I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Jim Grevatt. I am a Managing Consultant at Energy Futures Group, located at 10298 Route 116, Hinesburg, VT 05461.

Q. Please describe Energy Futures Group.

A. Energy Futures Group ("EFG") is an energy efficiency consulting firm established in 2010. EFG specializes in the design, implementation, and evaluation of energy efficiency, demand response, renewable energy and other distributed energy programs and policies. EFG has worked on behalf of utilities and other energy efficiency program administrators, public utility commissions, other government agencies, and environmental, low-income, and affordable housing advocacy organizations in 36 states, seven Canadian provinces, and several countries in Europe. EFG's recent work has included serving as advisors on the development of efficiency program portfolios and policies in eight of the ten highest-ranking states in the American Council for an Energy-Efficient Economy's ("ACEEE") 2018 State Energy Efficiency Scorecard.[1] In addition, EFG has authored or co-authored reports on lessons learned from leading residential retrofit programs in North America and Europe; the key pitfalls that can be encountered in performing energy efficiency potential studies; emerging practices in the use of energy efficiency to defer or entirely avoid electric transmission and distribution upgrades; a regional residential lighting strategy for the Northeast; the effectiveness of leading efficiency financing initiatives; and a national best practices manual for cost-effectiveness analysis of efficiency resources.[2]

Q. Please summarize your professional and educational experience.

A. I have worked in the energy efficiency industry since 1991 in a wide variety of roles. Prior to joining EFG, I served as the Director of Residential Energy Services at Efficiency Vermont and the District of Columbia Sustainable Energy Utility. I also served as the Manager of Energy Services at Vermont Gas Systems, managing both residential and commercial energy efficiency programs. I have extensive hands-on experience conducting hundreds of energy audits for Vermont's Low-Income Weatherization Assistance Program and Vermont Gas Systems' demand side management (DSM) programs.

In my current role as Managing Consultant at EFG, I have advised regulators, utilities and other energy efficiency program administrators, environmental organizations, and low-income and affordable housing advocates in numerous states, including Missouri, Mississippi, Maryland, North Carolina, Pennsylvania, Delaware, Virginia, New Jersey, Illinois, California, Vermont, Maine, Colorado, New Mexico, Nevada, Iowa, and New Hampshire, as well as British Columbia. I use my in-depth knowledge of energy efficiency program operations and management, and my experience in strategic planning, to help ensure that programs achieve their desired market impacts. I received a B.F.A. from the University of Illinois. My resume, attached as Exhibit JMG-1, provides additional detail regarding my professional and educational experience.

Q: Have you previously testified before the Florida Public Service Commission?

A: No, I have not.

Q: Have you previously testified before other similar state regulatory bodies?

A: Yes, I have provided expert witness testimony before utility commissions in North Carolina, Colorado, Nevada, Kentucky, Iowa, and British Columbia, and have authored public comments on behalf of clients in multiple proceedings in Pennsylvania. I have also appeared numerous times before the Maryland Public Service Commission.

II. TESTIMONY SUMMARY

Q: What is the purpose of your testimony?

A: My testimony assesses the reasonableness of the energy efficiency savings goals proposed in this proceeding by the Florida utilities. My testimony focuses most heavily on the goals proposed by Florida Power & Light Company (FPL). However, because I address policy issues related to goal setting, as well as generic concerns regarding the methodology used to develop the efficiency potential study upon which all the utilities' goals are based, my testimony also addresses the goals of Duke Energy Florida, LLC, Gulf Power Company, Tampa Electric Company, JEA, and Orlando Utilities Commission.

Q: Please summarize the conclusion you have reached with regard to the utilities' proposed savings goals.

A: The utilities' proposed savings goals are unreasonably low. Specifically, the utilities' proposals would leave enormous amounts of cost-effectively achievable energy savings potential untapped. That may require them to invest in more expensive supply options, saddling their customers with higher electricity bills as a result.

Q: What is your basis for that conclusion?

A: There are two primary reasons I conclude that the utilities' proposed goals are unreasonably low:

1. Misguided reliance on the Ratepayer Impact Measure (RIM) test.

The utilities argue that the RIM test is the appropriate cost-effectiveness test for determining what efficiency measures to promote. However, the RIM test is not actually a test of cost-effectiveness. Rather, it is a test of a measure's or program's potential to cut into utility profits (i.e., lost revenue), which would only effect rates if it caused utilities to seek regulatory approval to increase rates to remain just as profitable as without the efficiency programs. Therefore, it is really just a test of whether rates, and thus bills, could go up for non-participants if a utility goes below the lower bound on their allowed return on equity and increases rates through a rate case, because participants will see bills go down even if rates increase. And, even as such a test, it is not particularly useful. That is why no other state in the country relies on the RIM test as the sole or even primary determinant of whether an efficiency measure or program merits utility investment. It is also why the RIM test is not applied to supply-side investments; if it were, many supply-side investments, such as new power plants and capacity upgrades to substations, would be routinely rejected.

That is not to say that potential rate impacts should not be a consideration in determining the level and pace of cost-effective efficiency investments. They just should not be the only factor considered. Instead, as discussed in the National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency

Resources, regulators should consider trade-offs between bill savings, participation levels, and rate impacts. For example, basing FPL's efficiency savings goals on the amount of savings the Company estimates to be cost-effectively achievable under the Total Resource Cost (TRC) test, instead of no efficiency measures (only demand response measures passed the RIM test), would increase rates by only five thousandths of a penny per kWh ($0.00005/kWh), but would reduce the cumulative net present value of revenue requirements (CPVRR) by over $100 million. Simply dismissing the opportunity to provide such benefits to customers on the basis of an almost imperceptible rate increase does not seem reasonable.

2. Reliance on a fundamentally flawed efficiency potential study.

The efficiency potential study significantly understates the level of energy efficiency savings that can be achieved cost-effectively under the TRC test. First, and probably most importantly, it screens out all measures that have less than a two-year payback on the grounds that is necessary to exclude free riders. That alone cuts the estimate of achievable potential roughly in half. However, the potential study had already excluded all naturally occurring savings – the savings that would be associated with free riders – before it applied the two-year payback screen. Doing this means that presumed free riders were effectively removed from the estimate of savings potential twice, thus the two-year screen inappropriately removed only non-free rider savings potential.

The potential study also artificially and arbitrarily assumed that financial incentives for efficiency measures could not be greater than the level at which the "payback" would be bought down to two years. Again, the rationale was to limit free ridership based on the assumption that customers facing paybacks of two years or less would all invest in such measures. However, there is no empirical or analytical basis for that assumption. In fact, as discussed further in Section IV of my testimony, the utilities' own analyses suggest that limiting financial incentives to a two-year payback would dramatically reduce the number of customers who would participate in programs – directly contradicting the stated basis underlying the assumption.

Other conservatisms built into the potential study include the omission of early retirement measures; some unreasonably high assumptions regarding non-incentive costs; and various other measure-specific concerns. I discuss all of these concerns in greater detail in the following sections of my testimony.

Q: Given these concerns, what would you recommend the utilities' savings goals be?

A: I recommend that the utilities' savings goals be based on the amount of savings that would be cost-effectively achievable under a properly applied TRC test – i.e. one that corrected for all of the problems with the potential study that I have discussed. Unfortunately, those problems are so numerous and complex that the utilities' studies cannot be readily modified to produce appropriate goals. Thus, I recommend that the PSC examine the magnitude of the problems with the potential study, in conjunction with an examination of the actual achievements of leading southern utilities such as Duke Energy Carolinas – which achieved savings equal to 1.67% of annual sales to customers eligible to participate in its programs in 2018 – and Entergy Arkansas – which achieved savings equal to 1.44% of sales to eligible customers in 2018.

III. PROBLEMS WITH PRIMARY RELIANCE ON THE RIM TEST

1. The RIM test is not a cost-effectiveness test.

Q: Please describe the RIM test.

A: The RIM test compares (1) utility system benefits (avoided energy costs, avoided T&Dtrm costs, avoided capacity costs, etc.) to (2) the sum of (A) utility system costs (efficiency program costs) plus (B) lost revenues. It is only a test of whether rates will go up if the utility seeks and receives rate adjustments necessary to maintain the level of profits it would have earned absent the efficiency programs. It is not a test of cost-effectiveness.

Q: Why is it not a test of cost-effectiveness?

A: Because it doesn't just assess changes in costs. A cost is an expense or sacrifice incurred to produce an object, service, or outcome. Efficiency program spending is a cost. However, lost revenues, which are central to the RIM test and typically dominate the so-called "cost" portion of the RIM benefit-cost test equation, are not actually a cost.

Q: Why are lost revenues not a cost?

A: Lost revenues can occur when efficiency programs cause total electricity sales to decline, requiring the recovery of both a utility's fixed costs (e.g. the CEO's salary, the cost of trucks and repair crews, etc.) and its past, sunk costs (e.g. a power plant built in the past for which costs – along with a rate of return to provide profits for a utility's shareholders – are still being recovered) to be spread over a smaller volume of sales. No new costs are incurred. The utility still needs to recover the same amount of money that has been approved by regulators for its fixed costs. But because the same amount of money needs to be recovered over a smaller volume of sales, rates may need to be increased.

Q: Isn't it important to understand the rate impacts of efficiency programs?

A: Yes. But rate impact assessment is different from cost-effectiveness assessment. When faced with a choice between an electric bill for 1000 kWh at $0.10/kWh ($100 total) or a bill for 800 kWh at $0.11/kWh ($88 total), customers will be better off to choose the latter because it will cost them less even though the rate is higher.

The real issue with rate impacts caused by efficiency programs is that not every customer will see their bill go down; while efficiency program portfolios can be designed to be broad and diverse enough so that all customers have the opportunity to participate, not every customer will choose to take advantage of those opportunities and participate. Thus, concerns about possible rate impacts driven by lost revenues are really concerns about non-participants. Put another way, the RIM test is really a test of impact on those customers who choose not to participate in an efficiency program.

Q: Does the RIM test have value as a test of impact on non-participants?

A: It has some value, but even as a test of impact on non-participants it is not particularly helpful on its own. For one thing, a RIM benefit-cost ratio does not tell you by how much rates will go up or down. Further, it doesn't tell you how many customers would be adversely affected, particularly over a multi-year period. Nor does it tell you which customers would be adversely affected. Finally, it doesn't tell you anything about the benefits you would be forgoing if you allow concerns about non-participants to determine all investment decisions.

Q: Why do those things matter? Why isn't it reasonable to strictly adhere to RIM test results and eliminate efficiency programs that produce any rate impacts and therefore any amount of impact on those who choose not to participate?

A: Conceptually, it is never a good idea to pursue an investment when its benefits do not exceed its costs, however any economic analysis must monetize all costs and benefits if it is to be used dispositively. One can point to examples in which regulators approve investments that nominally increase costs on the basis of benefits that are understood, but that are not precisely valued. For example, regulators regularly approve upgrades to the distribution system in order to improve reliability. Similarly, as discussed in Mr. Wright's testimony, regulators in some states approve low income efficiency programs even when they do not pass the TRC or other cost-effectiveness tests. However, in both of those examples the underlying rationales for approval are still that benefits exceed costs. In the example of distribution system investments, regulators are making a judgment that increased reliability – a benefit – is worth the cost. In the low income efficiency program example, regulators are making a judgment that the equity benefits of serving low income customers and/or other unquantified or unmonetized benefits (e.g. reduced utility credit and collection costs, health, and safety benefits, etc.) are worth the cost. Put simply, regulators are still adhering to the principle that benefits must exceed costs. It is just that some benefits have not been monetized so that they fit easily into a cost-effectiveness test, and regulators are using their informed judgment to compensate for that.

In contrast, there is no conceptual reason to always reject any and all investments that may increase rates and/or that may result in inequities between different customers. While those outcomes may in isolation (i.e. all other things being equal) be undesirable, they are often accompanied by other outcomes that are highly desirable, requiring regulatory consideration of trade-offs. Indeed, regulators approve rate increases and make decisions in other proceedings regularly that create some level of inequity between different customers. That can happen as a result of approvals of supply-side investments that increase rates (which I discuss further below), as a function of rate design decisions,[3] and probably in other ways as well. Regulators approve such investments when they conclude that the benefits associated with the investments are substantial enough to outweigh equity concerns.

Put another way, regulators routinely – either explicitly or implicitly – consider trade-offs between rate impact and/or equity concerns on the one hand, and benefits to the system as a whole or to customers as a whole on the other. That same consideration of trade-offs should apply to consideration of which energy efficiency program investments to support as well.

2. The RIM test is not applied to supply-side investments.

Q: Is the RIM test typically applied to supply-side investments?

A: No, not in my experience.

Q: What would happen if it was?

A: Many proposed supply side investments would fail. Put simply, because the RIM test is a test of whether rates may go up, any supply-side investment that would raise rates, all other things being equal, would fail the RIM test.

Q: On p. 39, lines 18-23 of his testimony, FPL witness Whitley states the following: "Because all customers on FPL's system are served by the Supply option if that option is chosen, all customers are 'participants' in the selected Supply option. Electric rates and bills for all customers move in the same 'direction', either up or down from year-to-year compared to another Supply option that could be selected. Therefore, there is no subsidization of one group of customers by another group."

Do you agree?

A: No. I disagree with both the notion that all customers are "participants" when a supply investment is made and – more importantly – the assertion that there is no subsidization of one group of customers by another group when supply-side investments are made.

Q: Why do you disagree?

A: Consider supply-side investments that are made solely to address growing demand – either at the system-level (e.g. a new power plant) or at the local level (e.g. a substation capacity upgrade). By definition, the need for those supply-side investments is driven solely by new customers who are adding load to the system and/or existing customers whose demands are growing. If we are making an analogy to efficiency programs, they are the only "participants" in the supply-side investment. The new power plant and/or the new substation is being built to meet their needs, not the needs of customers whose demand is not growing. It is hard to understand how existing customers whose demand has remained unchanged or even declined could be characterized as "participants" in a substation capacity upgrade driven entirely by other customers' peak demands.

More importantly, the costs of the new power plant and/or the substation capacity upgrade in this scenario will not be borne solely by the customers whose new demand or growing demand created the need for the supply-side investments. Instead, to the extent that these costs are recovered through rates, they will be borne by all customers, including those existing customers whose demand did not grow. In the case of a substation (or other distribution system) capacity upgrade, customers who are not even served by the substation being upgraded will pay some (if not most) of the cost. That is the very definition of cross-subsidization.

Q: Are you suggesting that there is a problem with how the costs of supply-side investments are allocated?

A: I am not offering an opinion on that subject. I am simply making the point that there may not only be rate increases, but also cross-subsidization between different customers when supply-side investments are made. Thus, strict adherence to the RIM test in order to eliminate any rate impact and any cross-subsidization between customers is imposing a very different "screen" on efficiency program investment decisions than regulators impose on supply-side investment decisions – even though efficiency programs can be a lower cost alternative to some of those supply-side investments. In supply-side proceedings, not using the RIM test requires regulators to appropriately apply their judgment in assessing benefits, whereas the use of the RIM test in energy efficiency proceedings falsely implies that such judgment is not required.

3. Reliance on RIM test means rejecting hundreds of millions of dollars of bill savings.

Q: What are the implications of adopting the RIM test as the basis for determining whether an efficiency measure or program is promoted?

A: The short answer is that rejecting all efficiency measures that fail the RIM test will result in total electric bills for the state that are hundreds of millions of dollars higher than they could have been.

Q: What is the basis for that statement?

A: As Table 1 shows, the cumulative present value of revenue requirements (CPVRR) for FPL's TRC plan was $104 million lower than the CPVRR for the RIM plan it has proposed instead. And that is just for FPL. Also, it is a very conservative estimate of the amount of bill reductions that could be achieved because of numerous problems with FPL's analysis of achievable TRC potential which I discuss in the next section of my testimony.

Q: What would be the trade-off in terms of rate impact for adopting the FPL TRC plan (instead of its proposed RIM Plan) and achieving that $104 million in CPVRR savings?

A: As Table 1 shows, the trade-off, also based on FPL analyses, would be an average increase in electric rates of about five thousandths of a penny per kWh (or less than a 0.06% increase) – if the utility sought and received approval for rate adjustments necessary to keep its profits at the same level as without efficiency programs.

Table 1: Bill Savings and Rate Impacts of FPL TRC Plan (vs. RIM Plan)[4]

	CPVRR		Levelized Rate		
Plan	(millions $)	Difference from RIM Plan (millions $)	($/kWh)	Difference from RIM Plan ($/kWh)	Difference from RIM Plan (percent)
TRC	$52,924	-$104	0.096332	$0.000054	0.056%
RIM	$53,028	$0	0.096278	$0.000000	0.000%

4. No other state relies on RIM to screen out efficiency measure or programs.

Q: Are you aware of any other state that relies on the RIM test to screen efficiency measures or programs out of demand-side management (DSM) portfolios?

A: No. A number of jurisdictions consider the results of the RIM test along with the results of a variety of other tests when determining which efficiency programs to support. However, to my knowledge, no other state in the country relies on the RIM test as the sole or even primary determinant of whether individual efficiency measures or programs merit utility investment. Indeed, in 2012 the American Council for an Energy Efficient Economy published a report that showed that only one of the 41 states that relied upon one cost-effectiveness test as its "primary" test– Virginia – used RIM[5] as the primary test, and in 2018 the Virginia General Assembly passed legislation rejecting that practice.[6]

To my knowledge, there are only three notable changes with regard to the use of the RIM test since that report was published. First, in 2014, Florida shifted to relying on RIM as its primary test.[7] Second, as noted above, Virginia no longer relies on RIM as its primary cost-effectiveness test. Instead, the state currently supports any efficiency program that passes three of the following four tests: RIM, TRC, Utility Cost Test

(UCT) and Participant Cost Test (PCT).[8] Third, the state of Iowa partially applies RIM at the total portfolio level, which is notably different from the Florida utilities' proposed approach of using RIM to screen out individual efficiency measures and programs. Efficiency measures and programs that fail the RIM test are included in DSM portfolios to the extent that demand response programs that pass RIM provide enough downward pressure on rates to offset the upward pressure on rates associated with the efficiency programs. Even under this constraint MidAmerican Energy proposed an annual utility energy efficiency investment of roughly $165 million between 2019-2023.[9]

IV. PROBLEMS WITH THE FLORIDA POTENTIAL STUDIES

1. Measures with paybacks of less than two years were inappropriately excluded.

Q: How did the Florida utilities treat efficiency measures with a payback of less than two years in their assessments of efficiency potential?

A: All such measures were removed from estimates of efficiency potential.[10]

Q: What is the rationale put forward by the Florida utilities for excluding all efficiency measures with a payback of less than two years from their efficiency potential studies?

A: The utilities suggest that this exclusion is necessary and appropriate to "minimize the impact of 'free riders.'"[11] The underlying rationale is explained by FPL witness Koch:

> "It simply recognizes that rational customers will act in their own economic interest and take measures to reduce energy consumption, if it is sufficiently attractive economically for them to do so without a utility incentive payment. It is also an example of a free market economy working as it should – rational economic decisions being made in one's best interest without government intervention through mandates or provision of incentives."

Q: Do you find that argument to be persuasive?

A: No. There are several major problems with the argument:

1. The utilities have provided no empirical evidence or data to support the notion that all efficiency measures with a payback of less than two years are or would be routinely purchased or installed by customers in the absence of utility programs.
2. The argument that customers would adopt measures with short paybacks because it is economically rational ignores the underlying premise for utility sponsored efficiency programs: that market barriers often preclude customers from investing in efficiency measures that are cost-effective.
3. Even in cases in which there are no non-financial market barriers, some customers will not buy measures with two-year paybacks because they are even more short-term focused than that. Low income customers are good examples. This is discussed further in Mr. Wright's testimony.

4. The utilities' own analyses of achievable potential – in which they assume that significant portions of potential for measures with initial paybacks of longer than two years would not be captured if financial incentives for such measures were limited to

reducing paybacks to two years – directly contradicts the premise that all or most customers would invest in measures with paybacks that short.

5. In developing estimates of technical potential – the foundation for both economic and achievable potential – Nexant already accounted for naturally-occurring efficiency. Thus, the potential effects of free ridership were already excluded from the estimates of savings potential before the application of the two-year payback screen. Thus, the two-year payback screen is a redundant adjustment for free riders that artificially makes cost-effective efficiency potential appear to be lower than it really is.

Q: How does the application of a two-year payback screen to eliminate efficiency measures from estimates of economic and achievable potential ignore the underlying premise for utility-funded efficiency programs?

A: The underlying premise for utility-funded efficiency programs is that such programs are necessary to address market barriers to customer adoption of cost-effective efficiency resources. Those market barriers can take many forms, including many non-financial forms. Key examples of market barriers that can stop customers from investing in measures, even those with short payback periods, include:

- Lack of awareness of a DSM measure;
- Lack of awareness of potential savings benefits – both of customers who would buy or install measures and sometimes of sales staff for retailers, contractors, or other vendors selling products;
- Concern with service or product degradation;
- Availability of a DSM measure;
- Past experiences with DSM measures;
- Competing demands for available financial resources;

- Split incentives – between the entity or individuals that must pay for a measure and the entity or individuals that would receive the benefits (e.g. between landlords and tenants and between builders and home-buyers); and
- Limited or inadequate technical expertise of trade allies (e.g. HVAC contractors, new construction design professionals, builders).[12]

Q: Are there data to support the notion that the combination of market barriers faced by consumers leads to less than universal purchase and installation of measures with paybacks of up to two years?

A: Yes. First, one can look at market shares for efficient products that the utilities removed from their estimates of efficiency potential because of their short paybacks. Consider, for example, Energy Star commercial griddles and Energy Star computer servers. Both measures were removed from FPL's TRC analysis because of the two-year payback screen,[13] but both have national market shares of under 20%.[14]

Q: Can you provide examples of how the utilities' own analyses of achievable potential directly contradict the premise that all or most customers would invest in measures with paybacks of two years or less?

A: Consider the two-speed pool pump measure. This measure passed the TRC test for FPL and had an estimated payback without any efficiency program incentives of 3.5 years. Because FPL (and the other utilities) assume that financial incentives for measures cannot buy the customer payback to less than two years, the Company assumed that its program rebates could only cover 43% of the measure cost and that the remaining 57% of the incremental cost of the measure would need to be borne by its customers. Under that assumed constraint, the Company estimated that an efficiency program promoting this measure could only acquire 4% of the savings potential because the out-of-pocket cost to customers would still be relatively high.[15] Put another way, FPL has estimated that even with the cost bought down to a two-year payback, 96% of its customers would not buy the measure! That obviously and fundamentally contradicts the notion that the vast majority of customers considering efficiency measures with two-year paybacks would buy such measures and therefore be free riders in any utility programs promoting such measures.

Q: How did Nexant exclude naturally-occurring efficiency from its estimates of technical potential?

A: Nexant makes clear that it excluded two forms of naturally-occurring efficiency from its estimates of technical potential in section 5.1.1 of its potential study report:

1. savings that will materialize in the future as a result of government codes and standards; and
2. additional savings that will materialize in the future because some customers will buy products more efficient than required by such minimum standards without utility-funded efficiency programs – what Nexant calls "baseline measure adoption."

As Nexant put it, the result is an estimate of "net penetration rates" (emphasis added) which represents "the difference between the anticipated adoption of efficiency measures as a result of DSM efforts and the 'business as usual' adoption rates absent DSM intervention." This was accomplished by:

> "…discuss[ing] the assumptions included in the base sales forecast with the [utility's] load forecasting group to determine the assumptions on naturally-occurring efficiency adoption, as well as using utility-specific and regional data on current levels of efficiency adoption that were

included in the applicability factors applied to each measure."[16]

Q: How does the fact that Nexant excluded naturally-occurring efficiency from its estimates of technical potential make the application of the two-year payback screen when estimating economic potential "redundant" as a mechanism for removing free riders?

A: By definition, free riders are efficiency program participants that would have installed promoted measures without the program. Again, by definition, the savings from such potential free ridership are included in Nexant's estimate of naturally-occurring efficiency (baseline measure adoption) which Nexant excluded from its estimates of technical potential. In other words, Nexant's estimates of technical potential already removed any savings from customers who could be candidates to be free riders. Because economic potential and achievable potential are both subsets of technical potential, no additional adjustments are necessary to remove potential "free riders" at those stages of the analysis. Thus, the fact that Nexant and/or the utilities applied a two-year payback screen at the economic potential stage means that they have inappropriately "double-adjusted" for potential free riders.

Q: Are you suggesting that because Nexant excluded the effects of naturally-occurring efficiency from the potential study that utility programs to promote efficiency cost-effective measures with paybacks of two years or less would not have free ridership?

A: No. I am simply saying that the exclusion of naturally-occurring efficiency is, by itself, all that is necessary to develop estimates of net savings potential – i.e. savings after removing free riders – that is cost-effectively achievable. The next step is to design programs to acquire that potential. Inevitably, most such programs will have some level of free ridership – from both measures with shorter paybacks and measures with longer paybacks. The level of free ridership will be a function of the market and the program design.

Q: Do you agree that it is appropriate to address free ridership, both in setting savings goals and in the design and implementation of programs?

A: Yes. As already discussed, if the two-year payback screen were removed from the potential study the result would be an estimate of net savings potential – i.e. excluding any savings from possible free riders. After addressing other concerns discussed below this would be an adequate basis for goal setting. Then, when the utilities design and implement programs to capture that level of savings potential, the savings they produce from such programs should be evaluated and adjusted to exclude the effects of free ridership. That is the way concerns regarding free ridership are addressed in numerous other jurisdictions.

Q: In his deposition, witness Herndon stated that although he was unaware of any other jurisdiction that adjusted estimates of efficiency potential by removing measures with two-year paybacks or less, he was aware of programs in other jurisdictions that limit financial incentives to levels necessary to buy paybacks down to two years.[17] Doesn't that support the notion that applying a two-year payback screen is a reasonable approach to removing free riders from the potential study?

A: No. To the contrary, it supports the alternative approach that I have suggested instead. Potential studies that already adjust for naturally-occurring efficiency do not need and should not have another arbitrary adjustment applied to their estimates of savings potential. And no other state or potential study of which either I or Mr. Herndon are aware does that.[18] However, once savings goals are set, it is appropriate to design programs to minimize free ridership (in conjunction with other objectives). For some measures or some programs in some markets, one option that can make sense is to limit incentives to levels that are associated with customer paybacks of two years, or some other time period. For other measures, programs, and markets that would not make sense. In fact, in my experience, while payback may be one factor that is considered in the determination of incentive levels, specific financial incentive payback limits are typically only applied in other jurisdictions to custom Commercial and Industrial programs targeting larger business customers. Put simply, this is a program design issue not a potential study or goal setting issue.

Q: What is the effect of the application of the two-year payback screen to the utilities' estimates of TRC cost-effective achievable potential?

A: As sensitivities to their analyses, the utilities each estimated how much higher the estimates of economic potential would be if the two-year payback screen was reduced to one year. As Table 2 shows, just reducing the two-year payback screen to one year would increase estimates of economic potential by 54% for FPL and by 26% to 71% for the other utilities. Two of the utilities – TECO and Gulf – provided estimates of economic potential without a two-year payback screen. I have estimated that number for FPL by rerunning its cost-effectiveness tool. The result of eliminating the inappropriate two-year payback screen entirely is to increase the estimate of economic potential by 80% for Gulf, 139% for TECO and over 150% for FPL. Put simply, eliminating the two-year screen results in roughly a doubling – or more – of cost-effective savings potential.

Table 2: Impact of Two-Year Payback Screen on TRC Economic Potential

	TRC Economic Energy Efficiency Potential (GWh)			% Increase in TRC Econ Potential vs. 2-Year Payback Screen	
Utility	w/2-year payback screen	w/1-year payback screen	without payback screen	1-Year Payback Screen	No Payback Screen
FPL	3554	5490	8905	54%	151%
Duke	3117	3915	n.a.	26%	n.a.
TECO	747	1275	1785	71%	139%
Gulf	981	1253	1762	28%	80%
Orlando	465	710	n.a.	53%	n.a.
JEA	1024	1383	n.a.	35%	n.a.

2. In estimating achievable potential, incentives were inappropriately limited to levels necessary to buy customer paybacks down to two years.

Q: How did the utilities address the issue of payback periods for cost-effective efficiency measures whose payback without financial incentives was greater than two years?

A: The utilities included efficiency measures that were cost-effective and had paybacks of greater than two years in their estimates of achievable potential. But when estimating how much savings was achievable from those measures, they assumed that they could not provide financial incentives greater than the amount that would be associated with buying the customer payback down to two years. Again, the rationale that they put forward for adopting this assumed limitation was that buying paybacks down to levels below two years would mean paying free riders.

Q: Is that a reasonable conclusion?

A: No. For reasons I have already stated, it is not reasonable to assume that all measures with a two-year payback or less will be universally purchased and installed without a utility program. Further, as I've also already discussed, the utilities own estimates of achievable potential show that they do not actually believe that buying paybacks down to two years will ensure that most customers will purchase and install such measures. If they actually did believe that, then their estimates of achievable potential would be the same as (or very close to) their estimates of economic potential; instead, as Table 3 shows, they are dramatically lower, particularly for FPL.

Table 3: Achievable Potential as Percent of Economic Potential With a Two Year Payback Screen

Utility	GWh: TRC Econ Potential w/2-year payback screen	GWh: TRC Achievable Potential	AP as % of EP
FPL	3554	196	6%
Duke	3117	432	14%
TECO	747	305	41%
Gulf	981	222	23%
Orlando	465	137	29%
JEA	1024	262	26%

Q: What are the implications of this inappropriate assumption?

A: By the utilities' own admission, this assumption has the effect of lowering estimates of achievable potential. In fact, as Table 3 shows, only TECO estimates that it can achieve as much as 40% of its economic potential; none of the other utilities estimate that they can achieve even 30% of their economic potential. Put simply, for measures for which market barriers are such that it is not possible to achieve significant market penetration without driving paybacks to less than two years, the utilities' estimates of achievable savings potential have been artificially reduced.

Q: Why is FPL's estimate of the portion of economic potential that it can achieve – 6% – so much lower than all the other utilities?

A: I am not certain. However, it is worth noting that FPL essentially adopted a three-year payback screen. It did this by assuming that the incentives it could offer for measures with paybacks of between two and three years (when buying paybacks down to two years) were too small to have an impact on the market, so they eliminated such measures from their achievable potential estimates.[19] The result was eliminating about half of the TRC cost-effective measures that passed the two-year payback screen when estimating TRC achievable potential. I do not know if the other utilities did the same thing. If they did not, then this could be a big part of the reason FPL's estimates of achievable potential, as a percent of economic potential, is so much lower than the others.

3. Potential study inappropriately excludes early retirement measures.

Q: What is "early retirement"?

A: Early retirement is when an efficiency program successfully encourages a customer to cost-effectively replace a still functioning piece of electricity-consuming equipment before that equipment would otherwise have been replaced.

Q: How did the potential studies exclude such measures?

A: The potential study assumes that the only opportunity for efficient equipment measures is at the time such equipment would naturally turn over, when customers have already made a decision to replace equipment. Thus, it assumed that the portion of the market that can be affected each year is equal to the number of customers with a particular piece of equipment divided by the average measure life of that equipment. For example, if a commercial light fixture has an average life of 15 years, the potential study assumed that one-fifteenth of the existing stock of such light fixtures would get replaced each year and that efficiency upgrades could only occur at that pace.

Q: Is it reasonable to limit estimates of savings potential to such time of turnover opportunities?

A: No. It is usually true that the costs of efficiency savings are lower at the time of natural turnover than through early retirement. Indeed, early retirement is probably not cost-effective for many measures. However, that is not true for all measures. In fact, there are some measures for which early retirement can be quite cost-effective and from which substantial savings can be realized. Commercial light fixtures are notable examples. In fact, savings from such measures – at least in the short to medium term – can be substantially higher than savings that are achievable when waiting until time of natural turnover. This is because the baseline from which savings from early retirement measures should be initially measured (i.e. the existing equipment efficiency) can be much less efficient than the baseline for a standard new piece of equipment.[20]

Q: Do utility efficiency programs in other states include early retirement measures?

A: Yes. Again, not for all measures, but for some measures. In fact, early replacement is common enough that a number of states' Technical Reference Manuals (TRM), which document common assumptions and/or protocols for estimate savings, include specific reference to early retirement measures (alternatively called early replacement measures) and how to estimate savings for them. For example, the Arkansas TRM "allows for early replacement of certain measures that have been verified through a number of evaluations." It further states that such early replacement has the benefit of

> "being able to claim higher energy savings for the remaining useful life (RUL) of the equipment (the efficiency difference between the new, efficient equipment and the existing equipment), and then dropping to lower energy savings rates (under higher baselines) only for the period of the EUL that exceeds the RUL (the difference between new, efficient equipment and a code baseline)."[21]

Illinois is an example of another state whose TRM explicitly allows for calculating savings from existing equipment efficient levels for early retirement measures.[22]

Q: What was the utilities' rationale for excluding early retirement measures from the potential study?

A: FPL has suggested that the reason early retirement measures were not included in estimates of achievable potential is that there was a "lack of reliable information on early retirement adoption rates."[23]

Q: Is that a reasonable explanation?

A: No. As noted above, a number of utilities across the country run programs that include some early retirement measures. They all develop estimates of participation rates for those programs when developing plans they submit to their regulators.

Q: What are the implications of excluding early retirement measures from the potential study?

A: Excluding early retirement measures has the effect of reducing estimates of achievable potential, at least in the near to medium-term (e.g. in the next five years) during which the less efficient existing equipment would have been the baseline from which to measure savings.

4. Cost-effective mid-efficiency measures excluded from economic savings potential when higher-efficiency measures – to which all savings potential was assigned when estimating technical potential – fail economic screening.

Q: What should happen when estimating technical potential and economic potential from end uses for which there are multiple potential "tiers" of efficiency improvement?

A: When estimating technical potential, the most efficient measure should be assumed to be purchased and/or installed. For example, for residential pool pumps for which there are two efficiency upgrade options – two-speed pumps and variable speed pumps – the estimate of technical potential should be based on the presumption that all new pool pumps are the most efficient option, or variable speed pumps. To ensure that there is no double-counting of savings, the study should assume no market penetration of the less efficient upgrade option, or two-speed pumps.

When estimating economic potential, all of the savings should be assumed to come from the most efficient measure that passes the cost-effectiveness test, which may be a lower level of efficiency than was included in the technical potential estimate. For example, if the most efficient option on which technical potential was based – variable speed pool pumps in the example I've been using – fail cost-effectiveness screening, but the less efficient option of two-speed pool pumps pass, the economic potential should be based on the presumption that all new pool pumps purchased in the future will be two-speed pool pumps.

Q: Is that how the utilities and their consultant estimated technical potential and achievable potential?

A: That is how all the utilities estimate technical potential. However, it is not how they all estimated economic potential. At least FPL and TECO failed to assign economic savings potential to measures that could cost-effectively provide levels of efficiency above baseline when the most efficient alternative measure used to estimate technical potential was not cost-effective.

Q: Can you provide an example?

A: I will give two FPL examples, one related to the efficient pool pumps discussed above and another related to air source heat pumps as replacements for electric resistance furnaces.

I'll start with savings potential from efficient pool pumps. Because variable speed pool pumps are more efficient than two-speed pool pumps, FPL estimated technical potential from pool pumps based entirely on the savings that variable speed units could provide. That amounted to about 58 MW of summer peak savings, 33 MW of winter peak savings and 280 GWh of annual energy savings.[24] Again, that is the appropriate way to estimate technical potential. Then, when conducting cost-effectiveness screening, FPL found that although the two-speed pool pump passed the TRC test, the variable speed pool pump did not. Once it realized that was the case, the Company should have included in its estimate of economic potential the savings that could be provided by two-speed pool pumps. However, it neglected to do that. Instead, even though the two-speed pool pump was TRC cost-effective, the Company estimated that the economic savings potential from the measure was zero.[25]

Similarly, when analyzing the savings potential by displacing electric resistance heating, the utilities analyzed two options: (1) a SEER 14 air source heat pump and a SEER 21 air source heat pump. Because SEER 21 is more efficient than SEER 14, FPL estimated technical potential from heat pumps replacing electric resistance heat based entirely on the savings that SEER 21 systems could provide. That amounted to about 77 MW of summer peak savings, 95 MW of winter peak savings and 474 GWh of annual energy savings.[26] Again, that is the appropriate way to estimate technical potential. Then, when conducting cost-effectiveness screening, FPL (and TECO) found that although the SEER 14 air source heat pump displacing electric resistance heat passed the TRC test, the SEER 21 alternative did not. Once it realized that was the case, FPL and TECO should have included in their estimate of economic potential the savings that could be provided by SEER 14 air source heat pumps displacing electric resistance heat. However, they neglected to do that. Instead, even though the SEER 14 air source heat pump displacing electric resistance heat was TRC cost-effective, FPL and TECO estimated that the economic savings potential from the measure was zero.[27]

Q: What is the effect of the two TRC cost-effective measures you have identified as being inappropriately excluded from FPL's estimates of economic potential?

A: It is substantial. As Table 4 shows, just correcting the omitted savings from these two measures could increase FPL's estimate of TRC economic energy savings potential by 25%. It would also increase FPL's estimate of TRC economic winter peak savings by 33% and summer peak savings by 5%.

Table 4: Corrected FPL Pool Pump and ASHP Economic Potential Estimates

	Technical Potential			FPL Econ Potential			Corrected Econ Potential		
Measure Name	**GWh**	**S-MW**	**W-MW**	**GWh**	**S-MW**	**W-MW**	**GWh**	**S-MW**	**W-MW**
Two-Speed Pool Pump	0	0	0	0	0	0	92	29	28
Variable Speed Pool Pump	280	58	33	0	0	0	0	0	0
SEER 14 ASHP vs elec res heat	0	0	0	0	0	0	223	0	46
SEER 21 ASHP vs elec res heat	474	77	95	0	0	0	0	0	0
Totals for Both Measure Groups	**754**	**135**	**128**	**0**	**0**	**0**	**316**	**29**	**74**
FPL Total for Other Residential							1251	618	228
% Increase from Correction							**25%**	**5%**	**33%**

Q: How did you develop those estimates of corrected economic potential?

A: I compared FPL's estimates of the per unit savings of the lower tier efficiency measure to the higher tier alternative. For example, two-speed pool pumps produce only 33% of the energy savings, 50% of the summer peak savings and 87% of the winter peak savings that a variable speed pool pump would produce.[28] I then multiplied those ratios by the technical potential of the higher tier measure to estimate the economic potential of the lower tier measures.

Q: Have you identified and quantified the impact of all measures for which this problem occurs within FPL's estimates of economic potential?

A: No. That would require a substantial amount of analysis which, given the range of issues I have had to address, I was not able to undertake as part of drafting this testimony. Nor have I assessed the extent to which this may be a problem for the other utilities.

5. Some non-incentive cost assumptions are unreasonably high.

Q: How did the utilities apply non-incentive costs when estimating achievable savings potential?

A: The utilities made assumptions about average program costs per measure and included those costs when assessing which measures were cost-effective for estimates of potential.[29]

Q: Have you reviewed those assumptions?

A: Only for FPL.

Q: Did you find FPL's non-incentive cost assumptions to be reasonable?

A: Some appear to be unreasonably high. For example, FPL assumes that the average non-rebate cost for promoting investment in residential LED light bulbs is $29 per light bulb! That is unfathomably high. By way of comparison, Commonwealth Edison, the electric utility serving the Chicago metropolitan area, rebated approximately 11.25 million light bulbs in its 2018 Residential Lighting Discounts program.[30] Its non-incentive costs for the program were $5.98 million[31] – or about

$0.53 per light bulb. In other words, FPL assumed a non-rebate cost per light bulb that was on the order of 55 times higher than ComEd's actual program experience.

Similarly, FPL assumes that the non-incentive costs per low flow showerhead and per faucet aerator are $29, or more than four times the total cost of the showerhead and nearly ten times the cost of the aerator. Again, that is unfathomably high.

Q: What are the implications of using such unreasonably high assumptions for non-incentive costs?

A: It depends. To the extent that the measures with problematic non-rebate cost assumptions were excluded from the estimates of achievable potential because they had paybacks of less than two years, as appears to be the case with low flow showerheads, there is no effect because FPL had already (inappropriately) excluded such measures from its estimate of achievable potential. However, it appears that some measures with potentially high savings potential (e.g. residential LED light bulbs) may have been excluded from TRC economic potential, and therefore TRC achievable potential as well, because of the unreasonably high non-incentive costs.

6. Assorted other potential study conservatisms contribute to underestimation of achievable cost-effective savings potential.

Q: Have you identified any other problematic assumptions with the utilities' efficiency potential studies?

A: Yes, though I have not exhaustively reviewed every assumption in the studies. There are literally at least tens of thousands of different assumptions, so reviewing every one of them, as well as how they all interact, would have been an enormous undertaking which I did not have the resources to pursue and for which this kind of proceeding is not well-suited given the amount of back-and-forth questioning that would be required. However, I have selectively examined a number of assumptions and identified more granular concerns. Examples are as follows:

Understating residential heat pump water heating savings per unit. In estimating savings for residential heat pump water heaters, the utilities make a couple of problematic assumptions that lead to understating savings. First, the Energy Factor assumed for a heat pump water heater – 2.5[32] – is at the low end of the range for available models. Indeed, of the 58 models with capacities of less than 55 gallons that are Energy Star rated, only two had Energy Factors of below 2.8; the average was 3.3 – or about 25% more efficient than assumed by the utilities.[33] In addition, the utilities inappropriately used a "manufactured home square footage adjustment" to reduce estimated savings potential for heat pump water heaters installed in manufactured homes by 41%.[34] There is no basis for reducing water heater savings down by the size of the home. Water heater savings are primarily a function of the number of occupants in the home; the utilities' savings formula for heat pump water heaters had already accounted for the fact that manufactured homes have fewer occupants than single family homes.[35]

- Artificial cap on measure lives of 20 years. Nexant appears to have assumed that measures cannot have lives of longer than 20 years.[36] That is too short for a number of measures such as attic insulation or wall insulation added to homes, whole house fans, and centrifugal chillers. Other jurisdictions assume lives for such measures of 25 years[37] or even longer. Capping measures at 20 years results in understating of the cost-effectiveness of some measures.

- Use of average line loss rates rather than marginal line loss rates to convert savings at the customers' meters to savings at the generator.[38] Efficiency programs' impact on line losses are – by definition – equal to marginal loss rates. This is important because line losses grow (largely) exponentially with load,[39] meaning that marginal line loss rates are much higher than average line loss rates. Thus, by using average loss rates the utilities are understating the economic value of efficiency savings.
- Failure to include all participant benefits in TRC test. It appears as if the utilities included only electric system benefits in the calculation of the TRC test. They exclude a number of additional participant benefits such as other fuel savings (e.g. natural gas savings that can occur when insulating a home with central air conditioning and gas heat), water savings (e.g. associated with low flow showerheads), or any of a range of non-energy benefits. The utilities suggest that is appropriate because inclusion of such benefits is "inconsistent with the test's purpose which is to evaluate DSM measures from an all resource perspective." However, other fuel savings and water savings are "resource benefits." More importantly, the utilities have misconstrued the conceptual purpose of the TRC test, which is to assess cost-effectiveness from the combined perspective of the utility system and program participants.[40] By including all participant costs, but not all participant benefits, the utilities' TRC analyses violate one of the fundamental principles of cost-effectiveness analysis, with the result being a bias against efficiency resources.[41]

7. Combined effect of potential study conservatisms is dramatic understating of achievable potential.

Q: What is the combined effect of all of the conservatisms in the utilities' potential studies on the bottom line estimates of achievable savings?

A: That is very difficult to precisely quantify without essentially conducting a new analysis in which all assumptions are re-examined and revised (as needed), which I did not have the resources to do and for which this kind of proceeding is not well-suited. However, the impact is huge. As noted earlier, just eliminating the inappropriate two-year payback screen would have the effect of increasing TRC economic potential by roughly half.

An alternative way to approach this question is to compare what the Florida potential studies suggested was economically achievable under the TRC test to what utilities in other leading states in the South have recently achieved. As Table 5 below shows, Duke Energy Carolinas (DEC) achieved savings equal to approximately 1.67% of sales to eligible customers in 2018.[42] That is at least 7.5 times greater than what any of the Florida utilities have suggested is TRC achievable and more than 90 times what FPL has suggested is TRC achievable – even though DEC was not implementing a plan designed to achieve all cost-effective savings. Similarly, Entergy Arkansas achieved savings equal to approximately 1.44% of its 2018 sales to eligible customers.[43] That is at least 6.5 times what any of the Florida utilities have suggested is TRC achievable and about 80 times what FPL has suggested is TRC achievable – again, even though Entergy Arkansas was not implementing a plan designed to achieve all cost-effective savings.

Table 5: Florida TRC Achievable Estimates vs. Leading Southern Utility Actuals[44]

Utility	State	Study or Actual?	Year(s)	Annual TRC Achievable Savings (GWh)	Total Eligible Sales (GWh)	Savings as % of Eligible Sales
FPL	FL	Study	2020-2029	20	108,514	0.02%
Duke	FL	Study	2020-2029	43	38,024	0.11%
TECO	FL	Study	2020-2029	31	19,187	0.16%
Gulf	FL	Study	2020-2029	22	10,809	0.21%
Orlando	FL	Study	2020-2029	14	6,568	0.21%
JEA	FL	Study	2020-2029	26	11,825	0.22%
Duke Energy Carolinas	**NC/SC**	**Actuals**	**2018**	**811**	**48,454**	**1.67%**
Entergy	**AR**	**Actuals**	**2018**	**256**	**17,730**	**1.44%**

V. RECOMMENDATIONS

Q: What cost-effectiveness test would you propose that the Public Service Commission (PSC) rely upon in setting the utilities' energy efficiency savings goals?

A: As I stated earlier in this testimony, I strongly recommend against relying on the RIM test, as it is not a test of cost-effectiveness, has limited value in assessing potential impacts on non-participants, and is not used when assessing the reasonableness of supply-side resources for which energy efficiency can be a lower cost alternative. Conceptually, a properly executed TRC test – one that fully accounts for all utility system and participant impacts – is a much better gauge of the value of efficiency. The PSC could also consider a separate assessment of potential rate impacts, along with estimates of how many customers may participate over a 10-year period, to determine whether any constraints on acquisition of all TRC cost-effective efficiency potential may be warranted in order to balance concerns about impacts on any customers who choose not to participate.

Q: Are you suggesting that the PSC base the utilities' energy efficiency savings goals on their current estimates of TRC cost-effective achievable potential?

A: No. As I also discussed above, the TRC test as used by the utilities does not account for all utility system benefits or all participant benefits and therefore understates what is cost-effective. Perhaps even more importantly, there are numerous other problems with the utilities' efficiency potential studies' methodologies and assumptions that lead to significant underestimation of cost-effective potential, even under their definition of the TRC.

Q: How would you suggest the PSC establish efficiency savings targets for the utilities in this proceeding?

A: If the PSC does not order that the Utilities conduct a properly executed TRC Test, and given the absence of a defensible empirical analysis of cost-effective efficiency potential in the state, one approach would be to make an attempt at partially correcting the utilities' TRC economic potential results as I discuss below. This would be a very conservative approach as many issues leading to lower TRC results would remain unaddressed (such as FPL assigning zero economic potential to certain measures). Another approach would be to base energy efficiency targets on what the leading utilities in the South are already achieving. Specifically, the PSC could require each Florida utility to ramp up to 1.50% incremental annual savings per year – a level comparable to the 1.67% Duke Energy Carolinas achieved in 2018 and the 1.44% achieved by Entergy Arkansas in 2018.

Q: Couldn't comprehensive corrections be made to the utilities' potential studies to address the problems you have identified?

A: Yes, conceivably. However, the problems are numerous, complicated, and interactive. Moreover, it is likely that there are others that I have not been able to identify given the limited time available to review numerous assumptions for literally thousands of efficiency measure permutations for six different utilities. Put simply, it would be an enormous undertaking to comprehensively address the issues I raised in my testimony, as well as ensure that there are no others that need addressing.

Q: Can you illustrate the magnitude of the impact of correcting for any of the problems you have identified?

A: Yes. I have estimated the impacts of correcting just two of the many problems noted: (1) the double-adjustment for free riders resulting from the application of a two-year payback screen; and (2) unreasonably low expectations by most of the utilities (the one possible exception being TECO) regarding the portion of economic potential that is achievable. As Table 6 shows, just correcting those two problems – by not using any payback screen and assuming that about half of economic potential is achievable instead of the 6% assumed by FPL and the 14 to 29% assumed by all but one of the other utilities (TECO assumed 41%) – would suggest that at least average annual savings ranging from 0.4% to 0.8% of annual electricity sales, depending on the utility, would be cost-effectively achievable over the 2020 to 2029 period.

Table 6: Results of Eliminating Two-Year Payback Screen and Assuming 50% of Economic Potential is Achievable

Utility	2017 Annual Sales (GWh)	Utility Estimates of Average Annual Achievable Potential (GWh)	Utility Estimates of Achievable Potential as Percent of Sales	10-Year TRC Econ Potential without 2-Year Payback Screen (GWh)	Average Annual TRC Econ Potential without 2-Year Payback Screen (GWh)	Partially Corrected Average Annual Goal at 50% of Econ Potential (GWh)	Partially Corrected Average Annual Savings as Percent of Sales
FPL	108,514	20	0.02%	8905	891	445	0.4%
Duke	38,024	43	0.11%	5599	560	280	0.7%
TECO	19,187	31	0.16%	1785	179	89	0.5%
Gulf	10,809	22	0.21%	1762	176	88	0.8%
OUC	6,568	14	0.21%	835	84	42	0.6%
JEA	11,825	26	0.22%	1839	184	92	0.8%

Q: How did you estimate economic potential without a two-year payback screen?

A: As discussed above, both TECO and Gulf provided their own estimates of TRC economic potential without any payback screen. I have used their estimates. For FPL, I computed the amount of TRC cost-effective savings without a two-year payback screen using all of FPL's measure assumptions and the confidential analytical tool provided by the Company. I did not have such a tool for Duke, Orlando, or JEA, so I assumed that their TRC economic potential without a two-year payback screen would be approximately 80% higher than their own estimates of TRC economic potential with such a screen. The 80% increase is equivalent to Gulf Power's increase, the lowest of the three increases either made available by the utilities themselves or which I was able to compute.

Q: Why did you assume that half of the economic potential would be achievable?

A: That is a level consistent with several efficiency potential studies I have reviewed. For example, a recent efficiency potential study conducted for DTE, one of the two large investor-owned utilities in Michigan, estimated that the utility could achieve savings equal to 15.1% of its sales – about 46% of the estimated economic potential of 32.5% – over an 11-year period.[45] Similarly, a 2015 Arkansas efficiency potential study estimated that roughly 50% (2282 GWh out of 4594 GWh) of the savings the study found to be "economic" was achievable over the 2016 to 2025 period.[46] And a 2018 study for the city of New Orleans found that maximum achievable potential over ten years – 25% of sales – was 56% of the economic potential.[47]

Q: What would the utilities annual savings goals be if they were based on TRC cost-effective and achievable savings potential, as corrected for the two problems you just discussed (i.e. eliminating a two-year payback screen and assuming 50% of economic potential is achievable over ten years)?

A: Assuming that the utilities could ramp up energy savings at the pace of at least 0.3% of sales per year (e.g. a utility whose goals are to ramp up to 0.6% of sales per year would take two years to get to that point),[48] and assuming that the peak savings to energy savings ratios in the economic potential would be reflective of the ratios in achievable potential,[49] the savings would be as shown in Tables 7, 8, and 9 below. Comparable tables broken down into Residential and Non-Residential values are provided as Exhibit JMG-2 to my testimony.

Table 7: GWh Savings Based on Partially Corrected TRC Achievable

	Annual	Incremental Annual Energy Savings (GWh)										10-Year
Utility	Sales	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
FPL	108,514	326	445	445	445	445	445	445	445	445	445	4,333
Duke	38,024	114	228	280	280	280	280	280	280	280	280	2,582
TECO	19,187	58	89	89	89	89	89	89	89	89	89	861
Gulf	10,809	32	65	88	88	88	88	88	88	88	88	802
Orlando	6,568	20	39	42	42	42	42	42	42	42	42	393
JEA	11,825	35	71	92	92	92	92	92	92	92	92	842

Table 8: Summer MW Savings Based on Partially Corrected TRC Achievable

	TRC	Summer Peak MW										10-Year
Utility	kWh/kW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
FPL	3889	84	115	115	115	115	115	115	115	115	115	1114
Duke	2935	39	78	95	95	95	95	95	95	95	95	880
TECO	5475	11	16	16	16	16	16	16	16	16	16	157
Gulf	5063	6	13	17	17	17	17	17	17	17	17	158
Orlando	5299	4	7	8	8	8	8	8	8	8	8	74
JEA	5381	7	13	17	17	17	17	17	17	17	17	156

Table 9: Winter MW Savings Based on Partially Corrected TRC Achievable

	TRC	Winter Peak MW										10-Year
Utility	kWh/kW	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
FPL	6650	49	67	67	67	67	67	67	67	67	67	652
Duke	5625	20	41	50	50	50	50	50	50	50	50	459
TECO	6736	9	13	13	13	13	13	13	13	13	13	128
Gulf	5933	5	11	15	15	15	15	15	15	15	15	135
Orlando	7802	3	5	5	5	5	5	5	5	5	5	50
JEA	7858	5	9	12	12	12	12	12	12	12	12	107

However, because these tables reflect savings estimates based on only partial corrections to the utilities' analyses, they significantly underestimate what is really cost-effectively achievable. Again, since it is not possible to make all the needed corrections to the utilities' analyses in this proceeding, I recommend that the PSC consider what the leading Southern utilities have achieved as being what is cost-effectively achievable – i.e. ramping up to energy savings equal to approximately 1.5% of sales per year.

Q: What would be a reasonable ramp up period for getting to a 1.50% per year savings goal?

A: Assuming (as above) that the utilities could ramp up at a rate of 0.3% energy savings as a percent of sales per year, it would be reasonable to ramp up to the 1.50% per year level over a five-year period. Table 10 shows the resulting trajectory of savings assuming a baseline level of sales consistent with 2017 sales levels. That may be conservatively low if sales increase over time.

Table 10: Proposed Energy Efficiency Savings Goals (GWh)

Utility	Incremental Annual Energy Savings (GWh)										10-Year Total
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
All	0.30%	0.60%	0.90%	1.20%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	12.00%
FPL	326	651	977	1,302	1,628	1,628	1,628	1,628	1,628	1,628	13,022
Duke	114	228	342	456	570	570	570	570	570	570	4,563
TECO	58	115	173	230	288	288	288	288	288	288	2,302
Gulf	32	65	97	130	162	162	162	162	162	162	1,297
Orlando	20	39	59	79	99	99	99	99	99	99	788
JEA	35	71	106	142	177	177	177	177	177	177	1,419

Q: If the PSC adopted a 1.50% per year savings goal, what would you recommend with regards to summer and winter peak demand savings goals for energy efficiency programs for each utility?

A: I cannot recommend specific peak demand savings targets because I arrived at these energy savings targets from a "top down" perspective on what is reasonable rather than from a "bottom up" approach to estimating savings. As discussed above, this top down approach was necessitated by the numerous problems with the utilities' efficiency potential studies that rendered them completely insufficient as a reference for the magnitude of cost-effectively achievable savings potential. If the studies' estimates of the ratios of TRC economic potential for summer and winter peak savings to TRC economic potential for energy savings would be applicable to the much more realistic and substantial 1.50% per year energy savings goals, the results would be as shown in Table 11 below. Comparable tables of peak savings by sector, as well as energy savings by sector, are provided in Exhibit JMG-3 of my testimony. However, I would suggest additional analysis be undertaken to determine whether those ratios would hold under an effective set of programs designed to achieve the energy savings goals. Thus, I would recommend that the PSC initiate a process to more carefully assess peak demand savings potential, perhaps even as part of the utilities' energy efficiency program plan filings, in order to establish such goals.

Table 11: Peak Savings Based on Florida Studies' TRC kW/kWh Ratios

Utility	TRC kWh/kW Ratio	Summer Peak MW 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-Year Total
FPL	3889	84	167	251	335	419	419	419	419	419	419	3349
Duke	2935	39	78	117	155	194	194	194	194	194	194	1555
TECO	5475	11	21	32	42	53	53	53	53	53	53	421
Gulf	5063	6	13	19	26	32	32	32	32	32	32	256
Orlando	5299	4	7	11	15	19	19	19	19	19	19	149
JEA	5381	7	13	20	26	33	33	33	33	33	33	264

Utility	TRC kWh/kW	Winter Peak MW 2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	10-Year Total
FPL	6650	49	98	147	196	245	245	245	245	245	245	1958
Duke	5625	20	41	61	81	101	101	101	101	101	101	811
TECO	6736	9	17	26	34	43	43	43	43	43	43	342
Gulf	5933	5	11	16	22	27	27	27	27	27	27	219
Orlando	7802	3	5	8	10	13	13	13	13	13	13	101
JEA	7858	5	9	14	18	23	23	23	23	23	23	181

Q: Do you have any other recommendations?

A: Yes. To address concerns about equity, I would recommend that the PSC also adopt goals specifically for savings from low income customers. Mr. Wright's testimony has more specific suggestions in that regard.

Q: Does that conclude your testimony?

A: Yes, it does.

[1] Weston Berg, et al., "The 2018 State Energy Efficiency Scorecard," American Council for an Energy Efficient Economy, report U1808, (Oct. 2018), available at https://aceee.org/research-report/u1808.

[2] Woolf, Tim et al., *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, Edition 1, Spring 2017 (https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf)

[3] For example, if residential electricity rates do not include demand charges, residential customers who place disproportionately high demands on the system at the time of peak – and who therefore impose higher costs on the system – are effectively cross-subsidized by those who do not. That is not to say that residential demand charges are necessarily a good idea; there may be good reasons for not having them. I am simply making the point that rate design decisions can result in some level of cross-subsidization.

[4] CVPRR values are from Excel files provided by FPL in response to Staff Interrogatory 18. Levelized rates are from FPL Witness Whitley Exhibit AWW-10, attached as Exhibit JMG-4.

[5] Kushler, Martin, Seth Nowak and Patti White., *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs*, ACEEE Report U122, February 2012 (pp. 59-60).

[6] Va. Code § 56-576 (2018).

[7] Order Number PSC-14-0696-FOF-EU in Docket Numbers 130199-EI, 130200-EI, 13201-EI, 130202-EI, 130203-EM, 130204-EM, and 130205-EI (issued December 16, 2014).

[8] Va. Code § 56-576 (2018).

[9] MidAmerican Energy Company Application for Energy Efficiency Plan 2019-2023, Application Exhibit 4: Budget Accounting for Costs, Iowa Utilities Board Docket EEP-2018-002.

[10] For example, see testimony of witness Herndon, p. 19, lines 8-10; FPL response to SACE Interrogatory 21, attached as exhibit JMG-7.

[11] Testimony of FPL witness Koch, p. 20, lines 20-21.

[12] Ironically, most of these are recognized by the utilities (*see* FPL response to SACE Interrogatory 23, attached as exhibit JMG-12).

[13] FPL response to SACE 1st Interrogatory No. 25, Attachment No. 1, attached as exhibit JMG-8.

[14] *ENERGY STAR Unit Shipment and Market Penetration Report Calendar Year 2017 Summary*, https://www.energystar.gov/ia/partners/downloads/unit_shipment_data/2017/2017%20Unit%20Shipment%20Data%20Summary%20Report.pdf?e685-3425.

[15] FPL Response to SACE PODs No. 3, attached as exhibit JMG-9.

[16] FPL response to SACE interrogatory 48, attached as exhibit JMG-10.

[17] Jim Herndon Deposition Transcript, pp. 47-48, attached as exhibit JMG-11.

18 Response to SACE Interrogatory 17; Jim Herndon Deposition Transcript, p. 65, attached as exhibit JMG-11.

19 FPL response to SACE POD 3, attached as exhibit JMG-9.

20 For example, in small commercial direct install programs – a very common program nationally – it is quite common to find many T12 linear fluorescent light fixtures that can be replaced "early". If one were to wait several years until those T12s are replaced naturally, the baseline becomes a much more efficient T8. LED alternatives still provide substantial savings relative to T8s, but not nearly as much as relative to T12s. Thus, programs that promote early retirement of T12s with LEDs can produce very large savings for the first several years of the life of the LED replacement and then lower (though still substantial) savings in the remaining years of its life.

21 Arkansas Public Service Commission, Arkansas Technical Reference Manual at 92-93, Version 8.0, Approved in Docket 10-100-R, applicable beginning January 1, 2019 (http://www.apscservices.info/EEInfo/TRMV8.0.pdf).

22 2019 Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 7.0, Volume 1: Overview and User Guide, Final, September 28, 2018, Effective January 1, 2019 (http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_7/Final_9-28-18/IL-TRM_Effective_010119_v7.0_Vol_1_Overview_092818_Final.pdf), attached as exhibit JMG-13.

23 FPL response to SACE Interrogatory 39, attached as exhibit JMG-39.

24 Excel file "20190015 – SACE's 1st PODs No. 2 – Economic Potential Calculations", see the "TP Table" tab, attached as exhibit JMG-5. The technical potential for variable speed pool pumps that I show are for measures RSFN505 (which refers to new homes) and RSFT505 (which refers to existing homes in which pump pumps "turnover"), the vast majority coming from the latter measure.

25 *Id.*, "TRC Med Fuel no CO2" tab which lists all measures that passed cost-effectiveness screening and should be therefore contributing to economic potential, attached as exhibit JMG-6. Measures RSFN504 and RSFT504, which are the two-speed pool pumps in single family homes, are listed but show zero economic potential; measures RSFN505 and RSFT505 – the two variable speed pool pumps are not listed because they did not pass the cost-effectiveness test.

26 Excel file "20190015 – SACE's 1st PODs No. 2 – Economic Potential Calculations", see the "TP Table" tab, attached as exhibit JMG-5. The technical potential for SEER 21 air source heat pumps displacing electric resistance heat is the sum of savings from measures RMON311, RMOT311, RFMN311, RFMT311, RSFN311 and RSFT311.

27 *Id.*, "TRC Med Fuel no CO2" tab, attached as exhibit JMG-6, which lists all measures that passed cost-effectiveness screening and should be therefore contributing to economic potential. RMON311, RMOT311, RFMN311, RFMT311, RSFN311 and RSFT311 – the six SEER 14 air source heat pumps displacing electric resistance heat (both new construction and existing building turnover for three different residential building types) – are all shown as passing the TRC test, but all show zero economic potential. For TECO, Excel file "(BS 158) Final Rev – Residential Energy Efficiency – Economic Potential," tab "TRC EP," shows SEER 14 air source heat pumps

displacing electric resistance heat as passing the TRC test, but with zero economic potential, attached as exhibit JMG-20.

[28] FPL document produced in response to SACE POD 2, excel file "20190015 – SACE's 1st PODs No. 2 – Residential Batch File – Final.xlsx," attached as exhibits JMG-16 and JMG-17.

[29] For example, see Section 6.1.1 of the Nexant potential study reports and FPL witness Whitley's testimony on p. 25, lines 4-6.

[30] Itron, *ComEd Residential Lighting Discounts Program and Holiday Light Exchange Program Impact Evaluation Report*, April 10, 2019 (http://ilsagfiles.org/SAG_files/Evaluation_Documents/ComEd/ComEd_CY2018_Evaluation_Reports_Final/ComEd_Residential_Lighting_Discounts_CY2018_Impact_Evaluation_Report_2019-04-10_Final.pdf), attached as exhibit JMG-15.

[31] ComEd's 2018 4th quarter report (http://ilsagfiles.org/SAG_files/Quarterly_Reports/ComEd/2018/ComEd_2018_Q4_Report_Spreadsheet.pdf)

[32] "20190015 – SACE's 1st PODs No. 10 – Residential Measure Algorithm Extract.xlsx," attached as exhibit JMG-18.

[33] https://www.energystar.gov/productfinder/product/certified-water-heaters/

[34] "20190015 – SACE's 1st PODs No. 2 – Residential Batch File – FINAL.xlsx", 2019-RES Batch tab.

[35] "20190015 – SACE's 1st PODs No. 10 – Residential Measure Algorithm Extract.xlsx"

[36] See "20190015 – SACE's 1st PODs No. 2 – Residential Batch File – FINAL.xlsx" and 20190015 – SACE's 1st PODs No. 2 – Commercial Batch File – FINAL.xlsx". The only exception to this 20-year limit is for ground source heat pumps for which a life of 22 years is assumed.

[37] For example, see the commonly referenced measure life report GDS, *Residential and Commercial/Industrial Lighting and HVAC Measures*, prepared for the New England State Program Working Group (SPWG), June 2007 (https://www.iar.unicamp.br/lab/luz/ld/Arquitetural/interiores/ilumina%e7%e3o%20industrial/measure_life_GDS.pdf).

[38] For example, see FPL response to SACE Interrogatory 9, attached as exhibit JMG-19.

[39] Lazar, Jim and Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements, published by the Regulator Assistance Project*, August 26, 2011 (https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/?sf_data=results&_sf_s=lazar+line+loss).

[40] Woolf, Tim et al., *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, Edition 1, Spring 2017 (https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf)

[41] *Id.*

[42] DEC savings are divided by sales from non-opt out customers. Data are from DEC response to SACE data request 2-1 in North Carolina Docket 2019-89-E.

[43] Entergy Arkansas savings are divided by sales from non-self-direct customers. Data are from Entergy's Arkansas Energy Efficiency Program Portfolio Annual Report, filed in Docket No. 07-085-TF, May 1, 2019 (http://www.apscservices.info/pdf/07/07-085-TF_662_1.pdf).

[44] Florida utility annual sales values are for 2017, from the Energy Information Administration Annual Electric Power Industry Report, Form EIA-861 detailed data files (https://www.eia.gov/electricity/data/eia861/). This would result in modest overstating of 2020 to 2029 achievable savings as a percent of sales if future sales levels are likely to be higher than in 2017.

[45] GDS Associates, *DTE Energy Electric Efficiency Potential Study*, December 2018, filed as Exhibit A-20 in DTE's recent Integrated Resource Planning proceeding before the Michigan Public Service Commission, Docket U-20471.

[46] Navigant, Arkansas Efficiency Potential Study, Final Report, prepared for the Arkansas Public Service Commission, June 1, 2015.

[47] Optimal Energy, *Study of Potential for Energy Savings in New Orleans, Final* (August 31, 2018).

[48] This is consistent with the range of ramp up periods I have seen in other jurisdictions. For example, in Michigan, DTE ramped up from zero savings in 2008 to 0.42% of sales in 2009, 0.89% in 2010 and 1.15% in 2011 – or a little faster than the 0.3% per year pace I have assumed (*see* testimony of K.L. Bilyeu, DTE, in DTE's current IRP proceeding, Docket U-20471).

[49] The ratios that I use are based on economic potential with no payback screen for FPL, TECO and Gulf, because I had energy and peak savings estimates available for a no payback screen scenario for those utilities. For the other utilities I used energy to peak savings ratios that they reported for a one-year payback screen.