STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2016 Integrated Resource Plans and	)	Joint Report of the Public Staff; Duke
Related 2016 REPS Compliance	)	Energy Carolinas, LLC; and Duke Energy
Plans	)	Progress, LLC

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission (Public Staff), by and through its Executive Director, Christopher J. Ayers, and respectfully submits the following joint report with Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), (collectively, Duke), addressing these utilities' target reserve margins pursuant to the Commission's June 27, 2017, *Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans* (2016 IRP Order) in this Docket.

Introduction

On pages 16 and 17 of the 2016 IRP Order, the Commission summarized the comments submitted by the Public Staff regarding DEC's and DEP's proposed reserve margins, including the following:

1) Forced Outage Rates: Extreme cold events in 2014 and 2015 resulted in unexpectedly high demand for DEC and DEP that, along with forced outages at several facilities, led to operating margins falling well below the utilities' target reserve margins. Since that time, the utilities have

made operational and capital investments in freeze protection to make their systems more resilient to cold weather, but these additional freeze protections were not incorporated into the forced outage rates used by Astrapé in updating DEC's and DEP's reserve margin studies. The Public Staff also expressed concern that the approach used by Astrapé may overestimate the impacts of demand response at the time of these extreme temperature events, and thus the level of reserve margin needed.

2) <u>Determining Load during Extreme Weather Conditions:</u> The Public Staff also commented on the methods used by Astrapé to construct the default hourly load for use in the reserve margin study. DEC and DEP constructed this information based on a neural network, but in extreme temperature conditions in the summer and winter, the neural network model breaks down and a regression equation was used instead. After meeting with the Company, the Public Staff was satisfied that this approach was reasonable.

3) <u>Future Economic Load Growth:</u> The Public Staff commented that Astrapé assumed that the probability distribution for future economic load growth error is symmetrical, approximating a normal distribution. However, the Public Staff noted that this distribution is more likely to be log-normal and skewed rather than normally distributed, such that the probability of a lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate.

4) Load Multiplier Values: The Public Staff also commented that the load multiplier values that Astrapé used represent much higher and lower load deltas than supported by historic data, and recommended that Astrapé provide the basis for the range of the load multipliers and the probabilities for points between those ranges that make up the distribution.

The Public Staff ultimately commented that it was not convinced that the recommended 17% reserve margin based on the winter peak is fully supported, and recommended that the Commission direct DEP and DEC to continue to evaluate the methods and assumptions utilized in their 2016 reserve margin studies to try to better understand the relationships between extreme weather events and load response, as well as economic and load growth rates, and update this information as needed in their next IRPs.

In addition, the Southern Alliance for Clean Energy (SACE), the Natural Resources Defense Council (NRDC), and the Sierra Club filed joint comments, including an attachment entitled "Review and Evaluation of the Reserve Margin Determinations for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans" by James F. Wilson (Wilson Report), in which Mr. Wilson commented that the reserve margins used in the 2016 IRPs were improperly inflated based on the following three factors:

1) The reserve margin studies extrapolated the relationship between cold temperatures and winter loads that occurred in some hours in recent

years over much lower temperatures that have not occurred for decades in a manner that greatly exaggerates the magnitude of the loads likely to occur under extreme cold conditions.

2) The economic load forecast uncertainty that was layered on top of the weather-related load distributions was also exaggerated, and is not supported by the underlying data upon which it was based.
3) The reserve margin studies relied upon the DEC and DEP peak load forecasts, and treated them as forecasts of mean or average peak loads; however, at least in the case of DEC, the forecast value apparently was not a mean value, and was likely several hundred megawatts in excess of the mean forecast, which would bias the reserve margin by making it higher.

Mr. Wilson concluded that the risk of very high loads, especially in winter, was substantially exaggerated in the reserve margin studies, and, therefore, the recommended increases in DEC's and DEP's reserve margins were unsupported.

In its reply comments, Duke stated that it appropriately addressed the Public Staff's concerns regarding the reserve margin studies, and that it continues to fully support the findings recommending minimum 17% winter reserve margin targets for DEC and DEP. Duke acknowledged that DEC and DEP have experienced significantly higher loads than projected during recent cold weather events, and that the significant load response to cold weather experienced in 2014 and 2015, along with the high penetration of solar resources on the Duke system and in the interconnection queues, were the primary drivers for conducting the new reserve margin studies in 2016.

Duke replied that it had provided data responses to the Public Staff indicating that the regression equations were based on peak hours on weekdays during the 2014 and 2015 time period, and that to correct the cold weather days in the synthetic load shapes, only the peak load hour of the day was modified using the regression equation and that the rest of the daily loads were scaled up or down based on a standard cold weather day load shape. Duke indicated that it had responded further to discovery showing the comparison of the synthetic loads with actual history and that the predicted loads calibrated well with actual load response experienced in 2014 and 2015.

In response to the Public Staff's contention that the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect operational investments in freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage, Duke noted that the outage data used in the 2016 reserve margin study was based on NERC Generating Availability Data System (GADS) data for 2010-2014. In response to the Public Staff's discussion regarding the fact that the outage assumptions were not adjusted to reflect the additional subsequent freeze protection investments in Duke's generating plants, Duke pointed out that the reserve margin studies captured the impact of unit outages through "random" Monte Carlo simulations, and although the outage draws are based on historic seasonal data, the outage draws are independent of temperature in the simulations. Duke stated that the inclusion or exclusion of a couple of randomly occurring, short-term duration unit outages will not have a significant impact on the system equivalent forced outage rate (EFOR) values and that the few hours during which freezing problems may have occurred would typically have little impact on individual unit EFOR values or the reserve margin study results. Duke noted, however, that if unit outages were "forced" to occur on extreme cold days within the simulations similar to 2014 and 2015, then it would put upward pressure on the reserve margin. Duke commented that Astrapé modeled this potential as a cold weather sensitivity, and that the results of the sensitivity analysis showed a significant impact on loss of load expectation and resulted in an increase in the reserve margin target of greater than 2%. As such, Duke did not force these cold weather outages into the base case of the reserve margin study.

Last, Duke noted that the analysis shows that these outages were extremely isolated and short in duration. Because the outages are modeled independently from weather in the base case, removing the cold weather related outages has little to no impact on the overall reserve margin study results as reflected by the slight change in EFOR, and that based on the lessons learned in 2014 and 2015, Astrapé and Duke did not believe it prudent to force the outages to occur during the extreme cold temperatures in the base case analysis and thus only modeled the average EFOR across the winter.

In its 2016 Order, the Commission concluded that the reserve margins included in the utilities' IRPs were reasonable for planning purposes. However, the Commission found the analyses by the Public Staff and the Wilson Report to be helpful regarding the question of whether DEC and DEP should move to a 17% winter reserve margin target. The Commission concluded that such a move was not supported by the evidence in this proceeding, and that the concerns outlined by the Public Staff, as well those discussed in the Wilson Report, should be acknowledged by DEC and DEP and fully addressed in their 2017 IRP updates.

On pages 22 to 23 of the 2016 IRP Order, the Commission stated that:

> The analyses regarding reserve margin targets is extremely technical and complicated, made even more so by the advent of winter peaking on DEP and DEC's systems. The Commission relies heavily on the Public Staff's review and analysis to make its decisions on this subject. Therefore, the Commission determines that DEC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

On September 1, 2017, DEC and DEP filed their 2017 IRP Update Reports, in which they acknowledged the concerns outlined by the Public Staff and Mr.

Wilson's report regarding reserve margins and winter capacity planning, and indicated that Duke and the Public Staff planned to file a joint report summarizing the on-going review and conclusions within 150 days of the filing of the Companies' 2017 IRP updates as directed by the Commission.

On January 30, 2018, the Public Staff filed a motion requesting an extension to submit the report until February 16, 2018, which the Commission granted on February 1, 2018. On February, 16, 2018, the Public Staff filed a second motion for an extension of time to file the report until March 30, 2018; the request was granted by the Commission on the same day.

Discussions between the Public Staff and Duke

Since the issuance of the 2016 IRP Order, Duke and the Public Staff have had further discussions to identify and address the areas of concern regarding the reserve margin targets. Duke and the Public Staff held conference calls on July 25, 2017 and October 4, 2017 to discuss the issues and identify actions needed to resolve outstanding items. Duke responded to multiple requests for information and evaluated multiple inputs and scenarios that were suggested by the Public Staff. Duke and Astrapé met with the Public Staff at their offices on December 12, 2017 to present results of the additional analyses to see if common agreement could be reached regarding the reserve margin targets utilized by DEC and DEP. Attached is the slide deck presented at the December 12, 2017 meeting. Duke and Astrapé responded to further requests for information and provided additional simulation results requested by the Public Staff following the December 12, 2017 meeting.

While discussions have been helpful, the Public Staff and Duke did not reach consensus on all of the issues. The following sections describe the findings and comments raised by each party.

Public Staff Comments:

Following the last discussion between parties on December 12, the Public Staff on January 8, 2018, requested that Duke run two additional scenarios, to which Duke provided responses on January 22, 2018. The Public Staff believes these additional combined scenarios are important for arriving at an appropriate reserve margin. The scenarios are:

- Public Staff Scenario #1 (PS-S1):
    - 2-year probability for economic uncertainty using the Public Staff's load forecasting error (LFE) analysis +
    - Remove cold weather outages and continue using 2010 – 2014 GADS data +
    - Combined case
- Public Staff Scenario #2 (PS-S2):
    - 2-year probability for economic uncertainty using the Public Staff's load forecasting error (LFE) analysis +

- Remove cold weather outages and continue using 2010 – 2014 GADS data +
- Base case

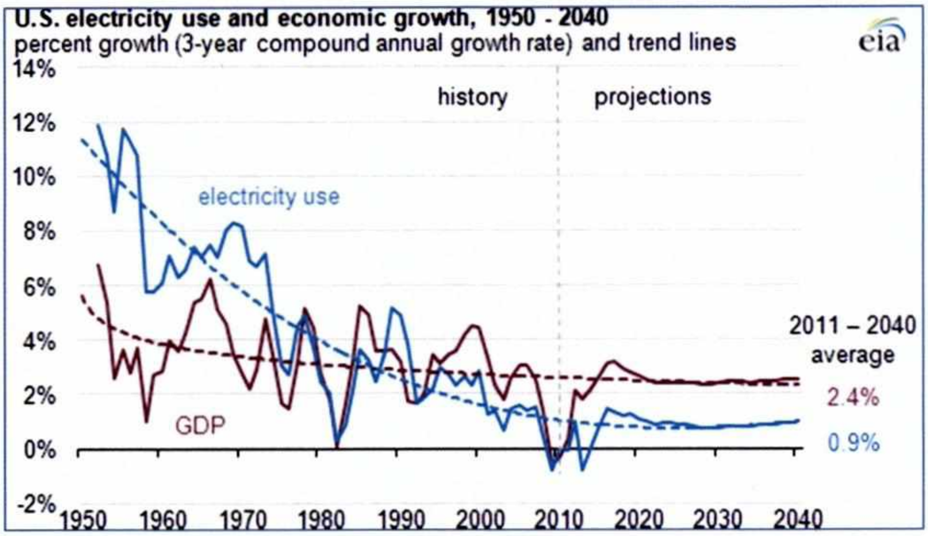
The most important element in each of the new scenarios is the updated LFEs. The purpose of an LFE in a probabilistic model like SERVM[1] used by Astrapé is to represent the probability of the Company under- or over-forecasting electricity demand. The Company stated in its May 10, 2017 reply comments that "while the finer details of the modeling can be debated, the impact of including economic load growth uncertainty in the resource adequacy studies is relatively small." The Public Staff disagrees, and the results of PS-S1 and PS-S2 support the Public Staff's position – using better load forecasting errors resulted in approximately a one percentage point reduction in reserve margin.

Because the reserve margin is, in fact, very sensitive to the uncertainty in forecasting demand, it is critical to model the uncertainty appropriately. The Public Staff believes that Astrapé's methodology for deriving the LFE is problematic and will likely result in an incorrect calculation. Rather than using available data on electricity demand or load forecasting directly, Astrapé instead evaluated historical economic forecasting data to find the forecasting error in economic forecasts, then applied a 40% multiplier to those results to proxy the forecasting error in demand forecasting. As the Public Staff pointed out in its Initial Comments to the 2016 IRP,

[1] The SERVM (Strategic Energy and Risk Valuation Model) is a system dispatch model that evaluates the ability of the system's capacity resources to meet load obligations every hour in a year for thousands of weather, load forecast error, and unit performance combinations.

the relationship between electricity demand and economic growth has changed over time (see Figure 1). Applying a simple 40% multiplier does not reflect the actual relationship of electricity demand and economic growth and is, therefore, distorting.

Figure 1



Because of the complexity in the relationship between electricity demand and economic growth, a better approach for understanding the uncertainty in demand forecasts is simply to evaluate demand forecasts, the approach taken by the Public Staff. The Public Staff compiled electricity demand forecasts made by the Energy Information Administration (EIA) from 1995 through 2015. The Public Staff had previously compiled demand forecasts from North Carolina utilities, their predecessor companies, and electric membership corporations.[2] The Public Staff

[2] Carolina Power & Light (2003-2004), Progress Energy Carolinas (2006, 2008); Duke Power (2002-2006, 2008); Dominion (2003-2006, 2008-2009); and North Carolina Electric Membership Corporation (2003-2004).

then evaluated this combined data set to calculate revised LFEs for demand forecasting that it requested the Company use in PS-S1 and PS-S2.

Duke noted in its response to the Public Staff's January 8, 2018 request that it is non-intuitive that the one-year LFE that the Public Staff calculated has greater uncertainty than the two-year LFE. The Public Staff notes that these LFEs are empirically-based calculations using actual electricity demand forecasts by North Carolina utilities and the EIA. While it is beyond the scope of this report to determine *why* the one-year load forecasts by North Carolina utilities and the EIA have greater uncertainty than the two-year forecasts, the fact remains that, empirically, these one-year forecasts do have greater uncertainty than two-year forecasts. Furthermore, the Public Staff's calculated LFEs are based directly on load forecasts rather than Astrapé's more convoluted approach that starts with economic forecast uncertainty and then scales down 40% to proxy the uncertainty in load forecasts. Therefore, the Public Staff's LFEs are a more appropriate and accurate representation of the uncertainty in electricity demand forecasting than Astrapé's. The reserve margin results with the Public Staff LFEs (PS-S1 and PS-S2) are therefore more accurate.

Both new Public Staff scenarios also remove the extreme cold weather outages that occurred in 2014 from NERC GADS data from 2010 – 2014, which changes the winter season system capacity weighted EFOR as shown in Table 1 below:

Table 1

[BEGIN CONFIDENTIAL]

	Base Case	Remove Cold Weather Outages
DEC	[redacted]	
DEP		

[END CONFIDENTIAL]

The Public Staff asked for the extreme cold weather outages to be removed from the GADS data because the Company subsequently invested in winterization measures to reduce the risk of forced outages in its power plants due to cold weather. Therefore, the Public Staff believes that it is appropriate to remove these particular outages from the original GADS data to better reflect the new probability of extreme cold weather outages after winterization. When this change in EFOR was modeled separately, DEP's reserve margin went down 0.15 percentage points, while DEC's reserve margin remained unchanged. *See* Table 2 below. The average reduction in reserve margin for DEC and DEP was 0.07 percentage points and, as a combined entity, was 0.1 percentage points. The Public Staff expects that the change in EFOR had a comparable impact on reserve margin for PS-S1 and PS-S2.

In its May 10, 2017 reply comments, Duke stated that the change in EFOR from removing 2014 extreme cold outages would "have little impact on study results." While it is technically true that this one change would have a small impact on results, it is important to review the impact of the aggregated changes proposed in the integrated Public Staff scenarios (PS-S1 and PS-S2) rather than one change in isolation and to recognize that the results of these integrated scenarios do have an impact on study results.

The only difference between the two Public Staff scenarios, PS-S1 and PS-S2, is that in PS-S1, DEC and DEP are modeled as a single entity, while in PS-S2, they are modeled as separate entities. The Public Staff recognizes Regulatory Condition 3.5 (Least Cost Integrated Resource Planning and Resource Adequacy) from the Commission's June 29, 2012, *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct* (*Merger Order*) in Docket Nos. E-2, Sub 998, and E-7, Sub 986, which provides that:

> DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

While DEC and DEP are currently separate in terms of planning, at an operational level – the level most relevant to reserve margins, it has been developing a Joint Planning Case that would allow DEP and DEC to share firm capacity, collectively defer generation investment by utilizing each other's capacity when available, and by jointly owning or purchasing new capacity additions. Under this Joint Planning Case, the appropriate scenario for calculating a reserve margin would be PS-S1, which assumes that DEC and DEP operate on a combined basis.

As shown below in Table 2, PS-S1 results in an approximately 15% reserve margin, and PS-S2 results in an approximately 16% average reserve margin.

Table 2

	Original	December 12, 2017			PS Scenarios
	Base Case	Remove Cold Weather Outages	2 year LFE (original distribution)	3 year LFE lognormal distribution	2 year PS LFE + Remove cold weather outages
DEC	16.70%	16.70%	16.25%	16.70%	15.85% (PS-S2)
DEP	17.50%	17.35%	17.25%	17.45%	16.30% (PS-S2)
Average	17.10%	17.03%	16.75%	17.05%	16.08% (PS-S2)
Combined	16.25%	16.15%			15.05% (PS-S1)

The Public Staff believes that Astrapé's Combined scenario has particular merit when one considers how the two companies have a shared interest to "keep the lights on" for all of their customers, as demonstrated on February 20, 2015, when DEC provided DEP with 700 MW of generation on a non-firm basis. While DEC and DEP are separate utilities and cannot jointly plan for future capacity needs, the Joint Dispatch Agreement allows for the sharing of energy between utilities that enables a more economical generation cost at certain times. In the Combined scenario, Astrapé relaxed several constraints in the model to simulate how the combined Duke system would compare to the Base Case in which DEC and DEP were separate. In all scenarios with combined operation, including those initially modeled by Astrapé and new scenarios requested by the Public Staff (PS-S1 and PS-S2), the resulting reserve margins are significantly lower than when DEC and DEP are modeled separately. As noted in the Companies' initial filing in Docket Nos. E-2, Sub 998, and E-7, Sub 986, "Although PEC and DEC each will continue to develop and file annual integrated resource plans, upon consummation of the merger, the planning of the two systems will be coordinated to a greater extent." The Public Staff continues to support separate long range capacity planning as performed in their IRPs; however, for this investigation of the appropriate reserve margin, the Public Staff believes the combined scenarios developed by Astrapé and the alternative combined scenario deserve greater consideration.

The Public Staff recognizes that outage rates may be higher with extreme cold weather because while winterization has been implemented, it may not prevent all cold weather outages; further research on this issue is appropriate in subsequent reserve margin studies. The Public Staff also recognizes that slightly higher outage data experienced from 2015-2017, rather than the data as modeled from 2010-2014, would have the result of supporting an increase in reserve margin. The Public Staff believes that DEC's and DEP's ability to operate like a combined entity in some circumstances helps to offset the impact of updated cold weather EFOR assumptions; therefore, the Public Staff believes that a more than fair reserve margin would be equal to the results of PS-S2 (15.8% for DEC and 16.35% for DEP) or an average of approximately 16% for both DEC and DEP.[3]

Finally, the Public Staff understands that recent extreme cold weather resulted in a peak demand that left the Company's operating reserve margin in the single digits. Rather than viewing this as a cause for alarm or justification for an

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[3] The Public Staff notes that in their 2016 Resource Adequacy Studies, DEC under the physical reliability results met its 1 day in 10 year LOLE standard with a 16.5% reserve margin and DEP met its 1 day in 10 year LOLE metric with a 17.5% winter reserve margin. Duke then suggested that using an average of 17% winter reserve margin for both utilities to ensure overall resource adequacy.

even higher reserve margin, the Commission should see that the system worked as intended; the reserve margin level was appropriate in providing sufficient capacity to cover peak demand. Inclusion of load and system response information from these recent extreme events in future reserve margin studies will also help inform and refine these studies going forward

Duke Comments:

The 2016 Resource Adequacy studies (2016 studies) resulted in a shift to winter capacity planning and an overall increase in planning reserves. Given these changes, the Companies recognize and appreciate the interest from the Public Staff and other intervenors in reviewing and vetting the study assumptions and results. The Companies retained Astrapé Consulting (Astrapé) to conduct the 2016 studies. Astrapé is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé has extensive experience in resource adequacy modeling and has performed similar studies using the SERVM model for clients across the country and abroad including Southern Company, Tennessee Valley Authority (TVA), Santee Cooper, Entergy, Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), California Public Utilities Commission (CPUC), Federal Energy Regulatory Commission (FERC), Electric Power Research Institute (EPRI), and many others.

Duke and Astrapé believe that the inputs and assumptions incorporated in the 2016 studies strike a reasonable balance in capturing the risks that can impact reliability. While the Public Staff has focused on a couple of areas they believe are conservative (i.e., assumptions may lead to the adoption of higher reserve margins), the Companies and Astrapé believe there are more significant assumptions that may have been somewhat aggressive (i.e., assumptions may lead to the adoption of lower reserve margins). When considering the prudency and appropriateness of a target reserve margin, it is the Company's position that a holistic review of the study is more appropriate than focusing only on specific individual factors that in isolation could potentially support a lower reserve margin.

Throughout the process, the Companies have made significant efforts to be transparent and responsive to intervenor questions and concerns. In addition to the resource adequacy study reports that were published in 2016, the Companies and Astrapé met with the Public Staff at their offices on September 22, 2016 to present study results and answer the Public Staff's questions, discussed study findings in recent IRP filings and Stakeholder meetings, submitted detailed reply comments addressing issues raised by intervenors in Docket No. E-100, Sub 147, and responded to numerous discovery requests across multiple IRP and Avoided Cost dockets. As directed by the Commission, the Companies have worked with the Public Staff over the past few months in continued efforts to resolve outstanding concerns with the 2016 studies. Below are additional comments offered by Duke to help inform the Commission in its reserve margin review and determination.

Impact of Cold Weather Outages

Unit forced outages are a key driver of the need for reserve capacity. At any given time, generators may experience equipment failures and be unavailable to serve load. In addition, extreme weather and high demand periods can further stress generation equipment and impact outage rates. The reserve margin requirement is largely correlated to unit outage rates. For example, a 1% increase in the system capacity weighted forced outage rate would result in an approximate 1% increase in the reserve margin. The resource adequacy studies captured the impact of unit outages through "random" Monte Carlo simulations calibrated to historic unit performance data. Although the outage draws are based on historic seasonal outage data, the outage draws were independent of temperature in the simulations. As will be subsequently discussed in more detail, to the extent higher outage rates occur during high load periods driven by extreme weather, this "correlation" of higher outage rates with higher loads was not used in the base case study, rather a simple seasonal average was used instead.

The Companies did include a cold weather outage sensitivity in the 2016 studies to examine the impact of unit outages that are forced to occur concurrent with cold weather and high load, similar to the outages experienced by the Companies during the 2014 and 2015 winter periods. The results of the sensitivity showed a need to increase the reserve margin by greater than 2%. However, this sensitivity was conducted for information purposes. The ability to force these cold weather outages was not included in the base case of the 2016 studies given the Companies' subsequent investments and improvements in freeze protection following the 2014 and 2015 cold weather events. The Companies and Astrapé noted to Public Staff that this was an "aggressive" assumption in as much as additional freeze protection will not entirely remove the correlation of higher outage rates during higher demand periods. In particular, during extreme weather, customer demand is very high which results in the system's oldest and least efficient units running for longer durations than they would under normal conditions. As a result, outage rates greater than the seasonal average outage rates used in the base case would be expected.

The Public Staff notes in their comments that the raw outage data used in the studies was not adjusted to remove the actual cold weather outages experienced in 2014 and 2015. The Companies note that since the outages were simulated as random outage draws in the base case, the inclusion or exclusion of a couple of randomly occurring, short-term duration, unit outages did not have a significant impact on the system average forced outage rates or reserve margin results. To satisfy the cold weather outage issue raised by the Public Staff, Astrapé ran simulations with the outages removed to further demonstrate that excluding the outages did not have a significant impact on study results. As presented on slide 6 of the attachment, removing the outages reduced the reserve margin by less than 0.1%. As previously discussed, this is in contrast to the cold weather outage sensitivity that forced capacity offline concurrent with cold temperatures and high demands as described above, which does have a significant impact on reliability.

In summary, the Public Staff's request to remove cold weather forced outages moved the reserve margin target lower by less than 0.1%, as compared to a possible 2% increase in reserve margin that could be needed when higher outage rates during high load conditions are taken into consideration. Given this fact, the Companies and Astrapé actually consider the outage rate assumptions used in the base case to be somewhat aggressive (i.e., assumptions may lead to the adoption of lower reserve margins). Furthermore, the outage rates were based on 2010-2014 Generating Availability Data System (GADS) data. However, refreshing outage rate assumptions using 2015-2017 data would actually increase the reserve margin approximately 0.5% to 1.0%.

Astrapé noted to the Public Staff in the December 12, 2017 meeting that many of its clients now include the correlation of outage rates and high demand operation in their resource adequacy studies. The Companies will consider including this correlation in future studies and note that this single issue could have the potential to increase the reserve margin by a greater factor than all of the issues raised by the Public Staff in support of a lower reserve margin.

Economic Load Growth Uncertainty

Given that the load forecast is based on underlying assumptions regarding growth of the economy and the impact on load, actual peak demands experienced in the future will likely be greater than or less than the forecasted values. In turn, this economic load forecast error (LFE) can result in the need to advance or delay projected resource needs. For example, a resource need projected today for 2022, may move forward or later in time as the load forecast and underlying assumptions change from year-to-year. Given that it takes approximately 3-5 years to license and construct new generating facilities, Astrapé incorporated three years of economic load forecast uncertainty in the 2016 studies.

The Public Staff agreed that it was appropriate to include the economic load forecast uncertainty; however, the Public Staff disagreed with the assumptions used to capture the uncertainty. On January 8, 2018, the Public Staff provided LFE assumptions to simulate in place of the assumptions used in the study. Astrapé ran the simulations and the Companies subsequently provided the results to the Public Staff. Using the Public Staff's LFE assumptions, the simulations showed that the reserve margin could be reduced from 17% to about 16%. However, the Companies and Astrapé do not agree with the Public Staff's assumptions and do not support the scenario results defined by the Public Staff.

As shown in the Table 3 below, the Public Staff's assumptions are extremely biased to over-forecasting load and show very little probability of under-forecasting load. The table shows that the 2-year LFE assumes that load will be at or below the forecast 82.6% of the time compared to above the forecast only 17.3% of the time. In reviewing other public resource adequacy studies, it is not common to see such bias included as an input in the study. In fact, PJM, NY-ISO and ISO-NE all assume the load forecast represents a 50/50 forecast meaning that the realized load is equally likely to fall either above or below the forecast, similar to the assumptions used in the Duke study.[4]

Further, the 2-year LFE produced by the Public Staff actually shows greater certainty of under-forecasting load as compared to the 1-year LFE. For example, the 2-year LFE shows loads will be under-forecasted by 3% or more 17.3% of the time while the 1-year LFE shows loads will be under-forecasted by 3% or more 23.3% of the time. This result is non-intuitive since forecast error typically increases with the number of years projected. For example, there should be greater foresight in expected peak demand growth one year in advance versus two years in advance. The heavily skewed results of over-forecasting and the greater certainty in load two years in advance versus one year in advance call into question the reasonableness of the Public Staff's LFE methodology and assumptions.

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[4] See https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/nepool_oc_review/2014/icr_2017_2018_report_final.pdf - see page 21.

http://www.nysrc.org/pdf/Reports/IRM%20Study%20Appendices%202017%20Final.pdf - see page 16.

http://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx - see page 24 - PJM uses a standard deviation and normal distribution to uncertainty around the forecast.

Table 3
Public Staff Load Forecast Error Assumptions

	Load Forecast Error Levels				
	-6%	-3%	0%	3%	6%
	Load Forecast Error Probabilities				
1 year	11.0%	29.1%	36.5%	18.9%	4.4%
2 year	15.4%	33.0%	34.2%	14.6%	2.7%
3 year	36.3%	29.2%	22.0%	9.7%	2.9%

The Companies believe that the Public Staff's LFE assumptions are very aggressive which may lead to the adoption of lower reserve margins. Given that the Public Staff's LFE assumptions are heavily skewed to over-forecasting load, the results largely eliminate the LFE impact because it assumes load will be over forecasted 82.6% of the time. Thus, use of the Public Staff's economic load forecast uncertainty assumptions would essentially negate the majority of the impact of including LFE as an uncertainty and thus require close to perfect knowledge of future peak demands. Load forecast uncertainty based on the 50/50 probability will more reasonably capture fluctuations in load growth compared to a scenario expecting an over-forecast of load the vast majority of the time. The Companies continue to support the load forecast uncertainty as modeled in the 2016 studies.

Actual versus Projected Peak Demands

To further demonstrate the volatility and uncertainty in load experienced during recent winter periods, Table 4 below shows actual versus projected peak demands for 2014 through 2018 for DEC and DEP. The actual peak demands have been adjusted to remove any impacts of demand reduction programs that were activated at the time of the peaks (i.e., demand reduction program activations were added back to the load). The table shows the significant variance between actual versus projected peak demands in some years, particularly for DEP. For example, actual loads exceeded projected loads by approximately 500 MW to 3,200 MW for DEP. While some of this difference can be explained by colder than normal temperatures, the data illustrates the significant load volatility and uncertainty that has been experienced in recent winter periods. As an example, in 2015 DEP experienced negative operating reserves (i.e., relied on non-firm purchases to meet load) when actual load exceeded forecast by almost 3,200 MW. Based on the 2014 IRP, DEP's planning reserves going into the 2015 winter period were approximately 32% which is almost twice as great as the 17% reserve margin target being recommended. If DEP had entered the winter of 2015 at the minimum 17% target then there may have been a different outcome in its ability to serve load. A similar situation occurred in January 2018 with DEP again relying on non-firm purchases to serve load even though planning reserves for the winter of 2018 were approximately 25% based on the 2017 IRP.

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Table 4
2014-2018 Projected vs Actual Peak Demands

	Date	Time (HE)	Projected Peak (MW)	Actual Peak[1] (MW)	Actual minus Projected Peak (MW)	System Temp at Peak Hour (F)
			DEC			
2014	30-Jan	8 a.m.	17,678	18,253	575	12.0
2015	20-Feb	8 a.m.	17,350	18,910	1,560	10.3
2016	19-Jan	8 a.m.	17,632	18,013	381	17.3
2017	9-Jan	9 a.m.	18,463	17,428	(1,035)	18.7
2018[2]	5-Jan	8 a.m.	18,734	18,935	201	12.0
			DEP			
2014	7-Jan	8 a.m.	12,492	14,398	1,906	11.5
2015	20-Feb	8 a.m.	12,579	15,755	3,176	9.6
2016	19-Jan	8 a.m.	12,699	13,244	545	18.8
2017	9-Jan	8 a.m.	13,323	14,414	1,091	14.9
2018[2]	7-Jan	8 a.m.	13,423	15,549	2,126	9.0

[1]Actual peak demands have been adjusted to remove the impact of demand reduction programs that were activated at the time of the peak (i.e., DR impacts added back to load).
[2]Preliminary January 2018 data.

Combined DEC and DEP System Results

As part of the 2016 studies, the Companies asked Astrapé to run a sensitivity to examine the benefit in terms of reserve margin requirements of combining the DEC and DEP systems into a single Balancing Authority (BA). The Combined Case analysis simulates operation of the DEC and DEP generation systems as a single BA by allowing the Companies to provide preferential support to each other in times of reliability need such as sharing capacity, demand reduction programs, operating reserves, etc. The Combined Case shows that the reserve margin can be reduced from 17% to 16.3% if DEC and DEP can operate as a single BA. However, the Companies note that merger conditions 3.5, 4.1 and 4.2 set forth in NCUC Docket No. E-2, Sub 998 and Docket No. E-7, Sub 986 specifically preclude DEC and DEP from operating as a single BA. Thus, while there is a reliability benefit of operating the DEC and DEP systems as a single BA, current merger conditions and operating practices preclude the Companies from operating in this manner. Also, the FERC would need to approve any request for DEC and DEP merging into one BA or sharing capacity between the BAs. A prior attempt to obtain FERC approval for sharing capacity between the DEC and DEP BAs failed to receive approval.

Regardless of the reality of how the Companies can and do legally operate their power systems, the Public Staff continues to push the combined case results as the basis for adopting a lower reserve margin target. As support, the Public Staff notes that "DEC provided DEP with 700 MW of generation on a non-firm basis" at the time of the February 20, 2015 winter peak demand. Duke has explained that at the time of the February 20, 2015 peak, DEP purchased 700 MW of non-firm energy, 500 MW of which was from DEC through use of the Joint Dispatch Agreement (JDA). In addition, DEC was purchasing 857 MW of non-firm energy. Thus, DEC and DEP combined were purchasing 1,087 MW (700 + 857 – 500) of off-system non-firm energy to meet load on February 20, 2015. DEC did not give preferential support to DEP but rather the companies used a JDA non-firm transfer of energy from DEC to DEP to benefit consumers, no different than JDA transactions that are conducted on a daily basis. This transaction is also no different than what was modeled in the base case reliability study that shows the need for a 17% winter reserve margin. This transaction does not reflect the preferential reliability support that is assumed in the combined case scenario.

As further support of the combined case results, the Public Staff also notes the following statement from the Companies' initial filing in Docket Nos. E-2, Sub 998, and E-7, Sub 986:

> "Although PEC and DEC each will continue to develop and file annual integrated resource plans, upon consummation of the merger, the planning of the two systems will be coordinated to a greater extent."

The Public Staff may have misinterpreted the intent of this statement. The Companies are simply noting their intention to use consistent models, methods, inputs, assumptions, IRP report formats, etc. to better align planning practices and consistency between the two utilities, rather than insinuating a move toward joint capacity planning.

Market Capacity Assistance

In its comments regarding recent extreme cold weather that resulted in operating reserves in the single digits, the Public Staff notes:

> "Rather than viewing this as a cause for alarm or justification for an even higher reserve margin, the Commission should see that the system worked as intended; the reserve margin level was appropriate in providing sufficient capacity to cover peak demand."

The Public Staff is correct in noting the reliability benefits of being an interconnected utility. In fact, the Island Case sensitivity conducted as part of the 2016 studies showed that capacity assistance from neighboring utilities allows DEC and DEP to reduce their reserve margin by almost 6% to take advantage of load diversity and forced outage diversity within the region. Thus, there are times when it is expected that the Companies will need to rely on capacity support from neighboring utilities. However, the Public Staff fails to note that the Companies were not at their minimum 17% planning targets in January 2018, but rather DEC carried 21% and DEP carried 25% planning reserves into the 2018 winter period and DEP again relied on non-firm purchases and negative operating reserves to serve load.

During high demand periods, neighboring utilities are often constrained and purchases are expensive, non-firm and recallable. However, even during times of extreme peak demands the SERVM model shows that significant purchases are available from neighboring utilities in the 2016 studies. To illustrate the robust level of market support included in the studies, the Companies and Astrapé presented study results for the worst cold weather year to the Public Staff at the December 12, 2017 meeting (reference slide 33 of the attachment). The results showed that SERVM simulated non-firm market purchases of up to 3,000 MW for DEC and 2,600 MW for DEP during high load periods. In addition, approximately 750 MW was purchased at the time of the highest simulated peak demand for DEC and approximately 800 MW was purchased at the time of the highest simulated peak demand for DEP, for a total of 1,550 MW for the combined Companies. In contrast, the combined Companies relied on a total of 1,087 MW of non-firm power at the time of the 2015 peak demands which occurred at a much warmer winter temperature compared to the worst weather year in the study.

Thus, the Companies and Astrapé believe that the robustness of the power market assumed in the resource adequacy studies is somewhat aggressive (i.e., may lead to adoption of lower reserve margins). The Companies plan to re-examine the assistance area modeling in future resource adequacy studies to ensure that market capacity support is not being overstated. Given that market assistance allows the Companies to reduce their reserve margins by about 6%, a relatively small change in modeling assumptions could easily lead to a significant impact on reserve margin results. This issue, when viewed in the greater context of the 2016 Resource Adequacy Studies, represents another area that the Companies believe could be on the aggressive side while Public Staff does not recognize this concern.

Duke Summary Comments

The Companies have expended a significant amount of resources both internally and through external consultant resources in efforts to satisfy the Public Staff and other intervenors with the inputs, assumptions, model, methodology and results of the 2016 Resource Adequacy Studies. Duke clearly recognizes the importance of achieving accurate results to ensure reliability; however, the Pubic Staff continues to focus on a few issues on one side of the risk ledger instead of considering the reasonableness of the study as a whole. While the Public Staff may believe that the economic load forecast uncertainty assumptions incorporated in the study were conservative (i.e., may lead to the adoption of higher reserve margins), the Companies and Astrapé believe that the data and assumptions used in the study strike a reasonable risk balance when considered in total. The Public Staff also states in its comments that "it is important to review the impact of the aggregated changes…" The Companies agree and thus find it curious that the Public Staff would only focus on assumptions that would lower the reserve margin and stop short of considering the more significant input assumptions noted by the Companies and Astrapé, including outage rate modeling and market assistance modeling, that may have been somewhat aggressive and lead to the adoption of lower reserve margins.

Work began on the current studies in 2015 and the studies were completed in 2016. Given the need to periodically reassess resource adequacy and reserve margin needs, the Companies plan to conduct new resource adequacy studies within the next couple of years. In particular, the Companies will consider the correlation of unit forced outages and load, and also reassess market assistance modeling assumptions. Relatively small changes in either of these factors could have a significant impact on reserve margin results.

The Companies note, and history has shown, that going into the winter with a 17% winter reserve margin does not eliminate reliability risk for the Companies. At that level, load can be expected to be shed once every ten years. The Companies believe that by adopting a reserve margin below that level, the

Commission would be accepting a level of reliability that is worse than 1 day in 10 years LOLE. The Companies propose that the Commission adopt the 2016 study recommendation resulting in a 17% minimum winter reserve margin target and mandate the Companies to complete new studies prior to their 2020 IRP filings.

Public Staff Recommendations:

1. DEC and DEP should utilize a 16% reserve margin for planning purposes in their 2018 IRPs and until such time that a new resource adequacy study is conducted.

Duke Recommendations:

1. DEC and DEP will utilize a minimum 17% winter reserve margin for planning purposes until such time that a new resource adequacy study is conducted.

Joint Duke and Public Staff Recommendation:

1. DEC and DEP DEC and DEP will update their reserve margins no later than the 2020 biennial IRP filings to reflect updated peak load and forecast data, weather, and other relevant inputs.

Respectfully submitted this the 2nd day of April, 2018.

PUBLIC STAFF
Christopher J. Ayers
Executive Director

David T. Drooz
Chief Counsel

Electronically submitted
s/ Tim R. Dodge
Staff Attorney

430 North Salisbury Street
4326 Mail Service Center
Raleigh, North Carolina 27699-4300
Telephone: (919) 733-6110
Email: tim.dodge@psncuc.nc.gov

CERTIFICATE OF SERVICE

I do hereby certify that I have this day served a copy of the foregoing Joint Report on each of the parties of record in this proceeding or their attorneys of record either by electronic delivery or by deposit in the U.S. Mail, postage prepaid.

This the 2nd day of April, 2018.

Electronically submitted
s/ Tim R. Dodge

E-100, Sub 147

2017




2016 RESOURCE ADEQUACY STUDY – OUTSTANDING ISSUES

December 12, 2017

Agenda / Table of Contents

DUKE ENERGY.

- Introductions
- Review status of Public Staff Issues List
    1. Impact of cold weather outages
    2. Extreme weather modeling
    3. Economic load growth uncertainty
    4. Enhanced sensitivity analysis
    5. Combined DEC and DEP system results
- Summary of inputs
- Conclusions and recommendations
- Action items
- Introduction to Effective Load Carrying Capability (ELCC)

Issue 1: Cold Weather Outages
Public Staff

DUKE ENERGY

- "… A number of plants in the system experienced forced outages because of the extreme cold due to controls and other essential systems being frozen or inoperable at those temperatures. Since that time, DEP and DEC have made capital and operational investments in freeze protection. Their systems should now be more resilient to cold weather and, therefore, less likely to experience such narrow operating margins. However, responses to Public Staff data requests indicate that the forced outage rates Astrapé assumed for the reserve margin study were not adjusted to reflect this additional freeze protection, potentially overestimating the likelihood of outages at winter peak and overestimating the recommended planning reserve margin percentage." (Public Staff 2016 IRP Comments, p. 44-45)

- Reference: DEC/DEP 2016 IRP Reply Comments, p. 17-20

Issue 1: Cold Weather Outages
Cold Weather Outage Sensitivity

DUKE ENERGY.

- 2016 Resource Adequacy studies included a cold weather outage sensitivity that assumed incremental cold weather outages in all hours when the system temperature was below 18 °F
- Cold weather sensitivity was based on actual cold weather outages experienced during 2014 and 2015
- Results showed a significant increase in reserve margin requirements of about 2.5% when including incremental outages concurrent with cold weather and high load

2016 Resource Adequacy Study Cold Weather Outage Sensitivity		
	Base Case	**Cold Weather Outages**
DEC	16.7%	19.0%
DEP	17.5%	19.8%

Issue 1: Cold Weather Outages
System Capacity Weighted EFOR

- Outage data used in the resource adequacy studies was based on 2010-2014 GADS data
- The studies accounted for seasonal differences in outage rates (Summer, Winter, Spring/Fall seasons)
- No correlation of outage rates vs temperature (other than seasonal) was captured in study
- SERVM draws random outages (by season) using the Monte Carlo technique
- The table below shows that removing the handful of cold weather outages does not have a significant impact on the winter capacity weighted EFOR

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System Capacity Weighted EFOR for 2010-2014 (Winter Season)

	Base Case (2016 Resource Adequacy Study)	Remove Cold Weather Outages
DEC	[redacted]	[redacted]
DEP	[redacted]	[redacted]

Issue 1: Cold Weather Outages
Reserve Margin Results

DUKE ENERGY

- Removing the cold weather outages from the 2016 Resource Adequacy studies only reduces the target reserve margin by less than 0.1%
- Removing the cold weather outages reduces the target reserve margin for the Combined Case by about 0.1% (Combined Case results discussed later in Issue 5)

Winter Reserve Margin Results (1 Day in 10 Year LOLE)		
	Base Case (2016 Resource Adequacy Studies)	Remove Cold Weather Outages
DEC	16.70%	16.70%
DEP	17.50%	17.35%
Average DEC_DEP RM	17.10%	17.025%
Combined Case Results	16.25%	16.15%

Issue 1: Cold Weather Outages
2015-2017 EFOR Data Comparison

DUKE ENERGY

- Outage data used in the resource adequacy studies was based on 2010-2014 GADS data
- Use of 2015-2017 data would suggest slightly higher reserve margins

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Annual System Capacity Weighted EFOR

	2016 Resource Adequacy Study (2010-2014)	2015-2017 Data
DEC	[redacted]	[redacted]
DEP	[redacted]	[redacted]

CONFIDENTIAL PLANNING INFORMATION

Issue 1: Cold Weather Outages
Summary/Conclusions

DUKE ENERGY.

- Operating during extreme weather will always be more challenging despite any weather hardening implemented
- Removing cold weather outages completely from the record has minimal effect on reserve margin results (<0.1%) since outages are drawn randomly and they only represent 2-3 days out of 1500+
- Forcing historical cold weather outages to occur in simulated cold weather periods is a more appropriate reflection of risk and has a larger impact on reserve margin results (+2-3%). Cold weather hardening has mitigated, but not removed, this risk.
- Incorporating more recent outage data in the resource adequacy studies would put upward pressure on reserve margin results
- System capacity weighted EFOR values used in the resource adequacy studies compare favorably to industry benchmark data
- Outage rate assumptions used in the studies are appropriate for assessing resource adequacy and are considered to be somewhat aggressive (assumptions may lead to adoption of lower reserve margins) given more recent outage data and given that forced outages were not correlated to temperature

Issue 2: Extreme Weather Modeling
Wilson Report

DUKE ENERGY.

- "First, the RA Studies extrapolated the relationship between cold temperatures and winter loads that occurred in some hours in recent years over much lower temperatures that have not occurred for decades in a manner that greatly exaggerates the magnitude of the loads likely to occur under extreme cold conditions." (SACE, NRDC and the Sierra Club 2016 IRP Comments, Wilson Attachment B, p. 2)

- Reference: DEC/DEP IRP Reply Comments, p. 50-51

Issue 2: Extreme Weather Modeling
Number of Weather Years

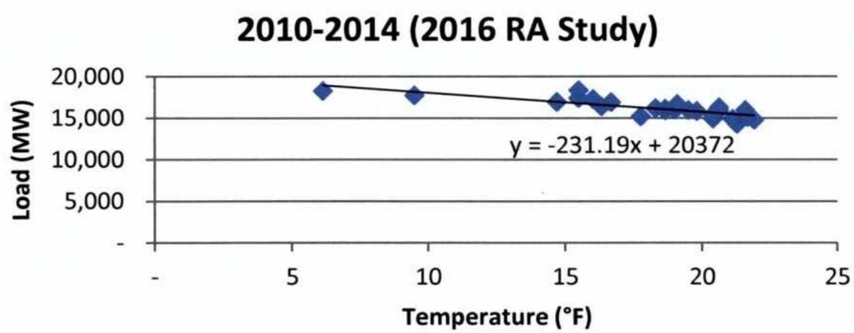
- In response to Data Request 2-8 submitted by the Companies to SACE (2016 IRP Docket), asking what SACE believes is the correct number of historic weather years that should be incorporated in the resource adequacy studies, SACE, NRDC and the Sierra Club replied:

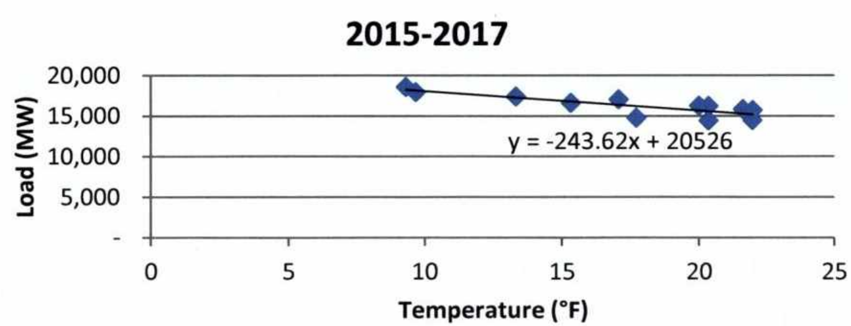
  "Mr. Wilson was not asked to identify or propose a correct number of weather years that should be incorporated into the resource adequacy studies, and therefore has not evaluated this question."

- Apparently Mr. Wilson did not evaluate the correct number of historic weather years that should be included in the resource adequacy studies, and thus has no foundation for his criticism of the number of years used in the Companies' resource adequacy assessment
- NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area..."
- The number of historic weather years used in the resource adequacy studies was appropriate

Issue 2: Extreme Weather Modeling
DEC Regression Equations

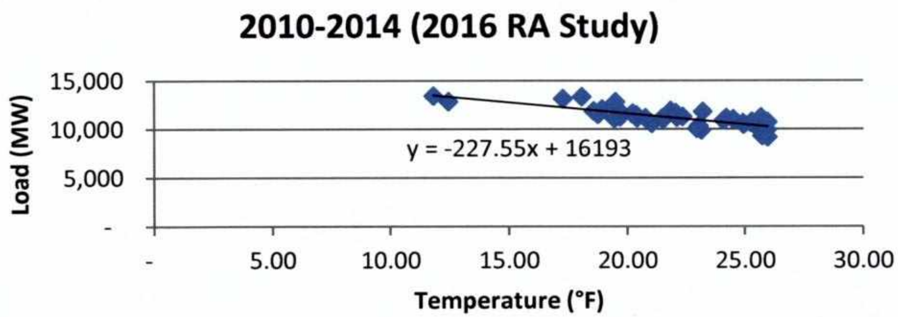
- Regression equations were developed to capture the relationship of load and temperature during extreme weather
- 231 MW per degree change in temperature was used to determine peak loads at extreme cold temperatures
- Use of more current data would suggest a similar load response to temperature (244 MW per degree)

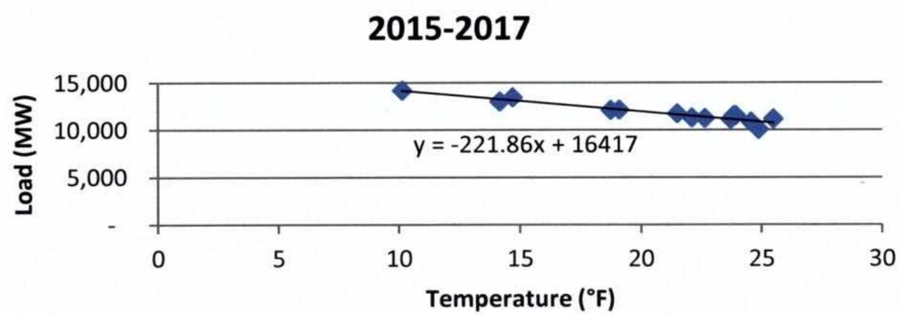




Issue 2: Extreme Weather Modeling
DEP Regression Equations

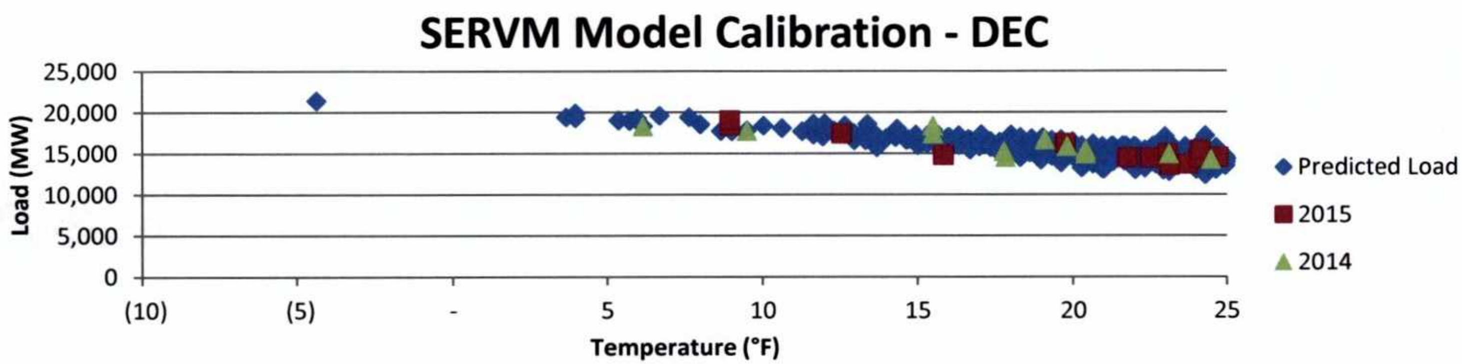
- Regression equations were developed to capture the relationship of load and temperature during extreme weather
- 228 MW per degree change in temperature was used to determine peak loads at extreme cold temperatures
- Use of more current data would suggest a similar load response to temperature (222 MW per degree)

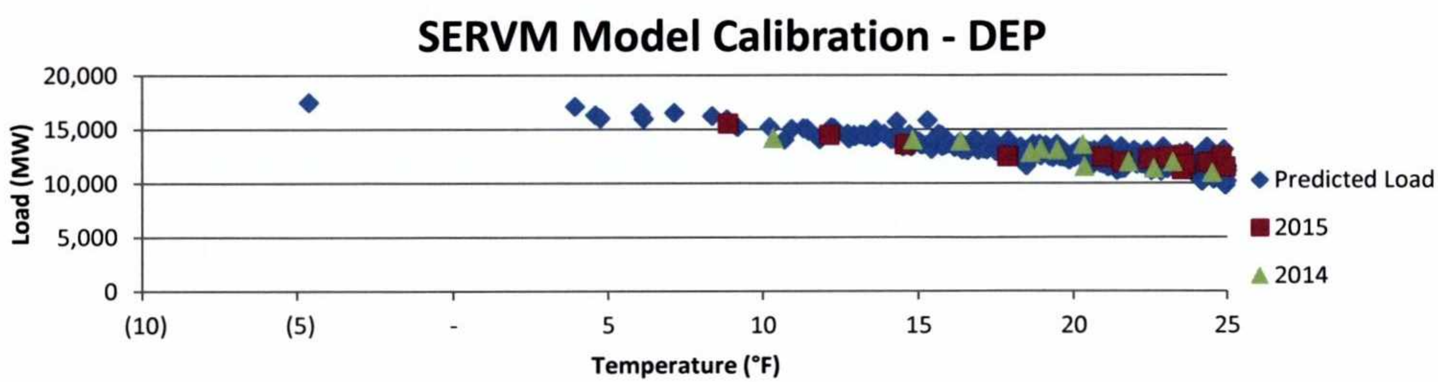




Issue 2: Extreme Weather Modeling
SERVM Projected Daily Peak Demands

- The figures demonstrate that the loads predicted by SERVM calibrate well with the actual load response observed in 2014 and 2015

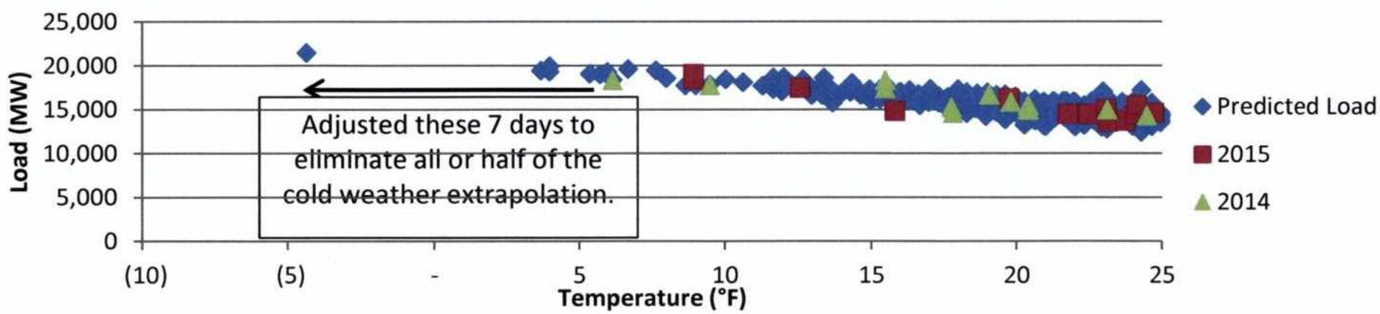




Issue 2: Extreme Weather Modeling
Effect of Cold Weather Extrapolation (DEC)

DUKE ENERGY.

- Astrape estimated the reserve margin impact if the cold weather extrapolation was reduced by 50%
  - Loads were adjusted for days with temperatures below the lowest day seen in 2014 and 2015
    - Impacted 7 days out of the 36 years as shown in the chart below
  - Reducing the cold weather extrapolation by 50% lowered the reserve margin requirement by 0.3%
  - No estimates were performed for DEP
  - While Astrape believes the methodology used for these estimates is reasonable, the SERVM model would need to be rerun to achieve precise results.



Issue 2: Extreme Weather Modeling
DEC and DEP Actual Peak Demands 2014-2017

DUKE ENERGY

- The all-time annual peak demand for each Company occurred on February 20, 2015
- Even though weather was milder in 2017 compared to 2014, DEP experienced a winter peak in 2017 that slightly exceeded the 2014 winter peak (net of demand reduction programs)
- DEP 2017 peak demand exceeded forecast by about 1,100 MW
- The Companies continue to experience significant load response to cold weather even at non-extreme temperatures

	Date	Actual Peak[1] (MW)	System Temp at Peak Hour (°F)
2014 DEC	1/30/2014	18,356	12.0
2014 DEP	1/7/2014	14,159	11.6
2015 DEC	2/20/2015	18,589	10.3
2015 DEP	2/20/2015	15,515	11.1
2016 DEC	1/19/2016	17,136	17.3
2016 DEP	1/19/2016	13,244	20.2
2017 DEC	1/9/2017	16,860	18.7
2017 DEP	1/9/2017	14,407	14.9[2]

[1]Actual peak demands have not been adjusted to reflect the impact of demand reduction programs that may have been activated at the time of peak.

[2]RDU temperature appears to be an outlier (9 °F) which lowers the system temperature at time of peak.

Issue 2: Extreme Weather Modeling
Public Staff – Regression Equation Time of Day

DUKE ENERGY.

- "... This equation represents the peak daily load associated with the lowest temperature recorded that day, not necessarily occurring at the same hour. Astrapé appears to be using this peak day equation to determine hourly load for each hour of historic temperature data below 25 degrees. For example, if a day has 24 hours of temperature below 25 degrees, then this equation represents the load response at each of those hours regardless of time of day. Therefore, the Public Staff is concerned that the approach used by Astrapé may overestimate the demand response associated with these low temperatures and thus the level of reserve margin needed." (Public Staff 2016 IRP Comments, p. 46)

- Reference: DEC/DEP 2016 IRP Reply Comments, p. 20-22

Issue 2: Extreme Weather Modeling
Public Staff – Regression Equation Time of Day

DUKE ENERGY.

- The Public Staff's initial interpretation was that application of the cold weather regression equations was not time of day sensitive
- However, the regression equations were based on weekday peak hours during the 2010 through 2014 time period
- To correct the cold weather days in the synthetic load shapes, only the peak load hour of the day was modified using the regression equation and the rest of the day was scaled up or down based on a standard cold weather day shape
- In other words, the load response to extreme temperatures at 3:00 a.m. and 12:00 p.m. on a cold winter day was well below that of the load response at the peak hour of the day around the 7:00 a.m. time frame
- All cold weather days maintained an expected dual peak

Issue 2: Extreme Weather Modeling
Wilson Report – PJM Cold Weather Splines

DUKE ENERGY.

- "This casual approach stands in contrast to the rigorous process and analysis that the load forecasters at PJM Interconnection, LLC …"

  "PJM's enhanced methodology now employs additional "weather splines" (essentially, regressions over ranges of temperatures), in order to more accurately capture the relationships between load and temperature over different temperature ranges, including extreme hot or cold conditions." (SACE, NRDC and the Sierra Club 2016 IRP Comments, Wilson Attachment B, p. 8-9)
- After reviewing PJM's cold weather load forecast and spline development, Astrapé and the Companies only identified a single cold weather spline at temperatures less than 25 degrees which is very similar to the method employed by Astrapé.

Issue 2: Extreme Weather Modeling Summary/Conclusions

DUKE ENERGY.

- The purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy
- Load response to cold weather experienced during winters of 2014 and 2015 was a principle driver for updating the 2012 Resource Adequacy studies
- The Companies and Astrape recognize that the regression equations used to model the relationship between extreme cold weather and load are key drivers of the resource adequacy study results
- The challenge is that the availability of recent load versus temperature data is limited at these extreme cold temperatures
  - Temperatures as low as about -5 F were experienced in the coldest historic weather year
  - Recent load data is only available for temperatures down to about +6 F for DEC and +9 F for DEP

Issue 2: Extreme Weather Modeling Summary/Conclusions (continued)

DUKE ENERGY

- Regression equation data used in study was based on 2010-2014 cold weather events
- Use of more current data (2015-2017) supports assumptions used in study
- The loads predicted by SERVM calibrate well with the actual load response observed in 2014 and 2015
- Based on estimates, reducing the effects of cold weather extrapolation by half of that assumed in base case would reduce the DEC reserve margin by about 0.3%
    - This assumes half of the load impact for temperatures below those experienced since 2010 (7 occurrences in the 36 year weather history)
- The Companies continue to experience significant load response to cold weather even at non-extreme temperatures
- Astrape's use of a single cold weather spline is very similar to "PJM's enhanced methodology" that was noted by SACE, NRDC and the Sierra Club consultant Wilson
- The Companies will reassess resource adequacy if additional extreme cold weather is experienced that would allow further study of temperature impact on load
- The Companies and Astrape welcome any further suggestions or enhancements from the Public Staff regarding extreme cold weather modeling

Issue 3: Economic Load Growth Uncertainty
Number of Years

DUKE ENERGY.

- The resource adequacy studies assumed 3 years of economic load growth uncertainty to reflect the approximate amount of time it would take to certify, permit and build a new generation resource or otherwise significantly change the resource plan
- In response to Data Request 1-5 submitted by the Companies to the Public Staff (2016 IRP Docket) regarding the inclusion of economic load growth uncertainty in the resource adequacy studies, the Public Staff responded:

  The number of years of economic uncertainty should be less than or equal to the study year minus the current year.

Issue 3: Economic Load Growth Uncertainty
Number of Years

- Shape of the probability distribution changes significantly (more narrow) as the number of years of load forecast error decreases

Load Forecast Error Multiplier	3 Year LFE (Base Case) Probability	2 Year LFE Probability	1 Year LFE Probability
0.96	7.9%	2.1%	0.0%
0.98	24.0%	22.8%	11.7%
1.00	36.3%	50.1%	76.6%
1.02	24.0%	22.8%	11.7%
1.04	7.9%	2.1%	0.0%

Issue 3: Economic Load Growth Uncertainty
Number of Years: Reserve Margin Results

DUKE ENERGY

- Moving from 3 year to 2 year load forecast error reduces the reserve margin by about 0.35%
- Moving from 3 year to 1 year load forecast error reduces the reserve margin by about 1%

Winter Reserve Margin Results (1 Day in 10 Year LOLE)			
	1 year LFE	2 year LFE	3 Year LFE (Base Case)
DEC	15.75	16.25	16.70
DEP	16.50	17.25	17.50
Average DEC_DEP RM	16.125	16.75	17.10

Issue 3: Economic Load Growth Uncertainty
Public Staff – Probability Distribution

DUKE ENERGY.

- "In reality, this distribution is more likely to be log-normal rather than normal and skewed such that the probability of a lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate." (Public Staff 2016 IRP comments, p. 46)

  "... the load growth multipliers appear to be overestimated on both the high and low side. Those high values are driving the tails of the distribution to extreme values that, in turn, are driving up the reserve margin value." (Public Staff 2016 IRP Comments, p. 50)

- Reference: DEC/DEP 2016 IRP Reply Comments, p. 22-24

Issue 3: Economic Load Growth Uncertainty Probability Distribution

DUKE ENERGY.

- The underlying GDP data was fit to both a normal distribution (Base Case) and a lognormal distribution to assess the impact on study results
- The load forecast error (LFE) probabilities for the normal and lognormal distributions are similar

Load Forecast Error Multiplier	Normal Distribution Probability (Base Case, 3-Yr LFE)	Lognormal Distribution Probability (3 Year LFE)
0.96	7.9%	8.2%
0.98	24.0%	23.8%
1.00	36.3%	36.3%
1.02	24.0%	24.2%
1.04	7.9%	7.5%

Issue 3: Economic Load Growth Uncertainty Probability Distribution: Reserve Margin Results

DUKE ENERGY.

- Use of a lognormal distribution does not have a significant impact on reserve margin results (<0.1%)

Winter Reserve Margin Results (1 Day in 10 Year LOLE)		
	Normal Distribution (Base Case, 3-Yr LFE)	**Lognormal Distribution (3-Yr LFE)**
DEC	16.70	16.70
DEP	17.50	17.45
Average DEC_DEP RM	17.10	17.075

Issue 3: Economic Load Growth Uncertainty Summary/Conclusions

- Reducing the economic load growth uncertainty from 3 years to 2 years would reduce the reserve margin by about 0.35%

- Reducing the economic load growth uncertainty from 3 years to 1 year would reduce the reserve margin by about 1%

- Employing a log normal distribution would have very little impact on reserve margin results since the probably multipliers do not change significantly

- Tailwinds of economic growth include uncertainty in the adoption rate of electric vehicles, the rate of electrification of industrial processes that are fossil fuel driven, level of economic development within the service territory and the potential resurgence of growth in single family dwellings

- Given that it takes 3-5 years to put new generation infrastructure in place, the Companies and Astrape believe that 3 years of economic load growth uncertainty is appropriate

Issue 4: Enhanced Sensitivity Analyses Wilson Report

DUKE ENERGY.

- "Resource adequacy studies necessarily involve numerous assumptions about loads and resources…

  To fully understand and valued how the loss of load occurs, the following questions should be explored:
  - When loss of load occurs, what is the day of week, hour, weather condition, and load level?
  - What conditions have combined to cause the extremely high load, if applicable?
  - Which resources are unavailable at that time and in what quantities, and why are they unavailable? In particular, what is the state of demand response, pumped hydro, and purchases through the interties?"

  (SACE, NRDC and Sierra Club 2016 IRP comments, Appendix A of Wilson Attachment B, p. 20)

Issue 4: Enhanced Sensitivity Analyses
Astrape – Validation of Data and Results

DUKE ENERGY.

As part of the model validation and debugging process, Astrape performs a thorough review of the following items:

- Hourly reports (i.e. SERVM debug reports) for many scenarios and iterations from the model with a focus on LOLE hours and validates the following:
  - Load
  - Unit Outages and Planned Maintenance
  - Hydro Output
  - Thermal Resource Output
  - Hydro and Pump Storage
  - Demand Response
  - Renewable Output
  - Market Purchases
- Load uncertainty distributions
- Forced outages and system cumulative outage reports; cold weather outages
- Neighbor reliability and assistance
- Dispatch and unit operations
- Hourly unit output/temperature correlations

These detailed reports are not typically turned on when running all the simulations due to the amount of data, run time, etc.

Issue 4: Enhanced Sensitivity Analyses
DEC Conditions During Firm Load Shed Events

- Table represents averages during EUE hours
- Represents tail events
- Average of 634 hours out of 31,536,000 hours simulated
- See Excel for more details

	Summer/Winter 50/50 Forecast	Summer Nuclear Capacity	Summer Fossil Capacity	Summer CT Capacity	Summer Hydro Capacity	Summer Pump Storage Capacity	Purchases	Summer Renewable Nameplate (NUG Hydro, Biomass, Solar)	Summer/ Winter Demand Response Capacity	Forced Outages
Initial Assumptions	18,996/18,688	6,125	7,943	3,247	1,103	2,140	N/A	1,400	1,117/514.2	N/A
	Load (MW)	Nuclear (MW)	Fossil (MW)	CT (MW)	Hydro (MW)	Pump Storage (MW)	Purchases (MW)	Renewable (MW)	Demand Response (MW)	
Averages During all EUE Hours	20,910	5,792	6,977	3,234	536	2,113	603	404	718	1,608
Average during winter EUE hours (415 hours)	21,317	5,983	7,100	3,392	633	2,116	733	246	510	1,389
Average during summer EUE hours (219 hours)	20,138	5,431	6,743	2,935	352	2,106	355	705	1,113	2,023

Issue 4: Enhanced Sensitivity Analyses
DEP Conditions During Firm Load Shed Events

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- Table represents averages during EUE hours
- Represents tail events
- Average of 1,110 hours out of 31,536,000 hours simulated
- See Excel for more details

	Summer/Winter 50/50 Forecast	Summer Nuclear Capacity	Summer Fossil Capacity	Summer CT Capacity	Summer Hydro Capacity	Summer Pump Storage Capacity	Purchases	Summer Renewable Nameplate (NUG Hydro, Biomass, Solar)	Summer/ Winter Demand Response Capacity	Forced Outages
Initial Assumptions	13,385/13,442	3,554	5,444	4,124	218	0	N/A	2,395	925/496.1	N/A
	Load (MW)	Nuclear (MW)	Fossil (MW)	CT (MW)	Hydro (MW)	Pump Storage (MW)	Purchases (MW)	Renewable (MW)	Demand Response (MW)	
Averages During all EUE Hours	15,461	3,526	5,186	4,374	216	-	703	475	502	836
Average during winter EUE hours (903 hours)	15,756	3,573	5,299	4,504	218	-	776	409	455	767
Average during summer EUE hours (207 hours)	14,301	3,343	4,741	3,861	210	-	413	738	708	1,105

Issue 4: Enhanced Sensitivity Analyses Purchases from Neighbors

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- The Island Case sensitivity conducted as part of the 2016 Resource Adequacy study showed that capacity assistance from neighboring utilities allows DEC and DEP to reduce their reserve margin by almost 6% to take advantage of load diversity and forced outage diversity within the region
- During high demand periods, neighboring utilities are often constrained and purchases are expensive, non-firm and recallable
- However, even during times of extreme peak demands the model assumes that significant purchases are available from neighboring utilities
- Notably, DEC and DEP relied on a total of over 1,000 MW of non-firm power when they set their all-time record peak demands on February 20, 2015

Issue 4: Enhanced Sensitivity Analyses
Purchases from Neighbors during Worst Weather Year (1982)

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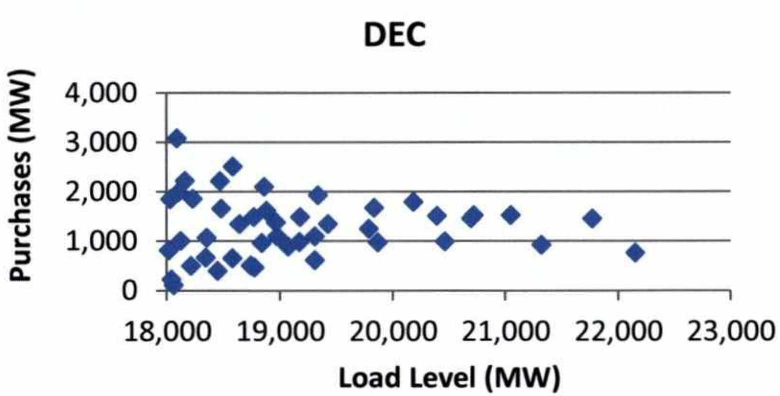
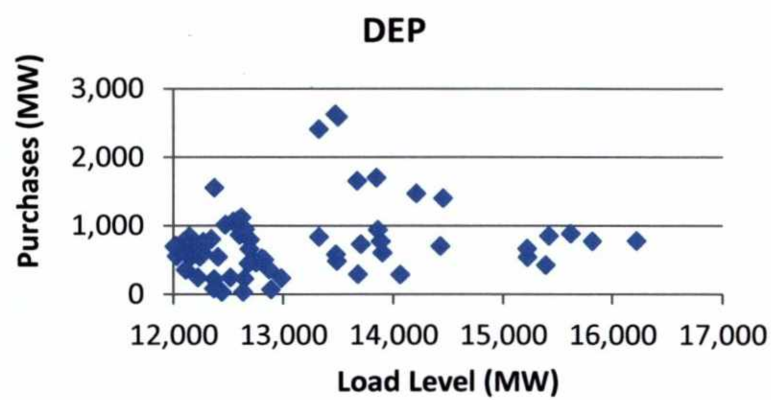
- The graphs below show that SERVM simulated non-firm market purchases of up to 3,000 MW for DEC and 2,600 MW for DEP during high load periods
- Approximately 750 MW was purchased at the time of the highest simulated peak demand for DEC
- Approximately 800 MW was purchased at the time of the highest simulated peak demand for DEP
- The robustness of the power market assumed in the resource adequacy studies is considered to be somewhat aggressive (may lead to adoption of lower reserve margins)





Issue 4: Enhanced Sensitivity Analyses

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- Detailed Excel files can be provided to the Public Staff addressing the sensitivity analysis items noted in the Wilson report

Issue 5: Combined Case Analysis Discussion
Public Staff

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"In view of DEC's provision of 500 MW of non-firm power to DEP during the 2015 polar vortex, as discussed by Nelson Peeler during his March 2, 2015 presentation to the Commission, is it reasonable to attribute the greater weight to the Combined Case scenario as identified in Table 18 of the DEC and DEP Reserve Adequacy Studies?"

- Purpose of the Combined Case sensitivity was to estimate the benefit in terms of reserve margin requirements of combining the DEC and DEP systems into a single Balancing Authority (BA)
- The Combined Case analysis reflects operation of the DEC and DEP generation systems as a single BA which would allow the Companies to provide preferential support to each other in times of reliability need such as sharing of capacity, demand reduction programs, operating reserves, etc.
- The Combined Case shows that the reserve margin can be reduced from 17% to 16.3% if DEC and DEP can operate as a single BA
- Merger conditions 3.5, 4.1 and 4.2 set forth in NCUC Docket No. E-2, Sub 998 and Docket No. E-7, Sub 986 specifically preclude DEC and DEP from operating as a single BA

Issue 5: Combined Case Analysis Discussion
Public Staff

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Merger conditions 3.5, 4.1 and 4.2 set forth in NCUC Docket No. E-2, Sub 998 and Docket No. E-7, Sub 986:

- Merger Condition 3.5
  Least Cost Integrated Resource Planning and Resource Adequacy. DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy…
- Merger Condition 4.1
  Conditional Approval and Notification Requirement. DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA, control area or transmission system…
- Merger Condition 4.2
  Advance Notice Required. To the extent that DEC and PEC desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and PEC shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement…

2016 Resource Adequacy Studies
Summary of Inputs

Assumption	Value	Conservative/Neutral/ Aggressive[1]	RM Impact from Base Case
Cold weather outage penalty	None applied to cold weather days	Aggressive	+2.5% if 2014/2015 applied on cold weather days
EFOR	[redacted]	Aggressive	[redacted]
Cold weather Impact on Loads	Linear regression for lower temps (loads~18% higher than weather normal for DEC, and 21% for DEP)	Uncertain but based on raw data, neutral	
LFE	3 year LFE	Conservative/Neutral	-0.3% reduction in RM if moving to 2 year LFE
Market Assistance	up to 3,000 MW	Aggressive	+6% based on the Island Case (200 MW - 3,000 MW of market assistance during peak hours)

[1]Aggressive assumptions may lead to adoption of lower reserve margins
Conservative assumptions may lead to adoption of higher reserve margins

2016 Resource Adequacy Studies
Conclusions and Recommendations

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- The 2016 DEC and DEP Resource Adequacy studies incorporated significant changes in solar penetration and winter load volatility that resulted in a shift to winter capacity planning and an increase in the planning reserve margin

- The Companies and Astrape believe that the data and assumptions used in resource adequacy studies strike a reasonable risk balance when considered in total

- The 2016 resource adequacy studies also demonstrated the economic benefits of minimizing total reliability costs to customers and showed economic reserve margin ranges of up to about 19% for DEC and 20% for DEP (95^{th} percentile confidence level) to minimize substantial firm load shed and high cost risk. On a probabilistic weighted average basis, the net cost to customers of going from 15% to 17% is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years.

2016 Resource Adequacy Studies Conclusions and Recommendations

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- Recommend adopting 2016 Resource Adequacy study results (17% winter reserve margin) for DEC and DEP

- The Companies will reassess resource adequacy if significant changes occur that could affect input assumptions or reserve margin results, such as additional extreme cold weather and load observations

- Continue to study the capacity benefits of solar (i.e., Effective Load Carrying Capability)

- Remember: DEP carried 21% summer planning reserve margin (32% winter reserve margin) into 2015, but experienced real time operating reserves of -3% during February 20th polar vortex
  - DEC purchased 857 MW of non-firm capacity
  - DEP purchased 700 MW of non-firm capacity (500 MW from DEC on JDA schedule)

- Going into the winter with a 17% winter reserve margin does not eliminate reliability risk for the Companies. At that level, load can be expected to be shed once every ten years. Planning to a reserve margin below that level, the Companies believe the Commission is accepting a level of reliability that is worse than 1 day in 10 years.

2016 Resource Adequacy Studies
Action Items

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- Identify any remaining outstanding issues
- Identify any further actions needed to finalize resource adequacy study recommendations
- Identify actions to complete 150-day status report to NCUC
- Other?

Effective Load Carrying Capability Introduction

- Effective Load Carrying Capability (ELCC) of a resource, such as solar, can be defined as the equivalent amount of CT capacity that can be avoided while still maintaining the same level of generation system reliability

- The Companies are currently working with Astrape to determine the capacity value (i.e., ELCC) of solar

- The Companies plan to complete this work and incorporate results in the next biennial avoided cost rate filing