solar/DG policies along with a normalized target as a percentage increase per year. Figure 7.6 provides just cumulative PV/DG targets. State targets range from 0.1% of sales to 4% of sales in five to fifteen year periods. More than half of the states promote solar/DG at a level exceeding 0.10% per year on average, and 7 states promote solar/DG at more than 0.2% per year on average. In contrast, PV systems installed on FPL and DEF's systems over the past 5 years are very small. Those systems generate about 6 GWh for DEFand 27 GWh for FPL, which are about 0.02% to 0.03% of their 2012 sales or 0.003% to 0.005% per year over a 5 year period or 0.005% to 0.009% per year over a 3 year period (which corresponds to the period of the solar pilot programs).

Table 7.6 Summary of Solar/Distributed Generation Targets under State RPS Policies[36]

State	Technology goal (as % of sales)	Technology	Target Year	% Target per Year of Policy
Arizona	4.50%	DG	2025	0.24%
New Jersey	4.10%	Solar	2027-2028	0.27%
New Mexico	4.00%	Solar	2020	0.31%
Delaware	3.50%	PV	2025-2026	0.23%
Colorado	3.00%	DG	2020	0.30%
DC	2.50%	Solar	2023	0.21%
Maryland	2.00%	Solar	2020	0.15%
Minnesota	1.50%	Solar	2020	0.13%
Illinois	1.50%	PV	2025-2026	0.11%
Nevada	1.50%	Solar	2025	0.09%
Massachusetts	0.90%	Solar	2020	0.13%
New York	0.60%	DG	2015	0.12%
Texas	0.60%	Non-Wind	2020	0.04%
Pennsylvania	0.50%	PV	2020-2021	0.04%
Ohio	0.50%	Solar	2024	0.03%
New Hampshire	0.30%	Solar	2014	0.04%
Rhode Island	0.30%	Solar	2020	0.02%
Missouri	0.30%	Solar	2021	0.02%
North Carolina	0.20%	Solar	2018	0.02%
Oregon	0.10%	PV	2025	0.01%

Figure 7.6. Summary of Solar/Distributed Generation Targets under State RPS Policies (% of Sales)



[36] Developed based on information from the DSIRE website, available at http://www.dsireusa.org.

Q. Do you think utility programs could influence Florida's solar PV market? If so, please explain how.

A. Yes. As explained in DEF and FPL's testimony, the number of payback years influence consumer decisions for adopting energy efficiency measures, and customer payback should influence customers' decisions whether to purchase solar PV and Solar Hot Water (SHW) systems. Thus, if the Utilities were to provide some kind of financial support such as rebates or low-interest loans to their customers, such support should increase the number of customers adopting solar systems.

Utility programs could even reduce purchase price of solar systems instantly if the programs could purchase systems in bulk by teaming up with a handful of solar PV installation or marketing companies. Overtime, more installation will develop the solar system installation market in the state, spur competition, and reduce costs.

Q. Should the Utilities continue to offer their solar rebate programs?

A. Yes. These programs are consistent with FEECA's policy goals and provide benefits to participants, as well as system-wide benefits to all customers. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, it is the intent of "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id.* Solar PV systems clearly meet most of these objectives and benefits, and are likely to be cost-effective today if benefits are fully accounted for, and are highly likely to be very cost-effective by 2020 as discussed above in my testimony.

Q. Should Florida utilities modify their rebate program designs?

A. Yes. Florida utilities including Duke and FPL should investigate further whether the current level of incentives is sufficient or excessive to spur solar system development in

the state. If they find rebates are excessive, they could consider to what extent rebates should be reduced.

In addition, the utilities should consider offering low-interest loans for solar systems along with reduced level of rebates. In some cases, loans are more helpful than rebates for customers to install solar systems because there are always customers who do not have capital or access to loans.

Lastly, as mentioned above, the utilities should consider coordinating solar system installations by their customers so as to take advantage of bulk purchase practices.

Q. What do you recommend that the Commission do with regard to demand-side renewable goals in this docket?

A. I recommend that the Commission require the Utilities to continue to provide PV programs to their customers, with the modifications to the current programs outlined above. In addition, the Commission should open a separate docket to investigate appropriate additional goals for demand-side renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar PV systems.

8. REGULATORY SUPPORT

Treatment of Lost Revenues

Q. Do you think the Utilities should be allowed to recover lost revenues from efficiency programs somehow?

A. Yes. The Utilities should not be penalized financially as a result of successful implementation of efficiency programs. Without recovery of these lost revenues, the Utilities cannot be expected to implement comprehensive, meaningful efficiency programs, their customers will be deprived of the lowest-cost resource, and total electricity costs will be significantly higher.

Q. How should the Utilities recover the lost revenues from DSM programs?

A. I recommend that the Commission require the Utilities to implement a revenue decoupling mechanism to recover the lost revenues from DSM programs. Decoupling is a

modification to traditional ratemaking that allows a company to recover a target level of revenues, regardless of the level of sales that occur between rate cases.

Revenue decoupling does not suffer from the fundamental flaws listed above regarding direct recovery of lost revenues. Revenue decoupling provides much more comprehensive and much better financial incentives with regard to all the Utilities' actions that might affect customer sales. I have been involved in several states that use direct recovery of lost revenues as well as several states that use revenue decoupling, and the difference is striking. Utilities that are allowed revenue decoupling are significantly more supportive of DSM and other demand resources, and the entire regulatory context around efficiency and demand resource planning is significantly less contentious and adversarial. Further, there are ways to design revenue decoupling mechanisms that not only protect consumers but ensure that customers are better off than under traditional ratemaking.

If the Commission does not somehow address the recovery of lost revenues, then it is very likely that the Utilities will continue to understate the value of DSM, propose sub-optimal DSM goals, and deprive customers of the opportunity to significantly reduce their electricity bills.

Q. Has the issue of decoupling been addressed before by the Commission?

A. Yes. In December 2008 the Commission prepared a report to the Legislature on utility revenue decoupling. FPSC, *Report to the Legislature on Utility Revenue Decoupling* (Dec. 2008), *available at* http://www.psc.state.fl.us/publications/pdf/electricgas/ Decoupling Report_To_ Legislature.pdf. At that time, the Commission decided not to implement revenue decoupling, because "Florida is already paving a path toward the objectives of decoupling without incurring the cost and difficulties associated with design, implementation and maintenance of a specific decoupling mechanism." *Id*. at 5.

Q. Is there evidence in the current dockets that the Utilities are paving a path toward more comprehensive implementation of cost-effective DSM programs?

No. In fact, the evidence presented in these dockets suggests the opposite. As described in Section 6, the Utilities' DSM programs are already much smaller than those of most

other states, and the DSM goals proposed in these dockets would essentially take the Utilities on a path of less and less DSM. In addition, the Utilities' analyses in these dockets are so clearly heavily biased against DSM programs, that one can only conclude that the Utilities really do not want to implement DSM programs and achieve DSM savings for their customers. This is quite likely due to the financial disincentive associated with DSM programs. A revenue decoupling mechanism would eliminate this disincentive, and create a much more positive regulatory environment for setting future DSM goals.

Q. How should the Commission proceed on this issue of decoupling?

A. I recommend that the Commission open a separate docket to investigate whether revenue decoupling should be implemented to align the Utilities' financial incentives with the state's efficiency policies and goals. There are many important implications of revenue decoupling, and the issues are best addressed in a docket dedicated to investigating them.

Shareholder Incentives

Q. Why is it necessary to provide utilities with shareholder incentives for implementing DSM programs?

A. While decoupling is necessary to eliminate the financial disincentive that utilities experience with efficiency, it does not provide utilities with positive financial incentives. When given the choice between investments in supply-side resources, which can be included in rate base and contribute toward utility profits, and investments in DSM that are simply passed through to customers, utilities will prefer the former.

Q. Does the Commission have authority to provide the Utilities with shareholder incentives for implementing successful DSM programs?

A. Yes. The recent amendments to FEECA allow the Commission to "authorize financial rewards for those utilities over which it has ratesetting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals." Section 366.82(8), F.S. Further, FEECA is to be liberally construed. *See* Section 366.81.

Q. Is it necessary that DSM programs be included in rate base in the same way that supply-side resource are?

A. No. The two investments have different financial and ratemaking implications, and thus do not need to be treated identically for shareholder incentive purposes. What is important is that the DSM shareholder incentives be: (a) large enough to provide the utility management with the incentive to pursue DSM programs; and, (b) designed in a way that encourages the implementation of cost-effective, successful DSM programs that are in the customers' best interests. It is also important to keep the shareholder incentives reasonably low, so that customers are not required to pay more than necessary for a utility to implement successful DSM programs.

Q. What type of shareholder incentive mechanism would you recommend to achieve these objectives?

A. Here I summarize an DSM shareholder incentive mechanism that the Commission should establish:

- A utility will have the opportunity to earn a maximum of eight percent of its total annual DSM budget as a shareholder performance incentive. The amount of this total incentive that each utility earns will depend on what portion of its efficiency savings target it achieves, as prescribed below.
- A utility will not be allowed to earn any shareholder incentive until it achieves at least 80 percent of its annual efficiency savings goal.
- If a utility achieves 80 percent of its annual efficiency savings goal, it will be entitled to keep four percent of the annual efficiency budget as a shareholder incentive
- If a utility achieves 100 percent of its annual efficiency savings goal, it will be entitled to keep six percent of the annual efficiency budget as a shareholder incentive.
- If a utility achieves 120 percent of its annual efficiency savings goal, it will be entitled to keep eight percent of the annual DSM budget as a shareholder incentive.

- If a utility achieves efficiency savings that are between 80 percent and 120 percent of its annual efficiency savings goal, it will be entitled to keep an portion of the annual DSM budget determined by linear interpolation between four and eight percent.

- Shareholder incentives will only be allowed for DSM program savings that are measured and verified and presented to the Commission in annual reports.

Q. How should the Commission proceed on this issue of shareholder incentives?

A. I recommend that the Commission consider the issue of shareholder incentives in the same generic docket that it uses for investigating revenue decoupling. Like decoupling, shareholder incentives require consideration of some important details, and most of the issues should be relevant to all Florida utilities. A single generic docket would allow the Commission to address both revenue decoupling and shareholder incentives in a comprehensive way.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.