**The Costs and Benefits of**

**Distributed Solar Generation in Georgia**

**Published: 1/17/2019**

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**SECTION 1 – EXECUTIVE SUMMARY**

**Introduction**

The purpose of this document is to present the results of an illustrative analysis to determine the impacts of distributed solar penetration in Georgia. The purpose of this analysis is to develop a general expectation regarding the costs and benefits of distributed solar in Georgia and to assess the impacts to the operation of the Georgia Power Electric System.

**Process and General Approach**

This analysis of the costs and benefits of distributed solar was performed according to the processes and methodologies described in the document titled “A Framework for Determining The Costs and Benefits of Renewable Generation in Georgia” (“Framework”). An assumption was made for the purposes of these calculations that the distributed solar could be implemented overnight, thus 2019 is the first year of the study. For clarification, the distributed solar block analyzed in this study is added to Georgia Power Company’s (“Georgia Power” or the “Company”) existing planning case to determine the incremental costs and benefits.[[1]](#footnote-1)

**Summary of Results**

Table 1 contains a summary of the results for the next 1,000 MW of distributed solar. The results[[2]](#footnote-2) shown in Table 1 are levelized[[3]](#footnote-3) across 30 years beginning in 2019. The value shown in each category is incremental to the base case and represents the benefit or cost of an additional 1,000 MWs of distributed solar to the Georgia Power electric system. The acquisition costs of distributed solar facilities are ***not*** included in this analysis.

**Table 1: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| Avoided Energy Costs | **REDACTED** |
| Deferred Generation Capacity Costs | **REDACTED** |
| Deferred Transmission Investment | **REDACTED** |
| Reduced Distribution Losses | **REDACTED** |
| Distribution Operations Costs |  |
| Ancillary Services - Reactive Supply and Voltage Control |  |
| Generation Remix | **REDACTED** |
| Support Capacity (Flexible Reserves) | **REDACTED** |
| Bottom Out Costs |  |
| Long Term Service Agreement (LTSA) Costs |  |
| Program and Administration Costs |  |
| Total Net Avoided Cost | **REDACTED** |

Figure 1 provides a pictorial representation of the results shown in Table 1.

**Figure 1: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)**

**REDACTED**

Figure 2 illustrates the benefit and cost impacts for 10, 15, 20, 25, and 30-year terms on a levelized basis. The values in Figure 2 are illustrative and should not be used to infer any specific value of distributed solar generation in any particular year and should not be used to price any particular distributed solar program. Should there be a need to develop such pricing mechanisms, an analysis should be performed using consistent Framework methodologies and project-specific details and assumptions.

**Figure 2: Levelized Costs and Benefits of Distributed Solar Generation ($/MWH)**

**REDACTED**

**Conclusions**

A number of conclusions can be drawn from these results. First, because of how these specific results were calculated and the assumptions used in calculating them, one conclusion that ***should not*** be made from these results is that solar can or should be added on the system at rates derived from these particular solar cost benefit results. These results are based on a number of assumptions that were made for the purpose of determining the relative impacts of adding distributed generation solar on the system and not for the purpose of determining costs and benefits for any particular project or program. Any specific solar project or program should be evaluated in a similar manner using the Framework along with the appropriate assumptions associated with that program or project.

Conclusions that ***can*** be drawn from these results include the following important observations:

1. Excluding acquisition costs, the total benefit provided by distributed generation solar exceeds the total cost caused by distributed generation solar.
2. Compared to the avoided energy benefits provided by distributed generation solar, the deferred generation capacity costs and deferred transmission investment benefits are relatively small.
3. Support Capacity costs are immediately incurred.

**SECTION 2 – DISTRIBUTED GENERATION SOLAR COST-BENEFIT RESULTS**

**Distributed Solar Hourly Profiles**

The energy profile in Table 2 for this study is consistent with the approach described in the Joint Recommendation, which was approved by the Georgia Public Service Commission on December 22, 2016, to implement the Framework.

**Table 2: Generation Profile for Distributed Generation Solar (MW)**

**REDACTED**

**Avoided Energy Costs**

In accordance with the Framework, the avoided costs used in this analysis are the official avoided costs for the Southern Company electric system. For this analysis, therefore, the B2018 moderate gas $0 carbon (“MG0”) avoided cost scenario was used as the basis for determining the solar-weighted avoided energy costs. Table 3 below depicts the average energy costs by month for the MG0 case for the year 2019.

**Table 3: Representation of MG0 Avoided Costs for 2019 ($/MWH)**

**REDACTED**

The avoided energy costs were then applied to the distributed solar generation profile by hour for each year to calculate the expected avoided energy benefit. Table 4 shows the avoided energy costs for the next 1,000 MW of distributed solar generation.

**Table 4: Avoided Energy Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

The avoided energy costs were then levelized on a 30-year basis using an **REDACTED**% Weighted Average Cost of Capital (“WACC”) resulting in the solar-weighted avoided energy costs in Table 5 below.[[4]](#footnote-4)

**Table 5: Levelized Solar-Weighted Avoided Energy Costs ($/MWH)**

|  |  |  |
| --- | --- | --- |
|  |  | |
| Solar-Weighted Avoided Energy Costs | | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

**Deferred Generation Capacity Costs**

Consistent with the evaluation of any new generation resource, no capacity value was applied to the solar generation until the first year of need for Georgia Power. The year of need is identified in the official expansion plan, which includes all previously committed solar resources at the time the B2018 expansion plan was created. In this case, the first year of need in the B2018 expansion plan is 2028.

The value of the deferred generation capacity was based upon the B2018 Retail Capacity Price Forecast (“RCPF”) for Georgia Power Company as identified below in Table 6. Values are only shown beginning in the year of need.

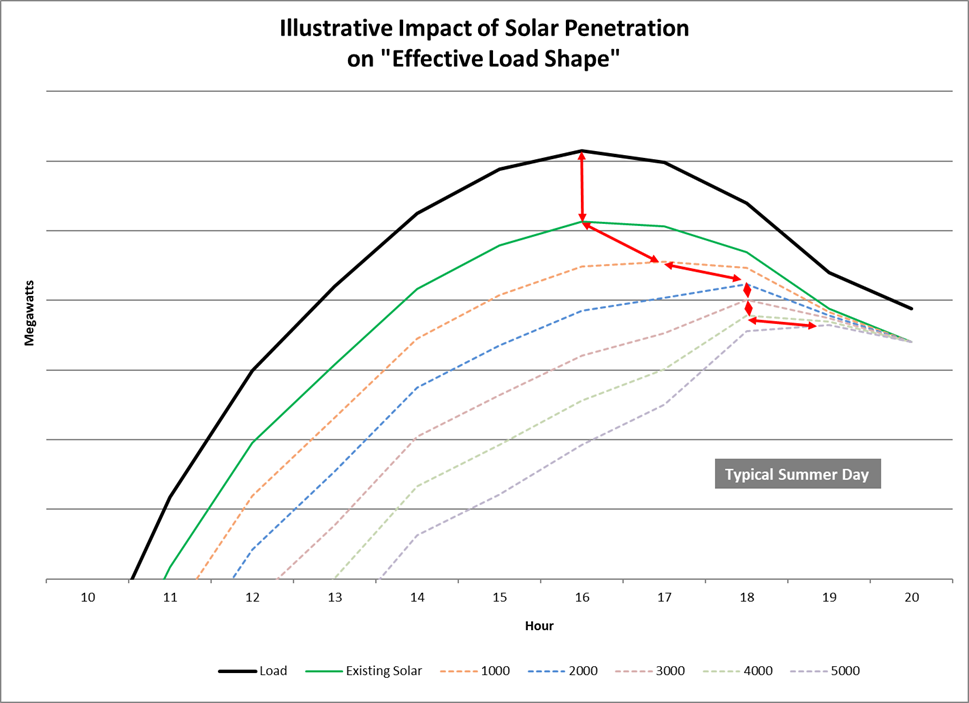
**Table 6: B2018 Retail Capacity Price Forecast ($/kW-yr) beginning with year of need**

|  |  |
| --- | --- |
| Year | Price Forecast |
| 2028 | **REDACTED** |
| 2029 | **REDACTED** |
| 2030 | **REDACTED** |
| 2031 | **REDACTED** |
| 2032 | **REDACTED** |
| 2033 | **REDACTED** |
| 2034 | **REDACTED** |
| 2035 | **REDACTED** |
| 2036 | **REDACTED** |
| 2037 | **REDACTED** |
| 2038 | **REDACTED** |
| 2039 | **REDACTED** |
| 2040 | **REDACTED** |
| 2041 | **REDACTED** |
| 2042 | **REDACTED** |
| 2043 | **REDACTED** |
| 2044 | **REDACTED** |
| 2045 | **REDACTED** |
| 2046 | **REDACTED** |
| 2047 | **REDACTED** |
| 2048 | **REDACTED** |

The amount of deferred capacity to be applied to the RCPF is determined using the current budget’s version of the Capacity Worth Factor Table (“CWFT”). The CWFT represents the relative worth of capacity from one period to another (i.e., hour, month, season, etc.). As such, the Incremental Capacity Equivalent (“ICE”) factor is calculated by calculating the sum-product of the CWFT and the distributed resource profile and dividing by the maximum output of the distributed resource (i.e., 1,000 MW). For this study, the capacity equivalent was an Incremental Capacity Equivalent (“ICE”) factor of **REDACTED**%.

Figure 3 below shows a graphical representation of how various levels of distributed solar generation might impact the effective load on a peak day in the year 2020. As the figure demonstrates, at distributed solar generation penetration levels of 5,000 MW and greater, there is a negligible impact on the peak load because the effective peak load has shifted to approximately 7PM, moving the effective peak into the evening (i.e., past sunset) hours.

**Figure 3: Impacts of Distributed Solar on Effective Peak Load**

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Note: “Existing Renewables” reflects the impact of all renewable resources currently or committed to be installed on the Southern Company electric system by the year 2021.

Using the base case year of need of 2028, the deferred generation capacity cost evaluation was then calculated for each year. Table 7 shows the results of this deferred capacity cost evaluation, which was then levelized on a 30-year basis using an **REDACTED**% WACC resulting in the dollar per-MWH deferred capacity costs in Table 8 below.

**Table 7: Deferred Generation Capacity Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

**Table 8: Levelized Deferred Generation Capacity Costs ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| Deferred Generation Capacity Costs | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

**Deferred Transmission Investment**

As established in the Framework, the Deferred Transmission Investment represents the value of the transmission projects deferred as a result of additional distributed solar on the system. The deferred transmission investment was determined based on a previous study performed for the Southern Company electric system. First, the long run (20 year) incremental cost of transmission expansion was identified. This cost included the various transmission projects that would be needed assuming 300 MW of load growth per year[[5]](#footnote-5) starting in 2023 and continuing over a period of 20 years without installation of the distributed solar generation. The total transmission projects identified equated to a total long run incremental cost of transmission of $**REDACTED**/kW[[6]](#footnote-6) in 2018$.

Using these transmission projects as a baseline, 1,000 MW solar tranches at the system level were evaluated to determine which transmission projects could be deferred (and for how many years) as a result of adding the distributed solar generation. The amount of distributed solar that was assumed to be available and offsetting load at the peak (i.e., coincident with the transmission peak load) was **REDACTED**%[[7]](#footnote-7) of the installed amount (approximately **REDACTED** MW for the 1,000 MW tranche). The deferral cost (i.e., the Economic Carrying Cost or “ECC”) of these projects then served as the basis for determining the avoided transmission cost associated with the additional distributed solar. Table 9 below shows a summary of the calculated avoided transmission cost for the first 1,000 MW of additional distributed solar generation using this methodology.

**Table 9: 20-Year Deferred Transmission Investment Cost (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2020 M$) | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

Because the deferred transmission analysis was performed on a 20-year basis and the remainder of the solar cost benefit analysis was performed on a levelized 30-year basis, the transmission deferred cost values were converted to a 30-year basis for consistency. Consistent with the extrapolation methodology explained in the Framework, the conversion was accomplished by using the average annual ECC of the last 10 years of the 20-year analysis for year 21. This value is then escalated at the Transmission Capital Cost Escalator, which is base inflation, for the remainder of the study period. The results of this conversion are shown below in Table 10.

**Table 10: 30-Year Equivalent Deferred Transmission Investment Cost**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

Finally, this 30-year equivalent deferred transmission investment cost was levelized consistent with the other cost benefit components. Table 11 below shows these results.[[8]](#footnote-8)

**Table 11: Levelized Deferred Transmission Investment Costs ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| Deferred Transmission Costs | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

**Reduced Distribution Losses**

As established in the Framework, a system-weighted distribution loss profile was applied to the 1,000 MW solar profile and then evaluated against avoided energy costs to determine the distribution loss impact.[[9]](#footnote-9) Because system avoided energy costs are calculated at the transmission substation level, the loss factors for the distributed losses were calculated based on losses from the transmission substation level down to the distribution feeder level. Although an 8,760-hour loss factor profile was used, the average avoided distribution loss impact associated with the distributed solar across the year was **REDACTED**% of the distributed solar profile. This 8,760 hourly loss factor was applied to the 8,760 distributed solar generation profile in each year to calculate an 8,760 loss profile for each year. This loss profile, like the distributed solar generation profile, was then multiplied in each hour by the avoided energy cost to get the avoided distribution losses cost. Table 12 below shows the levelized avoided distribution losses cost values that resulted from this calculation.

**Table 12: Levelized Reduced Distribution Losses ($/MWH)**

|  |  |  |
| --- | --- | --- |
|  |  | |
| Reduced Distribution Loss | | **REDACTED** |

\*Positive values represent benefits in the cost benefit determination.

**Distribution Operations Costs**

Georgia Power Company has not yet developed a methodology to calculate the expected distribution operating costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Ancillary Services – Reactive Supply and Voltage Control**

Georgia Power Company has not yet developed a methodology to calculate the expected reactive supply and voltage control costs associated with significant penetrations of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Ancillary Services – Regulation**

The incremental Regulating Reserve requirement associated with the distributed solar generation was determined using 10-minute solar output data from the Electric Power Research Institute (“EPRI”) research project titled *Distributed PV Monitoring and Feeder Analysis 2010-2014* (“EPRI Study”). This study evaluated the solar production of a wide distribution of pole-mounted solar panels spread across Georgia and Alabama. A series of geographically diverse sets of output data (ranging from a single site to an aggregate of all the sites studied) were analyzed to determine their 10-minute ramp volatility. The results are shown in Figure 4 below.

**Figure 4: Ramp rate cumulative frequency, 10-minute intervals, and various DPV aggregations.**

**REDACTED**

From this figure, it can be seen that the 10-minute ramp varies widely from a single installation to a highly geographically diverse set of installations. Because NERC BAL-001 Reliability Standard requires Balancing Authorities to establish Regulating Reserve requirements that are sufficient such that Area Control Error crosses the zero point in at least 90 percent of the 10-minute periods in each month, the 95th percentile of the 10-minute ramp volatility was chosen to establish the impact that distributed solar generation has on Regulating Reserve requirements.[[10]](#footnote-10) At the 95th percentile, the 10-minute ramp volatility ranges from approximately 25% for a single facility to below 10% for an aggregation of widely dispersed facilities. For this analysis, which evaluates the costs and benefits of a highly diverse penetration of distributed solar generation, it was determined that the appropriate 10-minute ramp curve to use from the EPRI Study was the one labeled “Sites A-G + AL, 10min,” which represents the most geographically diverse aggregation of the research data. Based on this profile, the ramp-down periods were calculated and from those a 12x24 chart was created of the 95th percentile values, representing an average day per month. This 12x24 chart was then used to create a repeated daily shape for each month (totaling 8,760 hourly values). This stream of hourly values is then multiplied by the CWFT, yielding a **REDACTED**% decrease to the original ICE factor. The cost impact associated with the decrease in ICE Factor is reported in the Support Capacity results below.

**Generation Remix Costs**

Generation Remix costs include a capital component and a production component. In accordance with the Framework, the Generation Remix capital costs were determined by performing a Strategist run for the distributed solar generation added and comparing the resulting expansion plan to the expansion plan without the incremental solar. The differences in the expansion plan were valued at the ECC of the specific generation technology selected in the Strategist runs. Using these costs, the Generation Remix capital component costs (or savings) were calculated for the additional solar. However, as indicated in the Framework, because these costs also include the deferred capacity benefits, those benefits were subtracted from this calculation to eliminate double counting those benefits. Table 13 shows the net present value (“NPV”) of these Generation Remix capital costs in 2019$.

**Table 13: Generation Remix Capital Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019) | **REDACTED** |

\*Positive values in this table represent benefits.

Pursuant to the Framework, the Generation Remix production costs were determined by performing a production cost model run using the incremental solar profile and expansion plans determined during the capital cost evaluation and then comparing the resulting production cost to the production cost of the prior case. Similar to the process followed previously, a smoothing process was applied to this change in production costs from 2037 and beyond. A Compound Annual Growth Rate (“CAGR”) was calculated from the first year of need (2028) to 2036 and this CAGR was then applied to the 2036 values to determine 2037 and later. As indicated in the Framework, the avoided energy cost for the solar generation was subtracted from this calculation to avoid double counting those benefits. Table 14 shows the NPV of the Generation Remix production costs in 2019$.

**Table 14: Generation Remix Production Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019) | **REDACTED** |

\*Negative values in this table represent costs.

The total Generation Remix, therefore, equals the sum of the Generation Remix capital costs and the Generation Remix production costs. Table 15 shows the total Generation Remix.

**Table 15: Total Generation Remix (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019) | **REDACTED** |

\*Positive values in this table represent benefits.

These values were then converted into 30-year levelized values as shown in Table 16.

**Table 16: 30-Year Levelized Generation Remix Costs ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| Generation Remix Costs | **REDACTED** |

\*Positive values in this table represent benefits

**Support Capacity**

Support Capacity costs include a capital component and a production component. In accordance with the Framework, the total amount of Support Capacity needed was determined by calculating the sum of[[11]](#footnote-11):

1. The incremental Regulating Reserve requirement; and
2. The impact of the Forecast Error associated with the incremental distributed solar on expected unserved energy.

For each of the factors identified above, the impact was determined according to the procedure and methodology set forth in the Framework.

As identified in the Ancillary Services-Regulation section above, the Regulating Reserve portion of Support Capacity was calculated as a **REDACTED**% decrease in the ICE factor as shown in Table 21 below in the row labeled “Regulation Impact.” Strategist does not specifically model Regulation. Therefore, the capacity costs associated with this Regulating Reserve requirement was valued at the ECC of a CT beginning in the year of need.

As stated in the Framework, the solar Forecast Error portion of the Support Capacity was determined by developing an 8,760 solar forecast error table from the solar data in the EPRI Study. A “persistent forecast” assumption[[12]](#footnote-12) was made from the data and a resulting assumed forecast error for each hour was determined. Although an 8,760 forecast error profile was developed and used, Table 17 shows the average hourly solar forecast error by month that was assumed for the analysis.

**Table 17: Solar Forecast Error[[13]](#footnote-13)**

**REDACTED**

This forecast error matrix was then applied to the latest Capacity Worth Factors Table [[14]](#footnote-14) to determine the expected impact that the assumed solar forecast error would have on expected unserved energy. That calculation indicated that solar forecast error resulted in an impact to the solar capacity value of **REDACTED**% of the installed solar capacity. In other words, this was the impact to the capacity value of the incremental solar to restore the system to its previous level of assumed reliability. This **REDACTED**% was applied to the 1,000 MW solar tranche to determine the amount of Support Capacity needed as a result of solar forecast error and is shown in Table 18 below in the row labeled “Forecast Error Impact.”

Table 18 below shows the resulting decrease in the ICE factor attributed to Regulating Reserve requirement and solar Forecast Error Impact. Together, the two calculations represent the total Support Capacity requirements for 1,000 MW of distributed solar added to the Georgia Power electric system.

In the case of battery storage coupled with distributed solar, the declared use case of an appropriately sized battery would reduce or eliminate the Support Capacity costs due to a smoother (less intermittent) or more predictable (less forecast error) solar output from the facility. Additionally, the battery charge duration must be taken into consideration when reduction of Support Capacity is being contemplated. In other words, a battery system designed to to reduce short-duration intermittency would not necessarily be capable of also reducing forecast error over a period of several hours.

**Table 18: Decrease in ICE Factor for Support Capacity(%)**

|  |  |
| --- | --- |
| Support Capacity Component |  |
| Regulation Impact | **REDACTED** |
| Forecast Error Impact | **REDACTED** |

Both the Regulation Impact and Forecast Error Impact were accounted for in Strategist to determine – relative to the Strategist case with the distributed solar added – any advancement costs (or deferral benefits) associated with the addition of these requirements. The difference in resulting capital costs between the incremental solar case and the respective base case represents the capital cost associated with Support Capacity. Table 19 below shows the NPV differences in capital costs for distributed solar.

**Table 19: Support Capacity Capital Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Negative values in this table represent costs.

As specified in the Framework, the Support Capacity production costs were calculated by modeling the expansion plan results from the Strategist cases in a production cost model and calculating the differences in production costs. In addition to modeling the expansion plan changes, the additional Regulating Reserves were modeled in the production cost model as an increase in Spinning Reserve requirement. Table 20 shows the results of the Support Capacity production cost calculations.

**Table 20: Support Capacity Production Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Negative values in this table represent costs.

The sum of the Support Capacity capital costs and the Support Capacity production costs represents the total Support Capacity Costs, shown below in Table 21.

**Table 21: Total Support Capacity Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental PV (2019 M$) | **REDACTED** |

\*Negative values in this table represent costs.

These values were then converted into 30-year levelized values in $/MWH as shown in Table 22.

**Table 22: Levelized Support Capacity Capital Costs ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| Support Capacity Capital Costs | **REDACTED** |

\*Negative values in this table represent costs.

**Bottom Out Costs**

Georgia Power Company has not yet developed an agreed-upon methodology to calculate the bottom out costs associated with penetration of distributed solar generation. Therefore, this section is included as a placeholder for future updates to this analysis.

**Long-Term Service Agreement (“LTSA”) Costs**

Georgia Power Company has not yet developed a methodology to calculate the LTSA impacts related to penetration of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Program and Administration Costs**

Georgia Power Company has not yet developed a methodology to calculate the expected program and administrative costs associated with penetration of distributed solar. Therefore, this section is included as a placeholder for future updates to this analysis.

**Conclusions**

As stated in the Executive Summary, the following conclusions can be drawn from these results:

1. The total benefit provided by distributed solar generation exceeds the total cost caused by distributed solar generation.
2. Compared to the avoided energy benefits provided by distributed solar, the deferred generation capacity costs and deferred transmission investment benefits are relatively small.
3. Support Capacity costs are immediately incurred.
4. Should battery storage be contemplated as a coupled device with distributed generation solar, depending on the intended use case and minimum sizing of the battery storage system relative to the maximum output of the distributed solar facility, some or all of the Support Capacity costs could be credited back to the distributed solar project. This is due to the elimination of either Forecast Error or additional Regulating Reserves, again, depending on the declared use case of the battery storage system.

Based on these conclusions, all new proposed distributed solar resources should be evaluated in light of all previously committed solar projects so that the declining value of solar generation can be appropriately measured.

1. In this case, the existing planning case refers to Georgia Power’s 2018 base case including all existing solar and wind commitments but not including those renewable resources recommended as part of the 2019 Integrated Resource Plan. [↑](#footnote-ref-1)
2. All values are in $/MWH of solar generation. Positive values represent benefits. Negative (red) values represent costs. Areas that are shaded are components that, while appropriately factored into an assessment of the costs and benefits of solar, were not calculated in this iteration of the cost-benefit analysis because the methodology is still under development. The values shown are not indicative of any specific value of distributed solar generation in any particular year, and should not be used to price any particular distributed solar program. Should there be a need to develop such pricing mechanisms, an analysis should be performed using consistent Framework methodologies and project-specific details and assumptions. [↑](#footnote-ref-2)
3. A levelized value is a single value that can be applied annually much like an annuity or mortgage payment. These levelized values were calculated by determining the annual annuity value that produces the same Net Present Value as the nominal stream of costs and benefits considered in the analysis. [↑](#footnote-ref-3)
4. The energy component of deferred transmission losses is included as part of these avoided energy costs. [↑](#footnote-ref-4)
5. Across the entire Southern Company electric system. [↑](#footnote-ref-5)
6. Determined as the sum of the capital costs of all the projects identified in the study (in 2018$) divided by the assumed long-term load growth of 6,000 MW. [↑](#footnote-ref-6)
7. Determined as the average expected output of the distributed solar during hours 15 and 16 (3-4PM) in the months of June-August. [↑](#footnote-ref-7)
8. The demand component of deferred transmission losses is included as part of this deferred transmission cost. [↑](#footnote-ref-8)
9. This distribution loss profile included impacts of transmission substation losses, subtransmission substation and line losses, distribution substation losses, and distribution line losses. [↑](#footnote-ref-9)
10. Choosing the 90th percentile would create risk that the Balancing Authority could not meet the requirements in the standard and choosing the 100th percentile would have been overly conservative, resulting in greater than necessary cost impacts. [↑](#footnote-ref-10)
11. At this time, the Southern Company has not developed an agreed-upon methodology for determining the ramping requirements of a significant penetration of renewable resources. [↑](#footnote-ref-11)
12. A “persistent forecast” is one in which the current hour’s actual output is used as a basis for determining the forecast for the next hour. Since solar forecast data was not available, a “persistent forecast” was developed from the historical output. This manufactured forecast served as the basis for determining the forecast error. [↑](#footnote-ref-12)
13. Hours in which no generation occurs have been excluded from this table since no solar forecast error would be present. [↑](#footnote-ref-13)
14. The latest version of the Capacity Worth Factor Table is from B2018. B2019 data was not fully available for this analysis. [↑](#footnote-ref-14)