PUBLIC DISCLOSURE

Unit Retirement Study

2022 Integrated Resource Plan

1. Introduction

In the Unit Retirement Study ("URS") for the 2022 Integrated Resource Plan ("IRP"), Georgia Power Company ("Georgia Power" or the "Company") has conducted economic evaluations for Georgia Power's coal-fired units and certain combustion turbine ("CT") units. These economic evaluations compare the costs and benefits of continued operation for these units versus replacement options. The combination of modest load growth, environmental compliance costs, carbon risk, forecasted low gas prices, and cost-effective replacement generation increases the economic pressure on these units. Most notably, the Company's 2022 IRP includes specific actionable and cost-effective replacement generation. This combination of factors was incorporated into the Company's economic assessment of its remaining coal-fired generation, which is further described in this technical appendix.

2. Key Analysis Assumptions

2.1. Incremental Operating Costs

The URS incorporates the incremental costs associated with continued operation of the facility. Unit characteristics combined with marginal replacement fuel cost, variable operations and maintenance ("O&M") cost, and emissions costs were used to model projected energy benefits. Costs associated with continued operation included projected fixed O&M, maintenance capital expenditures, environmental capital expenditures, and firm gas transportation costs.

O&M includes all labor, materials, engineering and support services, and overhead costs necessary to operate the plant. O&M costs are broken out between fixed and variable O&M for each study. Fixed O&M is directly reflected in the asset valuation model ("AV Tool"). Variable O&M, fuel costs, and emissions costs are netted out of each unit's energy benefits and are derived by the production cost model, AURORA. Maintenance capital costs, which are also reflected in the AV Tool, are the projected capital expenditures necessary to maintain reliable operation through the analysis period.

2.2. Incremental Cost of New Environmental Controls

Incremental environmental capital and the associated O&M expenditures projected to be required for environmental compliance are not included in the ongoing operation expenditures described in Section 2.1. Therefore, these investments are reflected in each unit retirement study and include the incremental capital and O&M estimates associated with compliance with the Coal Combustion Residuals ("CCR") rules, Section 316(b) Cooling Water Intake Structure rule of the Clean Water Act ("316(b)"), National

Pollutant Discharge Elimination System ("NPDES") thermal compliance, and the Steam Electric Power Generating Effluent Limitations Guidelines ("ELG") rule. The control requirements and dates included in the analyses are based on the compliance requirements of environmental rules and regulations for which the Company has compliance plans in place. For each of the units analyzed, all environmental controls are expected to be necessary for compliance with final environmental rules. Additional information about environmental rulemakings and their projected compliance requirements can be found in the Environmental Compliance Strategy in Technical Appendix Volume 2.

Asset Retirement Obligations ("AROs"), such as pond closure costs, were not included in the study because these expenditures are required regardless of whether the plant continues operation or is retired.

Table 1: Environmental Control Projects by Plant and Rule

Control Category	316(b)	CCR	ELG
Bowen			Wastewater Management
Gaston	Intake Screens 316b Tech Studies		
Scherer		Landfill Gypsum Cells	Wastewater Management
Wansley		Landfill	Wastewater Management

Table 2: Project Totals for Environmental Controls by Category (in Millions of Dollars)

	Control Category		
Plant Name	**316(b)**	**CCR**	**ELG**
Bowen			**REDACTED**
Gaston[1]	**REDACTED**	**REDACTED**	**REDACTED**
Scherer[2]	**REDACTED**	**REDACTED**	**REDACTED**
Wansley		**REDACTED**	**REDACTED**
*GPC ownership dollars only shown (represents capital investment does not include additional O&M) **CCR Environmental Controls do not include ARO expenditures			

2.3. Scenarios

The Company considers multiple views of the future price of natural gas, future pressure on the Company's carbon-dioxide ("CO_2") emissions, future cost and performance of generating technologies, and future electricity consumption. For B2022, the Company assembled these multiple views of those four areas into eleven scenarios. For more information on the scenarios, please see Chapter 7 in the 2022 IRP Main Document. The Company's 2022 IRP retirement studies were completed using seven scenarios, which focus on the \$0/ton, \$20/ton, and \$50/ton carbon price scenarios. This set of scenarios provides a wide-range of economic signals that sufficiently inform retirement decisions.

Table 3: Unit Retirement Study Scenarios

Scenario	Natural Gas View	Greenhouse Gas Pressure View	Short Name
1	Moderate Price Path	\$0 fee	MG0
2	Moderate Price Path	\$20+ fee	MG20
3	\$50 CO2 Price Path	\$50+ fee	\$50
4	Lower Price Path	\$0+ fee	LG0
5	Lower Price Path	\$20+ fee	LG20
6	Higher Price Path	\$0+ fee	HG0
7	Higher Price Path	\$20+ fee	HG20

[1] Gaston values based on GPC retail jurisdiction
[2] Scherer values based on GPC retail jurisdiction

2.4. Avoided Energy Costs or Energy Benefit

This item represents the energy benefit or the marginal energy-related costs that are avoided on the system in any given hour (including components associated with marginal replacement fuel costs, variable O&M, fuel handling, compliance related environmental costs, intra-day commitment costs, and transmission losses). To determine the energy benefit, or avoided energy costs, of the retire and replace decision, the Company begins by generating hourly marginal energy costs in AURORA without applying a predetermined retire and replace decision. To generate these hourly marginal costs, the Company assumes the coal units under retirement consideration continue to operate throughout the planning horizon. Applying this assumption, the Company then generates hourly marginal energy costs using the AURORA production cost model. The resulting marginal energy-related costs represent the Pre-Retirement Avoided Energy Costs ("PAEC"). The Company then uses these PAEC to determine the relative energy benefit of the existing unit and the replacement unit. The AURORA model is utilized to economically dispatch both the existing unit and the replacement unit(s) against the same marginal costs, or PAEC, to derive the energy benefit for each unit. This energy benefit determination was completed for each of the seven scenarios.

2.5. Replacement Capacity Costs

For each analysis, the Company evaluates the avoided cost associated with the replacement generation costs. Historically, the Company's URS assumed the cost of a generic repeatable self-build replacement unit. However, as a result of the 2019 IRP, the Company issued a capacity request for proposals ("RFP") to identify replacement capacity for potentially retiring resources. The capacity-RFP generated cost-effective natural gas combined cycle ("CC") and CT resources from the market at attractive prices. The results of the capacity-RFP, including cost and unit characteristics, provide the Company with actionable information to consider in the 2022 IRP retirement decisions. To incorporate this information, the costs and benefits of each winning capacity-RFP resource were added together, or grouped, creating a combined mix of replacement capacity or a portfolio of capacity-RFP resources ("Portfolio")[3]. This Portfolio was then utilized to reflect the current cost of replacement generation to compare to existing resources. The cost of the Portfolio is summarized in Table 4. The annual cash flows modeled and associated workpapers are provided in workpaper "TS_2022IRP_URS Portfolio Costs.xlsx".

[3] A generic combustion turbine filler unit was utilized on the backend of the Portfolio for any PPA in the Portfolio for which the expiration date occurs prior to the end of the last PPA expiration date.

Table 4: RFP Replacement Portfolio

Portfolio	Unit Type	Nominal Capability[4] (MW)	Winter Capability (MW)	2025 Capacity Payment ($/kW-yr)[5]	FT (k$-yr)	PPA Start Date	PPA End Date
Plant Wansley Unit 7	CC	598	622	REDACTED	REDACTED	12/1/2024	11/30/2034
Plant Dahlberg Units 2&6	CT	152	171	REDACTED	REDACTED	6/1/2025	5/31/2035
Plant Harris Unit 2	CC	660	689	REDACTED	REDACTED	12/1/2024	11/30/2034
Plant Dahlberg Units 1,3, &5	CT	228	256	REDACTED	REDACTED	1/1/2028	12/31/2037
Plant Monroe Units 1-2	CT	309	360	REDACTED	REDACTED	12/1/2024	11/30/2039
Plant Dahlberg Units 8-10	CT	228	258	REDACTED	REDACTED	6/1/2025	5/31/2035
Total			2,356				

Upon the expiration of the Portfolio, solar and battery storage was used as replacement generation. For units that were not allocated replacement generation from the Portfolio, solar and battery storage was the assumed replacement generation. Solar costs assumed are consistent with PPA prices from recent renewable RFPs for solar without storage. The solar portion was considered an energy only resource and sized based on the megawatt size of the existing unit. For battery storage, the Company assumed generic repeatable replacement resources. The associated costs for battery storage include installation capital, fixed O&M, variable O&M and maintenance capital. A 4-hour duration battery was used with 83.4% round trip efficiency. The costs and benefits of the battery storage were sized to match the existing unit assuming its capacity equivalence. Table 5 summarizes these assumptions.

Table 5: Replacement Solar and Storage Assumptions

	Battery[6]	Solar
Capacity Equivalence	90%	0%
Duration	4-hour	N/A
Round Trip Efficiency	**REDACTED**	N/A
Overnight Construction Costs	**REDACTED**	N/A
Recurring Fixed Cost	**REDACTED**	N/A
PPA pricings		$20/MWh escalating at 3%

[4] Nominal capability aligns with the resources summer capability. This amount is used as a basis for the annual capacity payments received by the resource under the terms of its Power Purchase Agreement.
[5] Represents capacity price in 2025 for all PPAs except Plant Dahlberg 1,3&5, which represents 2028 capacity price
[6] Battery costs in 2021$

2.6. Transmission Avoided Costs

For each analysis, the Company evaluates the transmission costs implications created by the potential retirement of existing units. The transmission costs are based on an established rank order in which the units are assumed to be retired. The costs included in the studies represent the incremental costs of each incremental retirement decision. The study reflects these costs as a benefit to continuing to operate the existing unit(s).

2.7. Deferred Generation Capacity Costs

Both existing and replacement units are assigned capacity value based on the magnitude of capacity need in a given year, amount of capacity above the target reserve margin, and the ability of a resource to provide capacity value. For the 2022 IRP, the Company's determination of capacity value is based on the winter system target reserve margin of 26% as that is the most constraining seasonal need for Georgia Power. For the existing units, the magnitude of capacity need after retirement, up to the size of the existing unit, is valued at the economic carrying cost ("ECC") of a CT. If the existing unit is larger than the capacity need, the amount of capacity above the target reserve margin is given no capacity value. For the replacement units, capacity value is assigned starting when the unit is assumed to reach operation and is valued consistent with the existing unit.

3. Methodology

The economic analysis compares the incremental costs and benefits of the existing unit(s) to the incremental costs and benefits of an assumed replacement unit(s). The type and timing of replacement capacity evaluated for particular unit(s) were based on an assumed rank order of retirements. The economic analysis also includes a determination of capacity value, hourly production cost modeling, and cost implications to the transmission system. Changes in energy values, capital cost, and other fixed costs were captured in the comparison to help determine the most economic option for customers. The results of these analyses were one of the primary determinants in the basis for the Company's decision to invest, retire, or defer action on the unit(s) studied.

3.1. Retirement Ordering

The assumed retirement order can impact the economic analysis. This impact predominantly materializes in reliability costs, such as the cost associated with replacement capacity. When addressing replacement capacity needs, it may be possible for the Company to retire a certain amount of capacity with minimal near-term replacement capacity. However, when additional units are under consideration for overlapping retirements, it may not be possible to reliably retire this larger amount of capacity without addressing the combined impact on capacity needs or assessing the reliability needs of the transmission system. It may be possible to reliably retire a certain amount of capacity with modest transmission system improvements. However, as retirements increase, the interactive nature of the system requires assessments that consider the lack of generation associated with multiple retirements. Additionally, the length of time required to complete transmission system improvements is also considered in the 2022 IRP retirement ordering. The Company considered these reliability impacts through the establishment of an assumed retirement order. It is important to specify that the retirement ordering is not the final economic result. Table 6 represents the Company's assumed retirement order based on reliability and other key factors.

Table 6: Assumed Retirement Ordering

Retirement Order	Units	GPC Retail Capacity	Co-owned	Projected Earliest Transmission Retirement Date[7]
1	Wansley 1-2	933 MW	Yes	2022
2	Bowen 1-2	1,432 MW	No	2027
3	Gaston 1-4	460 MW	Yes	2027
4	Scherer 3	504 MW	Yes	2022
5	Scherer 1-2	144 MW	Yes	2028
6	Bowen 3-4	1,768 MW	No	2030+

3.2. Replacement Capacity Allocations

Based on the rank order, the Portfolio of replacement capacity was then allocated to each unit under retirement consideration. This allocation occurred until the total capacity of the portfolio was exhausted. The amount of allocated capacity was based on the amount of capacity need or unit size associated with each incremental retirement decision as described in each unit(s) analysis in this technical appendix. The Portfolio of replacement capacity allocations are listed in Table 7 and in the provided workpaper "TS_2022IRP_URS_Replacement_Portfolio.xlsx".

Table 7: Incremental Capacity Allocation

Decision By Unit	Retired Capacity (MW) [8]	Replacement Assumption	2028 Capacity Need (MW)	Portfolio Allocation (MW)	Remaining Portfolio (MW)	Generic Capacity Need (MW)
None	0	Capacity-RFP	0	0	**2356**	**0**
Wansley 1-2	933	Capacity-RFP	304	304	**2052**	**0**
Bowen 1-2	1,432	Capacity-RFP	1432	1432	**620**	**0**
Gaston 1-4	460	Capacity-RFP	460	460	**160**	**0**
Scherer 3	504	Capacity-RFP and Generic Capacity	504	160	**0**	**344**
Scherer 1-2	144	Generic Resource	648	0	**0**	**144**
Bowen 3-4	1,768	Generic Resource	1768	0	**0**	**1768**
Total	**5,241**			**2,356**		**2,256**

[7] Date represents end of year (i.e. 12/31/XX)
[8] Capacity in retail jurisdiction

4. Summary of Study Results

The following tables (Sections 4.1-4.6) represent the net present value ("NPV") of customer benefit associated with each unit. The results are calculated by comparing the existing unit's costs and benefits to the corresponding costs and benefits of the appropriate replacement unit. When a positive value is shown for a scenario, the NPV value (benefit less cost) of the existing unit is greater than the NPV value (benefit less cost) of its replacement generation indicating customer benefit from continued operation of the existing unit. Appendix A summarizes the costs and benefits of continued operation for each set of coal-fired and gas-steam units for the moderate-gas, zero-dollar carbon ("MG0") scenario over the study period (2025-2052).

4.1. Plant Wansley Units 1-2

As discussed in Section 3.1, Plant Wansley Units 1-2 were considered first for retirement. The retirement of Wansley 1-2 in 2025 creates a need of 304 MW in 2028. Results represent the costs and benefits for the continued operation of Georgia Power's ownership share of Wansley 1-2 compared to replacement capacity.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Portfolio Replacement w/ Generic CT Filler 2025-2039; Solar and Storage from 2040-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Transmission Benefit: **REDACTED**

Table 8: Plant Wansley Units 1-2 Results

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

**GPC ownership shown*

4.2. Plant Bowen Units 1-2

As discussed in Section 3.1, Plant Bowen Units 1-2 were considered second for retirement and incremental to the Plant Wansley Units 1-2 decision. Results represent the costs and benefits for the continued operation of Plant Bowen Units 1-2 compared to replacement capacity. Plant Bowen Units 1-2 retirement study did not include any avoided costs associated with ELG controls. The Company assumes that the total cost of ELG controls will not materially change with the number of units needing ELG controls. Therefore, the Company's decision to retire Plant Bowen Units 1-2 would not avoid ELG costs unless Plant Bowen Units 3-4 are also retired. The results of the Plant Bowen Unit 3-4 retirement study are shown below in Section 4.6.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Portfolio Replacement w/ Generic CT Filler 2025-2039; Solar and Storage from 2040-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Transmission Benefit: **REDACTED**

Table 9: Plant Bowen Units 1-2 Results

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

4.3. Plant Gaston Units 1-4

As discussed in Section 3.1, Plant Gaston Units 1-4 were considered next for retirement and incremental to the Plant Wansley Units 1-2 and Plant Bowen Units 1-2 decisions. Results represent the costs and benefits for the continued operation of Georgia Power's ownership of Plant Gaston Units 1-4 compared to replacement capacity. Due to ELG compliance, coal backup is assumed unavailable starting in 2029 for Gaston 1-4. Therefore, year-round firm transportation ("FT") was required beginning in 2029. Deferring retirement until year-end 2028 allows the Company to reduce operating costs while supporting a reliable transition of the fleet.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Portfolio Replacement w/ Generic CT Filler 2025-2039; Solar and Storage from 2040-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Firm Transportation: $REDACTED (annual FT starts in 2029)
- Transmission Benefit: $0 for GPC

Table 10: Plant Gaston Units 1-4 Results

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

**GPC ownership shown (retail only)*

4.4. Plant Scherer Unit 3

As discussed in Section 3.1, Plant Scherer Unit 3 was considered next for retirement and incremental to the Plant Wansley Units 1-2, Plant Bowen Units 1-2, and Plant Gaston Units 1-4 decisions. Results represent the costs and benefits for the continued operation of Plant Scherer Unit 3 compared to replacement capacity. Plant Scherer Unit 3 retirement study did not include any avoided capital costs associated with the ELG controls. The Company assumes that the total capital cost of ELG controls will not materially change with the number of units needing ELG controls. Therefore, the Company's decision to retire Scherer 3 would not avoid ELG capital costs unless Plant Scherer 1-2 are also retired. Plant Scherer Units 1-2 retirement study is shown below in Section 4.5. The Company's study does reflect the potential to avoid incremental environmental costs including the gypsum pond discharge. Deferring retirement until year end 2028 allows the Company to reduce operating costs while supporting a reliable transition of the fleet.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Portfolio Replacement w/ Generic CT Filler 2025-2039; Solar and Storage from 2040-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Transmission benefit: **REDACTED**

Table 11: Plant Scherer Unit 3 Results

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

**GPC ownership shown (retail only)*

4.5. Plant Scherer Units 1-2

As discussed in Section 3.1, Plant Scherer Units 1-2 were considered next for retirement and incremental to the Plant Wansley Units 1-2, Plant Bowen Units 1-2, Plant Gaston Units 1-4, and Plant Scherer Unit 3 decisions. Results represent the costs and benefits for the continued operation of Plant Scherer Units 1-2 compared to replacement capacity. With the Company's assumed decision to retire Plant Scherer Unit 3, all remaining ELG costs would be avoided with the retirement of Plant Scherer Units 1-2.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Solar and Storage from 2029-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Transmission Benefit: **REDACTED**

Table 12: Plant Scherer Units 1-2

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

**GPC ownership shown*

4.6. Plant Bowen Units 3-4

As discussed in Section 3.1, Plant Bowen Units 3-4 were the final units considered for retirement and incremental to the Plant Wansley Units 1-2, Plant Bowen Units 1-2, Plant Gaston Units 1-4, Plant Scherer Unit 3, and Plant Scherer Units 1-2 decisions. Results represent the costs and benefits for the continued operation of Plant Bowen Units 3-4 compared to replacement capacity. With the Company's assumed decision to retire Plant Bowen Units 1-2, all ELG costs would be avoided with the retirement of Plant Bowen Units 3-4.

Key Assumptions (Mid-year NPV (2025-2052) in millions of dollars):

- Replacement Capacity: Solar and Storage from 2028-2052
- Avoided Environmental Controls (includes avoided environmental O&M): **REDACTED**
- Transmission Benefit: **REDACTED**

Table 13: Plant Bowen Units 3-4 Results

Study 2025-2052: 2025 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	**REDACTED**	**REDACTED**	
LG20	**MG20**	**HG20**	**$50**
REDACTED	**REDACTED**	**REDACTED**	**REDACTED**

5. Retirement Timing Considerations

The Company's retirement recommendations are based on the results of long-term continued operation analysis provided in Section 4 of this document. To determine the appropriate retirement date for each unit, the Company also considers upcoming environmental requirements, reliability impacts, and possible cost reduction strategies, while necessarily achieving an orderly fleet transition. An advantage to planning a longer-term retirement strategy is the ability for the Company's remaining coal-fired resources to optimize and ultimately reduce operating costs, where feasible. This is possible through the establishment of a known retirement date to strategically maintain the assets in a manner that meets the needs of the system and optimize investment. The Company considers the ability to operate its remaining coal units at lower operating costs in the years leading up to a known retirement date in the timing of its decertification recommendations. Table 14 below summarizes the planning budget for continued long-term operation compared to a possible budget with a 2028 retirement date scenario. The potential for optimization and savings with these low-cost operating budgets is a key consideration in the recommended retirement strategy.

Table 14: Potential Budget Savings[9] by Unit from 2025-2028 (in Millions of Dollars) for a 2028 Retirement Scenario

Capital without Retirement (k$)	2023	2024	2025	2026	2027	2028
Bowen 1-2	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Gaston 1-4	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

2028 Retirement Capital (k$)	2023	2024	2025	2026	2027	2028
Bowen 1-2	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Gaston 1-4	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Scherer 3	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Total	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Reduction	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Capital Cost Savings REDACTED

[9] *Cost reflected is recovered from the retail jurisdiction. Does not include certain common costs that remain when continuing to operate Bowen 3-4 and Scherer 1-2. Does not additional capital investment costs to comply with the ELG Rule or other future environmental requirements.*

6. Combustion Turbine Studies

The Company conducted retirement studies on the following oil-fired CTs: Plant Boulevard Unit 1, Plant Wansley Unit 5A, and Plant Gaston Unit A. Due to the age, size, and relationship to retiring steam generation, the Company completed a 10-year cost/benefit study for these units.

Table 15: Combustion Turbines Information

Units	GPC Winter Capacity
Boulevard CT	18.6 MW
Wansley 5A	32.1 MW
Gaston A	9.7 MW

6.1. Plant Boulevard Unit 1

Study 2022-2031: 2022 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	REDACTED	REDACTED	
LG20	**MG20**	**HG20**	**$50**
REDACTED	REDACTED	REDACTED	REDACTED

6.2. Plant Wansley Unit 5A

Study 2022-2031: 2022 NPV $M			
LG0	**MG0**	**HG0**	
REDACTED	REDACTED	REDACTED	
LG20	**MG20**	**HG20**	**$50**
REDACTED	REDACTED	REDACTED	REDACTED

**GPC ownership shown*

6.3. Plant Gaston Unit A

Study 2022-2031: 2022 NPV $M			
LG0	MG0	HG0	
REDACTED	REDACTED	REDACTED	
LG20	MG20	HG20	$50
REDACTED	REDACTED	REDACTED	REDACTED

**GPC ownership shown*

Appendix A

Moderate-Gas, Zero-Dollar Carbon

NPV (2025-2052) in Millions of Dollars

	Generation Unit Cost and Benefits	Plant Wansley Units 1-2	Plant Bowen Units 1-2	Plant Gaston Units 1-4	Plant Scherer Unit 3	Plant Scherer Units 1-2	Plant Bowen Units 3-4
Existing Unit	Energy	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Capacity	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Avoided Transmission	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Eval Unit Maintenance Capital	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Fixed O&M	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Firm Gas Transportation	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Environmental Capital	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Environmental O&M	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Total Benefits to the System	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Replacement Unit	Energy	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Capacity	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Capacity Payment	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	FT	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Generic CT Filler	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	BESS Maintenance Capital	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Fixed O&M	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	In-Service BESS Capital	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Solar Cost	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Total Replacement Benefit to the System	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
	Net Benefit (Existing minus Replacement)	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**