FILED OCT 14, 2015
DOCUMENT NO. 06557-15
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

SOUTHERN ALLIANCE FOR CLEAN ENERGY

PETITION FOR DETERMINATION OF NEED

REGARDING THE OKEECHOBEE CLEAN ENERGY CENTER UNIT 1

DIRECT TESTIMONY OF JOHN D. WILSON

DOCKET NO. 150196-EI

OCTOBER 14, 2015

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is John D. Wilson. I am Director of Research for Southern Alliance for Clean Energy ("SACE"), and my business address is 1810 16th Street, NW, 3rd Floor, Washington, DC 20009.

Q. Please state briefly your education, background and experience.

A. I graduated from Rice University in 1990 with a Bachelor of Arts degree in physics and history. I received a Master in Public Policy from the John F. Kennedy School of Government at Harvard University in 1992 with an emphasis in energy and environmental policy, and economic and analytic methods. Since 1992, I have worked in the private, non-profit and public sectors on a wide range of public policy issues, usually related to energy, environmental and planning topics.

I became the Director of Research for SACE in 2007. I am the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. In this capacity, I am responsible for leading dialogue with utilities and regulatory officials on issues related to resource planning and financial regulation, particularly as they relate to energy efficiency, renewable energy, and conventional generation resources. This takes the form of formal testimony, comments, presentations and/or informal meetings in the states of Alabama, Georgia, Florida, North Carolina and South Carolina, and with respect to the Tennessee Valley Authority. A copy of my resume is attached as Exhibit JDW -1.

Q. Have you previously testified before the Commission?

A. Yes, I testified on behalf of SACE and the Natural Resources Defense Council in the 2009 FEECA goals proceeding, filed in Docket Nos. 080407-EG through 080413-EG.

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

A. I am testifying on behalf of SACE.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I'm sponsoring the following exhibits:

Exhibit JDW-1	Resume of John D. Wilson
Exhibit JDW-2	Generation Reserve Margin Study, Duke Energy Carolinas, Astrape Consulting, 2012.
Exhibit JDW-3	Bob Barrett, "The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion," February 28, 2014. Sim Deposition, Ex. 3.
Exhibit JDW-4	FPL, "Calculation of 'Generation – Only Reserve Margins," undated. Sim Deposition, Exhibit 2 (p. 49).

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked to review the issue of whether there is a need for FPL's proposed Okeechobee Clean Energy Center (OCEC) Unit 1 for the reasons set forth by FPL in its Petition filed with the Commission on September 3, 2015. In particular, my testimony focuses on the two criteria upon which FPL relies for the claimed need for the OCEC Unit 1: (1) a total minimum reserve margin (RM) of 20% (for summer and winter); and (2) a minimum generation-only reserve margin (GRM) of 10% (for summer and winter). If FPL's 20% reserve margin is excessive, and if its 10% GRM is unnecessary, then FPL's proposed OCEC Unit 1 will result in a system that exceeds the need for electric system reliability and integrity, and this excess capacity is not needed nor does it come at a reasonable cost as these criteria are used in Section 403.519(3), Florida Statutes.

Q. Please summarize your testimony for the Commission.

A. It is my opinion that the Commission should evaluate FPL's Petition based on a 15% reserve margin (RM), rather than the 20% RM used as one basis for FPL's Petition in this docket. It is further my opinion that the Commission should reject the FPL created 10% generation-only reserve margin (GRM) upon which FPL relies as the second basis for its determination of need in this docket. Because application of a 15% RM and no GRM demonstrates that FPL does not currently have a system reliability need for the proposed OCEC Unit I, the Commission should deny the Petition.

III. <u>FPL'S RELIANCE ON A 20% RESERVE MARGIN</u>

Q. Are you familiar with the basis upon which FPL relies for the position that it has to meet a 20% reserve margin?

A. Yes. In Docket No. 981890-EU, three of Florida's investor owned utilities (IOUs), including FPL, presented a Stipulation to the Commission containing the 20% minimum planning reserve margins. The Commission approved the Stipulation in Order No. PSC-99-2507-S-EU, issued December 22, 1999.

Q. Based on your review of Docket No. 981890-EU, did FPL advocate for a 20% reserve margin?

A. It doesn't appear so – at least not before the Stipulation was ultimately signed. In fact, prefiled testimony and prehearing statements in that proceeding indicate that all of the IOUs and the Florida Reliability Coordinating Council (FRCC) had conducted studies that individually and collectively supported the continued use of a 15% reserve margin. In filing their proposed agreement, the IOUs stated:

> "By offering this proposal, the IOUs do not mean to be misunderstood as agreeing with Staff's criticism of the planning criteria and methodology now employed by the IOUs and the FRCC. Rather, the IOUs hope to moot this criticism and help restore confidence on the part of the Commission and its Staff concerning the state of reserves in Peninsular Florida."[1]

Q. What was the basis for the 20% reserve margin ultimately stipulated to in Docket No. 981890-EU?

A. It appears that Staff testimony and recommendation was the only basis for the selection of the 20% reserve margin. The basis for the 20% RM is adequately summarized by the following four statements of the Staff's position:

- "My recommendation of a 20 percent reserve margin is based on the concern that utilities are not giving enough weight to the potential adverse effects of weather on their generation planning."[2]

[1] Florida Public Service Commission Staff Memorandum, "Reserve Margin Agreement," Docket No. 981890-EU (October 29, 1999).
[2] Trapp Testimony, p. 8, Docket No. 981890-EU (August 31, 1999).

- "Many of the capacity advisories experienced over the last few years have occurred during off-peak maintenance periods when unpredicted severe weather, forced outages, or catastrophic events have also occurred."[3]
- "… the conditions associated with the 1989 Christmas experience gives us a good baseline to determine if the system would be better or worse off given similar circumstances."[4]
- "Based on actual historical events, the FRCC should adopt a 20 percent reserve margin criterion."[5]

In other words, the 20% reserve margin still being used and relied on by FPL is derived from a 1999 Staff evaluation which compared the operation of the power systems in place during the 1980s and 1990s with historical conditions at those times.

Q. Do you believe it is good utility practice to rely on a historical and outdated evaluation such as this for determining a utility's current and proper reserve margin?

A. No, not for planning purposes. Nor do I believe that the Commission should grant an affirmative determination of need when the claimed basis for such need relies in large part on such an outdated evaluation.

Q. Can you provide an example of how such an outdated evaluation is no longer applicable to FPL's current system?

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[3] Staff Prehearing Statement, Issue 3, p. 6, Docket No. 981890-EU (October 7, 1999).
[4] Ballinger Testimony, p. 10, Docket No. 981890-EU (August 31, 1999).
[5] Staff Prehearing Statement, Issue 11, p. 8, Docket No. 981890-EU (October 7, 1999).

A. Since the 1980's and 1990's, FPL has invested in the improved reliability of its generating units. Moreover, technological advancements have made new plants that have gone online since this time more reliable. As noted by FRCC Witness Villar in 1999 testimony, "previous years' data may be invalid if it is not reflective of improvements in unit forced outage rates, changes in load forecasting methodologies, etc."[6] Indeed, circumstances have changed significantly, as demonstrated by FPL's improved reliability - between 1990 and 2011, FPL's fossil forced outage rate improved by roughly 50%.[7]

Q. Is a Stipulation like that approved by the Commission in 1999 a generally accepted method of selecting a reserve margin?

A. Not in my experience. I have participated in several proceedings in which the issue of reserve margin calculation has been addressed. For example, Exhibit JDW-2 is the *Generation Reserve Margin Study* conducted by Astrape Consulting for Duke Energy Carolinas in 2012. Astrape's approach is based on simulations of "various reserve margins to calculate the physical reliability metrics and corresponding reliability costs … to determine an optimal planning reserve margin."[8]

I have also reviewed similar material for all three IOUs in the Carolinas, for the Southern Company System (in Georgia Power IPR proceedings), for the Tennessee Valley Authority, and for numerous other utilities whose plans I have reviewed for benchmarking purposes. I do not recall reviewing any utility reserve

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[6] Mario Villar, Rebuttal Testimony submitted on behalf of the Florida Reliability Coordinating Council, p. 23, Docket No. 981890-EU (September 27, 1999).

[7] Roxane R. Kennedy, Testimony & Exhibits in Re: Petition for Rate Increase by Florida Power & Light Company), Exhibit RRK-5, Docket No. 120015-EI.

[8] Ex. JDW-2, at p. 4.

margin that is based on a significantly different method of analysis – with the notable exception of the 20% reserve margin established by stipulation in Florida.

Q. Are you aware of any recent studies or substantive analysis conducted by FPL which would support the continued use of a 20% reserve margin?

A. No. In fact, FPL witness Dr. Steven Sim testified during his telephonic deposition taken in this matter on October 8, 2015, that no such study or substantive analysis existed. Dr. Sim did reference an analysis performed by FPL at some point in time, ostensibly since 1999, which indicated support for a reserve margin less than 20%.

Q. Has FPL provided any evidence in support of the need for a 20% reserve margin?

A. No. According to the testimony of Dr. Steven Sim, FPL utilized a minimum total reserve margin of 20% for both seasons; however, his testimony contains no reference to any FPL or third-party study or substantive analysis to validate this 20% RM criteria.

Q. Is it reasonable to assume that the 20% reserve margin remains appropriate because in FPL's historical experience, its existing reserve margin has resulted in adequate reserve margins and reliable service?

A. No. Utilities may err in using such a "gut check" method for identifying when a significant adjustment in the reserve margin standard is needed. For example, in 2010, the North Carolina Utilities Commission required Duke Energy Carolinas to conduct a reserve margin study. The Commission observed:

> Duke stated that it does not dispute that it has not recently conducted a formal comprehensive reserve margin study as it has

> relied primarily upon historical experience to establish its target reserve margin for planning purposes. A 17% target planning reserve margin level has resulted in adequate reserve amounts in the past and has been deemed reasonable by the Commission in the context of prior IRPs filed by the Company. … Duke stated that it does not believe that a comprehensive study is required at this time. [9]

The result of Duke Energy Carolinas' reserve margin study (provided as Exhibit JDW-2) was to reduce Duke's reserve margin from 17% to 15.5%, which had a material impact on Duke's resource plan. [10]

Q. Do you think that the Commission might reasonably rely upon a 20% reserve margin to provide an extra margin of safety?

A. No. In 1999 testimony by FPL Witness Roberto R. Denis, he explained that the approach used by FRCC to analyze the suitability of the 15% reserve margin "properly balances system reliability vs. cost by recognizing that over forecasting can lead to overbuilding, and thus higher costs, as surely as under forecasting can have an effect on ratepayers."[11] If the Commission continues to rely upon a 20% reserve margin to establish need without adequate, current evidence that such a reserve margin is needed, it will surely lead to overbuilding by FPL.

Q. If the 1999 Stipulation is no longer appropriate for the Commission to rely on for FPL's current and proper reserve margin, what should the Commission look to in this regard?

A. I recommend the Commission adopt the standard used by the Florida Reliability Coordinating Council (FRCC) until such a time as FPL, or the FRCC, provides

[9] North Carolina Utilities Commission, Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans, Docket No. E-100, Sub 128 (Oct. 26, 2011) at 18.

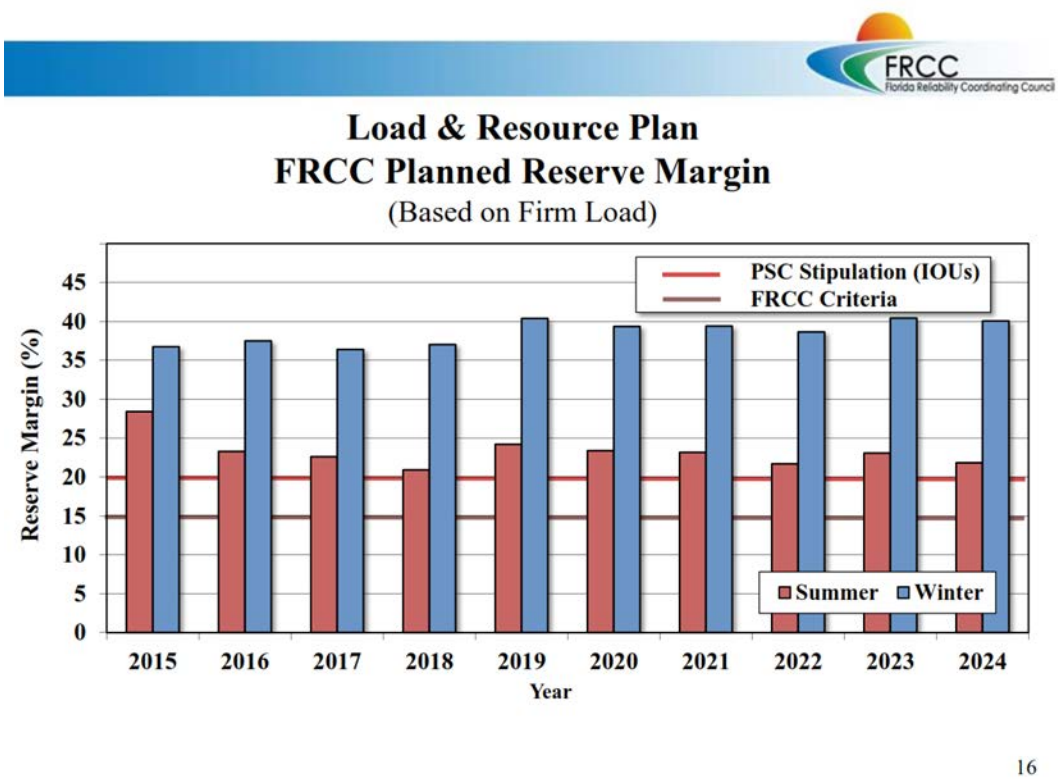
[10] North Carolina Utilities Commission, Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 137 (Oct. 14, 2013) at 18.

[11] Denis rebuttal Testimony, p. 17, Docket No. 981890-EU (September 27, 1999).

analysis and a revised reserve margin recommendation for the Commission to consider.

Q. Has the FRCC changed its 15% reserve margin since the 1999 Stipulation?

A. No. The Florida Reliability Coordinating Council (FRCC) still uses a 15% reserve margin, as indicated on the figure below. Also indicated is that both summer and winter planned reserve margins are well in excess of the 15% FRCC reserve margin criterion. Even though the capacity represented by OCEC Unit 1 is about one-third of the net increase to utility-owned capacity in the FRCC region by 2019, it would still be less than 2% of total FRCC summer capacity.



Source: Stacy Dochoda, *Florida Public Service Commission 2015 Ten-Year Site Plan Workshop: FRCC Presentation* (September 15, 2015).

Q. What are your conclusions regarding FPL's reliance on the 20% RM as a basis for the need to construct the OCEC Unit 1 in this docket?

A. It is my opinion, for several reasons stated earlier in my testimony, that the Commission should require FPL to use a 15% reserve margin as opposed to the 20% RM relied upon by FPL to demonstrate a need for the OCEC Unit 1. These reasons include: the 20% RM: (1) is based on a 1999 Staff evaluation of historical conditions which no longer reflect reality, including, but not limited to, the improved operating reliability of existing and new FPL power plants; (2) is not based on a commonly accepted analytical method of calculating reserve margins; and (3) is not supported by any recent studies or substantive analyses demonstrating that it is a proper reserve margin – for planning purposes or otherwise. Moreover, the 15% RM is supported by ongoing and updated analysis conducted by the FRCC in its 2015 annual assessment.

IV. FPL'S RELIANCE ON A 10% GENERATION-ONLY RESERVE MARGIN

Q. FPL also relies on a 10% generation-only reserve margin (GRM) criterion as a basis for the need for the OCEC Unit 1. How is the calculation of the GRM different from the standard reserve margin calculation?

A. In the standard reserve margin calculation, the forecast peak load is adjusted for load control program resources and energy conservation program resources, resulting in what is called the firm peak load. FPL's GRM criterion does not include these adjustments.

Q. Is the GRM criterion commonly accepted throughout the utility industry?

A. No, the GRM is a recently created FPL criterion, and it is not a commonly accepted resource planning criterion throughout the utility industry. I am not aware of any other utility that uses a GRM criterion. For example, in a recent report for the Eastern Interconnection States' Planning Council and the National Association of Regulatory Utility Commissioners (EISPC/NARUC), the only mention of a generation only reserve margin is in reference to FRCC.[12]

Q. Has the FRCC adopted a generation-only reserve margin criterion?

A. No. With respect to the GRM, the FRCC has noted that "the FRCC and certain utilities are also examining system reliability utilizing a generation-only Reserve Margin perspective."[13] FRCC later explains, "In 2014, FPL adopted a minimum 10% generation-only reserve margin (GRM) as a third reliability criterion in its Integrated Resource Planning (IRP) process."[14] While the FRCC monitors FPL's GRM, it has not adopted a GRM criterion, nor have any publicly available documents from FRCC explained how a GRM criterion might be set at a necessary level, if such exists.

Q. Has FPL ever relied on this GRM criterion in a Petition for Determination of Need prior to the current docket?

A. Not to my knowledge – rather, it is my understanding that FPL has always relied on the more commonly accepted resource planning criteria of RM and LOLP.

Q. What led FPL to create this GRM criterion?

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[12] Astrape Consulting, *The Economic Ramifications of Resource Adequacy White Paper*, funded by US Department of Energy for the Eastern Interconnection States' Planning Council and the National Association of Regulatory Utility Commissioners (January 2013).

[13] Florida Reliability Coordinating Council, *FRCC 2015 Load & Resource Reliability Assessment Report*, FRCC-MS-PL-056 Version 1 (July 2015), p. 5.

[14] *Id.* at p. 14.

A. Dr. Steven Sim's direct testimony does not provide an explanation as to the reason FPL created the GRM criterion other than the simple assertion that it "focuses solely on the need … to ensure there is an appropriate balance between generation and DSM resources." FPL's 2015 Ten-Year Site Plan (TYSP) does provide a slightly more substantive explanation of the utility's concern, "A resource plan with a higher GRM value is projected to result in more MW being available to system operators on adverse peak load days, and in lower LOLP values, than a resource plan with a lower GRM value, even though both resource plans have an identical total reserve margin."[15] Nonetheless, this discussion does not justify the addition of the higher GRM value.

In his telephonic deposition, Dr. Steven Sim testified that it was created in response to two occurrences: (1) the adoption by the Commission of DSM goals for FPL in 2009; and (2) a high load event on January 10, 2011.

Q. Do you have any concerns about the creation of the GRM criterion based solely on the above two occurrences?

A. Yes. In regards to the Commission's 2009 adoption of DSM goals for FPL, not only did FPL never meet those goals, but those goals have been superseded by significantly lower goals adopted by the Commission in 2014 and are no longer in effect for FPL.

The January 10, 2011, high load event is described by FPL Vice President Bob Barrett in a February 2014 presentation included as Exhibit JDW-3. This event was a result of a combination of factors, including cold winter temperatures

[15] FPL 2015 TYSP, p. 56.

driving a high electric heat load and what appears to be a loss of about 1,110 MW (4%) of FPL firm generation resources. Although news reports described some localized outages, FPL did not curtail firm load and retained 1,144 MW of load management capability. I have summarized relevant information from FPL documentation below.

	Anticipated FPL 2009 10-Year Site Plan	Actual January 10, 2011[16]
Firm Generation Capacity	25,982 MW[17]	24,872 MW
Peak Demand	18,697 MW	24,872 MW
DSM	1,730 MW	Activated 561 MW
Emergency Power	450 MW [18]	Sold 426 MW

The FRCC described this as an "extremely high winter peak … the coldest winter on record (or very close) in many areas of Peninsular Florida." Nonetheless, FRCC noted, "All planned load control programs served their designed purpose and firm load was served throughout the peak load period."[19]

FPL also noted that Turkey Point 4 tripped several hours after the peak event, making an additional 750 MW of generation unavailable. If Turkey Point 4

[16] Exhibit JDW-3, p. 16.
[17] According to the Florida Reliability Coordinating Council *2010 Load and Resource Plan,* FPL had a winter net capability of 25,843 MW on January 1, 2010.
[18] Exhibit JDW-3, p. 20.
[19] Florida Reliability Coordinating Council, Inc., *2010 Load & Resource Reliability Assessment Report* (July 6, 2010).

had tripped during the peak event, FPL could have utilized its load management resources or reclaimed its emergency power support from other utilities.

Q. Has FPL provided any other information explaining why a GRM criterion is necessary and warranted in its resource planning?

A. Yes, as presented on slide 14 in Exhibit JDW-3, Mr. Barrett of FPL believes the need for the GRM criterion "can be supported by 3 points."

Q. FPL's first point is "'All resource plans with identical total reserve margins are not created equal' from an operational perspective (a higher GRM plan will result in significantly more total resources – generation and load management – available for system operators than a lower GRM plan in severe peak conditions)." Please respond.

I agree that resource plans with identical total reserve margins will be less reliable to the extent they rely on load management to a greater extent. I do not agree that FPL has demonstrated that energy conservations programs have this effect. For this reason, I disagree that a higher GRM plan is necessarily less reliable than a lower GRM plan.

According to material I reviewed, FPL determined that energy conservation programs (e.g., home insulation projects) result in higher loss of load probability (LOLP) on a MW-for-MW basis than generation. FPL's analysis relies on two flawed assumptions.

First, FPL estimates that monthly demand reduction peaks in August, but is lower in other summer months, presenting a reliability risk that the effect of programs such as Residential HVAC will be less than planned for on peak days.[20] This analysis appears to be based on average monthly savings, not on a peak analysis. Average savings should peak during August, since August days tend to be hotter on average. But to the extent that peak events in June are driven by the same type of hot conditions that are more likely to occur in August, these programs should perform identically. I am unaware of evidence that energy efficiency or load control program technologies perform less effectively on a hot June or October day than on an equally hot August day.

Second, FPL cites uncertainty about the performance of future EE programs, presenting a reliability risk in the form of load forecast uncertainty. This analysis is unreliable because it (1) is out of date (based on 2002 technology) and (2) is based on a simple average of program uncertainty without any evidence that averaging is the proper statistical technique, given the likelihood that there are relationships between the program outcomes.[21] This type of analysis should be supported by a current evaluation, measurement and verification (EM&V) study conducted by an independent consultant and its novel application in this circumstance certainly requires greater scrutiny.

Nonetheless, I do agree with one of the reasons FPL gives for DSM programs adversely affecting LOLP relative to generation resources. Exhibit JDW-3 (p. 7) illustrates FPL's discussion of load management "fatigue."[22] I agree with FPL's conclusion that evidence on this topic is "inconclusive," but

[20] FPL, "Comparison of Generation vs. DSM: 1 MW in August Basis," Sim Deposition Exhibit 2 (undated).

[21] FPL, "Confidence Levels Around DSM EE Summer MW (2002 Monitoring Data Applied to 2012 MW)," Sim Deposition Exhibit 2 (undated).

[22] Ex. JDW-3, at p. 7.

nonetheless, it is reasonable for FPL to plan around this issue. While customer response to load management requests is usually quite good for the first several times, FPL reasonably concludes that there should be "No greater than 10 events/year," among other limitations. To the extent that a peak event repeatedly draws on load management resources, it could result in lower customer response and hence a higher LOLP associated with use of load management resources.

Q. Does the issue of load management "fatigue" justify adoption of the GRM?

A. No. The GRM designed by FPL includes energy conservation programs, which are not subject to "fatigue." In fact, just the opposite as many of these programs involve the use of passive measures (e.g., insulation) or installation of lower power equipment.

It is worth noting that in the EISPC/NARUC paper on resource adequacy I referred to earlier, there is no discussion of energy conservation programs presenting a risk to resource adequacy. In contrast, Astrape Consulting did model the impacts of load management (or demand response) programs on reserve margin requirements.

Instead of the GRM, FPL should consider a reliability criterion that only differs from the standard reserve margin with respect to consideration of load management programs. In addition to discussion in the EISPC/NARUC paper, such a criterion appears to have been recommended by Staff of the Florida Public Service Commission, as presented in Exhibit JDW-4.

The "FPSC Staff Method Gen-Only Reserve Margin" differs from the FPL GRM by adjusting peak load to consider the impact of conservation programs (as in the standard reserve margin criterion) but differs from the standard reserve margin by excluding load control programs from the peak load adjustment.

Q. FPL's second point is, "A resource plan with a higher GRM value is projected to be more reliable from an LOLP perspective." Please respond.

A. Technically, yes, but the point is mooted by the data. As I have discussed above, if the reason that a plan has a higher GRM value is less reliance on load control, then I agree that a higher GRM plan would have a higher LOLP.

However, as illustrated in Exhibit JDW-3 (p. 5), FPL's data do not support a concern that the "higher LOLP" is leading to significant risk. According to FPL, the difference between a 5% GRM and a 10% GRM is 0.01 days/year.

As noted in Dr. Sim's testimony, FPL already applies a "maximum loss-of-load probability (LOLP) of 0.1 day per year." Simply stating that a lower GRM value corresponds to a more adverse LOLP value does not explain what additional reliability risk is presented by a utility with a GRM of less than 10% but a LOLP that meets the LOLP standard. In fact, while FPL's LOLP is not included in Dr. Sim's testimony, FPL estimated it as 0.02 days per year (Exhibit JDW-3, p. 5). Furthermore, even in the 5% GRM case, the LOLP projection provided by FPL is only 36% of its LOLP standard. FPL has simply failed to present a problem that the GRM is needed to solve.

Q. FPL's third point is, "A resource plan with a higher GRM value is projected to have to use its LM resources less frequently." Please respond.

A. Yes, the more generation resources FPL invests in, at customer expense, the less it will rely on load management resources. Failing to make reasonable use of its load management programs would be a waste of customer resources invested to develop those programs.

Q. Is any form of generation-only reserve margin the best way to address concerns about load management resources?

A. No. Concerns about the scale and responsiveness of load management resources are adequately addressed using a standard reserve margin method under guidance provided by the North American Electric Reliability Corporation ("NERC").

Florida utilities appropriately calculate reserve requirements by comparing system generation resources (and net transactions with other systems) to net internal demand. As defined by NERC, net internal demand includes unrestricted non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load and demand response.[23]

It is possible that demand response or load management programs may not perform at the level indicated by subscribed capacity. Such programs often depend on communication with the customer, customer acceptance at the time of peak, and critical infrastructure performance. If such technical issues result in less demand reduction than anticipated, whether routinely or during periods of critical demand, it is appropriate to consider such factors in establishing the contribution of load management to firm supply. NERC guidance, in fact, indicates that demand response programs should be considered in net internal demand to the extent that they are dispatchable and controllable.[24]

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[23] NERC, *Reliability Assessment Guidebook*, Version 3.1 (August 2012), p. 15.
[24] *Id.*

In reviewing FPL and FRCC discussion of the GRM, I did not come across any suggestion that such technical issues are actually impairing the dispatchable and controllable nature of FPL load management programs (other than "fatigue" as discussed above). NERC guidance does not suggest that there should be an upper limit set for a particular resource, including load management.

FPL applies a similar method when considering the impact of solar energy on its reserve margin. In its 2015 TYSP, FPL notes, "Approximately 46% of the 25 MW of PV at DeSoto, and 32% of the 10 MW of PV at Space Coast, are considered as firm generating capacity for summer reserve margin purposes."[25] Without necessarily agreeing with the values selected by FPL, I agree strongly with the application of seasonal-specific capacity values for resources whose dispatch or control is impaired for any reason. This may apply to any resource type, for example, I am aware that some utilities derate the summer capacity values of certain nuclear or other thermal generation units due to the likelihood of limitations in the supply or performance of cooling water.

Most often, however, load management resources are not considered at risk for underperformance. When studying Duke Energy Carolinas' reserve margin, Astrape modeled load management resources without remarking on any technical issues that might suggest a need for a lower capacity value.[26] While technical issues may exist that result in less demand reduction achieved than expected, our review of Duke Energy Carolinas' activation history data did not

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[25] FPL 2015 TYSP, at, p. 17.

[26] Astrape Consulting, Inc., *Duke Energy Carolinas 2012 Generation Reserve Margin Study* (August 2012), p. 33-34, 47-48. For example, Astrape modeled various sensitivities reflecting general operational concerns affecting reserve margin planning, such as weather diversity. None of these sensitivities reflected general technical considerations related to the response of demand response resources.

reveal shortfalls. DEC reported that its demand response programs have been activated a number of times, and most programs achieved reductions consistent with (or even in excess of) expected reductions.[27]

It is also worth noting that SACE took some issue with how Duke Energy Carolinas implemented its reserve margin calculation. In response to SACE's comments, in its order on the 2012 utility IRPs issued on October 14, 2013, the North Carolina Utilities Commission ("NCUC") stated that DEC "should consider demand response in programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP."[28] This order confirmed SACE's interpretation of NERC guidelines.

Accordingly, while I do not agree that a GRM criterion is necessary for reliability purposes, to the extent that FPL provides evidence that its load management programs have an activation history that reveals a shortfall in reductions, then I would agree that such a shortfall should be considered in its reserve margin analysis. When forecasting net internal demand, FPL could reasonable adjust the capacity value of its load management programs to reflect experience.

Q. What are your conclusions regarding FPL's reliance on the 10% GRM as a basis for the need to construct the OCEC Unit 1 in this docket?

A. In addition to my points above, the FPL's utilization of its GRM criterion will skew its resource decisions towards "putting steel in the ground." In other words,

[27] Duke Energy Carolinas, 2012 IRP, p. 148. The sole exception is the Power Manager (air conditioner) program, in which activation events since 2010 achieved 3-17% less reduction than expected.

[28] North Carolina Utilities Commission, Order Approving Integrated Resource Plans and REPS Compliance Plans, Docket No. E-100, Sub 137 (Oct. 14, 2013) at pp. 20-21.

as long as FPL relies on this criterion for future resource planning, the company will overemphasize building new power plants as opposed to looking to DSM or energy efficiency, or simply more efficient utilization of existing resources, to meet its future resource needs. By adopting an unnecessary and wrongly designed criterion, FPL's customers will carry the cost of unnecessary power plant construction.

V. FPL'S ANALYSIS OF ALTERNATIVES TO THE OCEC UNIT 1

Q. Could FPL have avoided the need for the proposed OCEC Unit 1 through a more full and thorough evaluation of all reasonably available cost-effective alternatives?

A. Potentially. FPL continues to underutilize all cost-effective alternatives to conventional generation, including, but not limited to, energy efficiency. As discussed in the testimony of Natalie Mims, SACE explained in the recent FEECA proceedings how FPL had the opportunity to pursue much higher levels of energy efficiency at a much lower cost than building and operating new power plants.

Q. Are there any renewable energy sources or technologies reasonably available to FPL which might mitigate the need for the proposed OCEC Unit 1?

A. Yes. FPL has not fully explored renewable energy opportunities that could reduce risks to customers from variable fuel costs and other factors. If FPL had made greater investments in energy efficiency and pursued opportunities to procure renewable energy in South Carolina, it might be possible for FPL to avoid adding any additional natural gas power plants – including the proposed OCEC Unit 1 - and the costs that they represent for customers.

Q. What about solar technologies?

A. FPL did not appear to consider solar resources as a generation alternative in its most recent ten-year site plan. FPL did explain new plans to add three new photovoltaic (PV) facilities with nameplate ratings of approximately 74.5 MW each. However, it is notable that these units are identified in "step 1" of FPL's resource planning process in which it applies assumptions regarding FPL's "current projection of new generating capacity additions …"[29] In other words, FPL's newest solar facilities are not the result of FPL's resource planning process as described in the ten-year site plan, but are the result of some other business development process that is not clearly described.

If FPL considered solar resources as a generation alternative to natural gas (alone or in combination), then solar technologies would be mentioned as one of the resource alternatives evaluated in "step 2," in which competing resource options are evaluated to meet FPL's resource needs. The outcome of the process is reported as "three more generation changes," including the proposed CC unit and two short-term PPAs.[30]

In my experience reviewing many utility resource plans, especially those in the Southeast, utilities often fail to evaluate solar as a resource. Only recently have a few utilities, notably the Tennessee Valley Authority, evaluated solar, wind and energy efficiency as alternatives in their capacity optimization models.

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[29] FPL IRP p. 49-50.

[30] FPL IRP p. 57.

More typically, a utility will include solar as a defined model input, which is what FPL explicitly describes doing in this instance.

Q. Have you seen any information specific to FPL's analysis of using PV solar to meet all or a portion of the need that it now wants to meet with the OCEC Unit 1?

A. During Dr. Sim's deposition, in response to a SACE document request, FPL provided incomplete information about additional analysis it may have performed regarding solar with respect to meeting the purported need it now wants to meet with OCEC Unit 1. This incomplete information did not convince me that FPL includes solar as a resource alternative in its planning model.

Because of the incomplete nature of the information provided, I cannot speculate as to the extent that solar technologies could substitute for any need that may exist (now or in the future) for a combined cycle natural gas plant. I would expect FPL to increase its plans to invest in solar resources if solar was included in the capacity optimization model process. I do know from experience that as utilities like the Tennessee Valley Authority make such changes in their model process, the most cost-effective plans do include significantly increased investments in solar and wind resources. Surely in the Sunshine State, the results would be favorable to growth in solar power.

VI. CONCLUSION

Q. Based on your opinions regarding FPL's misplaced reliance on the 20% RM criterion and the 10% GRM criterion in this docket, what are your conclusions about FPL's need for the OCEC Unit 1?

A. Based on my recommendation that the Commission evaluate FPL's Petition using FRCC's 15% reserve margin rather than the 20% reserve margin adopted in the 1999 Stipulation, and my recommendation to disregard the unfounded GRM criterion, FPL does not need any new capacity in 2019, and no significant amount of new capacity in 2020, as illustrated below. As a result, FPLs' Petition should be denied.

August of the Year	Projected Summer Total Reserve Margin w/o Additions in 2019 & 2020	Projected Total MW Needed to Meet Total Reserve Margin (MW)	
		20% Reserve Margin	15% Reserve Margin
2015	26.7%	(1,421)	(2,488)
2016	21.3%	(287)	(1,376)
2017	20.9%	(190)	(1,301)
2018	20.0%	(1)	(1,129)
2019	15.7%	988	(157)
2020	14.3%	1,320	161

Q. Does that conclude your direct testimony?

A. Yes, it does.

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EXPERIENCE

Southern Alliance for Clean Energy

Director of Research, Asheville, North Carolina and Washington, DC, 2007 – present
- Manage technical and regulatory advocacy
- Conduct supporting research and policy development across all program areas

Galveston-Houston Association for Smog Prevention

Executive Director, Houston, Texas, 2001 – 2006
- Member, Regional Air Quality Planning Committee
- Member, Transportation Policy Technical Advisory Committee
- Member, Steering Committee, TCEQ Interim Science Committee
- Awards & recognition from the City of Houston, *Houston Press*, and environmental groups

The Goodman Corporation

Senior Associate, Houston, Texas, 2000 – 2001
- Transportation and Urban Planning Consulting
- Project Manager, Houston Main Street Corridor
- Project Manager, Houston Downtown Circulation Study
- Project Manager, Austin Corridor Planning
- Project Manager, Ft. Worth Berry Street Corridor Initiative

Florida Legislature

Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Tallahassee, Florida, 1997- 1999
- Coordinator, Florida Government Accountability Report, 1999
- Coordinator, Project Management Software Implementation, 1999
- Creator and Editor, *Florida Monitor Weekly*, 1998 - 99
- Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures

Florida State University

Environmental Management Consultant, Tallahassee, Florida, 1997
- Project staff, *Florida Assessment of Coastal Trends*, 1997

Houston Advanced Research Center

Research Associate, Center for Global Studies, The Woodlands, Texas, 1992 - 96
- Coordinator, Houston Environmental Foresight, 1993 - 96
- Coordinator, Rio Grande/Rio Bravo Basin Initiative, 1992 - 94
- Secretary, Task Force on Climate Change in Texas, 1992 - 94
- Researcher, *Policy Options: Responding to Climate Change in Texas*, 1992 - 93

US Environmental Protection Agency

Student Assistant, Climate Change Division, Washington, DC, 1991 - 92
- Special Achievement Award, 1991

EDUCATION

Harvard University

Master in Public Policy, John F. Kennedy School of Government, 1992
- Concentration areas: Environment, negotiation, economic and analytic methods

Rice University

Bachelor of Arts, conferred *cum laude*, 1990
- Majors: Physics (with honors) and history

Additional Training and Experience

Spanish language; Advanced computer skills; Served and led political committees for the Sierra Club and Clean Water Action; Certified Master Wildlife Conservationist, Leon County Extension Service

PUBLICATIONS

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(Lead author or significant contributor)

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Southern Alliance for Clean Energy, *Cornerstones: Building a Secure Foundation for North Carolina’s Energy Future* (May 2008).

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2012

Duke Energy Carolinas 2012 Generation Reserve Margin Study

Astrape Consulting
8/17/2012

Contents

REDACTED
[redacted]

Executive Summary

The reserve margin study performed by Astrape Consulting was requested by Duke Energy Carolinas in response to North Carolina Utilities Commission Order dated October 26, 2011 in Docket No. E -100, Sub 128. The Order requires DEC to perform a comprehensive reserve margin study and include it as part of its 2012 biennial IRP report.

The optimal planning reserve margin for Duke Energy is based on providing an acceptable level of physical reliability and minimizing economic costs to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but it is economically unreasonable for a load serving entity to maintain enough reserves to meet this expectation. From a physical reliability perspective, Loss of Load Expectation (LOLE) decreases as reserve margin increases. The most common physical metric used in the industry is to target a system reserve margin that meets the one day in 10 year standard which is interpreted as one firm load shed event every 10 years (LOLE = 0.1). A firm load shed event occurs when load plus spinning reserves is greater than available capacity and all options including market purchases and demand response have been exhausted. This results in unserved energy for a firm customer. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. The economic optimum is defined as the point where the cost of additional reserves plus the cost of reliability events on customers is minimized. For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
  - Resources are defined based on summer ratings and include Demand Response
  - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

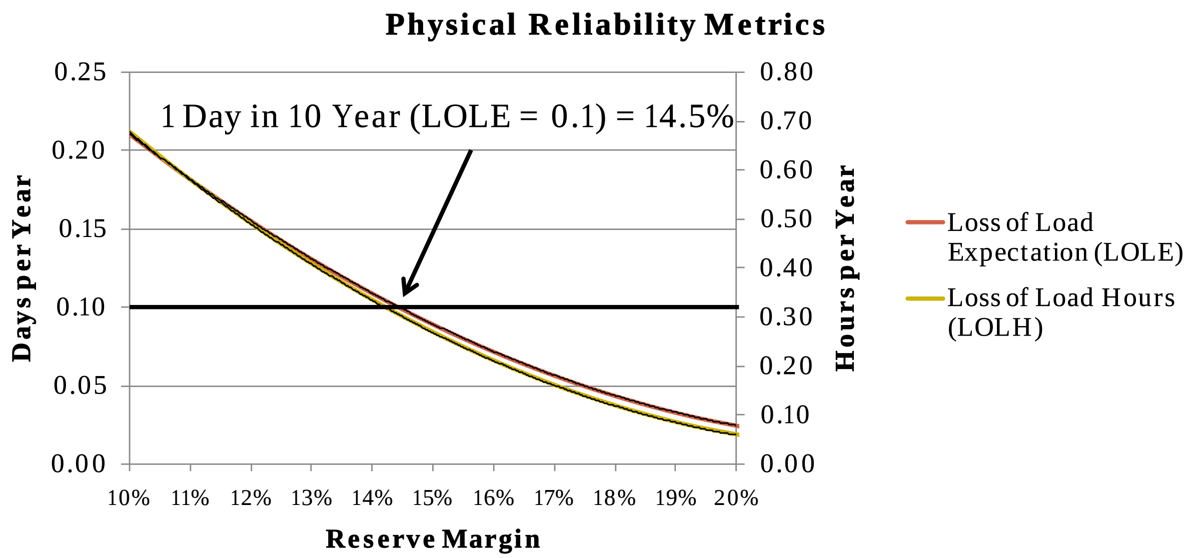
Astrape Consulting has taken a stochastic approach in modeling the uncertainty of weather, economic load growth, unit availability, hydro availability, and transmission availability for emergency tie assistance. Utilizing a multi-area reliability model called SERVM (Strategic Energy and Risk Valuation Model), over 1 million yearly simulations were performed at various reserve margins to calculate the physical reliability metrics and corresponding expected reliability costs. The physical metrics and reliability costs were used to determine an optimal planning reserve margin.

From an economic perspective, the study defines the capacity costs as the annual carrying costs associated with the marginal resource which for this study is a new natural gas combustion turbine. The study defines reliability energy costs as any energy costs the system experiences above the dispatch cost of the marginal resource. These costs include the dispatch of expensive peaking resources such as oil CTs, net imports of expensive market purchases during capacity shortages, and the societal cost of unserved energy.

Summary of Results and Key Insights

The reserve margin that results in 1 day in 10 year LOLE (0.1 days per year) is 14.5% as shown in Figure ES1. Loss of load hours (LOLH) approaches 0.30 hours per year at the 14.5% reserve margin.

Figure ES1. Physical Reliability Metrics



In resource adequacy simulations, firm load shed events are sensitive to inputs due to their infrequent nature. Weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions can shift the 0.1 LOLE reserve margin by several percentage points as shown in the sensitivity section of the report. As an example, emergency hydro assumptions impacted Duke's system LOLE substantially. If the portion of the 1,100 MW hydro capacity that is designated as emergency capacity is available to be used a few hours a month, then the target LOLE reserve margin shifts from 14.50% to 11.25%. This emergency designated block varies by year and month, but during drought conditions, it represents 700-750 MW of unavailable capacity as seen in 2007 and 2008. From a planning perspective, it is difficult to assess the availability of this capacity during drought conditions, and given experience in recent drought years such as 2007 and 2008, it is not prudent to expect this capacity to be available during peak conditions. However, by approaching resource adequacy planning from a more holistic perspective, the target reserve margin is not as sensitive to individual inputs. For this reason, we recommend assessing the economics in addition to the physical reliability metrics. This allows planners to not only assess the comprehensive benefits of incremental capacity, it also allows for better calibration of physical reliability metrics.

The economic reliability assessment which balances the costs and benefits of incremental capacity is seen in Figure ES2 which demonstrates that the long-term minimum cost reserve margin is 14%. As reserve margin increases, the CT carrying costs rise and the reliability energy costs made up of production costs above a CT, net imports above a CT, and expected unserved energy decrease. Between 14% and 16%, the flatness of the curve indicates that there is not a significant cost impact to being slightly above the minimum cost point. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and can provide substantial risk benefit.

Figure ES2. Minimum Weighted Average Cost Reserve Margin

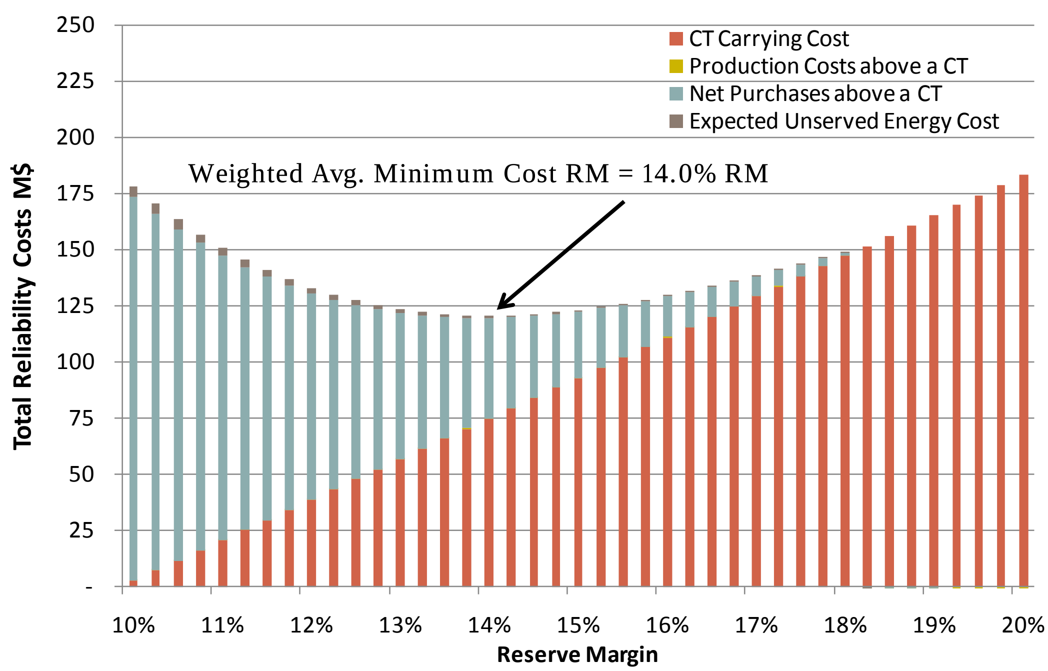
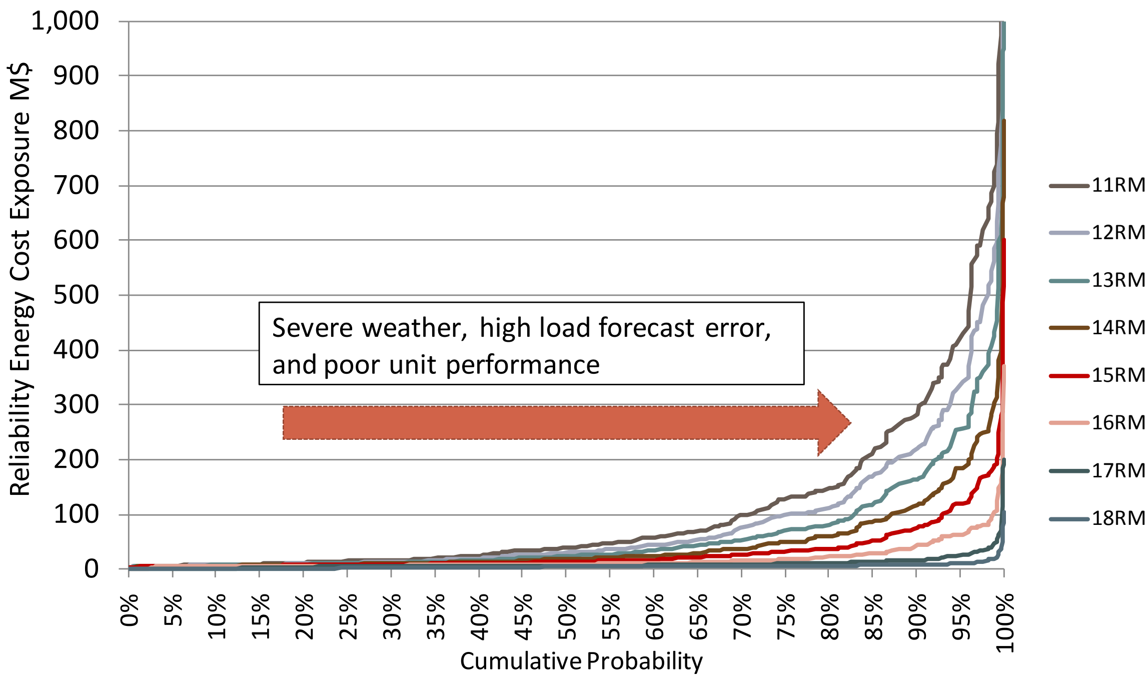


Figure ES3 demonstrates the distribution of reliability energy costs seen in Figure ES2 at each reserve margin level. It should be noted that even at the economic optimum reserve margin of 14% there is still potential for high reliability cost years due to abnormal weather, economic growth, or poor unit performance in the region as shown in the following figure. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

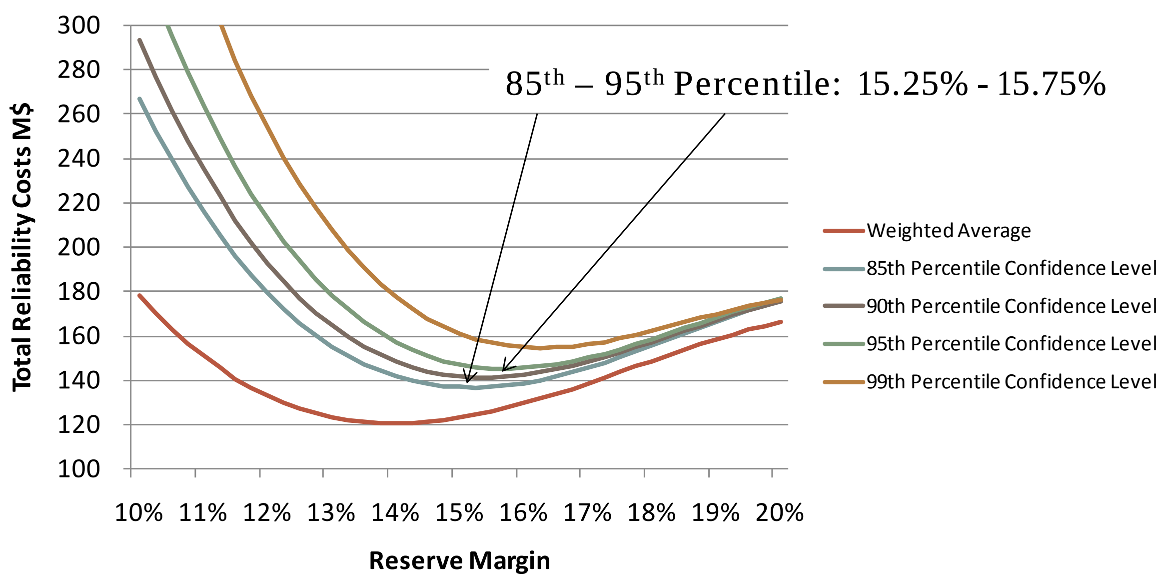
Figure ES3. Distribution of Reliability Energy Costs



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure ES3, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure ES3 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure ES4. This assessment showed that in 10% of all scenarios, Duke

Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level curve in Figure ES4. As stated previously, when we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million in any given year as seen in Figure ES3.

Figure ES4. Optimal Reserve Margins over a Range of Confidence Intervals



Recommendation

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target threshold of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year 2016 was chosen because it is three to four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility. By looking three to four years out, this study reflects a longer term optimal reserve margin. Lower economic load forecast error as well as surrounding market conditions could potentially allow the company to carry slightly lower reserves in the short term.

Although 2016 was selected for the base case simulations, the SERVM simulation results should apply for the 3 to 5 year period following 2016 assuming that resource mixes and market structures do not change drastically over that term. To that end, several sensitivities were run to reflect changes in the market that could occur in this time period as well as a look at a 2023 Study Year.

B. Load Modeling

Table 1. 2016 Load Forecast

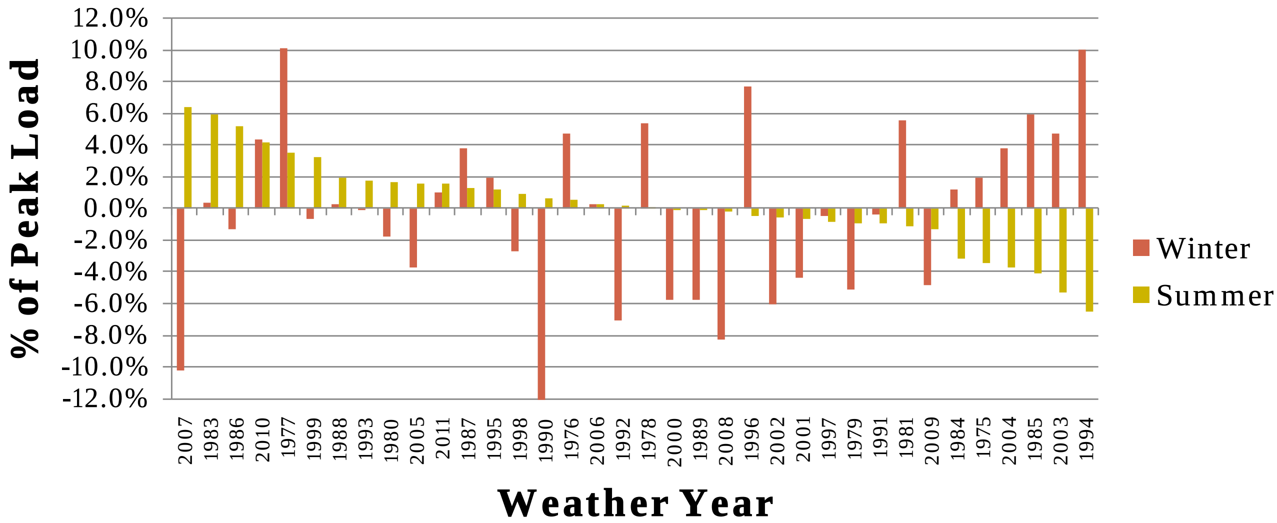
Month	Energy (MWh)	Peak Load (MW)
January	9,163,558	18,891
February	8,191,438	18,033
March	7,845,982	16,797
April	7,311,837	14,012
May	7,885,201	16,407
June	9,015,082	18,675
July	9,509,029	19,476
August	9,595,229	19,075
September	8,256,070	17,595
October	7,486,890	14,687
November	7,541,890	16,048
December	8,669,874	17,756

Table 1 displays the peak and energy forecasts for 2016 under normal weather conditions. The company is expected to have a winter peak of 18,891 MW and a summer peak of 19,476 MW. All values include the reduction for energy efficiency but exclude any other DSM reductions.

To model the effects of weather uncertainty, 37 historical weather years were developed to reflect the impact of weather on load. A neural network program was used to develop relationships between weather observations and load based on the last five years of historical weather and load. Different relationships were built for each month of the year using hourly temperature, time of day, day of week, 8 hour prior temperature, 24 hour prior temperature, 48 hour prior temperature, and heating and cooling degree hours.

These relationships were then applied to the last 37 years of weather to develop 37 load shapes for 2016. Equal probabilities were given to each of the 37 load shapes in the simulation. Figure 1 ranks all weather years by peak summer load for the system. In the most severe weather conditions, the summer peak can be approximately 6% higher than the peak under normal weather conditions and 10% for the winter. The reason for the larger variation in winter loads is the larger variation of temperature versus normal weather of 10 to 13 degrees whereas in the summer maximum variation versus normal weather is only 6 degrees.

Figure 1. Peak Load Variability Vs. Normal Weather



The difference in frequency of high load periods during winter versus summer can be seen in Figure 2. The duration of high load is far less in the winter causing the summer to have higher reliability risk. So despite higher variation in winter peak loads, sustained high loads in the summer cause the majority of reliability events.

Figure 2. Frequency of High Load Hours for Winter and Summer

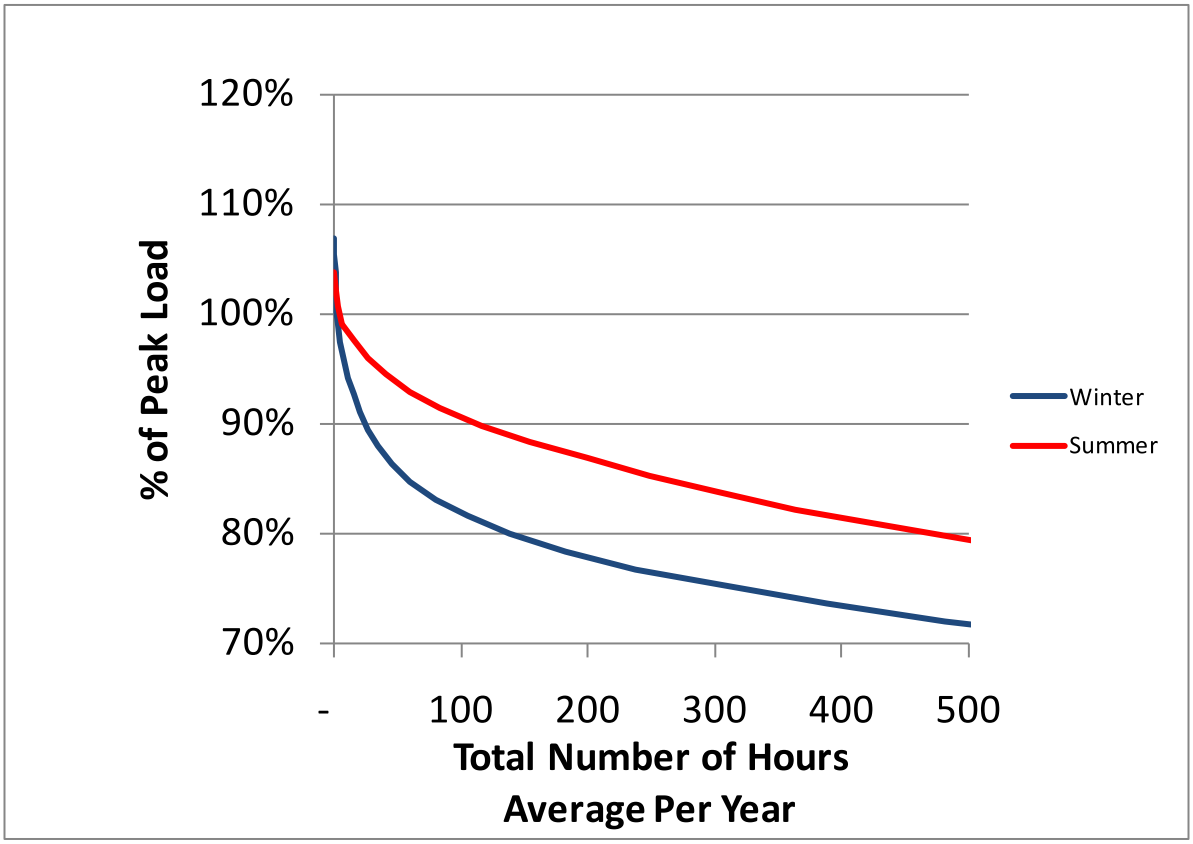


Table 2 summarizes the combined summer and winter peaks by weather year. The table shows that recent years including 2007 and 2010 were among the most severe summers.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks

Max	20,721	6.40%
Forecast	19,476	

Rank	Year	Peak	Versus Forecast (%)
1	2007	20,721	6.4%
2	1983	20,634	5.9%
3	1986	20,485	5.2%
4	2010	20,289	4.2%
5	1977	20,156	3.5%
6	1999	20,106	3.2%
7	1988	19,856	2.0%
8	1993	19,808	1.7%
9	1980	19,789	1.6%
10	2005	19,777	1.5%
11	2011	19,772	1.5%
12	1987	19,729	1.3%
13	1995	19,702	1.2%
14	1998	19,645	0.9%
15	1990	19,600	0.6%
16	1976	19,583	0.6%
17	2006	19,533	0.3%
18	1992	19,517	0.2%
19	1978	19,492	0.1%
20	2000	19,462	-0.1%
21	1989	19,461	-0.1%
22	2008	19,429	-0.2%
23	1996	19,388	-0.4%
24	2002	19,362	-0.6%
25	2001	19,345	-0.7%
26	1997	19,317	-0.8%
27	1979	19,300	-0.9%
28	1991	19,288	-1.0%
29	1981	19,247	-1.2%
30	2009	19,225	-1.3%
31	1984	18,859	-3.2%
32	1975	18,797	-3.5%
33	2004	18,750	-3.7%
34	1985	18,670	-4.1%
35	2003	18,446	-5.3%
36	1994	18,202	-6.5%
37	1982	17,849	-8.4%

Winter Peaks

Max	20,798	10.1%
Forecast	18,891	

Rank	Year	Peak	Versus Forecast (%)
1	1977	20,798	10.1%
2	1982	20,798	10.1%
3	1994	20,778	10.0%
4	1996	20,347	7.7%
5	1985	20,015	5.9%
6	1981	19,944	5.6%
7	1978	19,902	5.4%
8	2003	19,790	4.8%
9	1976	19,777	4.7%
10	2010	19,713	4.3%
11	1987	19,614	3.8%
12	2004	19,605	3.8%
13	1995	19,259	1.9%
14	1975	19,254	1.9%
15	1984	19,121.20	1.2%
16	2011	19,082	1.0%
17	1983	18,950	0.3%
18	2006	18,947	0.3%
19	1988	18,934	0.2%
20	1993	18,884	0.0%
21	1991	18,823	-0.4%
22	1997	18,801	-0.5%
23	1999	18,761	-0.7%
24	1986	18,650	-1.3%
25	1980	18,561	-1.7%
26	1998	18,383	-2.7%
27	2005	18,192	-3.7%
28	2001	18,068	-4.4%
29	2009	17,969	-4.9%
30	1979	17,929	-5.1%
31	2000	17,809	-5.7%
32	1989	17,807	-5.7%
33	2002	17,745	-6.1%
34	1992	17,551	-7.1%
35	2008	17,325	-8.3%
36	2007	16,953	-10.3%
37	1990	16,130	-15%

From an annual energy perspective, the following table shows the top 10 highest weather years. Table 3 shows that 2010 had energy consumption 5% higher than normal as both winter and summer seasons were severe. The second highest weather year was only 2.5% higher than average energy.

Table 3. Weather Years Ranked by Total Energy

Annual Energy
Top 10

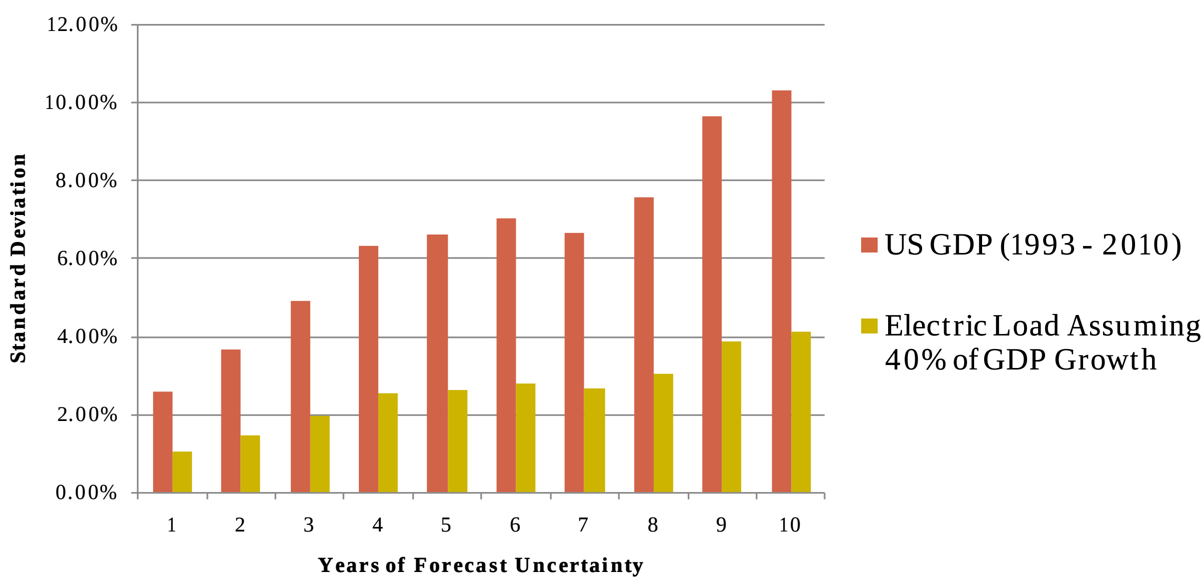
Max	106,073,456	5.0%
Forecast	101,065,715	

Rank	Year	Peak	Versus Forecast (%)
1	2010	106,073,456	5.0%
2	1977	103,627,852	2.5%
3	1993	103,014,691	1.9%
4	1980	102,568,028	1.5%
5	1987	102,319,099	1.2%
6	1978	102,300,173	1.2%
7	1986	102,249,879	1.2%
8	2007	102,241,193	1.2%
9	1981	102,065,451	1.0%
10	1988	101,879,158	0.8%

C. Load Forecast Error

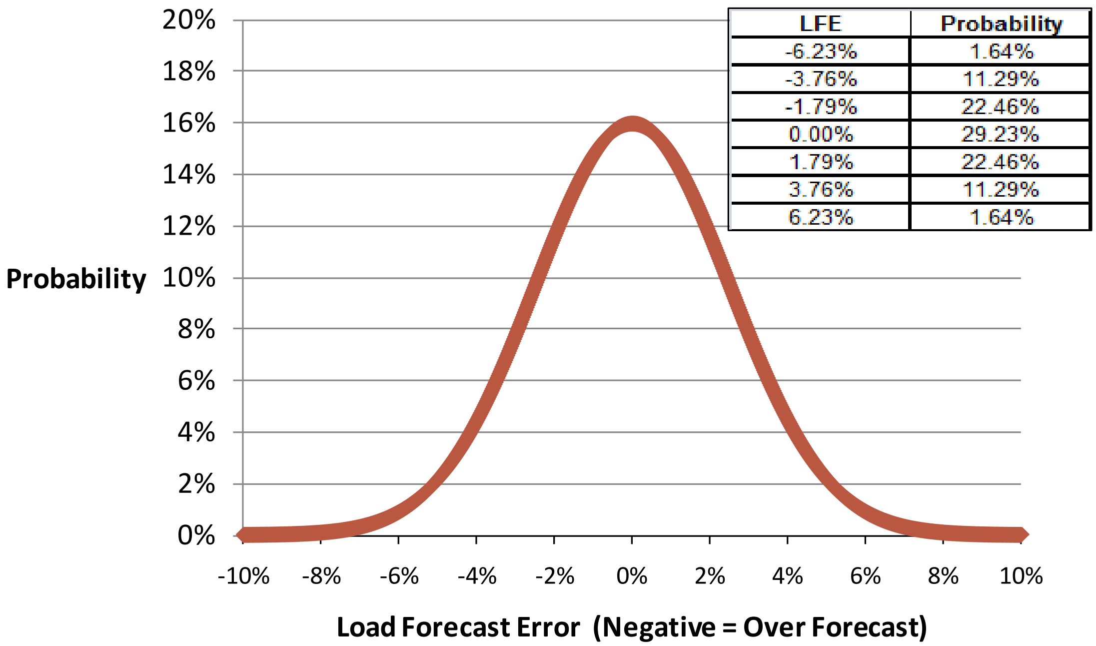
An analysis was performed using the historical Congressional Budget Office four year prior forecasts of GDP and comparing those forecasts to actual data from 1993 – 2010. Comparing how well GDP was predicted four years in advance provides insight into the economic uncertainty that should be applied to utility loads. The chart below shows the standard deviation of historical GDP forecast error for forecasting one to ten years in advance. As expected, the standard deviation of forecast error increases as the number of years increase. Based on discussions with Duke, electric load is assumed to grow at about 40% of GDP growth. Assuming four year forecast error, standard deviation for load forecast error uncertainty for utility load is 2.5% as shown in the following figure. If lead times for new generation changed substantially, then the standard deviation used to develop the economic load forecast error would need to be adjusted accordingly. However, it is unlikely that typical generation resources can be installed and brought in-service in less than three to four years given the time needed for environmental and regulatory approvals, construction, and startup testing.

Figure 3. Standard Deviation of GDP forecast error (1 to 10 Year Projections)



Astrape also performed a comparison of the company's historical four year prior forecasts to actual weather normalized load. Astrape observed that in recent years there was a tendency to over forecast given the economic downturns seen in the last decade. However, the standard deviation of load forecast error was 3.34%, which was in the range of the CBO study. The company and Astrape determined that using 2.5% was a reasonable value for the standard deviation and Astrape developed a normal distribution as shown in the following Figure 4. The continuous distribution was converted into a discrete distribution with the 7 points shown for use in determining discrete scenarios to be modeled. As an example of how to interpret the economic uncertainty data, there is a 1.64% chance that load will be 6.23% greater than forecasted.

Figure 4. Load Forecast Error



LFE	Probability
-6.23%	1.64%
-3.76%	11.29%
-1.79%	22.46%
0.00%	29.23%
1.79%	22.46%
3.76%	11.29%
6.23%	1.64%

SERVM utilized each of the 37 weather years and applied each of these seven load forecast error points to create 259 different load scenarios.

D. Resources

The resources and seasonal capacities for the 2016 study are shown in the following tables.

Table 4. Nuclear Resource Capacities (MW)

Unit Name	January	July
Catawba 1	891	857
Catawba 2	881	847
McGuire 1	900	844
McGuire 2	900	844
Oconee 1	875	856
Oconee 2	875	856
Oconee 3	875	856
Totals	6,196	6,196

Table 5. Baseload and Intermediate Resource Capacities (MW)

Unit Name	January	July
Allen 1	167	162
Allen 2	167	162
Allen 3	270	261
Allen 4	282	276
Allen 5	275	266
Belews Creek 1	1135	1110
Belews Creek 2	1135	1110
Cliffside 5	562	556
Cliffside 6	825	825
Marshall 1	380	380
Marshall 2	380	380
Marshall 3	658	658
Marshall 4	660	660
Buck CC	508	500
Buck CC Duct	120	120
Dan River CC	508	500
Dan River CC Duct	120	120
CPL SOR A	2	2
CPL SOR D	3	3
CPL SOR E	2	2
NUG	26	26
Totals	8,185	8,079

Retired by 2016
Buck 3
Buck 4
Buck 5
Buck 6
Cliffside 1
Cliffside 2
Cliffside 3
Cliffside 4
Dan River 1
Dan River 2
Dan River 3
Riverbend 4
Riverbend 5
Riverbend 6
Riverbend 7

Table 6. Peaking Resource Capacities (MW)

Unit Name	January	July
Lee 1 NG	100	100
Lee 2 NG	100	102
Lee 3 NG	170	170
Lee CT1	41	41
Lee CT2	41	41
Lincoln CT1	93	79.2
Lincoln CT2	93	79.2
Lincoln CT3	93	79.2
Lincoln CT4	93	79.2
Lincoln CT5	93	79.2
Lincoln CT6	93	79.2
Lincoln CT7	93	79.2
Lincoln CT8	93	79.2
Lincoln CT9	93	79.2
Lincoln CT10	93	79.2
Lincoln CT11	93	79.2
Lincoln CT12	93	79.2
Lincoln CT13	93	79.2
Lincoln CT14	93	79.2
Lincoln CT15	93	79.2
Lincoln CT16	93	79.2

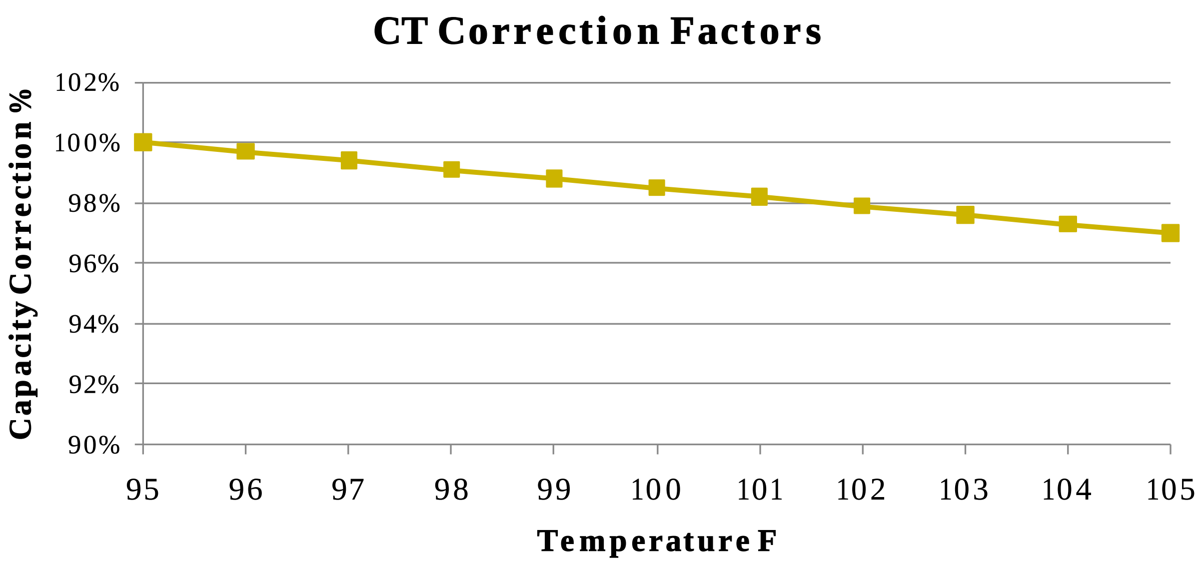
Unit Name	January	July
MillCreek CT1	92	74
MillCreek CT2	92	74
MillCreek CT3	92	74
MillCreek CT4	92	74
MillCreek CT5	92	74
MillCreek CT6	92	74
MillCreek CT7	92	74
MillCreek CT8	92	74
Rockingham CT1	165	165
Rockingham CT2	165	165
Rockingham CT3	165	165
Rockingham CT4	165	165
Rockingham CT5	165	165
Anson Hamlet CT	4	4
CPL Peaking CT	2	2
IRP CT 1	900	740
IRP CT 2*	0	740
Totals	4,410	4,628

Retired by 2016
Buck CT1
Buck CT2
Buck CT3
Buzzard Roost CT1
Buzzard Roost CT2
Buzzard Roost CT3
Buzzard Roost CT4
Buzzard Roost CT5
Buzzard Roost CT6
Buzzard Roost CT7
Buzzard Roost CT8
Buzzard Roost CT9
Buzzard Roost CT10
Dan River CT1
Dan River CT2
Riverbend CT1
Riverbend CT2
Riverbend CT3
Riverbend CT4

*IRP CT 2 is in service in June, 2016

All summer ratings in the previous tables are based on 95 degree F. On an hourly basis, SERVM can adjust the capacity of each resource based on the historical hourly temperature for the weather year being modeled. Because the maximum output of peaking units degrades as temperatures increase, the derating multipliers in Figure 5 were utilized to derate the units above 95 F. The multipliers were developed based on the Duke CT fleet which assumes a degradation of 0.3% of capacity per degree. This ensures correlation of capacity output with load since both are highly dependent on the hourly temperature.

Figure 5. Summer Rating Capacity Multipliers



The hydro portfolio is modeled in segments that include Run of River (ROR), Scheduled (Peak Shaving), and Emergency Capacity. The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. If included, the emergency capacity is used only to prevent firm load shed and the model allows the emergency mode to "borrow" energy from the future dispatch of the scheduled hydro portion with the constraint that the energy amount is enough for only a few hours. Typically hydro resources are not able to be dispatched at their nameplate capacity during peak hours due to water constraints or river flow requirements as seen in 2008. By modeling the hydro resources in these three segments, the model captures the appropriate amount of capacity dispatched during peak periods. See the confidential Appendix for the details regarding hydro capacities.

Figure 6 shows the total breakdown of scheduled versus emergency hydro based on the last 37 years of weather. Out of the total 1,100 MW of capacity owned by the company, only 442 MW on average is dispatched during peak periods. During drought years, less than 390 MWs are dispatched on peak in specific months. For this reason, the use of emergency hydro was not included in the base case results due to recent experience, but a sensitivity was performed that included the additional emergency hydro capacity which could be utilized for a few hours per month.

Figure 6. Scheduled Capacity versus Emergency Capacity

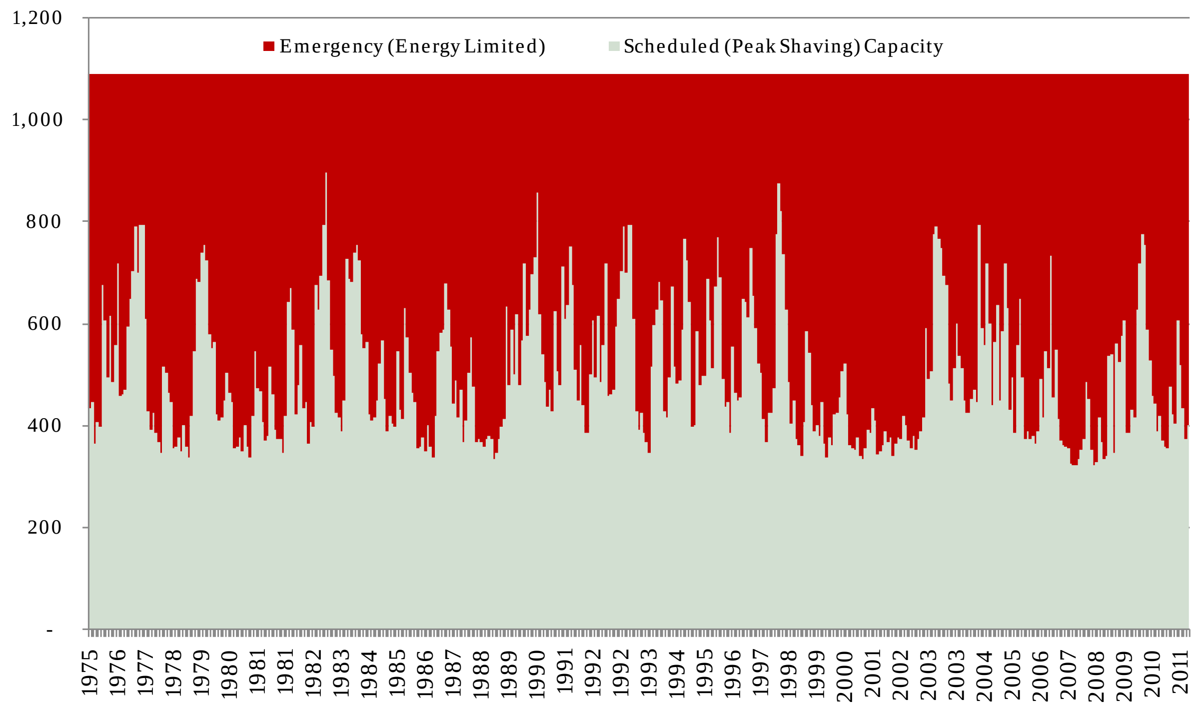


Figure 7 demonstrates the variation of hydro energy by weather year which is input into the model. The drought shown in 2001, 2007, and 2008 is captured in the reliability model.

Figure 7. Hydro Energy by Weather Year

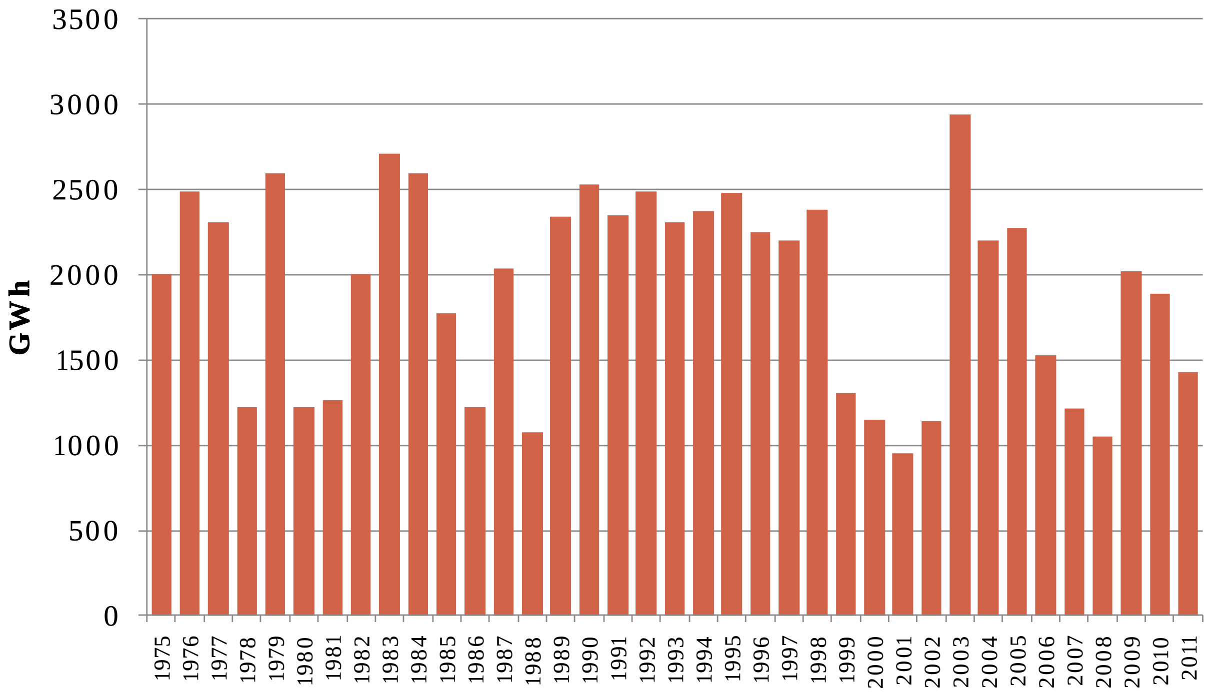


Figure 8 compares actual history of the dispatch level of the hydro resources for a 2008 and 2009 as a percentage of time versus how the model dispatches the resources. The figure demonstrates the drought conditions that were seen in 2008 and also shows that the model is capturing a realistic dispatch of the hydro resources.

Figure 8. Hydo Dispatch Calibration: Percent of Time above Capacity Threshold

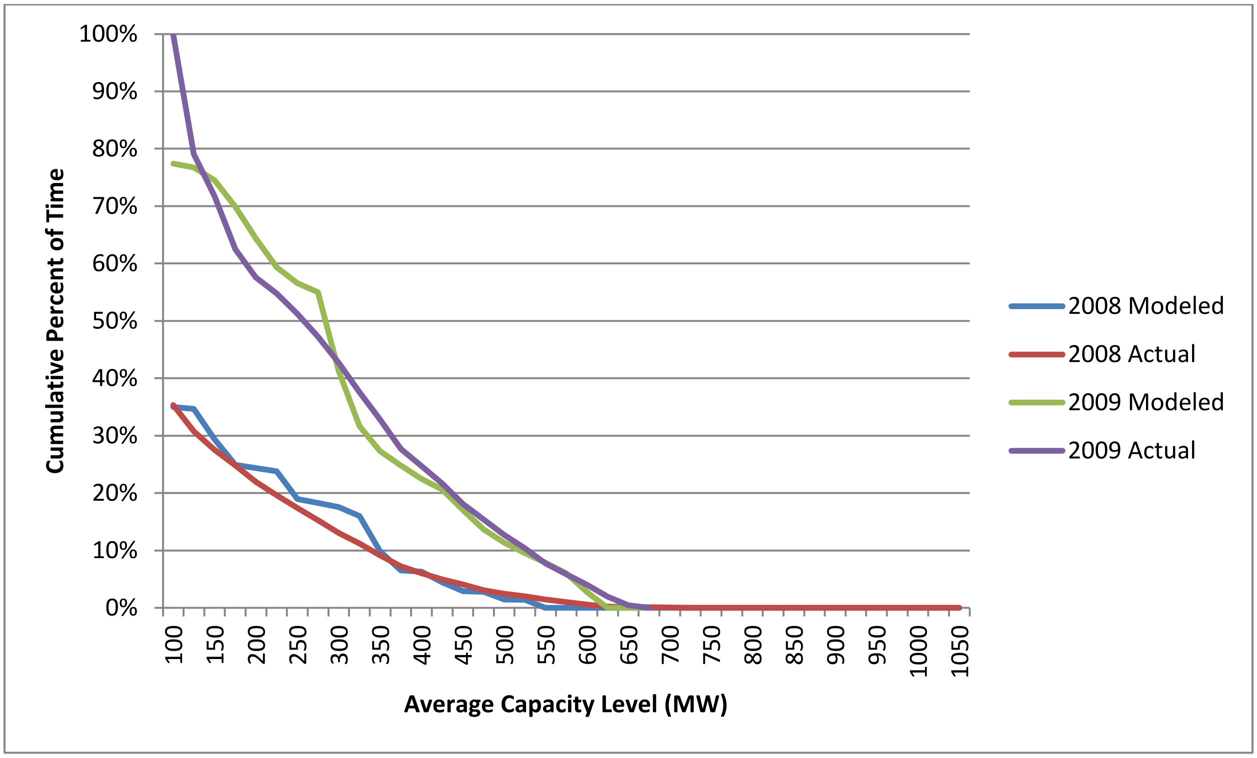


Table 7. Pump Storage Resources

Unit Name	January	July	Reservoir Capacity (MWh)	Reservoir Generating Hours
Bad Creek	1360	1360	33,030	24
Jocasse	780	780	57,540	74

Total	2140	2140

Pumping for pumped storage occurs anytime energy is available. During constrained periods, pumped storage resources are given dispatch priority to maintain a maximum level in the storage ponds. During less constrained periods, the dispatch order is switched so that the energy is used before CT's are dispatched. SERVM uses any excess capacity to fill up the ponds including economic purchases from the market. In actual practice, this process may be performed slightly differently to minimize production cost during off-peak periods. However, the model architecture is appropriate for reliability modeling, because it is always economic to build up the reservoirs of storage units with any generating asset available if that is what is required to have the units available to operate to avoid unserved energy.

Table 8. Renewable Resources

Unit Name	January	July
Solar – Nameplate Capacity	49	49
Wind – Nameplate Capacity	318	318
Landfill Gas	32	32
Poultry_PPA	14	14
Biomass_PPA	134	134
Totals	547	547

For reserve margin calculations, Solar capacity is given a 50% capacity credit and wind capacity is assumed to have a 15% capacity credit. For these resources, an 8760 hourly generation shape was used. The average summer and winter shapes are shown in Figure 9 and Figure 10. For each day, SERVM draws a daily shape from all the days in the month. Because historical data is unavailable, this random draw is used for all weather years.

Figure 9. Solar Profile

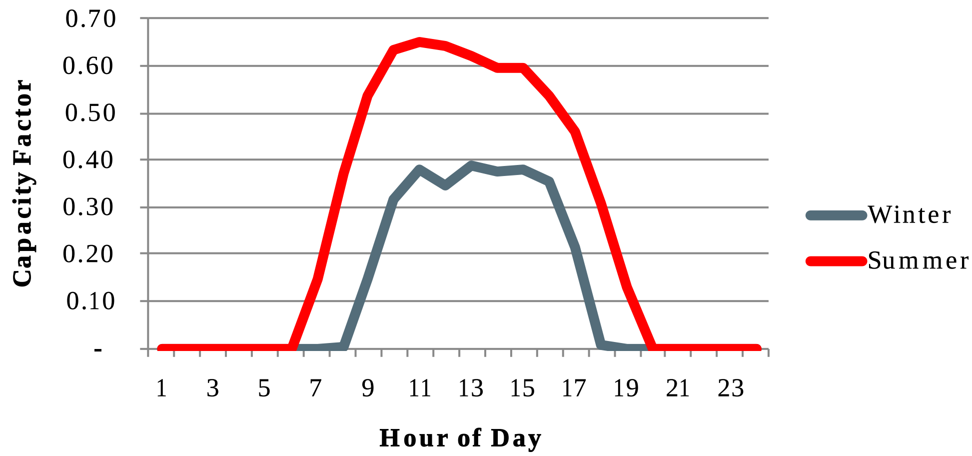
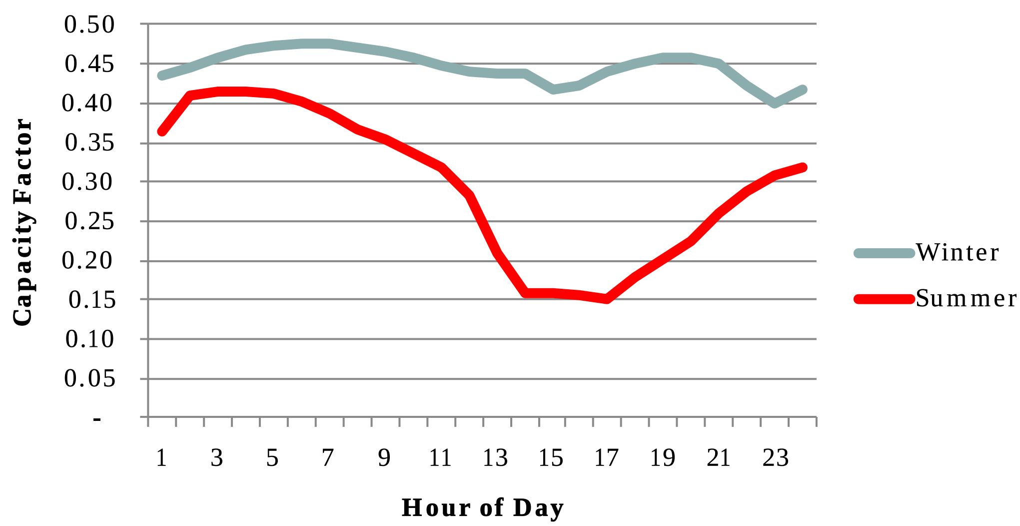


Figure 10. Wind Profile



E. Unit Outage Data

Unlike typical production cost models, SERVM does not use an EFOR for each unit as an input. Instead, historical GADS data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. For this RM Study, 2007-2011 GADS events were entered into SERVM. The events are entered using the following variables:

<u>Full Outage Modeling</u>
Time-to-Repair Hours
Time-to-Fail Hours

<u>Partial Outage Modeling</u>
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

<u>Maintenance Outages</u>
Maintenance Outage Percentage - % of full outages that are maintenance outages. SERVM uses this percentage and allows units to remain online until the following weekend if they are needed in the short term.

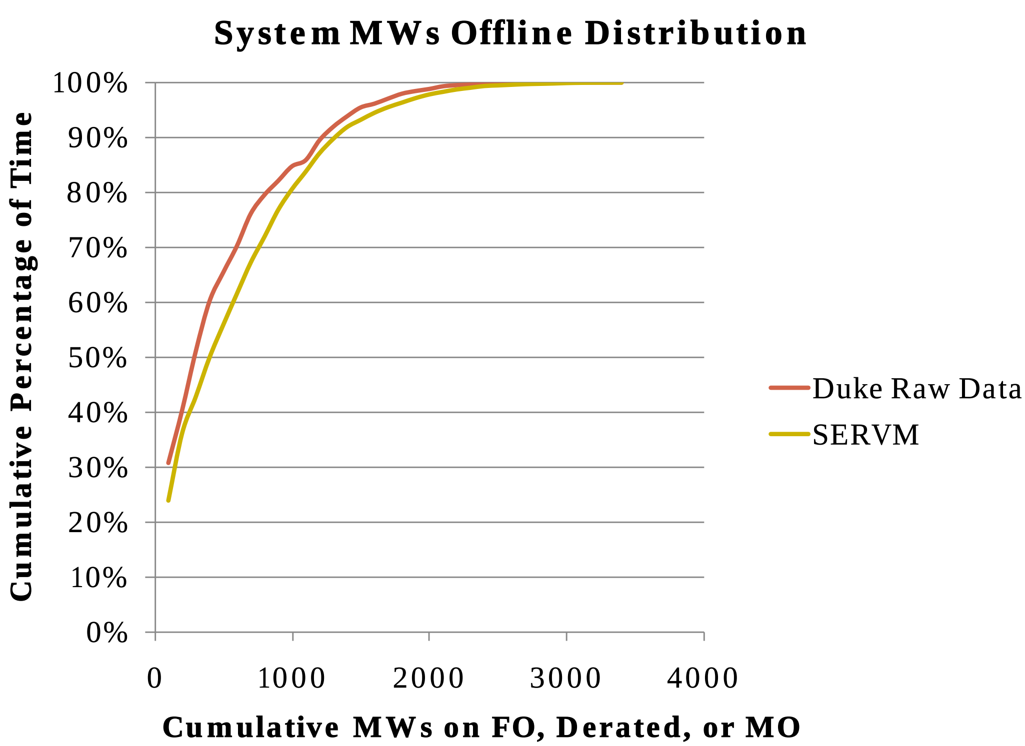
For example purposes, assume that from 2007 – 2011, Allen 1 had 15 full outage events and 30 partial outage events reported in the GADs data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data along with the other variables listed above. These multiple Time-to-Repair and Time-to-Fail distributions are used by SERVM. Because typically there is an improvement in EFOR across the summer, the data is typically broken up into seasons resulting in a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Assume Allen 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new

Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

Unit Outage Calibration

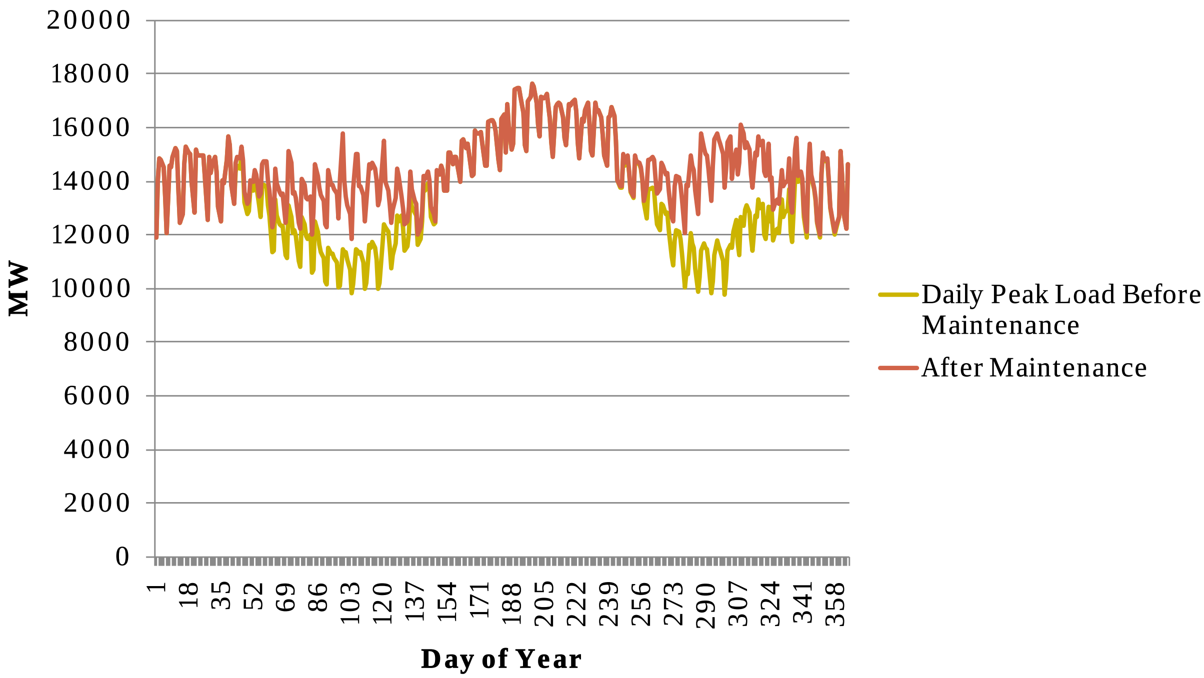
The critical aspect of unit performance modeling for a reliability study is the cumulative MW offline distribution. Most reliability problems are due to significant coincident outages. Figure 11 shows the distribution of outages for Duke Energy. The model has been calibrated to ensure this distribution is captured. Based on the data in the figure 10, the company may have 1,000 MW of capacity offline in 15% of all the hours. This equates to approximately 5% in reserve margin unavailable. System and individual outage rates are located in the confidential Appendix of this report. System and individual outage rates are located in the confidential Appendix of this report.

Figure 11. System Capacity Offline as a Percentage of Time



To capture the impact of planned maintenance, the 2016 maintenance schedule was modeled which removes capacity during the shoulder months of the year. Figure 12 shows that when planned maintenance is assumed in the shoulder months that the resulting load level between winter and shoulder periods is relatively flat.

Figure 12. Daily Peak Load Plus Planned Maintenance Requirement



F. Demand Response

A total of 987 MWs of demand response were modeled in the simulation. Energy efficiency (EE) was directly removed from load in the simulation while the resources in Table 9 were modeled as resources to be called upon given a reliability event. SERVM takes into account the constraints on demand response and dispatches accordingly. These constraints include a maximum number of hours per year, hours per day, days per week, and shadow dispatch price for the resources to be called.

Table 9. Demand Response Summary

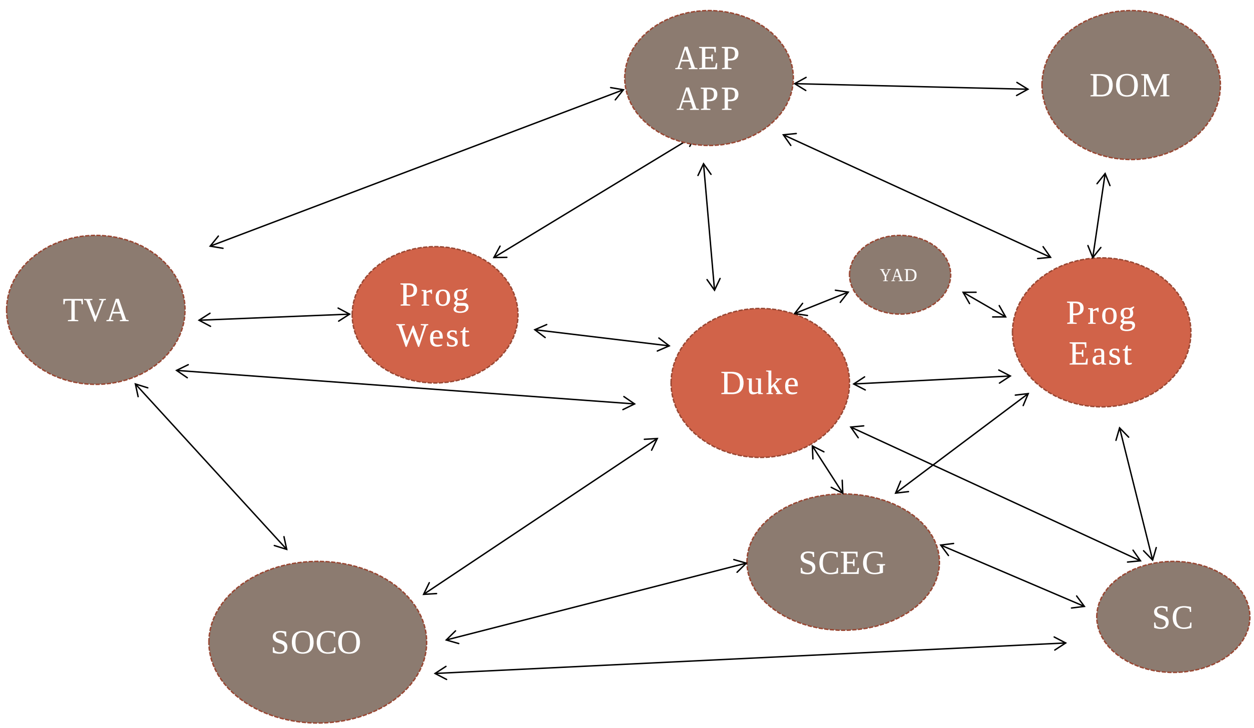
Unit Name	January Capacity	July Capacity	Hours Per Year Limit	Hours Per Day Limit	Days Per Week Limit
PowerManager	0	432	100	10	7
PowerShare0/5	8	9	40	8	7
PowerShare5/5	8	9	40	8	3
PowerShare10/5	8	9	40	8	3
PowerShare15/5	8	9	40	8	3
PowerShare_Mand	381	381	100	10	7
PowerShare_Generator	14	14	100	10	7
PowerShare_IS	111	110	150	10	7
PowerShare_SG	16	16	8760	24	7
Total	552	987			

G. Multi Area Modeling

The surrounding market must play a significant role in resource adequacy even for a utility the size of Duke Energy Carolinas. If several large generators are offline due to outage during peak season, it is likely that the company would depend on market purchases from surrounding regions.

The market representation used in SERVM was developed through consultation with Duke Energy Staff, EIA forms, Company Integrated Resource Plans (IRP), and reviews of NERC resource adequacy assessments. The base case level of reserves for neighbors is based on target reserve margins for surrounding neighbors. Using this methodology ensures that the company is not leaning on an external market more than is reasonable. Figure 13 shows the topology used for the region.

Figure 13. Regional Topology



Each neighbor's hourly loadshape was modeled based on historical hourly temperature data similarly to the Duke load. By using hourly weather, load diversity was captured for each neighboring area. Diversity of peak load is important to understand especially when examining physical reliability metric results. Table 10 shows the average diversity for summer months across all 37 years for each area. These values represent the percentage reduction from peak load that the neighbor is on average experiencing when Duke is experiencing its peak load. To ensure that Duke was not overstating the expectation of weather diversity and therefore available capacity from neighbors, Astrape believed it was prudent to cap the weather diversity in any given peak hour at 3%. A sensitivity assuming no weather diversity was simulated to understand the impact that weather diversity has on lowering the target reserve margin.

Table 10. Neighbor Diversity Factors

	Summer Diversity
SOCO	1.5%
AEP	1.7%
Dominion	1.9%
TVA	1.5%
SCEG	1.3%
Santee Cooper	1.3%
Progress East	1.2%
Progress West	3.3%

Table 11 displays a capacity and load summary of each of the neighbors including its current target reserve margin. The reserve margin calculations in this table assume that the interruptible capacity is included as a resource. While it is recognized that the region currently contains more capacity than these targets, it is not prudent to expect these additional reserves to be available long term. Outage rates for neighboring units were developed using existing Progress and Duke resources sorted by unit type and capacity size. Hydro resources reflect similar dispatch to the Progress and Duke hydro portfolios.

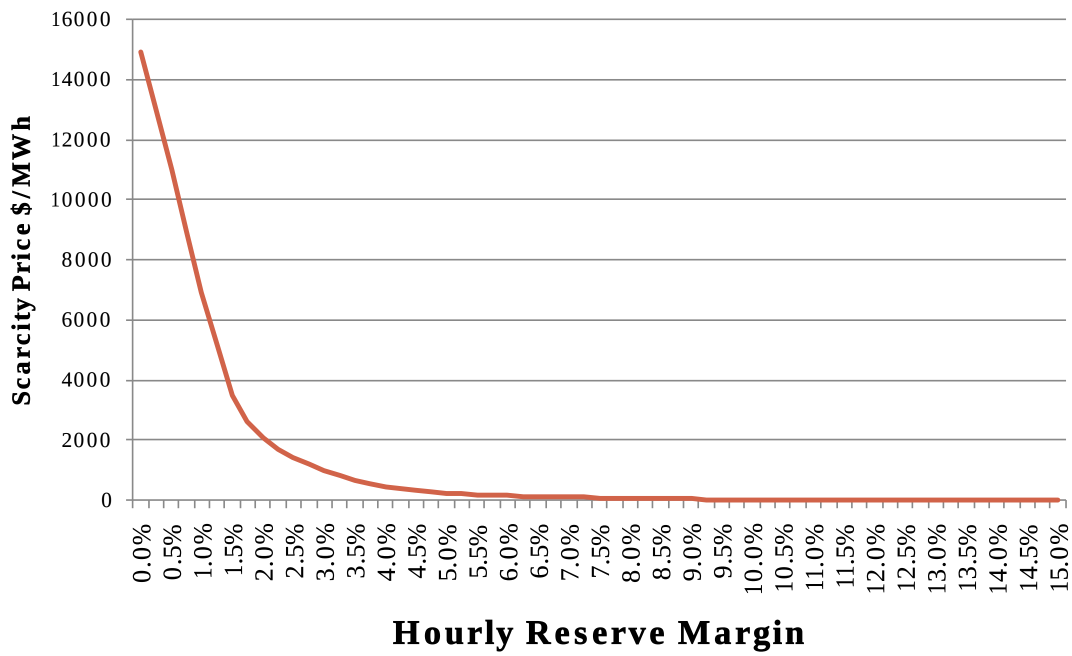
Table 11. Neighbor Capacity, Load, and Target Reserve Margin

	Progress	Southern Company	Santee Cooper	SCE&G	TVA	AEP_APP	DOM	Yadkin
Nuclear	3,563	6,895	318	2,066	7,832	0	3,501	
Coal and CC*	6,899	37,247	3,974	2,547	19,618	6,155	10,347	
Peaking	4,243	8,943	780	322	5,450	450	4,135	
Hydro	335	2,379	457	240	4,254	554	318	215
Pump Storage	0	1,186	0	576	1,739	238	3,003	
Interruptible	932	2,600	424	225	1,500	0	230	
Total Summer Capacity	15,972	59,249	5,953	5,976	40,393	7,397	21,534	215
Summer Peak Load	13,835	51,101	5,155	5,138	35,000	6,372	18,686	
Summer Reserve Margin	15.4%	15.9%	15.5%	16.3%	15.4%	16.1%	15.2%	

*includes renewable capacity

The costs of market purchases were calibrated using Duke Energy historical purchases and other market pricing data from the southeast region. As shown in Figure 14, scarcity pricing is based on the shortage in the specific region. As the excess capacity approaches zero, the price of capacity approaches the cost of unserved energy. Such an event is rare but can occur as a function of severe weather, poor unit performance, and significant load forecast error.

Figure 14. Scarcity Pricing Model



Available Transmission Capacity and TRM

The import capability is made up of Available Transmission Capability (ATC) and Transmission Reliability Margin (TRM). ATC is the non firm hourly transmission expected to be available in the market place while TRM is the portion of the transmission system that is held back for reliability needs. TRM is a fixed number while ATC is highly volatile. Due to its highly volatile nature, ATC is represented as a distribution to capture hours when there is little capacity to hours when there is abundance. The distributions used in SERVM are based on historical hours in 2011 during peak periods. It should be noted that these limits do not represent the amount of generation available from neighbors but only serve as the import constraint. Given these constraints, it is expected that the limiting factor will be generation availability from neighbors rather than transmission. However, transmission capability will be a critical sensitivity in the final analysis.   See the appendix for details regarding the values used for ATC and TRM.

H. Carrying Cost of Capacity

The cost of carrying incremental reserves was based on the capital cost, fixed O&M, and estimated transmission upgrades of four Advanced CTs with a total summer rating of 740 MW. The cost assumptions were based on estimates provided by Duke Energy. The appendix displays the characteristics and costs of the four CT site used to develop the capacity costs and the avoided and levelized costs by year.

I. Operating Reserve Requirements

Duke provides 500 MW of spinning reserves and 600 MWs of total operating reserves which was implemented into the model.

J. Cost of Unserved Energy

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003 and 2009. The national studies were compilations of other surveys performed by utilities over the last two decades. The national study split the customer classes into residential, small commercial and industrial, and large commercial and industrial. The 2009 study shows higher costs for commercial and industrial consumers compared to 2003. We expect that the costs of outages have risen rapidly in recent history for commercial and industrial customers due to the impact of technology; however both Duke and Astrape questioned the $92.16/kWh values shown in the 2009 Study for Small C&I. Given the magnitude of the values seen in both studies, Astrape and Duke determined that $15,000/MWh was a reasonable base case assumption   Due to the infrequent nature of unserved energy; the sensitivity results demonstrate that this assumption is not the main driver of the results.

Table 12. Unserved Energy Costs

	Class Breakdown %	2003 DOE Study 2003$/kWh	2009 DOE Study 2008$/kWh	2003 DOE Study 2016$/kWh	2009 DOE Study 2016$/kWh
Residential	35%	1.15	1.10	1.45	1.27
Small C&I	37%	26.00	79.90	32.79	92.16
Large C&I	28%	15.00	23.80	18.92	27.45
Weighted Average $/kWh				17.93	42.23
Average of Studies $/kWh				30.08	

V. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. Deterministic selection of extreme events will not give an accurate representation of the operation of any system during such an event, nor would it be possible to estimate a distribution of when such events could occur. For Duke Energy, SERVM utilized 37 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 400 iterations of unit outage draws to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 37 weather years * 7 load forecast errors * 10 reserve margin levels = 2590 total cases. For each of these cases, 400 iterations of unit outage draws are performed which means over one million yearly simulations were completed for the analysis. From this analysis, expected reliability costs can be calculated and compared to the cost of adding additional reserves.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 13. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 13. Case Probability Example

Weather Year	Weather Year Probabilitiy	Load Forecast Error	Load Forecast Error Probability	Total Case Probability (Weather Yr Prob x LFE Prob)
1975	2.70%	-6.23%	1.64%	0.0443%
1975	2.70%	-3.76%	11.29%	0.3051%
1975	2.70%	-1.79%	22.46%	0.6070%
1975	2.70%	0.00%	29.23%	0.7900%
1975	2.70%	1.79%	22.46%	0.6070%
1975	2.70%	3.76%	11.29%	0.3051%
1975	2.70%	6.23%	1.64%	0.0443%
1976	2.70%	-6.23%	1.64%	0.0443%
1976	2.70%	-3.76%	11.29%	0.3051%
1976	2.70%	-1.79%	22.46%	0.6070%
1976	2.70%	0.00%	29.23%	0.7900%
1976	2.70%	1.79%	22.46%	0.6070%
1976	2.70%	3.76%	11.29%	0.3051%
1976	2.70%	6.23%	1.64%	0.0443%

For this study, reliability costs are defined as the following:

1) Carrying Cost of Reserves + Production costs above that of a CT + Imports above the cost of a CT + Expected Unserved Energy Costs - Sales above that of a CT

These components are calculated for each of the above cases and weighted based on probability to calculate an expected reliability cost for the year.

B. Reserve Margin and Capacity Margin Definition

For this study, reserve margin is defined as the following:

- Reserve Margin = (Resources – Demand) / Demand
    - Demand is the Average Summer System Peak Load and has not been reduced by Demand Response
    - Resources are defined based on summer ratings and include Demand Response
    - The solar capacity within the study was given a 50% capacity credit while wind was given a 15% capacity credit (consistent with the 2011 IRP)

VI. Base Case Results

A. Physical Reliability Results

From a physical reliability standpoint, Figure 15 shows LOLE in events per year and LOLH in hours per year for the base case. The one day in 10 year standard (LOLE = 0.1 events per year) falls at a 14.5% summer reserve margin and the LOLH is approximately 0.30 hours per year for that level of reserves. Figure 16 displays expected unserved energy (EUE) at varying levels of reserves. At the 14.5% reserve margin level, EUE is 170 MWh. As demonstrated in the additional sensitivities, physical reliability metrics are sensitive to input assumptions such as weather diversity, transmission availability, neighbor reserve levels, and emergency hydro assumptions.

Figure 15. Base Case LOLE and LOLH

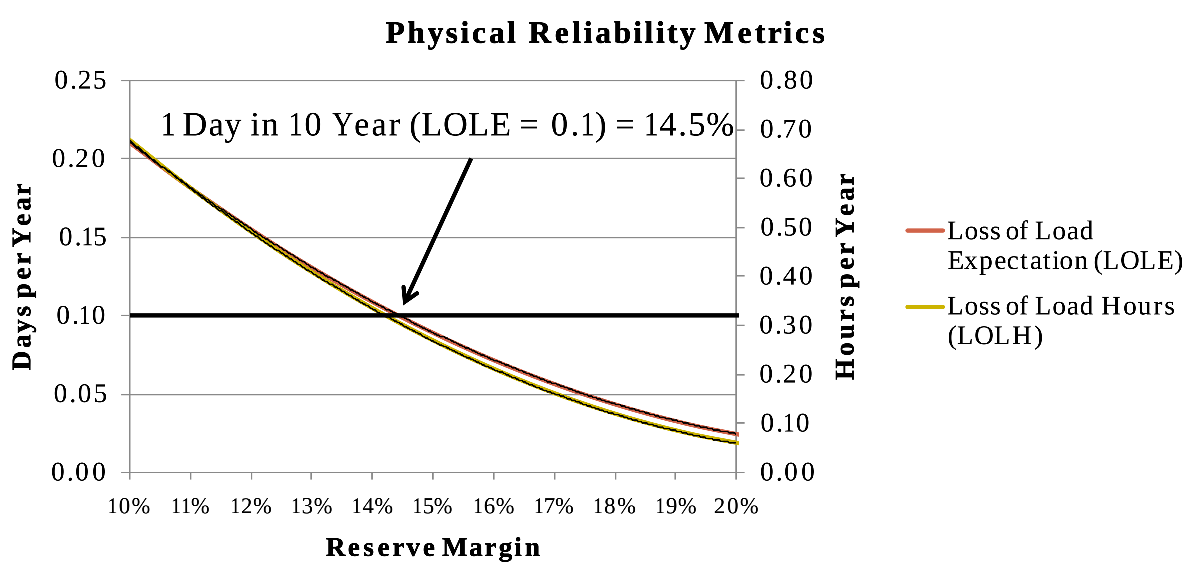
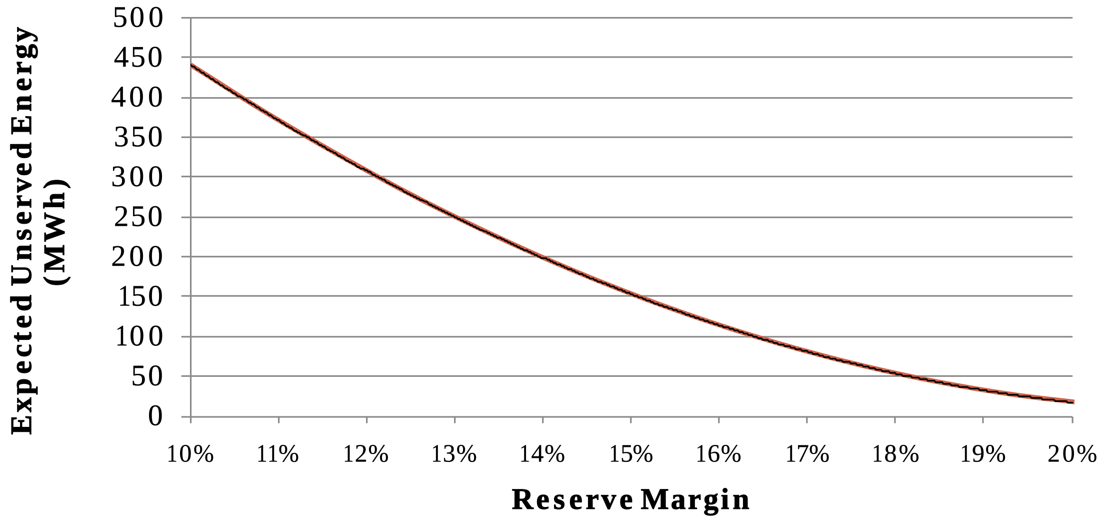


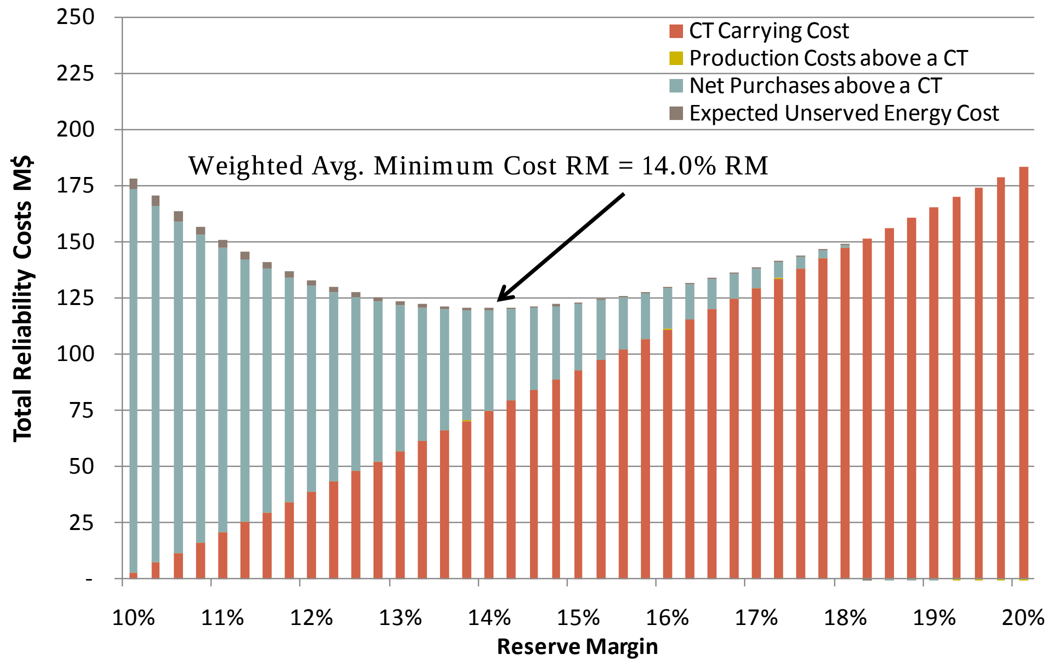
Figure 16. EUE



B. Economic Results

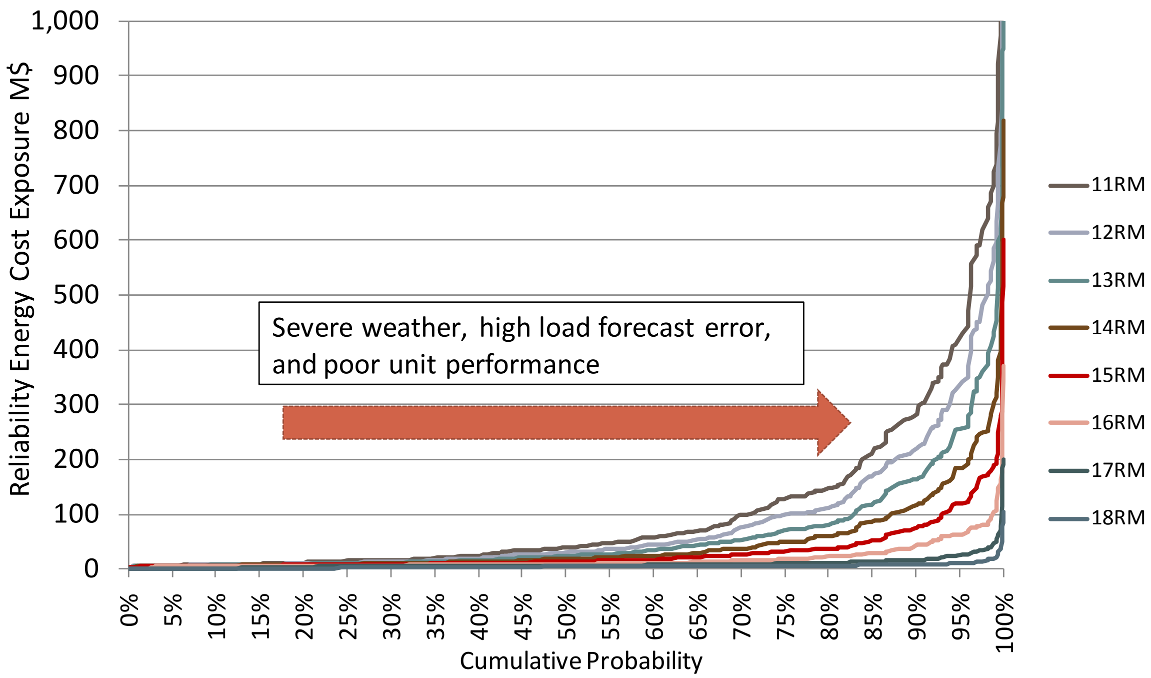
As previously discussed, physical reliability metrics only provide guidance for meeting a few peak load hours over a multi-year study period, and are therefore difficult to calibrate. To supplement the information provided by the base case LOLE analysis, economic reliability metrics were taken into consideration. Economic reliability costs include all costs from the next highest cost resource after a marginal CT all the way to the economic impact of shedding firm load. Since additional capacity will have some benefits in every year, this type of analysis is easily calibrated to actual practice and then allows accurate extrapolation to extreme scenarios. The base case economic results are shown in Figure 17. Based on these results, the long-term minimum cost reserve margin based on the weighted average of all results is 14%. As reserve margin increases, reliability energy costs (Production cost above a CT, net reliability imports above a CT, and cost of unserved energy) decrease while CT carrying cost increases. The flatness of the curve between 14% and 16% should be noted. Since resource additions are too large to perfectly target a reserve margin, some years will inevitably result in reserve margins that are higher than the average economic optimum. The expected financial impact of these additions to the total system cost is not substantial, since the capacity above the weighted average target also brings some financial benefit. For example, the annual expected difference in cost between the 14% reserve margin and 16% reserve margin is only $9 million and the higher level of reserves may provide risk benefits.

Figure 17. Base Case Weighted Average Economic Reserve Margin



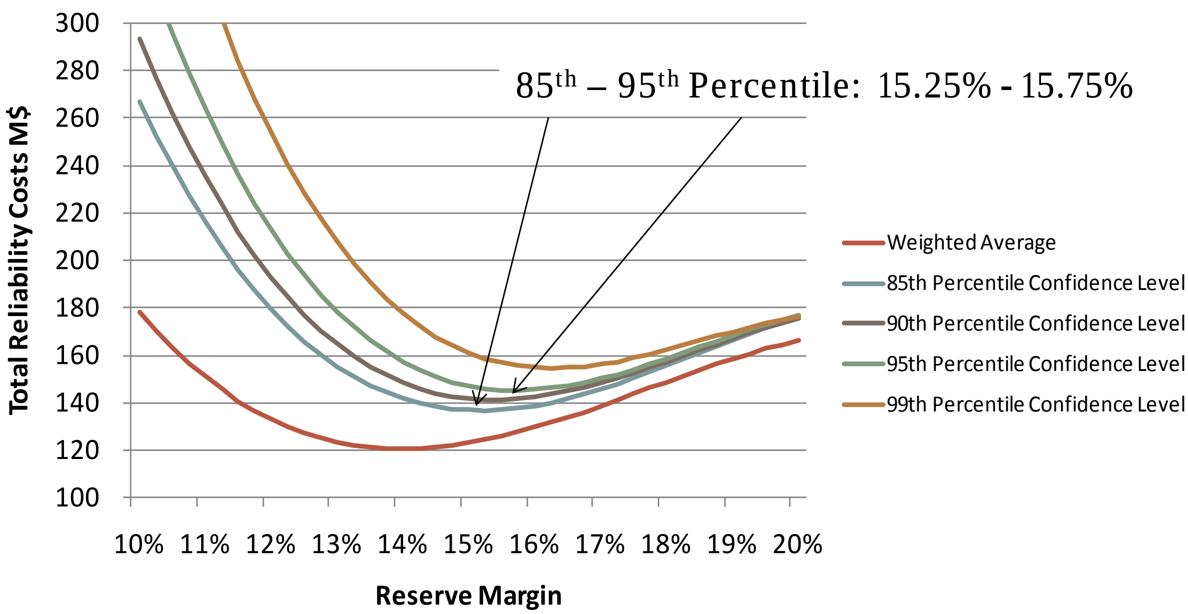
The previous figure represents the weighted average cost exposure and does not illustrate the high cost outcomes that can occur at each reserve margin level. While CT costs are mostly fixed, reliability energy costs are volatile dependent on the weather, load forecast error, or unit performance in a given year, so other confidence levels should be reviewed. While over a 30 year period this may be the optimal reserve margin, any single year can have significant risk at a 14% reserve margin level. Figure 18 shows the reliability energy costs on a probability weighted basis. At a 14% reserve margin, there is a 5% chance that reliability energy costs could exceed $185 million in any given year and a 1% chance that it could exceed $303 million.

Figure 18. Base Case Reliability Cost Exposure Distribution



Next we examined the optimal economic reserve margin recognizing the different risk profile of energy costs and capacity costs. By comparing capacity costs to reliability energy costs during years with extreme weather or poor unit performance as seen in Figure 18, we assessed the tail benefit of additional capacity. The reliability energy costs seen in Figure 18 were taken at different confidence levels (85%, 90%, 95%, and 99% probabilities) and added to the fixed capacity costs at each reserve margin to form the confidence level curves in Figure 19. This assessment showed that in 10% of all scenarios, Duke Energy would receive an economic benefit by adding efficient natural gas turbines up to a reserve margin of 15.50%. This is shown by the 90% confidence level (probability) curve in Figure 19. As we review the weighted average curve in the same figure we can see that by adding capacity to achieve a 16% reserve margin versus a 14% reserve margin, average annual costs only increase by $9 million, but the additional capacity acts as an insurance product to customers. In fact, 10% of the time customers would see their cost exposure decrease by at least $70 million as seen in Figure 18.

Figure 19. Risk Adjusted Reserve Margins



VII. Sensitivity Analysis

The following sensitivities were performed on the base case to only understand the movement in target reserve margins for both physical and economic metrics.

- Include Emergency Hydro: Allows the full nameplate capacity of the hydro fleet to be dispatched during peak periods.
- No Weather Diversity: All neighbors were given the same load shape as Duke to force all neighbors to peak at the same time.
- 50% ATC: The distributions of ATC were reduced by 50% to understand how transmission was impacting the base case results.
- Island Case: Duke is modeled as an island with no outside assistance.
- +2% Neighbor RM Level: The capacity of all neighbors was increased by a 2% reserve margin.
- +50% System EFOR: The EFOR for all Duke resources was increased by 50%.

- Marginal Resource Cost: +/- 25%: The capacity costs for the marginal resource was varied by +/-25%.
- EUE Cost: The cost of unserved energy was varied from $5,000/MWh to $25,000/MWh.
- 2023 Study Year: The study year was moved from 2016 to 2023. Load growth and generation expansion were included for each region and escalation in all economic factors such as the cost of EUE, scarcity pricing, and fuel prices was included for this sensitivity.

Table 14 shows the results of each sensitivity simulated. It is seen that the 0.1 LOLE reserve margin is more sensitive to key assumptions than the weighted average economic case. As discussed previously, this occurs because LOLE is impacted by only a few hours while economics looks at the broader economic impact of all costs above the costs of a CT.

The results show that LOLE is very sensitive to emergency hydro assumptions, weather diversity, and neighbor assistance while the economic results were more stable. Allowing the emergency hydro to be available during all peak periods decreases the LOLE target RM by 3.25% to 11.25% while the economic results were unchanged. Excluding weather diversity shifted the LOLE target up by 3.75 percentage points and the economic target up by 1 percentage point. Dividing the ATC distributions in half had a 1 percentage point impact on the LOLE target and a 2.5 percentage impact on economic results. The ATC sensitivity impacted transmission availability for every hour and so impacted the economic results more than LOLE. However, this sensitivity still indicates that even if substantial changes were to occur to the transmission system (loss of 50% of hourly available transmission capacity), target reserve margins would not need to shift dramatically. Increasing neighbor reserve levels by 2% shifted the LOLE target down by 3.75 percentage points and the economic target down by 0.75 of a percentage point. The island sensitivity should be seen purely as an academic exercise demonstrating the level of reserves the company would carry if it had no outside assistance. If Duke was a stand- alone utility, then it would need to carry reserves of 23.25%. In studying the year 2023, the target only changed slightly. It is expected that a long term reserve margin study should evaluate an optimal target three to five years in the future and therefore 2023 would need to be reviewed again in the 2018 to 2020 time frame.

Regarding the Economic Sensitivities, the cost of unserved energy had little impact on the overall results since firm load shed events are so rare, however, the cost assumed for the marginal CT resource moved the economic reserve margin by approximately +/- .75 of a percentage point. As the marginal resource cost increases, the economic target decreases.

Table 14. Sensitivities

	Physical	Economics	
	LOLE: 1 in 10 Standard Target RM	Weighted Average Target RM	90% Target RM
Base Case	14.50%	14.00%	15.50%
Include Emergency Hydro	11.25%	14.00%	15.50%
No Weather Diversity	18.25%	15.00%	16.75%
50% ATC	15.50%	16.50%	17.50%
Island Case	23.25%		
+2% Neighbor RM	10.75%	13.25%	15.25%
+50% System EFOR	16.75%	16.25%	17.50%
2023 Study Year	14.25%	14.00%	15.75%
EUE Cost: $25,000/MWh		14.00%	15.75%
EUE Cost: $5,000/MWh		13.75%	15.25%
Marginal Resource Cost: +25%		13.25%	14.75%
Marginal Resource Cost: -25%		14.75%	16.00%

VIII. Conclusions/Recommendations

Astrape recommends that Duke set its absolute minimum reserve margin at the 14.5% LOLE target (LOLE = 0.1) and recommends a target of 15.50% based on the 90% confidence level economic target. Since capacity is added in large blocks to take advantage of economies of scale, the actual reserve margin will often be somewhat higher than the target of 15.5%. As shown in the charts and data above, a reserve margin target in the range of 14.5% to 16% produces similar total customer costs whether at the low end or high end of the range. To accommodate large resource additions such as nuclear, coal, or even larger combined cycle resources, the reserve margin would likely rise above the top end of the reserve margin range. However, the additional production cost and economy of scale benefits provided by such resources would likely justify their addition. Therefore, the recommended target reserve margin of 15.50% with a range of 14.5% to 16% should not be considered absolute as all resource decisions should be made on a case-by-case basis.

The results should be reviewed periodically as there are shifts in generation mix, DSM, intermittent resource penetration, or load shape that could impact results. Provided that the results are greatly impacted by regional reserve margins, it is also recommended that Duke keep a close eye on the surrounding market. Short term capacity decisions should also be reviewed on a case-by-case basis. Since physical capacity changes can rarely be implemented inside a 3-year window, the cost of any procurement should be weighed against the distribution of reliability events and the distribution of reliability costs associated with not purchasing the capacity. Even in cases when Duke is below its minimum target reserve margin, economic and physical reliability metrics may suggest not procuring additional capacity. Or an analysis may suggest purchasing more capacity than is needed to achieve the minimum target.

VIX. Confidential Appendix

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FPL

The Need for a 3rd Reliability Criterion for FPL: a Generation-Only Reserve Margin (GRM) Criterion

Bob Barrett
VP Finance
February 28, 2014

A Note Regarding this New Presentation

- **This presentation first addresses 4 "carry over" topics from the Dec. 6th meeting:**
  1. What does a projected LOLP value really mean?
  2. LM customer "fatigue" benchmarking results.
  3. Benefits of generation reserves during pre-hurricane periods.
  4. Emergency declarations and regulatory scrutiny.

- **The presentation then discusses FPL's need for a new reliability criterion from 3 perspectives:**
  1. A "looking back" analysis of the Winter peak day of 2010 and what might have occurred if FPL had entered that January having a Summer GRM of 10% or 5%*
  2. A "looking forward" analysis using the year 2021
  3. Why 10% is a reasonable value for the new GRM criterion

- **The presentation concludes with a summary of "next steps"**

* Unless otherwise noted, all GRM values are Summer GRM values (because the Summer GRM values will have the most impact on resource planning)

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Executive Summary

- A generation-only reserve margin (GRM) reliability criterion is desirable from an operational perspective for several reasons:
  - If two resource plans have an identical total reserve margin value, but one plan has a 10% GRM and the other a 5% GRM, the 10% GRM plan can provide operators with hundreds of additional MW of reserves (generating and/or load management) during severe peaks
  - A higher GRM plan can also provide operators with significant additional reserves when hurricanes force early shut downs of nuclear units
- A GRM reliability criterion is also desirable from a resource planning perspective because it can lower LOLP projections
- A GRM criterion of a minimum of 10% matches well with Operation's projected need for 2,650 MW of "operational generation reserves" (i.e., generation above forecasted load)

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The 1st topic, "what does an LOLP value mean?", is addressed both by looking at the calculatioı and providing an interpretation

How is an LOLP Value Calculated?

- LOLP calculations project the probability that a utility will not be able to serve 100% of its firm load (i.e., at least 1 MW of firm load cannot be served) during the time period analyzed after all available generation and LM have been used
- LOLP calculations do not provide information regarding: (1) the MW amount that cannot be served; and (2) the duration of the event
- The probability of not being able to serve all firm load is calculated for the peak hour for each day in the year
- These daily probabilities are then summed to derive a monthly probability of not being able to meet firm load on a peak hour during the month
- Then the monthly probabilities are summed to derive an annual probability of not being able to meet firm load on a peak hour during the year
- Thus an LOLP value is a sum of daily probabilities (which can exceed 1.00) and the LOLP value is commonly expressed in terms of "days per year"

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A monthly breakdown of previously provided annual LOLP projections is provided below

Monthly Breakdown of Previous LOLP Values

- In the 12/06/2013 presentation, two LOLP values were presented for the year 2021: 0.0358 days/year for a 5% GRM plan and 0.0257 days/year for a 10% GRM plan
- The following table shows a monthly breakdown of these values:

Month	w/ 5% GRM: Projected Days per Individual Month	w/ 5% GRM: Projected Cumulative Days per Year	w/ 10% GRM: Projected Days per Individual Month	w/ 10% GRM: Projected Cumulative Days per Year
January	0.000018	0.0000	0.000003	0.0000
February	0.000000	0.0000	0.000000	0.0000
March	0.000030	0.0000	0.000004	0.0000
April	0.000002	0.0001	0.000001	0.0000
May	0.000065	0.0001	0.000022	0.0000
June	0.001522	0.0016	0.000819	0.0008
July	0.000436	0.0021	0.000351	0.0012
August	0.001456	0.0035	0.001203	0.0024
September	0.031795	0.0353	0.023089	0.0255
October	0.000506	0.0358	0.000210	0.0257
November	0.000000	0.0358	0.000000	0.0257
December	0.000000	0.0358	0.000000	0.0257
Annual Days per Year =		0.0358		0.0257

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LOLP discussion may be "flipped" from "days per year" to "years per day" terms to provide an easier-to-use interpretation

A Useful Interpretation of LOLP Values

- If one assumes that a projected LOLP value for a given year remains constant for each year in an LOLP analysis, one can project how many years will pass before the utility will not be able to meet firm load (i.e., before the sum of the annual LOLP values = 1.0) by dividing the annual LOLP into 1.0

- Some utilities, such as Hawaiian Electric Company, use this "years per day" format when reporting results of LOLP analyses

- The 5% GRM plan had an annual LOLP value of 0.0358 which converts to 27.9 years, and the 10% GRM plan had an annual LOLP value of 0.0257 or 38.9 years, before LOLP sums to 1.0

In this analysis, the 10% GRM plan is projected to allow FPL to meet firm load for 11 more years without an interruption than with the 5% GRM plan

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Regarding the 2nd topic of LM "fatigue", benchmarking data was sought from multiple sources

Benchmarking Results

- The DSM group contracted with Esource to canvas various industry leaders (utilities / consultants)
- No empirical data exists on customer fatigue due to over use of LM, but opinions received are in-line with FPL's view regarding avoiding LM fatigue:
  - No greater than 10 events/year
  - Events should be spread out throughout the year (e.g., not all in summer or extreme winter events)
  - Events should not be prolonged (e.g., greater than 2-3 hours)
- Ahmad Faruqui, Ph.D., an industry expert, stated this is a question "for which I have not been able to find any good data"
  - He implied a range for which fatigue may occur: "Survey results indicate that the maximum realistic call duration for ERCOT is 4 hrs. and frequency should be no greater than 10 events/year."

LM benchmarking on customer fatigue is inconclusive

The 3rd topic is the relevance of generation reserves to address generation needed prior to hurricane landfall

Generation Margins Needed Pre-Hurricane

- Prior to land fall, loads are high due to customers cooling their homes and lowering refrigerator temperatures
- High loads prior to land fall occur while FPL is shutting down specific units
  - For example, a hurricane impacting the St. Lucie units (almost 2,000 MW of generation/gross output), must go to 60% output as early as 24 hours prior to land fall, and complete shut down at 18 hours prior to hurricane winds at the site.
- Activation of LM due to a capacity shortfall prior to landfall would have an impact on our customers' preparations including efforts to pre-cool their homes
- A generation reserve of approximately 2,650 MW (as discussed on slide 20 – Operational generation reserves) provides additional reliability, allowing service for our customers prior to hurricane impact

Operations prior to hurricane landfall must consider the unavailability of specific generation and impact to customers

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If a hurricane impacts both PTN and PSL, there is high potential to shut down both units

PTN and PSL Impact and Generation Reserves

- Over the past 100 years, multiple hurricanes have impacted the PTN and PSL areas
- In 1960, Hurricane Cleo (Category 2) may have resulted in sustained hurricane force winds at both PTN and PSL (no anemometers in area)
- Both plants, with output of approx. 3,600 MW, would need to shut down if affected

- The operational generation reserves provide additional reliability to mitigate the unavailability of generation prior to hurricane impact

The impact of a hurricane affecting PTN and PSL would require the use of large amounts of LM. Shedding of firm customers is not expected.

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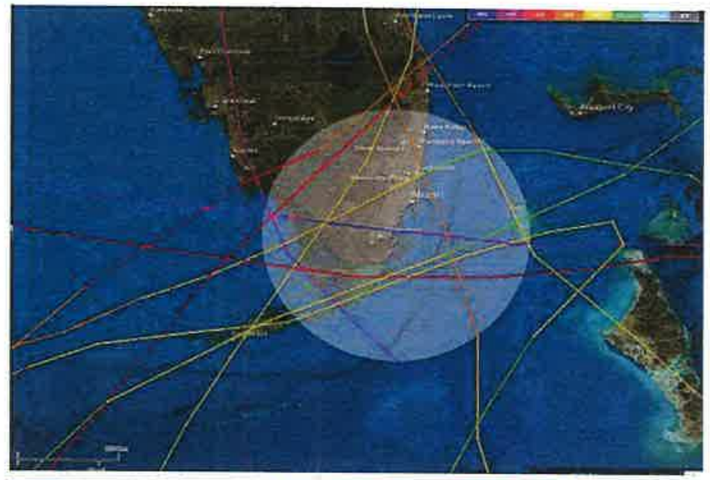
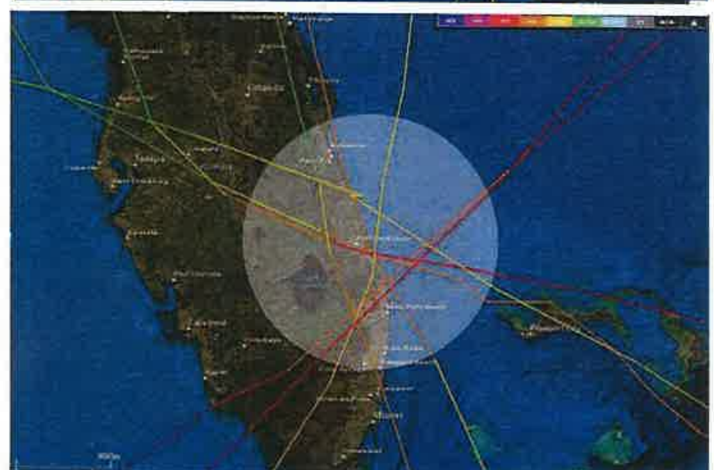
Generation reserves are needed to account for generation during periods prior to hurricane landfall

Generation Reserves Needed Pre-Hurricane

- **From the period of 1960-2013 eleven hurricanes tracked within 65 nautical miles of Turkey Point and another 8 hurricanes tracked within 65 nautical miles of St. Lucie**
  - Turkey Point hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 13.9%
  - St. Lucie hurricanes would reduce the total reserve margin from 21.0% (year 2021) to 12.2%





The impact from a hurricane to one of the nuclear sites is significant, resulting in the loss of most of the generation reserves and likely needing to use LM

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The 4th topic is that the potential for regulatory implications due to emergency operations declarations

North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 NERC Reliability Standard: Declaration of Energy Emergency Alert (EEA)**
  - FPL's plan based on its interpretation of EOP-002 which is to declare an EEA-2 when LC capability is less (or close to less) than the required reserves necessary to cover the loss of largest FPL unit (FM2 at 1,515 MW by 2021)
    - -- Note: EEA-3 is when load shedding is eminent or underway
  - FPL plan will not result in a declaration for limited (e.g., less than 400 MW) use of LC
    - -- FPL has not declared an EEA under EOP-002
  - From discussions with peers in the Southeast and limited information on NERC website, FPL's practice appears to be consistent with historical declarations in other regions

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The 4th topic is that the potential for regulatory implications also influences FPL's operating philosophy (Cont'd)

North American Electric Reliability Corporation (NERC) Standards

- **EOP-002 triggers for EEA-2s is not clear, and recognized as such industry-wide**
  - Standard implies that a declaration of an EEA-2 is linked to LC deployment
  - FRCC procedure linking the FRCC Emergency Capacity Plan with EOP-002 does clarify triggers for EEA-2
- **NERC tracks EEA-2s and EEA-3s under EOP-002 to measure the number of events declared during peak load periods, this may serve as leading indicator of capacity shortfall**

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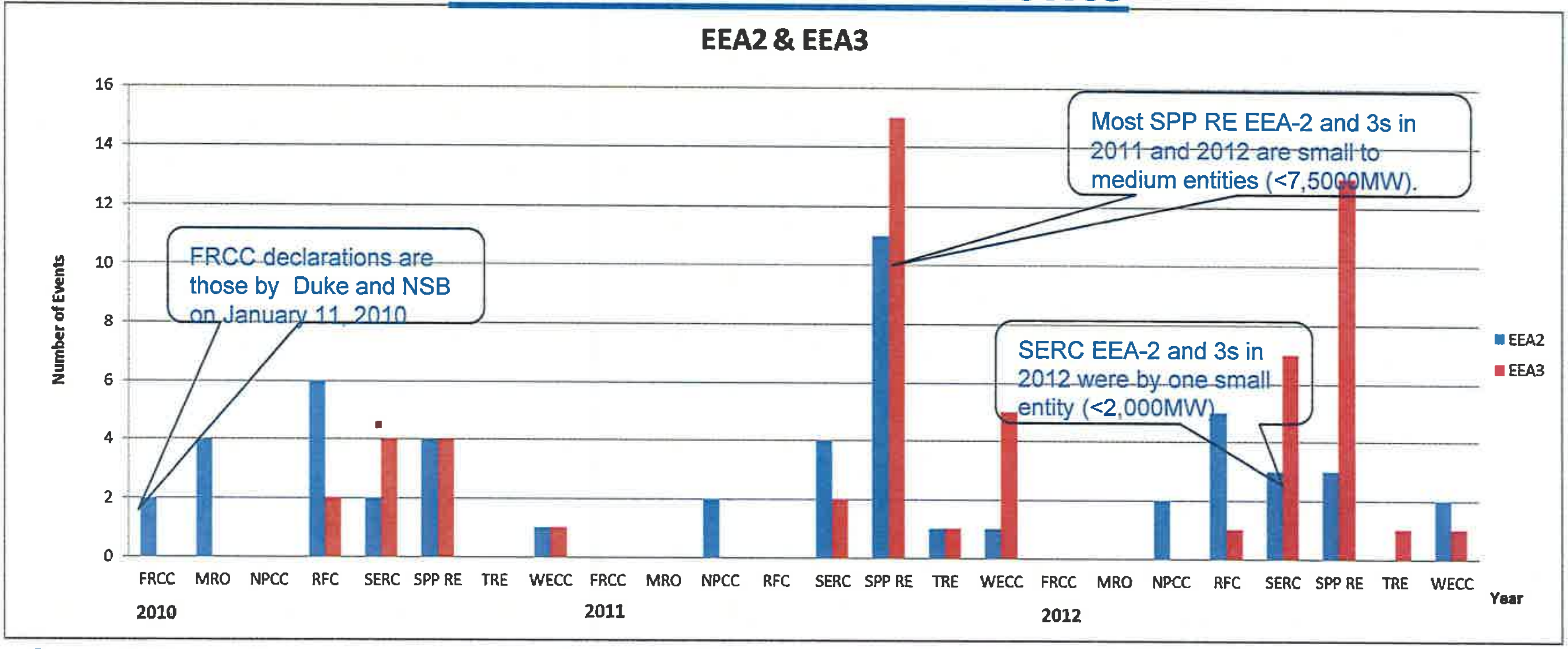
NERC historical tracking of alert declarations varies by region

EEA-2 and EEA-3 Events



- **Legitimate emergencies will be tracked by NERC**
  - NERC states that EEA-2 events calling solely for activation of DSM or interruption of non-firm load will be excluded from the metric in the future as demand response is a legitimate resource and are not of direct concern regarding reliability.

The potential, form, and results of regulatory scrutiny based on what NERC considers too many legitimate emergencies is unclear

FPL.

The need for a new GRM reliability criterion can be supported by 3 points

FPL's Need for a New Reliability Criterion

- **These 3 points (presented in decreasing order of importance) are:**
  1. "All resource plans with identical total reserve margins are not created equal" from an operational perspective (a higher GRM plan will result in significantly more total resources - generation and load management - available for system operators than a lower GRM plan in severe peak conditions)
  2. A resource plan with a higher GRM value is projected to be more reliable from an LOLP perspective (slides 3 through 5)
  3. A resource plan with a higher GRM value is projected to have to use its LM resources less frequently (from 12/06/13 presentation)
- **In regard to point 1 above:**
  - This point can be demonstrated by a "look backwards" analysis of Winter 2010 (slides 15 – 17 and Appendix slides 24 - 27)
  - This point can also be demonstrated by a "looking forward" analysis for Summer and Winter for the year 2021 (slides 18 & 19 and Appendix slides 28 -33)

FPL.

In the "look backwards" analysis, several perspectives were taken of the Winter peak day in 2010

Regarding the January 2010 Peak Day

- The first perspective was of what actually happened on that day (the 2009 Site Plan's projections for the year 2010 were used as the starting point for this analysis)

- The second perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 10% in 2010 (but an identical Summer total RM of 20.4%)

- The third perspective was to see how FPL's system would have fared if the resource plan had been different with a GRM of 5% in 2010 (but an identical Summer total RM of 20.4%)

FPL

Sufficient generation reserves are needed for peak load periods

January 11, 2010 (7- 8 AM) – All Time FPL Peak Load

- **Relative to the 2009 Ten Year Site Plan (TYSP), the total reserves for the Winter were 58.2% with a Generation Reserve Margin (GRM) of 42.9%. The Summer reserve margin was 20.4% with an 8.4% GRM**
  - FPL's load was 24,872 MW, 6,196 MW higher than forecasted
  - FPL entered day with 7.4% reserves, all in load management (LM)
  - 24,872 MW of generation was available
  - FPL implemented C/I LM and voltage reduction (561 MW)
  - FPL sold 526 MW of emergency power
  - 1,144 MW of LM remained available during the peak hour
  - No firm load was curtailed by FPL or any other Florida utility
  - Several hours after the peak hour Turkey Point 4 (PTN4) tripped with 750 MW of generation

In Winter 2010, the generation reserves were just sufficient to provide reliable operations with no curtailment of firm load in Florida

Analyses of Winter 2010, using different GRM values, provide a couple of key "takeaways"*

Takeaways from the January 2010 Peak Day Analyses

	Firm Load is Shed?		
Scenario	**W/ TP4**	**W/O TP4**	**Comments**
Actual: 8.4% GRM	No	No	If PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 10% GRM	No	No	A 10% GRM (as compared to a 5%) would have resulted in a 659 MW increase in LM reserves, and no utilities would have had to shed firm load Similar to the 8.4% GRM scenario, if PTN4 would have tripped prior to the peak, FPL would have implemented additional LM
w/ 5% GRM	No	Yes	W/O TP4 either FPL or another utility in Florida would have had to shed 52 MW of firm load impacting over 30,000 customers

Compared to 8.4%:
+213 w/10%
−446 w/5%
Δ = 659

* The actual analyses are presented in Appendix slides 24 - 27

On 1/11/10, a 5% GRM would have resulted in 30,000 firm load customers being shed, but a 10% GRM would have provided 659 MW of additional reserves

FPL

A "looking forward" analysis of 2021 addressed both Summer and Winter with 5% and 10% GRM-based resource plans

How the Analyses of 2021 Were Conducted

- The 2013 Site Plan's resource plan for the year 2021 was the starting point: 6.9% GRM, 21.0% Summer total RM, and 34.5% Winter total RM
- Then two alternate resource plans with the same 21.0% Summer total RM, but either 5% or 10% Summer GRM were "constructed" for Summer (comparable alternate resource plans for Winter 2021 were also constructed)
- To simplify the analysis, the alternate plans differed in regard to EE and generation only (similar results would occur if LM instead of EE had been varied in the plans)
- Identical changes of 9% were made to forecasted load, EE, and available generation (the percentage change chosen is arbitrary, but reasonable and consistent)
- The resulting available generation and total resources remaining after these changes were made are compared (note that EE's impact has already "happened" at the peak)

FPL

The "looking forward" analyses of resource plans for 2021 provides additional support for a 10% GRM-based resource plan compared to a 5% GRM-based plan

Key Points from the "Looking Forward" Analyses

- Only the 10% GRM-based resource plan is projected to allow FPL to meet firm load in both Summer and Winter of 2021
- Furthermore, when comparing the two GRM-based resource plans, the 10% GRM-based plan provides significantly more MW of resources for both Summer and Winter

	Summer of 2021			Winter of 2021		
	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM	w/ 10% GRM	w/ 5% GRM	Increased Total Reserves w/ 10% GRM
Total Reserves Remaining after Load, EE, and Generation Adjustments	34	(169)	202	2,921	2,193	728

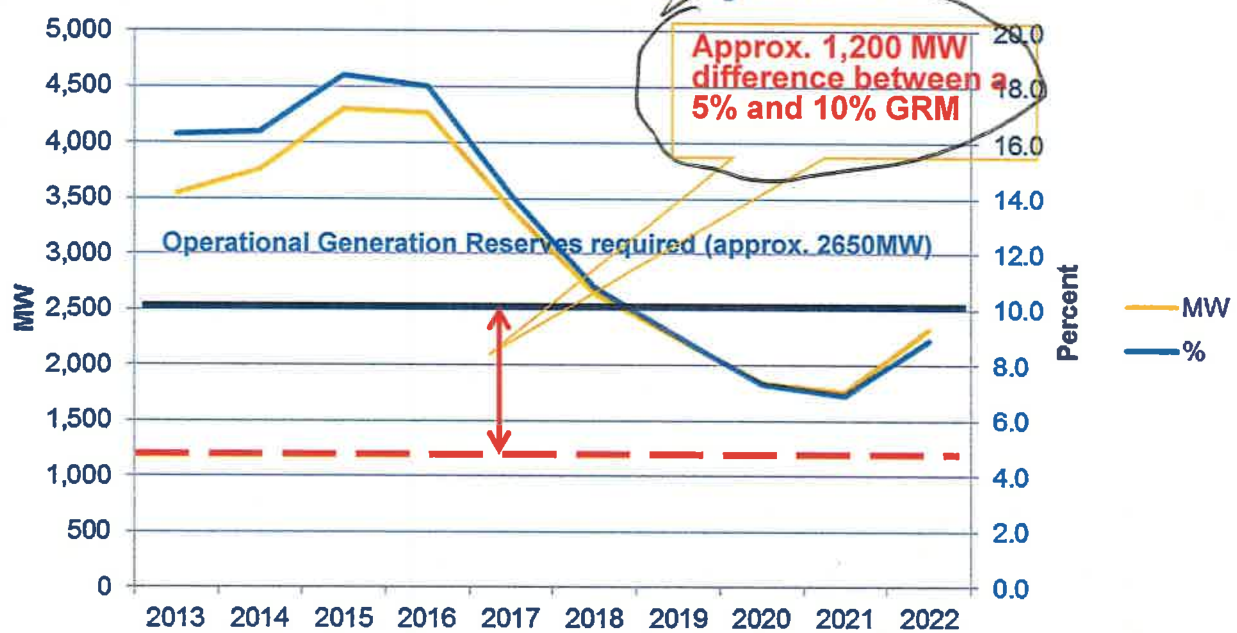
This "looking forward" analysis again shows system operators will have more resources for their use with a 10% GRM, rather than a 5% GRM, resource plan

FPL.

A 10% GRM criterion is a reasonable, easy-to-articulate proxy for FPL's operational generation reserves need

GRM Projections from FPL's 2013 Site Plan

Summer GRM Projections



- **FPL's goal is to maintain ~ 2,650 MW of Operational Generation Reserves to cover the following operational situations:**
  - ≈ 700 - Expected unavailable generation (687 MW)
  - ≈ 1,500 - The generation loss of the largest the largest unit (1,515 MW)
  - 450 - Real time operating reserves deployable within 15 minutes as part of the Florida Reserve Sharing Group (450 MW by 2021)

2,650

A 10% GRM is consistent with FPL's required operational reserves

FPL

FPL has begun using the new GRM criterion in its resource planning process and in 2014 analyses to be filed w/ the FPSC

Next Steps regarding the GRM Criterion

- Text explaining why FPL is using the new criterion will be included in the 2014 TYSP filing and as part of the DSM Goals testimony
- The explanation focuses on analyses comparing resource plans with 10% GRM vs. 5% GRM and include these key points :
  - A 10% GRM results in hundreds of MW of additional operational reserves on severe peak days
  - A 10% GRM results in lower LOLP projections
  - A 10% GRM criterion matches well with the approximately 2,650 MW of generation reserves necessary for operations
- Analyses supporting the 2014 TYSP and DSM Goals filings in April, and the 2014 NCRC filing in early May, all are using the 10% GRM criterion
- These analyses all assume that the 10% GRM criterion must be met beginning in the Summer of 2019

FPL

FPL is not making a separate filing seeking official FPSC approval for FPL's GRM criterion

Next Steps regarding the GRM Criterion (Continued)

- No separate filing/request seeking official FPSC approval for the new GRM criterion will be made
- The only time the FPSC has officially approved a reliability criterion is in the late 1990s when it approved the voluntary stipulation by FPL, TECO, and DEF to move from a 15% to a 20% total reserve margin criterion to close an FPSC docket examining Florida reserves
- TECO did not request approval for its similar supply side reserve margin which it has been using for approximately 10 years
- It is anticipated that discovery requests focused on the new GRM criterion will be received in regard to both the TYSP and DSM Goals filings

FPL

Appendix

FPL and others utilities in Florida were marginally able to serve their entire firm load and FPL met its operational reserve requirements with an 8.4% GRM

January 11, 2010 (7-8 AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
2009 TYSP resource plan projection for Summer 2010	22,916	21,147	220	20,927	1,899	19,028	3,888	20.4%	1,769	8.4%	---
2009 TYSP resource plan projection for Winter 2010	26,852	18,790	114	18,676	1,705	16,971	9,881	58.2%	8,062	42.9%	---
Note that all subsequent rows present adjustments to show how Jan 2010 peak day actual conditions differed from planned conditions shown on row (2)											
Load Adjustments on Jan 2010 peak day---											
Increase in FPL load served after EE (w/o DSM)				6,196							---
Resulting operating conditions on 2010 Winter peak hour	26,852			24,872	1,705	23,167	3,685	15.9%	1,980	8.0%	**Yes**

FPL.

FPL and other utilities in Florida were marginally able to serve entire firm load and meet operational reserve requirements with 8.4% GRM (additional adjustments)

January 11, 2010 (7-8AM) – All Time FPL Peak Load

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (7) - (5) - (3)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Generation / Load Management (CILC and Voltage reduction) Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						---
Operating conditions on 2010 Winter peak hour	24,872			24,311	1,144	23,167	1,705	7.4%	561	2.3%	Yes
Emergency Sales adjustments on Jan 2010 peak day resulted in 24,346MW of FPL load and 526MW of emergency sales. Total load (FPL and 3rd parties) served is 24,872MW											
Emergency sales (recallable)				526							---
Operating conditions on 2010 Winter peak hour	24,872			24,872	1,144	23,728	1,144	4.8%	0	0.0%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						---
Operating conditions on 2010 Winter peak hour	24,122			24,122	394	23,728	394	1.7%	0	0.0%	Yes

FPL.

Two "what if" analyses examined how FPL would have fared if it had entered Winter 2010 with a higher (10%) or lower (5%) GRM

"What If"for January 2010 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	---
Creation of Revised 10% GRM Summer Plan and Corresponding Winter Plan											
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 10% GRM	23,262	21,147	(72)	21,219	1,899	19,320	3,941	20.4%	2,115	10.0%	---
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	27,216	18,790	(37)	18,827	1,705	17,122	10,094	59.0%	8,426	44.8%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	27,216		(37)	25,058	1,705	23,353	3,863	16.5%	2,158	8.6%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	25,236			24,497	1,144	23,353	1,883	8.1%	739	3.0%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	25,236			25,023	1,144	23,879	1,357	5.7%	213	0.9%	Yes
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	24,486			24,273	394	23,879	607	2.5%	213	0.9%	Yes

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

FPL's generation and LM resources would have been greater with a 10% GRM than with 8.4% GRM

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FPL

The second "what if" analysis examined how FPL would have fared if it had entered Winter 2010 with a lower (5%) GRM

"What If"for January 2010 Peak Day w/ 5% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)	(11)
	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LM (w/o scram MW)	Forecasted Firm Load After EE and LM	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	Generation Reserve Margin	All firm load served by FPL and/or other FL utility?
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)	—
Creation of Revised 5% GRM Summer Plan and Corresponding Winter Plan											
Modify the 2009 TYSP resource plan for Summer 2010 to achieve a 5% GRM	22,204	21,147	806	20,341	1,899	18,442	3,762	20.4%	1,057	5.0%	—
Using Winter vs Summer differentials, and the modified Summer resource plan, create a comparable resource plan for Winter 2010	26,102	18,790	418	18,372	1,705	16,667	9,435	56.6%	7,312	38.9%	Yes
Load Adjustments on Jan 2010 peak day											
Increase in FPL load served after EE but prior to LM utilization				6,231							
Resulting operating conditions on 2010 Winter peak hour due to load	26,102		418	24,603	1,705	22,898	3,204	14.0%	1,499	6.1%	Yes
Generation / Load Management / Further FPL Load Adjustments of on Jan 2010 peak day											
	(1,980)			(561)	(561)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments	24,122			24,042	1,144	22,898	1,224	5.3%	80	0.3%	Yes
Emergency Sales Adjustments on Jan 2010 peak day											
Emergency sales				526							
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, & generation adjustments+Em. Sales	24,122			24,568	1,144	23,424	698	3.0%	(446)	-1.8%	No
TP Unit 4 Nuclear Trip on Jan 2010 prior to peak day											
TP Nuclear Adjustment	(750)			(750)	(750)						
Resulting operating conditions on 2010 Winter peak hour w/ load, LM, generation & TP adjustments	23,372			23,818	394	23,424	(52)	-0.2%	(446)	-1.9%	No

* The 2010 Tony letter showed FPL unit capability as 23,333 MW for Winter 2010 & 22,142 MW for Summer. The Winter/Summer ratio is 1.054.

Even after exhausting FPL's generation and LM resources, FPL would not have been able to meet its firm load with a 5% GRM

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FPL

Regarding a "look forward" to 2021, the 5% Summer GRM-based resource plan was examined first in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 5% GRM

Summer	(1) Total Projected Capacity	(2) Forecasted Peak Load	(3) Forecasted Utility EE	(4) = (2) - (3) Peak Load After EE	(5) Forecasted LC	(6) = (4) - (5) Forecasted Firm Load After EE and LC	(7) = (1) - (6) Total Reserves	(8) = (7) / (6) Total Reserve Margin as % of Firm Load	(9) = (1) - (2) or = (1) - (4) Generation Reserves	(10) = (9) / (2) GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	1,230	24,330	2,150	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(111)							
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	1,119	26,741	2,150	24,591	2,247	9.1%	97	0.3%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	1,119	26,741	2,150	24,591	(169)	-0.7%	(2,319)	-8.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 169 MW) of Total Reserves in Col. 7)

FPL

The 10% Summer GRM-based resource plan was examined next in regard to Summer peak

"What If" Summer 2021 Peak Day w/ 10% GRM

	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
Summer	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
10% GRM resource plan	28,116	25,560	174	25,386	2,150	23,236	4,880	21.0%	2,556	10.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE Reduction *			(16)							
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	158	27,702	2,150	25,552	2,564	10.0%	414	1.5%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	158	27,702	2,150	25,552	34	0.1%	(2,117)	-7.6%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL would be able to meet Summer firm load (as seen by the positive 34 MW of Total Reserves)

FPL

The 5% Summer GRM-based resource plan was examined next in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 5% GRM

Winter	Total Projected Capacity	Forecasted Peak Load	Forecasted Utility EE	Peak Load After EE	Forecasted LC	Forecasted Firm Load After EE and LC	Total Reserves	Total Reserve Margin as % of Firm Load	Generation Reserves	GRM
	(1)	(2)	(3)	(4) = (2) - (3)	(5)	(6) = (4) - (5)	(7) = (1) - (6)	(8) = (7) / (6)	(9) = (1) - (2) or = (1) - (4)	(10) = (9) / (2)
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
Winter resource plan corresponding to the Summer plan w/ 5% GRM	28,287	23,601	637	22,964	1,597	21,367	6,920	32.4%	4,686	19.9%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(57)							
Resulting actual operating conditions on 2021 peak hour	28,287	25,725	580	25,145	1,597	23,548	4,739	20.1%	3,142	12.2%
Unavailable Generation *	(2,546)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,741	25,725	580	25,145	1,597	23,548	2,193	9.3%	596	2.3%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM resource plan, FPL would be able to meet Winter firm load with 2,193 MW of Total Reserves to spare

FPL

The 10% Summer GRM-based resource plan was then examined in regard to Winter peak

"What If" Winter 2021 Peak Day w/ 10% GRM

Winter	(1) Total Projected Capacity (MW)	(2) Forecasted Peak Load (MW)	(3) Forecasted Utility EE (MW)	(4) = (2) - (3) Peak Load After EE (MW)	(5) Forecasted LC (MW)	(6) = (4) - (5) Forecasted Firm Load After EE and LC (MW)	(7) = (1) - (6) Total Reserves (MW)	(8) = (7) / (6) Total Reserve Margin as % of Firm Load (%)	(9) = (1) - (2) or Generation Reserves (MW)	(10) = (9) / (2) GRM (%)
Winter resource plan corresponding to the Summer plan w/ 10% GRM	29,634	23,601	90	23,511	1,597	21,914	7,720	35.2%	6,033	25.6%
Higher-than-Projected Peak Load *		2,124								
Lower-than-projected EE Reduction *			(8)							
Resulting actual operating conditions on 2021 peak hour	29,634	25,725	82	25,643	1,597	24,046	5,588	23.2%	3,991	15.5%
Unavailable Generation *	(2,667)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	26,967	25,725	82	25,643	1,597	24,046	2,921	12.1%	1,324	5.1%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM resource plan, FPL would be able to meet Winter firm load with 2,921 MW of Total Reserves to spare

FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary

"What If" Summer 2021 Peak Day w/ 5% GRM & LM Varying

Summer	(1) Total Projected Capacity	(2) Forecasted Peak Load	(3) Forecasted Utility EE	(4) = (2) - (3) Peak Load After EE	(5) Forecasted LC	(6) = (4) - (5) Forecasted Firm Load After EE and LC	(7) = (1) - (6) Total Reserves	(8) = (7) / (6) Total Reserve Margin as % of Firm Load	(9) = (1) - (2) or = (1) - (4) Generation Reserves	(10) = (9) / (2) GRM
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(MW)	(%)
5% GRM resource plan	26,838	25,560	830	24,730	2,550	22,180	4,658	21.0%	1,278	5.0%
Higher-than-Projected Peak Load *		2,300								
Lower-than-projected EE and LM Reduction *					(230)					
Resulting actual operating conditions on 2021 peak hour	26,838	27,860	830	27,030	2,321	24,710	2,128	8.6%	-192	-0.7%
Unavailable Generation *	(2,415)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	24,423	27,860	830	27,030	2,321	24,710	(287)	-1.2%	(2,608)	-9.4%

* A 9% adjustment was made to the starting point value in the first row.

With the 5% GRM plan, FPL would not be able to meet Summer firm load (as seen by the negative 287 MW of Total Reserves in Col. 7)

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FPL

Another "look forward to 2021" case was analyzed in which LM, not EE, was allowed to vary - continued

"What If" Summer 2021 Peak Day w/ 10% GRM & LM Varying

Summer	Total Projected Capacity (MW)	Forecasted Peak Load (MW)	Forecasted Utility EE (MW)	Peak Load After EE (MW)	Forecasted LC (MW)	Forecasted Firm Load After EE and LC (MW)	Total Reserves (MW)	Total Reserve Margin as % of Firm Load (%)	Generation Reserves (MW)	GRM (%)
10% GRM resource plan	28,116	25,560	830	24,730	1,494	23,236	4,880	21.0%	2,556	10.0%
Lower-than-projected EE and LM Reduction *		2,300								
Lower-than-projected EE Reduction *					(134)					
Resulting actual operating conditions on 2021 peak hour	28,116	27,860	830	27,030	1,360	25,671	2,445	9.5%	1,086	3.9%
Unavailable Generation *	(2,530)									
Resulting actual operating conditions on 2021 peak hour after Generation Adjustment	25,586	27,860	830	27,030	1,360	25,671	(85)	-0.3%	(1,445)	-5.2%

* A 9% adjustment was made to the starting point value in the first row.

With the 10% GRM plan, FPL comes closer to meeting Summer firm load (as seen by the negative 85 MW of Total Reserves in Col. 7)

FPL

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Calculation of "Generation - Only" Reserve Margins

FPL 2012 TYSP

	(1)	(2)	(3)	(4)	(5)	(6)	(7) = (5)+(6)	(8) = (4)-(7)	(9) = [(3)-(8)] / (8)	(10) = [(3) - (4)] / (4)	(11) = [(3)- ((4)-(6))] / [(4)-(6)]
August of the Year	Total Capacity (MW)	Planned Outage (MW)	Total Available Capacity (MW)	Load Forecast (MW)	Existing & Incremental Load Control (MW)	Incremental Conservation (MW)	Total DSM (MW)	Firm Peak (MW)	Standard Reserve Margin (%)	(FPL Method) Gen-Only Reserve Margin (%)	(FPSC Staff Method) Gen-Only Reserve Margin (%)
										16.2%	
2012	25,870	745	25,125	21,623	1,901	90	1,991	19,632	28.0%	15.5%	16.7%
2013	26,146	826	25,320	21,931	1,932	183	2,115	19,816	27.8%	14.4%	16.4%
2014	27,420	826	26,594	23,243	1,997	280	2,277	20,966	26.8%	15.6%	15.8%
2015	27,491	0	27,491	23,786	2,028	380	2,408	21,378	28.6%	13.2%	17.5%
2016	27,514	0	27,514	24,315	2,060	479	2,539	21,776	26.4%	10.6%	15.4%
2017	27,139	0	27,139	24,529	2,092	579	2,671	21,858	24.2%	10.0%	13.3%
2018	27,139	0	27,139	24,674	2,123	679	2,802	21,872	24.1%	8.4%	13.1%
2019	27,139	0	27,139	25,041	2,155	779	2,934	22,107	22.8%	6.4%	11.9%
2020	27,139	0	27,139	25,490	2,184	859	3,043	22,456	20.9%	5.5%	19.4%
2021	27,389	0				929					

PEF 2012 TYSP

	(1)	(2)	(3)	(4)	(5)	(6)	(7) = (5)+(6)	(8) = (4)-(7)	(9) = [(3)-(8)] / (8)	(10) = [(3) - (4)] / (4)	(11) = [(3)- ((4)-(6))] / [(4)-(6)]
August of the Year	Total Capacity (MW)	Planned Outage (MW)	Total Available Capacity (MW)	Load Forecast (MW)	Existing & Incremental Load Control (MW)	Incremental Conservation (MW)	Total DSM (MW)	Firm Peak (MW)	Standard Reserve Margin (%)	(FPL Method) Gen-Only Reserve Margin (%)	(FPSC Staff Method) Reserve Margin w/out LC/Intr. (%)
2012	12,003	789	11,214	9,810	842	46	888	8,922	25.7%	14.3%	14.9%
2013	11,903	789	11,114	9,693	889	87	976	8,717	27.5%	14.7%	15.7%
2014	11,782	789	10,993	9,779	882	124	1,006	8,773	25.3%	12.4%	13.9%
2015	11,936	0	11,936	10,024	904	156	1,060	8,964	33.2%	19.1%	21.0%
2016	11,209	0	11,209	10,076	914	184	1,098	8,978	24.8%	11.2%	13.3%
2017	11,209	0	11,209	10,385	967	208	1,175	9,210	21.7%	7.9%	10.1%
2018	11,209	0	11,209	10,580	980	230	1,210	9,370	19.6%	5.9%	8.3%
2019	11,976	0	11,976	11,037	1,005	251	1,256	9,781	22.4%	8.5%	11.0%
2020	11,976	0	11,976	11,242	1,030	273	1,303	9,939	20.5%	6.5%	9.2%
2021	13,068	0	13,068	11,339	1,047	292	1,339	10,000	30.7%	15.2%	18.3%