Southern Company
2022 Integrated Resource Plan
Resource Mix Study

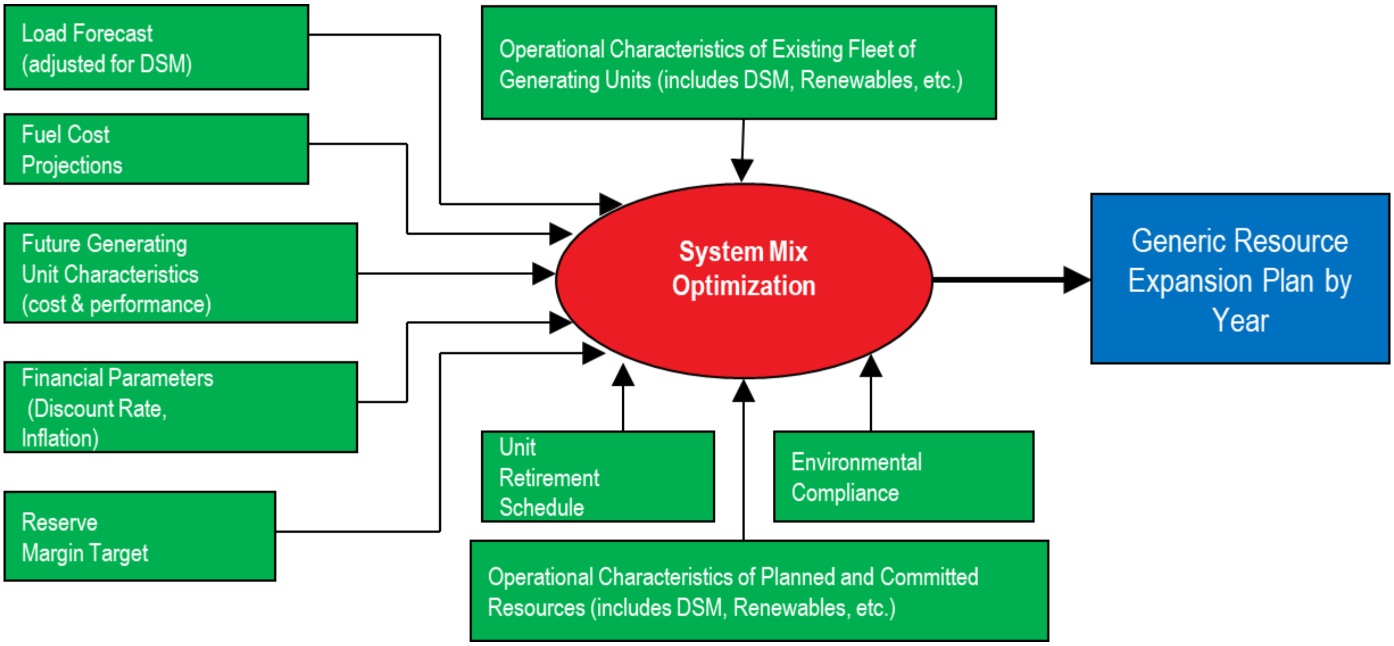
January 2022

1 SUMMARY

The primary objective of this study is to provide information regarding the development of an optimal least-cost resource mix or generic expansion plan. The generic expansion plan was selected to minimize revenue requirements while complying with reliability criteria, environmental laws, and regulations, considering risk and flexibility. This study provides an informative roadmap for long-term decisions. 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 Integrated Resource Plan ("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.

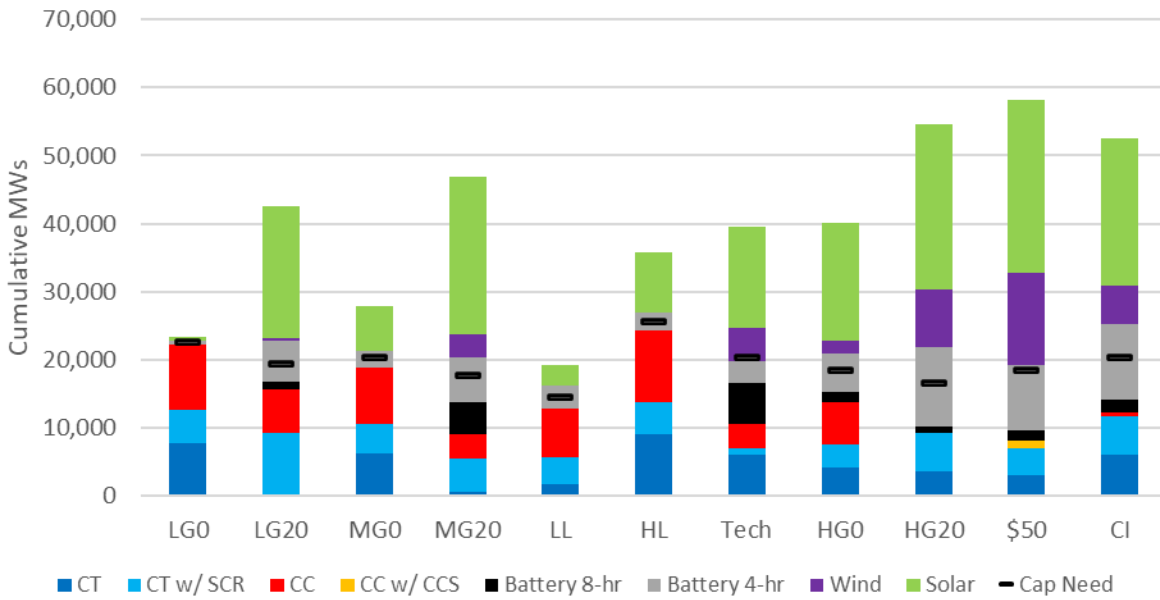
This report summarizes the results of the 2022 Resource Mix Study. The recommendations of the study provide input to an optimum resource addition schedule for the retail operating companies. The base case resource addition schedule is based on maintaining minimum winter and summer reserve margins and minimizing the total operating and capital costs over the planning horizon. While both summer and winter seasons are reviewed, future resource addition schedules will be based on the additions needed to meet the higher of the summer or winter capacity need. For this Budget 2022 ("B2022") Resource Plan, the winter capacity need occurred earlier and was higher than the summer capacity need for the entire planning horizon. Therefore, the system expansion plan includes additions to address the forecasted winter capacity needs. An overview of the expansion plan optimization process is shown in Figure 1 below.

Figure 1: Expansion Plan Optimization Process Overview



In developing a resource expansion plan, it is important to consider uncertainties that could impact planning decisions. Key uncertainties affecting planning include the evolution of natural gas prices, future environmental pressure—especially regarding carbon-dioxide, cost and performance of future generating technologies, and future load growth. Therefore, in developing its scenarios, the Company identifies different plausible viewpoints in each of these four areas. These viewpoints are combined to create 11 scenarios for the B2022 IRP. Shown in Figure 2 are the generic expansion plans (cumulative megawatts ("MWs") by 2041) for each scenario in the scenario design.

Figure 2: Budget 2022 Expansion Plans – Cumulative MWs by 2041



2 ASSUMPTIONS

The key inputs to the study are the cost of capital and escalation rates, a reliability criterion represented by the Target Reserve Margin, the operating data and retirement or projected unavailability dates of existing and committed generating units, projected demand side options ("DSOs"), load forecasts, fuel forecasts, and costs and performance characteristics of candidate generating technologies. The following provides details for each of these key inputs.

2.1 FINANCIAL ASSUMPTIONS

Cost of capital rates are based on the Markit June 2021 forecast. Table 1 details the capital structure and weighted costs used in the Mix Study.

Table 1: Capital Structure

Component	Ratio	Cost	Weighted	After Tax Hurdle Rate	Revenue Requirement Rate
Debt	45%	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Equity	55%	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Weighted Cost			**REDACTED**	**REDACTED**	**REDACTED**

2.2 RESERVE MARGIN

The 2022 IRP reflects a 16.25% Summer Target Reserve Margin and 26% Winter Target Reserve Margin for long-term resource planning decisions. Please see CHAPTER 5 of the IRP Main Document as well as Technical Appendix Volume 1 Reserve Margin Study for additional information on the Company's Target Reserve Margin assumptions.

2.3 EXISTING CAPACITY MIX

The current generating capacity of the retail operating companies consists of 21% coal, 45% oil and gas, 11% nuclear, 5% hydro and 18% other[1] (Solar, Solar + Storage, Wind, DSO, Biomass). Over the course of the planning horizon, the capacity mix will change due to many factors, including, but not limited to, unit rating changes, resource additions, nuclear license expirations, power purchase agreement expirations, and retirements. For planning purposes, discrete retirement dates of owned generating units were utilized in the base case. Please refer to ATTACHMENT A (PLANNED AND COMMITTED RESOURCES) and Technical Appendix Volume 1 Resource Mix Study (Georgia Power Territorial Base Case Load vs. Existing Capability Table) for more details.

2.3.1 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 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 are accounted for in the load forecast. Please see Technical Appendix Volume 1 Resource Mix Study (Georgia Power and System DSO Data) as filed electronically for additional information regarding DSO assumptions used in the 2022 IRP.

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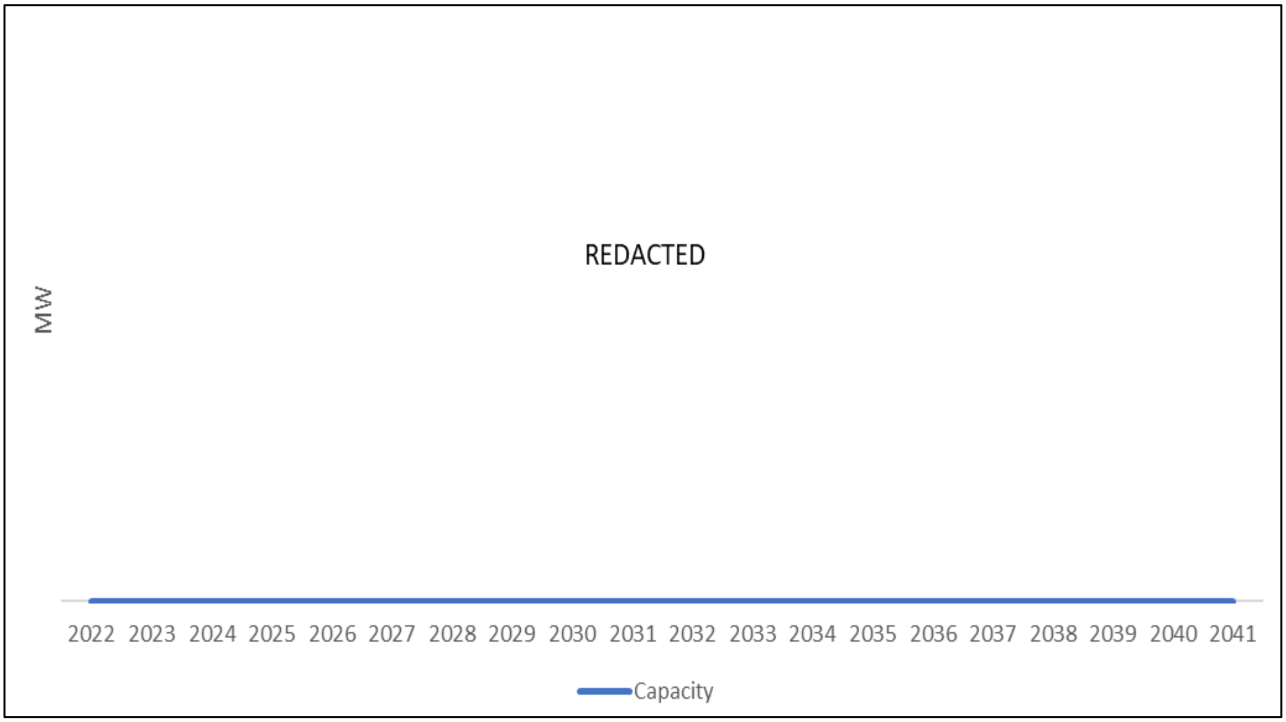
[1] A portion of the renewable nameplate generation capacity included in this value includes capacity where the renewable generator retains the related Renewable Energy Credits.

Figure 3 below shows the existing, planned, and committed system capacity changes for the 2022 – 2041 period.

Figure 3: Retail Operating Companies' Existing and Planned Capacity Forecast



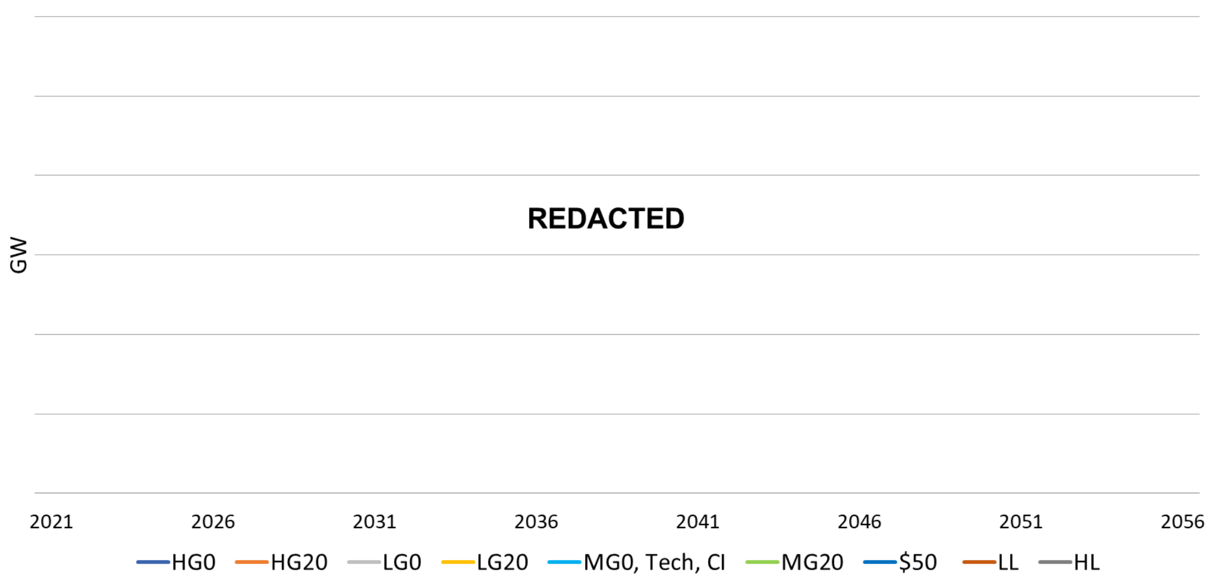
2.4 LOADS

Load forecasts were provided by each retail operating company. The System peak demand is the sum of each retail operating companies' non-coincident peak demand multiplied by a load diversity factor. The diversity percentages are based on a historical ten-year average of monthly diversities from 2011 through 2020 and can be found in Appendix C. More information on the Company's load forecasts can be found in CHAPTER 6 and the Budget 2022 Load and Energy Forecast presented in Technical Appendix Volume 1.

To address the uncertainty of future electricity consumption across a range of scenarios, the Company produces specific load forecasts for each scenario as shown in Figure 4. The Company's reference load forecast uses annually updated forecasts of electricity consumption throughout the planning horizon assuming the US Energy Information Administration's ("EIA") 2021 Annual Energy Outlook ("AEO") "Reference" gas price forecast and a $0 carbon view. The forecast is done separately for each of the three types of customers—residential, commercial, and industrial. For each scenario, this reference load forecast is adjusted to include the impacts of the changing fuel or carbon forecast used in that scenario. Additionally, the Company produces two other load forecast views used in the scenarios.

- **Electrification-influenced load growth:** A view of future load growth that considers significant electrification of energy uses that are currently utilizing other fuels including transportation and space and water heating. This view has larger load growth than in the base load forecast.
- **End-use efficiency and customer generation:** A view of future load growth that considers significant ongoing increases in end-use energy efficiency and an increasing role for customer-sited generation resources, e.g. rooftop solar. This view has smaller load growth than in the base forecast.

Figure 4: Scenario Load Forecast



2.5 FUEL FORECASTS

Near term base fuel costs are based on the Southern Company fuel budgeting process. For B2022, the Company adopted and adapted paths produced by EIA for its 2021 AEO for the long-term fuel costs. The following illustrations give the fuel price paths that the Company has used in the B2022 scenario analyses.

Figure 5: Views of future price of Natural Gas at Henry Hub

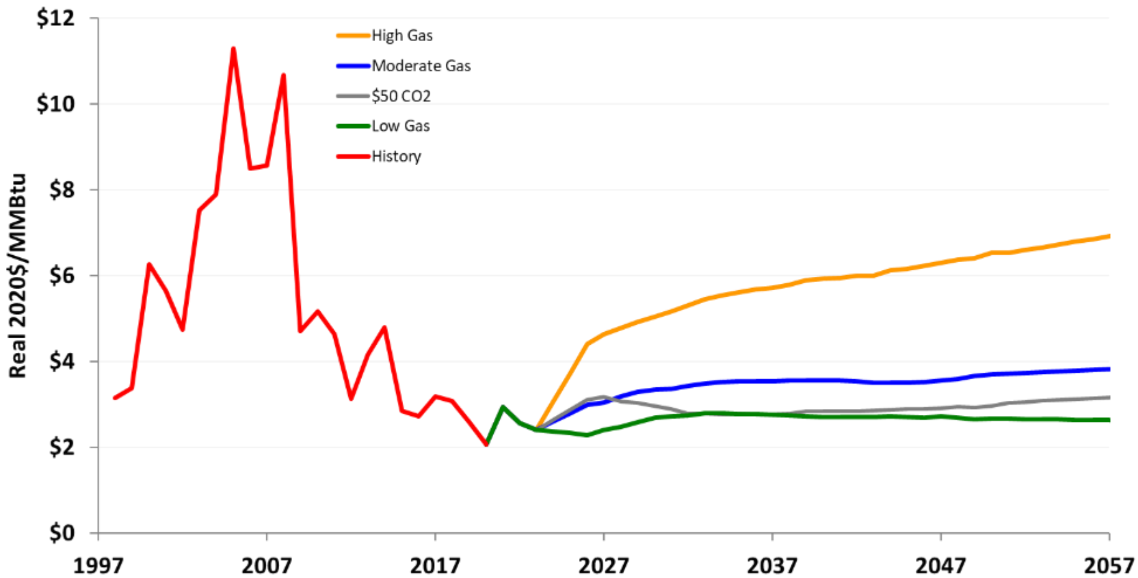


Figure 6: Views of future price of coal at mine, by scenario, Central Appalachia

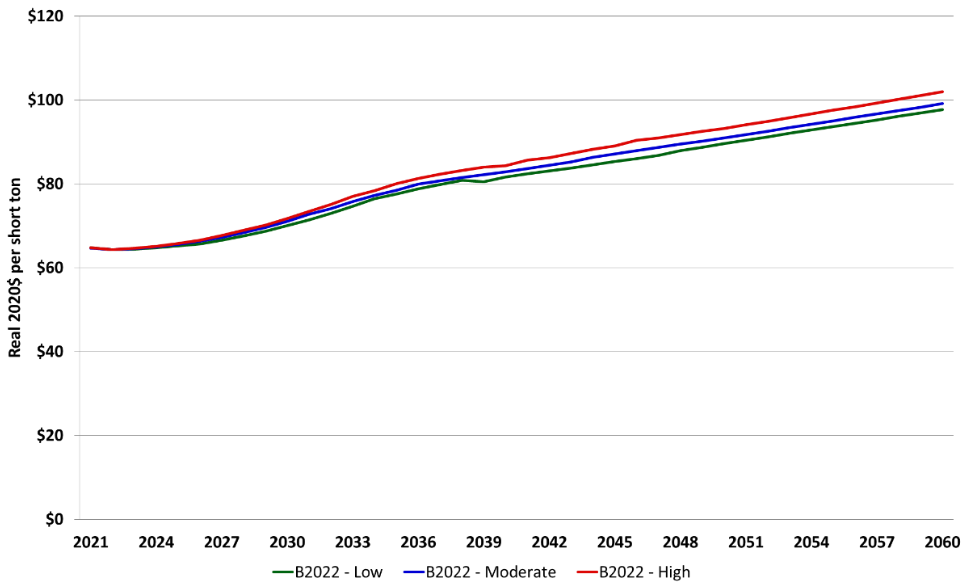


Figure 7: Views of future price of coal at mine, by scenario, Illinois Basin

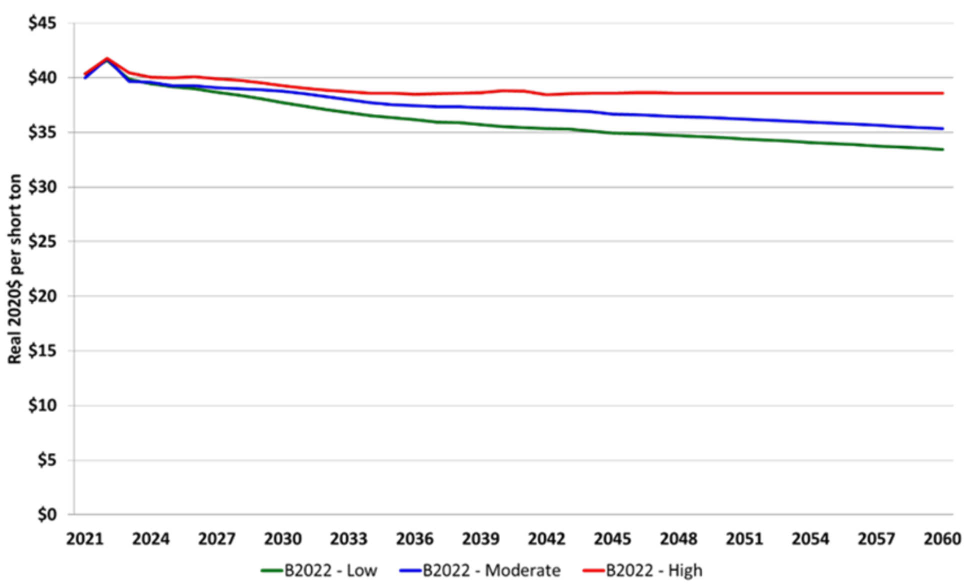


Figure 8: Views of future price of coal at mine, by scenario, Powder River Basin

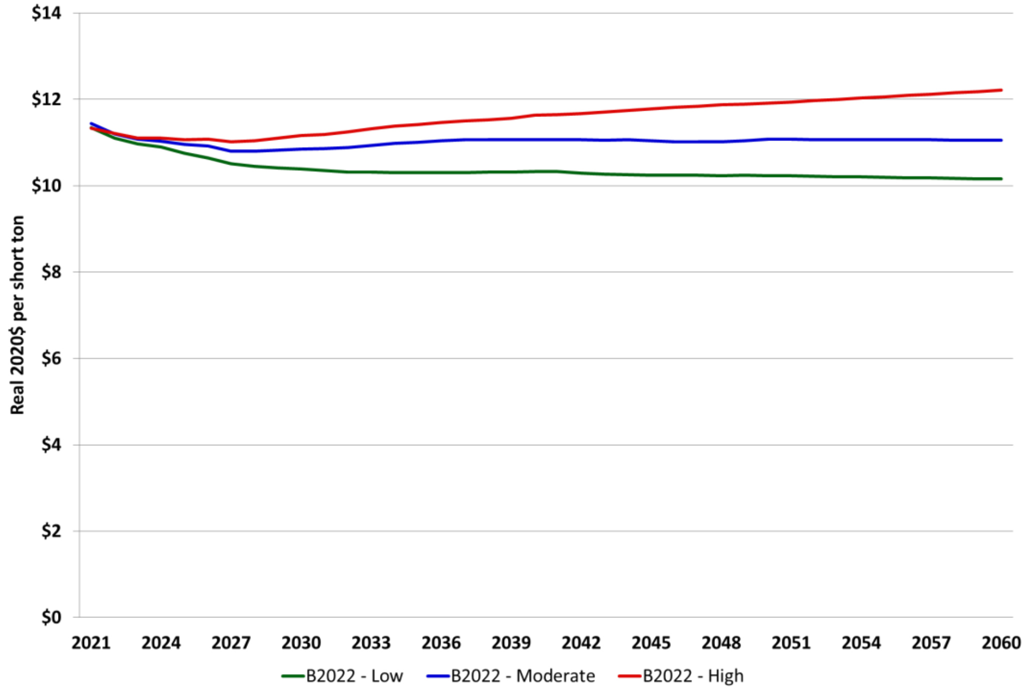
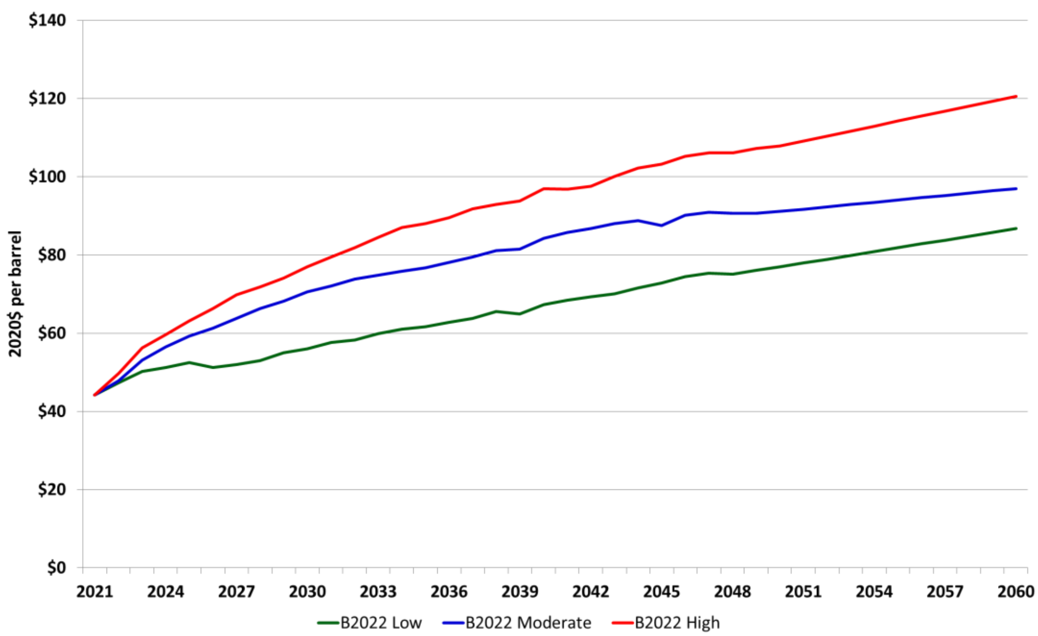


Figure 9: Views of future price of oil, West Texas Intermediate

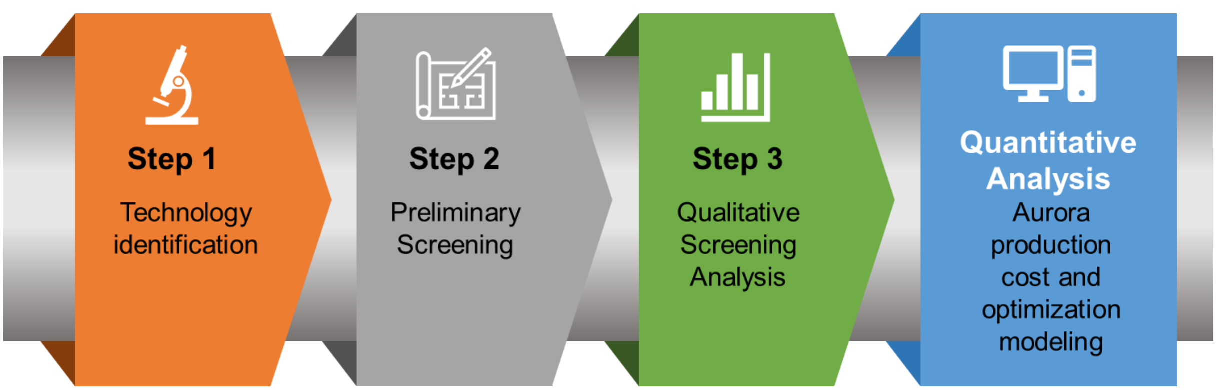


The candidate expansion unit gas price is a capacity need weighted average, by operating company, of several potential plant locations throughout the Southern Company System. Combined cycle additions include the cost of contracting for firm annual natural gas delivery and combustion turbine additions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

2.6 TECHNOLOGY SCREENING & CANDIDATE EXPANSION UNITS

The Company performs detailed expansion planning and production cost analysis during each IRP. This detailed analysis requires extensive and complex computational analysis. Therefore, the Company completes a technology screening assessment of new generation technologies to reduce the potential list of new supply-side options to a manageable list of technologies that are likely to be economically competitive. This technology screening assessment evaluates both established and emerging generating technologies. The objective is to assess the cost, maturity, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other relevant factors of new supply-side generation options.

The technology screening process includes three main steps: (i) the Technology Identification, (ii) Preliminary Screening, and (iii) Detailed Qualitative Screening Analysis. Supply-side options retained after these steps are then considered in the more detailed expansion plan modeling.



The screening process is useful for comparing costs of resource types but cannot be solely utilized for determining a long-term resource plan because future units must be optimized with an existing system containing various resource types. Results from the screening analysis provide guidance for the technologies to be further considered in the more detailed quantitative analysis phase of the planning process. All resources that passed Steps 1-3 of the technology screening process were offered to the model to be optimized with the existing system.

2.6.1 CANDIDATE EXPANSION UNITS

For B2022 analyses, the technologies that screened as potentially cost-effective included natural gas combined cycle (with and without carbon capture and sequestration), natural gas combustion turbine (with and without selective catalytic reduction ("SCR")), reciprocating internal combustion engine, solar photovoltaic, wind, and battery storage. For low-cost CO2 abatement technology ("Tech") case, the Company also considered nuclear and natural gas direct-fired supercritical CO2 cycle[2] with carbon capture and sequestration.

- **Natural Gas Combined Cycle ("CC")**: The Company's current assumption for planning purposes is that CC plants without carbon capture facilities are available for fleet expansion only through 2039 ($0 CO_2 view) or 2034 (all other CO_2 views). This is due to a corresponding planning assumption that beginning in 2035 or 2040, depending on the CO_2 view, new CC plants must capture 90% of their carbon dioxide emissions. The timing of this requirement is based on the Company's understanding of the existing Clean Air Act and its statutory schedule for review of abatement technologies and requirements (New Source Performance Standards and Best Available Control Technology). With a carbon capture facility, CC plants are referred to as natural gas combined cycle with carbon capture and utilization or storage ("CC-CCUS").
- **Natural Gas Combustions Turbines ("CT")**: The Company's current assumption for planning purposes is that natural gas combustion turbines are available for fleet expansion through 2034. Beginning in 2035, new CTs must significantly reduce their NOx emissions by being installed with a SCR device. The timing of this requirement comes from the Company's understanding of the existing Clean Air Act and its statutory schedule for review of abatement technologies and requirements.
- **Reciprocating Internal Combustion Engine ("RICE"):** RICE resources are available as an expansion resource beginning in the year of capacity need for each scenario. The Company's current assumption for planning purposes is that RICE resources use liquid or gaseous fuel to produce power through internal combustion.

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[2] Also referred to as a supercritical CO_2 cycle

- **Solar PV**: Solar PV with single-axis tracking is available as an expansion resource beginning in 2025. The Company's view is that its costs will continue to decline in real terms, meaning it will become increasingly cost-effective throughout the study timeframe. The Company has two views of the future cost of solar PV. The cost assumed in the Tech case is $20/MWh[3] and the cost assumed in all other scenarios is $25/MWh[4].
- **Wind**: Wind turbine is available as an expansion resource beginning in the year of capacity need for each scenario. The Company has two sets of view of the future cost of wind turbines. The cost is assumed to decline until 2030 in the Tech case and escalate using construction escalation in all other scenarios.
- **Battery storage**: Battery storage (4-hour and 8-hour options) is available as an expansion resource beginning in the year of capacity need for each scenario. The Company's view is that its costs will continue to decline, meaning that it will become increasingly cost-effective throughout the study timeframe. The Company has two views of the future cost of battery storage. Both views adopt costs that decrease for some portion of the planning horizon with the rate of that decline being higher in the Tech case and lower in all other scenarios.
- **Nuclear**: Generation III+ Small Modular Reactors and Generation IV Nuclear technology are available as expansion resources in the Tech case.
- **Direct-fired Supercritical CO_2 cycle**: Natural gas direct-fired zero or near-zero carbon emission technology. This resource is available as an expansion resource in the Tech case.

[3] $20/MWh in the first year of PPA and escalated at 3% thereafter
[4] $25/MWh in the first year of PPA and escalated at 3% thereafter

2.6.2 GENERIC UNIT COSTS AND PERFORMANCE

Table 2 shows the technology assumptions for the candidate units offered in the Budget 2022 Mix Study.

Table 2: Candidate Technology Assumptions

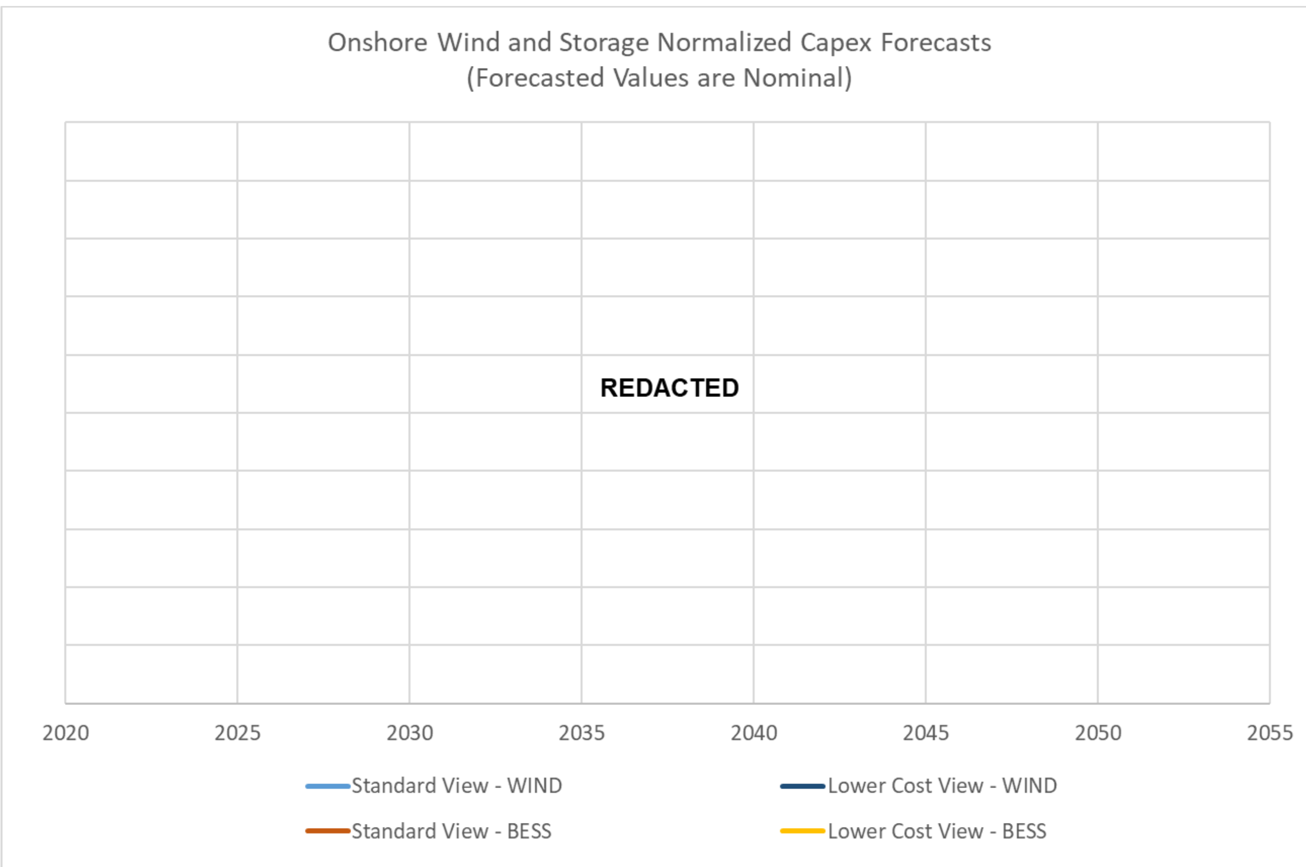
Technology	**Capacity Winter** (MW)	**ICE Factor**	**Average Heat Rate** (Btu/ kWh)	**Round Trip Efficiency**	**Fixed Capacity Factor**	**Overnight Cost** (2021$/ kW)	**Recurring Fixed Cost**[5] (2021$/ kW-yr)	**Variable O&M** ($/MWh)	**Asset Life** (Yrs)
Combined Cycle (CC)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combined Cycle with Carbon Capture & Sequestration (CC w CCS)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combustion Turbine (CT)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Combustion Turbine with Future Emission Controls (CT w SCR)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Reciprocating Internal Combustion Engines (RICE)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Solar Photovoltaic (PV) - Single Axis Tracker (SAT) - $25/MWh PPA	REDACTED	REDACTED			REDACTED		REDACTED		REDACTED
Onshore Wind Power	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED		REDACTED
Lithium-ion Battery Energy Storage System (BESS) - 4 Hr	REDACTED	REDACTED		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
Lithium-ion Battery Energy Storage System (BESS) - 8 Hr	REDACTED	REDACTED		REDACTED		REDACTED	REDACTED	REDACTED	REDACTED
The following are only included in the Company's low-cost CO_2 abatement technology view.									
Solar Photovoltaic (PV) - Single Axis Tracker (SAT) - $20/MWh PPA	REDACTED	REDACTED			REDACTED		REDACTED		REDACTED
Natural Gas-fired Supercritical CO_2 Cycle with CCS (Supercritical CO_2)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED	REDACTED	REDACTED
Generation III+ Small Modular Reactors (SMRs)	REDACTED	REDACTED				REDACTED	REDACTED		REDACTED
Generation IV Nuclear (Gen IV)	REDACTED	REDACTED	REDACTED			REDACTED	REDACTED		REDACTED

5 Recurring fixed costs includes Fixed O&M, Maintenance Capital, and Natural Gas Firm Transportation.

Construction cost escalation rates for all technologies except solar, wind, and battery energy storage are based on the Producer Price Index ("PPI") from the IHS Markit June 2021 Forecast, which is REDACTED% for the duration of the planning period. The Company used 3% as the escalation assumption for the generic solar option. The Company based this assumption on recent market data obtained through renewable RFP's.

Figure 10 shows the normalized cost projections for BESS and Southeast Wind, which show the escalation trajectory used in the B2022 study. The lower cost views are only used in the Tech case.

Figure 10: Normalized Cost Projections for BESS and Southeast Wind

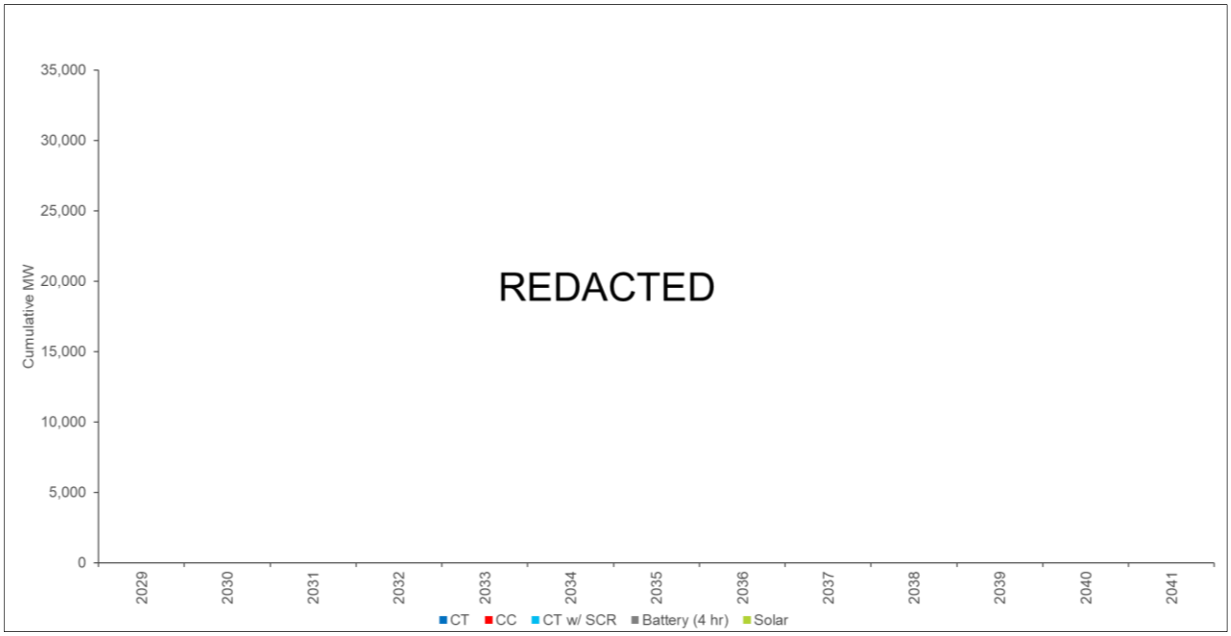


Aurora selects new units based on minimizing total operating and capital costs. In order to minimize potential size bias, a unit size of 300 MW was considered for all technologies. The model adds resources in multiples of 300 MW.

3 BASE CASE GENERIC EXPANSION PLAN

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. Figure 11 below shows the recommended capacity and energy addition schedule for generic expansion.

Figure 11: B2022 MG0 Expansion Plan



The conclusion of this study, based upon the results of the base case, sensitivities, and scenario case analyses, is that additional generation capacity requirements may involve a mixture of natural gas combined cycle (with and without carbon capture and sequestration), natural gas combustion turbine (with and without SCR), solar photovoltaic, wind, and battery storage. At the appropriate time, actual resource selection will occur in accordance with the Commission's RFP rules.

Please see Technical Appendix Volume 1 Resource Mix Study (GPC and System IRP Summary Data) as filed electronically for additional summary information regarding GPC and System capacity, peak demands and energies, actual and target reserve margins, and capacity needs.

4 SENSITIVITY ANALYSIS AND DISCUSSION OF RESULTS

4.1 PLANNING SCENARIO CASES

Due to the uncertainty related to long term fuel cost, carbon pressure, technology cost and performance, and future electricity consumption, the Company considers multiple views of the future price of natural gas, multiple views of future pressure on the Company's CO_2 emissions, multiple views of future cost and performance of generating technologies, and multiple views of future electricity consumption. For the 2022 IRP, the Company assembled these multiple views in those four areas into eleven planning scenario cases to explore the potential impacts. This resulted in eleven outlooks of capacity and energy mixes.

Scenario	Natural Gas Price Path	Greenhouse Gas Pressure	Technology Cost & Performance	Load	Short Name
1	Moderate	$0 fee	Tech Application Stds[6]	Reference[7]	MG0
2	Moderate	$20 fee	Tech Application Stds	Reference + MG20 delta	MG20
3	$50 CO_2	$50+ fee	Tech Application Stds	Reference + $50 delta	$50
4	Low	$0 fee	Tech Application Stds	Reference + LG0 delta	LG0
5	Low	$20+ fee	Tech Application Stds	Reference + LG20 delta	LG20
6	High	$0 fee	Tech Application Stds	Reference + HG0 delta	HG0
7	High	$20+ fee	Tech Application Stds	Reference + HG20 delta	HG20
8	Moderate	$0 fee	Tech Application Stds	High Electrification[8]	HL
9	Moderate	$0 fee	Tech Application Stds	High EE & DER adoption[9]	LL
10	Moderate	$0 fee	Low cost zero-CO_2 tech[10]	Reference	Tech
11	Moderate	CO_2 Intensity[11]	Tech Application Stds	Reference	CI

4.2 RESULTS SUMMARY

Please see Technical Appendix Volume 1 Resource Mix Study (Capacity Expansion Plans) as filed electronically for a summary of results for all scenarios and sensitivity analyses.

6 Southern Company Technology Application Standards which contain assumptions on generating technology cost and performance benchmarks.

7 Standard load forecasts produced by each Operating Company that serve as the reference forecasts.

8 Higher load growth based on the EPRI electrification study.

9 Lower load growth based on aggressive adoption of energy efficiency improvements and distributed resources.

10 Lower costs for solar, wind, storage, and Next Generation nuclear technologies.

11 The CO_2 intensity view reflects current legislative ideas that have the effect of imposing a shrinking annual cap on emissions.