**Southern Company**

**2019 Integrated Resource Plan**

**Resource Mix Study**

January 2019

# SUMMARY

## STUDY OBJECTIVE

The primary objective of this study is to provide information regarding the development of an optimum resource addition schedule. The resulting resource addition schedule was selected to minimize revenue requirements and electricity rates while complying with reliability guidelines, environmental laws and regulations, considering risk and flexibility. This supply-side plan will serve as the basis for a variety of financial and engineering studies over the next several years including the consideration of demand-side options (“DSOs”). The base case and all other cases contained in this Mix Study do not reflect commitments but instead are generic expansion plans used for planning and to support analyses. Under the framework established in the state of Georgia, when a capacity need is identified through an IRP, Georgia Power Company (“Georgia Power” or the “Company”) will meet such identified need in accordance with the Georgia Public Service Commission (“Commission”) request for proposal (“RFP”) rules and will utilize Georgia Power specific information as appropriate.

## ASSUMPTIONS

The key inputs to the study are the load forecasts, projected DSOs, cost of capital and escalation rates, a reliability criterion, costs and performance characteristics of candidate generating technologies, environmental compliance strategies, fuel forecasts and the operating data and retirement or projected unavailability dates of existing and committed generating units. For Georgia Power, discrete retirement dates of owned generating units were utilized in the base case for any particular unit for which decertification is requested in this filing. For remaining owned units, it was assumed that the respective thermal units would continue to operate throughout the planning period or upon expiration of a nuclear combined license. The load forecasts were completed in fall 2018. Escalation and cost of capital rates are based on the IHS Markit April 2018 forecast. Long term fuel price projections were developed for Southern Company by Charles River Associates (a.k.a. CRA International or “CRA”) as described in Technical Appendix Volume 1. Generation technology capital cost estimates and escalation were developed by Southern Company Engineering and Construction Services (or “E&CS”) and Southern Company Services Generation Planning and Development (or “GPD”). The reserve margin constraint used to develop the least cost summer resource addition schedule coincides with the present planning reserve guideline which recommends a 16.25% system Summer Target Reserve Margin. In addition, the Company is recommending a long-term Winter Target Reserve Margin. As such, a reserve margin constraint will also be applied. The reserve margin constraint used to develop the least cost winter resource addition schedule is a 26% system Winter Target Reserve Margin.

## EXISTING CAPACITY AND ENERGY MIX

Including Gulf Power, the retail operating companies’ primary fuel is gas/oil, accounting for approximately **REDACTED** % of their energy requirement with the balance provided by **REDACTED** % from coal, **REDACTED** % from nuclear, and **REDACTED** % from hydro and other. The generating capacity of the retail operating companies consists of 30% coal, 43% oil and gas, 9% nuclear, and 18% hydro and other.

## SELECTION OF CANDIDATE TECHNOLOGIES

Combined cycle (“CC”), CC with carbon capture and compression (“CCC”), combustion turbines (“CT”), and CT with Selective Catalytic Reduction (“SCR”) were the technologies selected for the mix analysis. The technology selection was based on results from the Technology Evaluation Process and Economic Screening reviewed in Section 4 of the Mix Study as well as CHAPTER 4 of the 2019 IRP Main Document.

## OPTIMIZATION PROCESS

Data about the existing generation system of the retail operating companies and various projections for the future load growth, DSOs, and cost and performance characteristics of candidate technologies were used in the generation production cost model, Strategist, and its optimization sub module, PROVIEW. PROVIEW uses a dynamic programming technique to develop the least cost capacity addition schedule. The model considers all possible combinations of capacity additions on a yearly basis that would satisfy reserve margin constraints. The combination of alternatives with the smallest production and capital cost over the planning horizon is the least cost plan. The output of the model was used as the primary guide in developing the base case system expansion plan for the retail operating companies.

## OPTIMUM MIX

The conclusion of this study, based upon the results of the base case, sensitivities, and scenario case analyses, is that additional generation capacity requirements will involve a mixture of combustion turbine generation, combustion turbine generation with SCR, combined cycle generation, and combined cycle generation with CCC. In cases without carbon dioxide (“CO2”) emissions cost, the combustion turbine and the combined cycle technologies comprised the majority of the new capacity added during the planning period. For cases that included CO2 emissions cost, as the CO2 prices reach elevated levels, combustion turbine with SCR and combined cycle generation with CCC are the primary technologies selected.

Due to the uncertainty related to long term fuel cost and carbon pressure, nine fully interrelated planning scenario cases were developed to explore the potential impacts. This resulted in nine internally-consistent outlooks of correlated fuel prices and carbon emissions costs, electricity demand and prices, and capacity and energy mixes.

As the time for commitment to new capacity approaches, additional detailed studies are performed to identify the resources for meeting specific retail operating company requirements. These projections will be reviewed as input data assumptions are updated.

## DEMAND-SIDE OPTIONS

Demand-side options are either “dispatchable” or “non-dispatchable.” Examples of dispatchable DSO include interruptible load and other options which can be controlled and dispatched by a utility. Examples of non-dispatchable DSO include options such as insulation or end-use equipment efficiency which are not directly controllable by a utility. Dispatchable DSOs were included as a capacity resource in this study. Non-dispatchable DSOs were accounted for in the load forecasts.

# INTRODUCTION

This report summarizes the results of the 2019 Resource Mix Study. The recommendations of the study provide input to an optimum resource addition schedule for the retail operating companies. The base case resource addition schedule is based on maintaining a minimum summer reserve margin and minimizing the total operating and capital costs over the planning horizon. In addition, given the Company’s recommendation to adopt seasonal planning and implement a long-term Winter Target Reserve Margin of 26%, an additional expansion plan sensitivity is included in Table 7 of this 2019 Resource Mix Study. While both summer and winter resource addition schedules are included in this 2019 Resource Mix Study, future resource addition schedules will be based on the additions needed to meet the higher of the summer or winter capacity need.

Southern Company is the parent of Georgia Power, Alabama Power Company (“Alabama Power”), Mississippi Power Company (“Mississippi Power”), Southern Power Company (“Southern Power”), and Southern Company Gas (formerly AGL Resources Inc.). On January 1, 2019, Southern Company completed the sale of Gulf Power Company (“Gulf Power”) and other Florida assets to NextEra Energy, Inc. However, for a Transition Period, Georgia Power, Alabama Power, Mississippi Power, Southern Power, and Gulf Power will continue to operate their respective electric generating facilities and conduct system operations (generally referred to as the “Pool”) pursuant to and in accordance with the provisions of the Southern Company System Intercompany Interchange Contract (“IIC”) as described in **Error! Reference source not found.** to the IRP Main Document. Therefore, except when noted otherwise, Alabama Power, Georgia Power, Mississippi Power, and Gulf Power are considered the retail operating companies (“Retail OpCos”) for this IRP. Sensitivities are provided to demonstrate the impacts to Georgia Power assuming Gulf Power does not participate in coordinated planning activities with the remaining Southern Company subsidiaries. These impacts are not material to Georgia Power in this IRP as demonstrated in Table 4.6.3a and Table 4.6.3b, as well as graphically in Figures 4.6.4a and 4.6.4b in the 2019 IRP Main Document Reference Tables and Figures section of Technical Appendix Volume 2. Southern Power produces its own separate generation expansion plan.

In developing a resource expansion plan, it is important to consider both investment risk and plan flexibility. The expansion plan needs to be flexible enough to adapt to the changing forecasts of load growth, inflation, construction escalation rates, fuel prices, and the cost of capital. Also, the expansion plan should be flexible with respect to changing environmental law and/or regulation. In addition, the investment risk associated with adding generation must be considered. For example, during construction of a plant, the state of the regional or national economy could change, resulting in slower than anticipated load growth. This could delay the need for additional capacity. Risk assessment includes considering the benefits of fuel diversity and evaluating the availability of various fuels.

The main optimization tool used in the mix analysis is the PROVIEW module in Strategist. The Strategist model uses many data inputs and assumptions in the process of optimizing system generation additions for the retail operating companies; the key assumptions are load forecasts, DSOs, candidate units, reserve margin, cost of capital, fuel forecast, and escalation rates.

PROVIEW uses dynamic programming techniques to develop the optimum resource mix (see Appendix E for a description of the algorithm). This technique allows PROVIEW to evaluate, in every year, each combination of generation additions that satisfy the reserve margin constraint. For each combination, annual operating costs are simulated and are added to the construction costs required to build that particular combination of resource additions. A least cost resource plan is developed only after reviewing many construction options.

Candidate units for mix analysis were selected based upon the results of the generation busbar analysis. Factors including cost and performance, maturity of technology, environmental issues, and risk to the system are considered when selecting candidate units. The candidate units for this study are:

* **REDACTED** MW Gas Only Combined Cycle – one unit site
* **REDACTED** MW Gas Only Combined Cycle with CCC – one unit site
* **REDACTED** MW Dual Fuel Combustion Turbine – four unit site
* **REDACTED** MW Dual Fuel Combustion Turbine with SCR – four unit site

Note: All MW output values are net of station service.

E&CS and GPD provided the candidate unit data that form the basis of comparison among various technologies. These data include $/kW EPC cost, construction schedule, heat rate, fuel type, and emission rates. These data were also used in the busbar comparisons that are developed to review the relative economics of each candidate technology. A busbar analysis is simply a calculation, over a range of capacity factors, of the total (fixed and variable) cost per kilowatt-hour to operate a generating unit. A busbar analysis is used to screen generating technologies and develop recommendations in the selection process of the candidate technologies carried forward into the resource mix analysis.

The reserve margin used to develop the base case least cost resource addition schedule coincides with the present planning reserve guideline, which recommends a 16.25% system Summer Target Reserve Margin.

# DATA ASSUMPTIONS

## STRATEGIST SUB-PERIOD DEFINITION

For an accurate estimation of production cost, Strategist divides the day into peak and off-peak hours called sub-periods for dispatch of the available resources. This feature provides a more realistic estimation of the operation of cycling and storage units with the load variations. For accuracy of modeling, pump storage units were allowed to pump in the off-peak sub-period and generate during the peak sub-period.

Table 1 shows the typical week periods that were modeled in Strategist. With changing load pattern over various seasons, hours included in each of the sub-periods are changed. Also, the lower load hours over the weekend are modeled to be in the off-peak sub-period.

1. Strategist Sub-Period Definition of Hours

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  | **Mon** | **Tue** | **Wed** | **Thu** | **Fri** | **Sat** | **Sun** |
| January | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| February | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| March | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| April | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| May | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| June | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| July | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| August | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| September | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| October | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| November | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| December | Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
|  | Off-Peak | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

## HYDRO UNIT MODELING

Conventional hydro energy was modeled as having two components: run of river and peak shaving. The two components were modeled as separate units. The energy and capacity of each type were derived from the records of historical operation of the Southern Company hydroelectric system. The run of river units were allowed to have a capacity factor of 100% while the peak shaving units have much lower capacity factors. The seasonal variation in the availability of total as well as firm hydro energy was modeled by monthly variations in the energy and capacity of each type.

## DEMAND-SIDE OPTIONS MODELING

Dispatchable DSOs (interruptible load and other options that are controllable and/or dispatchable by a utility) were included as capacity resources in this study. Each interruptible contract load was appropriately adjusted to equate it to the supply side by one or a combination of the following corresponding factors: availability factor, loss factor, and the Incremental Capacity Equivalent (“ICE”) factor. For all operating companies, non-dispatchable DSOs (options such as insulation or end-use equipment’s energy efficiency which are not directly controllable by the utility) are accounted for in the load forecast.

## FINANCIAL ASSUMPTIONS

Table 2 details the capital structure and weighted costs used in the Mix Study. Table 3 shows the escalation rates based on the IHS Markit April 2018 Forecast except as noted.

1. Capital Structure

| **Component** | **Ratio** | **Cost** | **Weighted** | **After Tax** | **Pretax** |
| --- | --- | --- | --- | --- | --- |
| Debt | 45% | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Equity | 55% | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Weighted Cost | | | **REDACTED** | **REDACTED** | **REDACTED** |

1. Discount and Inflation Rates

|  |  |
| --- | --- |
| **Component** | **Cost** |
| Discount Rate | **REDACTED** |
| Construction Escalation Rate | **REDACTED** |
| Long-Term Inflation Rate | **REDACTED** |
| Variable O&M | **REDACTED** |
| Fixed O&M | **REDACTED** |

## EXISTING UNITS

A discussion of the Strategist inputs associated with the existing units can be found in Section 1.2. These data are provided by each operating company and consist of the following:

* Unit Ratings
* In-Service Dates
* Retirement Dates
* Projected Unavailability Dates

## CANDIDATE UNITS

### Candidate Unit Installation Costs

Candidate units were selected based upon the results of the busbar analysis. As Table 4 shows, the candidate units for this study are combined cycle, combined cycle with CCC, combustion turbine and combustion turbine with SCR. The overnight construction cost, design data, reliability data, and operating and maintenance costs for these technologies are contained in the attached 2019 Integrated Resource Plan Generation Technology Data Book prepared by E&CS and GPD.

1. Candidate Technology Assumptions

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Combined Cycle** | **Combined Cycle with CCC** | **Combustion Turbine** | **Combustion Turbine with SCR** |
| Installed Cost  $/KW[[1]](#footnote-1) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Installed / In service Year | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Heat Rate | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Size (MW) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |
| Life (Years) | **REDACTED** | **REDACTED** | **REDACTED** | **REDACTED** |

Spending Curves:

Table 5 shows the direct spending curves used to spread the overnight construction cost over the entire construction period.

1. Direct Spending Curves

|  |  |  |
| --- | --- | --- |
| **Year** | **CT** | **CC** |
| **REDACTED** | | |

### Escalation and Performance Assumptions

Escalation and performance assumptions, for all technologies, were developed by SCS utilizing our own experience and supplementing with information from external consultants. Candidate units were modeled in Strategist by having construction costs for technologies inflate at **REDACTED**% for the duration of the planning period.

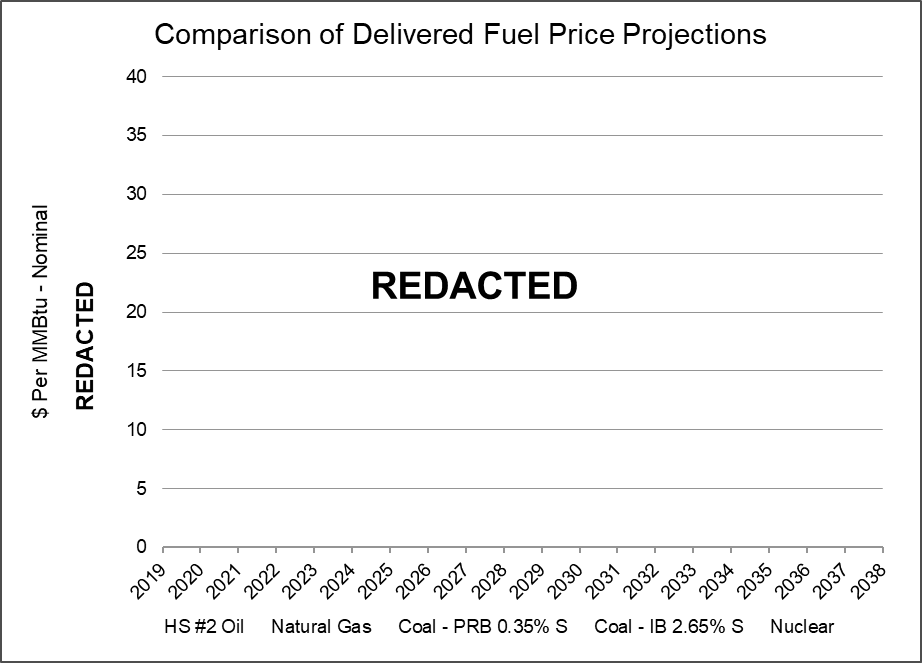
### Unit Sizes for Mix Study

The PROVIEW model selects new units based on minimizing total operating and capital costs. In order to minimize potential size bias, a unit size of 300 MW was considered for all technologies. The model adds resources in multiples of 300 MW. The actual unit additions are matched as closely as possible to this resource schedule of 300 MW units. For a slight improvement in accuracy, a smaller unit size (200, 100 MW) can be used, resulting in a considerable increase in the analysis time. However, for a system the size of Southern Company, a 300 MW unit size is appropriate.

## FUEL PRICES

Near term base fuel costs are based on the Southern Company fuel budgeting process. Long term base fuel costs are based on forecasts developed for Southern Company by CRA and reviewed in the Scenario Fuel Forecast in Technical Appendix Volume 1.

Figure 3.7.1 - Fuel Cost Projections



The candidate expansion unit gas price is a capacity need weighted average, by operating company, of several potential plant locations throughout the Southern Company system. Combined cycle additions include the cost of contracting for firm annual natural gas delivery and combustion turbine additions include the cost of contracting for firm summer only natural gas delivery.

## LOADS

Load forecasts were provided by each retail operating company. More information on load forecasts can be found in the Budget 2019 Load and Energy Forecasts in Technical Appendix Volume 1.

The load shape used in Strategist was derived from forecasted hourly load data for the retail operating companies. The development of the load profile used in Strategist is described below.

The retail operating companies’ base combined weather-normal summer peak demand is forecasted to increase at approximately 0.50% per year on average over the next 20 years, and the weather-normal winter peak demand is forecasted to increase at approximately 0.55%. As a result, additional generating capacity will be required to reliably meet the increasing demand and maintain the appropriate seasonal reserve margins.

### Representative Load Profiles (Seed Shapes)

Representative load profiles have been assembled and maintained for each operating company. Each company’s seed shape contains one year (8760 hours) of load data.

### Company Load Shape

The initial year of company load data was developed utilizing the Peak Demand Model (PDM). Refer to Technical Appendix Volume 1, Section 6 for a description. If the future years of the company load forecast represent typical load growth, each additional year is assumed to have the same shape as the initial year. If the load forecast includes additional influences, each additional year must be represented with a different seed shape.

### Retail Operating Companies’ Load Shape

The system load shape is the sum of each retail operating company 8760-hour load shape with each month’s peak constrained to fit the user-supplied diversity constraints. The diversity constraint is user supplied as a monthly percent diversity to forecast the system monthly target from the sum of each individual company monthly peak. The diversity percentages are based on a historical ten-year average of monthly diversities from 2008 through 2017 and can be found in Appendix C.

### Retail Operating Companies’ StrategistLoad Shape

The seed load shape used in Strategist was derived from Budget 2019 8760 hourly load data. The data was converted to typical week (168 hours) holding official monthly peaks and energy forecasts. Load forecast peaks and energies were then incorporated on a monthly basis.

# SELECTION OF CANDIDATE UNITS

The candidate generating units investigated were selected based on the results of the generation busbar analysis. The candidate generating technologies considered for future installation on the Southern Company electric system are:

1. **REDACTED** MW Gas Only Combined Cycle – one unit site
2. **REDACTED** MW Gas Only Combined Cycle with CCC – one unit site
3. **REDACTED** MW Dual Fuel Combustion Turbine – four unit site
4. **REDACTED** MW Dual Fuel Combustion Turbine with SCR – four unit site

Note: All MW output values are net of station service.

The candidate units are based on results from the Technology Evaluation Process and Economic Screening as described in CHAPTER 4 of the IRP Main Document. Selection is based on the results of the busbar assessment concerning the capital and operating costs, an evaluation of risk associated with installing the technology on the Southern Company electric system, and various other factors.

Intermittent resources were not included as technologies for the model to select due to model limitations associated with the inclusion of intermittent resources but instead were reflected in the model as planned and committed resources. Such planned resources include the recommended addition of 1,000 MW of renewable resources. Finally, the supply-side additions modeled in this Mix Study are not determinative of the resources that will ultimately be selected to meet an identified capacity need. Any capacity need identified through an IRP will be met in accordance with the Commission’s RFP rules.

In general, the operating characteristics and the projected costs associated with installing a more "proven" technology can be more accurately anticipated than a less “proven” technology. As a result, cost estimates for proven technologies can be developed with more confidence than estimates for an immature technology. Even though cost is an important aspect of evaluating technologies, risk factors associated with installing a technology must be considered. These risk factors include construction lead time, fuel diversity, environmental considerations, and operational flexibility.

Additionally, environmental factors must be considered in evaluating technologies. The environmental legislation and regulations applicable to the operation of utility generation are subject to change over time. As a result, the candidate technologies must be selected with present and potential emission compliance issues considered. Future improvements in real cost and operating efficiency associated with anticipated technological advancement of the design and manufacturing process were also projected (see Generation Technology Data Book found in Technical Appendix Volume 1).

# RECOMMENDATION

The following base case capacity addition schedule was used as an input to the integrated resource planning process for the Retail OpCos. The base case scenario reflects the moderate gas, zero-dollar carbon (“MG0”) scenario. Table 6 below shows the recommended summer capacity addition schedule for generic expansion units based on 300 MW capacity block sizes. The base case includes the proposed 1,000 MW of new renewable resources and thus the projected generic capacities below are evaluated after the addition of such renewable resources.

1. The Base Case (Summer) 

This schedule represents the lowest cost sequence of generic generation additions to the combined Retail OpCos when utilizing the base case assumptions. This schedule is the result of optimizing generation requirements based upon a minimum reserve margin, the base case load forecast, DSOs, and generation capital costs. Currently, the planning Summer Target Reserve Margin is 16.25% and the proposed Winter Target Reserve Margin is 26%. Table 7 below shows the recommended winter capacity addition schedule for generic expansion units.

1. Recommended Winter Case 

The conclusion of this study, based upon the results of the base case, sensitivities, and planning scenario case analyses, is that additional generation capacity requirements will likely be satisfied with a mixture of combustion turbine, combustion turbine with SCR, combined cycle, combined cycle with CCC, or purchases. At the appropriate time, actual resource selection will occur in accordance with the Commission’s RFP rules.

# SENSITIVITY ANALYSIS AND DISCUSSION OF RESULTS

## THE REFERENCE CASE

For the 2019 IRP, the reference case is based on the approved 16.25% Summer Target Reserve Margin for the MG0 scenario and is identical to the base case (see Table 8 below). The reference case was used to evaluate sensitivities where appropriate. These results indicate that additional generation capacity requirements will likely be satisfied with a mixture of CT and CC units. The reference case was allowed to optimize starting in year 2019. Capital cost projections will be reviewed as input data assumptions are updated. As mentioned earlier, the Strategist slice or block size in this case and all scenario and sensitivity cases discussed in the following sections is 300 MW.

1. The Reference Case



## LOAD FORECASTING VARIATIONS

1. No Load Growth

For the no load growth case, the load forecasts were held constant at 2019 levels throughout the planning period. As shown in the following table, the no load growth sensitivity resulted in **REDACTED** and **REDACTED** over the twenty-year planning period.

1. No Load Growth



1. High Load Growth

The load forecast for this sensitivity was developed by Georgia Power Load Forecasting to represent an optimistic forecast of load growth for Georgia Power. As shown in the following table, the high load growth sensitivity resulted in **REDACTED REDACTED** and **REDACTED REDACTED** over the twenty-year planning period.

1. High Load Growth Case 

* Low Load Growth

The load forecast for this sensitivity was developed by Georgia Power Load Forecasting to represent a pessimistic forecast of load growth for Georgia Power. As shown in the following table, the low load growth sensitivity resulted in **REDACTED REDACTED** and **REDACTED** over the twenty-year planning period.

1. Low Load Growth Case



## UNIT AVAILABILITY

1. Unit Availability Increase

For this sensitivity, unit availability was increased for all units by lowering EFOR by 0.5%. As shown in the table below, the unit availability increase sensitivity resulted in **REDACTED** over the twenty-year planning period.

1. Unit Availability Increase



1. Unit Availability Decrease

For this sensitivity, unit availability was decreased for all units by increasing EFOR by 1%. As shown in the table below, the unit availability decrease sensitivity resulted in **REDACTED REDACTED** over the twenty-year planning period.

1. Unit Availability Decrease 

## RATE IMPACT ANALYSIS

* See rate impact analysis in the Financial Review Section found in Technical Appendix Volume 2.

## IN SERVICE DATES OF SUPPLY AND DEMAND RESOURCES

1. No Non-Dispatchable DSM

The load forecast for this case was developed by Georgia Power Load Forecasting to represent a no non-dispatchable DSM forecast for Georgia Power. As shown in the table below, the no non-dispatchable DSM sensitivity resulted in **REDACTED REDACTED** over the twenty-year planning period. The need for additional capacity accelerated the need year **REDACTED**.

1. No Non-Dispatchable DSM



1. Aggressive Non-Dispatchable DSM Expansion

The Aggressive Case sensitivity includes programs from the recommended Proposed Case, but with customer participation at higher penetration levels and associated higher budgets, as well as additional programs, measures, and associated budgets to help reach approximately **REDACTED** percent cumulative energy savings by 2031 when compared to the Budget 2019 forecast. As seen in the following table, the aggressive non-dispatchable DSM sensitivity resulted in **REDACTED REDACTED** and **REDACTED** over the twenty-year planning period.

1. Aggressive Non-Dispatchable DSM Expansion 

## AVAILABILITY AND COST OF PURCHASE POWER

* Economy Energy Purchase

This sensitivity includes economy purchases of 1,000 MW during the peak hours of summer months and 1,500 MW during the peak hours of non-summer months. As shown in the following table, the economy energy purchase sensitivity resulted in **REDACTED REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. Economy Energy Purchase 

## PENDING FEDERAL AND/OR STATE LEGISLATION OR REGULATION

See Section 6.10.

## FUEL PRICES

See Section 6.10

## INFLATION IN PLANT CONSTRUCTION COSTS AND COST OF CAPITAL

* High Cost of Capital

The effects of elevated cost of capital were evaluated by assuming a **REDACTED** % increase in the cost of the capital funding sources. This case assumed cost of debt @ **REDACTED**% and cost of common equity @ **REDACTED** %. The capital structure of 45% debt and 55% common equity was not changed from the base case. The resulting discount rate increased by approximately **REDACTED** basis points from the base case. As shown in the following table, the high cost of capital sensitivity resulted in **REDACTED** **REDACTED** over the twenty-year planning period.

1. High Cost of Capital



* Double the Construction Escalation Rate

The effect of doubling the construction escalation rate was evaluated by doubling the current escalation rates and calculating new construction cost of generic unit additions. As shown in the following table, the double the construction escalation rate sensitivity resulted in **REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. Double the Construction Escalation Rate 

* One Half the Construction Escalation Rate

The effects of decreasing the construction escalation rates by half was evaluated by decreasing the current escalation rates and calculating new construction cost of generic unit additions. As shown in the following table, the one half the construction escalation rate sensitivity resulted in **REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. One Half the Construction Escalation Rate



## PLANNING SCENARIO CASES

With its scenario modeling consultant, Charles River Associates, the Company developed three possible future CO2 views and three possible future fuel market views. The scenarios created by the combination of these CO2 views and natural gas views were developed to represent a range of plausible outcomes. Each of the nine scenarios provides an internally-consistent view of fuel, electricity and other markets in the U.S. economy. Figure 6.10.1 depicts and summarizes the nine combinations of natural gas price and CO2 cost used to develop the scenario cases. For details on the scenario planning process, please see Technical Appendix Volume 1, Scenario Fuel Forecast.

**Figure 6.10.1** – Fuel and CO2 Price Matrix

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | | **CO2 Views** | | |
| **$0 CO2** | **$10 CO2** | **$20 CO2** |
| **Fuel Views** | **High Fuel** | HG0 | HG10 | HG20 |
| **Moderate Fuel** | MG0 | MG10 | MG20 |
| **Low Fuel** | LG0 | LG10 | LG20 |

1. Low Fuel $0 Carbon

As shown in the following table, the $0 carbon with low fuel prices and the associated loads, resulted in **REDACTED REDACTED** and an **REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. Effects of Low Fuel $0 Carbon



1. Moderate Gas $0 Carbon

As shown in the following table, the $0 carbon with moderate fuel prices and the associated loads resulted in **REDACTED** over the twenty-year planning period as this is the fuel market and carbon environment basis for the Base Case.

1. Effects of Moderate Fuel $0 Carbon



1. High Gas $0 Carbon

As shown in the following table, the $0 carbon with high fuel prices and the associated loads resulted in **REDACTED REDACTED** and **REDACTED REDACTED** over the twenty-year planning period.

1. Effects of High Fuel $0 Carbon



1. Low Gas $10 Carbon

As shown in the following table, the $10 carbon with low fuel prices and the associated loads, resulted in **REDACTED REDACTED** and **REDACTED REDACTED** over the twenty-year planning period.

1. Effects of Low Fuel $10 Carbon



1. Moderate Gas $10 Carbon

As shown in the following table, the $10 carbon with moderate fuel prices and the associated loads, resulted in **REDACTED REDACTED** and **REDACTED REDACTED** over the twenty-year planning period.

1. Effects of Moderate Fuel $10 Carbon



1. High Gas $10 Carbon

As shown in the following table, the $10 carbon high fuel prices and the associated loads, resulted in **REDACTED REDACTED** and **REDACTED REDACTED** over the twenty-year planning period.

1. Effects of High Fuel $10 Carbon



1. Low Gas $20 Carbon

As shown in the following table, the $20 carbon with low fuel prices and the associated loads, resulted in **REDACTED REDACTED**, **REDACTED REDACTED**, **REDACTED REDACTED REDACTED**, and **REDACTED REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. Effects of Low Fuel $20 Carbon



1. Moderate Gas $20 Carbon

As shown in the following table, the $20 carbon with moderate fuel prices and the associated loads, resulted in **REDACTED REDACTED**, **REDACTED REDACTED**, **REDACTED REDACTED**, and **REDACTED REDACTED REDACTED** over the twenty-year planning period.

1. Effects of Moderate Fuel $20 Carbon



1. High Gas $20 Carbon

As shown in the following table, the $20 carbon with high fuel prices and the associated loads resulted in **REDACTED** **REDACTED**, **REDACTED** **REDACTED**, and **REDACTED** **REDACTED** **REDACTED** over the twenty-year planning period.

1. Effects of High Fuel $20 Carbon



## SENSITIVITY RESULTS SUMMARY

The results of the sensitivity analyses are summarized in Appendix F.

1. Installed cost is the overnight cost plus escalation, AFUDC, and ad valorem taxes during construction. Dollar basis is nominal for in-service year. [↑](#footnote-ref-1)