**The Costs and Benefits of Fixed and Variable Wind**

**Delivered to Georgia**

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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 both variable and fixed wind[[1]](#footnote-1) delivered to the electric system in Georgia. The purpose of this analysis is to develop a general expectation regarding the costs and benefits of wind delivered to 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 wind 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”). Although the narrative in the Framework focuses largely on solar, the methods and principles apply to the analysis of any renewable resource.

An assumption was made for the purposes of these calculations that the wind could be implemented overnight, thus 2019 is the first year of the study. For clarification, this wind block is added to Georgia Power Company’s (“Georgia Power” or the “Company”) existing planning case to determine the incremental costs and benefits.[[2]](#footnote-2)

Finally, because the impacts to costs and benefits may be different for fixed wind as compared to variable wind, the analysis was performed for variable wind products. The primary difference between the variable and fixed wind is that fixed wind projects would not require Support Capacity since such fixed generation is known and scheduled in advance.

**Summary of Results**

Table 1 contains a summary of the results for the next 1,000 MW of wind. The results[[3]](#footnote-3) shown in Table 1 are levelized[[4]](#footnote-4) 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 MW of wind delivered to Georgia after considering the impact of the previous 1,000 MW of wind. The acquisition costs of wind projects are ***not*** included in this analysis.

**Table 1: Levelized Costs and Benefits of Wind ($/MWH)**

|  |  |
| --- | --- |
|  |  |
| **Avoided Energy** | **REDACTED** |
| **Deferred Generation Capacity Costs** | **REDACTED** |
| **Deferred Transmission Investment** | **N/A** |
| **Reduced Distribution Losses** | **N/A** |
| **Distribution Operations Cost** |  |
| **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 Wind ($/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 wind generation in any particular year and should not be used to price any particular wind product. Should there be a need to develop such pricing mechanisms, an analysis should be performed using consistent Framework methodologies along with project-specific details and assumptions.

**Figure 2: Levelized Costs and Benefits of Wind – ($/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 wind can or should be added on the system at rates derived from these particular cost benefit results. These results are based on several assumptions that were made for the purpose of determining the relative impacts of adding wind on the system and not for the purpose of determining costs and benefits for any particular project or program. Any specific wind project or program should be evaluated in a similar manner using the Framework along with the appropriate assumptions associated for that program or project.

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

1. Since the wind analysis studied imports of wind to Georgia at the bulk transmission level, there are no Deferred Transmission Investment benefits or Reduced Distribution Losses.
2. With Support Capacity costs being the primary difference in value between fixed wind and variable wind due to the use of the same assumed wind production profile, the procurement costs and/or transmission delivery costs of these two wind products may be significantly different even though their avoided cost values to Georgia Power are similar.
3. Due to the higher capacity factors of wind generation as compared to solar generation, the per-MWH costs for Support Capacity are smaller for wind than solar.

**SECTION 2 – WIND COST-BENEFIT RESULTS**

**Wind Profile**

For purposes of this analysis, the assumed wind profile was based on the Southwest (SW) wind profile as defined in the Joint Recommendation, which was approved by the Georgia Public Service Commission on December 22, 2016 in Docket No. 40161. Additionally, it was assumed that the wind would be delivered from western Oklahoma to the Southern Company transmission system with a cumulative transmission loss factor of 10%. Although the profile for fixed wind can be considerably different than the profile for variable wind, fixed wind profiles are often a matter of negotiation between parties; therefore, the profiles for fixed and variable wind for purposes of this analysis were assumed to be the same so that only the true differences associated with the variability and intermittency of variable wind would be reflected in the analysis. This 12x24 expected profile is shown below in Table 2.

**Table 2: Monthly Wind Output by Hour as a Percent of Nominal Capacity**

**REDACTED**

**Avoided Energy Costs**

In accordance with the Framework, the avoided energy costs used in this analysis are the official avoided energy costs for the Southern Company electric system. Therefore, for this analysis, the B2018 moderate gas $0 carbon (MG0) avoided cost scenario was used as the basis for determining the wind-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 Energy Costs for 2019 ($/MWH)**

**REDACTED**

The avoided energy costs were then applied to the wind 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 wind. Because the avoided energy cost calculation was based upon an hourly-integrated profile and the fixed wind profile was assumed to be the same as the variable wind profile, the avoided energy costs for fixed and variable wind were identical. The Company anticipates that avoided energy costs could be greater for fixed delivery projects than what was evaluated in this analysis; however, this is highly dependent on the final negotiated profile.

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

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

\*Positive values in this table represent benefits.

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

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

|  |  |
| --- | --- |
|  |  |
| **Avoided Energy ($/MWH)** | **REDACTED** |

\*Positive values in this table represent benefits.

**Deferred Generation Capacity Costs**

Consistent with the evaluation of any new generation resource, no capacity value was applied to the wind 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 renewable 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**%.

Using the base case year of need of 2028, the deferred generation capacity cost evaluation for both fixed and variable wind were 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 NPV (2019 M$)** | **REDACTED** |

\*Positive values in this table represent benefits.

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

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

\*Positive values in this table represent benefits.

**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 wind generation on the system. Since this wind analysis is based on wind that is imported into the Georgia Power system, there is no deferred transmission investment associated with wind generation in this analysis.

**Reduced Distribution Losses**

As with the Deferred Transmission Investment, since this wind analysis is not associated with distributed generation, there is no reduced distribution loss associated with wind generation in this analysis.

**Distribution Operations Costs**

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

**Ancillary Services – Regulation**

The incremental Regulating Reserve requirement associated with wind was determined using 10-minute wind output data that is available for the profile specified in the Framework. Using this data, the impact to regulation was determined by looking at the cumulative duration curve of the 10-minute “down” ramps (as a percent of nominal output) – in other words, the percent of time in which the 10-minute ramp down exceeded a particular value (95% as discussed in the following paragraph). These ramp downs would have implications on the regulation-up requirements to the system.

As was established within the Framework, the 95th percentile of the 10-minute ramp volatility was chosen to establish the impact that wind generation has on Regulating Reserve requirements.[[6]](#footnote-6) 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 Capacity Worth Factor Table, 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 wind generation added and comparing the resulting expansion plan to the expansion plan without the incremental wind. The differences in the expansion plan were valued at the economic carrying costs (“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 wind. 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 9 shows the net present value (“NPV”) of these Generation Remix capital costs in 2019$.

**Table 9: Generation Remix Capital Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| **Incremental NPV (2019 M$)** | **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 wind profiles 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 wind generation was subtracted from this calculation to avoid double counting those benefits. Table 10 shows the NPV of the Generation Remix production costs in 2019$.

**Table 10: Generation Remix Production Costs (M$)**

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

\*Positive values in this table represent costs.

The total Generation Remix costs, therefore, equal the sum of the Generation Remix capital costs and the Generation Remix production costs. Table 11 shows the total Generation Remix.

**Table 11: Total Generation Remix Costs (M$)**

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

\*Positive values in this table represent benefits.

These values were then converted into 30-year levelized values as shown in Table 12.

**Table 12: 30-Year Levelized Generation Remix Production 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[[7]](#footnote-7):

1. The incremental Regulating Reserve requirement; and
2. The impact of the Forecast Error associated with the incremental wind 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 14 below in the row labeled “Regulation Impact”. Strategist does not specifically model Regulation. Therefore, the capacity costs associated with this Regulation requirement was valued at the ECC of a CT beginning in the year of need.

Per the Framework, the wind Forecast Error portion of the Support Capacity was determined by developing an 8,760 wind forecast error table from the 33 years of available wind data. A “persistent forecast” assumption[[8]](#footnote-8) 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 13 shows the average hourly wind forecast error by month that was assumed for the analysis.

**Table 13: 12x24 Wind Forecast Error Profile**

**REDACTED**

This forecast error matrix was then applied to the latest Capacity Worth Factors table[[9]](#footnote-9) to determine the expected impact that the assumed wind forecast error would have on expected unserved energy. That calculation indicated that wind forecast error resulted in an impact to the wind capacity value of **REDACTED**% of the installed wind capacity. In other words, this was the impact to the capacity value of the incremental wind to restore the system to its previous level of assumed reliability. This **REDACTED**% was applied to the 1,000 MW of wind to determine the amount of Support Capacity needed as a result of wind forecast error and is shown in Table 14 below in the row labeled “Forecast Error Impact”.

Table 14 below shows the resulting decrease in the ICE factor attributed to Regulating Reserve requirement, and wind Forecast Error Impact. Together, the two calculations represent the total Support Capacity requirements for 1,000 MW of wind to the Georgia Power electric system. Fixed wind, because it is known and delivered on an hourly-integrated basis, would have neither Regulating Reserve nor Wind Forecast Error Impacts, therefore ***Fixed Wind had no Support Capacity costs.***

In the case of battery storage coupled with wind, 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) wind output from the facility. Additionally, the battery duration must be taken into consideration when reduction of Support Capacity is being contemplated. In other words, a battery system designed to reduce the short-duration intermittency would not necessarily be capable of also reducing the forecast error over a period of several hours.

**Table 14: Decrease in ICE Factor for Support Capacity (%) for Variable Wind**

|  |  |
| --- | --- |
|  |  |
| 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 wind added – any advancement costs (or deferral benefits) associated with the addition of these requirements. The difference in resulting capital costs between the wind case and the respective base case represents the capital cost associated with Support Capacity. Table 15 below shows the NPV differences in capital costs for wind.

**Table 15: Support Capacity Capital Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental NPV (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 16 shows the results of the Support Capacity production cost calculations.

**Table 16: Support Capacity Production Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental NPV (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 17.

**Table 17: Total Support Capacity Costs (M$)**

|  |  |
| --- | --- |
|  |  |
| Incremental NPV (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 18.

**Table 18: Levelized Support Capacity Costs ($/MWH)**

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

\*Negative values represent costs in the cost benefit determination.

**Bottom Out Costs**

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

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

Georgia Power Company continues to work to develop a methodology to calculate the LTSA impacts related to penetration of wind. 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 administrative costs associated with penetration of wind. 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. Since the wind analysis studied imports of wind to Georgia at the bulk transmission level, there are no Deferred Transmission Investment costs or Reduced Distribution Losses.
2. The difference in value between fixed wind and variable wind is relatively small due to the use of the same assumed wind production profile; therefore, while the procurement costs and/or transmission delivery costs of these two wind products may be significantly different, their avoided cost values to Georgia Power are similar.
3. Due to the higher capacity factors of wind generation as compared to solar generation, the per-MWH costs for Support Capacity are smaller for wind than solar.

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

1. Variable wind is wind that is received “as generated” on a moment to moment basis, fixed wind is wind that is known and scheduled in advance on an hourly-integrated basis. [↑](#footnote-ref-1)
2. 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-2)
3. All values are in $/MWH of wind delivered 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 wind, were not calculated in this iteration of the cost-benefit analysis because the methodology for doing so is either still under development. The values shown are not indicative of any specific value of wind generation in any particular year and should not be used to price any particular wind product. 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-3)
4. 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-4)
5. The energy component of deferred transmission losses is included as part of these avoided energy costs. [↑](#footnote-ref-5)
6. 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-6)
7. At this time, Southern Company has not developed an agreed-upon methodology for determining the ramping requirements of a significant penetration of renewable resources. [↑](#footnote-ref-7)
8. 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. A persistent forecast was developed from the historical output. This manufactured forecast served as the basis for determining the forecast error. [↑](#footnote-ref-8)
9. The latest version of the Capacity Worth Factor Table is from B2018. B2019 data was not fully available at the time this study was performed. [↑](#footnote-ref-9)