STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2018 Biennial Integrated Resource Plan) Updates and Related 2018 REPS) Compliance Plans)	PUBLIC STAFF RESPONSES TO COMMISSION QUESTIONS

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission ("Public Staff"), by and through its Executive Director, Christopher J. Ayers, and, pursuant to the Commission's August 27, 2019, *Order Accepting Integrated Resource Plans, Scheduling Oral Argument, and Requiring Additional Analyses* ("2018 IRP Order") in the above-referenced docket, provides responses to the information requested in Appendix A.

I. <u>Background:</u>

In Ordering Paragraph No. 7 to the 2018 IRP Order, the Commission directed Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP") (collectively, "Duke"), and the Public Staff, as specified in the body of the IRP Order, to respond to certain questions in Appendix A related to the utilities' winter reserve margins, load forecasts, carbon dioxide emissions reduction plans, and energy storage portfolios considered within the 2018 Integrated Resource Plan ("IRP"). The Commission specifically requested the Public Staff to respond to items 1, 2, and 4 of Appendix A and presents these responses forthwith. The

Public Staff notes that some subparts of items 1, 2, and 4 appear to be more oriented towards DEC and DEP, but has attempted to provide some input and information for the Commission's consideration.

II. Questions and Responses to Appendix A

1. *DEC and DEP's basis for using a 17% winter reserve margin target, including:*

    a. *Additional details for the contention that a holistic view of the Astrapé study's reasonableness is more appropriate than focusing on specific individual factors (such as those raised by the Public Staff) that could potentially result in a lower reserve margin. [See Page 18 of the Joint Report]*

Response:

The Public Staff notes that the section of the Joint Report referenced by the Commission states that "[w]hen 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." The Public Staff continues to maintain its position that in the case of the Resource Adequacy Study, individual factors, in isolation and in combination with other factors, can and do have an important impact on the reserve margin, which can influence DEC's and DEP's decisions on what type of generating resource to build and when.

    b. *An explanation and/or additional support for the following statement: "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 (95th 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." [See Page 38 of slide deck attached to the Joint Report] Produce all analyses supporting this cost-benefit claim.

Response:

The Public Staff notes that the statement in question was included in the slide deck provided by DEC and DEP at the December 12, 2017 meeting, and the Public Staff does not possess the information or software necessary to perform the modeling analysis that is required to respond to this request. Therefore, the Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

c. *A discussion detailing the "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck attached to the Joint Report.*

Response:

The Public Staff notes that the Wilson Evaluation of Duke IRP Reserve Margin Determinations[1] ("Wilson Report") echoed many of the same issues the Public Staff raised in its analyses of the Resource Adequacy Study. The Public Staff made significant requests for information and supporting data from DEC and DEP with respect to the Resource Adequacy Study, but did not specifically request sensitivity analyses of the items noted in the Wilson Report. The Public Staff respectfully submits that the information and supporting analyses requested by this

[1] Filed in Docket No. E-100, Sub 147 as Attachment B to the initial comments of SACE, NRDC, and the Sierra Club.

question are best provided by DEC and DEP.

d. *An explanation of "Firm Load Shed Event" and discussion of significance in Astrapé's Resource Adequacy Studies. [See Page 43 of Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study]*

Response:

It is the Public Staff's understanding that the firm load shed event identified in the Solar Ancillary Service Study is slightly different from the firm load shed events as defined in the Resource Adequacy Study.

In the Ancillary Service Study, a firm load shed event occurs when the model cannot meet intra-hour or inter-hour demand with available resources,[2] despite perfect foresight five minutes out, in any sub-hourly time-step. Astrapé increases the reserves held in the model until such a firm load shed event occurs only once every 10 years. In the Resource Adequacy Study, a firm load shed is assigned a specific cost per MWh of unserved energy and is defined to occur when generation is unable to meet load, despite neighboring utility assistance and DSM programs, in any hourly time-step.

e. *An explanation and additional characterization of the potential impact of increasing the loss of load expectation for DEP to approximately 0.13 days/year (one firm load shed event every 7.7 years) and for DEC to approximately 0.116 days/year (one firm load shed event every 8.6 years). [See Page 42 in DEP's IRP and Page 42 in DEC's IRP]*

[2] The Ancillary Service Study focused on intra-hour loss of load events occurring due to insufficient ramping capability; thus, 'available resources' refers only to the utility's own generating resources (including DSM and purchases from third-party facilities), and did not include assistance from neighboring utilities.

Response:

The Public Staff does not possess the ability to perform the detailed modeling analysis that is required to respond to this request. Therefore, the Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

f. *A discussion of the following statement included in Astrapé's 2016 Resource Adequacy Studies: "Across the industry, the traditional 1 day in 10 year standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh." [See Page 30 of both DEP's and DEC's 2016 Resource Adequacy Studies]*

   Include a discussion and assessment of the following statement: "One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, one day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard." [Brattle Group and Astrapé Consulting for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary Page iii, www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf]

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

g. *An analysis and conclusion as to what DEC's and DEP's reserve margins would be using an economically-optimal analysis, as* *discussed in the Brattle and Astrapé report noted in (f) above. Address the following statement: "Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications." [See reference in (f) above]*

Response:

The Public Staff does not possess the information necessary to perform the modeling analysis required to respond to this request. Therefore, the Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

h. *A detailed work plan for developing the update to Astrapé's Resource Adequacy Studies proposed for 2020. [See Page 32 of the Joint Report]*

Response:

The Public Staff notes that Page 32 of the Joint Report states that "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." DEC and DEP have not shared any work plan for developing the updated resource adequacy studies with the Public Staff at this time. As such, the Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

i. *A characterization and discussion of the impact and risks of potentially delaying the awarding of contracts associated with DEP's capacity and energy market solicitation until an updated Resource Adequacy Study is completed and effectively vetted. [See Page 81 of DEP IRP]*

Response:

The Public Staff believes that DEP is best suited to include a discussion of the impact and risks; however, the Public Staff notes that the cumulative effect of its recommendations in its March 7, 2019, initial comments would have reduced and delayed the need for the short term market purchases in DEP.[3] While it is the Public Staff's understanding that DEP has made significant progress in reviewing and selecting bids for its capacity and energy market solicitation, we also recognize the potential value in delaying awarding of contracts to prevent ratepayers paying for capacity that may not be necessary.

j. *A listing of the reserve margins included in DEC's and DEP's IRPs from 2003 through 2018;*

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

k. *An explanation of why DEC's and DEP's reserve margins have increased over the last 15 years;*

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

l. *DENC's reserve margin is 11.87% and PJM's reserve margin is 15.9%. DENC's and PJM's resource mix is comparable to Duke's.*

[3] See Figure 8 in the March 7, 2019 Corrected Initial Comments of the Public Staff on the 2018 IRPs of DEC and DEP, at 96.

Explain why DEC's and DEP's reserve margins are higher than DENC's and PJM's.

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP. However, the Public Staff notes that the sheer size and geographic diversity of PJM's resource mix leads to greater operational flexibility than that of the much smaller and more compact DEC and DEP systems.

The primary difference between DENC and PJM's planning reserves is based on DENC's application of a "coincident" or "diversification factor" to the DOM Zone coincidental and non-coincidental peak load to account for the fact that DENC's peak load has not typically occurred during the same hour as PJM's peak load. DENC calculates its coincident factor to be 96.47%, which it then applied to the PJM full planning reserve figure to calculate a DENC adjusted planning reserve of ~11.7%.[4]

m. *NERC's 2018 SERC-Southeast reference reserve margin level is 15%. Explain why DEC's and DEP's reserve margins are higher than NERC's.*

Response:

[4] See the March 7, 2019, DENC 2018 IRP – Virginia Corrections and Revisions Compliance Filing, in Docket No. E-100, Sub 157, at 11-13.

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

2. *Duke's basis for its load forecasts, including:*
    a. *Tables that show DEC's and DEP's summer and winter load forecasts prepared in each of the years 2003 through 2018 and the corresponding actual summer and winter peak loads for each year;*

Response:

The Public Staff does not have information on the summer and winter load forecasts for the years 2003 through 2009 readily available, but the attached tables in **Exhibit 1** provide a summary of the Summer and Winter Peak variance for both utilities for the years 2010 through the most recent data available for 2019. As stated in our 2018 IRP comments, the Public Staff finds the utilities' peak load and energy sales forecasts to be reasonable for planning purposes, but continues to have concerns with DEP's winter peak forecast, as illustrated by Table 2, and whether it is accurately capturing customer response to extreme cold temperature events.

b. *Analyses performed by Duke to determine which end uses are contributing to load spikes on extremely cold winter mornings*.

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

c. *As a part of DEP's Blue Horizons Project (BHP), DEP has had success in employing DSM in the Western Region to shave winter peaks. Discuss whether DEP's success in using DSM could be replicated by DEC in its North Carolina service territory. If that success can be replicated, explain why DEC has not done so. If not, explain why not.*

Response:

DEP's Western Region is more significantly winter peaking than its Eastern Region. Therefore, the more significant winter peaks are to a particular area, the greater the impacts of DSM programs designed to reduce winter peak loads in those areas. DEP relies upon its EnergyWise DSM program to achieve these savings in its Western Region by controlling the electric resistance heating elements found in heat pumps and electric water heaters. While similar programs would have load impacts in other regions of DEC's and DEP's service territories, typically, they have not proven to be cost-effective using the traditional cost of service tests recognized by this Commission. First, and foremost, is the issue of decreasing avoided costs. Second, the market potential is lower in most of DEC's service territory, and to a lesser extent, DEP's eastern territory due to the presence and availability of natural gas service for space heating and water heating.

In addition, DEP's Western Carolinas Modernization Program strategy was targeted at load reduction to eliminate or delay the need for new, additional fossil-fuel generation capacity in the Western Region. This clarity of purpose is not present in the remainder of DEP's or in DEC's service territories.

4. *With regard to Portfolio 7 in DEC's and DEP's 2018 IRPs (CT Centric with Battery Storage and High Renewables):*

a. A discussion of the differences of executing this portfolio compared to the base case (including the differences in Present Value of Revenue Requirement as well as specific changes to resource plans). [See Page 60 of DEP's IRP and Page 56 of DEC's IRP]

Response:

The Public Staff respectfully submits the differences in executing Portfolio 7 are best provided by DEC and DEP. With that being said, the Public Staff has reviewed the PVRR for the period 2018 – 2068 for each portfolio and for each scenario analyzed in DEC's and DEP's 2018 IRPs.[5]

In DEP, averaged over all nine scenarios, Portfolio 7 averages a PVRR $763 million greater than Portfolio 1. The single scenario with the lowest cost differential between the portfolios is the low fuel / no CO_2 scenario, which estimates the PVRR of Portfolio 7 to be $384 million greater than Portfolio 1. This difference is driven by higher capital costs and lower operating costs in Portfolio 7 compared to Portfolio 1.

In DEC, averaged over all nine scenarios, Portfolio 7 averages a PVRR $2,063 million greater than Portfolio 1. The single scenario with the lowest cost differential between the portfolios is the base fuel / no CO_2 scenario, which estimates the PVRR of Portfolio 7 to be $1,450 million greater than Portfolio 1. This difference is driven by higher capital costs and lower operating costs in Portfolio 7 compared to Portfolio 1.

[5] Scenarios include iterations of base / low / high fuel costs and base / no / high CO_2 costs. See DEP's IRP at 61.

b. *An examination of the cost of battery storage at existing distributed resource sites compared to the expected cost of DEP's capacity and energy market solicitation.*

Response:

The Public Staff respectfully submits that the information and supporting analyses requested by this question are best provided by DEC and DEP.

c. *Do the modeling and results in Portfolio 7 provide a statistically representative sample that can be extrapolated into a broader analysis and result by assuming the use of individual battery storage on existing and planned solar facilities, specifically including distribution interconnected QFs and the solar capacity to be brought on line pursuant to HB 589, on Duke's system? If not, explain how the modeling of battery storage added to or included in these solar facilities would differ from that employed in Portfolio 7.*

Response:

The Public Staff believes that DEC and DEP may have additional insight, but offers the following information for the Commission's consideration. In DEP only, Portfolio 7 was less expensive on a PVRR basis than Portfolio 6, generally as a result of lower operating costs offsetting higher capital costs over time.[6] However, the energy storage that was added was assumed to be 100% controlled by the utility and could only provide generation and energy transfer capabilities.[7] DC-coupled storage that is co-located with solar (as is typical for solar plus storage QFs) may face physical and contractual limitations on charging from the grid,[8] and is

[6] See Initial Comments of the Public Staff at 67.
[7] See DEP IRP at 98.
[8] For example, Tranches 1 and 2 of the CPRE allow solar plus storage facilities, but specifically prohibit the energy storage facility from charging from the grid.

designed to shift the energy produced by the solar generation facility to other, more valuable hours.

With that in mind, utility-owned grid-tied storage may operate in a fundamentally different manner than will third-party-owned DC-coupled storage, as the latter is highly dependent upon the price signals and terms of the contract provided to third party operators. The Public Staff believes additional modeling and analyses are required to understand the impact of third-party owned and operated energy storage systems located at existing and planned solar facilities. In addition, Portfolio 7 (and all energy storage within the IRP) only permits one "value stream" for energy storage: bulk energy shifting. Extrapolating these results to energy storage systems that are more distributed, and may be able to provide additional benefits,[9] calls for more robust modeling approaches to fully understand system benefits of such systems. Some approaches to evaluating energy storage systems in IRPs include Net Cost, Sub-Hourly Modeling, or Integrated Distribution System Planning.[10]

[9] See October 7, 2019, Revised Presentation of Kelsey Horowitz entitled "Overview of Approaches & Emerging Practices in Interconnection of Storage and Solar-Plus-Storage Facilities" in Docket No. E-100, Sub 164, at slides 18-38.

[10] See October 7, 2019, presentation by Jeremy Twitchell entitled "Energy Storage 101 & Emerging Practices for Modeling Storage in Resource Planning" in Docket No. E-100, Sub 164, at slides 28-31.

Respectfully submitted, this the 4th day of November, 2019.

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Electronically submitted
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CERTIFICATE OF SERVICE

I certify that a copy of these Comments has been served on all parties of record or their attorneys, or both, by United States mail, first-class or better; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 4th day of November, 2019.

Electronically submitted
s/ Tim R. Dodge

Exhibit 1

Table 1

DEP's Summer Peak Forecast Variance

	2011	2012	2013	2014	2015	2016	2017	2018
2010 Forecast Peaks	11,778	11,884	12,857	13,084	13,253	13,415	13,549	13,676
Actual Peaks	12,686	13,405	12,785	12,663	13,415	13,578	13,143	13,403
Variance	908	1,521	(72)	(421)	162	163	(406)	(273)
% Variance	8%	13%	-1%	-3%	1%	1%	-3%	-2%
2011 Forecast Peaks		11,537	12,491	12,624	12,753	12,903	13,054	13,230
Actual Peaks		13,405	12,785	12,663	13,415	13,578	13,143	13,403
Variance		1,868	294	39	662	675	89	173
% Variance		16%	2%	0%	5%	5%	1%	1%
2012 Forecast Peaks			12,862	13,021	12,848	13,019	13,185	13,332
Actual Peaks			12,785	12,663	13,415	13,578	13,143	13,403
Variance			(77)	(358)	567	559	(42)	71
% Variance			-1%	-3%	4%	4%	0%	1%
2013 Forecast Peaks				13,491	13,382	13,580	13,779	13,977
Actual Peaks				12,663	13,415	13,578	13,143	13,403
Variance				(828)	33	(2)	(636)	(574)
% Variance				-6%	0%	0%	-5%	-4%
2014 Forecast Peaks					13,074	13,247	13,417	13,603
Actual Peaks					13,415	13,578	13,143	13,403
Variance					341	331	(274)	(200)
% Variance					3%	2%	-2%	-1%
2015 Forecast Peaks						13,131	13,277	13,427
Actual Peaks						13,578	13,143	13,403
Variance						447	(134)	(24)
% Variance						3%	-1%	0%
2016 Forecast Peaks							13,277	13,384
Actual Peaks							13,143	13,403
Variance							(134)	19
% Variance							-1%	0%
2017 Forecast Peaks								13,140
Actual Peaks								13,403
Variance								263
% Variance								2%

Sources:

1. For 2014-2018 forecast peaks are from the annual IRP Adjusted Duke System Peak Peak and for 2010 to 2013, the forecast peaks are from DEP's Obligation after DSM & EE.

Table 2

DEP's Winter Peak Forecast Variance

	2011	2012	2013	2014	2015	2016	2017	2018	2019
2010 Forecast Peaks[1]	10,664	10,787	11,871	12,112	12,294	12,470	12,612	12,738	12,900
Actual Peaks	12,522	11,826	12,897	14,993	16,429	13,801	15,020	16,016	13,942
Variance	1,858	1,039	1,026	2,881	4,135	1,331	2,408	3,278	1,042
% Variance	17%	10%	9%	24%	34%	11%	19%	26%	8%
2011 Forecast Peaks[1]		10,900	11,890	12,066	12,224	12,406	12,582	12,775	12,908
Actual Peaks		11,826	12,897	14,993	16,429	13,801	15,020	16,016	13,942
Variance		926	1,007	2,927	4,205	1,395	2,438	3,241	1,034
% Variance		8%	8%	24%	34%	11%	19%	25%	8%
2012 Forecast Peaks[1]			11,907	12,078	12,243	12,426	12,602	12,758	12,935
Actual Peaks			12,897	14,993	16,429	13,801	15,020	16,016	13,942
Variance			990	2,915	4,186	1,375	2,418	3,258	1,007
% Variance			8%	24%	34%	11%	19%	26%	8%
2013 Forecast Peaks[1]				12,492	12,710	12,908	13,106	13,282	13,484
Actual Peaks				14,993	16,429	13,801	15,020	16,016	13,942
Variance				2,501	3,719	893	1,914	2,734	458
% Variance				20%	29%	7%	15%	21%	3%
2014 Forecast Peaks[1]					12,579	12,809	12,901	13,079	13,275
Actual Peaks					16,429	13,801	15,020	16,016	13,942
Variance					3,850	992	2,119	2,937	667
% Variance					31%	8%	16%	22%	5%
2015 Forecast Peaks[1]						12,877	13,027	13,200	13,386
Actual Peaks						13,801	15,020	16,016	13,942
Variance						924	1,993	2,816	556
% Variance						7%	15%	21%	4%
2016 Forecast Peaks[1]							13,308	13,427	13,592
Actual Peaks							15,020	16,016	13,942
Variance							1,712	2,589	350
% Variance							13%	19%	3%
2017 Forecast Peaks[1]								13,423	13,533
Actual Peaks								16,016	13,942
Variance								2,593	409
% Variance								19%	3%
2018 Forecast Peaks[1]									14,161
Actual Peaks									13,942
Variance									(219)
% Variance									-2%

Sources:

1. For 2014-2018 forecast peaks are from the annual IRP Adjusted Duke System Peak Peak and for 2010-2013 the forecast peaks are from DEP's Obligation after DSM & EE.

Table 3

DEC's Summer Peak Forecast Variance

	2011	2012	2013	2014	2015	2016	2017	2018	2019
2010 Forecast Peaks[1]	17,529	17,759	17,974	18,280	18,605	18,990	19,351	19,755	20,155
Adjusted Forecast[2]	16,829	17,059	17,274	17,580	17,905	18,290	18,651	19,055	19,455
Actual Peaks	15,420	17,933	16,757	17,397	18,742	19,119	18,811	18,008	17,736
Variance	(1,409)	174	(1,217)	(883)	137	129	(540)	(1,747)	(2,419)
% Variance	-8%	1%	-7%	-5%	1%	1%	-3%	-9%	-12%
2011 Forecast Peaks[1]		17,812	18,245	18,680	19,032	19,476	19,877	20,265	20,644
Adjusted Forecast[2]		17,112	17,545	17,980	18,332	18,776	19,177	19,565	19,944
Actual Peaks		17,933	16,757	17,397	18,742	19,119	18,811	18,008	17,736
Variance		821	(788)	(583)	410	343	(366)	(1,557)	(2,208)
% Variance		5%	-4%	-3%	2%	2%	-2%	-8%	-11%
2012 Forecast Peaks[1]			18,043	18,437	18,795	19,239	19,630	20,002	20,379
Adjusted Forecast[2]			17,343	17,737	18,095	18,539	18,930	19,302	19,679
Actual Peaks			16,757	17,397	18,742	19,119	18,811	18,008	17,736
Variance			(586)	(340)	647	580	(119)	(1,294)	(1,943)
% Variance			-3%	-2%	3%	3%	-1%	-6%	-10%
2013 Forecast Peaks[1]				18,529	18,738	19,100	19,445	19,788	20,164
Adjusted Forecast[2]				17,829	18,038	18,400	18,745	19,088	19,464
Actual Peaks				17,397	18,742	19,119	18,811	18,008	17,736
Variance				(432)	704	719	66	(1,080)	(1,728)
% Variance				-2%	4%	4%	0%	-5%	-9%
2014 Forecast Peaks[1]					18,533	18,869	19,177	19,495	19,853
Adjusted Forecast[2]					17,833	18,169	18,477	18,795	19,153
Actual Peaks					18,742	19,119	18,811	18,008	17,736
Variance					909	950	334	(787)	(1,417)
% Variance					5%	5%	2%	-4%	-7%
2015 Forecast Peaks[1]						18,672	18,974	19,350	19,381
Adjusted Forecast[2]						17,972	18,274	18,650	18,681
Actual Peaks						19,119	18,811	18,008	17,736
Variance						1,147	537	(642)	(945)
% Variance						6%	3%	-3%	-5%
2016 Forecast Peaks[1]							18,776	18,995	18,963
Adjusted Forecast[2]							18,076	18,295	18,263
Actual Peaks							18,811	18,008	17,736
Variance							735	(287)	(527)
% Variance							4%	-2%	-3%
2017 Forecast Peaks[1]								18,833	18,702
Adjusted Forecast[2]								18,133	18,002
Actual Peaks								18,008	17,736
Variance								(125)	(266)
% Variance								-1%	-1%
2018 Forecast Peaks[1]									18,264
Adjusted Forecast[2]									17,564
Actual Peaks									17,736
Variance									172
% Variance									1%

Sources:

[1] From the filed IRPs.

[2] For 2010-2018 Adjusted forecasts reflect a 700 MW reduction for a firm load that was in the forecasts, but not actual loads.

Table 4

DEC's Winter Peak Forecast Variance

	2011	2012	2013	2014	2015	2016	2017	2018
2010 Forecast Peaks[1]	16,885	17,124	17,328	17,612	17,930	18,250	18,636	18,930
Adjusted Forecast[2]	16,185	16,424	16,628	16,912	17,230	17,550	17,936	18,230
Actual Peaks	14,561	15,962	15,363	19,232	20,455	18,213	18,069	19,436
Variance	(1,624)	(462)	(1,265)	2,320	3,225	663	133	1,206
% Variance	-10%	-3%	-8%	14%	19%	4%	1%	7%
2011 Forecast Peaks[1]		17,359	17,773	18,177	18,543	18,891	19,305	19,694
Adjusted Forecast[2]		16,659	17,073	17,477	17,843	18,191	18,605	18,994
Actual Peaks		15,962	15,363	19,232	20,455	18,213	18,069	19,436
Variance		(697)	(1,710)	1,755	2,612	22	(536)	442
% Variance		-4%	-11%	9%	13%	0%	-3%	2%
2012 Forecast Peaks[1]			17,383	17,759	18,130	18,526	18,921	19,303
Adjusted Forecast[2]			16,683	17,059	17,430	17,826	18,221	18,603
Actual Peaks			15,363	19,232	20,455	18,213	18,069	19,436
Variance			(1,320)	2,173	3,025	387	(152)	833
% Variance			-8%	13%	17%	2%	-1%	4%
2013 Forecast Peaks[1]				17,678	18,053	18,401	18,724	19,013
Adjusted Forecast[2]				16,978	17,353	17,701	18,024	18,313
Actual Peaks				19,232	20,455	18,213	18,069	19,436
Variance				2,254	3,102	512	45	1,123
% Variance				13%	18%	3%	0%	6%
2014 Forecast Peaks[1]					17,684	18,029	18,364	18,672
Adjusted Forecast[2]					16,984	17,329	17,664	17,972
Actual Peaks					20,455	18,213	18,069	19,436
Variance					3,471	884	405	1,464
% Variance					20%	5%	2%	8%
2015 Forecast Peaks[1]						17,943	18,260	18,626
Adjusted Forecast[2]						17,243	17,560	17,926
Actual Peaks						18,213	18,069	19,436
Variance						970	509	1,510
% Variance						6%	3%	8%
2016 Forecast Peaks[1]							18,463	18,712
Adjusted Forecast[2]							17,763	18,012
Actual Peaks							18,069	19,436
Variance							306	1,424
% Variance							2%	8%
2017 Forecast Peaks[1]								18,817
Adjusted Forecast[2]								18,117
Actual Peaks								19,436
Variance								1,319
% Variance								7%

Source:

[1] From the filed IRPs.

[2] For 2010-2018 Adjusted forecasts reflect a 700 MW reduction for a firm load that were in the forecasts; but, not actual loads.