Docket No. E-2, Sub 1343
Presson Exhibit 5

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Solar Integration Service Charge (SISC) Study

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PREPARED FOR

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Executive Summary

The Solar Integration Service Charge ("SISC") Study is the third SISC Study ("Study" or "2023 Study") performed by Astrapé Consulting for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP" and together with DEC, the "Companies"), referred to herein as the Companies. The first study was conducted in 2018 and the second study was conducted in 2021 ("the 2021 study"). As part of the second 2021 study, the Companies, with input from the North Carolina Public Staff ("NCPS") and South Carolina Office of Regulatory Staff ("ORS"), retained The Brattle Group ("Brattle") as Technical Review Committee ("TRC") Principal consultant. Brattle coordinated TRC meetings to review the findings of the 2021 Study and separately authored a TRC report for the Companies to incorporate in their 2021 regulatory filings. In addition to Brattle, the TRC consisted of regulatory observers from the NCPS, ORS, and technical leads from three national labs. The TRC provided significant feedback and recommendations during a bi-weekly review process which commenced in March 2021 and concluded in July 2021. These recommendations were reflected in the 2021 study and now in the 2023 Study which is discussed throughout this report.

As DEC and DEP continue to add solar to their systems, understanding the impact the solar fleet has on real time operations is important. Due to the intermittent nature of solar resources and the requirement to meet real time load on a minute-to-minute basis, online dispatchable resources need to have enough flexibility to ramp up and down to accommodate unexpected movements in solar output. Not only can solar drop off quickly, but it can also ramp up quickly. Unexpected movement in either direction causes system ramping needs. When solar output drops off quickly, reliability can be an issue if other generators are not able to ramp up fast enough to replace the lost solar energy. When solar ramps up quickly, if other generators are not able to ramp down to match the solar output change, some solar generation may need to be curtailed. At low solar penetrations, the unexpected changes in solar output

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can be cost effectively accommodated by increasing upward ancillary service[1] targets within the existing conventional fleet. Increasing ancillary service targets forces the system to commit more generating resources which allows generators to dispatch at lower levels giving them more capability to ramp up. There is a cost to this increase in ancillary services because generators are operated less efficiently when they are dispatched at lower levels. Generators may also start more frequently, which also increases costs. As solar penetrations continue to rise, carrying additional ancillary services to mitigate solar uncertainty with the conventional fleet becomes more expensive. This 2023 Study analyzes multiple solar penetration levels and quantifies the cost of utilizing the existing fleet to reliably integrate the additional solar generation.

For this Study, the Strategic Energy and Risk Valuation Model ("SERVM") was utilized because it not only performs intra-hour simulations which include full commitment and dispatch logic, but also because its commitment and dispatch decisions can be performed against uncertain net load forecasts. This uncertainty results in flexibility excursions defined as an event where the online generation fleet is not able to ramp fast enough to match upward net load perturbations. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. At each solar penetration level, simulations were performed assuming the same ancillary service inputs that are used in SERVM simulations with zero solar capacity. The number of flexibility excursions were recorded from those simulations. Next, total flexibility excursions with solar generation were calibrated to the same level as in the zero solar simulations by increasing ancillary services in the form of load following reserves. The goal of the Study is to maintain the same ability to follow net load as demonstrated in the no solar base case in any solar

[1] Ancillary services are defined in further detail in the Model Inputs and Setup Section of the Study, but for purposes of this Study, load following, which is represented by 10-minute system ramping capability, was used to resolve flexibility gaps.

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penetration level analyzed. Finally, system costs were compared between operating with the zero-solar baseline ancillary services (lower cost, but more flexibility excursions) to operating with the higher-solar load following requirements (higher cost but achieves the same level of flexibility excursions that existed before the solar was added). The difference in cost is allocated to the solar energy and represents the Solar Integration Service Charge (SISC). The SISC was estimated for both an "island case," which assumes DEC and DEP need to follow their respective loads with their own resources and a "combined case", which approximates the joint dispatch agreement under which DEC and DEP are currently operating as recommended by the TRC.

Two levels of solar penetration were modeled for both DEC and DEP as shown in Table ES-1. The solar penetration scenarios reflect a range of solar capacity that would cover the Companies' expectations over the next 10 years consistent with the 2027 Study year. Calculating the SISC for these levels provides the Companies with a SISC value as a function of solar penetration to be used in setting the SISC. The Appendix includes a third (even higher) tranche of solar generation which was simulated but is not relevant to the current effort of setting the SISC due to solar capacity levels modeled that exceed the levels DEC and DEP will reach in the next several years.

Table ES-1. DEC and DEP Solar Penetrations Analyzed

	DEC MW	DEP MW	Total MW
Tranche 1	1,873	3,590	5,463
Tranche 2	2,738	4,392	7,130

Tables ES-2 and ES-3 show the results of the island cases for both DEC and DEP which were used to determine the load following requirements for each Company. As solar generation is added, net load volatility increases, causing flexibility excursions to increase. To reduce the excursions, additional load following is added across the day, which is discussed in detail later in the report. SERVM then commits to

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the higher load following target which causes an increase in costs. For DEC, Table ES-2 shows that as solar increases from 0 MW to 1,873 MW, on average 16 MW of additional load following across the daytime hours is required to maintain the same number of excursions that occurred in the 0 MW solar scenario. When tranche 2 is added to the analysis, which includes 2,738 MW, 26 MW of additional load following on average across daytime hours is required compared to the 0 MW solar case. Similar patterns are seen in DEP, as shown in Table ES-3. Tranche 1, which assumes 3,590 MW of solar capacity, requires 49 MW of additional load following on average across daytime hours. Tranche 2, which assumes 4,392 MW of solar capacity, requires 65 MW of additional load following on average across daytime hours.

Table ES-2. DEC Island Results

	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	1,873	2,738
Flexibility Violations (Events Per Year)	2.94	2.94	2.94
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	16	26

Table ES-3. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	3,590	4,392
Flexibility Violations (Events Per Year)	1.47	1.47	1.47
Realized 10-Minute Load Following Reserves (Average MW Over Daytime Hours Assuming 16 Hours) (MWh)	0	49	65

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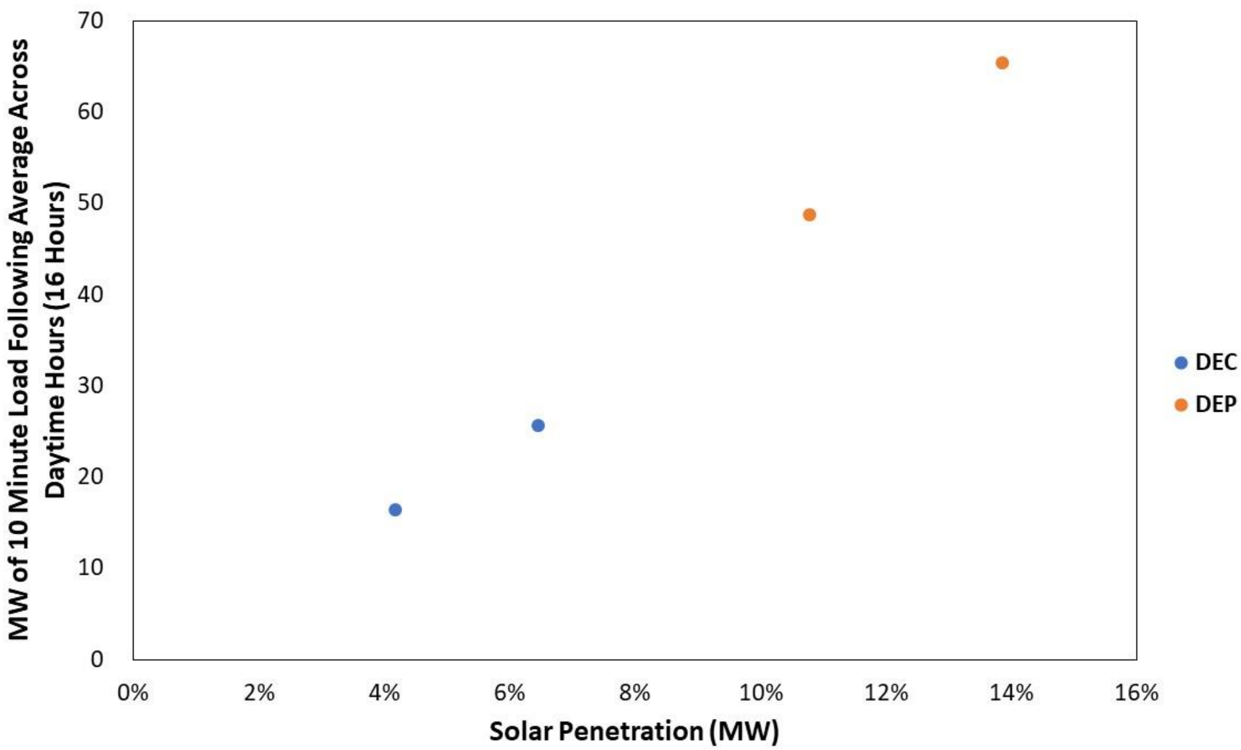
Figure ES-1 shows the load following increase as a function of solar penetration for both DEC and DEP.

Figure ES-1. Quantified Required Increase in Load Following Reserves as a Percentage of Solar Penetration



As requested by the TRC in the 2021 Study, the Study simulated the Joint Dispatch Agreement (JDA) between the DEC and DEP balancing areas to determine the SISC.[2] The combined JDA results reflect modeling the DEC and DEP balancing areas simultaneously with unlimited transmission capability between them similar to the 2023 Resource Adequacy Study.

In these simulations, the realized load following additions determined in the island case with separate balancing areas were targeted for the combined case except now economic transfers can be made on a

[2] The island SISC costs were also calculated and are shown in the body of the Study report.

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5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility. The results are shown in the following table. As expected, there are total savings versus the island scenario as discussed in the body of the report. These benefits then have to be allocated to each Companies' integration cost. Astrapé, along with the TRC and the Companies, determined in the 2021 Study it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis compared to the island results, which has also been applied in the updated 2023 Study. Table ES-4 shows the load following cost rate as well as the average and incremental SISC rates based on the JDA simulations. The average SISC rate represents the integration cost charge for the entire tranche of solar while the incremental SISC rate represents the integration cost charge only for the incremental level of solar between Tranche 1 and Tranche 2. The load following cost rate is the total production cost increase divided by the additional 10-minute load following reserves that are increased.

Table ES-4. Combined Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	1,873	3,590	5,463	2,738	4,392	7,130
Solar Generation (MWh)	4,209,236	7,498,434	11,707,670	6,496,508	9,627,651	16,124,160
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	39.24	39.24	39.24	42.82	42.82	42.82
Average SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.09	1.62	1.41
Incremental SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.46	2.11	1.77

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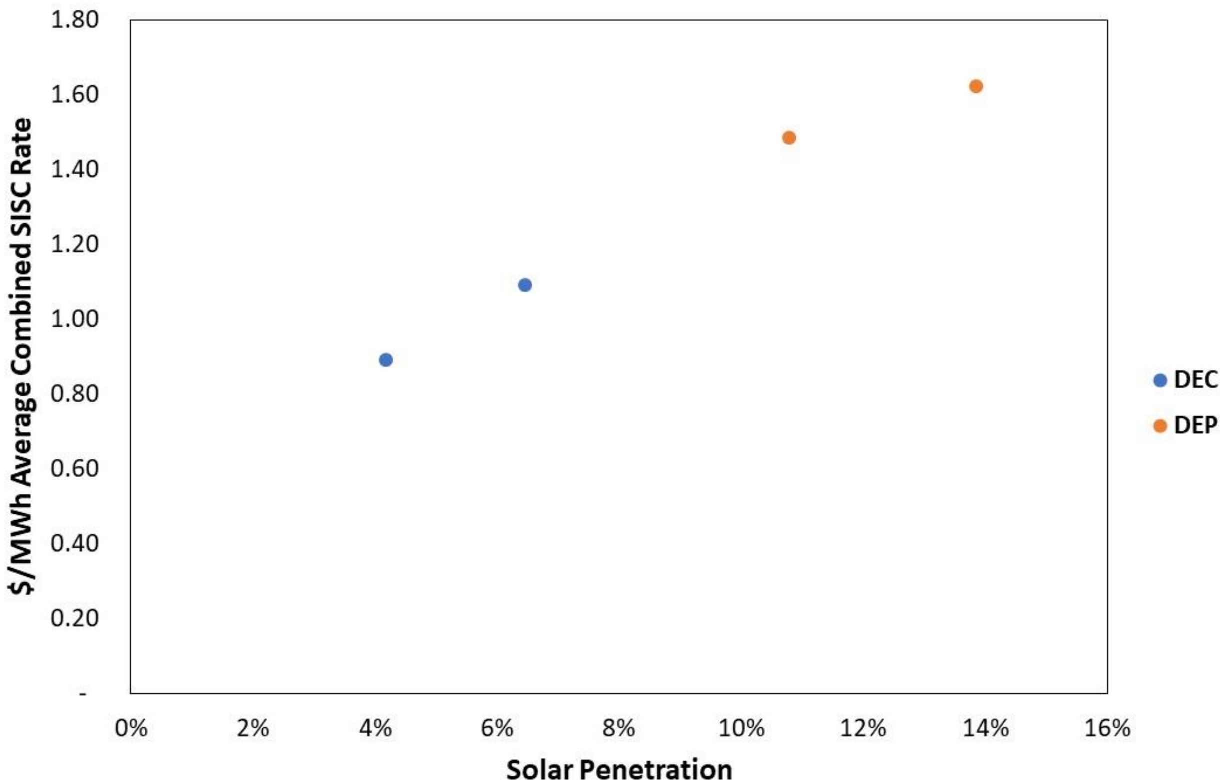
Figure ES-2 shows the average SISC for both tranches by Company for the combined cases.

Figure ES-2. Average Combined SISC Rates for Tranche 1 and 2



These SISC average and incremental rates across these tranches provide the Companies with information to determine a rate to be used in its avoided cost filing. There are average and incremental rates across a wide range of solar penetrations. The rates are highly correlated with the solar penetration as seen in Figure ES-2 so SISC rates for any penetration level can be deduced from the analysis.

Key Drivers of Change from the 2021 Study

There were a number of key changes to the systems modeled in the 2023 Study compared to the 2021 Study that drive changes in results. The first is the increase in gas prices compared to the 2021 Study. Since the 2021 study, the gas prices modeled have increased substantially which increases the costs of incremental load following and thus the SISC. However, this increase in gas price is offset by the addition

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of flexible resources. In the 2021 Study, there was approximately 180 MW of battery storage across the DEC and DEP systems. This has increased to approximately 700 MW of battery storage in the 2023 Study. The DEC system also added Lincoln 17, which is a flexible CT. Finally, Astrapé and the Companies incorporated feedback from the TRC regarding the 2021 Study and have incorporated the Southeastern Energy Exchange Market (SEEM) into the 2023 Study. These improvements to system flexibility decreased the incremental need for load following and despite the cost increase of incremental load following caused by gas prices, there is a net decrease in the SISC compared to the 2021 Study as a function of solar penetration.

The following sections of this report provide greater detail regarding the SISC study framework, model inputs, simulation methodology, and study results.

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I. Study Framework

The economic effects of adding significant solar generation to a fleet are generally analyzed in a production cost simulation model. These models perform a commitment and dispatch of the conventional fleet against the gross load minus the expected renewable generation. Comparing the economic results from simulations with significant solar against simulations with more conventional resources allows planners to assess the economic implications of these additions. However, these analyses typically commit and dispatch resources with an exact representation of the load and solar patterns. This perfect knowledge aspect of the simulations overstates the value of resources like solar because they have significant inherent uncertainty. This Study incorporates the inherent uncertainty and forces the production cost model to make decisions without perfect knowledge of the load, solar, or conventional generator availability. In this framework, the objective function of the commitment and dispatch is still to minimize cost.

The enforcement of reliability requirements in simulation tools with perfect foresight is generally through a reserve margin constraint. Each year is required to have adequate capacity to meet a particular reserve margin requirement. These types of simulations are unlikely to recognize reliability events partly because of their perfect foresight framework, but also because they use simplified generator outage logic. The outages at any discrete hour in the simulations typically represent average outages. In actual practice, reliability events are driven by coincident generator outages much larger in magnitude than the average. In the simulations performed for this Study, the SERVM model incorporates both load and solar uncertainty, as well as generator outage variability. In this framework, testing the capability of the conventional fleet to integrate solar resources is more reflective of actual conditions.

The inability to match generation and net load driven by solar output variability and volatility is different from capacity shortfall events analyzed in a typical resource adequacy analysis. They are events

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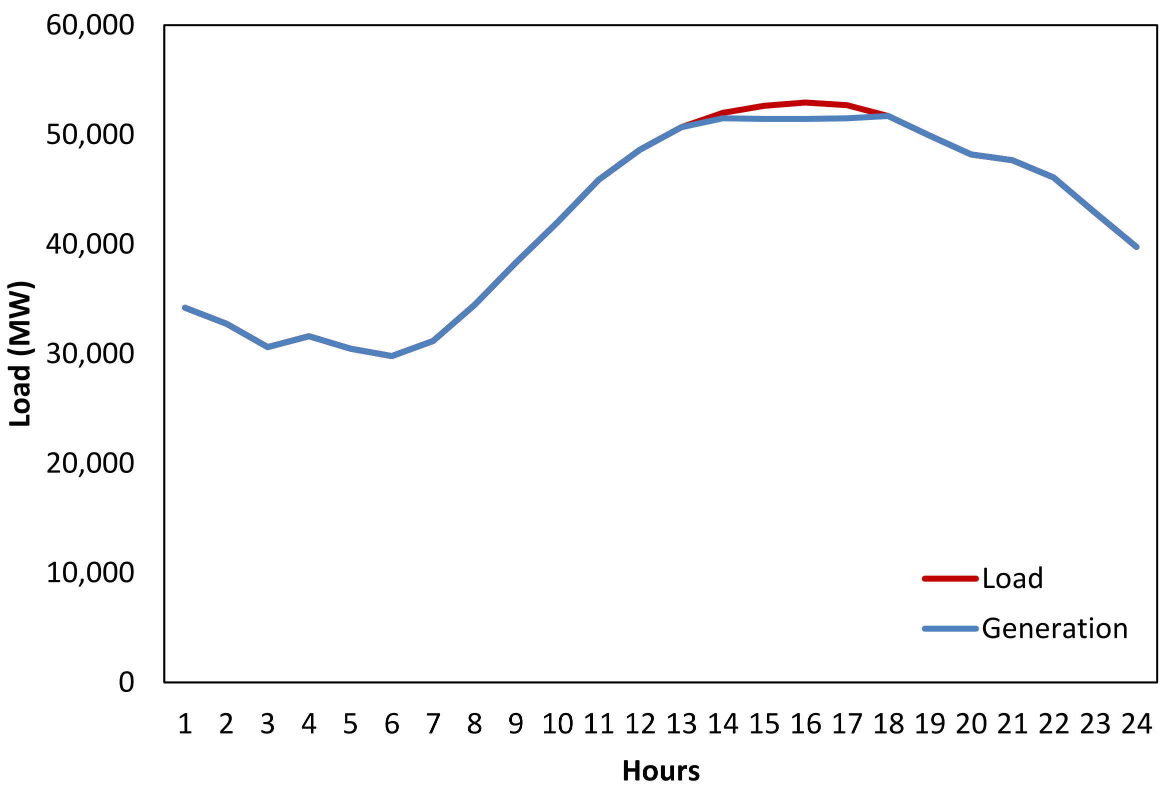
that could have been addressed by operating the existing conventional fleet differently. If solar output in a hypothetical system were to drop unexpectedly by 1,000 MW in a 5-minute period, only resources that are online or synched to the grid with the appropriate operating flexibility would be able to help alleviate the loss of the solar energy. So, for this analysis, the model differentiates events by their cause. Inputs are optimized such that events driven by a lack of capacity and events driven by a lack of flexibility achieve specific targets at minimum cost.

(1) Loss of Load Expectation (LOLE): number of days per year with loss of load due to capacity shortages. Figure 1 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 1. LOLE Example



(2) Flexibility Excursions: number of days per year the system cannot meet a known 5-minute net load ramp due to system flexibility shortfalls. In other words, there was enough capacity installed but not

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enough flexibility to meet the net load ramps, or startup times prevented a unit from coming online fast enough to meet the unanticipated ramps. The vast majority of the flexibility excursions occur in less than one hour.

Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is "one day in 10 years" LOLE, or 0.1 LOLE. To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period. Reliability targets for operational reliability are covered by the North American Electric Reliability Corporation ("NERC") Balancing Standards. The Control Performance Standards (CPS) dictate the responsibilities for Balancing Areas (BA) to maintain frequency targets by matching generation and load.

Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and the Balancing Authority Area Control Error Limit (BAAL) would be ideal. However, simulating violations of these standards is not possible. While the simulations performed in SERVM do not measure the NERC Balancing Standards, the flexibility excursions (times when a 5-minute known net load could not be met by the system's generation fleet) are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. Any periods in which generation is not able to meet load but there is sufficient installed capacity on the system are recorded as flexibility excursions. While there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, there is not a standard for flexibility excursions as measured by SERVM or in other solar integration modeling

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practices. Absent a standard, this Study assumes that maintaining the same level of flexibility excursions as solar penetration increases is an appropriate objective. The DEC and DEP systems were simulated with current loads and resources until operating reserves in the no solar case were similar to historical operating reserves. Running the system like this produces a number of flexibility excursions which would become the target that would be maintained after solar is added.

For each renewable penetration level analyzed, changes were made to the level of load following targeted to maintain the same number of flexibility excursions per year as seen in the base case with no solar. With more ramping capability provided by the increase in load following reserves, the unexpected drops in solar output are not as likely to create flexibility excursions. However, this creates a change in operating costs that has an impact on system costs. Comparing the total production costs assuming the same ancillary services targets used before the solar was added to the final, mitigated case production costs calculated using higher load following targets, which brings flexibility excursions back to the same level as the no solar case, determines the SISC on the system.

The more solar resources that are added, the more challenging and more expensive it becomes to carry the necessary additional ancillary services. In some hours, all conventional generation resources are dispatched near their minimum generation level in order to provide the targeted operating reserves, and yet the total generation is still above the load. This situation results in solar curtailment. The model assumes that any overgeneration can be used as load following and since incremental overgeneration is correlated with incremental solar penetration, higher curtailment is actually associated with lower SISC in this Study. Given existing solar contracts, this treatment is potentially optimistic in that curtailment may not be able to be used as flexibly as typical load following capability, and the real-world system may be committed and dispatched less optimally to avoid some curtailment that is shown in the model results.

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II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the SISC Study. The vast majority of inputs are consistent with 2023 Resource Adequacy Study completed for DEC and DEP. The model was simulated on 5-minute time intervals versus hourly intervals to capture the flexibility requirements of the system given imperfect knowledge around load, solar, and generating units. Simulating at 5-minute intervals requires additional information on generating resources and volatility distributions on load and solar as discussed in the following sections.

The utilities initially are modeled as islands for the SISC Study because each balancing area is responsible for its own NERC Compliance. However, given the joint dispatch agreements in place, DEC and DEP are dispatched as combined systems, which is discussed later in the combined JDA results. For resource adequacy, neighbor assistance capacity plays a significant role in the results. Weather diversity and generator outage diversity are benefits available to DEC and DEP regardless of the type of capacity neighboring regions build. Also, it is required to capture this assistance to achieve the one day in ten-year standard which equates to an LOLE of 0.1 events per year as outlined in the 2023 Resource Adequacy Study. To achieve approximately 0.1 LOLE in this study, additional resources at dispatch costs above a gas CT were included in both DEC and DEP systems to mimic outside purchases.

A. Load Forecasts and Load Shapes

Load Forecasts and Shape Modeling

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs for 2027 for both DEC and DEP which is in line with the 2023 Resource Adequacy Study.

Table 1. 2027 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP	Coincident System

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Summer	18,848 MW	12,773 MW	884 MW	13,612 MW	32,298 MW
Winter	18,165 MW	13,778 MW	1,197 MW	14,932 MW	32,765 MW

To model the effects of weather uncertainty, forty-three historical weather years (1980 - 2022) were developed to reflect the impact of weather on load. Based on recent historical weather and load[3], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from five weather stations across the DEC and DEP service territory. The weather stations included Charlotte, NC, Greensboro, NC, Greenville, NC, Raleigh, NC, Wilmington, NC, Fayetteville, NC, Asheville, NC, and Columbia, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last forty-three years of weather to develop forty-three synthetic load shapes for 2027. Equal probabilities were given to each of the forty-three load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2027.

Figures 2 to 7 below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for DEC, DEP-E, and DEP-W. The y-axis represents the percentage deviation from the average peak. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, and as seen in recent history, extreme cold temperatures can cause load to spike from additional electric strip heating and other heating sources.

[3] The historical load included January 2014 through September 2019.

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The highest summer temperatures typically are only a few degrees above the weather normal peak temperature and therefore do not produce as much peak load variation.

Figure 2. DEC Summer Peak Weather Variability

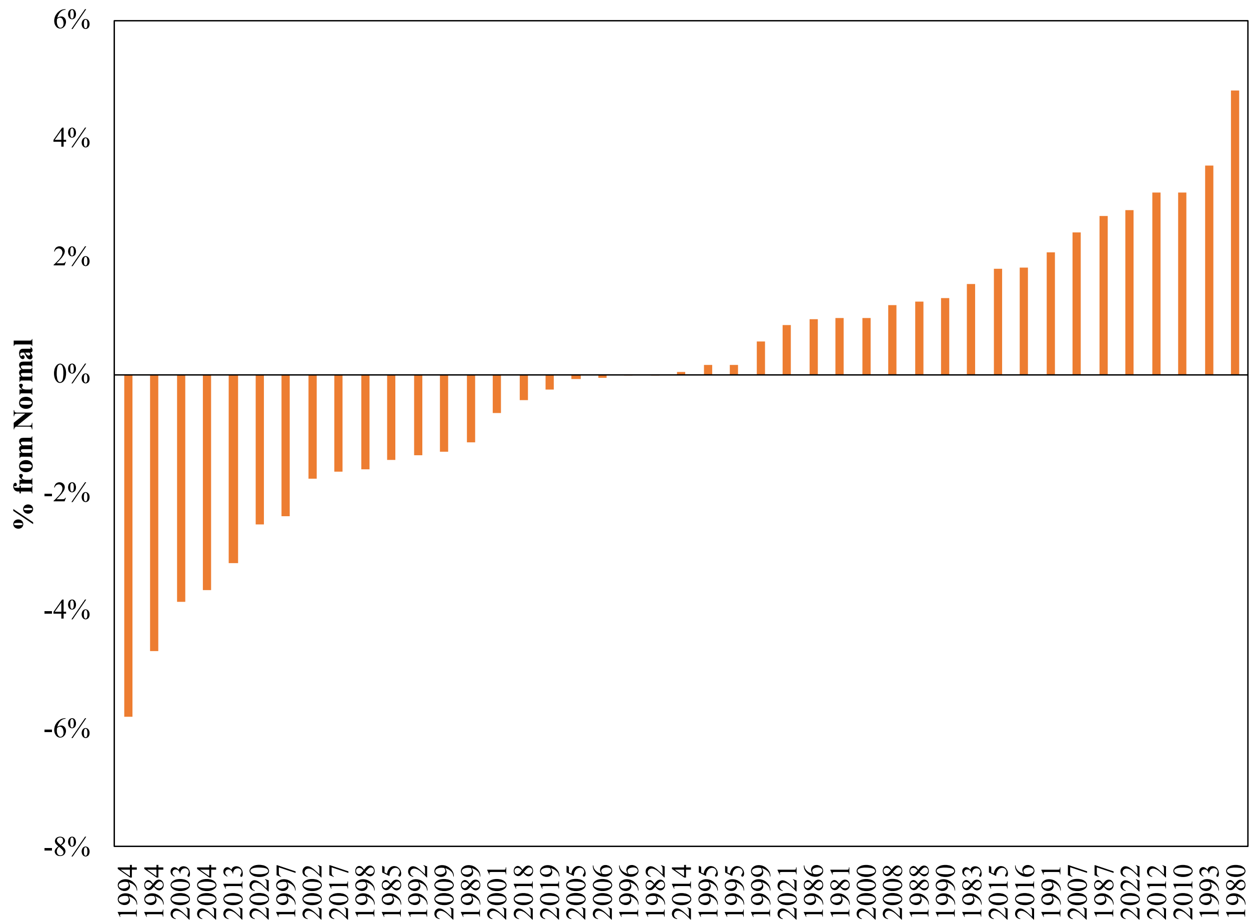

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Figure 3. DEC Winter Peak Weather Variability

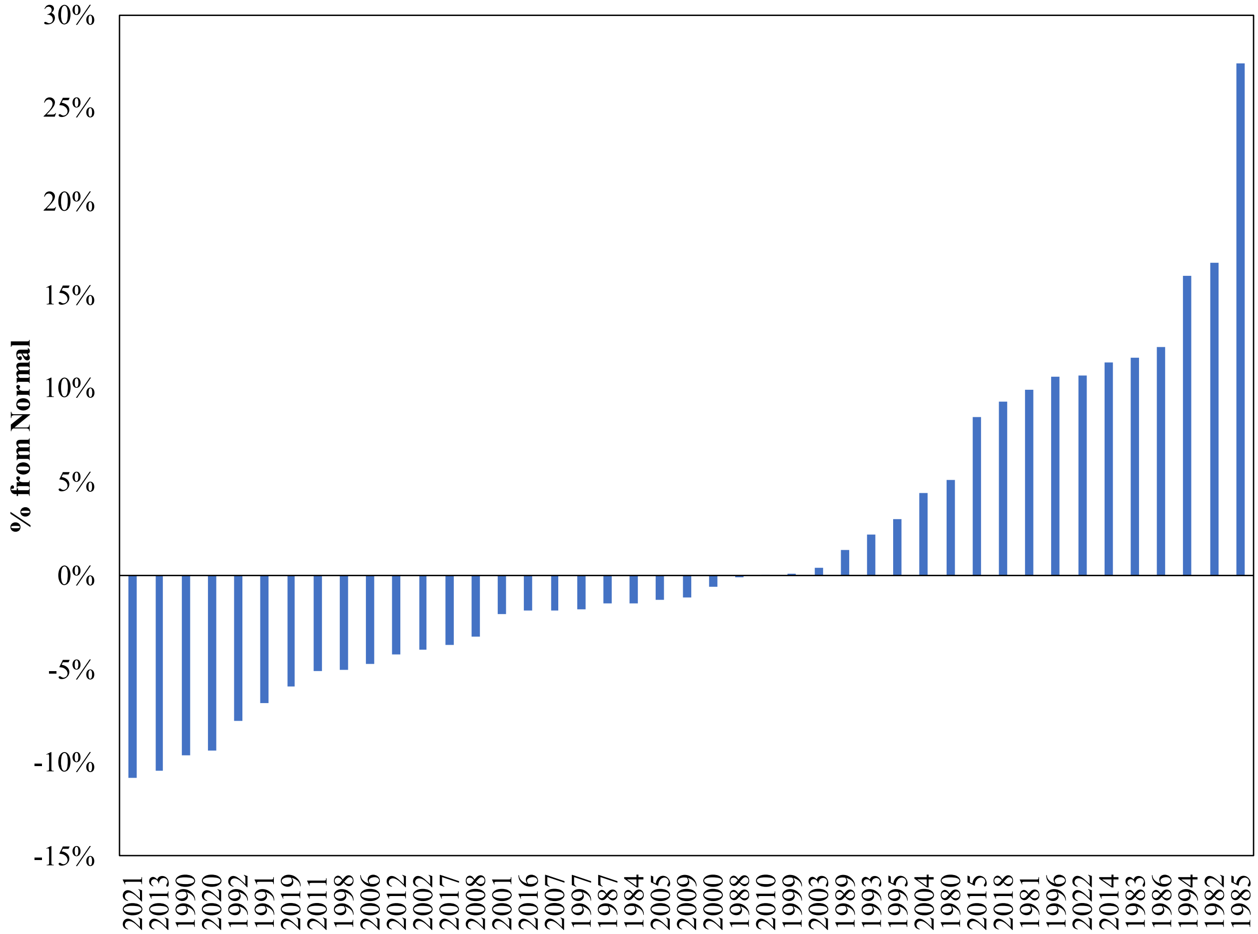

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Figure 4. DEP-E Summer Peak Weather Variability

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Figure 5. DEP-E Winter Peak Weather Variability

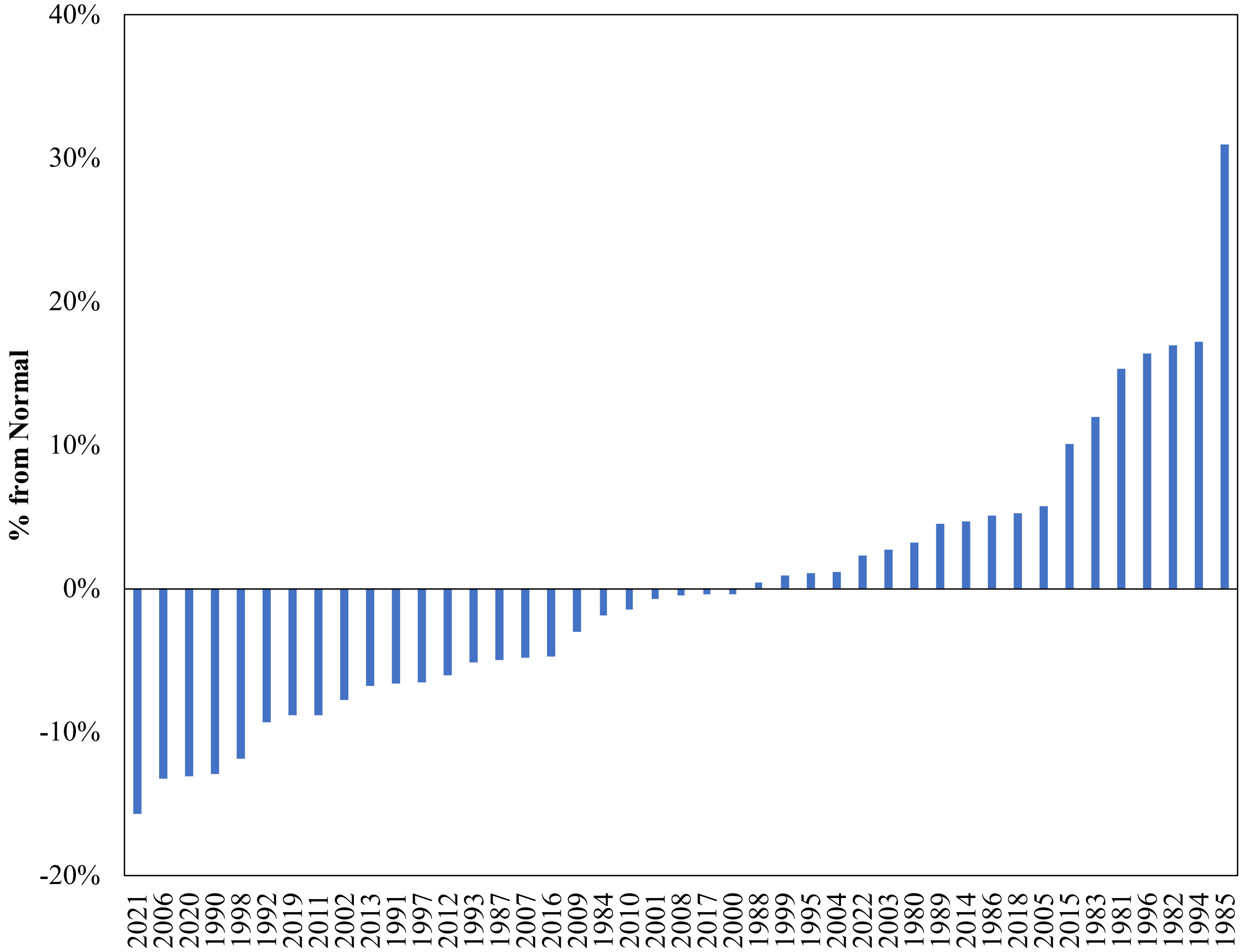

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Figure 6. DEP-W Summer Peak Weather Variability

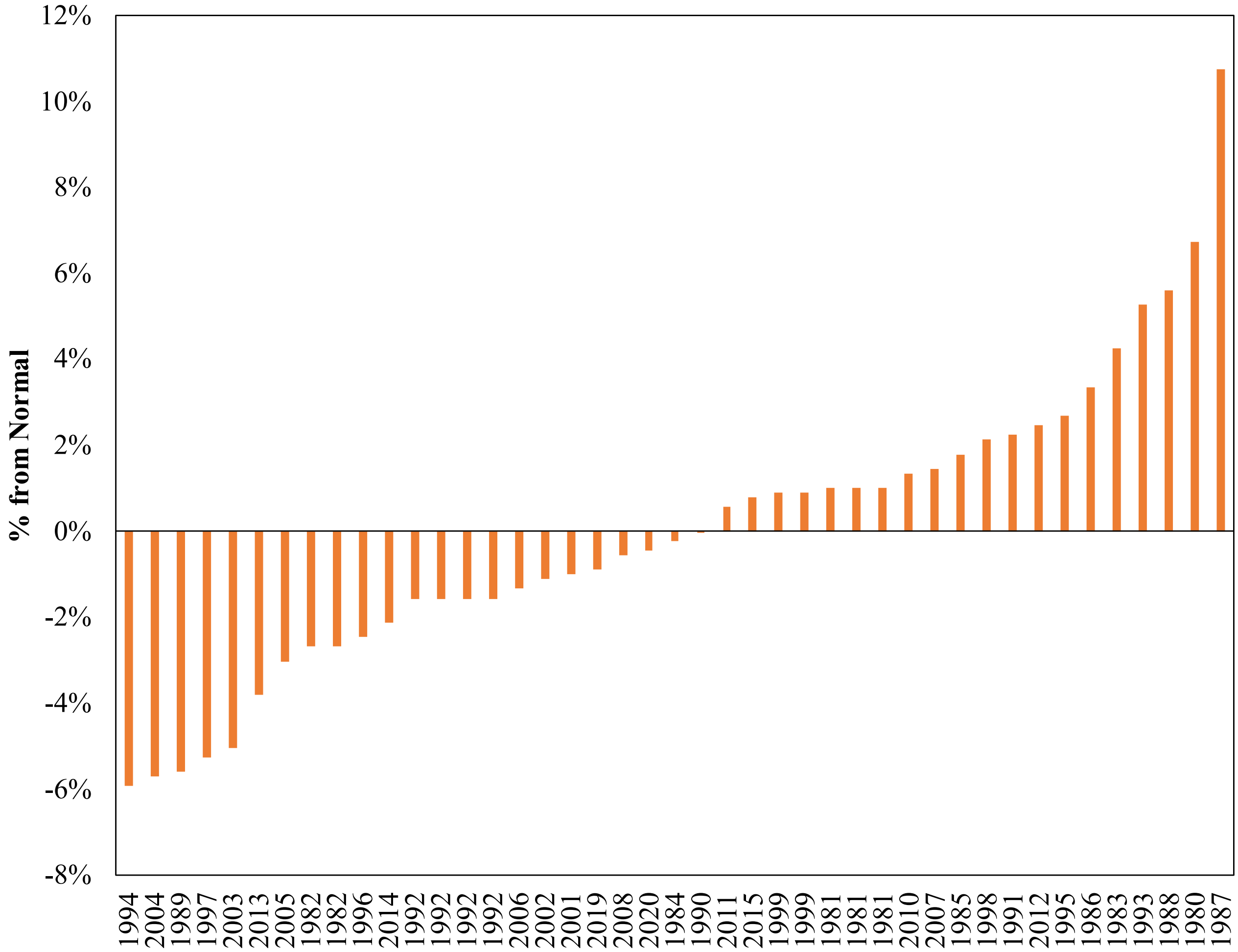

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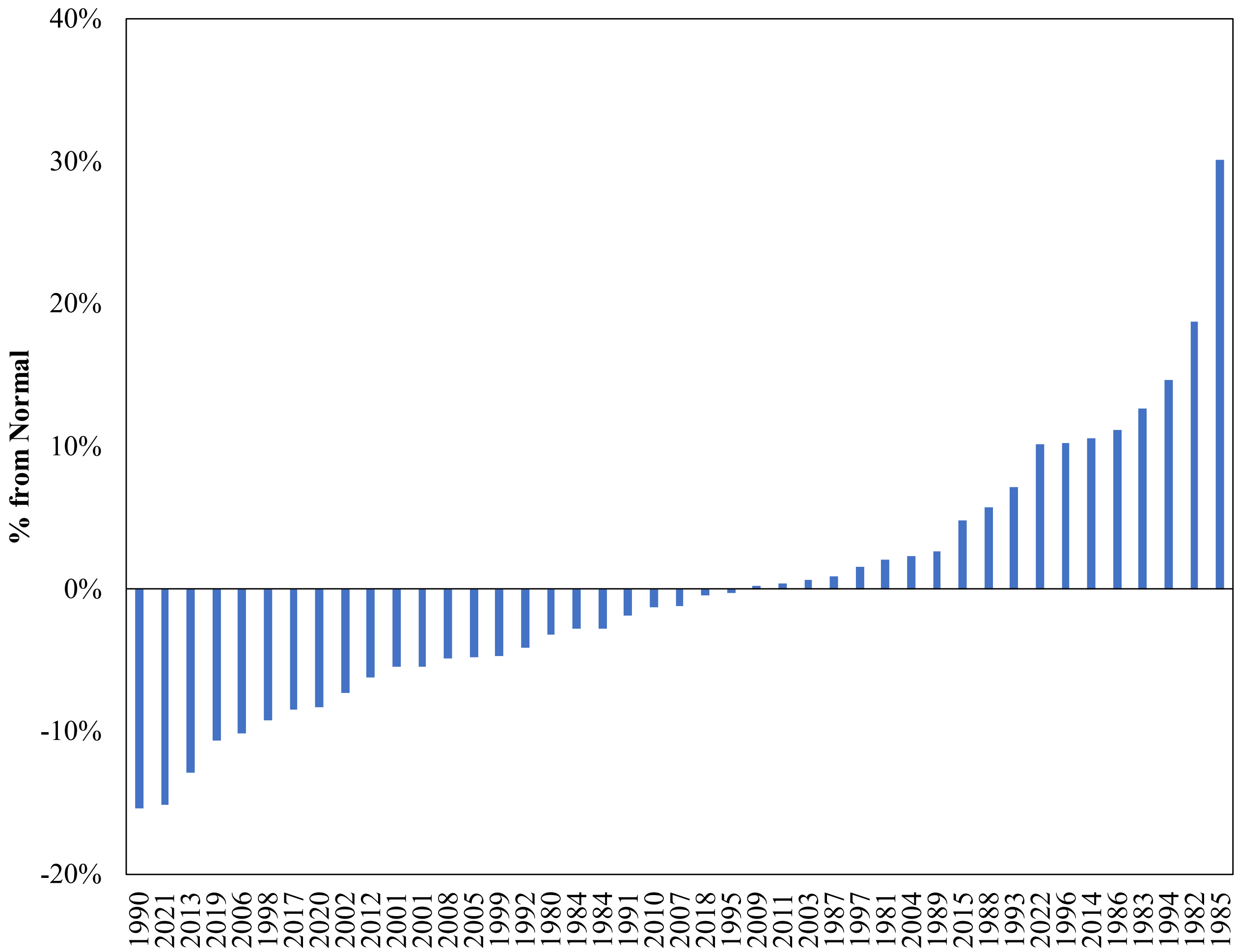
Figure 7. DEP-W Winter Peak Weather Variability



Economic Load Forecast Error

The same economic load forecast error multipliers used in the 2023 Resource Adequacy were used for this Study. Because these assumptions are included in the base case and the change case, they have minimal impact on the results of the Study. The economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their four-year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. The economic load forecast error distribution was developed using Moody's Analytics data. To estimate the economic load forecast error, the forecasts of both state population and

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Gross Domestic Product ("GDP") for different economic scenarios were used to determine the percent change from each economic scenario to the baseline scenario. The Moody's estimated likelihood of these percent changes was then applied, and the percent changes were adjusted by a factor of 0.4 which acknowledges that the load does not grow at a one-to-one ratio with GDP. The final distribution used in the study is provided in Table 2. As an illustration, 27% of the time it is expected that load will be over-forecasted by 2.31% four years out. Within the simulations, when DEC or DEP over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the forty-three weather years and applied each of these 3 load forecast error points to create 129 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability (%)
0.9806	27.0%
1.00	46.0%
1.0231	27.0%

B. Solar Shape Modeling

Table 3 shows the solar capacity levels that were analyzed. The solar penetration scenarios included two solar tranches which represent the expected amount of solar capacity that will be seen over the next 3-5 years, which is consistent with the 2027 study year.

Table 3. Solar Capacity Penetration Levels

	DEC MW	DEP MW	Total MW
Tranche 1	1,873	3,590	5,463
Tranche 2	2,738	4,392	7,130

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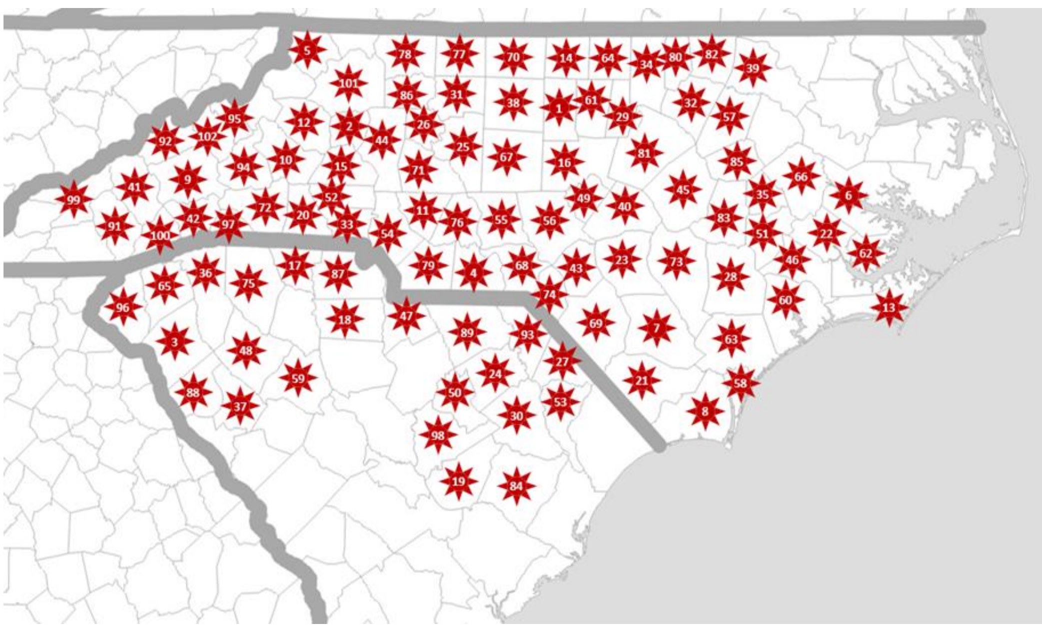
Similar to load shapes, the solar units were simulated with forty-three solar shapes representing forty-three years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. Figure 8 shows the county locations that were used, which represents a wide geographical area across both DEC and DEP balancing areas.

Figure 8. Solar Profile Locations



The differing solar tranches were developed based on the Base Case for the 2023 Resource Adequacy Study, shown in Table 4. In order to decrease up or down capacity from these total levels, the bifacial single axis tracking levels were proportionately adjusted. For DEC Tranche 1, all of the bifacial and a portion of single-axis tracking had to be removed since only 1,873 MW of solar was being modeled for that scenario.

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Table 4. Solar Capacity by Tranche

Unit Type	Inverter Loading Ratio (ILR)	DEC Capacity (MW)	DEP Capacity (MW)
Solar Fixed	1.3	1,142	3,161
Solar Fixed	1.6	121	239
Solar Single-Axis Tracking	1.3	575	179
Solar Single-Axis Tracking	1.6	258	164
Solar Bifacial Single-Axis Tracking	1.4	809	765
Total		2,905	4,507

Figures 9-11 shows Average January profiles for fixed, single-axis tracking, and bifacial solar resources. While the hourly shapes are important, it is the intra hour volatility that is discussed in the next section that drives the SISC.

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Figure 9. Average January Output for Fixed Tilt

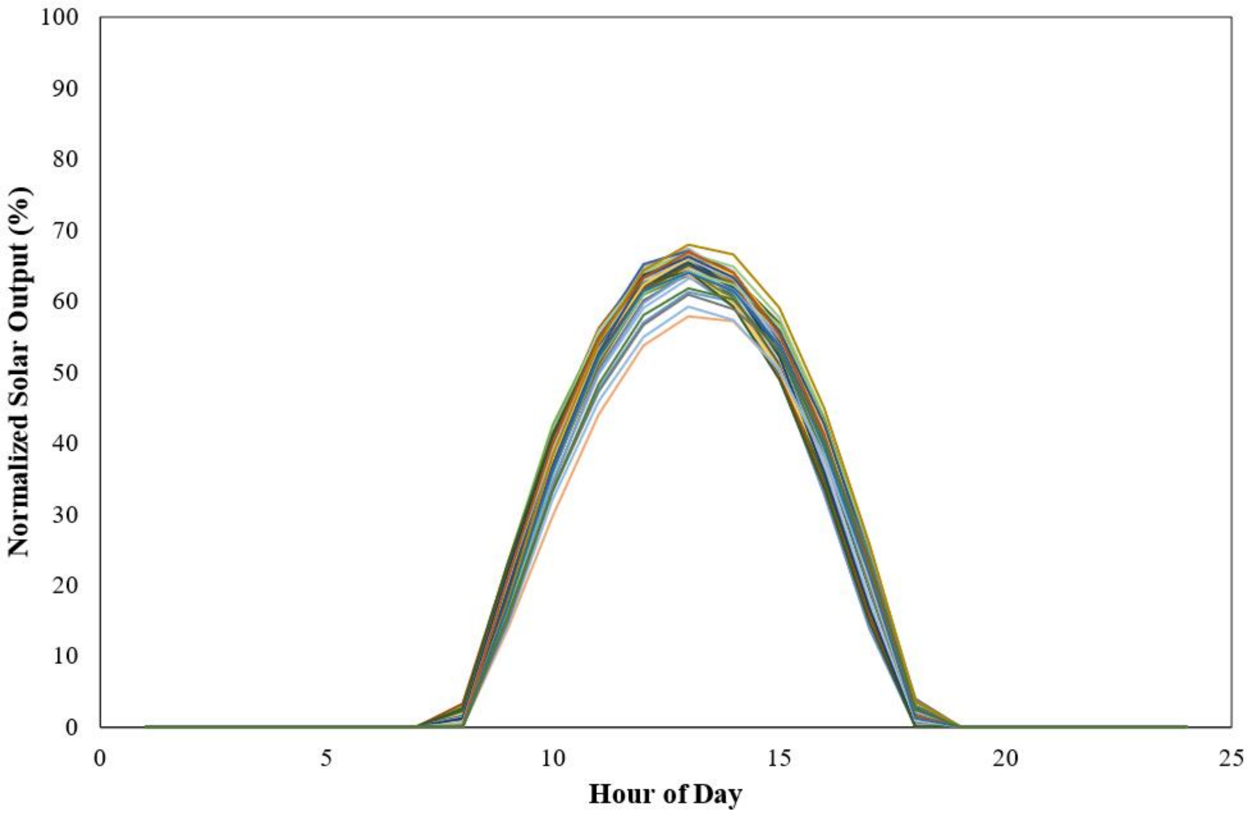

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Figure 10. Average January Output for Monofacial Single-Axis Tracking

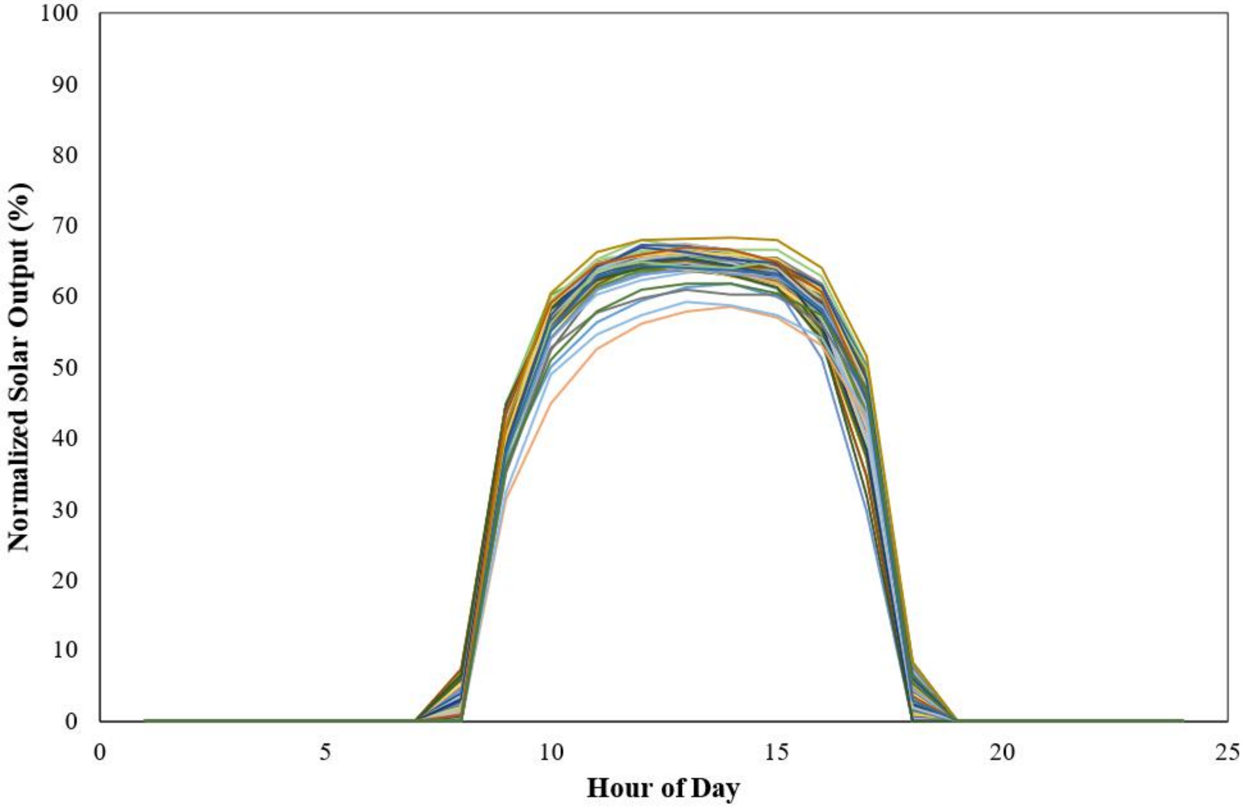

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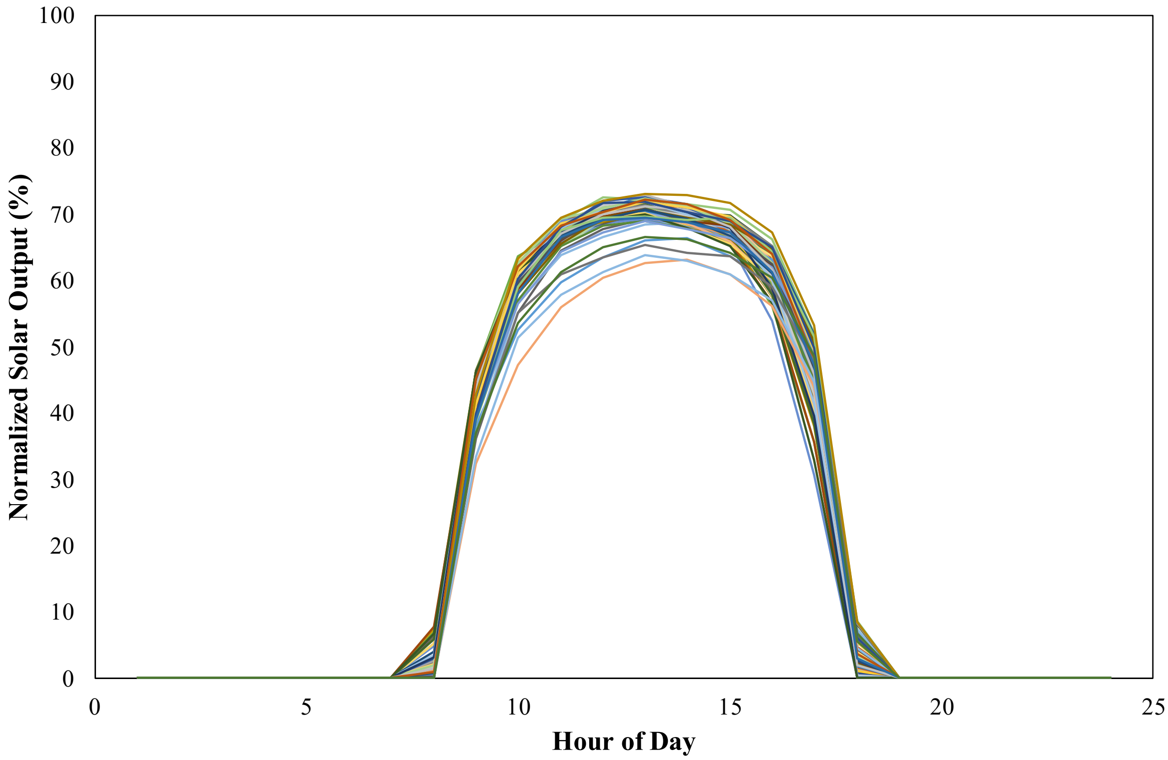
Figure 11. Average January Output for Bifacial Single-Axis Tracking



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C. Load and Solar Volatility

For purposes of understanding the economic and reliability impacts of net load uncertainty, SERVM captures the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used historical five-minute data for load and solar. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history which may include ramping units suddenly or starting quick start units.

Intra-Hour Forecast Error and Volatility

Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 12. The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute-to-minute basis. The solution to resolve the system's inability to meet load on a minute-to-minute basis is to increase operating reserves or add more flexibility to the system, which both result in additional costs.

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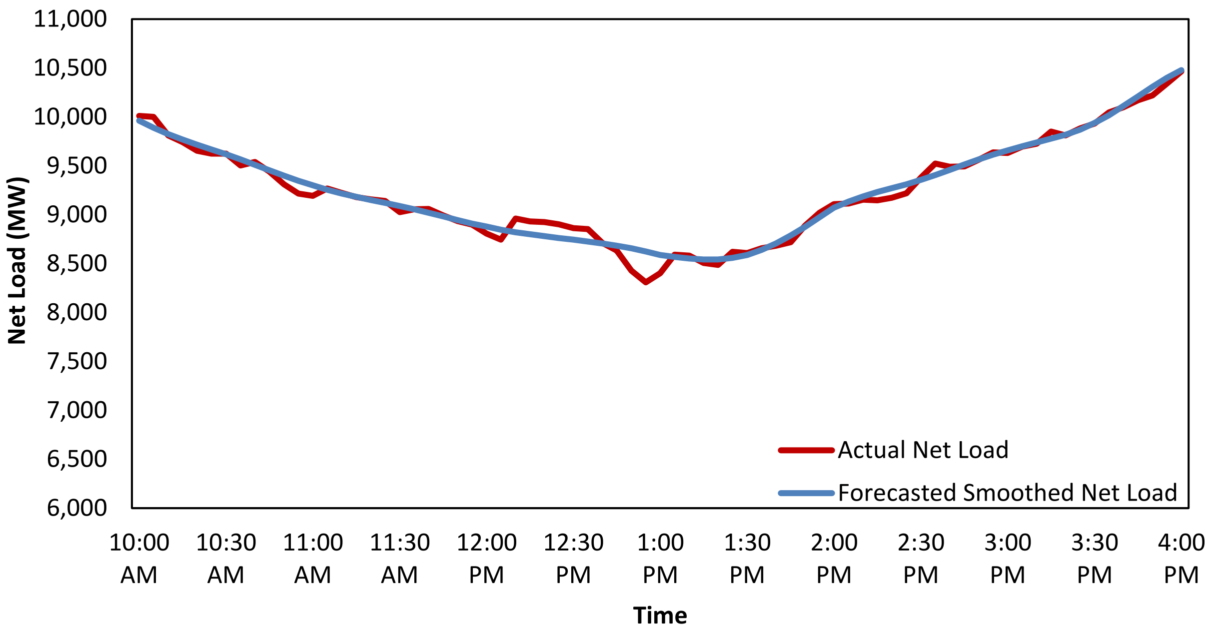
Figure 12. Volatile Net Load vs. Smoothed Net Load



The load volatility is shown in Table 5 below and is based on one year of 5-minute load data from 2022 in DEC and DEP. The 5-minute variability in load is quite low, ranging mostly between +/-1% on a normalized basis. The load volatility is included in the base case and the change cases. With no intermittent resources on the system, this is the net load volatility assumed in the modeling.

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Table 5. Load Volatility

Normalized Divergence (%)	Probability (%)
-2	0.000%
-1.75	0.000%
-1.5	0.003%
-1.25	0.010%
-1	0.138%
-0.75	1.145%
-0.5	8.906%
-0.25	43.174%
0	34.472%
0.25	10.106%
0.5	1.737%
0.75	0.262%
1	0.037%
1.25	0.005%
1.5	0.006%
1.75	0.001%
2	0.000%

The intra hour volatility of solar is higher than intra hour load volatility and is based on historical data from January of 2018 to December of 2022. The 5-minute data was analyzed, and days with anomalies or missing recordings were removed from the dataset. The historical data was aggregated at the DEC level and the DEP level. The historical DEC data represents solar tranches of 528 MW and 947 MW; the historical DEP data represents solar tranches of 1,925 MW, 2,624 MW, and 2,886 MW; and then the Combined historical data represents 3,652 MW. Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, the fact that

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larger units are coming on may dampen the diversity benefit. In line with the 2021 Study and feedback from the TRC, the raw historical data volatility was utilized and then extrapolated based on the diversity benefit trend seen in the historical data. The historical levels outlined above were used to extrapolate the additional levels utilized. The volatility declines with additional solar, and this dataset was trended out to 7,000 MW of solar as shown in Figure 13. The figure measures the 99th percentile of the 5-minute solar deviation as a percentage of nameplate capacity. This measure declines as solar penetration increases.

Figure 13. Declining Volatility as a Function of Solar Capacity

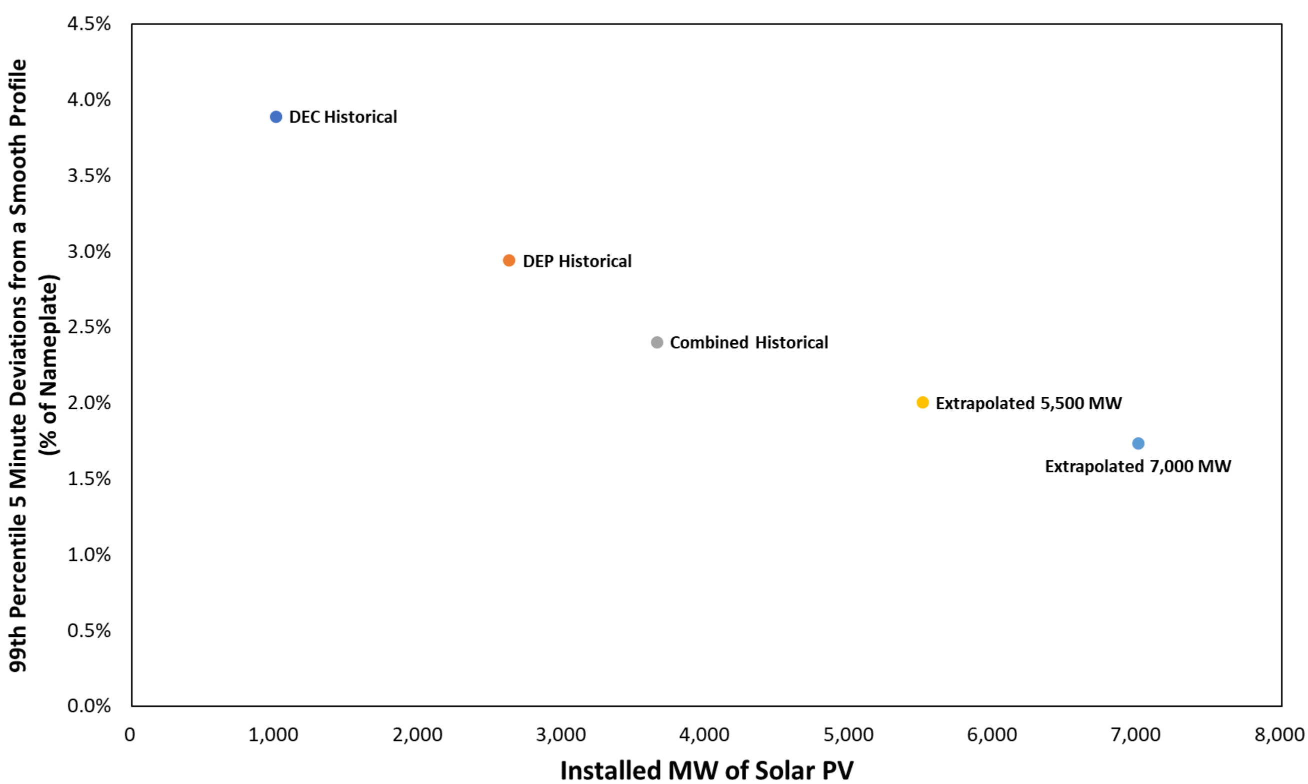

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Table 6 shows the probability at different 5-minute divergence levels across the 5 solar penetrations in the previous Figure. The table shows a steady decline in unitized volatility due to diversity benefits of larger portfolios.

Table 6. Solar Volatility

5 Minute Normalized Divergence	Probability %				
Solar Capacity Level MW	1,000	2,624	3,652	5,500	7,000
-14%	0.0%	0.00%	0.00%	0.00%	0.00%
-13%	0.0%	0.00%	0.00%	0.00%	0.00%
-12%	0.0%	0.00%	0.00%	0.00%	0.00%
-11%	0.0%	0.00%	0.00%	0.00%	0.00%
-10%	0.0%	0.00%	0.00%	0.00%	0.00%
-9%	0.0%	0.00%	0.00%	0.00%	0.00%
-8%	0.1%	0.01%	0.00%	0.00%	0.00%
-7%	0.1%	0.02%	0.00%	0.00%	0.00%
-6%	0.2%	0.07%	0.01%	0.00%	0.00%
-5%	0.5%	0.23%	0.07%	0.02%	0.01%
-4%	1.1%	0.64%	0.36%	0.15%	0.06%
-3%	2.3%	1.68%	1.49%	0.92%	0.56%
-2%	5.0%	4.86%	5.23%	4.47%	3.73%
-1%	17.6%	17.58%	19.84%	21.44%	22.64%
0%	63.6%	67.36%	65.78%	67.44%	68.66%
1%	5.2%	4.94%	5.44%	4.55%	3.76%
2%	2.2%	1.66%	1.38%	0.84%	0.51%
3%	1.0%	0.58%	0.31%	0.15%	0.06%
4%	0.5%	0.24%	0.07%	0.02%	0.01%
5%	0.2%	0.07%	0.02%	0.00%	0.00%
6%	0.1%	0.04%	0.00%	0.00%	0.00%
7%	0.1%	0.01%	0.00%	0.00%	0.00%
8%	0.0%	0.00%	0.00%	0.00%	0.00%
9%	0.0%	0.00%	0.00%	0.00%	0.00%
10%	0.0%	0.00%	0.00%	0.00%	0.00%
11%	0.0%	0.00%	0.00%	0.00%	0.00%
12%	0.0%	0.00%	0.00%	0.00%	0.00%
13%	0.0%	0.00%	0.00%	0.00%	0.00%
14%	0.0%	0.00%	0.00%	0.00%	0.00%

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D. Conventional Thermal Resources

Conventional thermal resources owned by the Companies and purchased as Purchase Power Agreements were modeled consistent with the Companies' portfolio for the 2027 study year. These resources are economically committed and dispatched to load on a 5-minute basis. Similar to the resource adequacy study, the capacities of the units are defined as a function of temperature in the simulations allowing for higher capacities in the winter compared to the summer. SERVM dispatches resources on a 5-minute basis respecting all unit constraints including startup times, ramp rates, minimum up times, minimum down times, and shutdown times. All thermal resources are allowed to serve spinning and load following reserves as long as the minimum capacity level is less than the maximum capacity. Units with automatic generation control (AGC) capability are allowed to serve regulation. Fuel prices were updated based on the Companies' 2023 Carbon Plan and Integrated Resource Plan filing in North Carolina[4] and Integrated Resource Plan filing in South Carolina.[5]

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data and is consistent with the 2023 Resource Adequacy Study. Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical (GADS) data events are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar units. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours

[4] Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas LLC and Duke Energy Progress LLC, Docket No. E-100, Sub 190 (filed Aug. 17, 2023).

[5] Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's 2023 Integrated Resource Plan, Docket Nos. 2023-8-E & 2023-10-E (filed Aug. 15, 2023).

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Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
Estimates based on future scheduled maintenance were utilized in the modeling.

To illustrate the outage logic, assume that from 2018 – 2022, a generator had 12 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically committed for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

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E. Hydro, Pump Storage Modeling, and Battery Modeling

The hydro portfolios in DEC and DEP are modeled as scheduled hydro and are used for shaving the daily net peak load but also includes minimum flow requirements. By modeling the hydro resources in this fashion, the model captures the appropriate amount of capacity dispatched during peak periods and is consistent with the 2023 Resource Adequacy Study.

In addition to conventional hydro, DEC owns and operates a pump hydro fleet consisting of 2,420 MW[6]. The fleet consists of two pump storage plants: (1) Bad Creek at a 1,640 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions. While the pumped-storage units have fast ramping capability, the range from minimum to maximum for generating is fairly low, providing minimal intra hour load following benefit for solar integration. The resources offer single speed pumping which doesn't allow for ramping capability during pumping. The pump storage fleet does assist in hourly energy balances which reduces curtailment significantly for DEC. Table 7 provides the characteristics of the pump-storage fleet.

[6] The Bad Creek station is modeled with a maximum capacity of 1,640 MW (410 MW per unit). Each of the four units can individually run at a maximum rated capacity of 420 MW. However, due to power tunnel limitations, all four units cannot run at their maximum rated capacity simultaneously. Therefore, if all four units were called to operate at maximum possible generation, they would be de-rated by 10 MW each with the highest possible station output at 1,640 MW.

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Table 7. Pump Storage Resources

DEC Pump Storage Unit	Gen Capacity (MW)	Gen Capacity Min (MW)	Pumping Capacity (MW)	Pumping Min Capacity (MW)	Pond Capacity (MWh)	Ramp Rate (MW/min)
Bad Creek_1	420	320	375	375	8,798	40
Bad Creek_2	420	320	375	375	8,798	40
Bad Creek_3	420	320	375	375	8,798	40
Bad Creek_4	420	320	375	375	8,798	40
Jocassee_1	195	185	205	205	3,803	40
Jocassee_2	195	185	205	205	3,803	40
Jocassee_3	195	185	205	205	3,803	40
Jocassee_4	195	185	205	205	3,803	40

The SISC Study also modeled 370 MW of standalone battery capacity in DEC and 333 MW in DEP. The batteries are allowed to be used for economic arbitrage and serve ancillary services to avoid flexibility excursions based on their state of charge and output capability. There were no constraints modeled on battery flexibility or number of cycles.

F. Southeastern Energy Exchange Market (SEEM)

In order to capture the benefits of SEEM, Astrapé analyzed historical transactions from November 2022 through September of 2023. Based on the historical data, the SISC Study included additional capacity of 100 MW in DEC and 100 MW in DEP that the Companies could dispatch within 15 minutes. The 100 MWs was split into four 25 MW units in both DEC and DEP meaning the system had access to 25 MW or up to 100 MW of energy blocks. Based on historical transaction pricing, Table 8 shows the costs assigned to these blocks of capacity ranged from $31/MWh to $58/MWh.

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Table 8. SEEM Resources

MW Size	DEP Price ($/MWh)	DEC Price ($/MWh)
25	38	31
25	45	44
25	50	51
25	56	58

G. Demand Response Modeling

Demand Response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints consistent with the 2023 Resource Adequacy Study. For 2027, DEC assumed 1,386 MW of Demand Response in the summer and 822 MW in the winter. DEP assumed 906 MW of summer Demand Response capacity and 434 MW of Demand Response winter capacity.

H. Study Topology

As discussed previously, the Companies were modeled as islands for this analysis because each balancing area is responsible for its own NERC requirements. By modeling in this manner, the required operating reserves and flexibility requirements are calculated for each of the Companies. Similar to the 2021 Study as recommended by the TRC, the analysis was performed assuming the Joint Dispatch Agreement (JDA) between DEC and DEP was utilized. In this scenario, each BA still holds its own operating reserves, but economic exchanges are allowed to reduce the costs of the additional load following requirements. The results sections show the results as an island and a combined DEC and DEP case.

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I. Ancillary Services

Ancillary service targets are input into SERVM. SERVM commits resources to meet energy needs plus ancillary service requirements. These ancillary services are needed for uncertain movement in net load or sudden loss of generators during the simulations. Within SERVM, these include regulation up and down, spinning reserves, load following reserves, and quick start reserves. Table 9 shows the definition of ancillary service for each study. Spinning reserves and load following up reserves are identical and represent the sum of the 10-minute ramping capability of each unit on the system. To maintain operational flexibility as solar resources are added, the load following up reserves are increased until the flexibility excursions seen in the "no solar" case are met. The load following up reserves represent an increase in ramping capability of the fleet meaning that more resources are turned on so that they can be operated further away from their maximum capacity level allowing for more ramping capability.

Table 9. Ancillary Services

Ancillary Service	Definition
Regulation Down Requirement	10 Minute Product served by units with AGC capability
Regulation Up Requirement	10 Minute Product served by units with AGC capability
Spinning Reserves Requirement	10 Min Product served by units who have minimum load less than maximum load
Load Following Down Reserves	10 Min Product served by units who have minimum load less than maximum load
Load Following Up Reserves	10 Min Product served by units who have minimum load less than maximum load
Quick Start Reserves Requirement	Served by units who are offline and have quick start capability

To ensure the operating reserves were at reasonable levels for the "no solar" case, Astrapé compared the realized 60-minute ramping capability in the model to historical dispatch data during the 2015-2018 time period when there were lower solar levels on the system. This comparison is shown in Figure 14. While this comparison would never be expected to be exact due to differences in weather, loads, resource mix, fuel prices, and generator performance among other things it does show that the modeled levels are

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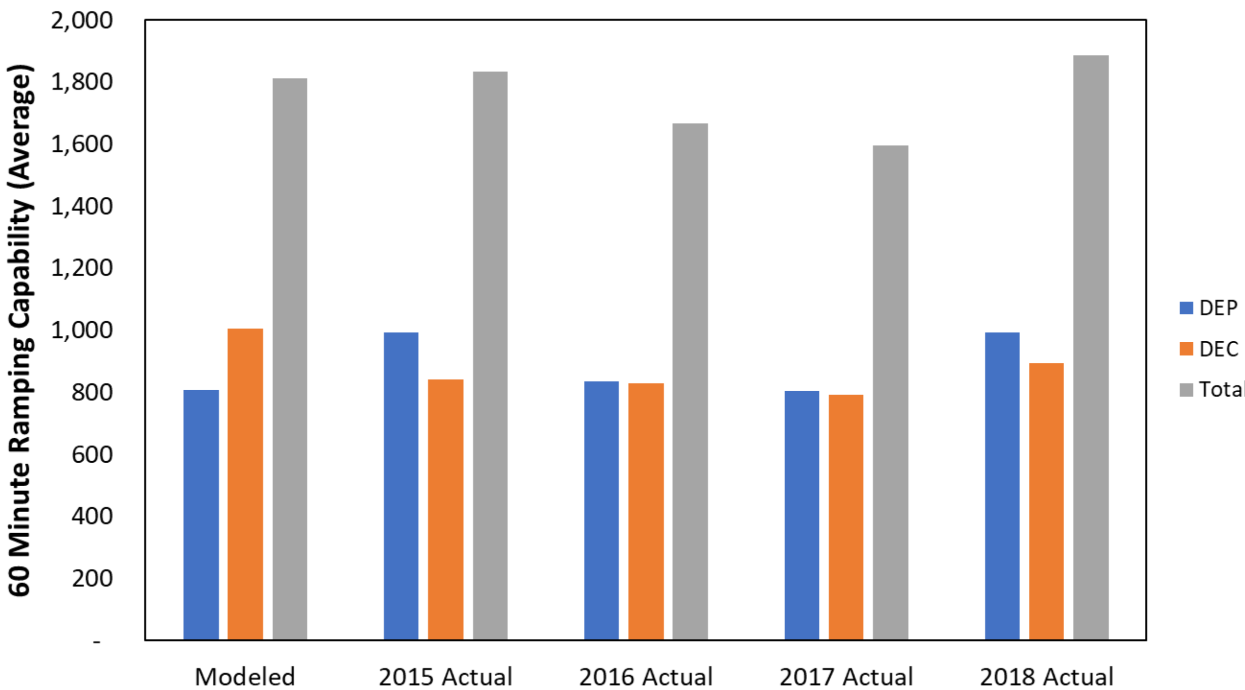
not unreasonable as a starting point to determine flexibility excursions in the no solar scenario. In the modeled scenario, battery capacity which did not exist in the historical data likely increases operating reserves in off peak periods as a battery provides operating reserves even if it is not charging or discharging. Non spinning reserves are available in all cases and SERVM uses those to mitigate flexibility excursions.

Figure 14. No Solar 60 Minute Ramping Capability Comparison



J. Flexibility Excursion

A flexibility excursion is calculated by the model as any day where resources could not meet load but there was additional installed capacity on the system. These flexibility excursions are not expected to represent firm load shed events, but rather are simply a measure of the fleet's ability to follow net load changes given a particular set of operating guidelines. This is distinguished from a firm load shed event which is due to insufficient resources when operators are required to begin rolling blackouts.

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III. Simulation Methodology

Since these flexibility excursions are low probability events, a large number of scenarios must be considered to accurately project these events. For this Study, SERVM utilized 43 years of historical weather and load shapes, 3 points of economic load growth forecast error, and 10 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 43 weather years * 5 load forecast errors * 10 unit outage iterations = 2,150 total iterations for each level of solar penetration simulated. Weather years and solar profiles were each given equal probability while the load forecast error multipliers were given their associated probabilities as reported in the input section of the report. This set of cases was simulated for each of the solar penetration levels in Table 10.

Table 10. Solar Penetration Levels

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW	Total Cumulative MW
No Solar	0	0	0	0	0
Tranche 1	1,873	1,873	3,590	3,590	5,463
Tranche 2	865	2,738	802	4,392	7,130

For each case, and ultimately each iteration, SERVM commits and dispatches resources to meet load and ancillary service requirements on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around net load is gained. Ultimately, SERVM forces the system to react to these uncertainties while

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maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, flexibility excursions and total costs are calculated where:

Total Costs = Fuel Costs + O&M Costs + Startup Costs

These flexibility excursions and cost components are calculated for each of the 2,150 iterations and weighted based on probability to calculate an expected total cost for each study simulated. As the systems are simulated from 0 MW of solar to several thousand MWs of solar, the net load volatility increases causing flexibility excursions to increase. In order to reduce these events down to the level that was seen in the no solar case, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities. Renewable curtailment is also captured in the model, and it is noted that curtailment is used as load following in the model. The model also uses quick start resources in all scenarios modeled.

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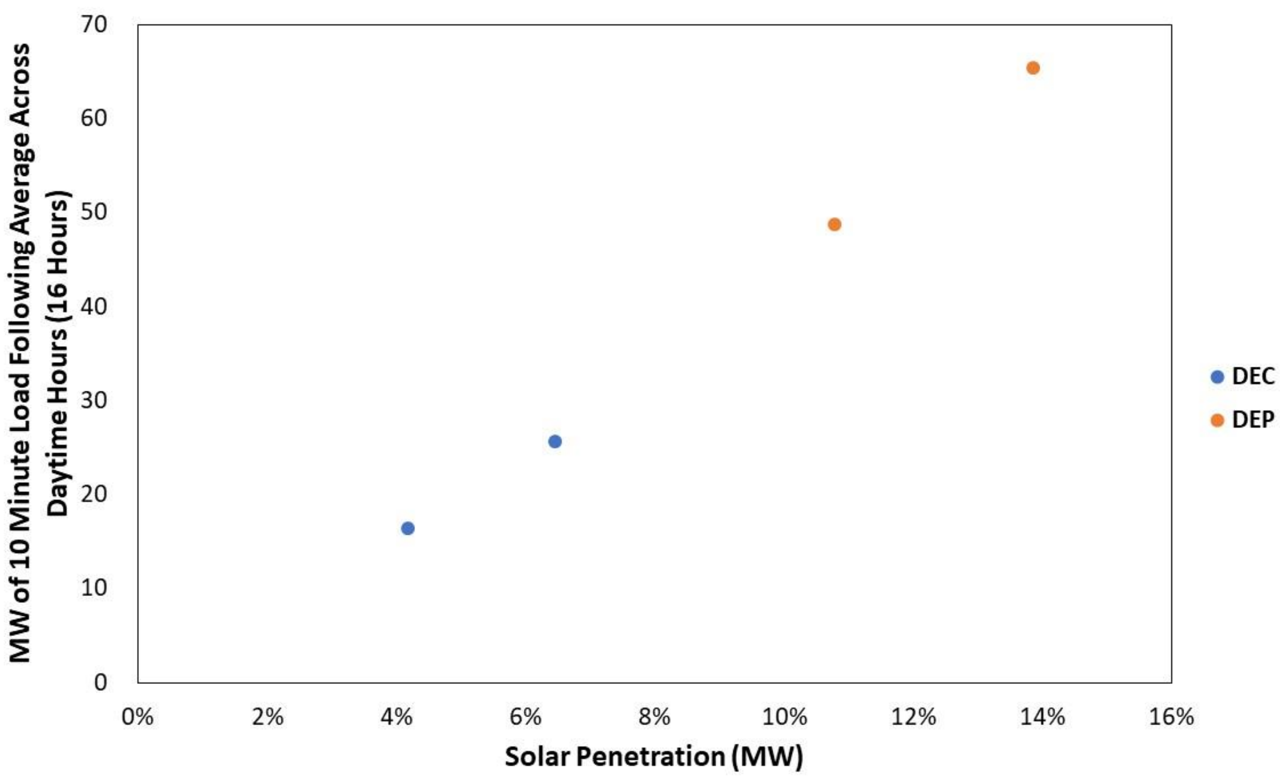
IV. Load Following Requirements

The Study added load following across the day to manage the solar ramps and volatility and targeted additions based on when the flexibility excursions were occurring. Figure 15 shows the quantified required increase in operating reserves for Tranche 1 and 2 for both DEC and DEP as a percentage of solar penetration. The additions are correlated to solar penetration as additional solar increases the load following reserves requirement.

Figure 15. Quantified Required Increase in Operating Reserves as a Function of Solar Penetration



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Figures 16-18 show heat maps of the flexibility excursions on a 12x24 basis for the DEC no solar case, DEC Tranche 1, and DEC Tranche 2 cases. In the no solar case, any flexibility excursions are during high load periods when operating reserves have a tendency to be lower.

Figure 16. DEC No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
2	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	7.1%	0.2%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
8	5.4%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.2%	0.2%
9	6.5%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.2%
10	5.9%	0.8%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.2%
11	2.1%	0.8%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.7%
12	3.9%	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
13	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	1.8%	4.6%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.1%	0.0%	0.7%	1.3%	2.3%	0.5%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.3%	0.1%	1.1%	1.6%	0.7%	0.1%	0.1%	0.1%	0.0%
18	0.1%	0.1%	0.0%	0.0%	0.3%	0.3%	3.6%	2.5%	1.0%	0.1%	0.0%	0.0%
19	0.1%	0.2%	0.4%	0.1%	0.2%	2.9%	0.6%	1.4%	0.1%	0.1%	0.2%	0.1%
20	0.4%	0.4%	0.3%	0.1%	0.1%	0.9%	3.0%	1.6%	0.2%	0.6%	0.6%	0.3%
21	0.2%	0.6%	0.1%	0.4%	1.5%	0.5%	0.7%	1.0%	0.6%	0.7%	0.2%	0.4%
22	0.3%	0.2%	0.3%	0.4%	0.5%	0.4%	0.6%	0.6%	0.3%	0.4%	0.3%	0.2%
23	0.1%	0.1%	0.2%	0.2%	0.3%	0.4%	0.5%	0.3%	0.2%	0.0%	0.2%	0.1%
24	0.0%	0.0%	0.1%	0.1%	0.4%	0.3%	0.4%	0.4%	0.7%	1.6%	0.1%	0.0%

As solar is added, the flexibility excursions move towards later in the afternoon or during solar ramp up periods as shown in Figures 17 and 18.

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Figure 17. DEC Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
2	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
5	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.4%	1.7%	0.2%	0.7%	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.2%	0.1%
7	0.6%	1.1%	1.2%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.7%	0.5%	2.1%
8	5.8%	0.2%	0.6%	1.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.5%	0.4%	0.3%
9	4.8%	0.9%	1.2%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.4%	1.0%	2.5%
10	4.0%	1.6%	1.2%	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.7%	1.7%
11	1.8%	1.1%	0.6%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.4%	0.8%
12	0.4%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	1.4%	0.0%	0.6%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.3%	0.3%	0.2%	2.2%	0.0%	0.1%
17	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.3%	0.6%	0.3%	4.7%	0.2%	0.2%
18	0.3%	0.5%	0.3%	1.1%	0.7%	0.3%	0.2%	0.3%	0.5%	4.2%	0.4%	0.0%
19	0.3%	0.3%	1.1%	2.7%	0.8%	0.4%	0.2%	0.3%	0.2%	2.1%	0.3%	0.3%
20	0.6%	0.6%	0.3%	0.1%	0.2%	0.1%	0.6%	0.1%	0.3%	2.1%	0.2%	0.3%
21	0.3%	0.4%	0.3%	0.2%	0.2%	0.1%	0.7%	0.2%	0.3%	2.4%	0.2%	0.4%
22	0.2%	0.2%	0.2%	0.3%	0.3%	1.3%	0.8%	0.5%	0.4%	0.5%	0.3%	0.3%
23	0.3%	0.1%	0.2%	0.4%	0.4%	0.2%	0.3%	0.3%	0.2%	0.2%	0.2%	0.1%
24	0.3%	0.0%	0.0%	0.1%	0.1%	0.4%	0.3%	0.3%	0.2%	0.0%	0.0%	0.1%

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Figure 18. DEC Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
2	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.6%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.5%	0.0%	0.4%	0.4%	1.4%	0.0%	0.0%	0.1%	0.7%	0.8%	0.0%	0.1%
7	4.1%	0.5%	0.9%	1.0%	0.3%	0.0%	0.0%	0.0%	0.1%	0.5%	0.5%	0.9%
8	1.6%	0.7%	1.2%	0.6%	0.3%	0.0%	0.0%	0.0%	0.1%	0.9%	0.7%	0.3%
9	2.3%	1.6%	1.4%	0.7%	0.3%	0.0%	0.0%	0.0%	0.0%	1.1%	1.8%	1.7%
10	2.1%	1.4%	1.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.3%	1.0%	2.8%
11	0.5%	0.8%	0.5%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.3%	0.5%
12	0.4%	0.2%	0.2%	0.1%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
13	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%
17	0.1%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.3%	0.2%	0.4%	0.1%	0.1%
18	0.2%	1.4%	0.3%	2.1%	1.6%	0.4%	0.6%	0.7%	2.4%	5.2%	2.1%	0.3%
19	0.3%	0.1%	2.0%	8.2%	2.9%	1.7%	1.1%	1.8%	1.8%	0.1%	0.1%	0.2%
20	0.3%	0.2%	0.2%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.1%	0.1%	0.3%
21	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.3%	0.1%	0.2%
22	0.5%	0.1%	0.1%	0.3%	0.6%	0.4%	1.7%	0.6%	0.3%	0.3%	0.2%	0.2%
23	0.3%	0.1%	0.2%	0.2%	0.5%	0.2%	0.2%	0.3%	0.2%	0.2%	0.2%	0.1%
24	0.4%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%

Figures 19-20 show the load following targets input into the model to lower the amount of flexibility excursions until they are at the same level as the no solar case. While these are the targets for the commitment, the realized incremental reserves are output as reported previously in Figure 15. Because the modeling can take advantage of periods where there are excess reserves due to commitment constraints on resources, the realized additional load following will always be less than the change in targets. In other words, there are periods where the target was increased but the system is already providing ample reserves on some of those days, so the incremental realized reserves reported in the results are less than these target input changes. These targets were adjusted upward in an iterative process by analyzing when the flexibility excursions were occurring and were increased until the number of events approached the number of events in the no solar case.

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Figure 19. DEC Tranche 1: Final Incremental Load Following Targets (MW)

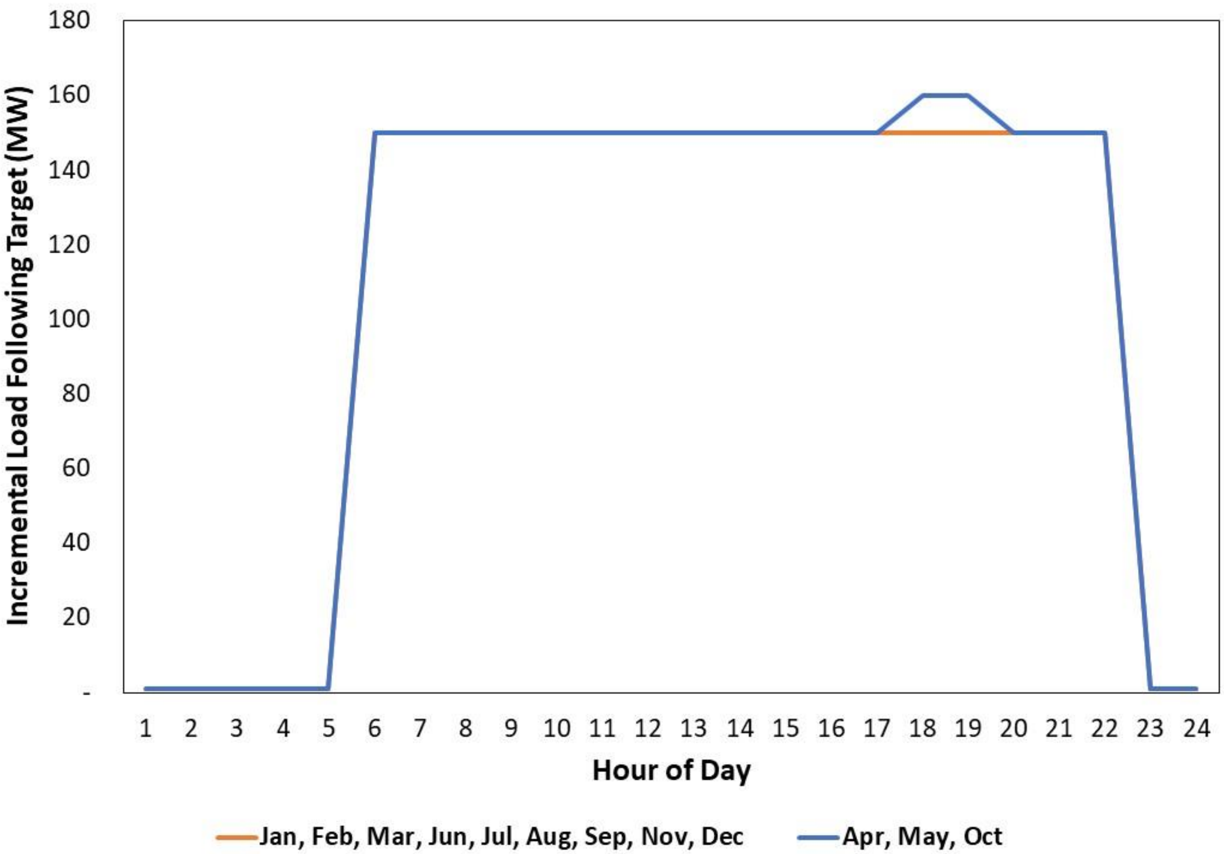

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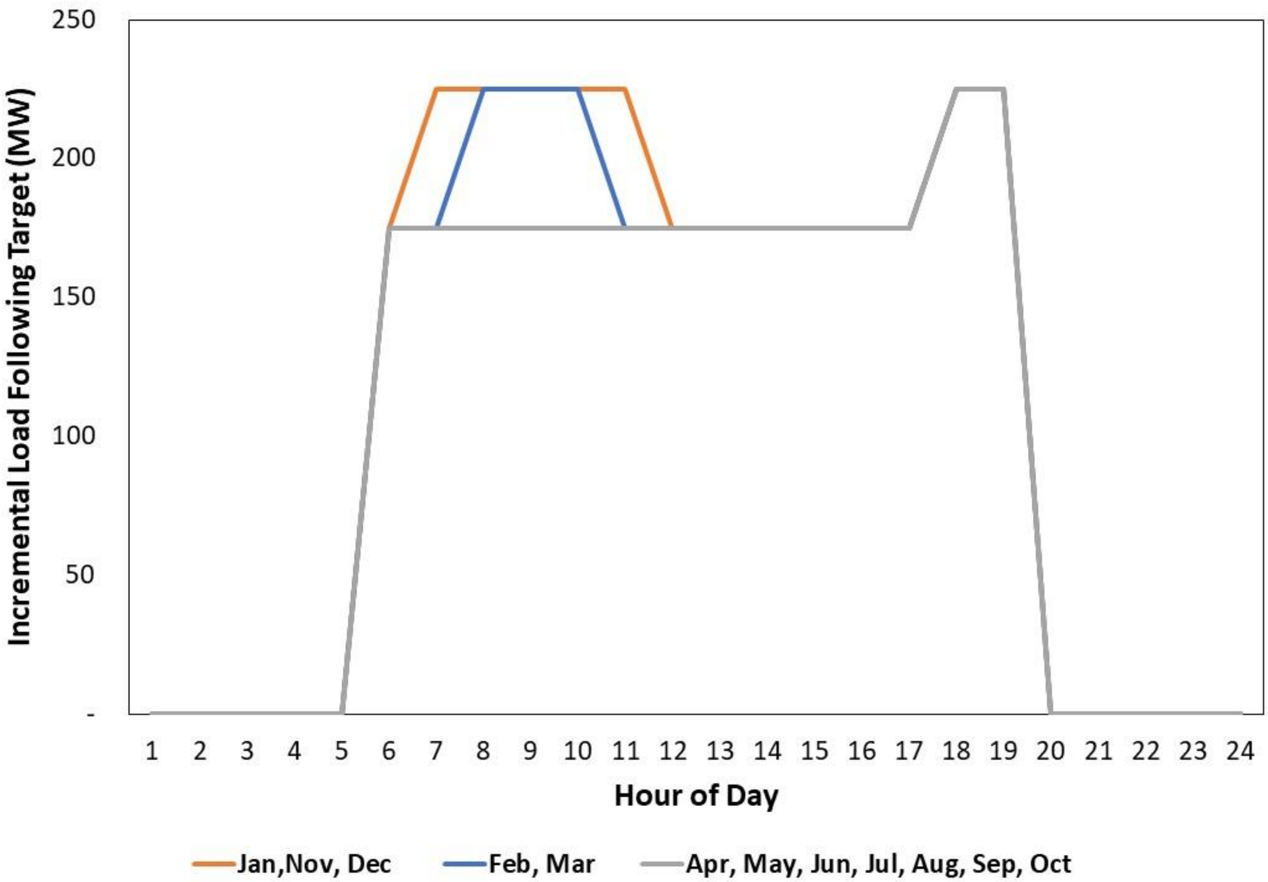
Figure 20. DEC Tranche 2: Final Incremental Load Following Targets (MW)



The same figures are shown for DEP in Figures 21-25 below.

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Figure 21. DEP No Solar Case: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
5	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.6%
6	0.5%	0.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.3%
7	0.6%	1.0%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%
8	1.1%	0.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%
9	2.0%	0.1%	0.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
10	0.9%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
11	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.1%	0.0%	0.0%	0.1%	0.0%	0.3%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%
14	0.2%	0.0%	0.0%	0.2%	0.0%	0.2%	3.0%	1.1%	0.1%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	1.1%	0.1%	0.3%	6.4%	1.4%	0.1%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	1.7%	0.2%	1.1%	11.0%	0.9%	0.1%	0.1%	0.0%	0.0%
17	0.0%	0.0%	0.0%	1.3%	0.2%	2.0%	12.1%	2.6%	0.1%	0.0%	0.0%	0.1%
18	0.0%	0.0%	0.0%	0.7%	0.2%	1.4%	9.7%	2.1%	0.1%	0.0%	0.1%	0.1%
19	0.5%	0.4%	0.2%	0.1%	0.0%	0.9%	4.3%	0.1%	0.0%	0.1%	0.1%	1.6%
20	0.4%	0.4%	0.2%	0.0%	0.0%	0.6%	0.4%	0.0%	0.0%	0.0%	0.2%	1.7%
21	0.1%	0.2%	0.1%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%
22	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.8%
23	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

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Figure 22. DEP Tranche 1 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.3%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
6	2.1%	0.4%	0.3%	0.6%	1.5%	0.1%	0.1%	0.0%	0.1%	0.3%	0.1%	0.5%
7	2.8%	0.7%	0.5%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%	0.3%	1.4%
8	2.6%	0.0%	0.1%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	1.6%
9	0.1%	0.2%	0.0%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%	0.1%	0.1%	0.4%
10	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%
11	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%	0.2%	0.0%	0.0%	0.1%
17	0.0%	0.0%	0.0%	0.1%	0.2%	0.6%	0.5%	0.8%	0.9%	0.8%	0.6%	0.1%
18	0.0%	0.5%	0.4%	1.2%	2.9%	1.8%	2.0%	3.4%	11.7%	3.4%	0.0%	0.0%
19	0.1%	0.1%	0.1%	4.6%	12.6%	11.6%	10.1%	4.3%	0.2%	0.0%	0.1%	0.4%
20	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

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Figure 23. DEP Tranche 2 Solar: Month by Hour of Day Heat Map of Flexibility Excursions as a Percentage of the Total MWh Excursions Before Load Following Is Added

	1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
4	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.2%	0.0%	0.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%
6	0.5%	1.3%	0.2%	1.4%	2.3%	0.1%	0.2%	0.0%	0.2%	0.3%	0.2%	1.1%
7	1.2%	2.8%	0.4%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.7%	0.4%	2.1%
8	1.7%	0.9%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%
9	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%
10	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.2%
11	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
17	0.1%	0.0%	0.0%	0.1%	0.2%	0.2%	0.3%	0.3%	0.7%	0.5%	0.3%	0.1%
18	0.0%	0.2%	0.1%	1.7%	2.7%	1.1%	1.2%	2.2%	8.8%	5.3%	0.0%	0.0%
19	0.1%	0.1%	0.0%	7.4%	11.3%	9.2%	9.8%	6.0%	0.5%	0.0%	0.0%	0.2%
20	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.2%
21	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

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Figure 24. DEP Tranche 1: Final Incremental Load Following Targets

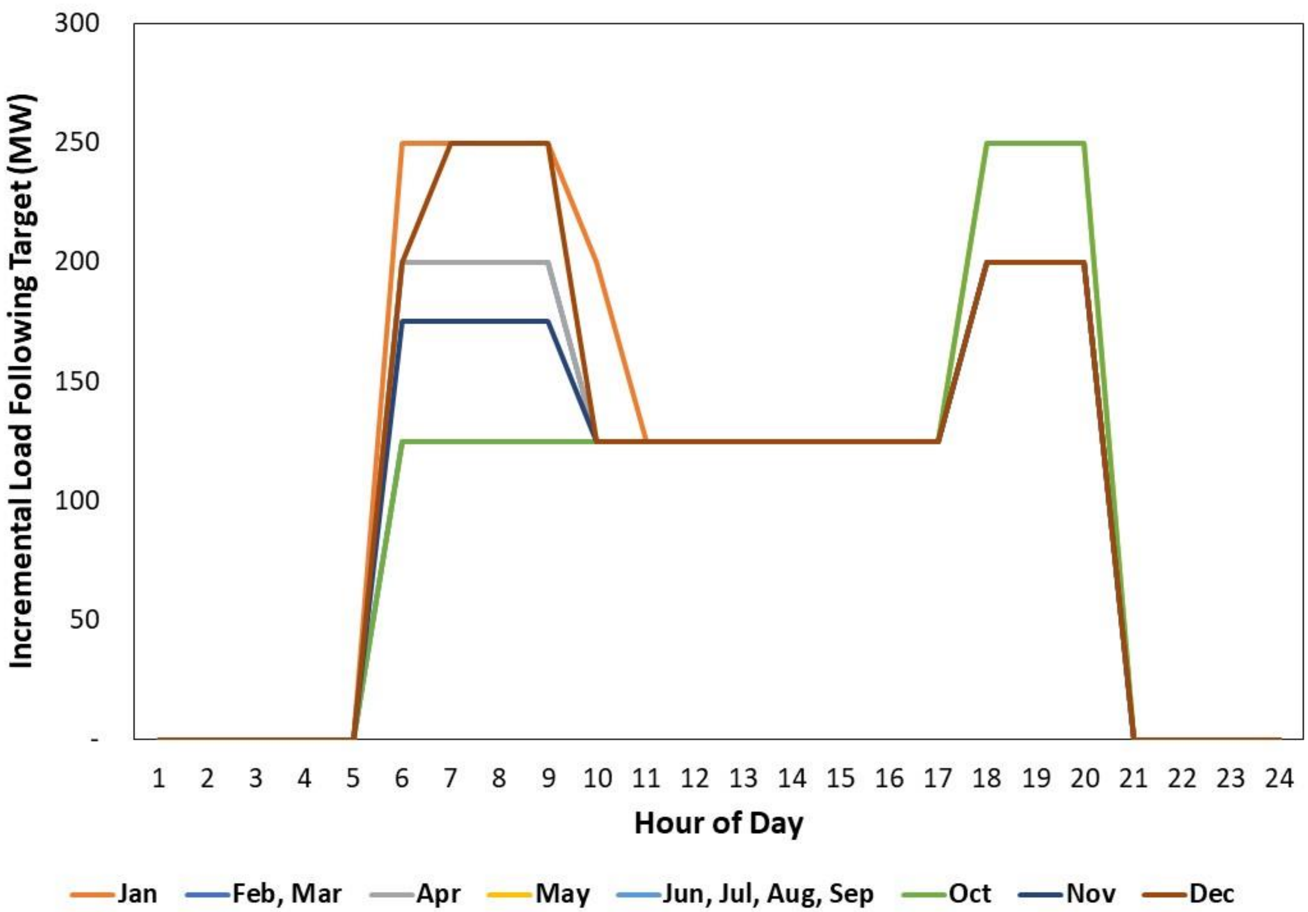

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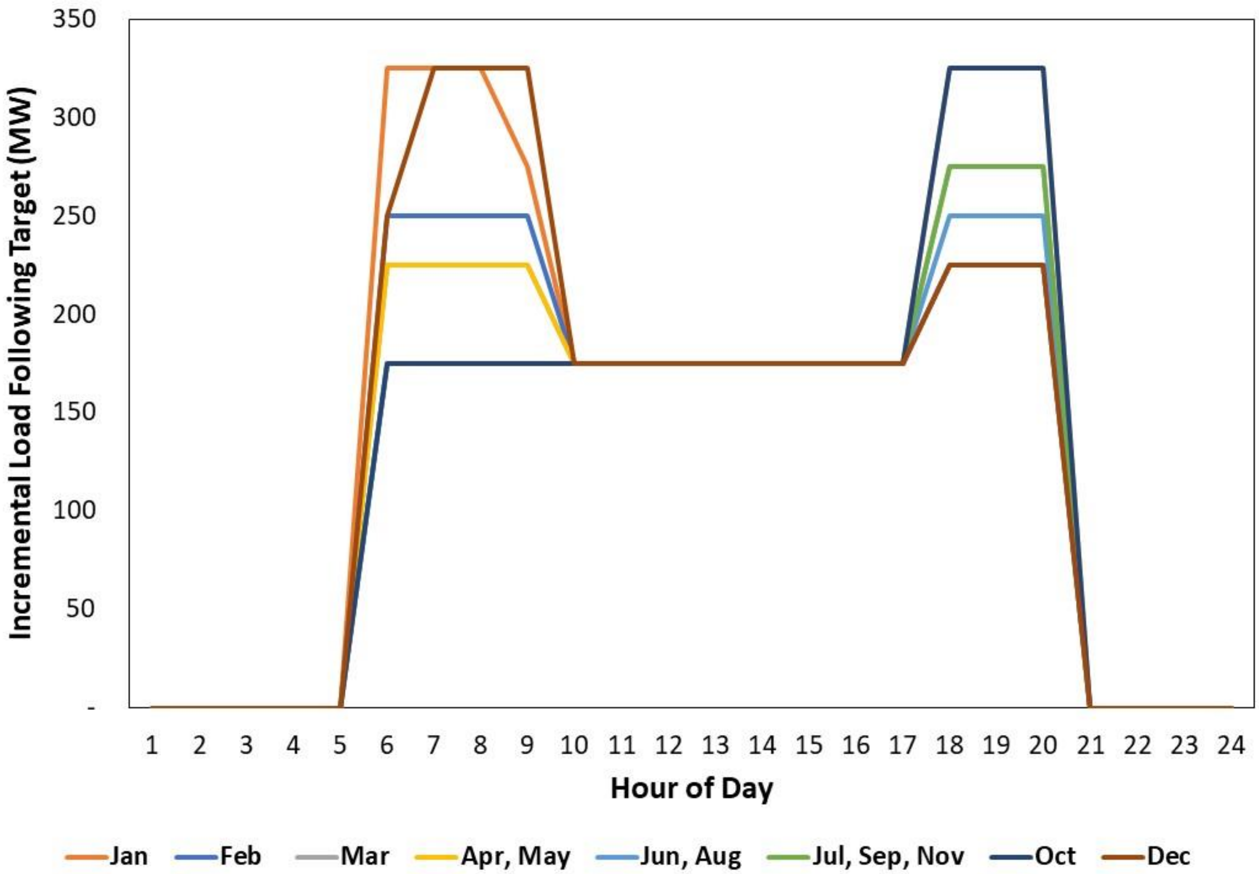
Figure 25. DEP Tranche 2: Final Incremental Load Following Targets for Commitment



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V. Island Results

Tables 11 and 12 show the results of the island cases for both DEC and DEP. As solar generation is added, net load volatility increases causing flexibility excursions to increase if nothing is done to mitigate them. To reduce the excursions, additional load following as presented in the previous sections are added into the model. This higher load following target causes an increase in costs. For DEC, the results show that as solar increases from 0 MW to 1,873 MW, 16 MW on average across daytime hours of additional load following is required to maintain the same number of flexibility excursions that occurred in the no solar base case. The total costs of the additional load following across the incremental 1,873 MW of solar generation is calculated as $1.18 /MWh. As Tranche 2 is added to the analysis, which includes 2,738 MW of solar, 26 MW of additional load following on average across daytime hours is required compared to the no solar base case. The total costs of the additional load following for the incremental tranche 2 solar is $1.63/MWh while the total average cost of the additional load following for tranche 2 solar is $1.33/MWh. The incremental cost represents the integration cost of the solar capacity that is added between Tranche 1 and Tranche 2. Similar patterns are seen in the DEP and the results are outlined in Table 12. Tranche 1, which assumes 3,590 MW of solar requires 49 MW of additional load following on average across daytime hours which results in $1.49/MWh. Tranche 2, which assumes 4,392 MW of solar capacity requires 65 MW of additional load following on average across daytime hours which results in a total cost of load following of $1.62/MWh. The incremental cost of Tranche 2 is $2.11/MWh.

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Table 11. DEC Island Results

	DEC No Solar	DEC Tranche 1	DEC Tranche 2
Total Solar (MW)	0	1,873	2,738
Flexibility Violations (Events Per Year)	2.94	2.94	2.94
Average SISC ($/MWh)	0	1.18	1.33
Incremental SISC ($/MWh)	0	1.18	1.63
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	16	26
Additional Curtailment Due to Solar and Load Following (MWh)	0	7,395	26,763
Additional Curtailment Only Due to Additional Load Following (MWh)	0	2,436	4,292
Solar Generation (MWh)	0	4,209,236	6,496,508
Percentage of Solar Generation Curtailed (%)	0	0.18%	0.41%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.058%	0.066%

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Table 12. DEP Island Results

	DEP No Solar	DEP Tranche 1	DEP Tranche 2
Total Solar (MW)	0	3,590	4,392
Flexibility Violations (Events Per Year)	1.47	1.47	1.47
Average SISC ($/MWh)	0	1.49	1.62
Incremental SISC ($/MWh)	0	1.49	2.11
Realized 10-Minute Load Following Reserves (Average MW Over Solar Hours Assuming 16 Hours) (MW)	0	49	65
Additional Curtailment Due to Solar and Load Following (MWh)	0	486,539	1,063,478
Additional Curtailment Only Due to Additional Load Following (MWh)	0	17,383	26,111
Solar Generation (MWh)	0	7,498,434	9,627,651
Percentage of Solar Generation Curtailed (%)	0	6.49%	10.77%
Percentage of Solar Generation Curtailed Due to Additional Load Following (%)	0	0.23%	0.27%

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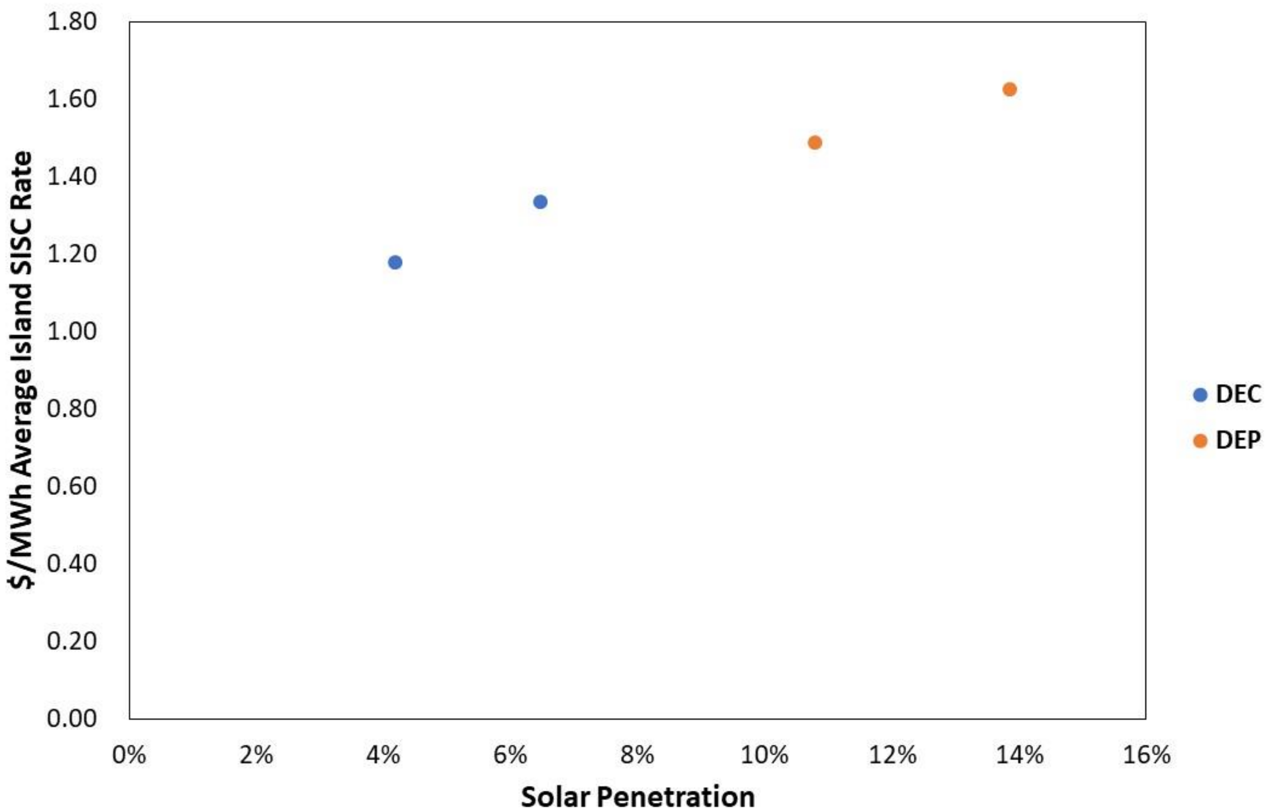
Figure 26 shows the island average SISC as a function of solar penetration for both DEC and DEP.

Figure 26. Average SISC as a function of Solar Penetration



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VI. Combined (JDA Modeled) Results

The combined (JDA Modeled) results model the two DEC and DEP balancing areas with unlimited transmission capability between them, which is consistent with the 2023 Resource Adequacy Study.

In these simulations, the realized load following additions determined in the island case were targeted for the combined case except now economic transfers can be made on a 5-minute basis. These economic transfers reduce system costs and in turn reduce integration costs. In discussions with the Companies' operators, this method is potentially optimistic because SERVM has perfect foresight within the 5-minute time step to dispatch generation in both zones to perfectly minimize system production costs, whereas the JDA may be subject to more uncertainty and less dispatch flexibility.

The results are shown below in Table 13 for both Tranche 1 and 2. As expected, when modeling the Combined case, the cost of load following goes down and for Tranche 1, the total costs decrease from 16 million dollars to 14.9 million dollars. This benefit is then allocated across the Companies to develop a lower SISC rate for each Company. Astrapé along with the TRC and the Companies in the 2021 Study determined it was most appropriate to allocate the benefit based on the rated cost of load following (in $/MWh) from the combined analysis.[7] The load following cost is the total production cost increase divided by the additional 10-minute load following reserves that are increased. This results in average and incremental SISC values assuming the benefit of the JDA as expressed at the bottom of Table 13. The average and incremental results are the same for Tranche 1 since it is the first tranche of solar studied. For DEC Tranche 2, the average SISC is $1.09/MWh and incremental SISC is $1.46/MWh. Similarly for DEP Tranche 2, the average SISC is $1.62/MWh and the incremental SISC is $2.11/MWh.

[7] As part of the allocation process, the DEP average SISC for the combined JDA case was capped at its island case SISC and total production costs of the combined JDA were maintained.

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Table 13. Combined (JDA Modeled) Results with Load Following Cost Allocation

	DEC Tranche 1	DEP Tranche 1	Combined Tranche 1	DEC Tranche 2	DEP Tranche 2	Combined Tranche 2
Solar Capacity (MW)	1,873	3,590	5,463	2,738	4,392	7,130
Solar Generation (MWh)	4,209,236	7,498,434	11,707,670	6,496,508	9,627,651	16,124,160
Island 10-Minute Load Following Reserves Needed (Average Over Daily 16 Hours) (MW)	16	49	65	26	65	91
Island 10 Min Load Following Cost Rate ($/MWh)	52.02	39.12	39.24	58.00	40.92	42.82
Island Integration Costs ($)	4,952,287	11,138,582	16,090,868	8,672,829	15,624,243	24,297,063
Average Island SISC ($/MWh)	1.18	1.49	1.27	1.33	1.62	1.41
Combined (JDA Modeled) 10-Minute Load Following Cost Rate ($/MWh)	39.24	39.24	39.24	42.82	42.82	42.82
Combined (JDA Modeled) Integration Costs ($)	3,748,345	11,138,582	14,886,926	7,094,647	15,624,234	22,718,881
Average SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.09	1.62	1.41
Incremental SISC with Combined (JDA Modeled) Load Following Cost Rates ($/MWh)	0.89	1.49	1.27	1.46	2.11	1.77

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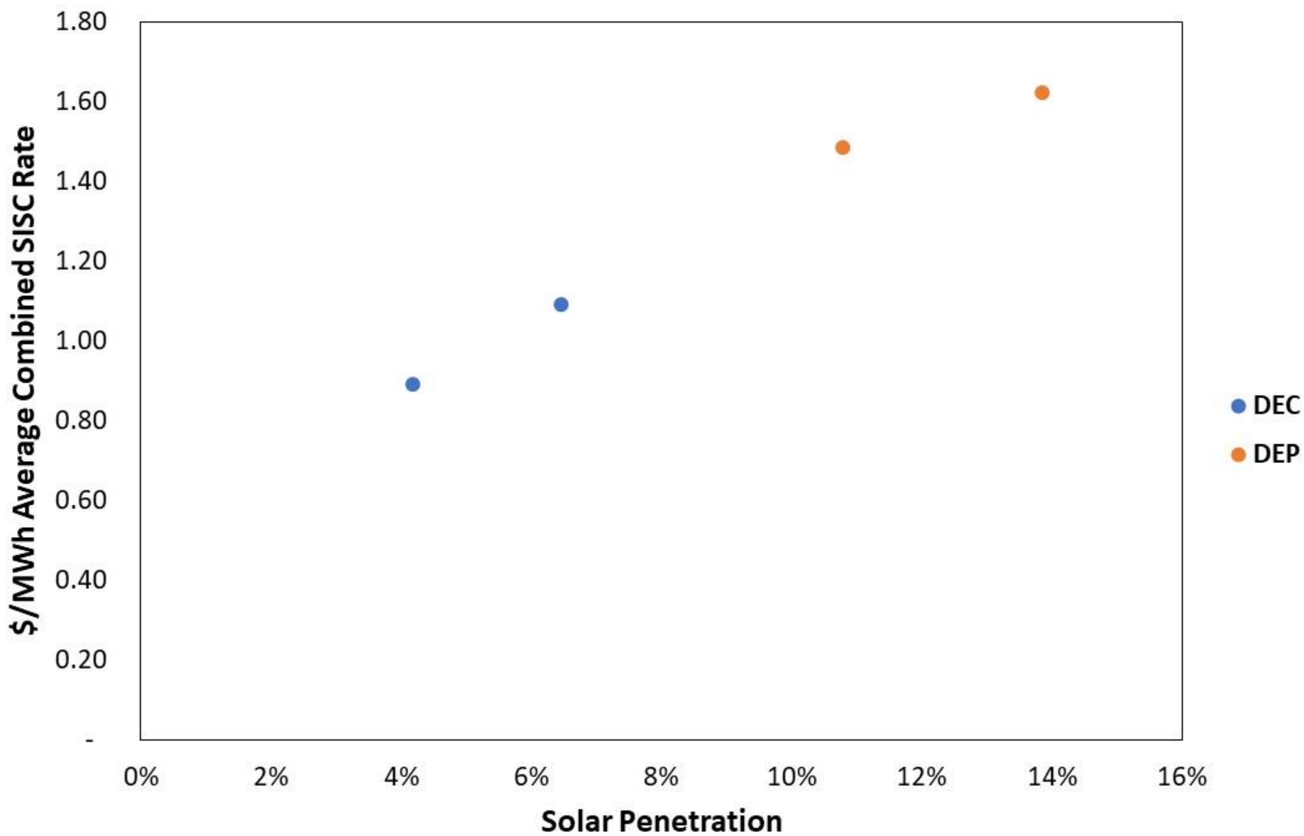
Figure 27 shows the average SISC for both tranches for the Combined Cases as a function of solar penetration.

Figure 27. Average Combined SISC Rates for Tranche 1 and 2



Lastly Table 14 shows the curtailment in the combined JDA case at the different solar levels. The table breaks up the curtailment into total curtailment from the no solar cases and into a category showing what portion of that curtailment occurred due solely to the load following increase. In the combined (JDA Modeled) case the overall solar curtailment is 0.07% for Tranche 1 and 0.56% for Tranche 2. Overall, low levels of curtailment take place in the Combined (JDA Modeled) case and are driven by the significant pump storage on the DEC system paired with additional battery capacity in both DEC and DEP.

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Table 14. Combined (JDA Modeled) Curtailment

	Tranche 1	Tranche 2
Renewable Capacity (MW)	5,463	7,130
Solar Penetration (%)	6.89%	9.49%
Renewable (MWh)	11,707,670	16,124,160
Additional Curtailment from No Solar Case (MWh)	8,499	89,913
Additional Curtailment from No Solar Case (% of Total Solar Gen)	0.072%	0.56%
Portion of Additional Curtailment Only Due to Additional Load Following (MWh)	961	6,799
Portion of Additional Curtailment Only Due to Additional Load Following (% of Total Solar Gen)	0.008%	0.042%

VII. Summary

As more solar is added to the DEC and DEP systems, additional ancillary services in the form of load following are required to meet load in real time. This Study simulated both the DEC and DEP systems to determine the amount of load following that was needed to maintain the same level of flexibility excursions the system experienced before the solar was added. The SISC was then calculated based on the costs of the additional load following. This was conducted for both DEC and DEP each as islands and then as a combined analysis, which assumes the JDA was used to economically provide the load following requirements. The values in the Study provide information for the Companies to propose a SISC for their Avoided Cost Filing.

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VIII. Appendix

Similar to the 2021 Study, a third tranche was also simulated representing 3,461 MW in DEC and 5,299 MW in DEP. This tranche has no impact on rates being set in the Companies Avoided Cost filing. The results for the island and combined case are shown in Table A.1 for informational purposes.

Table A.1. Tranche 3 Results

	DEC Tranche 3	DEP Tranche 3
Total Solar (MW)	3,461	5,299
Flexibility Violations (Events Per Year)	2.94	1.47
Average SISC - Island ($/MWh)	1.92	1.76
Incremental SISC - Island ($/MWh)	3.89	2.20
Realized 10 Min Load Following Reserves **(Average MW Over Solar Hours Assuming 16 Hours)** (MW)	36	83
Additional Curtailment Due to Solar and **Load Following - Island** (MWh)	77,126	2,000,445
Additional Curtailment Only Due to Additional **Load Following - Island** (MWh)	17,947	44,460
Solar Generation (MWh)	8,443,422	12,065,170
Percentage of Solar Generation Curtailed - Island (%)	0.913%	16.58%
Percentage of Solar Generation Curtailed Due to Additional **Load Following - Island** (%)	0.21%	0.37%
Combined (JDA Modeled) Tranche 3 Average SISC ($/MWh)	1.55	1.76