BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 158

In the Matter of:	)	
Biennial Determination of Avoided Cost	)	**NCSEA'S INITIAL**
Rates for Electric Utility Purchases from	)	**COMMENTS**
Qualifying Facilities – 2018	)	
	)	

Attachment 4

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Solar Capacity Value Study

8/27/2018

PREPARED FOR

Duke Energy

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I. Solar Capacity Value Study Summary

As Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) continue to add solar to their systems, understanding the reliability contribution of solar resources is critical for generation planning and projecting capacity needs as part of its Integration Resource Plan (IRP). Conventional thermal resources are typically counted as 100% of net capability in reserve margin calculations for future generation planning since these resources are fully dispatchable resources when not on forced outage or planned maintenance. Due to the intermittent nature of solar resources, it is not reasonable to assume that these resources provide the same capacity value as a fully dispatchable resource. Peak loads for DEC and DEP in the winter occur in the early morning and late evening when the solar output is low, while peak loads in the summer occur across the afternoon and early evening which is more coincident with solar output. Solar output shapes and the timing of peak demand periods must be considered to determine the capacity value or reliability contribution of a solar resource compared to a fully dispatchable resource such as a combustion turbine (CT).

Astrapé performed this capacity value study using the Strategic Energy Risk Valuation Model (SERVM) which was the same model utilized for the 2016 Resource Adequacy Studies. The inputs of the model are documented in the body of this report. Extensive work went into the development of fixed-tilt and single-axis-tracking solar profiles across a 13-location grid in North Carolina and South Carolina as laid out in the body of the report.

Astrapé calculated the incremental capacity value of solar across five solar penetration levels for each company. These results can be fit to a curve to estimate the capacity value of each MW of solar added to the system. The table below shows the different penetration levels of renewable solar generation. These levels are consistent with the Companies' estimates of penetration at the time of this analysis. Consistent with NC House Bill 589, solar additions were divided up into the categories of

Existing plus Transition and then an additional four tranches of solar that are expected over the next few years. However, note that the tranches discussed in this study reflect the Companies' total expected solar procurement which includes all utility scale requirements under NC HB 589 (CPRE, large customer programs and community solar). While the exact timing and amounts of transition and incremental solar additions may change over time, it is reasonable to assume the levels provided in the table below given the current procurement targets of the companies.

Table S1. Simulated Solar Penetration Levels

	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

The Existing Plus Transition capacity level was made up of mostly fixed-tilt solar with a small amount of single-axis-tracking solar. Existing behind the meter solar was modeled as a reduction in load. Table S2 provides the details for the existing plus transition capacity.

Table S2. Existing Plus Transition Capacity Breakdown

	DEC MW	DEP MW
Existing	679	1,923
Transition	161	1,027
Existing Plus Transition	840	2,950

Type	Technology	Inverter Loading Ratio	DEC MW	DEP MW
Existing: Utility Owned	Fixed-tilt	1.4	130	154
Existing: Standard PURPA	Fixed-tilt	1.3	549	1,769
Transition	Fixed-tilt	1.43	121	770
Transition	Single-Axis-Tracking	1.3	40	257
Total Existing Plus Transition			840	2,950

Tranches 1-4 solar resources were assumed to have a 1.4 inverter loading ratio with 75% being fixed-tilt and 25% being single-axis-tracking. The following table shows the capacity levels included within each tranche.

Table S3. Tranches 1 - 4 Capacity

Tranche	Technology	Inverter Loading Ratio	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
Tranche 1	75% fixed/25% Tracking	1.4	680	680	160	160
Tranche 2	75% fixed/25% Tracking	1.4	780	1,460	180	340
Tranche 3	75% fixed/25% Tracking	1.4	780	2,240	160	500
Tranche 4	75% fixed/25% Tracking	1.4	420	2,660	135	635

In order to calculate the capacity value of the solar resources, the DEC and DEP systems are simulated at the different solar penetration levels to identify projected firm load shed events. A firm load shed event occurs in an hour when DEC or DEP are short resources even after calling all demand response resources and fully utilizing assistance from external neighbors. Consistent with the reserve margin study, a Loss of Load Expectation (LOLE) for each Company is calculated and reserves are adjusted to target approximately 0.1 events per year. This is also referred to as the 1 day in 10-year standard.

LOLE by Season and Its Impact on Capacity Value

The LOLE may occur in the winter or the summer but as was seen in the 2016 Resource Adequacy Studies, winter LOLE is significantly higher than summer LOLE within both Companies due to increasing penetrations of solar capacity and the impact of cold weather uncertainty on load.

Table S4 shows the seasonal LOLE by Company for the different penetration levels. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summer during peak load hours, which occur in the afternoon and early evening, is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of nameplate solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE, thereby further shifting the seasonal weighting of LOLE to the winter. This is apparent by examining the LOLE results in the table. For example, the no-solar scenario for DEC shows a seasonal LOLE weighting of 59% summer and 41% winter. However, after adding the existing and transition solar, the seasonal weighting makes a dramatic shift to 69% winter and 31% summer. After Tranche 4 solar is added, the winter weighting increases to 93% and summer reduces to 7%. The updated load forecast used in the solar capacity value study shows DEP's winter peak forecast to be about 650 MW higher than its summer forecast for the 2020 study year, while DEC's winter forecast is about 340 MW lower than its summer forecasted peak. Even though DEC's summer peak is projected to exceed its winter peak, the LOLE for DEC is still heavily weighted in the winter due to solar capacity contribution at the time of summer versus winter peak demands.

Table S4 shows that the DEP no-solar scenario has a seasonal LOLE weighting of approximately 85% winter and 15% summer. The greater winter LOLE weighting for the DEP no-solar scenario, compared to the DEC no-solar scenario, is primarily the result of greater winter load volatility and a higher winter versus summer load forecast for DEP. DEP also has a significantly greater level of Existing Plus Transition solar compared to DEC, pushing the seasonal winter LOLE weighting to greater than 99%. Thus, solar levels greater than Existing Plus Transition for DEP will have solar capacity values based solely on their capacity contribution in the winter.

Table S4. DEC and DEP Seasonal LOLE Percentage

	DEC Incremental Solar	DEC Cumulative Solar	DEC LOLE	DEC LOLE	DEP Incremental Solar	DEP Cumulative Solar	DEP LOLE	DEP LOLE
	MW	MW	Summer %	Winter %	MW	MW	Summer %	Winter %
0 MW Level	-	-	59%	41%	-	-	14.7%	85.3%
Existing Plus Transition MW	840	840	31%	69%	2950	2,950	0.6%	99.4%
Tranche 1	680	1,520	21%	79%	160	3,110	0.5%	99.5%
Tranche 2	780	2,300	11%	89%	180	3,290	0.4%	99.6%
Tranche 3	780	3,080	7%	93%	160	3,450	0.3%	99.7%
Tranche 4	420	3,500	7%	93%	135	3,585	0.3%	99.7%

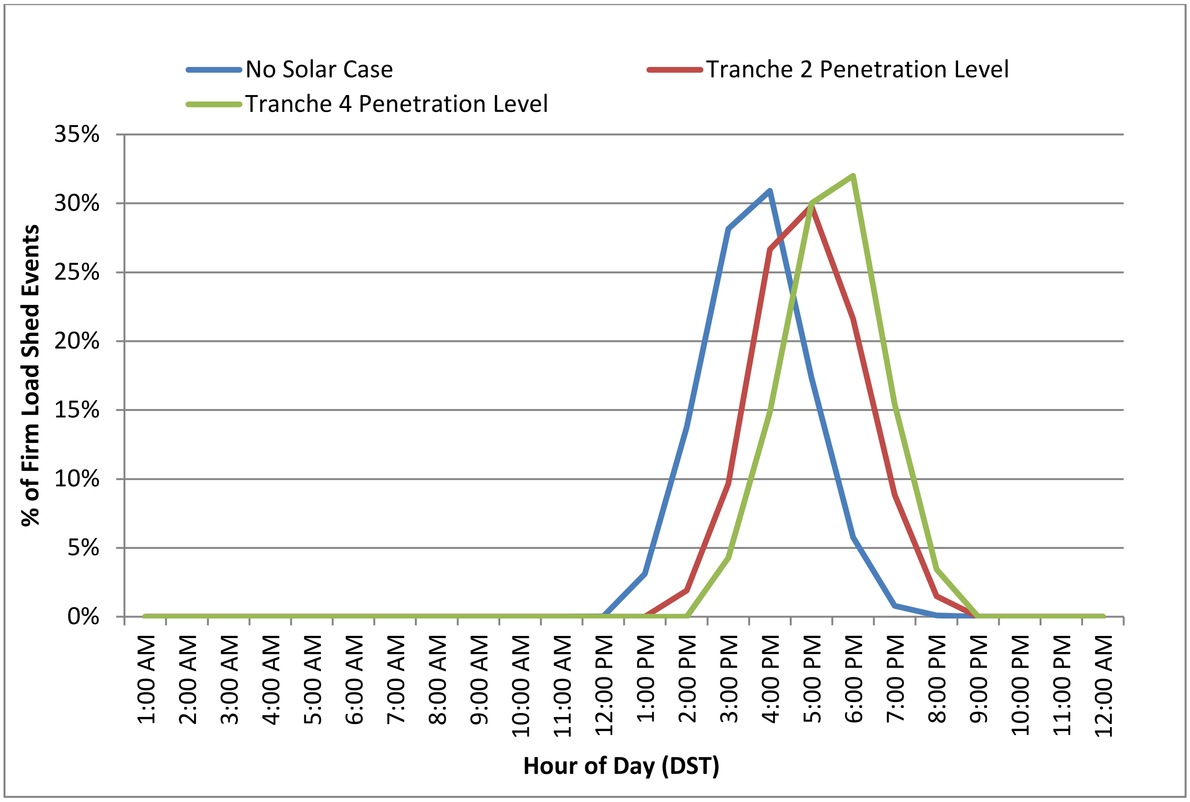
LOLE by Hour of Day and Its Impact on Capacity Value

The seasonal LOLE table alone allows for a reasonable approximation of the annual capacity value of solar resources. For example, assuming that solar receives a 50% value in the summer and a 5% value in the winter (similar to previous company estimates), then the annual capacity value for DEP at Tranche 4 could be estimated using the following formula: 5% winter capacity value * 99.7% winter LOLE weighting + 50% summer capacity value * 0.3% summer LOLE weighting = 5.1%. While this simplified approach captures the appropriate seasonal LOLE, it does not account for how the firm load shed events change across the day in each season as solar penetration grows, so the approximate calculations will not exactly match the values derived from the simulations.

To illustrate further, Figure S1 shows the percentage of firm load shed events in DEC by hour of day in the summertime for the no-solar case and two additional solar penetration levels. The percentages for each curve total to 100%. This figure demonstrates that the timing of the peak net load shifts to later in the evening across increasing solar penetration levels[1]. Before significant solar is added, both Companies are expected to experience load shed events primarily during the 1 pm - 6 pm hours in the summer with the most concentrated portion in the 3 pm to 5 pm hours as shown by the blue line. As solar capacity is added, the timing of the peak net load and therefore firm load shed hours are pushed out to later in the day when the solar output is lower. By the time Tranche 4 solar resources are included, the more concerning hours of the day in the summer are from 3- 8 pm when solar output is lower. This impact lowers the summer solar capacity value as solar penetration increases.

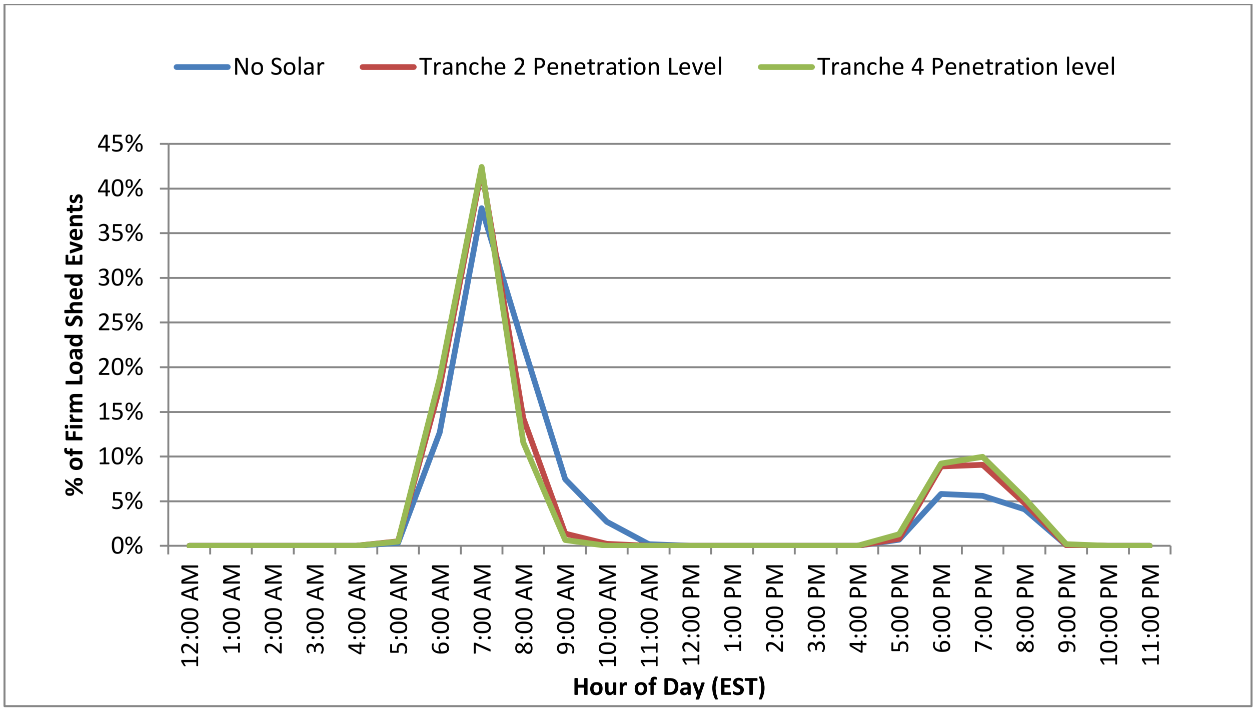
[1] Net load as discussed here reflects the gross load minus any renewable resources and represents the load that is served by the dispatchable fleet.

Figure S1. DEC % of Firm Load Shed Events by Hour of Day (Summer)



A similar pattern is seen in the winter as shown in the following figure. As solar penetration increases, the load net of solar output becomes lower in hours from 8 am to 5 pm causing more of the LOLE events to be concentrated in the 7 am hour when the solar has lower output. While small, this is the reason solar provides slightly less winter capacity value as more solar resources are brought online.

Figure S2. DEC % of Firm Load Shed Events by Hour of Day (Winter)



Solar Capacity Value Results

By modeling thousands of iterations in SERVM with 36 different weather years, both the seasonal and hourly pattern changes are captured across the different solar penetration levels. As solar increases, system LOLE shifts more heavily to the winter and the equivalent capacity value declines because the firm load shed events no longer occur during solar hours and become more prominent during hours with lower solar output.

Table S5 shows the DEC solar capacity value results. As discussed in the methodology portion of the report, SERVM simulations were performed at each solar penetration level with each level targeting a 0.1 LOLE per year. The probability-weighted output of the solar resource was then overlaid with the firm load shed event table to determine the final capacity values. The first MW of solar in DEC provides a 27% annual capacity value but after 840 MW are added, the next MW provides only an 11% equivalent annual capacity value[2]. The solar capacity values reflect the equivalent CT capacity value. A CT is given a 100% capacity credit so the first MW of DEC solar provides 27% of the capacity value that a CT provides. The fixed-tilt solar and the single-axis-tracking resources were evaluated separately with each additional tranche. The results show that at Tranche 1, fixed-tilt solar has a 6.5% annual capacity value while at Tranche 4 it is reduced to 1.2%. The capacity value for single-axis-tracking solar resources ranges from 10.9% to 2.9% across the four tranches on an annual basis.

Table S5. DEC Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEC - 0 Solar	2.5%	44.7%	27.2%
840	840	DEC - 840 Existing + Transition	0.9%	33.6%	11.1%
680	1,520	DEC - Tranche 1 - Fixed	0.5%	29.5%	6.5%
780	2,300	DEC - Tranche 2 - Fixed	0.4%	23.1%	2.9%
780	3,080	DEC - Tranche 3 - Fixed	0.2%	19.4%	1.6%
420	3,500	DEC - Tranche 4 - Fixed	0.2%	14.6%	1.2%
680	1,520	DEC - Tranche 1 - Tracking	2.0%	45.3%	10.9%
780	2,300	DEC - Tranche 2 - Tracking	1.8%	36.6%	5.6%
780	3,080	DEC - Tranche 3 - Tracking	1.3%	31.9%	3.4%
420	3,500	DEC - Tranche 4 - Tracking	1.1%	25.6%	2.9%

[2] All capacity values provided in the report represent the incremental capacity value of the next MW given the referenced solar penetration. The average capacity contribution for an entire block of solar resources can be estimated by averaging the incremental value for the first MW of the block and the incremental value for the first MW of the next block.

Figure S3 shows the results plotted as a function of solar capacity.

Figure S3. DEC Annual Capacity Value by Solar Penetration

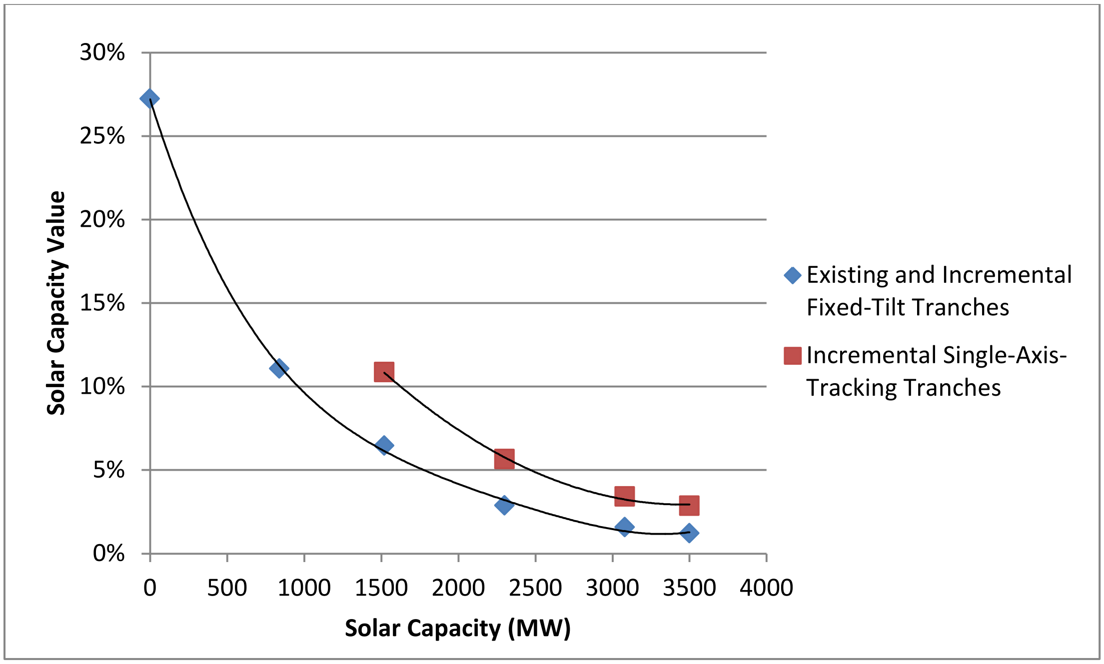


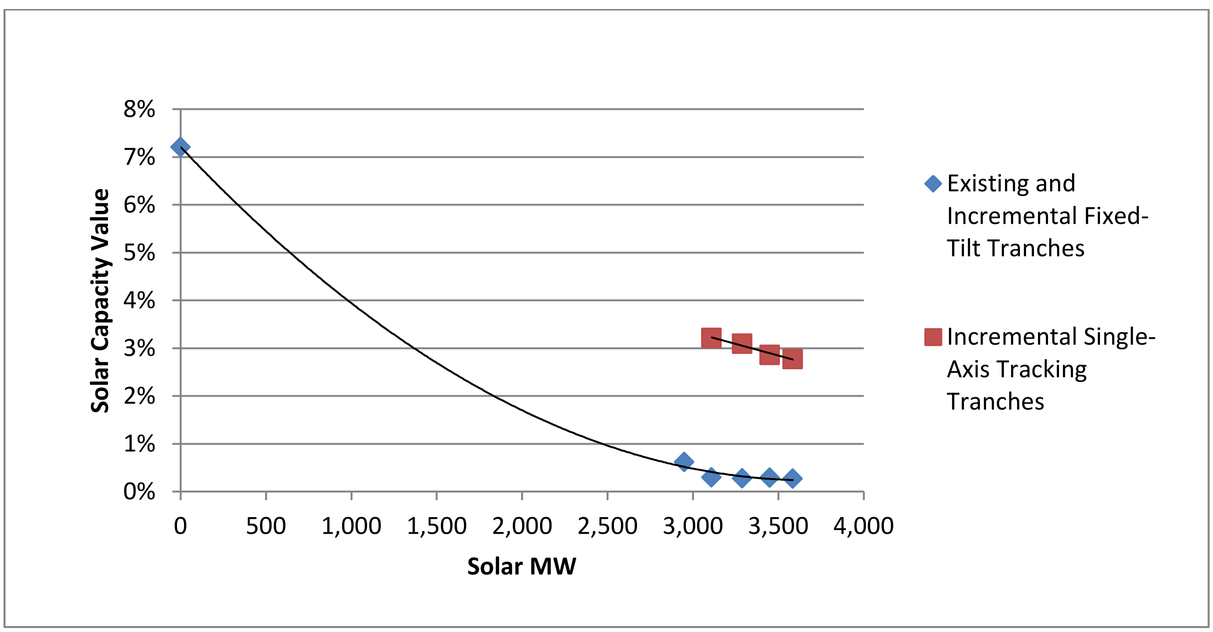
Table S6 shows results for DEP. As discussed earlier, the summer value proves to have very little weight in the annual value because over 90% of the LOLE occurs in the winter. By the time the 2,950 MW of existing and transition solar come online, the annual capacity value has already decreased substantially.

Table S6. DEP Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEP - 0 Solar	1.2%	35.4%	7.2%
2,950	2,950	DEP - 2950 Existing + Transition	0.6%	12.4%	0.6%
160	3,110	DEP - Tranche 1 - Fixed	0.3%	12.2%	0.3%
180	3,290	DEP - Tranche 2 - Fixed	0.3%	11.6%	0.3%
160	3,450	DEP - Tranche 3 - Fixed	0.2%	8.8%	0.3%
135	3,585	DEP - Tranche 4 - Fixed	0.2%	8.2%	0.3%
160	3,110	DEP - Tranche 1 - Tracking	3.2%	22.3%	3.2%
180	3,290	DEP - Tranche 2 - Tracking	3.1%	20.6%	3.1%
160	3,450	DEP - Tranche 3 - Tracking	2.8%	16.2%	2.9%
135	3,585	DEP - Tranche 4 - Tracking	2.7%	15.3%	2.8%

Figure S4 shows the DEP capacity values as a function of solar capacity.

Figure S4. DEP Annual Capacity Value by Solar Penetration



Fixed-Tilt vs. Single-Axis-Tracking

The differences in the single-axis-tracking and the fixed-tilt capacity values are illustrated in the July and January DEC profiles shown in the following figures. The additional output seen in the tracking in the early and late afternoon hours give it additional capacity value.

Figure S5. Average July Profiles

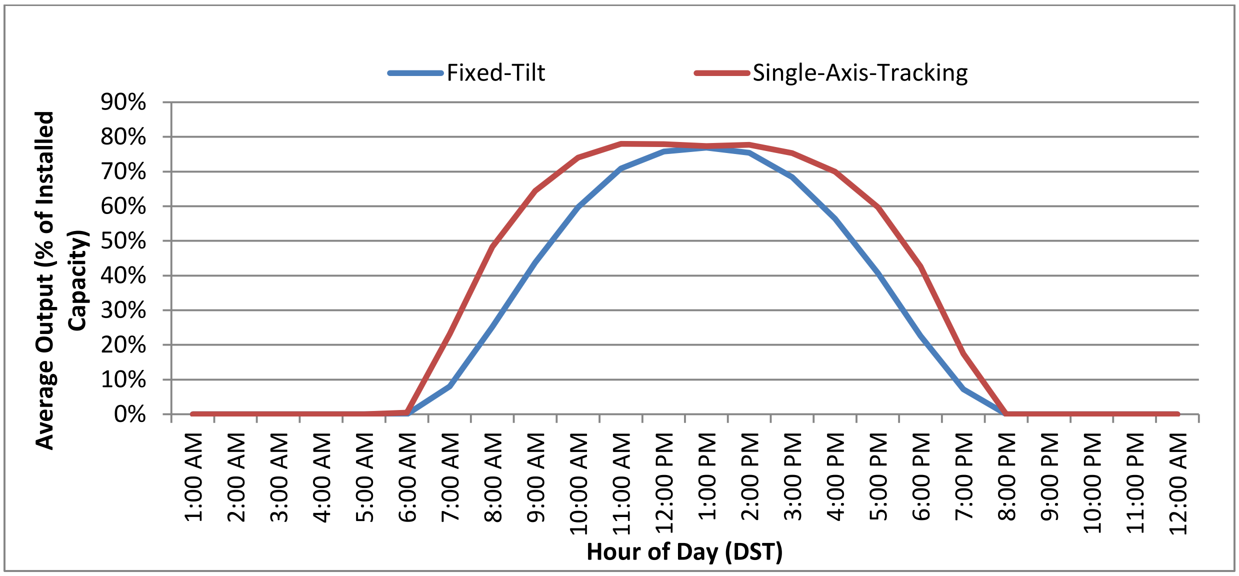
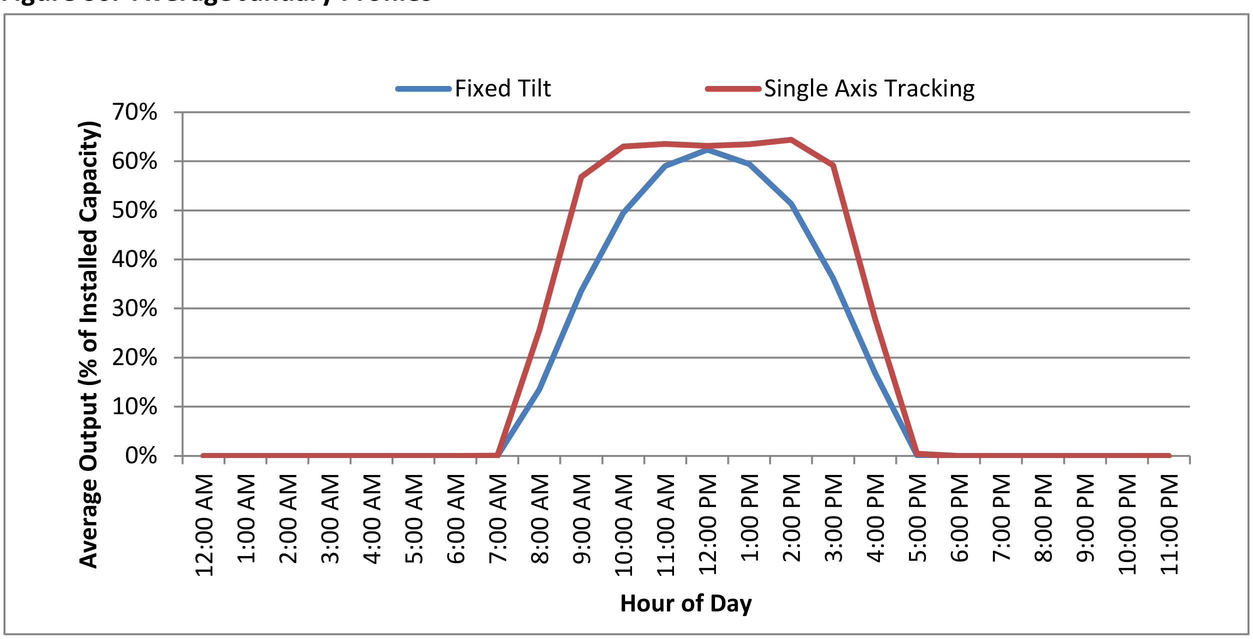


Figure S6. Average January Profiles



In summary, the winter LOLE to summer LOLE ratio drives the annual solar equivalent capacity values. Because the companies have higher winter LOLE values in hours when solar is not available, the resulting equivalent annual solar capacity values are significantly reduced. As solar penetration increases, the capacity values decrease further since the firm load shed events are shifted even further into hours when there is less solar output. However, single-axis-tracking resources do bring some additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.

II. Model Inputs and Setup

The following sections include a discussion on the major modeling inputs included in the Solar Capacity Value Study with an emphasis on loads and solar shapes.

A. Load Forecasts and Load Shapes

Table 1 displays the modeled seasonal peak forecast net of energy efficiency programs and behind the meter solar for 2020 for both DEC and DEP. The 2020 winter forecast for DEP is approximately 650 MW higher than the summer forecast which drives Loss of Load Expectation (LOLE) to be higher in the winter. In DEC, the winter forecast is approximately 340 MW less than the summer forecast making DEC's LOLE not as heavily weighted in the winter.

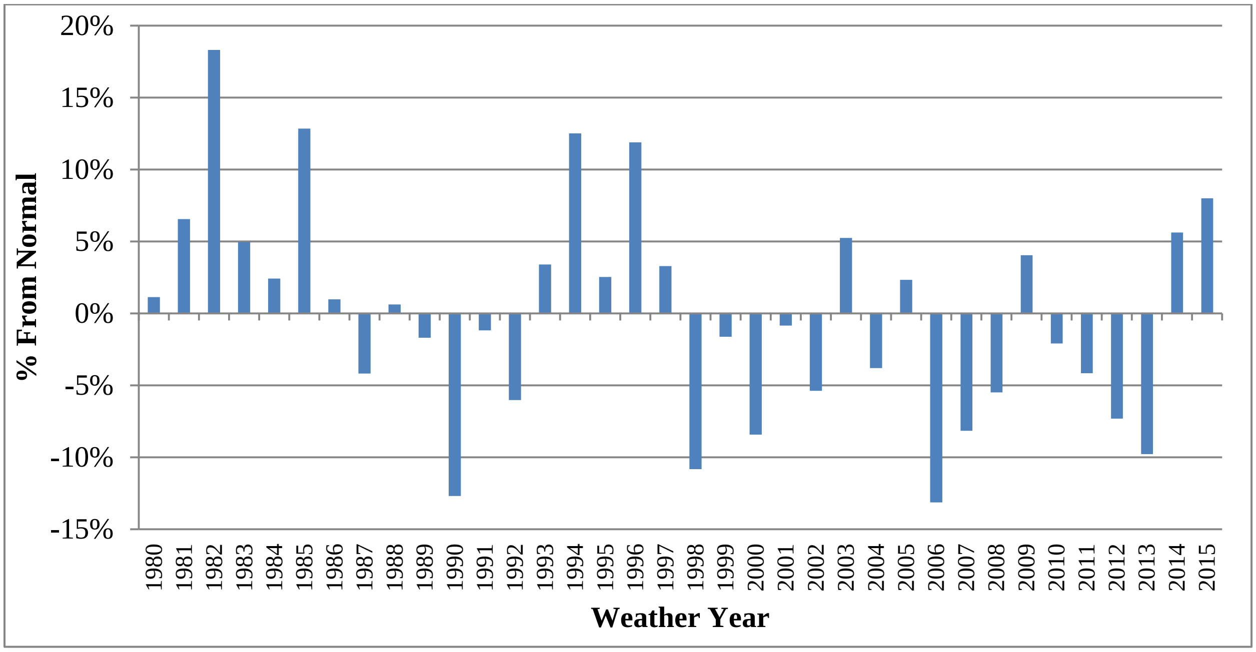
Table 1. 2020 Peak Load Forecast

	DEC	DEP East	DEP West	Coincident DEP
2020 Summer	18,260 MW	12,503 MW	828 MW	13,289 MW
2020 Winter	17,924 MW	12,866 MW	1,128 MW	13,946 MW

To model the effects of weather uncertainty, 36 historical weather years (1980 - 2015) were developed to reflect the impact of weather on load. These were the same 36 load shapes used in the 2016 Resource Adequacy Study. Based on historical weather and load, a neural network program was used to develop relationships between weather observations and load. Different weather to load relationships were built for each month. These relationships were then applied to the last 36 years of weather to develop 36 load shapes for 2020. Equal probabilities were given to each of the 36 load shapes in the simulation. The load shapes were scaled to align the normal summer and winter peaks to the Company's projected load forecast for 2020. Thus the "normal" summer peak reflects an average of the summer peak demands from the 36 load shapes. Similarly, the "normal" winter peak reflects an average of the winter peak demands from the 36 load shapes.

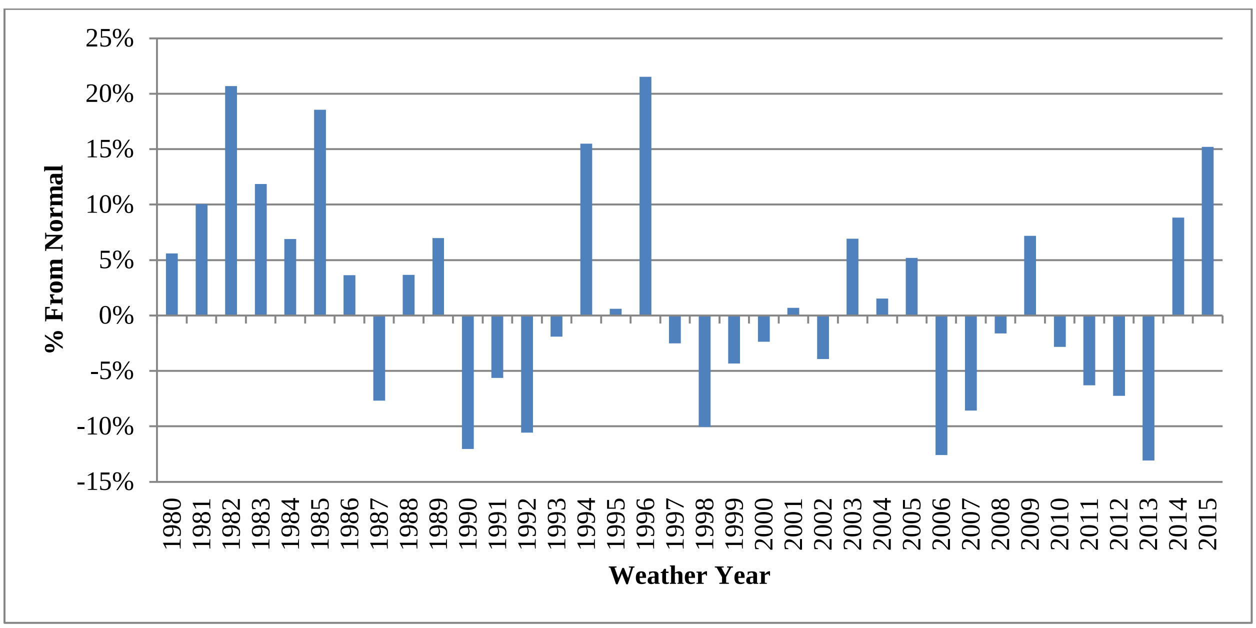
The figures below show the results of the weather load modeling by displaying the peak load variance for both the summer and winter seasons for each company. The y-axis represents the percentage deviation from the average peak. For example, a simulation using the 1985 DEC load shape would result in a summer peak load approximately 4.7% below normal and a winter peak load approximately 12.9% above normal. Thus, the bars represent the variance in projected peak loads for 2020 based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. Extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation. Based on the neural net modeling, the figures show that DEC and DEP summer peak loads can be almost 8% higher than the forecast due to weather alone, while winter peak can be about 18% higher than the forecast for DEC and more than 20% higher than the forecast for DEP in an extreme year.

Figure 1. DEC Winter Peak Weather Variability



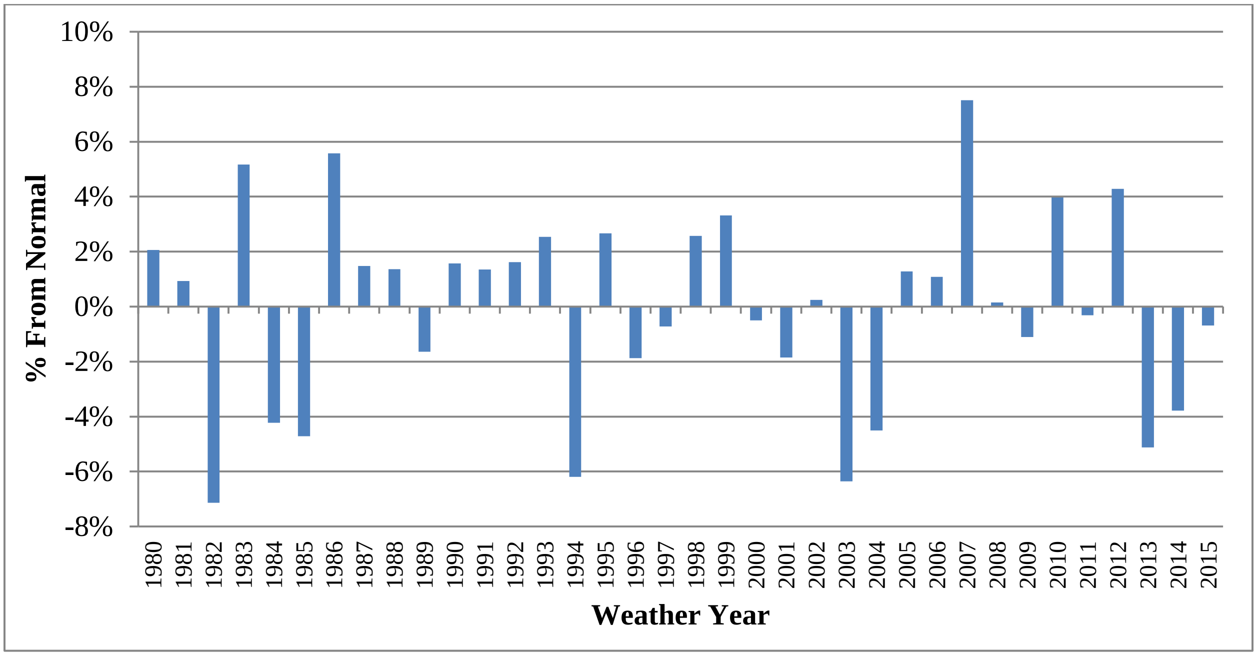
Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Figure 2. DEP Winter Peak Weather Variability



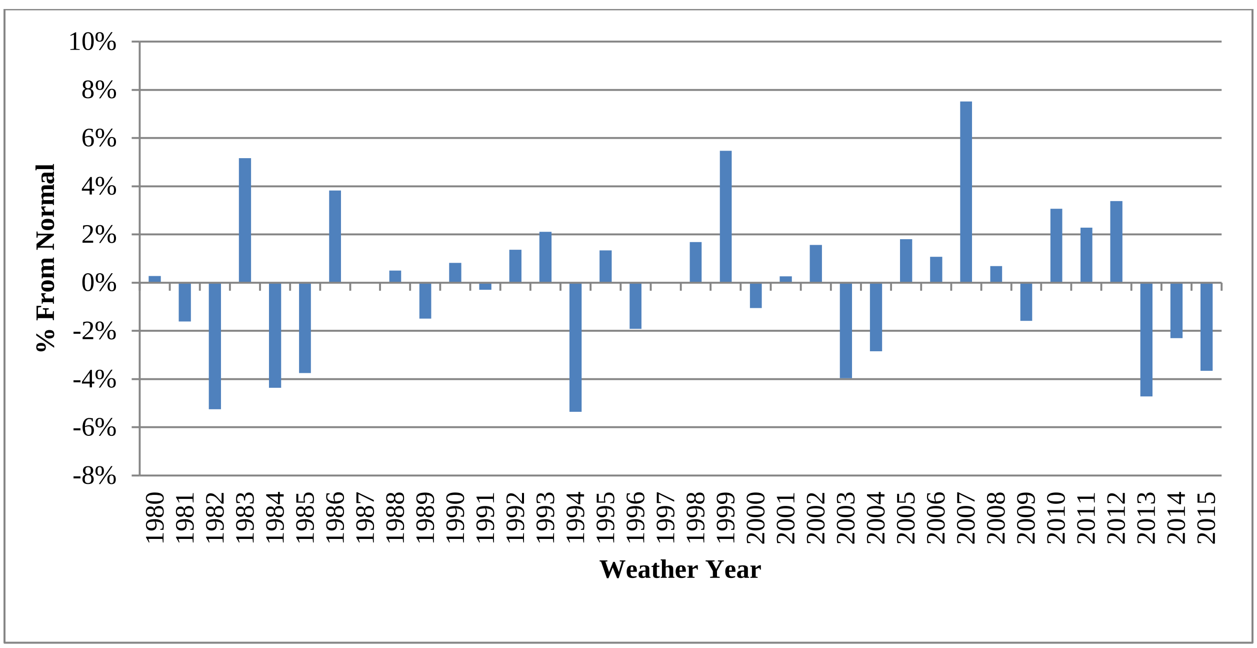
Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Figure 3. DEC Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the highest temperature occurred. Therefore, the loads are not always in the same order as the max temperature ranking.

Figure 4. DEP Summer Peak Weather Variability



Note: The peak load is impacted by the day of week the lowest temperature occurred. Therefore, the loads are not always in the same order as the min temperature ranking.

Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that the Companies have in their 3 year ahead load forecasts. Three to five years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate economic load forecast error, the difference between Congressional Budget Office (CBO) GDP forecasts 3 years ahead and actual data was fit to a normal distribution. Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 7.9% of the time, it is expected that load will be under-forecasted by 4%. Within the simulations, when DEC under-forecasts load, the external regions also under-forecast load. The SERVM model utilized each of the 36 weather years and applied each of these five load forecast error points to create 180 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 2. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.96	7.9%
0.98	24.0%
1.00	36.3%
1.02	24.0%
1.04	7.9%

B. Solar Shape Modeling

Table 3 lays out the solar capacity levels that were analyzed in the study along with the inverter loading ratios (ILR) assumed. The existing and transition capacity includes 840 MW in DEC and 2,950 MW in DEP. As discussed earlier, loads were already reduced for behind the meter solar. This capacity included utility-owned-generation, PURPA generation and additional expected solar capacity called transition capacity. The tranches of solar analyzed assumed 75% of the capacity was fixed-tilt and 25% was single-axis-tracking capacity all with a 1.4 inverter loading ratio.

Table 3. Solar Capacity Penetration Levels

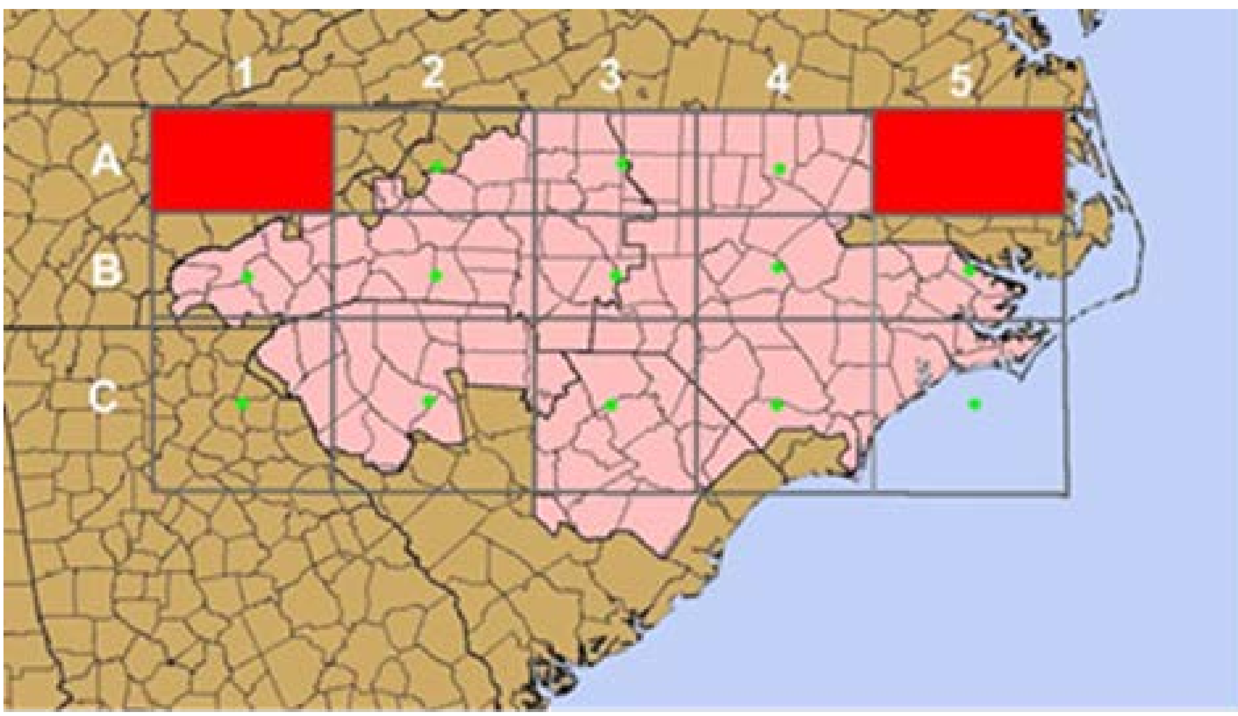
	DEC MW	DEP MW
Existing	679	1,923
Transition	161	1,027
Existing Plus Transition	840	2,950

Type	Technology	Inverter Loading Ratio	DEC MW	DEP MW
Existing: Utility Owned	Fixed-Tilt	1.4	130	154
Existing: Standard PURPA	Fixed-Tilt	1.3	549	1,769
Transition	Fixed-Tilt	1.43	121	770
Transition	Single-Axis Tracking	1.3	40	257
Total Existing Plus Transition			840	2,950

Tranche	Technology	Inverter Loading Ratio	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
Tranche 1	75% fixed/25% Tracking	1.4	680	680	160	160
Tranche 2	75% fixed/25% Tracking	1.4	780	1,460	180	340
Tranche 3	75% fixed/25% Tracking	1.4	780	2,240	160	500
Tranche 4	75% fixed/25% Tracking	1.4	420	2,660	135	635

Fixed and tracking solar profiles for the 36 weather years were developed in detail for each grid as shown in Figure 5.

Figure 5. Solar Profile Locations



Data was downloaded from the NREL National Solar Radiation Database (NSRDB) Data Viewer using the 13 latitude and longitude locations, detailed in Table 4, for the available years 1998 through

2015. Solar shapes were developed for the 1980 - 1997 time-frame by matching the closest peak load day from the two periods (1980 - 1997, 1998 - 2015) and using the same daily solar profile that was developed from the NREL dataset. An additional five solar shapes were calculated as variations of the "Actual Closest" peak load day to create additional variability among the solar shapes. The shapes were calculated by sorting the peak loads for the proper day (actual day +/- 1 day) in ascending order and offsetting the closest daily load shapes by choosing the days that most closely matched the load profiles plus or minus 1 or 2 days.

Table 4. Locations for Solar Profiles

Description	Latitude	Longitude
A2	36.13	-81.70
A3	36.17	-80.02
A4	36.09	-78.62
B1	35.33	-83.34
B2	35.41	-81.70
B3	35.41	-80.10
B4	35.45	-78.66
B5	35.41	-76.86
C1	34.57	-83.46
C2	34.53	-81.74
C3	34.49	-80.18
C4	34.45	-78.66
C5	34.57	-76.90

The solar capacity for DEP and DEC were modeled across the 13 location grid as follows:

Table 5. DEP Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1-4
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.4	1.3	1.43	1.3	1.4
Capacity MW	154	1769	770	257	160 - 635
Location Breakdown					
A2	0%	0%	0%	0%	0%
A3	0%	1%	1%	1%	1%
A4	20%	23%	14%	14%	14%
B1	0%	1%	1%	1%	1%
B2	0%	0%	0%	0%	0%
B3	7%	9%	7%	7%	7%
B4	14%	26%	8%	8%	8%
B5	11%	8%	9%	9%	9%
C1	0%	0%	0%	0%	0%
C2	0%	0%	1%	1%	1%
C3	23%	6%	35%	35%	35%
C4	23%	23%	21%	21%	21%
C5	1%	3%	2%	2%	2%
Total	100%	100%	100%	100%	100%

Table 6. DEC Solar by Location

	Utility Owned	Standard PURPA	Transition	Transition	Tranche 1-4
Technology (Fixed-tilt/Tracking)	Fixed	Fixed	Fixed	Tracking	Fixed/Tracking
DC/AC Ratio	1.4	1.3	1.43	1.3	1.4
Capacity MW	130	549	121	40	680 - 2,660

Location Breakdown %

A2	15%	7%	3%	3%	3%
A3	6%	22%	22%	22%	22%
A4	0%	9%	2%	2%	2%
B1	0%	0%	0%	0%	0%
B2	47%	33%	12%	12%	12%
B3	6%	16%	26%	26%	26%
B4	0%	1%	1%	1%	1%
B5	0%	0%	0%	0%	0%
C1	0%	1%	0%	0%	0%
C2	0%	7%	27%	27%	27%
C3	25%	2%	5%	5%	5%
C4	0%	1%	1%	1%	1%
C5	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%

Figures 6 and 7 show the January average daily solar profiles for 1980 to 2015 for tracking and fixed technologies, respectively. The tracking files have more output in the earlier and later hours than the fixed profile which ultimately provides additional capacity value as shown in the results.

Figure 6. January Daily Tracking Solar Profile

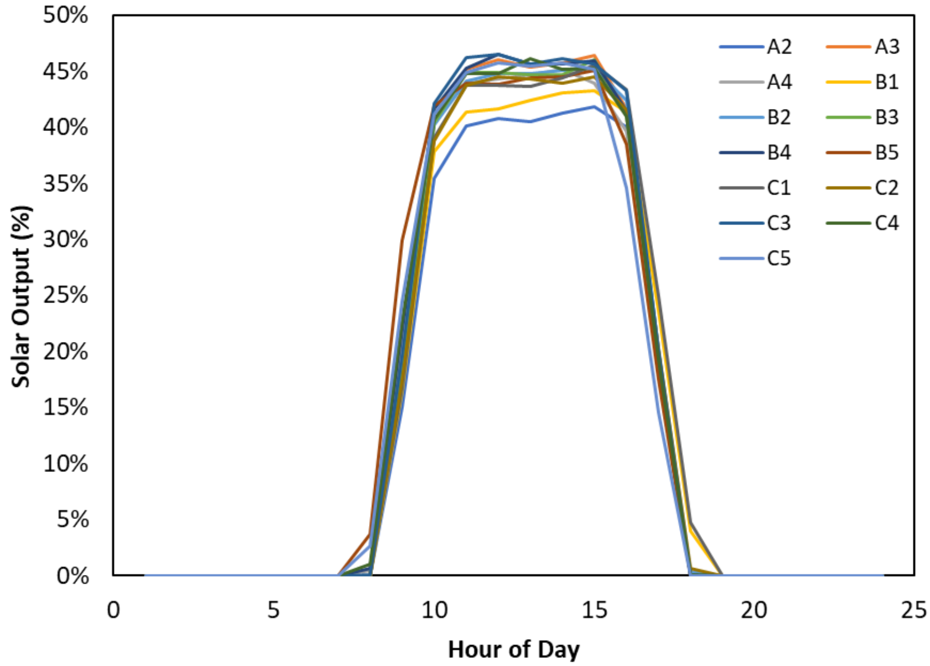
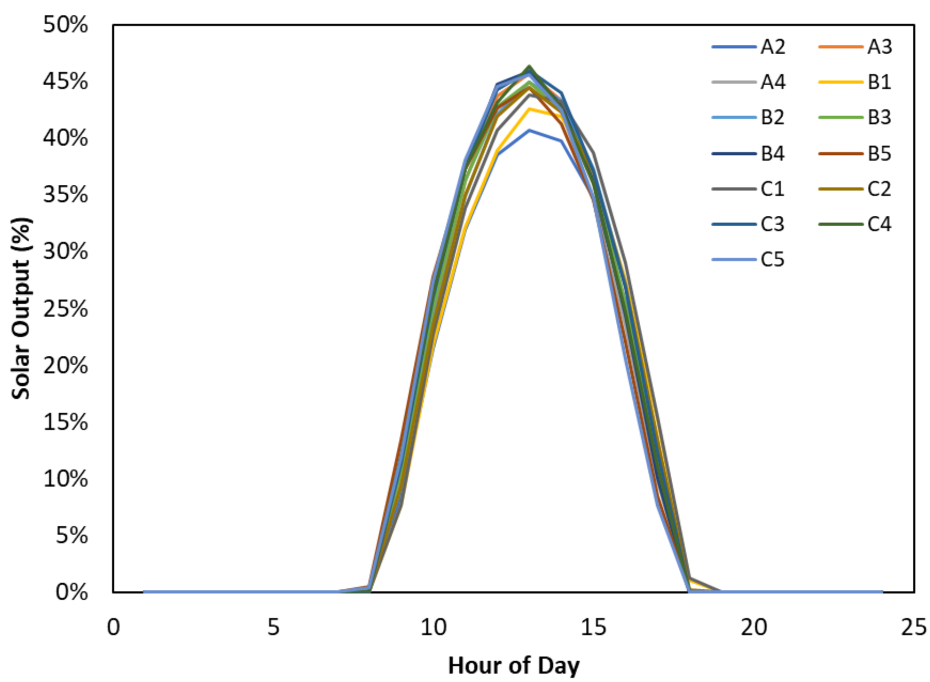


Figure 7. January Daily Fixed Solar Profile



Figures 8 and 9 show the August average daily solar profiles for 1980 to 2015 for tracking and fixed technologies, respectively.

Figure 8. August Daily Tracking Solar Profile

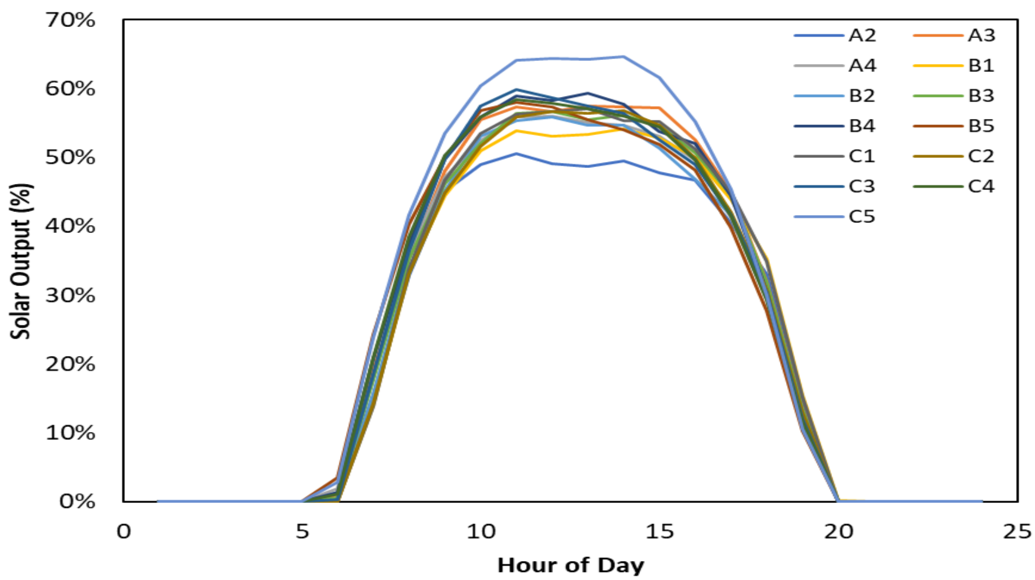
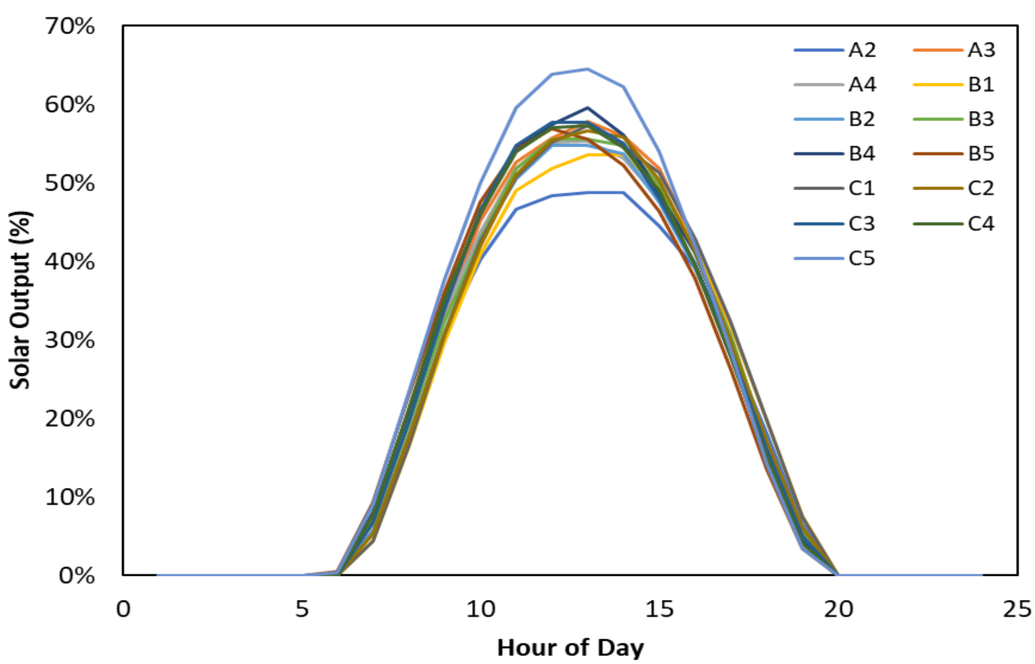


Figure 9. August Daily Fixed Solar Profile



C. Conventional Thermal Resources

Conventional thermal resources owned by the company and purchased as Purchase Power Agreements were modeled consistent with the 2020 study year. These resources are economically committed and dispatched to load. 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. Full winter rating is achieved at 35 °F.

The unit outage data for the thermal fleet in both Companies was based on historical Generating Availability Data System (GADS) data. 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
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
The actual schedule for 2019 was used.

To illustrate the outage logic, assume that from 2010 – 2014, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. 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, off peak, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. 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.

For neighboring regions, Astrapé used some of its in-house Time-to-Fail and Time-to-Repair distributions to capture a reasonable EFOR in each external region. The average EFOR in external regions was approximately 5%. Additional cold weather penalties were not included in the analysis.

Planned maintenance events are modeled separately and dates are entered in the model representing a typical year. For external resources, a 5% maintenance rate was applied to all units, and SERVM scheduled maintenance events which minimized the impact on reliability.

D. Hydro and Pump Storage Modeling

The hydro portfolios in DEC and DEP are modeled in segments that include Run of River (ROR) and Scheduled (Peak Shaving). The Run of River segment is dispatched as base load capacity providing its designated capacity every hour of the year. The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. By modeling the hydro resources in these two segments, the model captures the appropriate amount of capacity dispatched during peak periods. On average, the DEC hydro generates 400 - 600 MW during peak conditions while DEP generates approximately 200 MW during peak conditions.

In additional to conventional hydro, DEC owns and operates a pump hydro fleet that includes expected upgrades to be made by 2020. The total capacity included was 2,400 MW. (1) Bad Creek at a 1,620 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.

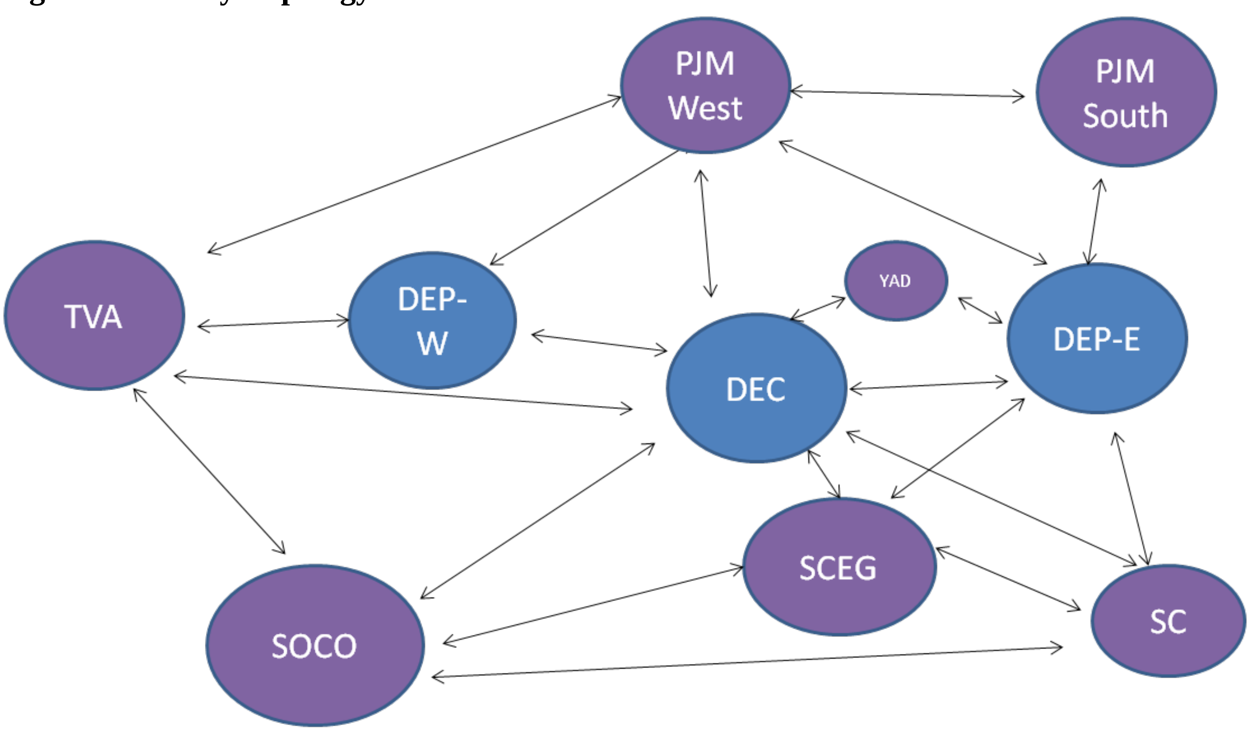
E. Demand Response Modeling

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. For 2020, DEC assumed 1,031 MW of demand response in the summer and 406 MW in the winter. DEP assumed 1,015 MW of summer capacity and 512 MW of winter capacity.

F. Topology and Neighbor Assistance

Consistent with the Company's Resource Adequacy Study, Figure 10 shows the study topology that was used for the study. To thoroughly quantify resource adequacy, it is important to capture the load diversity and generator outage diversity that a system has with its neighbors. For this study, the DEC and DEP systems were modeled with seven surrounding regions. The surrounding regions captured in the modeling included Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West, PJM South, Yadkin (YAD), South Carolina Electric & Gas (SCEG), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints. Loads for each external region were developed in a similar manner as the DEC loads. A relationship between hourly weather and publicly available hourly load was developed based on recent history, and then this relationship was applied to 36 years of weather data to develop 36 load shapes. Resources in each external region were added to achieve reasonable reliability in surrounding regions.

Figure 10. Study Topology



G. Firm Load Shed Event

A firm load shed event is calculated by the model as any day whether it is one hour or ten hours that resources could not meet load even after utilizing neighbor assistance and demand response programs. Regulating reserves of 216 MW in DEC and 134 MW in DEP were always maintained.

III. Simulation Methodology

Since firm load shed events are high impact, low probability events, a large number of scenarios must be considered to accurately project these events. For this study, SERVM utilized 36 years of historical weather and load shapes, 5 points of economic load growth forecast error, 6 differing solar shape patters, and 15 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 36 weather years * 5 load forecast errors * 15 unit outage iterations * 6 solar profiles = 16,200 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 framework was simulated for each of the solar penetration levels in the following table.

Table 7. Solar Penetration Levels

	DEC	DEC	DEP	DEP
	Incremental MW	Cumulative MW	Incremental MW	Cumulative MW
0 MW Level	-	-	-	-
Existing Plus Transition MW	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
Tranche 2	780	2,300	180	3,290
Tranche 3	780	3,080	160	3,450
Tranche 4	420	3,500	135	3,585

Consistent with the reserve margin study, a Loss of Load Expectation for each Company is calculated and both DEC and DEP systems were targeted to approximately 0.1 events per year[3]. This is also referred to as the 1 day in 10-year standard. The LOLE may occur in the winter or the summer but as was seen in the 2016 Resource Adequacy Study, the winter LOLE has increased compared to the summer LOLE within both Companies due to cold weather uncertainty, and an increase in solar capacity. As solar is added to the system, a higher percentage of the LOLE will occur in the winter because the output of solar in the summertime during peak load hours (afternoon and early evening hours) is naturally higher than the output during the winter peak load hours which occur early in the morning or late in the evening. In other words, when 1 MW of solar is added to the system, the 1 MW of solar reduces summer LOLE more than it reduces winter LOLE.

Once the timing of each firm load shed event is projected by SERVM. The solar profile is overlaid onto the loss of load events and the probability weighted solar contribution during those loss of load events is calculated. The minimum solar output seen during an hour with load shed is the output that is attributed to the capacity value calculation for each firm load shed event. For example, if an event lasted from hour 7 to hour 10 in the winter, and a 100 MW solar resource produced 0 MW in hour 7, 5 MW in hour 8, 20 MW in hour 9 and 40 MW in hour 10, then the addition of that solar resource did not remove the event because there was still load shed in hour 7. For this example, the 0 MW of output would be included in the capacity value calculation.

[3] The different penetration levels were between 0.09 LOLE and 0.11 LOLE as it is difficult to get exactly to 0.1 as different size units are added and removed.

IV. Results

Table 8 shows the seasonal LOLE by Company for the different solar penetration levels. Both companies have higher load uncertainty in the winter due to extreme weather, and lower demand response resources in the winter compared to the summer, causing more winter LOLE than summer LOLE. DEP's winter peak forecast is approximately 650 higher than its summer forecast and has substantially more existing plus transition solar than DEC, giving DEP a higher LOLE winter weighting compared to DEC. By the time tranche 4 solar is added each company, there is little to no summer LOLE risk as DEC winter LOLE represents 93% of the total LOLE and DEP winter LOLE represents 99.7% of the total LOLE.

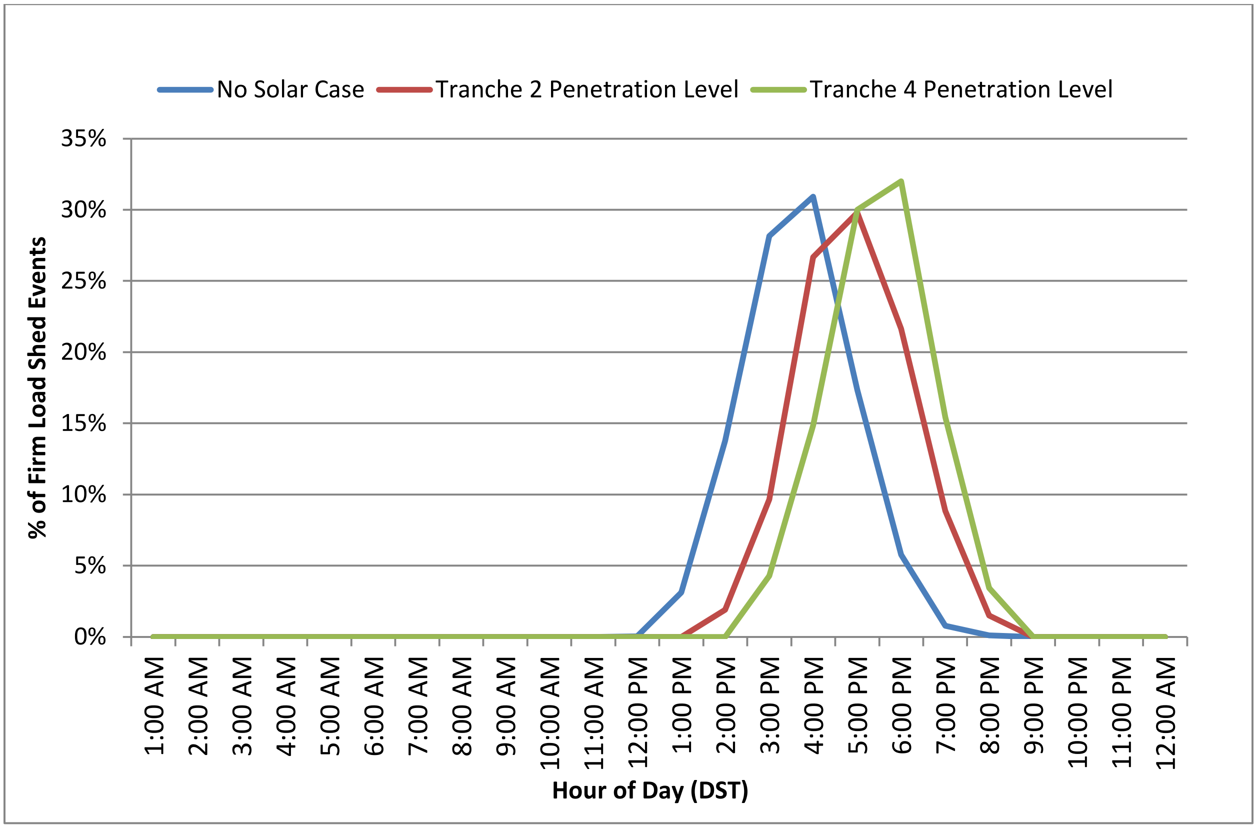
Table 8. DEC and DEP Seasonal LOLE %

	DEC Incremental Solar	DEC Cumulative Solar	DEC LOLE	DEC LOLE	DEP Incremental Solar	DEP Cumulative Solar	DEP LOLE	DEP LOLE
	MW	MW	Summer %	Winter %	MW	MW	Summer %	Winter %
0 MW Level	-	-	59%	41%	-	-	14.7%	85.3%
Existing Plus Transition MW	840	840	31%	69%	2950	2,950	0.6%	99.4%
Tranche 1	680	1,520	21%	79%	160	3,110	0.5%	99.5%
Tranche 2	780	2,300	11%	89%	180	3,290	0.4%	99.6%
Tranche 3	780	3,080	7%	93%	160	3,450	0.3%	99.7%
Tranche 4	420	3,500	7%	93%	135	3,585	0.3%	99.7%

The seasonal LOLE table alone allows for a reasonable approximation of the annual capacity value of solar resources. For example, assuming that solar receives a 50% value in the summer and a 5% value in the winter (similar to previous company estimates), then the annual ELCC for DEP at Tranche 4 could be estimated using the following formula: 5% winter value * 99.7% winter LOLE weighting + 50% summer value * 0.3% summer LOLE weighting = 5.1%. While this simplified approach captures the appropriate seasonal LOLE, it misses the timing of the events across the day in each season as solar penetration grows, so the approximate calculations will not exactly match the values derived from the simulations.

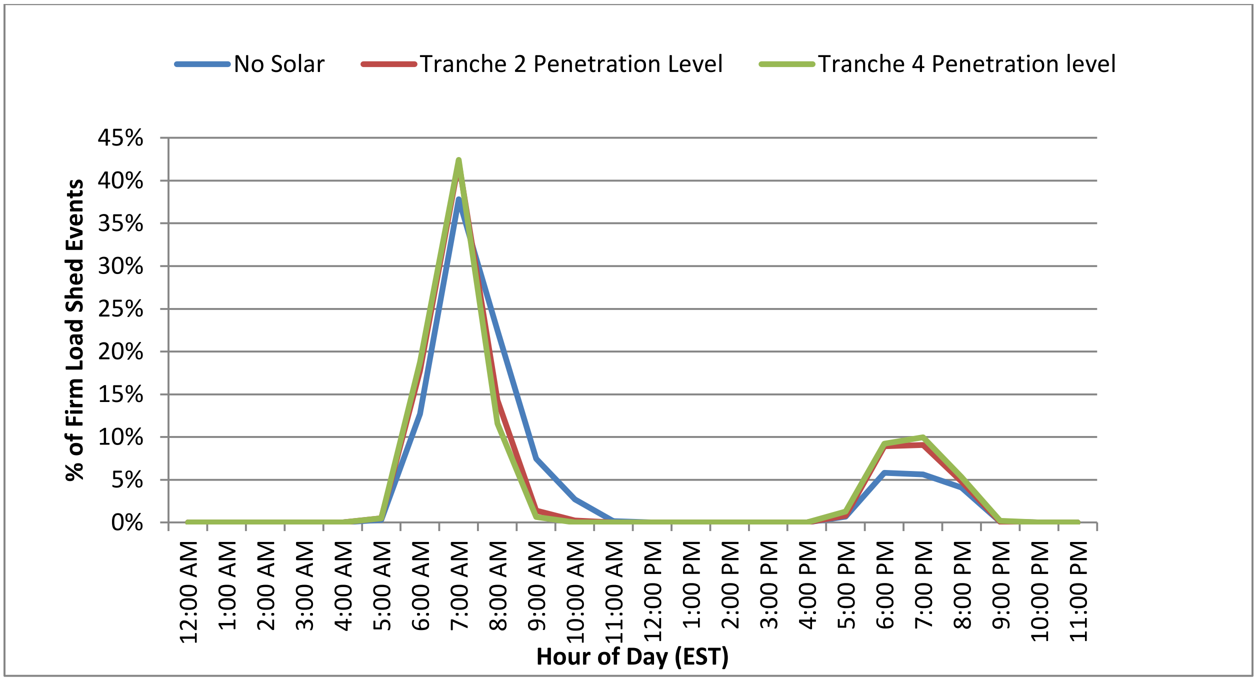
To illustrate further, the following figure shows the percentage of firm load shed events in DEC by hour of day in the summertime for the zero level solar and two additional solar penetration levels. This figure shows how peak net load shifts outward across different solar penetration levels. Before large additions of solar are added, both Companies experience load shed events during the 1 pm to 6 pm timeframe in the summer with the highest concentration between 3 pm and 5 pm. As solar capacity is added, the peak net load and therefore firm load shed hours are pushed out to later in the day when the solar is not able to produce as much output. By the time Tranche 4 has been included, the more concerning hours of the day are from hour 3 pm to 8 pm. This impact lowers the summer solar capacity value as solar penetration increases.

Figure 11. Summer Firm Load Shed Events by Hour of Day



A similar pattern is seen in the winter season as shown in Figure 12. The percentage of firm load shed events are plotted as function of time of day. Typically, LOLE events occur in the early morning and late evening hours when little solar output is available. As solar penetration increases, the net load becomes lower between 8 am and 5 pm causing more of the LOLE to be concentrated in the 7 am hour when the solar has lower output. This is a subtle shift but explains the slight decrease in winter capacity value as solar penetration increases.

Figure 12. Winter Firm Load Shed Events by Hour of Day



By modeling thousands of iterations in a Monte Carlo Model with 36 different weather years in SERVM, both the seasonal and hourly pattern change is captured across the different solar penetration levels. As solar increases, system LOLE shifts more heavily to the winter and capacity value declines because the firm load shed events begin to fade during solar hours and become more prominent during hours with lower solar output.

Table 9 shows the final DEC solar capacity value results for each penetration level. The first MW of solar in DEC is worth 27% in annual capacity value but after 840 MW are added, the next MW is worth 11% in annual capacity value. The fixed-tilt solar and the single-axis-tracking were evaluated separately with each additional tranche. The results show that at Tranche 1, the fixed-tilt solar has a 6.5% annual capacity value while Tranche 4 is reduced to 1.2%. The single-axis-tracking solar ranges from 10.9% to 2.9% from Tranche 1 to Tranche 4 on an annual basis. A steady decline in capacity value is seen across the winter and summer as the penetration increases just due to the firm load shed hours shifting to hours with less solar output and the seasonal LOLE weighting shifting more to the winter.

Table 9. DEC Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEC - 0 Solar	2.5%	44.65%	27.2%
840	840	DEC - 840 Existing + Transition	0.9%	33.6%	11.1%
680	1,520	DEC - Tranche 1 - Fixed	0.5%	29.5%	6.5%
780	2,300	DEC - Tranche 2 - Fixed	0.4%	23.1%	2.9%
780	3,080	DEC - Tranche 3 - Fixed	0.2%	19.4%	1.6%
420	3,500	DEC - Tranche 4 - Fixed	0.2%	14.6%	1.2%
680	1,520	DEC - Tranche 1 - Tracking	2.0%	45.3%	10.9%
780	2,300	DEC - Tranche 2 - Tracking	1.8%	36.6%	5.6%
780	3,080	DEC - Tranche 3 - Tracking	1.3%	31.9%	3.4%
420	3,500	DEC - Tranche 4 - Tracking	1.1%	25.6%	2.9%

Figure 13 shows the DEC results plotted as a function of solar capacity. This curve provides the annual capacity value of every incremental MW added to the system. The Existing MWs make up 840 MW and then the four tranches are added to that totaling 3,500 MW

Figure 13. DEC Capacity Value Results by Solar Penetration

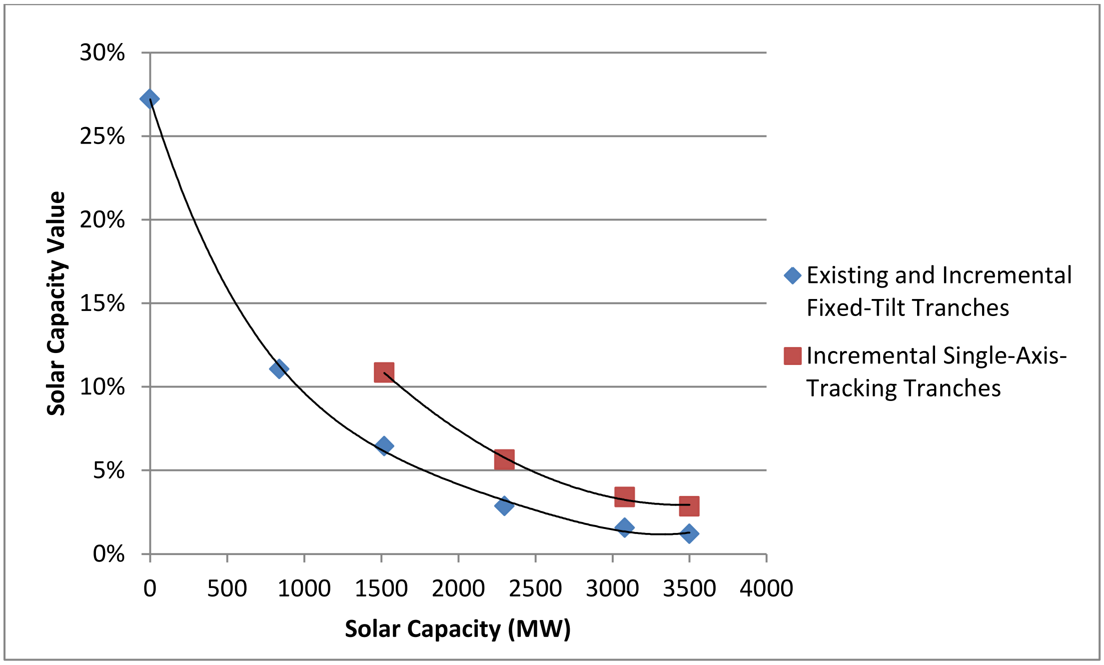


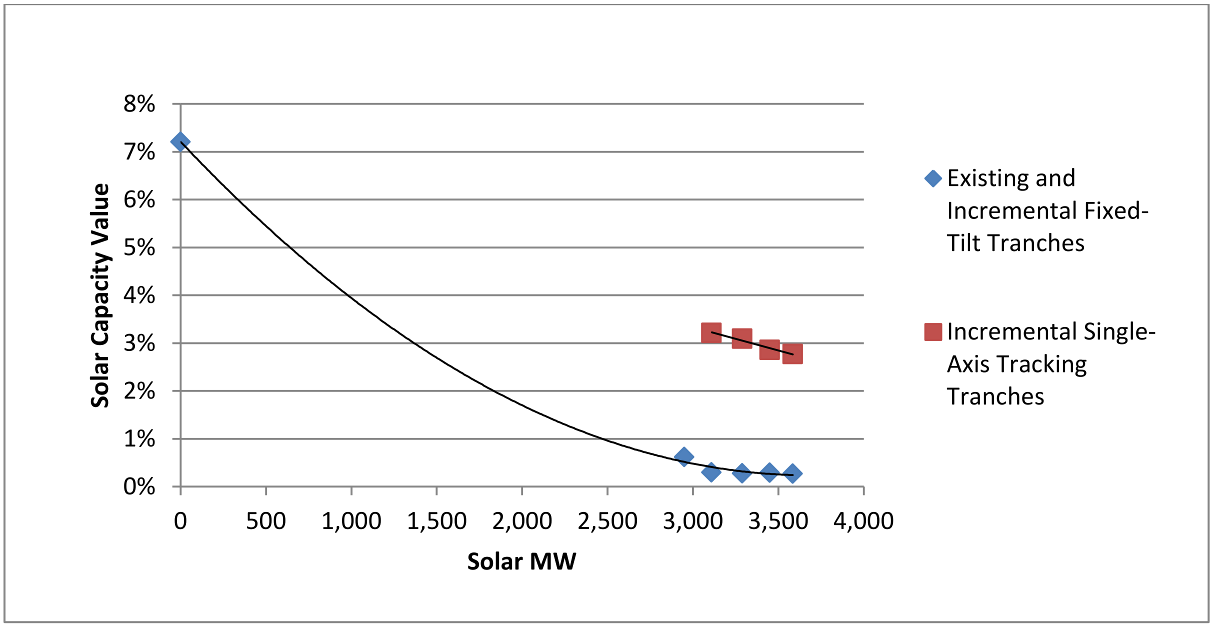
Table 10 shows solar capacity value results for DEP. As discussed earlier, the summer value proves to have very little weight in the annual value because over 90% of the LOLE occurs in the winter. Because the LOLE is so small in the summer for DEP, an additional simulation run was required which increased the load in DEP in only summer hours to surface enough reliability events to calculate the summer capacity value. By surfacing LOLE in the summer, accurate solar capacity values could be calculated although they still have little to no impact on the annual values.

Table 10. DEP Capacity Value Results by Solar Penetration

Solar Capacity at Each Penetration Level (Incremental MW)	Solar Capacity at Each Penetration Level (Cumulative MW)	Penetration Level	Winter	Summer	Annual
0	0	DEP - 0 Solar	1.2%	35.4%	7.2%
2,950	2,950	DEP - 2950 Existing + Transition	0.6%	12.4%	0.6%
160	3,110	DEP - Tranche 1 - Fixed	0.3%	12.2%	0.3%
180	3,290	DEP - Tranche 2 - Fixed	0.3%	11.6%	0.3%
160	3,450	DEP - Tranche 3 - Fixed	0.2%	8.8%	0.3%
135	3,585	DEP - Tranche 4 - Fixed	0.2%	8.2%	0.3%
160	3,110	DEP - Tranche 1 - Tracking	3.2%	22.3%	3.2%
180	3,290	DEP - Tranche 2 - Tracking	3.1%	20.6%	3.1%
160	3,450	DEP - Tranche 3 - Tracking	2.8%	16.2%	2.9%
135	3,585	DEP - Tranche 4 - Tracking	2.7%	15.3%	2.8%

Figure 14 shows the DEP capacity values as a function of solar capacity. The tranches are much smaller within the DEP region and therefore display little movement in the capacity value from tranche to tranche compared to the DEC results.

Figure 14. DEP Capacity Value Results by Solar Penetration



The differences in the tracking and the fixed-tilt capacity values are illustrated in the summer and winter profiles shown in the following figures. The additional output seen in the tracking in the early and late afternoon hours give it additional capacity value. As expected, the July profiles produce more output in the morning and early evening compared to the January profiles.

Figure 15. Average July Profiles

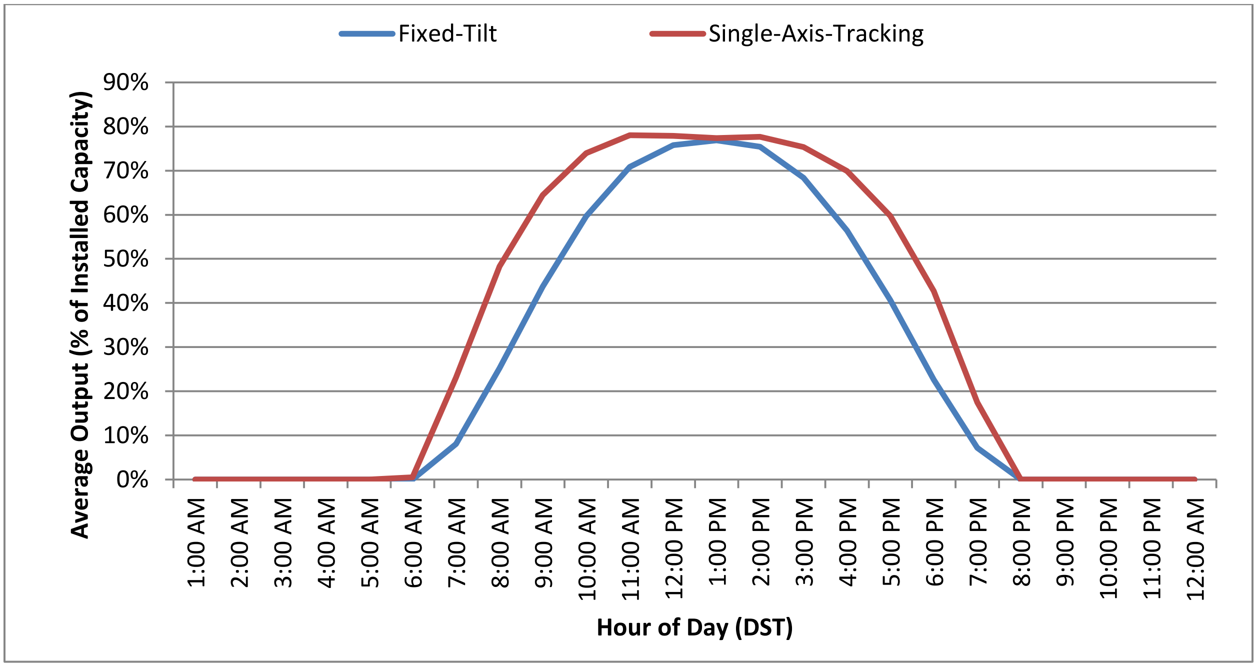
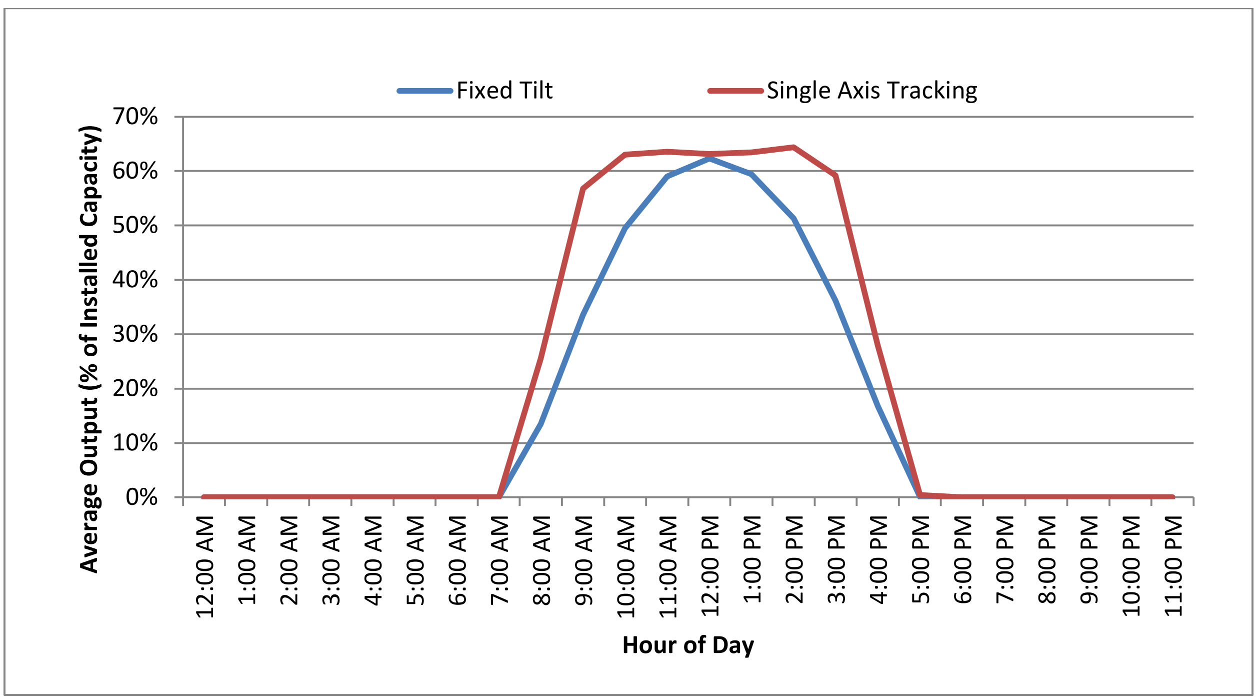


Figure 16. Average January Profiles



In summary, the following was seen in the study:

1. The winter LOLE to summer LOLE ratio is a major driver in the annual capacity values. The higher winter LOLE is driven by cold weather uncertainty and increases when solar capacity is added.

2. As solar penetration increases, the capacity values decrease further since the firm load shed events and net peak load are shifted to hours when there is less solar output.

3. Single-axis-tracking resources bring additional capacity value compared to fixed-tilt resources due to more output in morning and evening hours.