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# 2023 Electric Generation Integrated Resource Plan

VOLUME 2

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## List of Acronyms

AACE	Association for the Advancement of Cost Engineering	CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
ABWR	Advanced Boiling Water Reactor		
ACC	Air-Cooled Condenser	CFA	Clean Future Act
ACE	Affordable Clean Energy	CFB	Circulating Fluidized Bed
AFFF	Aqueous Film-Forming Foam	CFR	Code of Federal Regulations
AFS	Axial Fuel Staged	CNSC	Canadian Nuclear Safety Commission
AGP	Advanced Gas Path		
ALJ	Administrative Law Judge	CO2	Carbon Dioxide
AQC	Air Quality Control	COD	Chemical Oxygen Demand
ARDP	Advanced Reactor Demonstration Project	COL	Combined Operating License
ARP	Acid Rain Program	CPP	Clean Power Plan
ATI	Array Technologies, Inc.	CRL	Combustion Residual Leachate
AWE	Alkaline Water Electrolysis	CSAPR	Cross-State Air Pollution Rule
BACT	Best Available Control Technology	CTG	Combustion Turbine Generator
BART	Best Available Retrofit Technology	CWA	Clean Water Act
		DLE	Dry Low Emission
BBGS	Brandy Brach Generation Station	DLN	Dry Low Nitrogen Oxide
BESS	Battery Energy Storage System	DOAH	Florida Division of Administrative Hearings
BMS	Battery Management System	DOD	Depth of Discharge
BOEM	Bureau of Ocean Energy Management	DOE	Department of Energy
		DOI	U.S. Department of Interior
BOP	Balance-of-Plant	DRR	Data Requirements Rule
BSER	Best System of Emission Reduction	DWM	Division of Waste Management
		EGU	Electric Generating Unit
BTA	Best Technology Available	ELG	Effluent Limit Guidelines
BTU	British Thermal Unit	EON	Energy Options Network
BWR	Boiling Water Reactor	EPA	Environmental Protection Agency
CAA	Clean Air Act	EPC	Engineering Procurement Construction
CBM	Coal Bed Methane		
CCR	Coal Combustion Residuals	ERP	Environmental Resource Permitting
CCS	Carbon Capture and Storage		
CCUS	Carbon Capture, Utilization, and Storage	ESBWR	Economic Simplified Boiling Water Reactor
		ESS	Energy Storage System
CDF	Core Damage Frequency	FAC	Florida Administrative Code
CEMS	Continuous Emissions Monitoring System	FCG	Florida Electric Power Coordinating Group
CEQ	Council on Environmental Quality		

FDEP	Florida Department of Environmental Protection	MDCT	Draft Cooling Tower
FDH	Florida Department of Health	MGD	Million Gallons per Day
FGD	Flue Gas Desulfurization	MMBTU	Metric Million British Thermal Units
FMS	Fine-Mesh Screens	MPA	Mitsubishi Power Americas
FOAK	First of a Kind	MSR	Molten Salt Reactor
FPSC	Florida Public Service Commission	MVA	Megavolt Amperes
FWC	Florida Fish and Wildlife Conservation Commission	MWE	Megawatt Electric
GEC	Greenland Energy Center	NAAQS	National Ambient Air Quality Standards
GEH	General Electric-Hitachi	NCA	Lithium Nickel Cobalt Aluminum Oxide
GHI	Global Horizontal Irradiance	NEF	New Energy Finance
GMSL	Global mean sea level	NEPA	National Environmental Policy Act
HAL	Health Advisory Level	NESHAP	National Emission Standards for Hazardous Air Pollutants
HALEU	High Assay Low-Enriched Uranium	NMC	Lithium Nickel Manganese Cobalt Oxide
HAP	Hazardous Air Pollutant	NMFS	National Marine Fisheries Service
HPC	High-Pressure Compressor	NOAK	Nth of a Kind
HPT	High Pressure Turbine	NOx	Nitrogen Oxides
HRSG	Heat Recovery Steam Generator	NPDES	National Pollutant Discharge Elimination System
HTGR	High Temperature Gas-Cooled Reactor	NPM	NuScale Power Module
IGCC	Integrated Gasification Combined Cycle	NRHP	National Register of Historic Places
IMSR	Integral Molten Salt Reactor	NSPS	New Source Performance Standards
IPCC	Intergovernmental Panel on Climate Change	NSR	New Source Review
IPT	Intermediate Pressure Turbine	NSRDB	National Solar Radiation Database
ISO	International Standards Organization	NWP	Nationwide Permit
LFA	Lower Floridian Aquifer	OEM	Original Equipment Manufacturer
LFP	Lithium Iron Phosphate	PCS	Power Conversion System
LHV	Lower Heating Value	PEM	Proton Exchange Membrane
LLWR	Large Light Water Reactor	PFAS	Per- and Polyfluoroalkyl Substances
LMO	Lithium Manganese Oxide	PFBS	Perfluorobutane Sulfonic Acid
LOCA	Loss-of-Coolant Accidents	PFOA	Perfluorooctanoic Acid
LPC	Low-Pressure Compressor	PFOS	Perfluorooctane Sulfonic Acid
LPT	Low-Pressure Turbine	PM	Particulate Matter
LTO	Lithium Titanate	PPSA	Power Plant Siting Act
L TSA	Long-Term Service Agreement	PSC	Public Service Commission
MACT	Maximum Achievable Control Technology		
MATS	Mercury and Air Toxics Standard		

PSD	Prevention of Significant Deterioration
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RCRA	Resource Conservation and Recovery Act
RGP	Regional General Permit
RICE	Reciprocating Internal Combustion Engine
SAC	Single Annular Combustor
SAT	Single-Axis Trackers
SCADA	Supervisory Control and Data Acquisition
SDWA	Safe Drinking Water Act
SECARB	Southeast Regional Carbon Sequestration Partnership
SHPO	State Historical Preservation Officer
SIP	State Implementation Plan
SMR	Small Modular Reactor
SO <sub>2</sub>	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction
STG	Steam Turbine Generator
THPO	Tribal Historical Preservation Officer
TNC	The Nature Conservancy
TRI	Toxic Release Inventory
TRISO	Tri-Structural Isotropic
TSCA	Toxic Substances Control Act
USACE	U.S. Army Corp of Engineers
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
USFWS	U. S. Fish and Wildlife Service
VDR	Vendor Design Review
VFD	Variable Frequency Drive
WFGD	Wet Flue Gas Desulfurization
WMDCT	Wet Mechanical Draft Cooling Tower
WOTUS	Waters of the United States

Appendix A – Detailed PLEXOS Modeling Results

## A Detailed PLEXOS Modeling Results

Table A-1 - Near Term Capacity Expansion by Scenario

Scenario Analysis - Near Term Build Plans						
Year	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
2025	100MW - 50MW 4hr BESS 150MW - 75MW 4hr BESS		25MW - 25MW 1hr BESS 37.5MW - 37.5MW 1hr BESS 50MW - 50MW 1hr BESS 75MW - 75MW 1hr BESS	50MW-50MW 4hr BESS 150MW-75MW 4hr BESS	262MW-37.5MW 1hr BESS 150MW-75MW 4hr BESS	225MW-75MW 4hr BESS
2026	150MW Solar PV	150MW Solar PV	300MW Solar PV	300MW Solar PV	300MW Solar PV	300MW Solar PV
2027						
2028				50MW-50MW 4hr BESS		
2029	571 MW 1x1 H Class Gas	150MW Solar PV	571 MW 1x1 H Class Gas	571MW 1x1 H Class Gas	95MW Biomass 150MW-75MW 4hr BESS	346MW 1X0 H Class Gas 115MW 1X0 LMS 100 Gas
2030	150MW Solar PV	571 MW 1x1 H Class Gas	975MW Tier1 Solar PV	975MW Tier1 Solar PV	975MW Tier1 Solar PV 262MW-37.5MW 1hr BESS	975MW Tier1 Solar PV 338MW-37.5MW 1hr BESS
2031					450MW-75MW 4hr BESS	525MW-75MW 4hr BESS
2032					100MW-50MW 4hr BESS 450MW-75MW 4hr BESS	525MW-75MW 4hr BESS
2033			150MW Tier2 Solar PV	375MW Tier2 Solar PV	300MW Tier2 Solar PV 350MW-50MW 4hr BESS 750MW-75MW 4hr BESS	300MW Tier2 Solar PV 50MW-50MW 4hr BESS 525MW-75MW 4hr BESS

## Appendix A – Detailed PLEXOS Modeling Results

Table A-2 - Midterm Capacity Expansion by Scenario

Scenario Analysis – Midterm Build Plans						
Year	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
2034					300MW Tier2 Solar PV 550MW-50MW 4hr BESS 600MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2035					675MW Tier2 Solar PV 150MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2036			75MW Tier2 Solar PV	75MW Tier2 Solar PV	75MW Tier2 Solar PV 675MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2037					600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2038			37.5MW-37.5MW 1hr BESS	75MW-37.5MW 1hr BESS	450MW Tier2 Solar PV 100MW-50MW 4hr BESS 600MW-76MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2039			112MW - 37.5MW 1hr BESS	75MW-37.5MW 1hr BESS	300MW Tier2 Solar PV 50MW-50MW 4hr BESS 600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2040			75MW Tier2 Solar PV 75MW- 37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	375MW Tier2 Solar PV 350MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2041			75MW Tier2 Solar PV	150MW Tier2 Solar PV 25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS	300MW Tier2 Solar PV 500MW-50MW 4hr BESS 600MW-75MW 4hr BESS	75MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2042		50MW-25MW 1hr BESS 37.5MW-37.5MW 1hr BESS	236MW 1X0 F Class Gas	346MW 1x0 H Class Gas	400MW-50MW 4hr BESS 675MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

Table A-3 – Long Term Capacity Expansion by Scenario

Scenario Analysis - Long Term Build Plan						
Year	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
2043	236 MW 1x0 F Class Gas	25MW - 25MW 1hr BESS	346MW 1X0 H Class Gas	236MW 1x0 F Class Gas	1050MW Tier2 Solar PV 400MW-50MW 4hr BESS 525MW-75MW 4hr BESS	525MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2044	75MW - 37.5MW 1hr BESS	112MW - 37.5MW 1hr BESS			450MW-50MW 4hr BESS 825MW-75MW 4hr BESS	350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2045	236 MW 1x0 F Class Gas	112MW - 37.5MW 1 hr BESS	50MW - 25MW 1hr BESS 112MW - 37.5MW 1hr BESS 50MW - 50MW 4hr BESS	346MW 1x0 H Class Gas	525MW Tier2 Solar PV 350MW-50MW 4hr BESS 375MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2046		75MW - 75MW 4hr BESS	25MW - 25MW 1hr BESS 50MW - 50MW 4hr BESS		1125MW Tier2 Solar PV 400MW-50MW 4hr BESS 600MW-75MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2047	37.5MW - 37.5MW 1hr BESS		75MW-75MW 1hr BESS	25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS	975MW Tier2 Solar PV 400MW-50MW 4hr BESS 525MW-525MW 4hr BESS	900MW Tier2 Solar PV 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2048	37.5 MW - 37.5MW 1hr BESS	50MW-50MW 4hr BESS	75MW-25MW 1hr BESS 75MW-75MW 4hr BESS	150MW-75MW 4hr BESS	1050MW Tier2 Solar PV 450MW-50MW 4hr BESS 900MW-75MW 4hr BESS	900MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2049	37.5 MW - 37.5MW 1hr BESS	50MW-50MW 4hr BESS		25MW-25MW 1hr BESS	750MW Tier2 Solar PV 125MW-25MW 1hr BESS 225MW-37.5MW 1hr BESS 400MW-50MW 4hr BESS 525MW-75MW 4hr BESS	900MW Tier2 Solar PV 125MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2050	25MW - 25MW 1hr BESS	50MW-50MW 4hr BESS	25MW-25MW 1hr BESS	75MW-75MW 4hr BESS	1350MW Tier2 Solar PV 250MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 650MW-50MW 4hr BESS 600MW-75MW 4hr BESS	95MW Biomass 975MW Tier1 Solar PV 900MW Tier2 Solar PV 250MW-25MW 1hr BESS 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 525MW-75MW 4hr BESS
2051	25MW - 25MW 1hr BESS 50MW - 50MW 4hr BESS	50MW-50MW 4hr BESS	75MW-75MW 4hr BESS	75MW-75MW 4hr BESS		525MW-75MW 4hr BESS

Appendix A – Detailed PLEXOS Modeling Results

Table A-4 – Near Term Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Near Term Build Plans						
Year	Low Load	No Growth	High Fuel	Regulated CO <sub>2</sub>	NetZero	High Load
2025		100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	25MW-25MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS	300MW-37.5MW 1hr BESS 150MW-75MW 4hr BESS	150MW-37.5MW 1hr BESS 100MW-50MW 4hr BESS 150MW-75MW 4hr BESS
2026	75MW Solar PV		300MW Solar PV	150MW Solar PV	225MW Solar PV	300MW Tier1 Solar PV
2027					75MW Solar PV	
2028						
2029	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas	571MW 1x1 H Class Gas		571MW 1x1 H Class Gas
2030	150MW SolarPV	225MW Solar PV	975MW Tier1 Solar PV	150MW Solar PV	975MW Tier1 Solar PV	
2031					75MW-75MW 4hr BESS	
2032		75MW Solar PV				
2033			300MW Tier2 Solar PV		600MW Tier2 Solar PV 375MW-75MW 4hr BESS	

Appendix A – Detailed PLEXOS Modeling Results

Table A-5 – Midterm Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Midterm Build Plans						
Year	Low Load	No Growth	High Fuel	Regulated CO <sub>2</sub>	NetZero	High Load
2034					375MW Tier2 Solar PV	
2035					600MW Tier2 Solar PV	
2036						
2037					75MW Tier2 Solar PV 150MW-75MW 4hr BESS	
2038					75MW Tier2 Solar PV 975MW-75mw 4hr BESS	236MW 1x0 F Class Gas
2039					150MW Tier2 Solar PV 100MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2040					900MW Tier2 Solar PV 450MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2041			150MW Tier2 Solar PV		75MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2042	25MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS				900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	571MW 1x1 H Class Gas

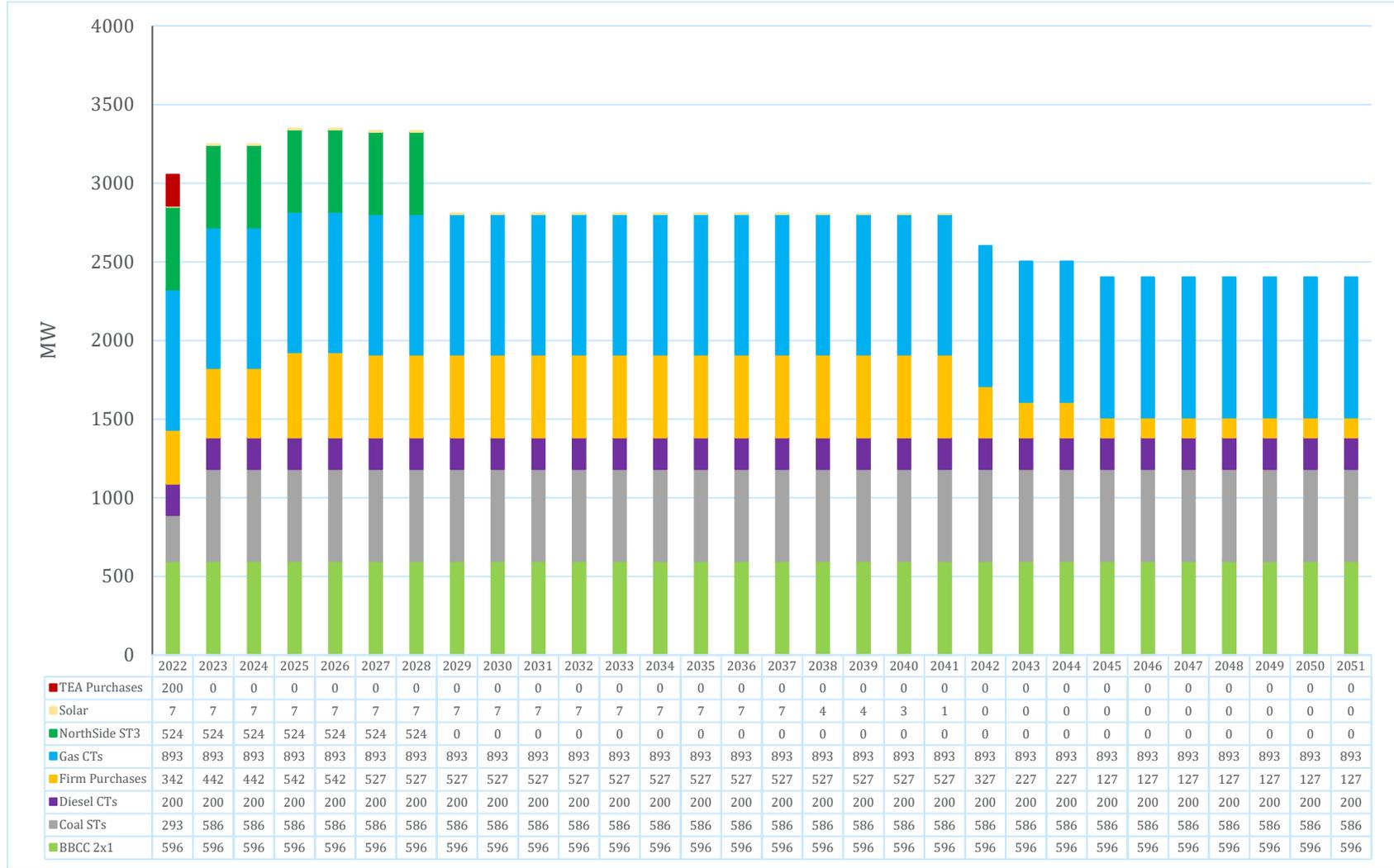
## Appendix A – Detailed PLEXOS Modeling Results

Table A-6 – Long Term Capacity Expansion by Sensitivity

Current Outlook Sensitivities - Long Term Build Plans						
Year	Low Load	No Growth	High Fuel	Regulated CO <sub>2</sub>	NetZero	High Load
2043	38MW-37.5MW 1hr BESS				900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2044	112MW-37.5MW 1hr BESS		25MW-25MW 1hr BESS 75MW-37.5MW 1hr BESS	25MW-25MW 1hr BESS 75MW-37.5MW 1hr BESS	900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	
2045	236MW 1X0 F Class Gas	150MW-37.5MW 1hr BESS	471MW 1x0 F Class Gas	471MW 1x0 F Class Gas	900MW Tier2 Solar PV 388MW-37.5MW 1hr BESS 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	346MW 1x0 H Class Gas 75MW-25MW 1hr BESS 38MW-37.5MW 1hr BESS
2046					900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2047					900MW Tier2 Solar PV 500MW-50MW 4hr BESS 975MW-75MW 4hr BESS	50MW-50MW 4hr BESS
2048	25MW-25MW 1hr BESS		38MW-37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	975MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 200MW-50MW 4hr BESS 150MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2049	50MW-50MW 4hr BESS		38MW-37.5MW 1hr BESS	38MW-37.5MW 1hr BESS	900MW Tier2 Solar PV 375MW-37.5MW 1hr BESS 350MW-50MW 4hr BESS 375MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2050	50MW-50MW 4hr BESS		38MW-37.5MW 1hr BESS	50MW-50MW 4hr BESS	95MW Biomass 450MW Tier2 Solar PV 38MW-37.5MW 1hr BESS 700MW-50MW 4hr BESS 450MW-75MW 4hr BESS	75MW-75MW 4hr BESS
2051	50MW-50MW 4hr BESS		75MW-75MW 4hr BESS	38MW-37.5MW 1hr BESS 50MW-50MW 4hr BESS	75MW-75MW 4hr BESS	75MW-75MW 4hr BESS

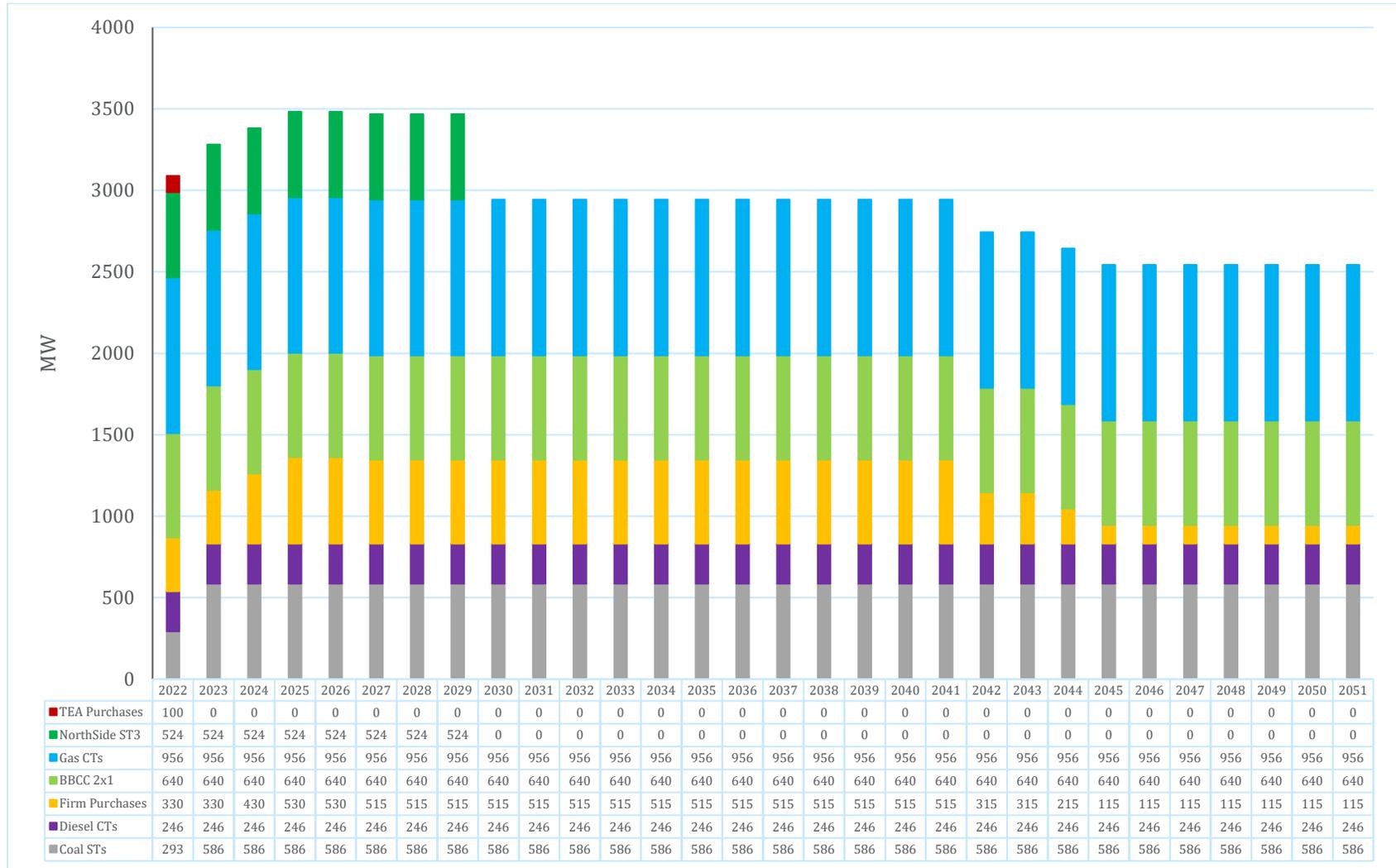
Appendix A – Detailed PLEXOS Modeling Results

Figure A-1 - Baseline Annual Firm Capacity (August) without Capacity Additions



Appendix A – Detailed PLEXOS Modeling Results

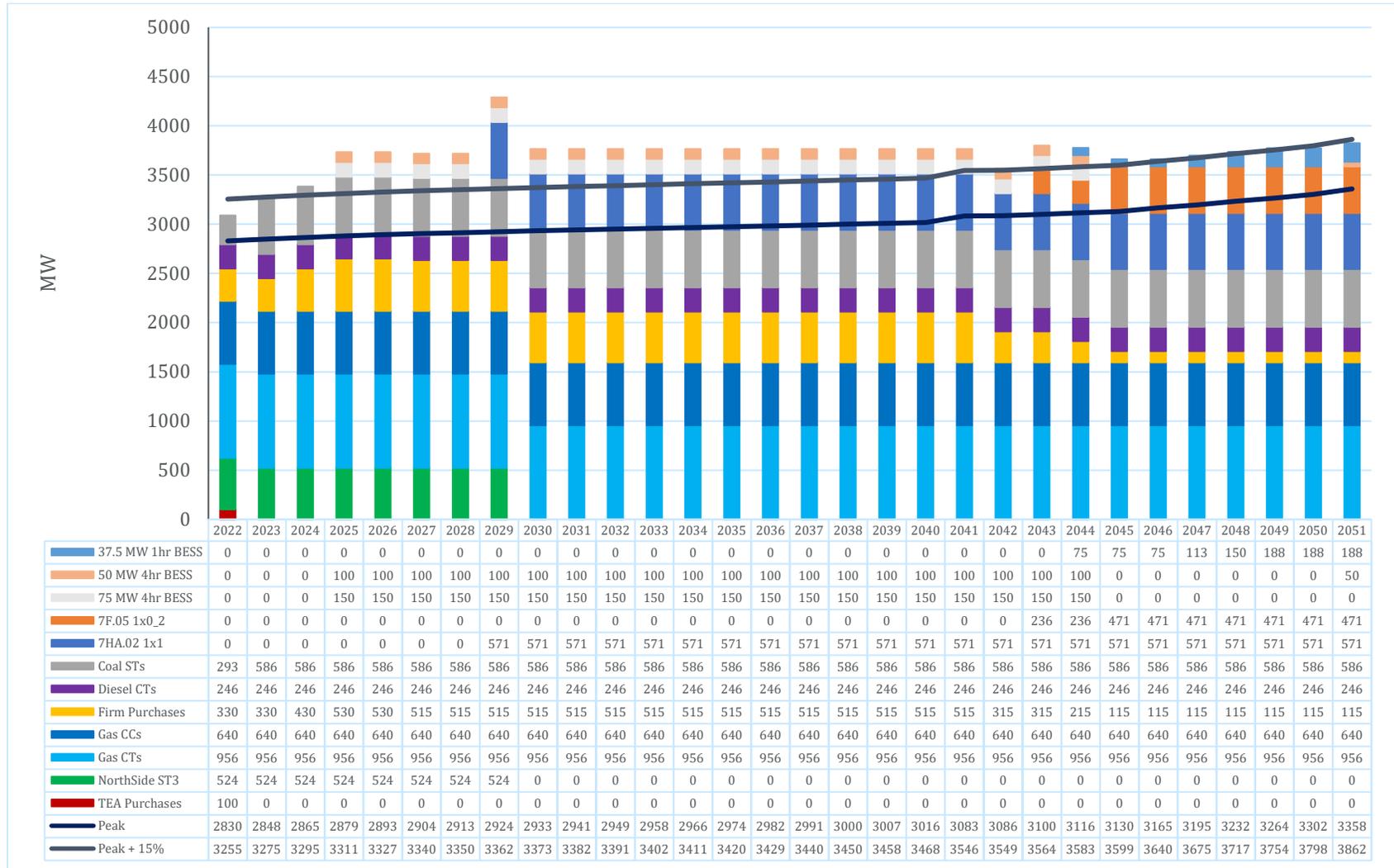
Figure A-2 - Baseline Annual Firm Capacity (January) without Capacity Additions





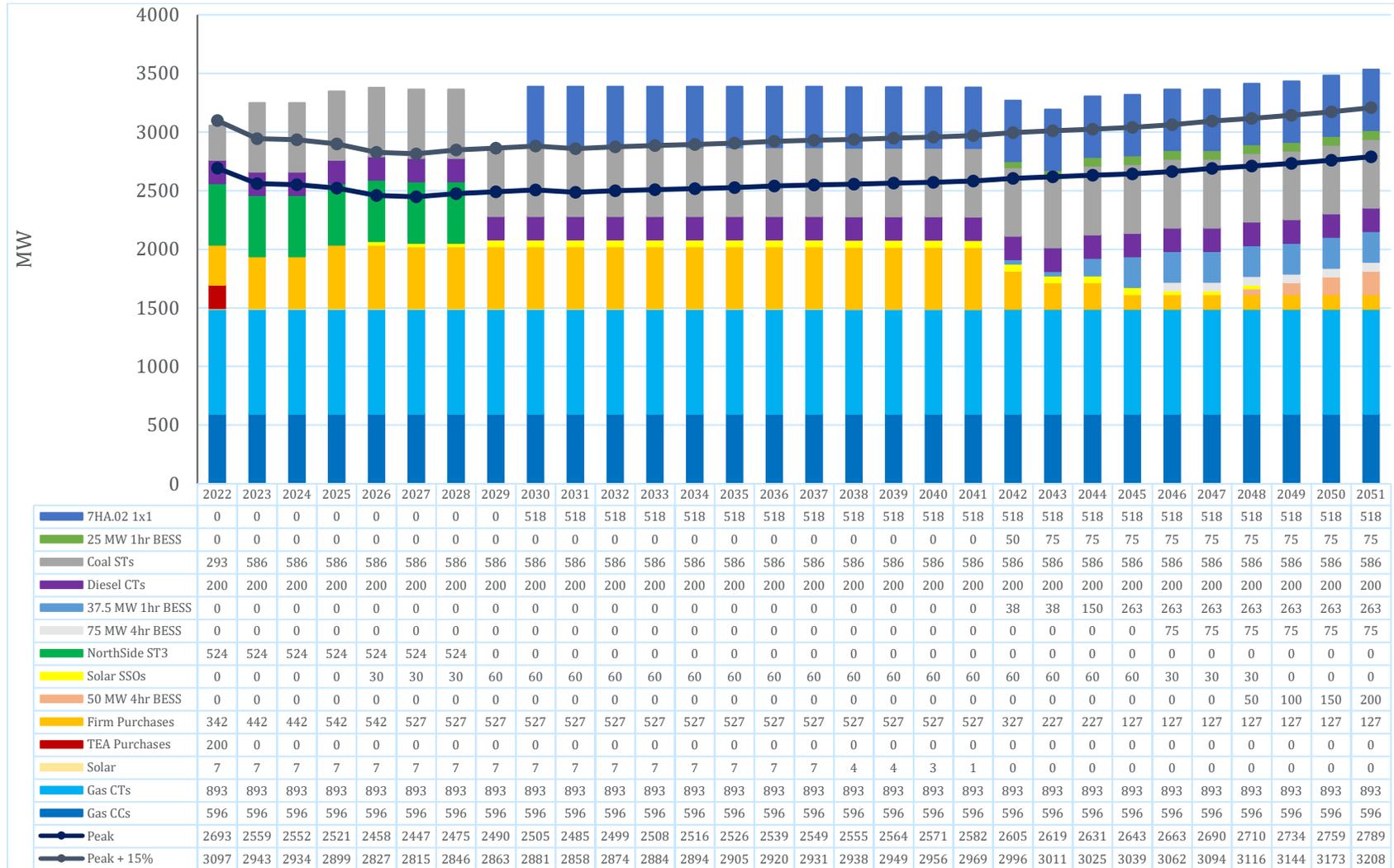
Appendix A – Detailed PLEXOS Modeling Results

Figure A-4 - Current Outlook Scenario – Annual Firm Capacity (January)



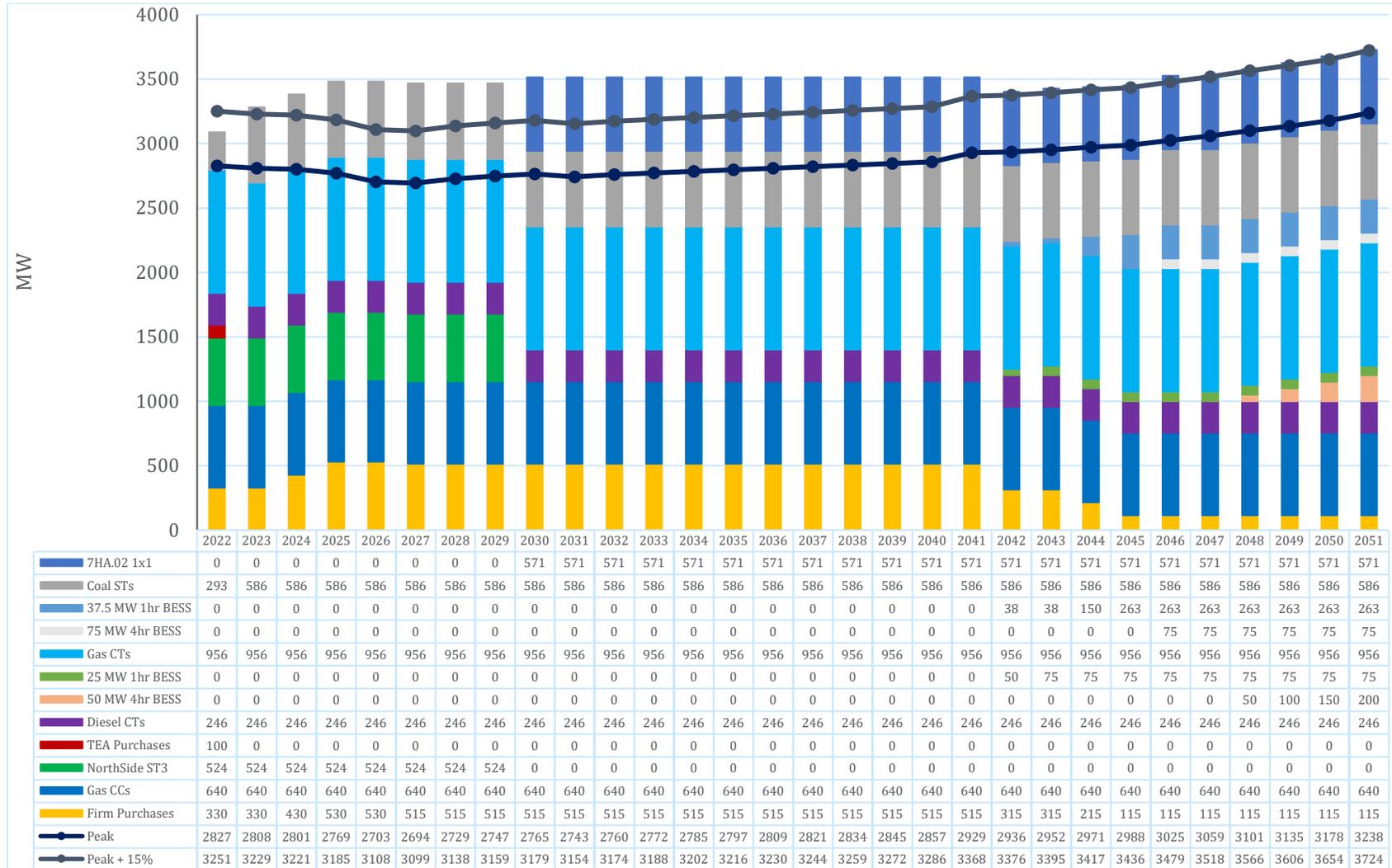
Appendix A – Detailed PLEXOS Modeling Results

Figure A-5 - Economic Downturn Scenario – Annual Firm Capacity (August)



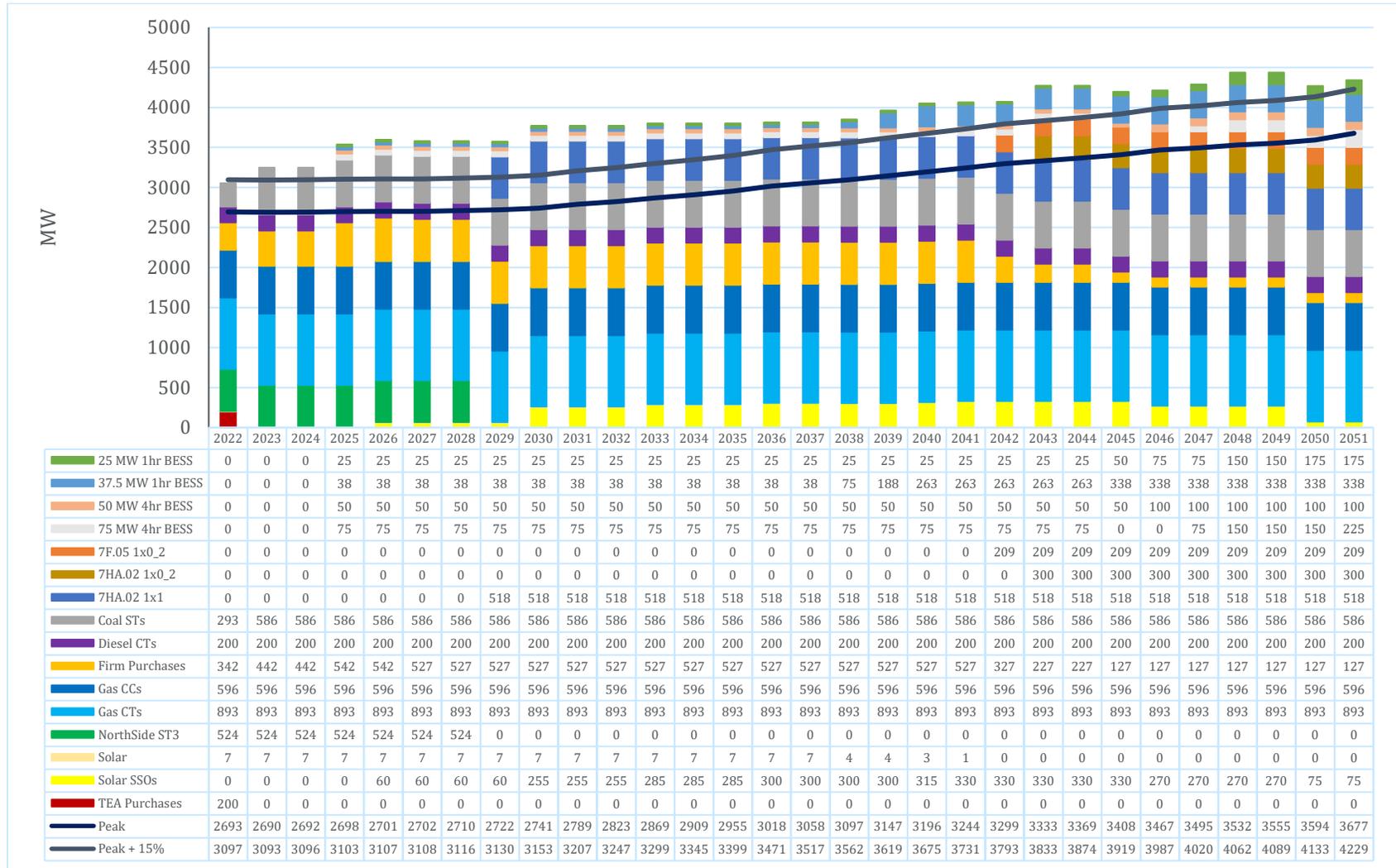
Appendix A – Detailed PLEXOS Modeling Results

Figure A-6 - Economic Downturn Scenario – Annual Firm Capacity (January)



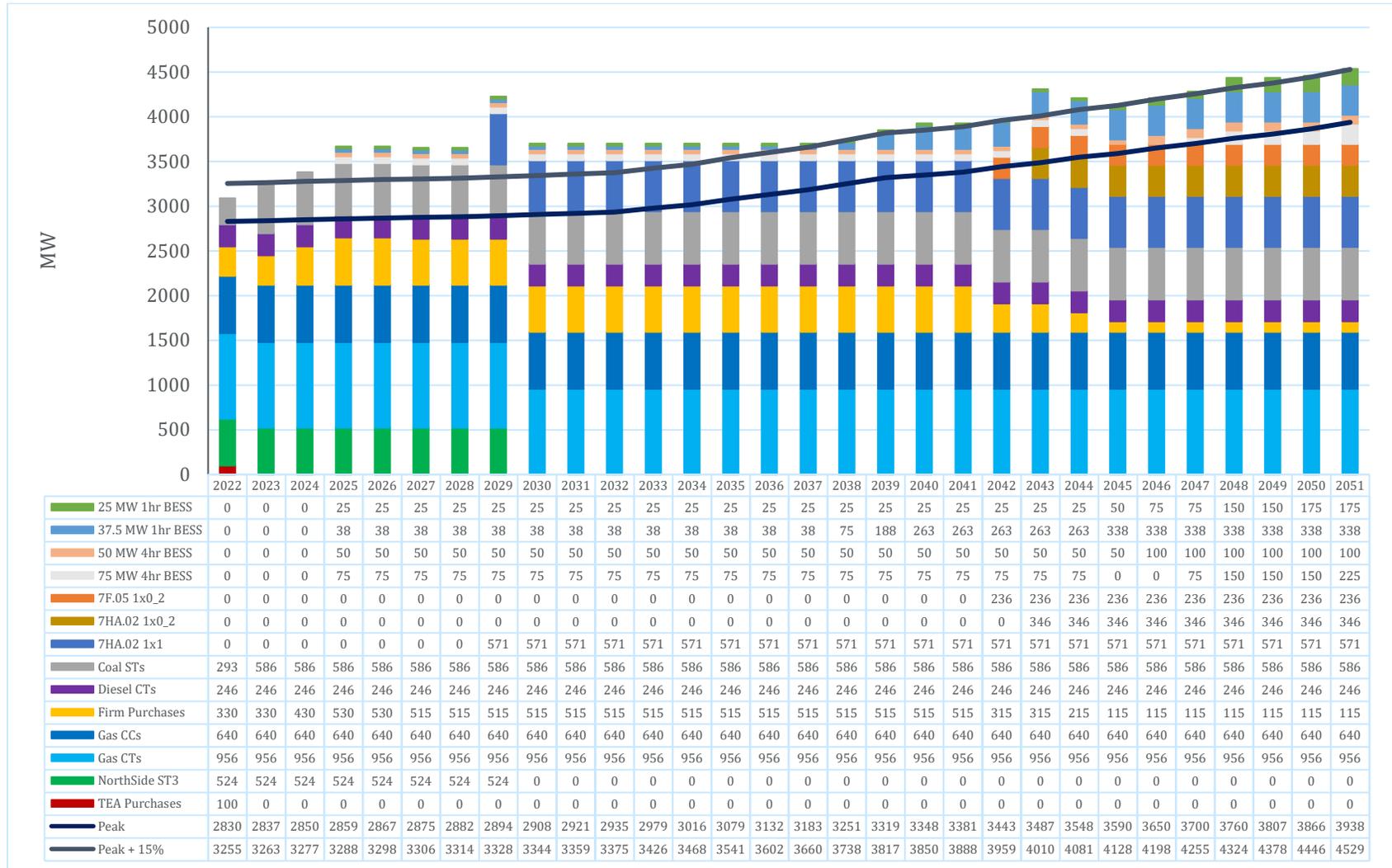
Appendix A – Detailed PLEXOS Modeling Results

Figure A-7 - Efficiency + DER Scenario – Annual Firm Capacity (August)



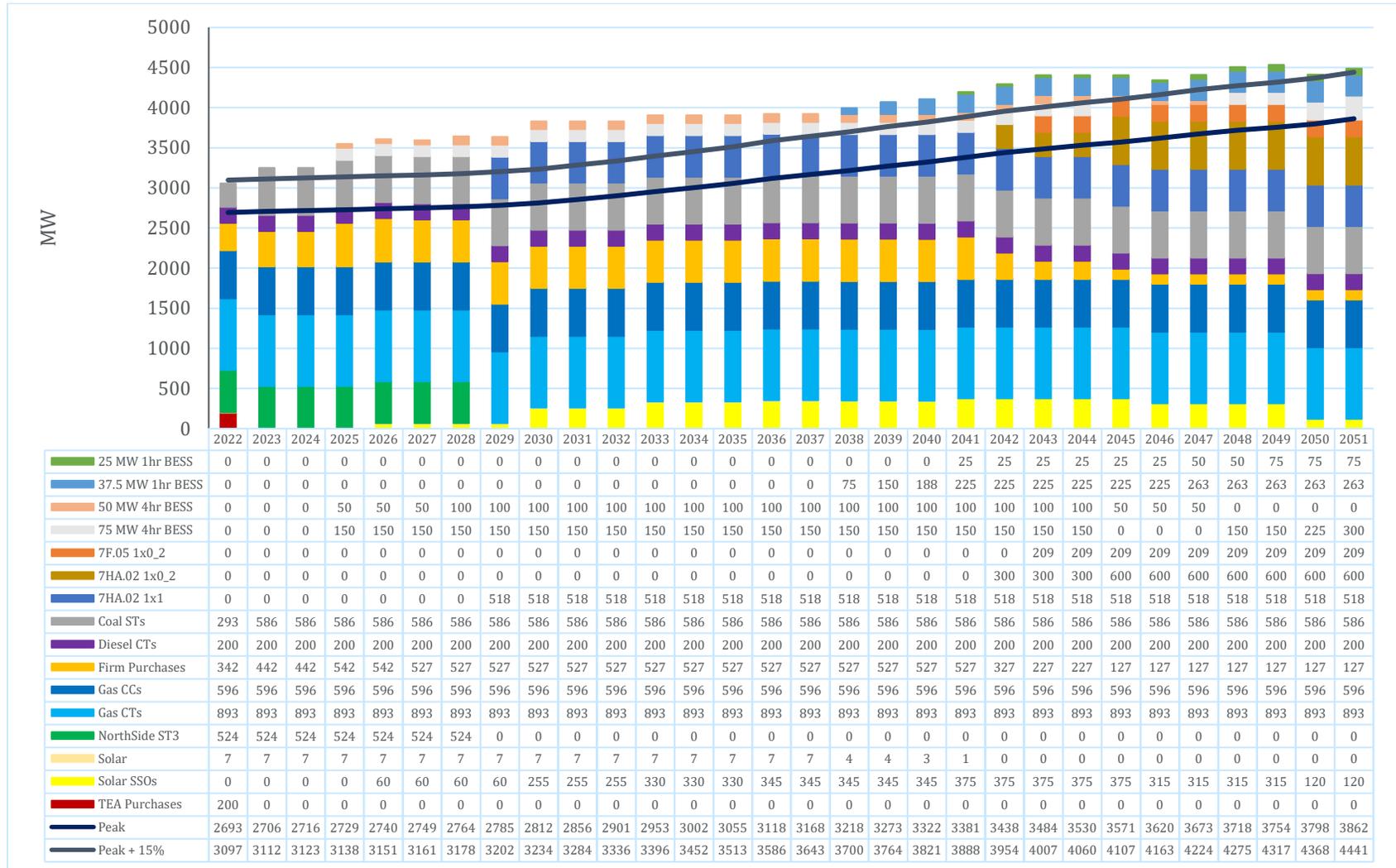
Appendix A – Detailed PLEXOS Modeling Results

Figure A-8 - Efficiency + DER Scenario – Annual Firm Capacity (January)



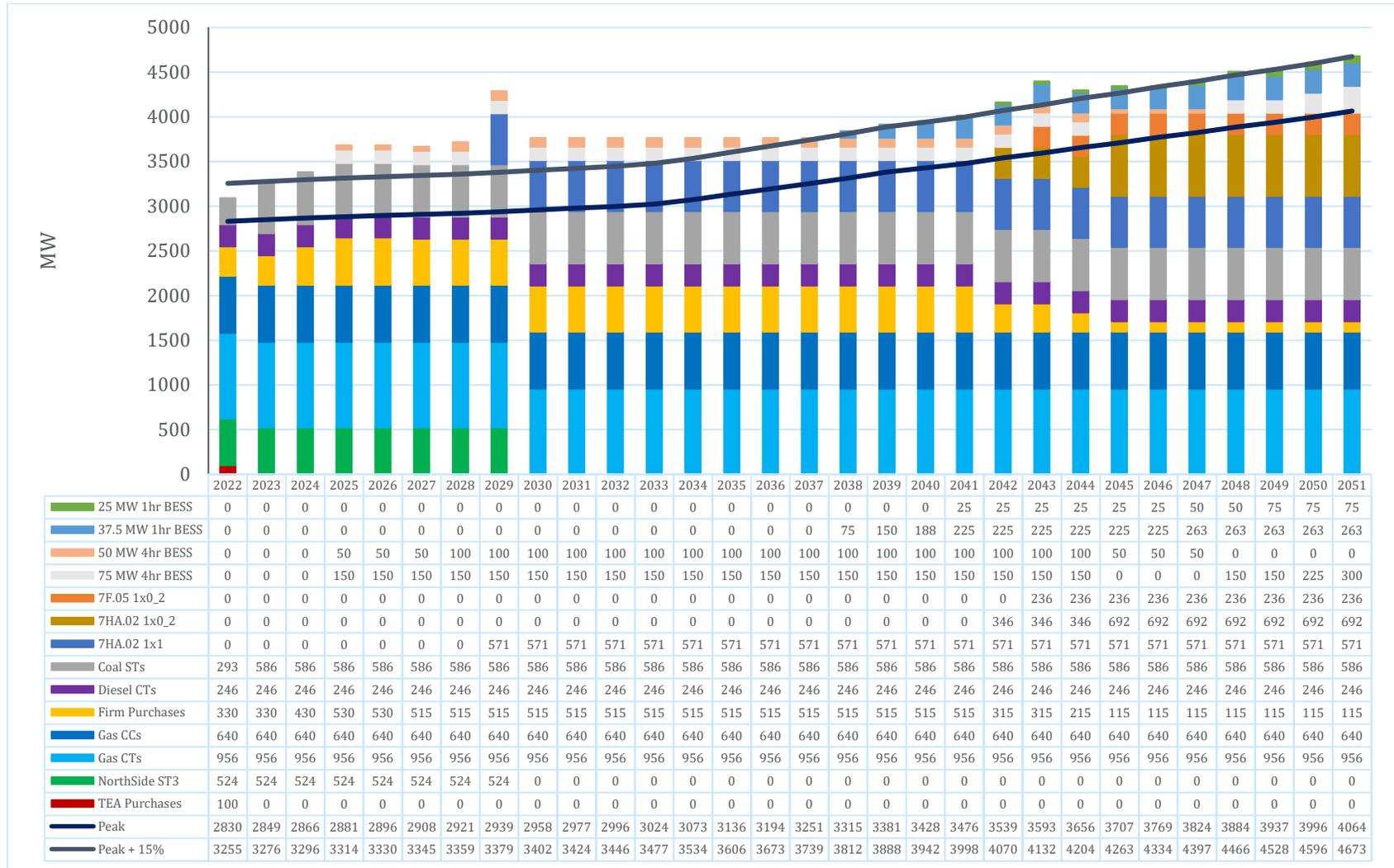
Appendix A – Detailed PLEXOS Modeling Results

Figure A-9 - Increased Electrification Scenario – Annual Firm Capacity (August)



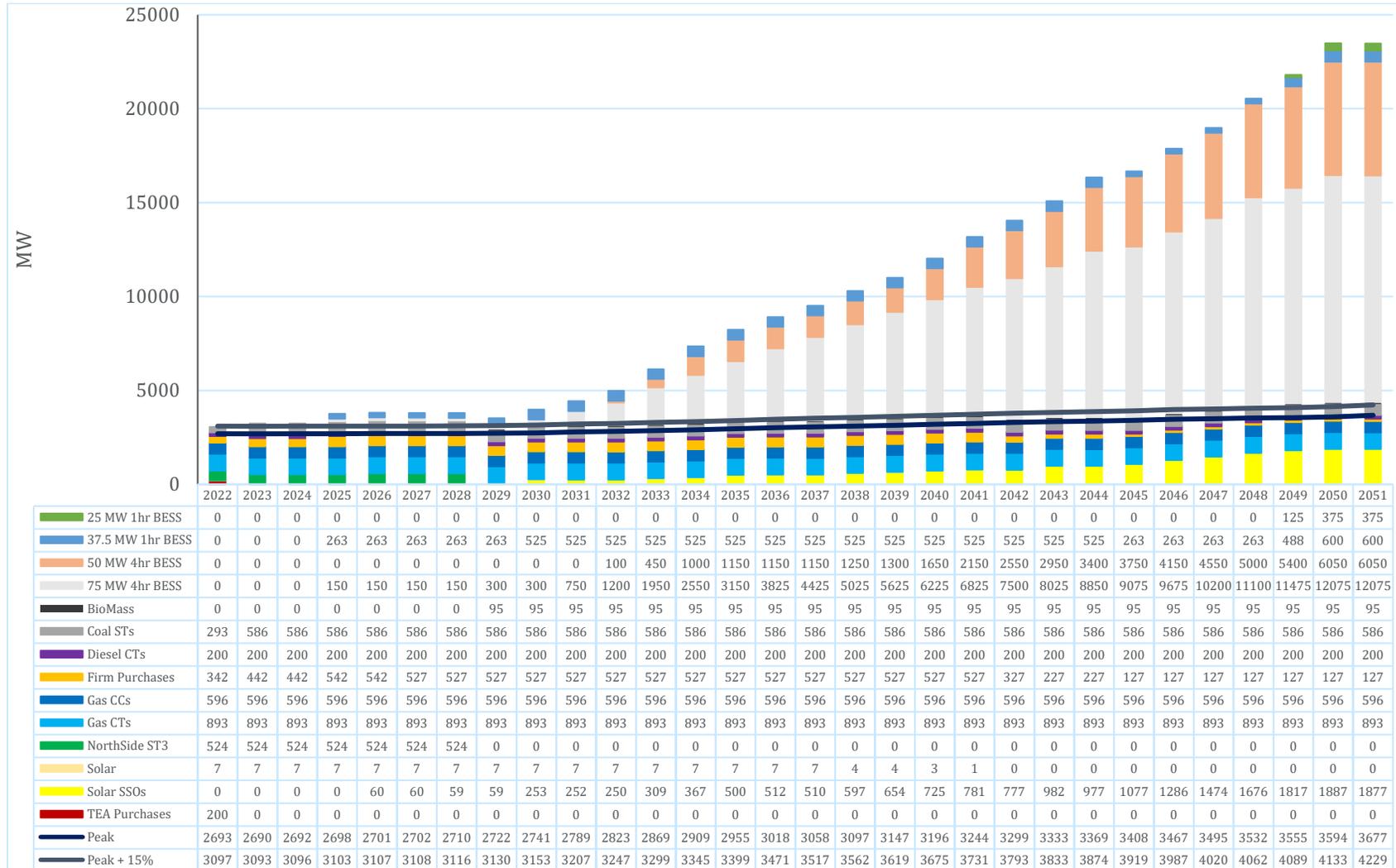
Appendix A – Detailed PLEXOS Modeling Results

Figure A-10 - Increased Electrification Scenario – Annual Firm Capacity (January)



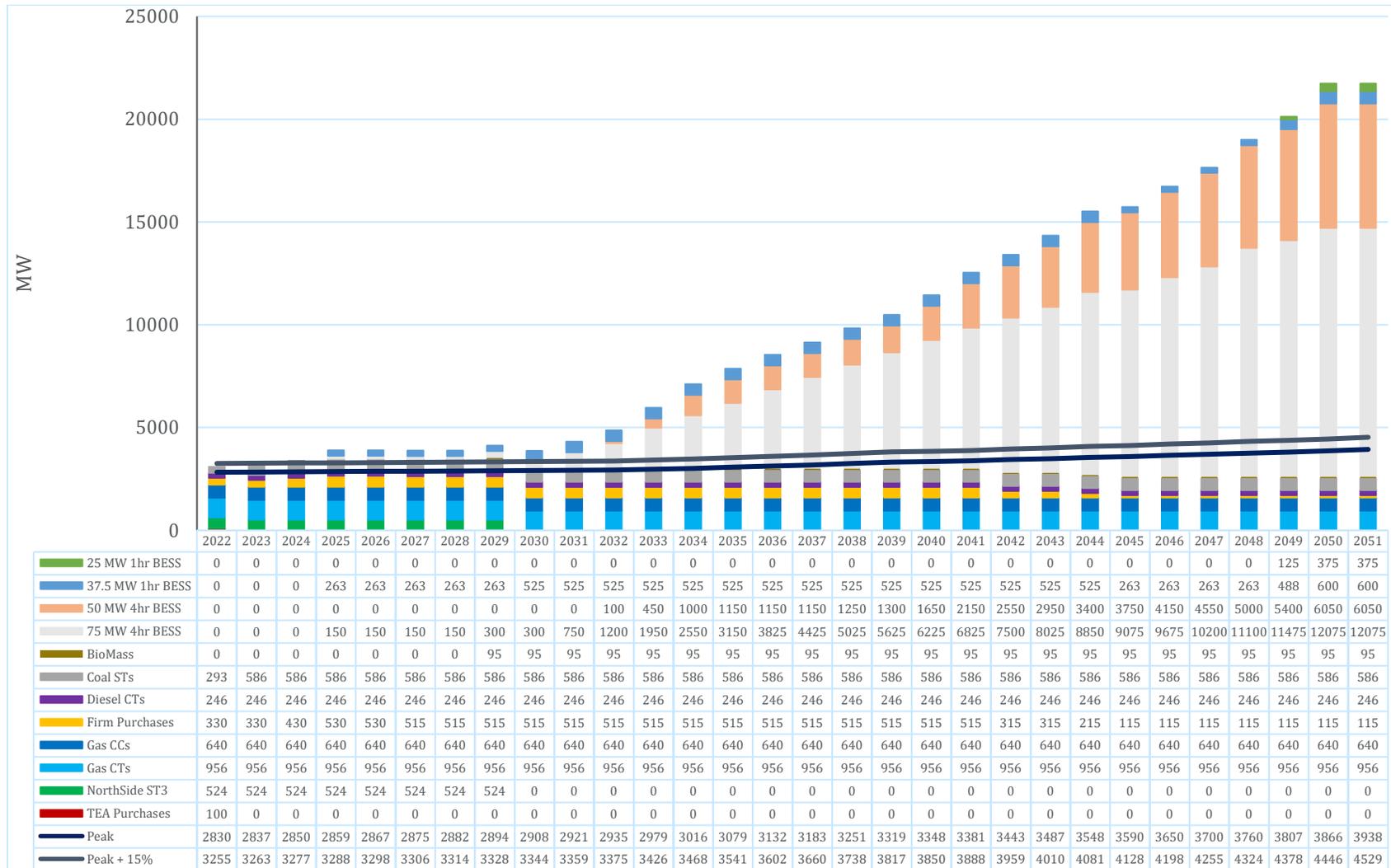
Appendix A – Detailed PLEXOS Modeling Results

Figure A-11 - Future Net Zero Scenario – Annual Firm Capacity (August)



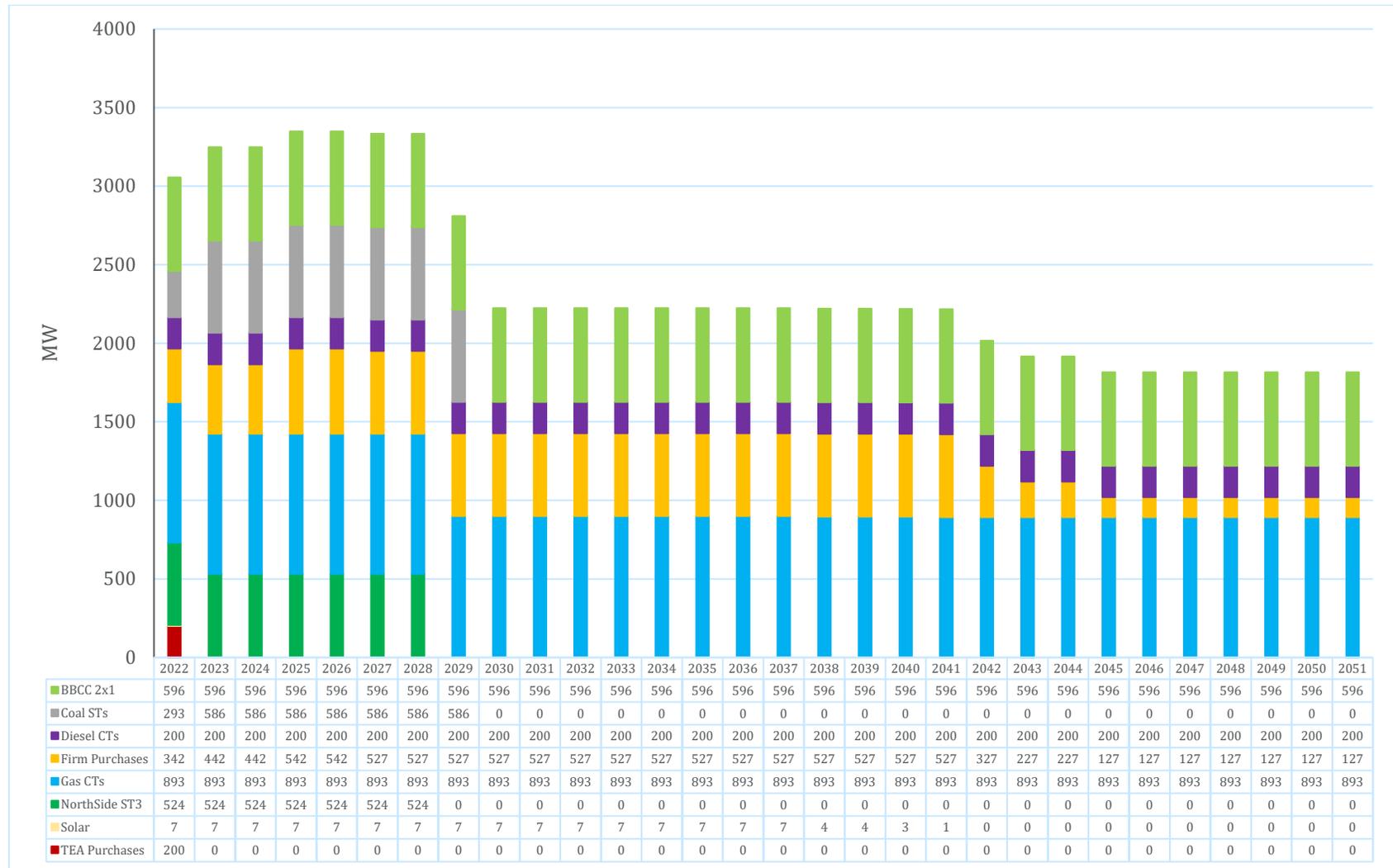
Appendix A – Detailed PLEXOS Modeling Results

Figure A-12 - Future Net Zero Scenario – Annual Firm Capacity (August)



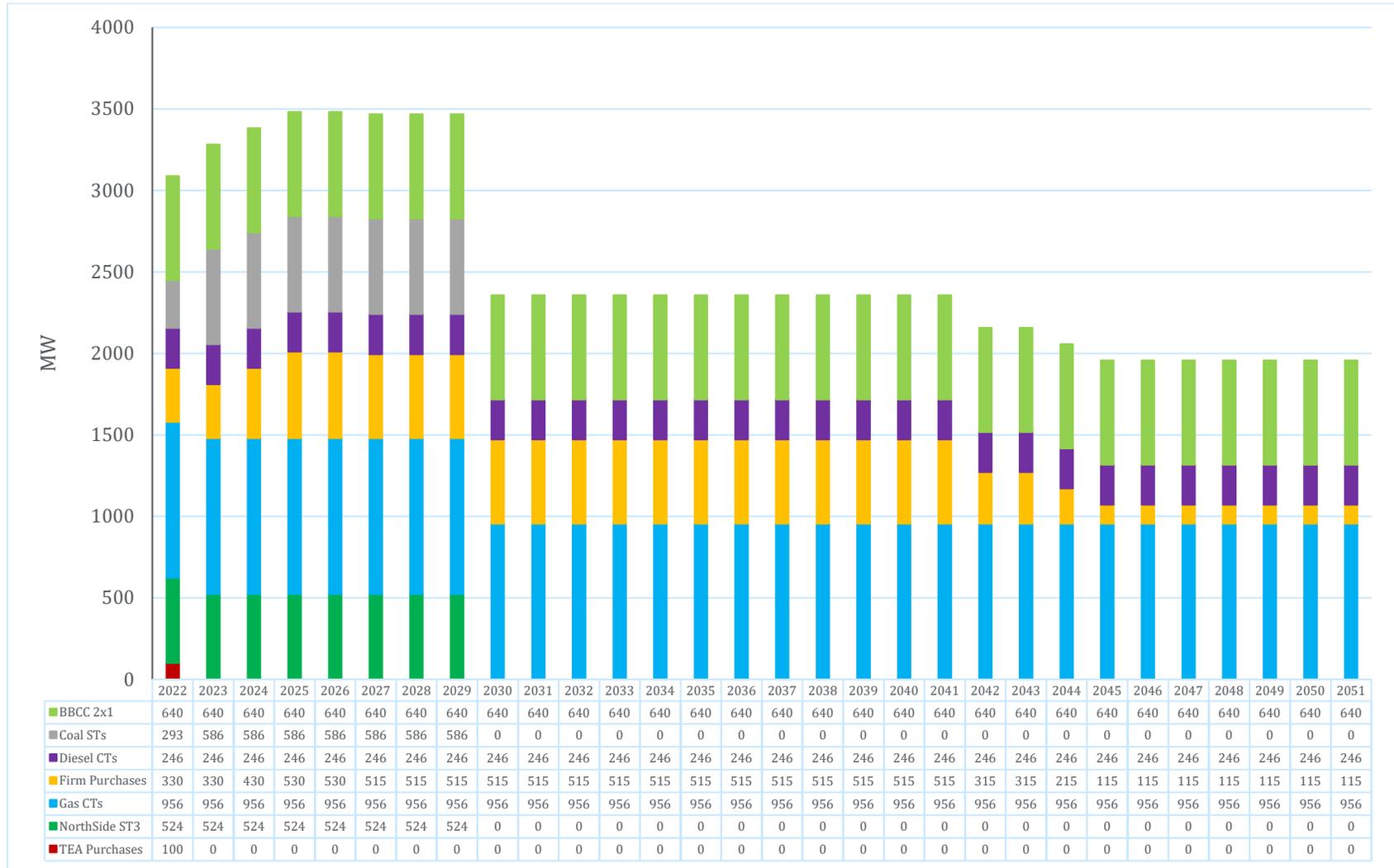
Appendix A – Detailed PLEXOS Modeling Results

Figure A-13 - Supplemental Scenario – Annual Firm Capacity (August) without Capacity Addition



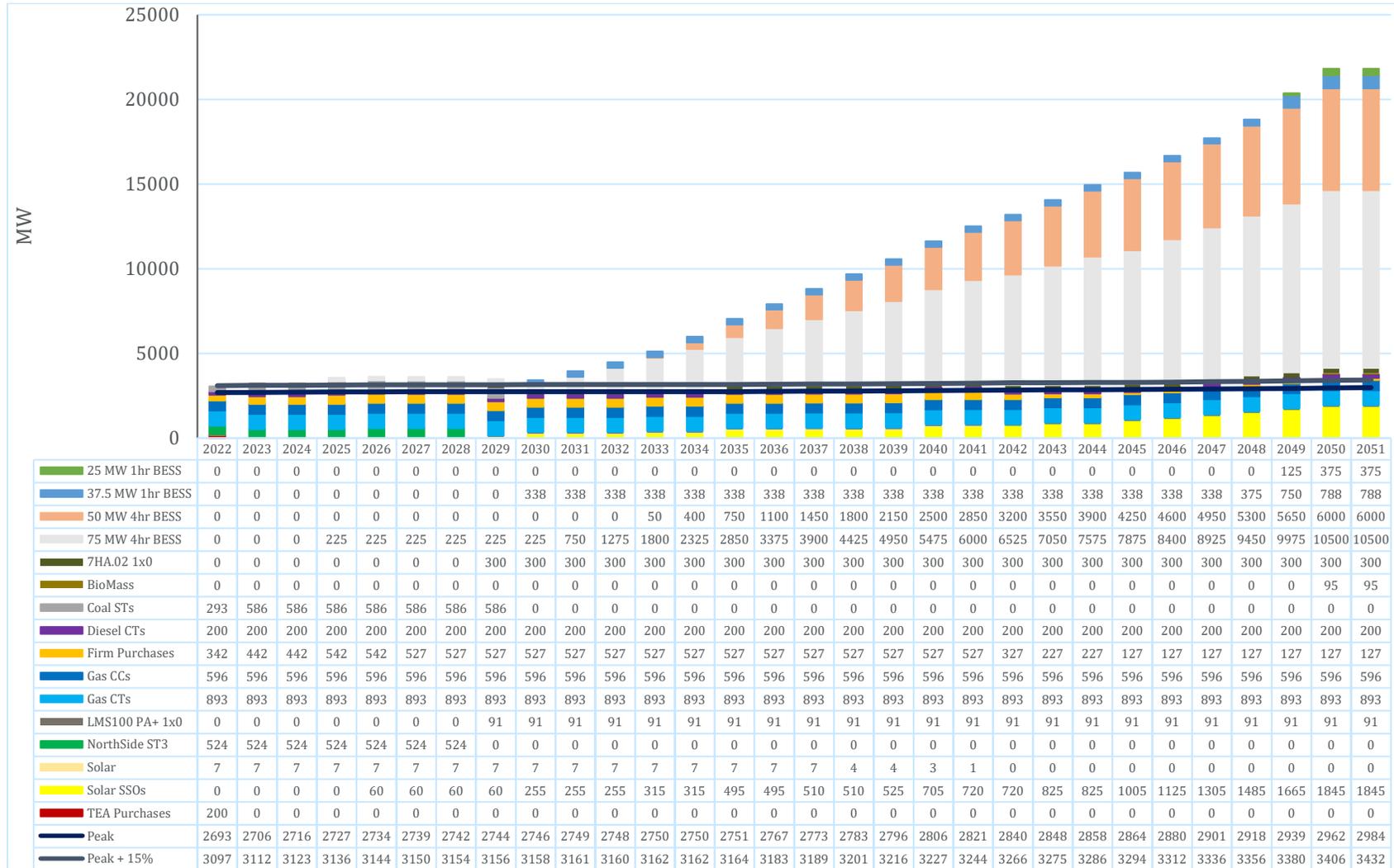
Appendix A – Detailed PLEXOS Modeling Results

Figure A-14 - Supplemental Scenario – Annual Firm Capacity (January) without Capacity Addition



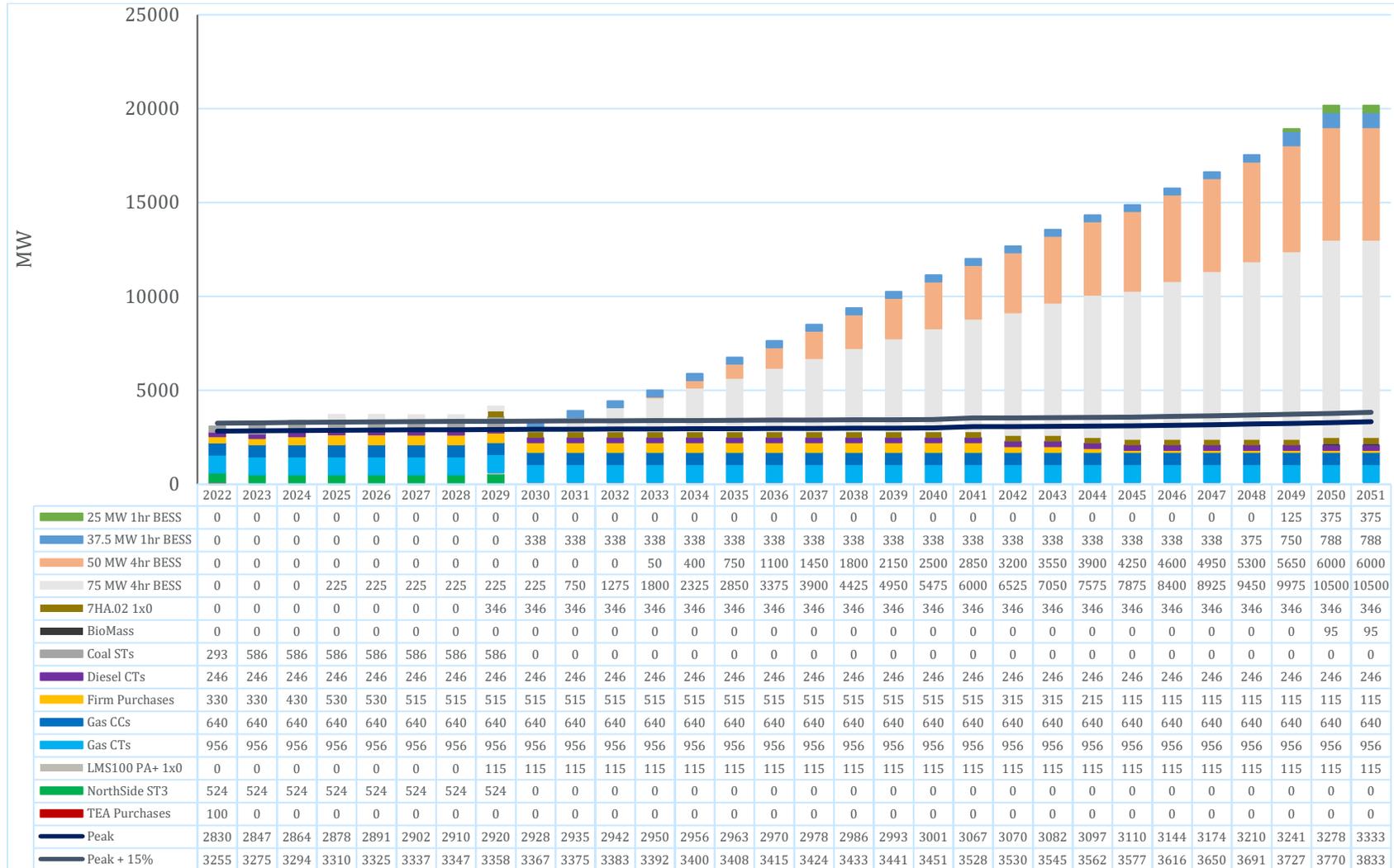
Appendix A – Detailed PLEXOS Modeling Results

Figure A-15 - Supplemental Scenario – Annual Firm Capacity (August)



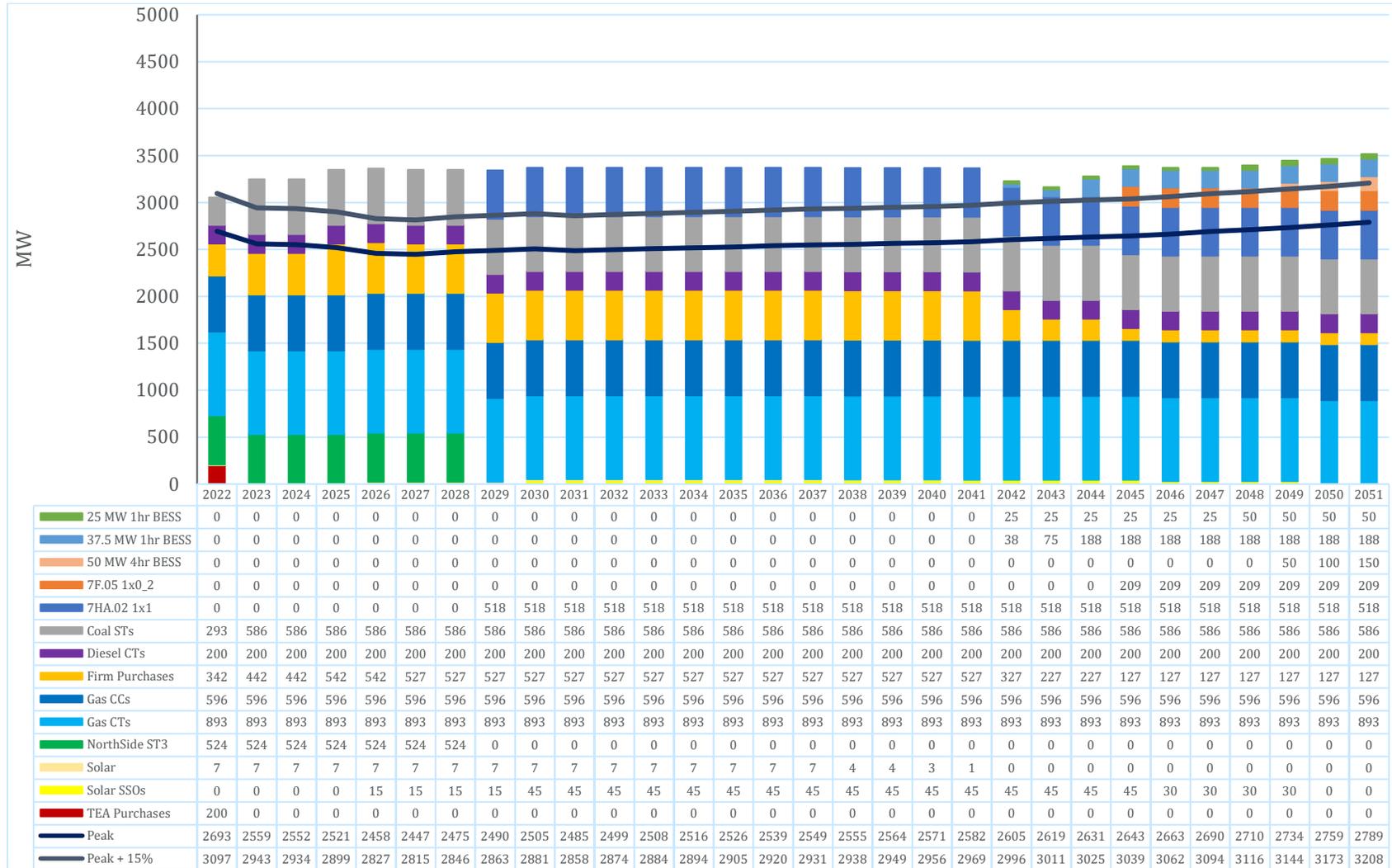
Appendix A – Detailed PLEXOS Modeling Results

Figure A-16 - Supplemental Scenario – Annual Firm Capacity (January)



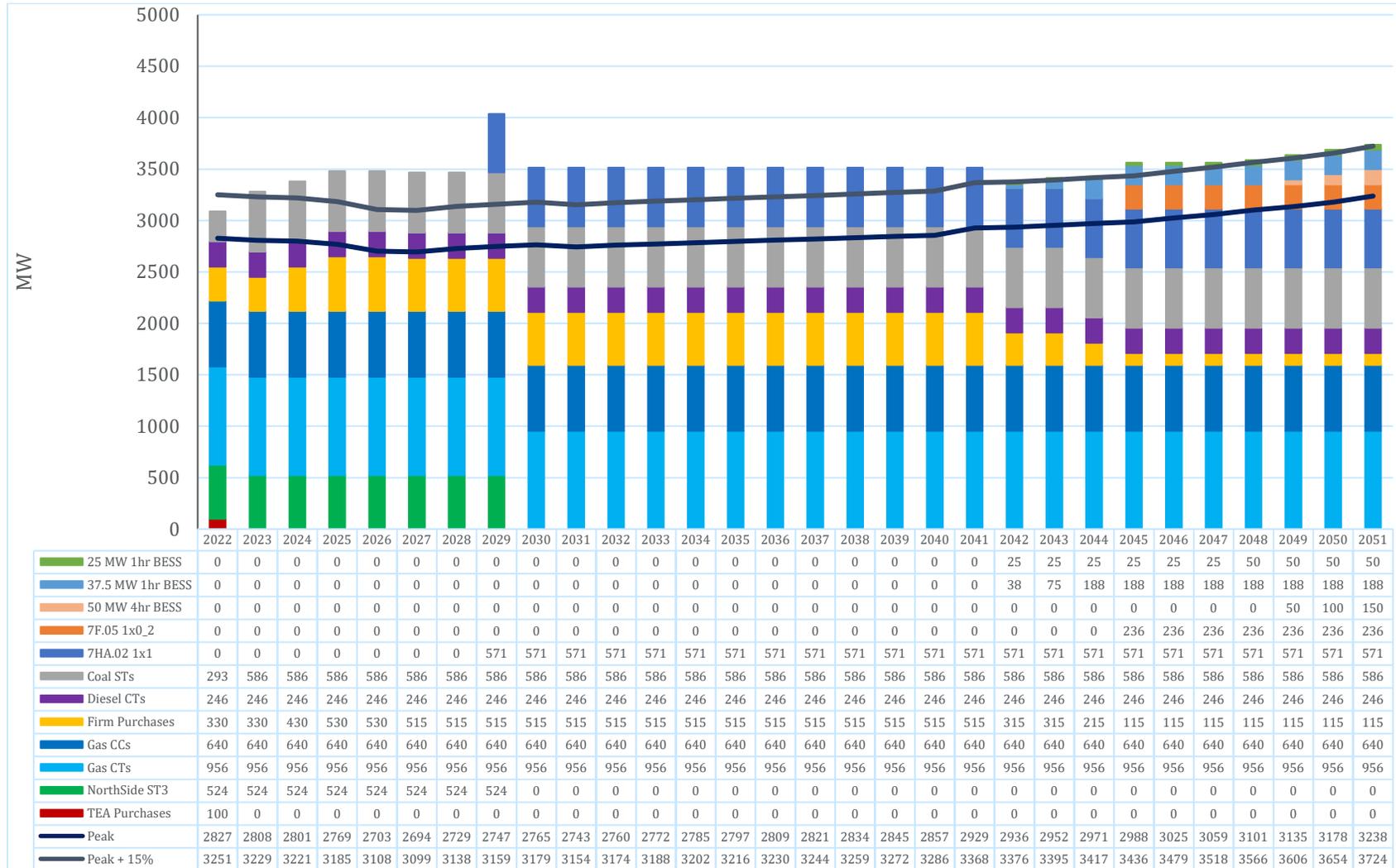
Appendix A – Detailed PLEXOS Modeling Results

Figure A-17 - Low Load Sensitivity – Annual Firm Capacity (August)



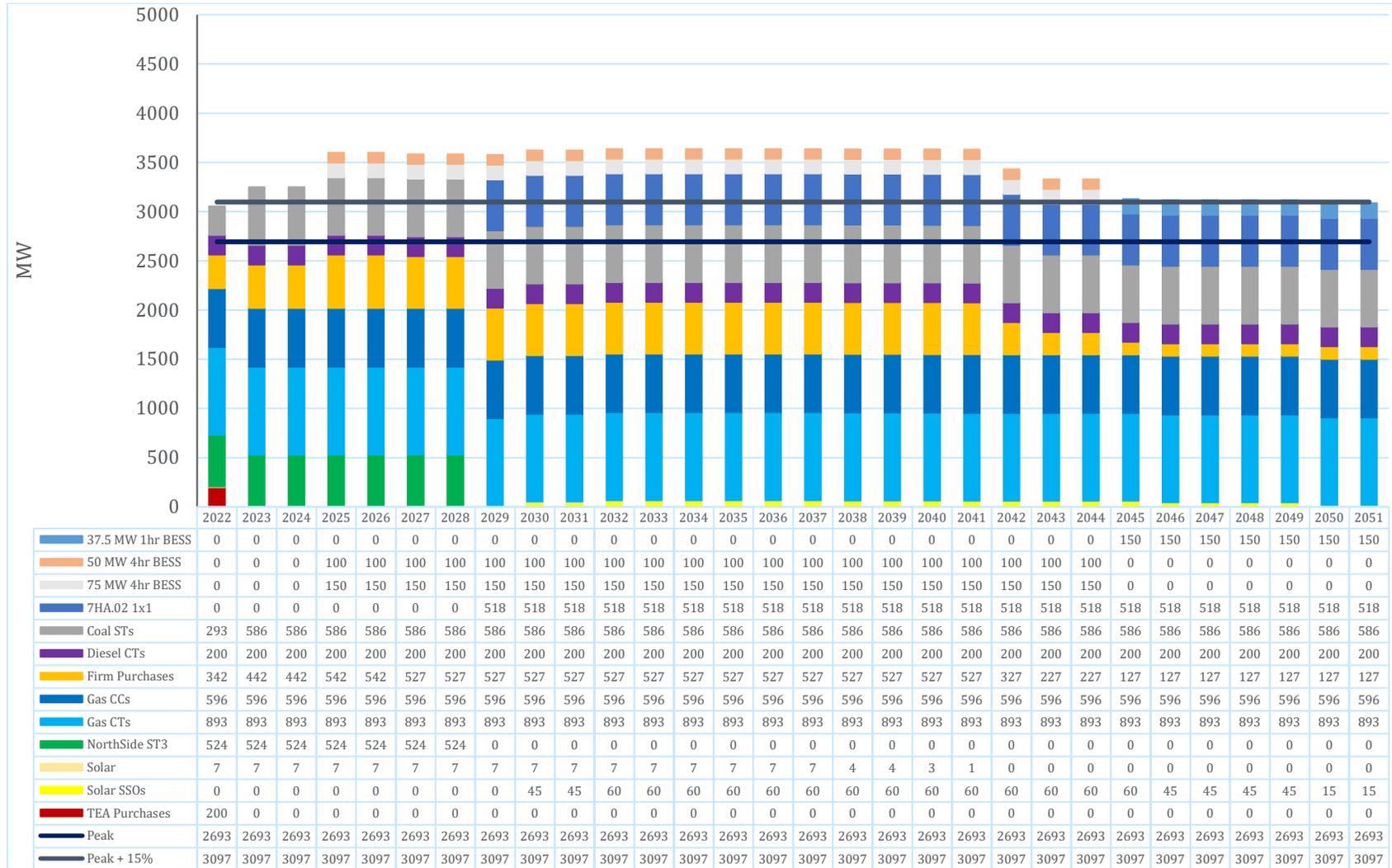
Appendix A – Detailed PLEXOS Modeling Results

Figure A-18 - Low Load Sensitivity – Annual Firm Capacity (January)



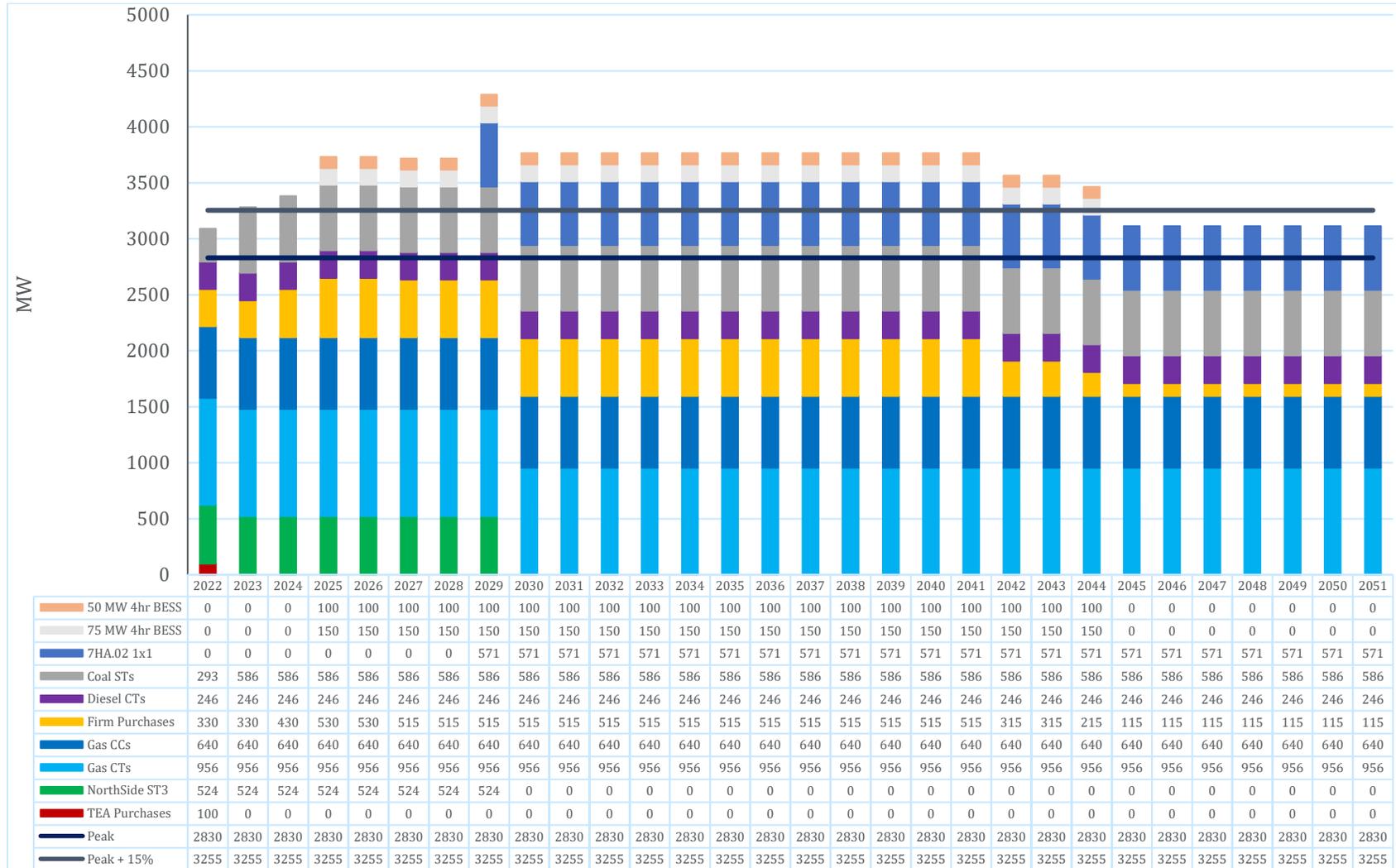
Appendix A – Detailed PLEXOS Modeling Results

Figure A-19 - No Load Growth Sensitivity – Annual Firm Capacity (August)



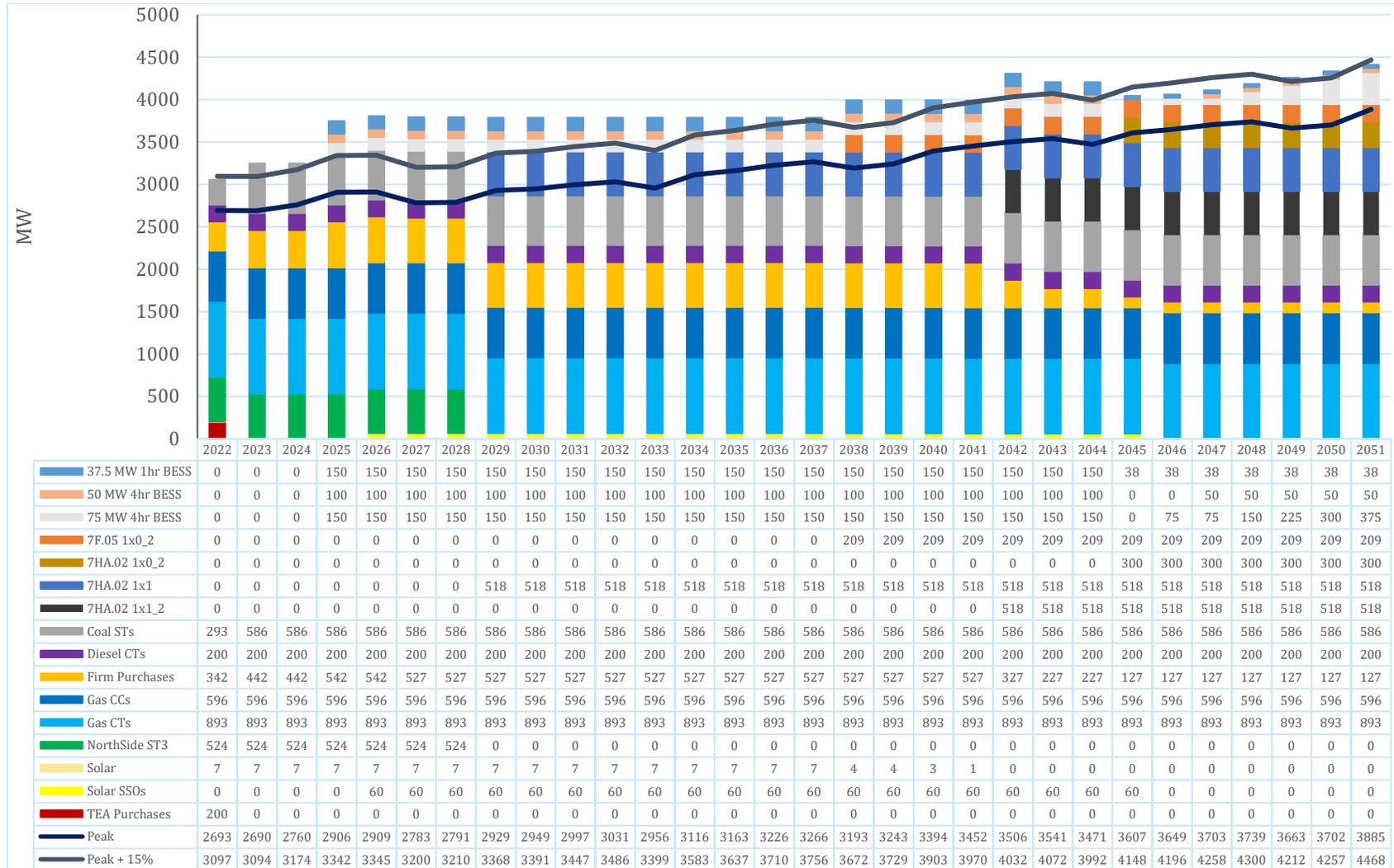
Appendix A – Detailed PLEXOS Modeling Results

Figure A-20 - No Load Growth Sensitivity – Annual Firm Capacity (January)



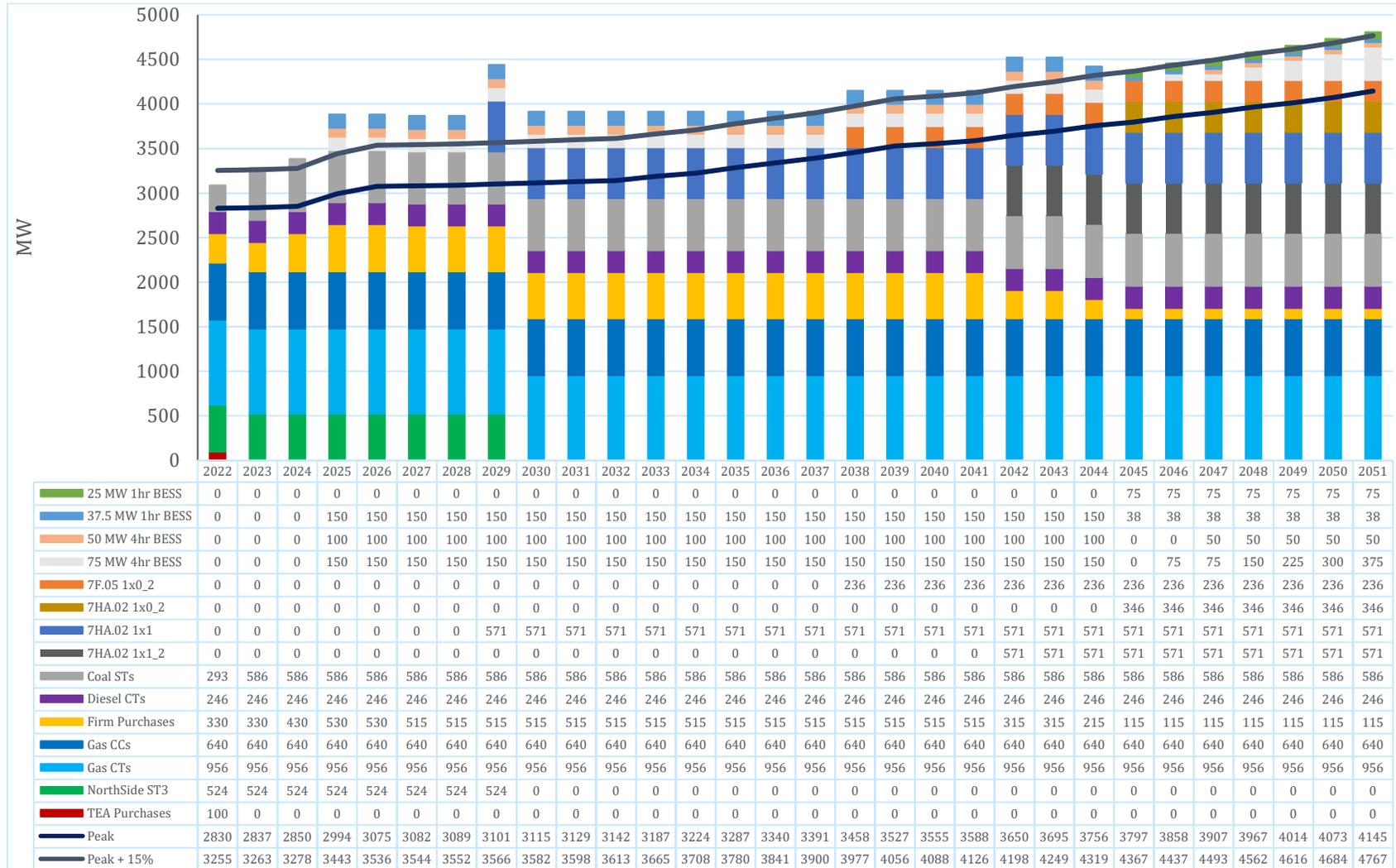
Appendix A – Detailed PLEXOS Modeling Results

Figure A-21 - High Load Sensitivity – Annual Firm Capacity (August)



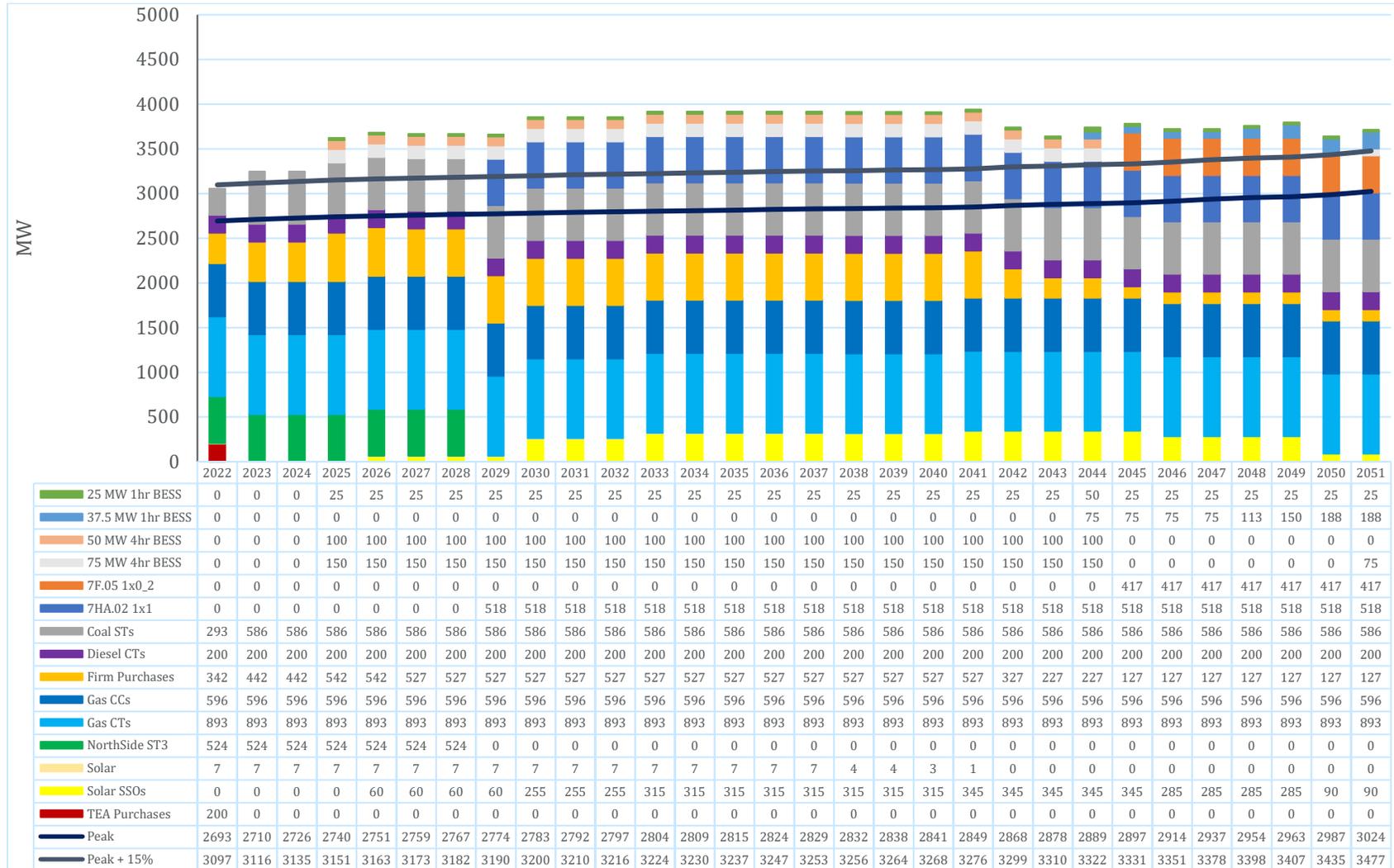
Appendix A – Detailed PLEXOS Modeling Results

Figure A-22 - High Load Sensitivity – Annual Firm Capacity (January)



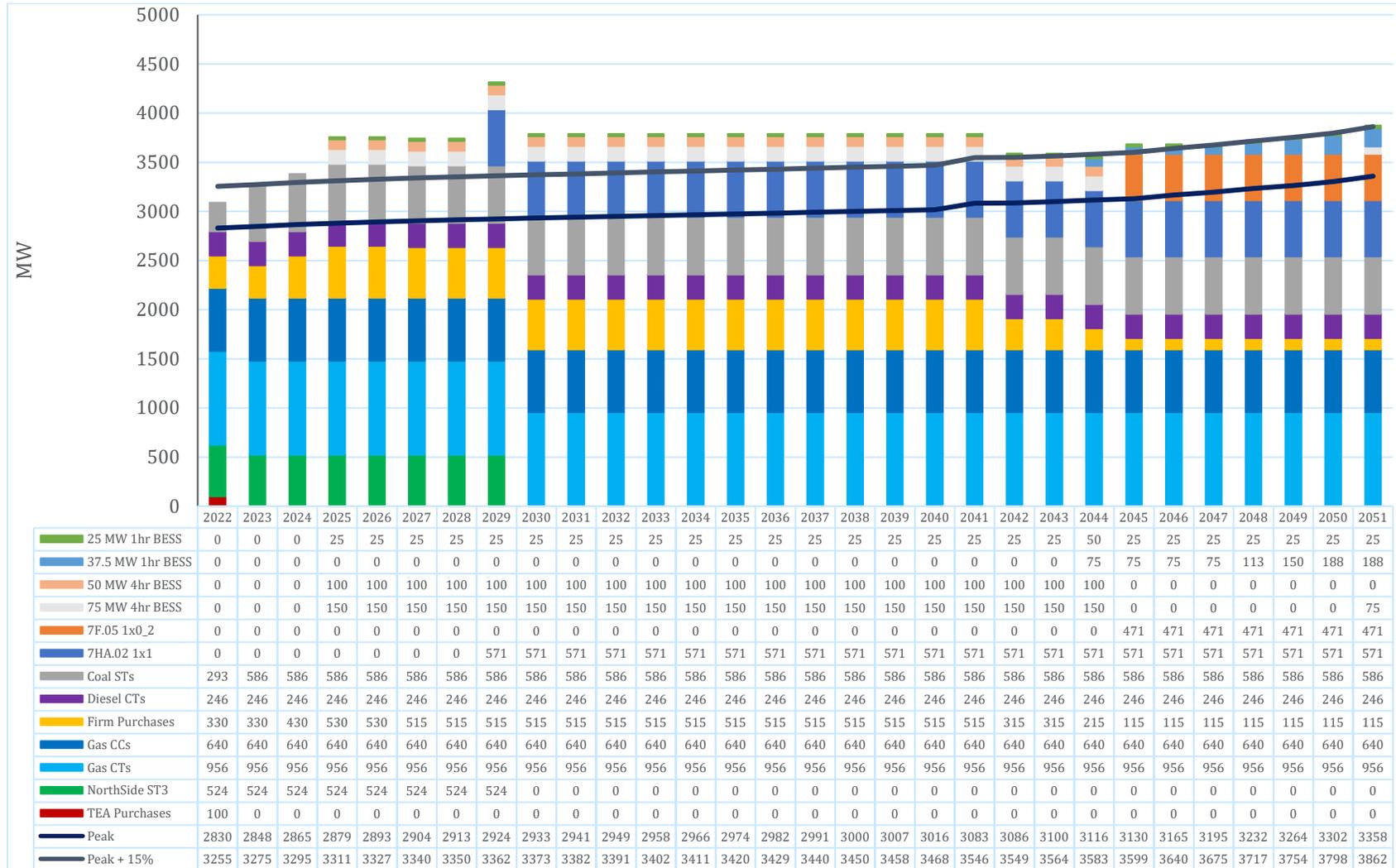
Appendix A – Detailed PLEXOS Modeling Results

Figure A-23 - High Fuel Sensitivity – Annual Firm Capacity (August)



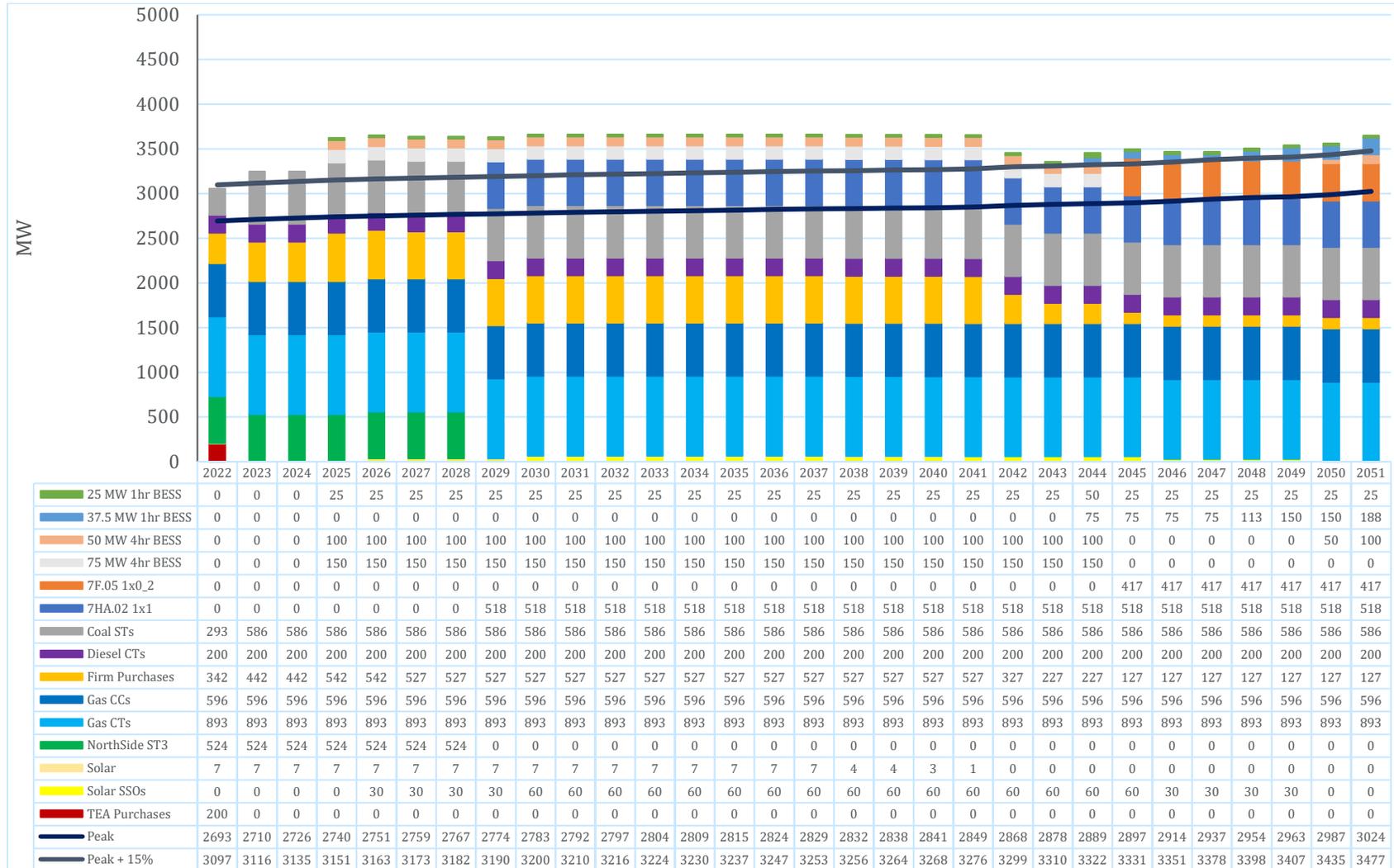
Appendix A – Detailed PLEXOS Modeling Results

Figure A-24 - High Fuel Sensitivity – Annual Firm Capacity (January)



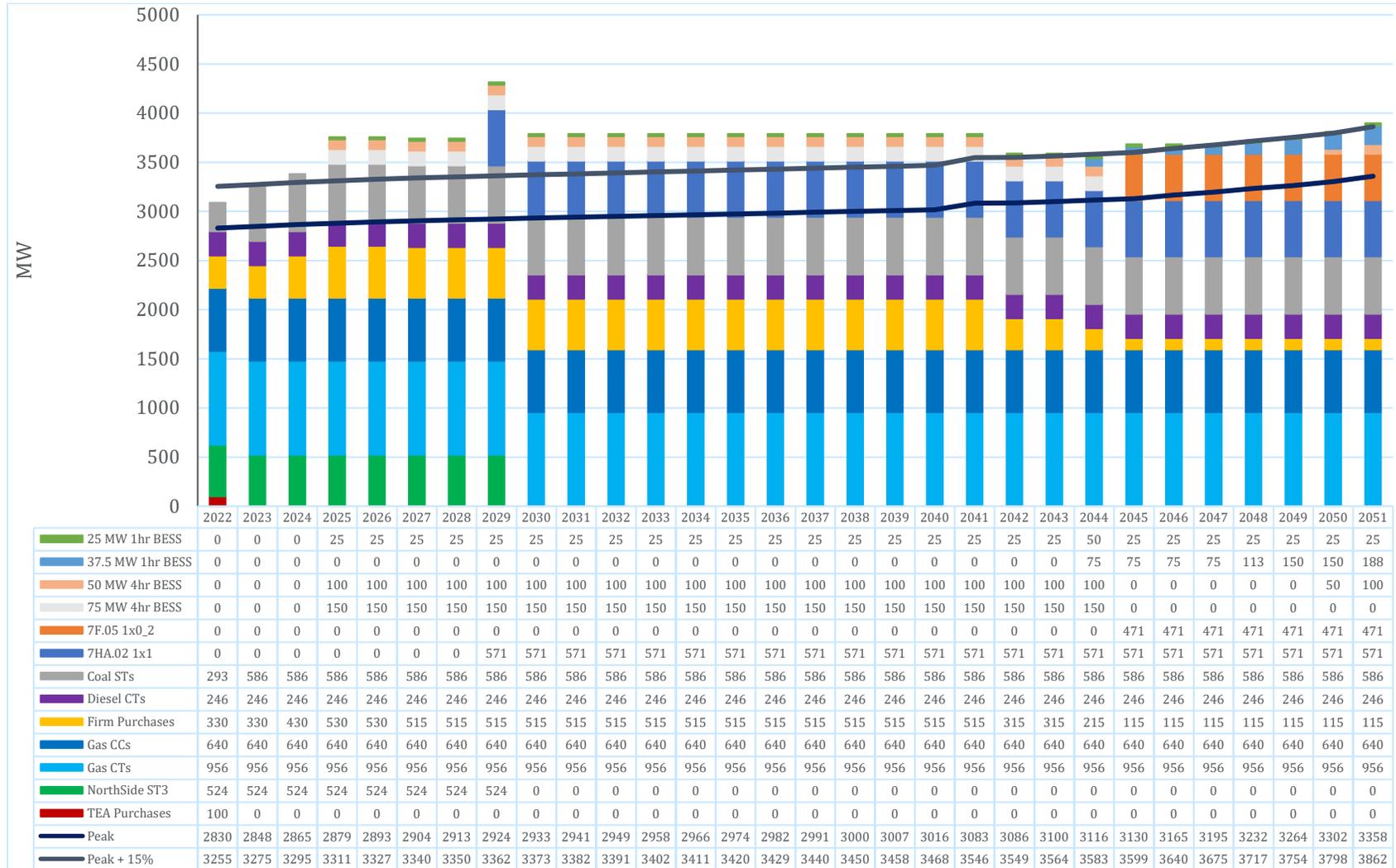
Appendix A – Detailed PLEXOS Modeling Results

Figure A-25 - Regulated CO<sub>2</sub> Sensitivity – Annual Firm Capacity (August)



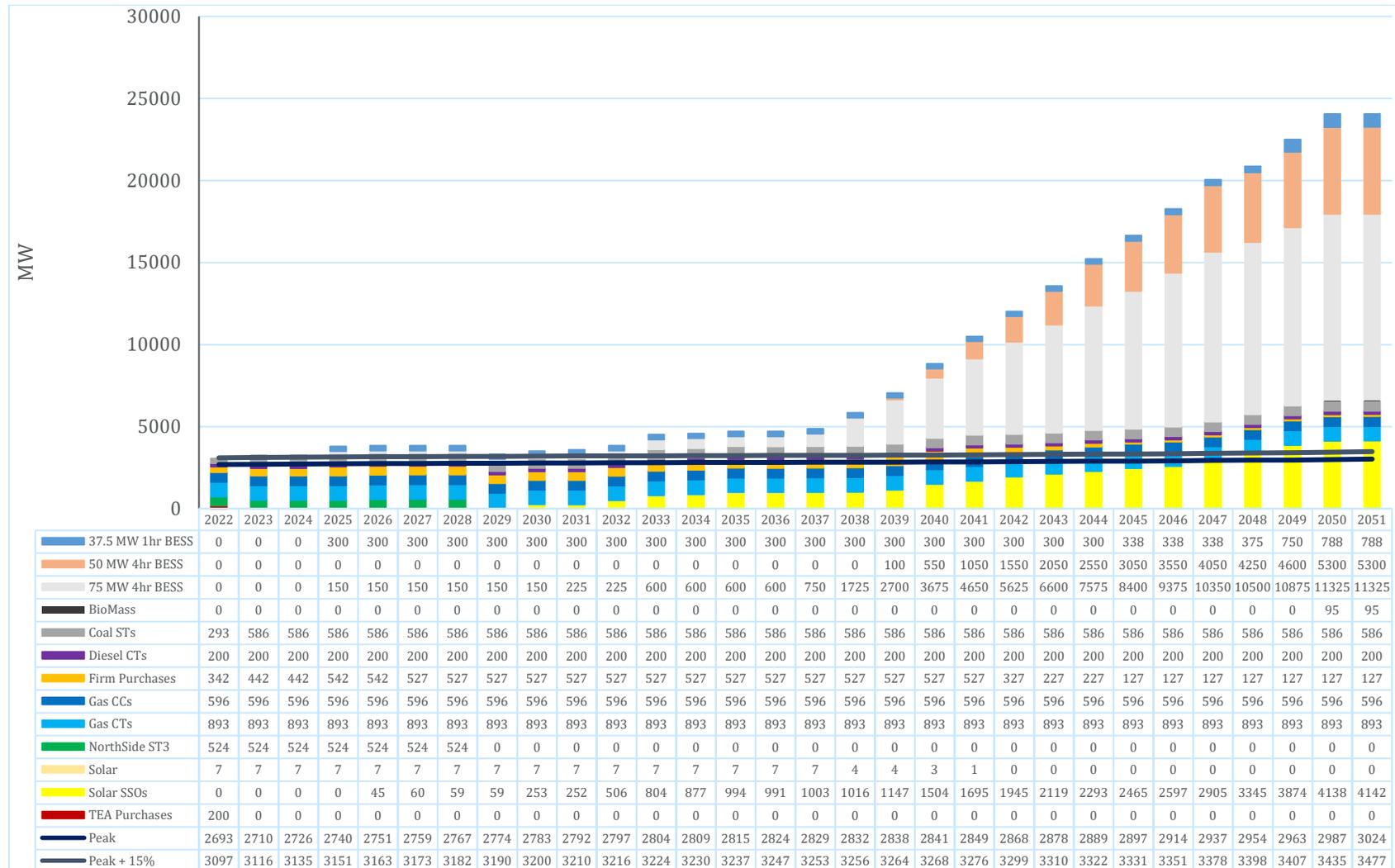
Appendix A – Detailed PLEXOS Modeling Results

Figure A-26 - Regulated CO<sub>2</sub> Sensitivity – Annual Firm Capacity (January)



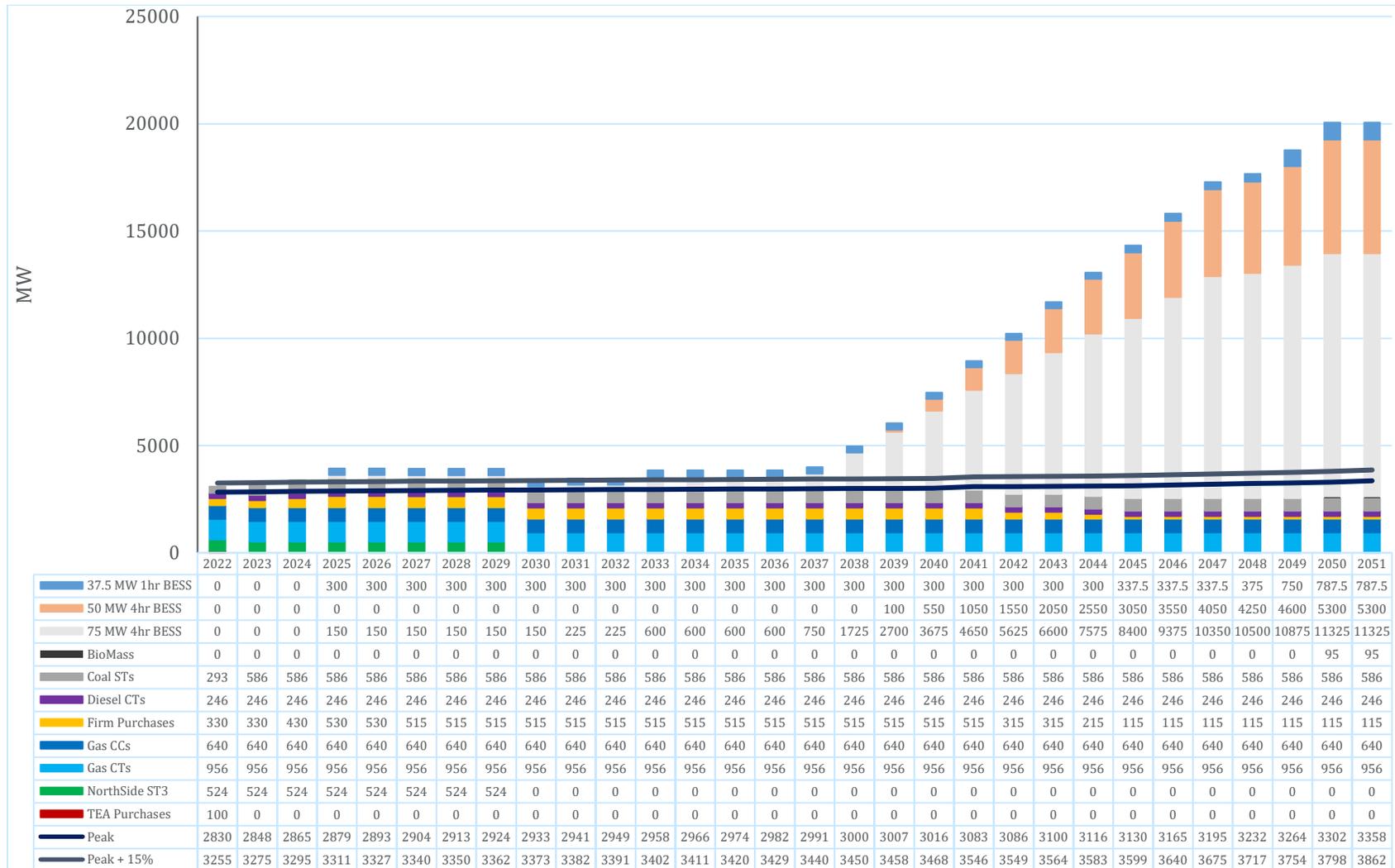
Appendix A – Detailed PLEXOS Modeling Results

Figure A-27 - Net Zero Sensitivity – Annual Firm Capacity (August)



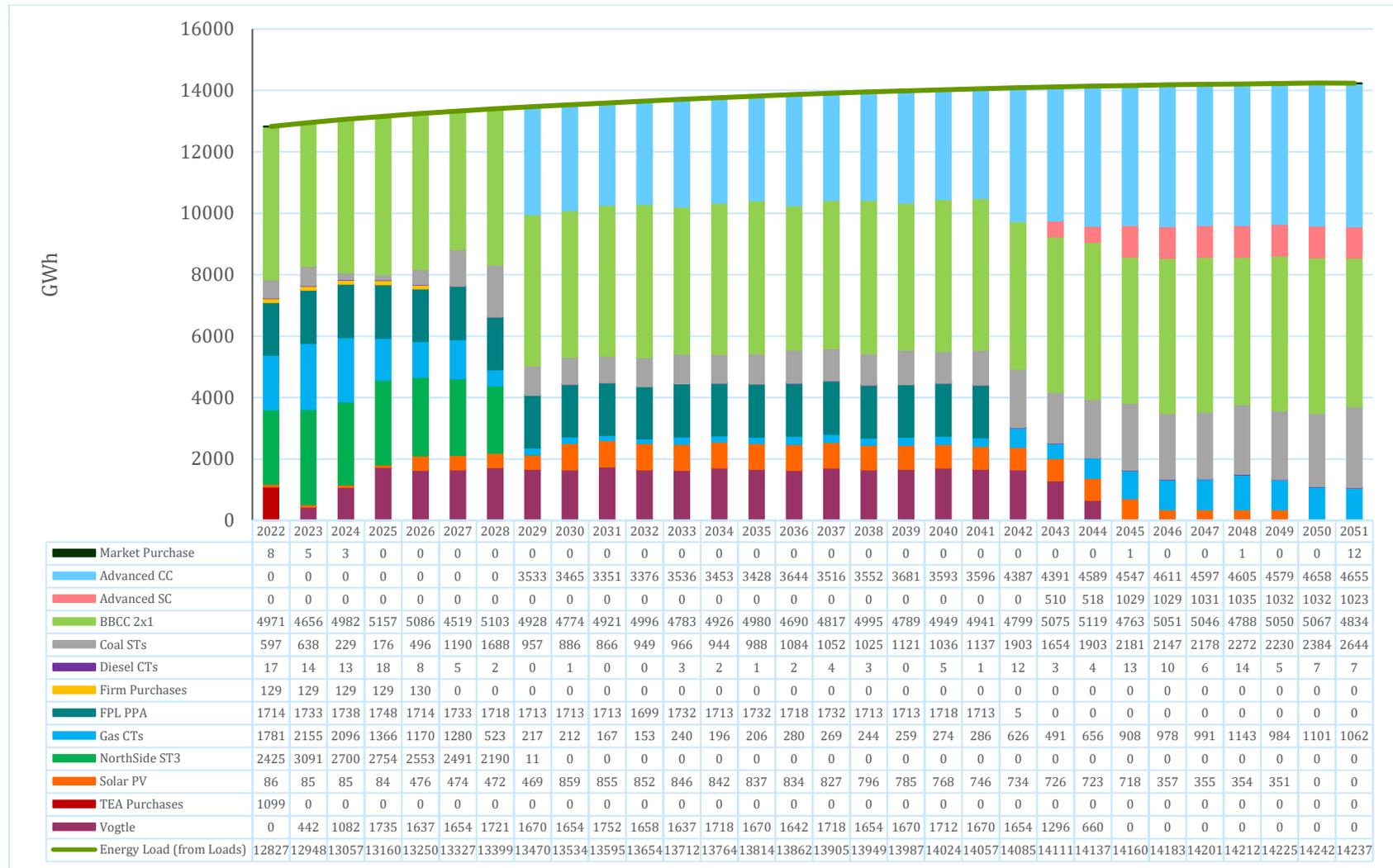
Appendix A – Detailed PLEXOS Modeling Results

Figure A-28 - Net Zero Sensitivity – Annual Firm Capacity (January)



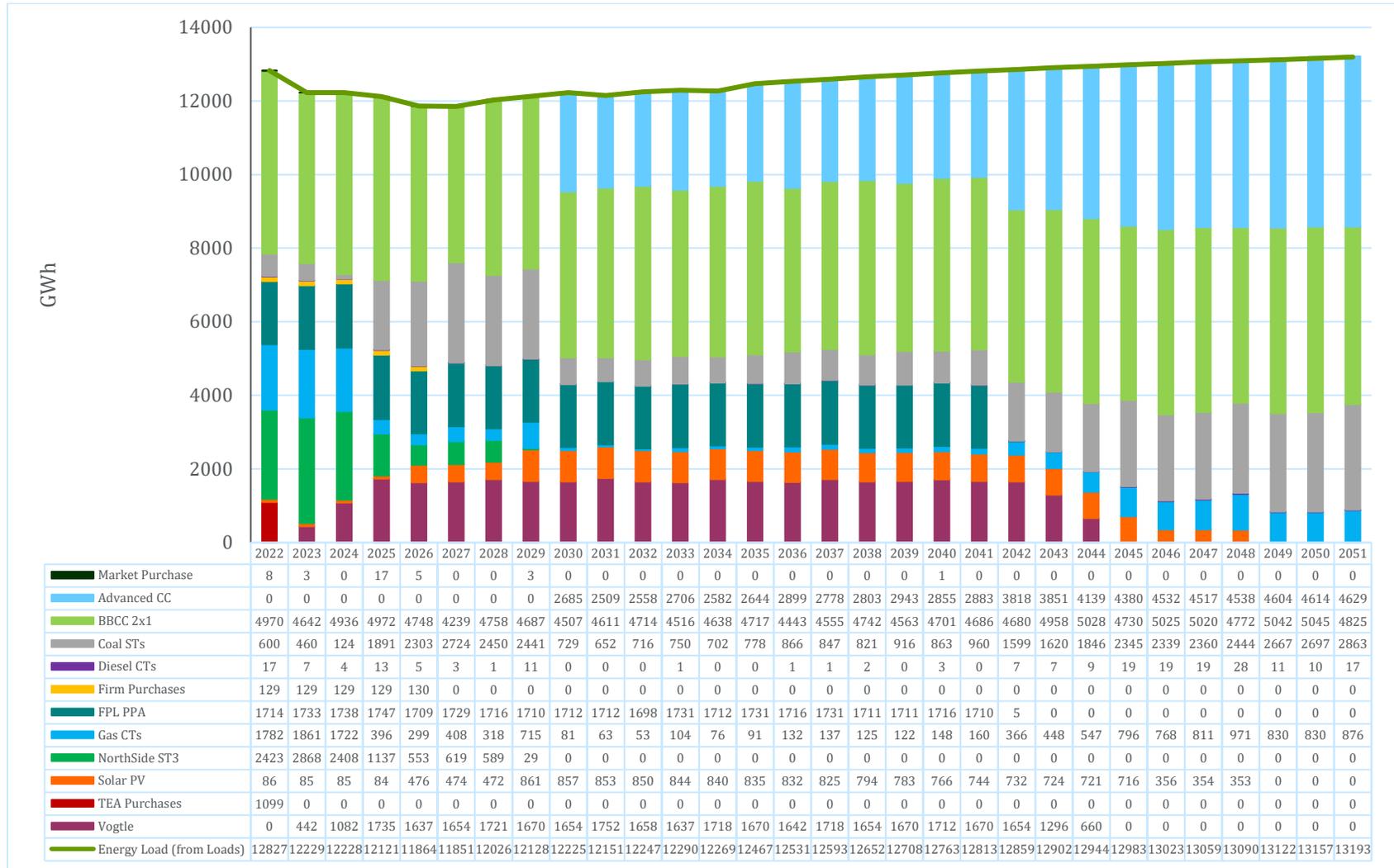
Appendix A – Detailed PLEXOS Modeling Results

Figure A-29 – Current Outlook Scenario – Annual Energy by Resource



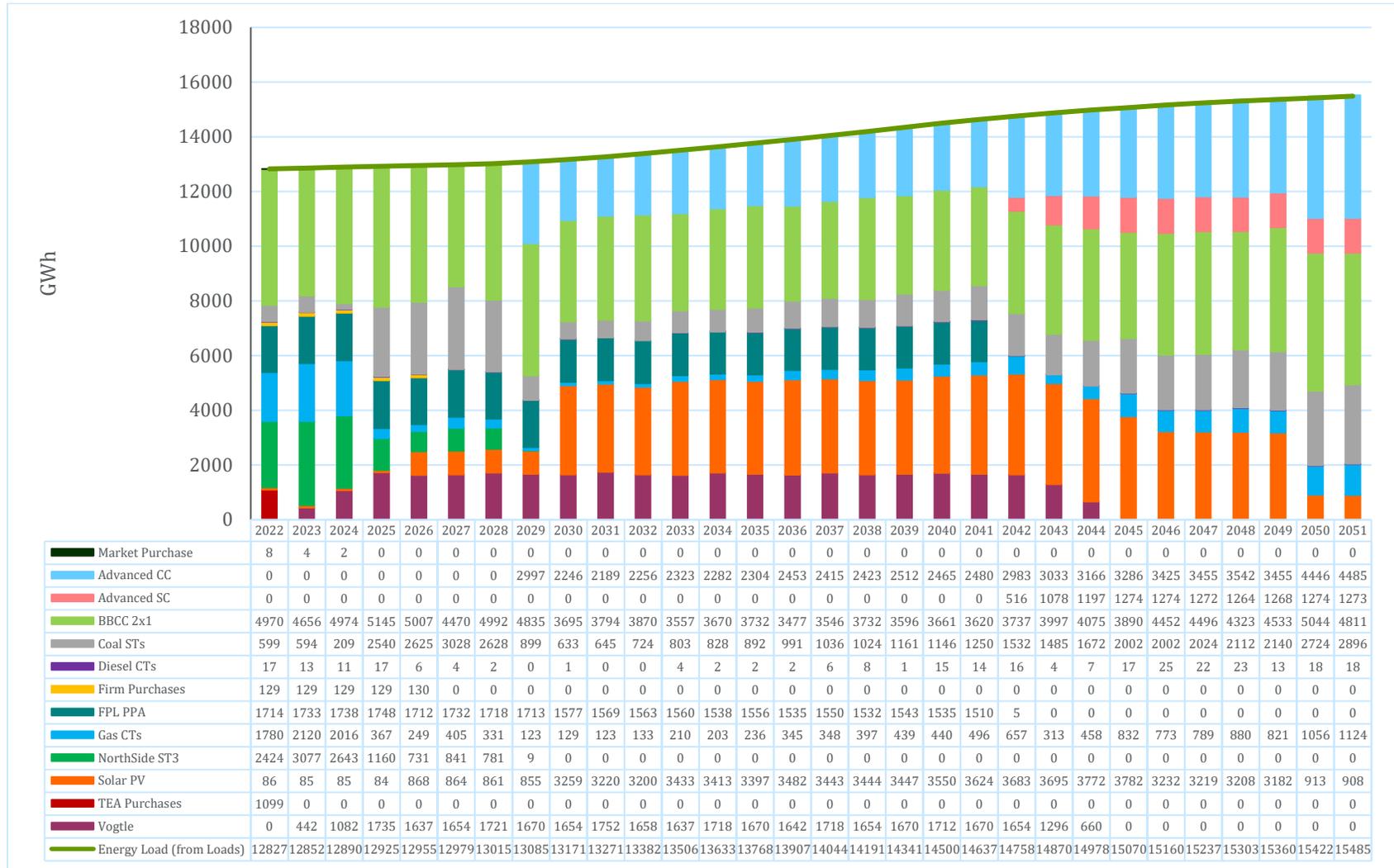
Appendix A – Detailed PLEXOS Modeling Results

Figure A-30 – Economic Downturn Scenario – Annual Energy by Resource



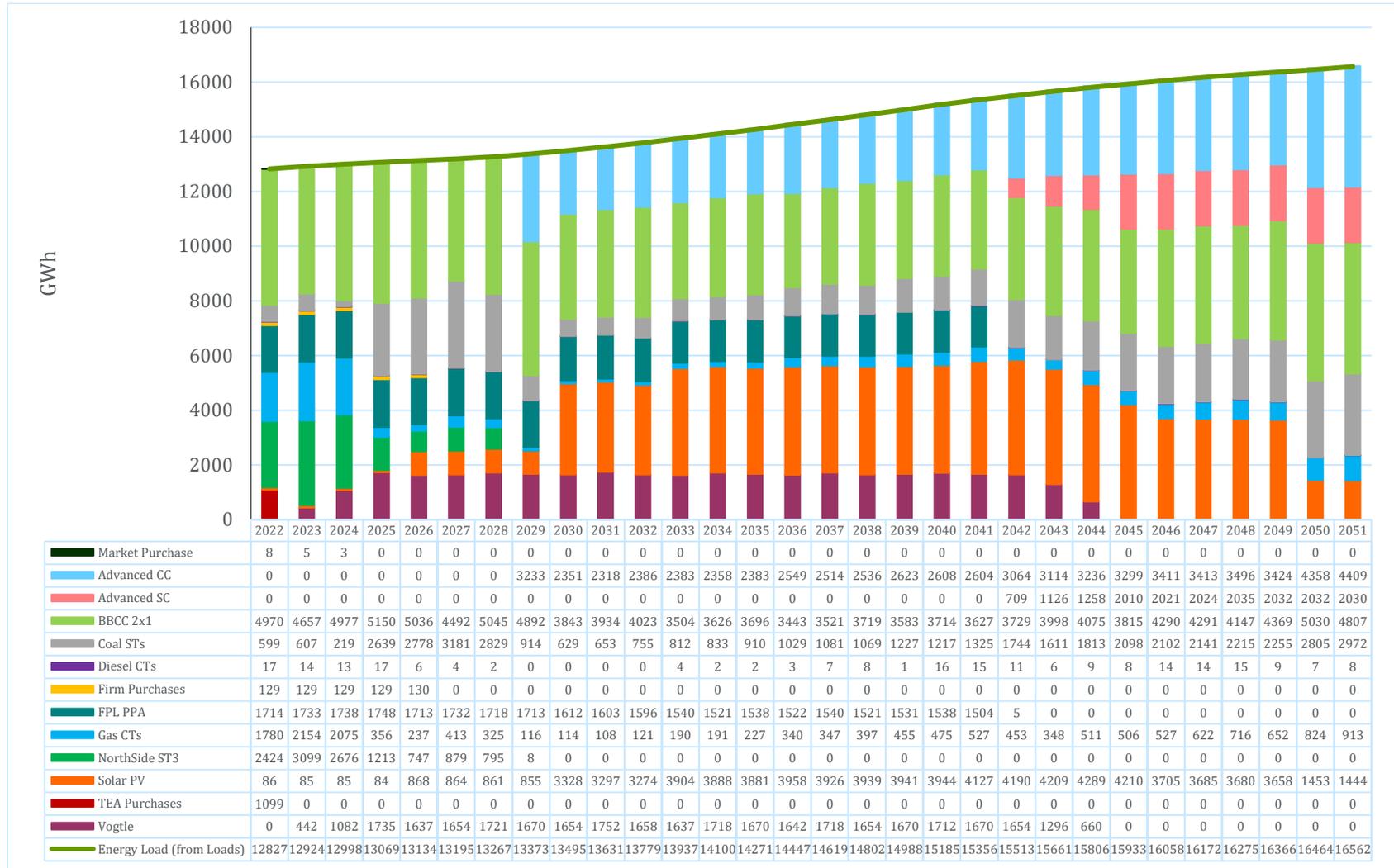
Appendix A – Detailed PLEXOS Modeling Results

Figure A-31 – Efficiency + DER Scenario – Annual Energy by Resource



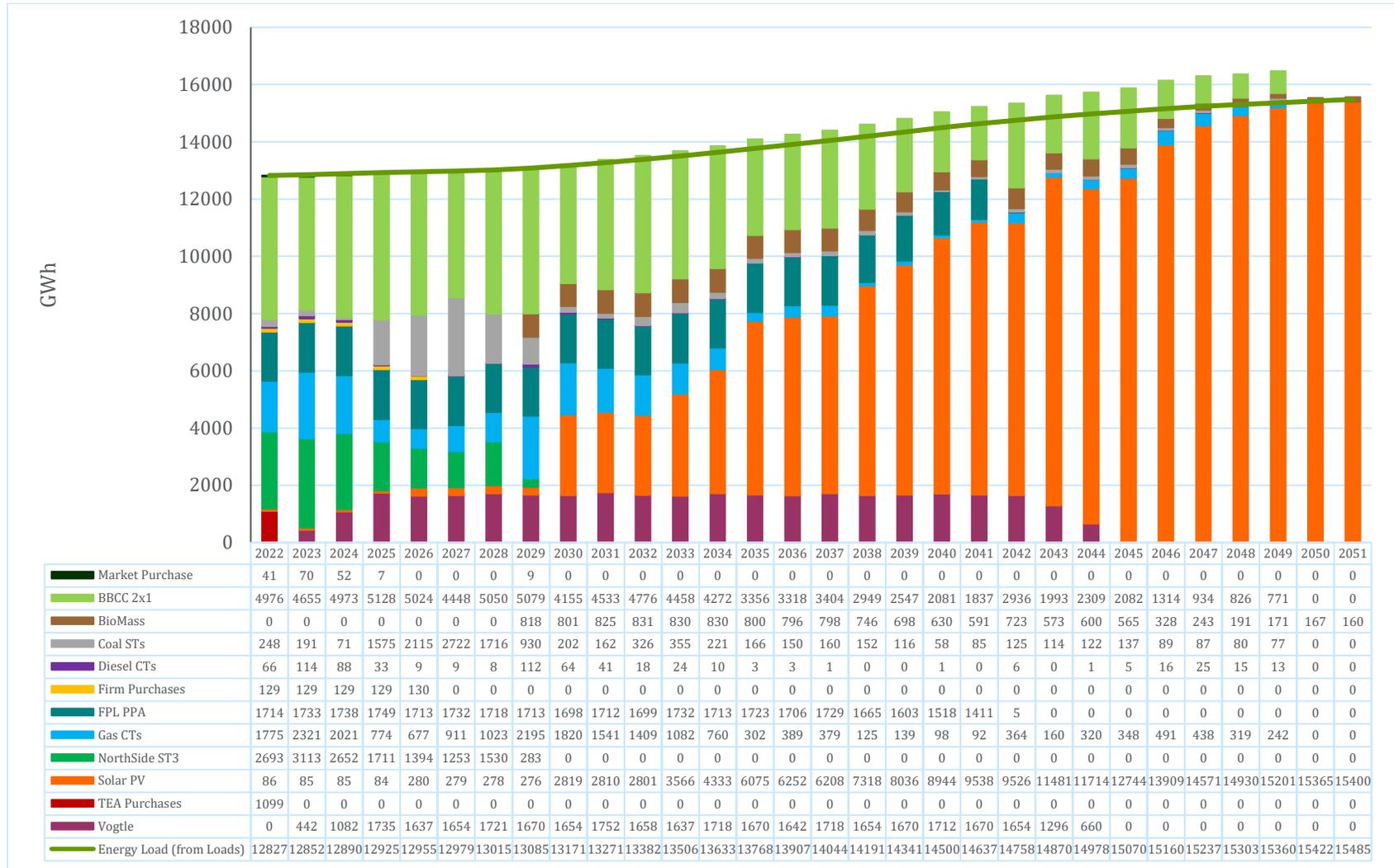
Appendix A – Detailed PLEXOS Modeling Results

Figure A-32 – Increased Electrification Scenario – Annual Energy by Resource



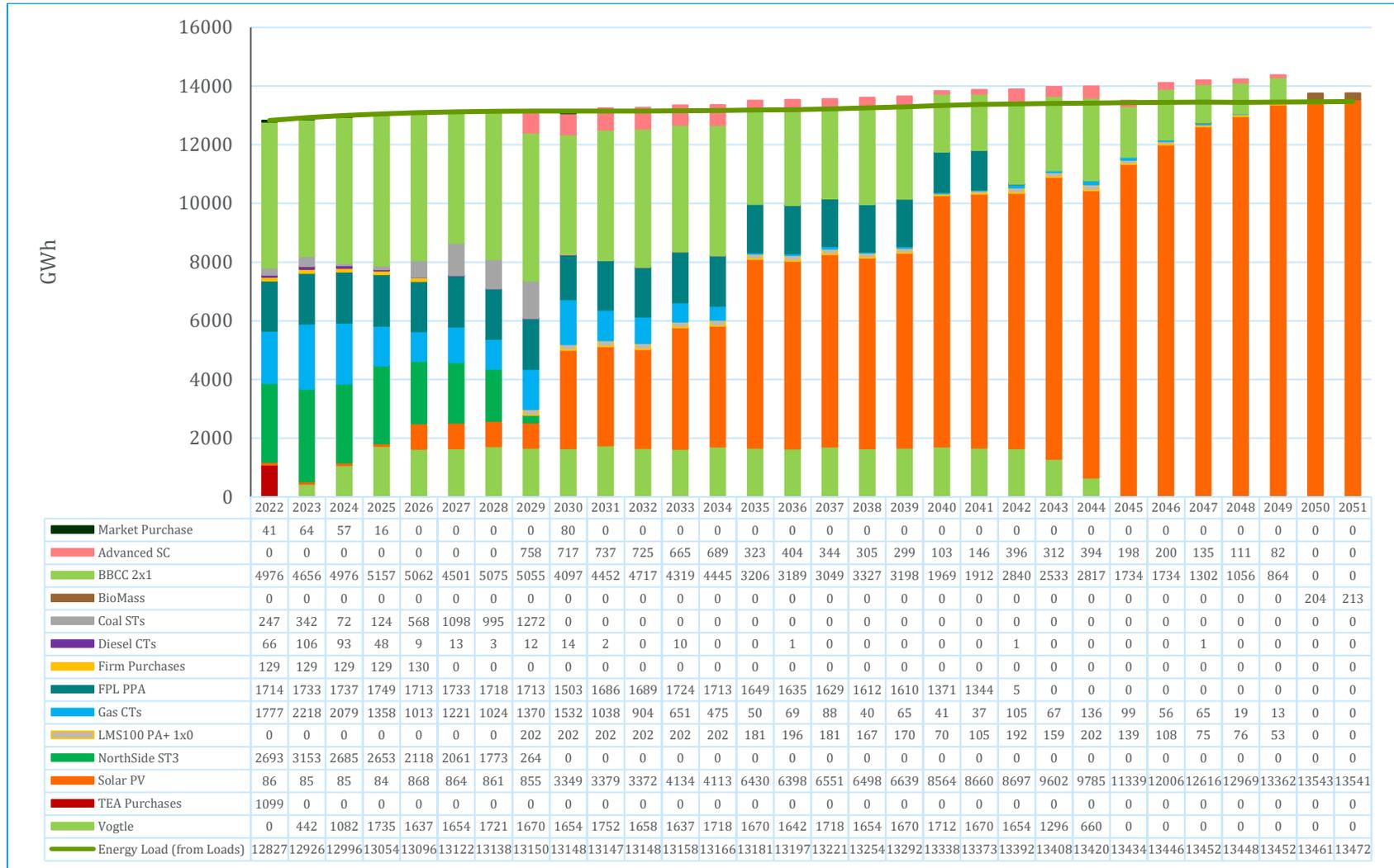
Appendix A – Detailed PLEXOS Modeling Results

Figure A-33 – Future Net Zero Scenario – Annual Energy by Resource



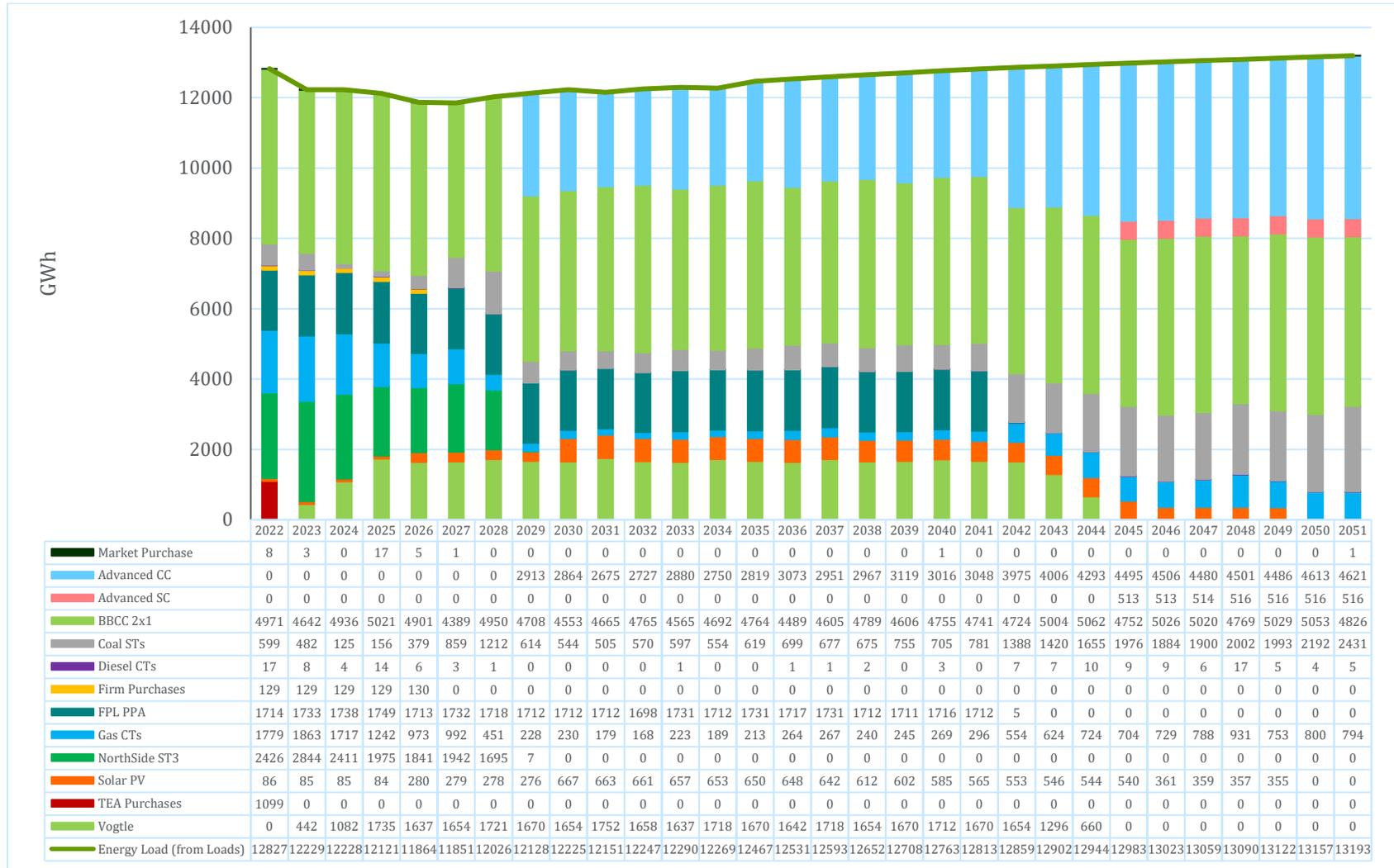
Appendix A – Detailed PLEXOS Modeling Results

Figure A-34 – Supplemental Scenario – Annual Energy by Resource



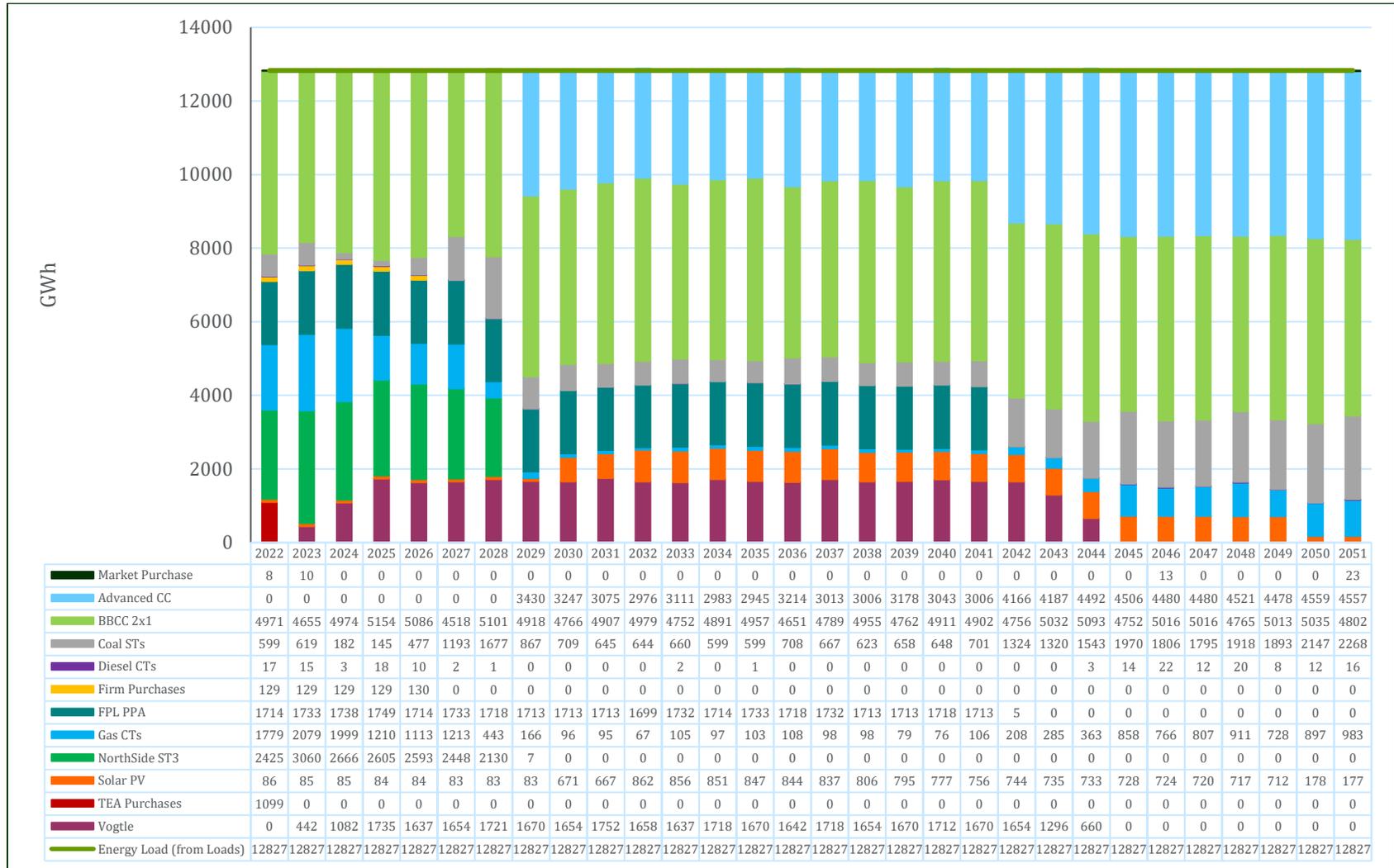
Appendix A – Detailed PLEXOS Modeling Results

Figure A-35 – Low Load Sensitivity – Annual Energy by Resource



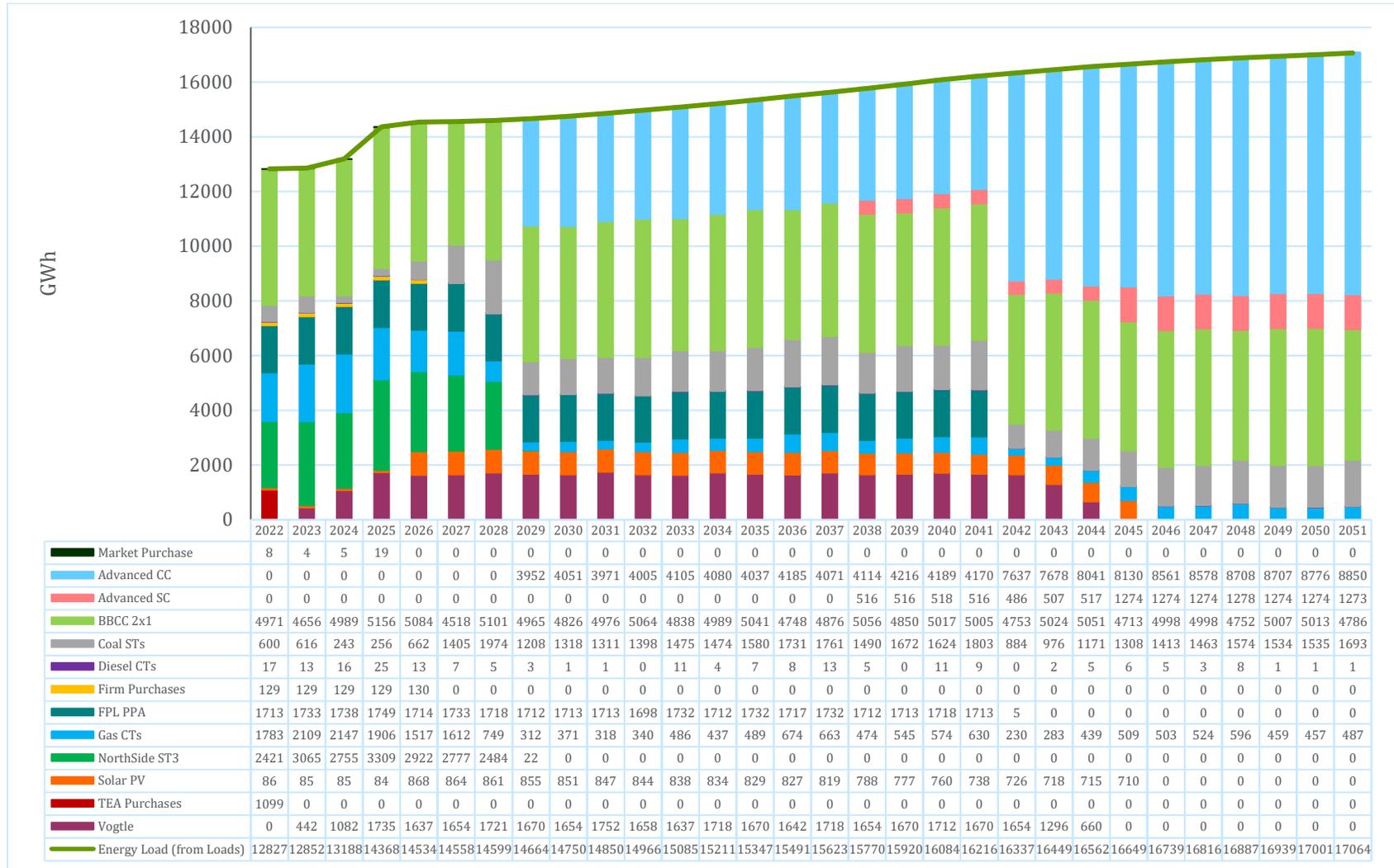
Appendix A – Detailed PLEXOS Modeling Results

Figure A-36 – No Load Growth Sensitivity – Annual Energy by Resource



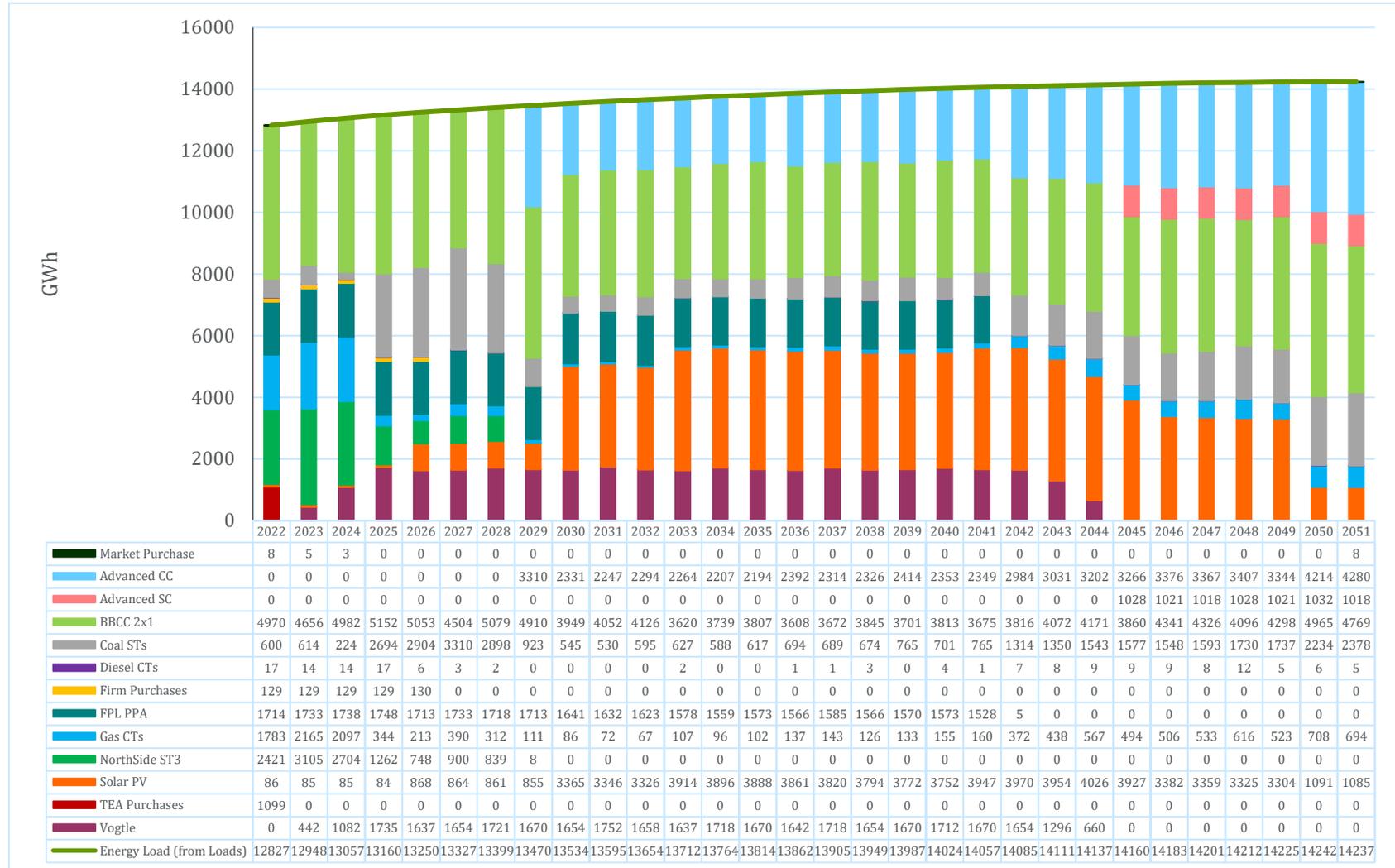
Appendix A – Detailed PLEXOS Modeling Results

Figure A-37 – High Load Sensitivity – Annual Energy by Resource



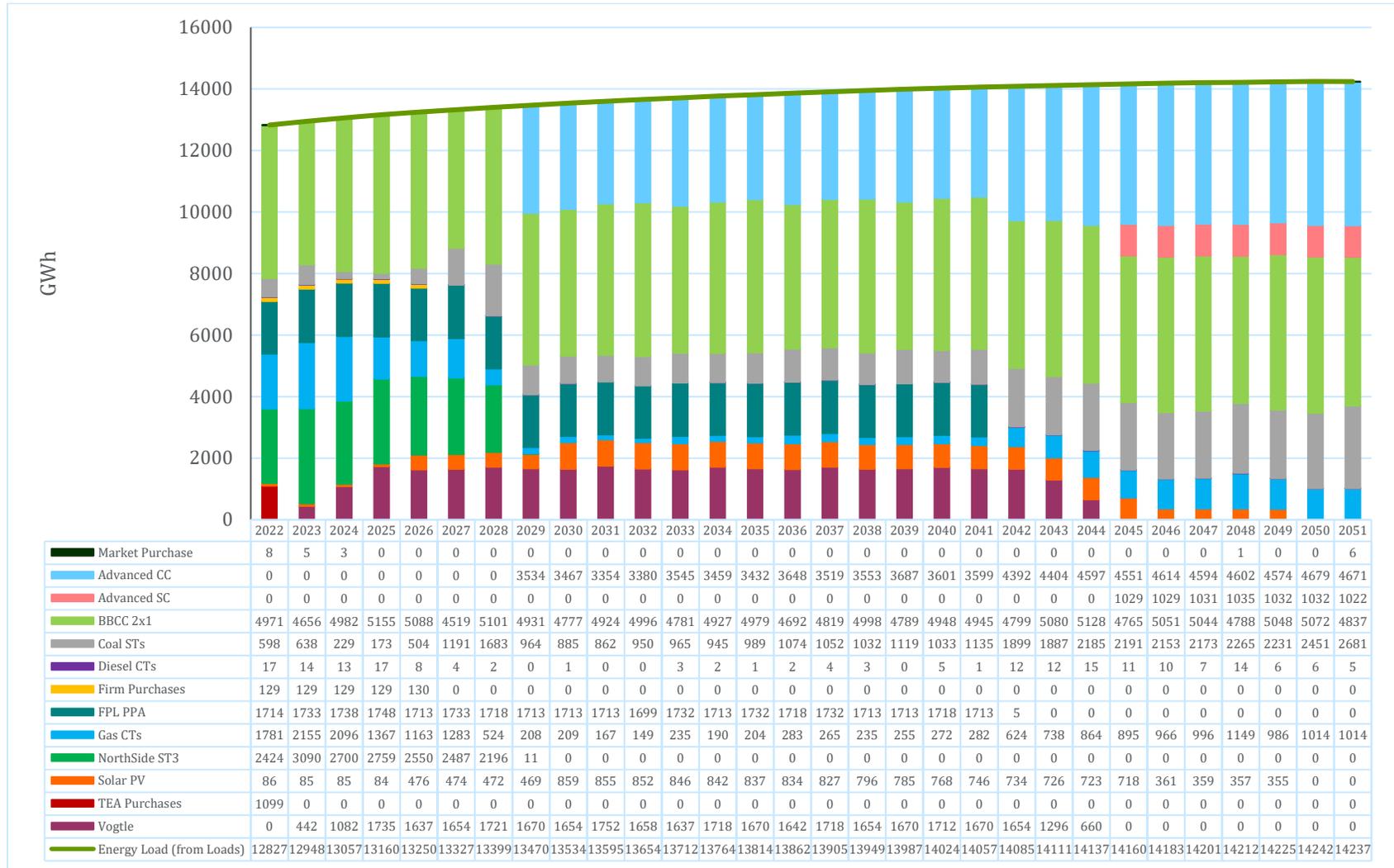
Appendix A – Detailed PLEXOS Modeling Results

Figure A-38 – High Fuel Sensitivity – Annual Energy by Resource



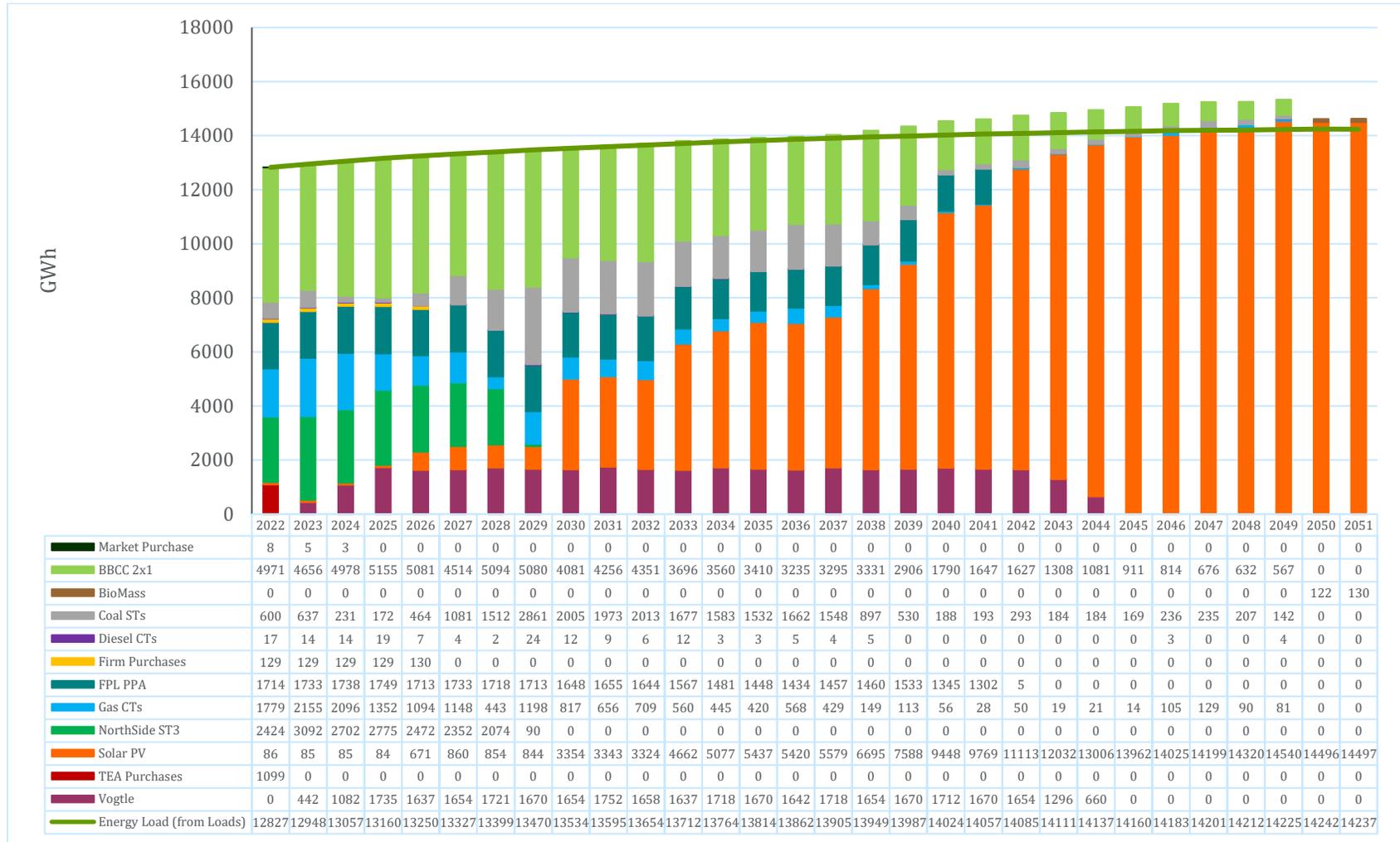
Appendix A – Detailed PLEXOS Modeling Results

Figure A-39 – Regulated CO<sub>2</sub> Sensitivity – Annual Energy by Resource



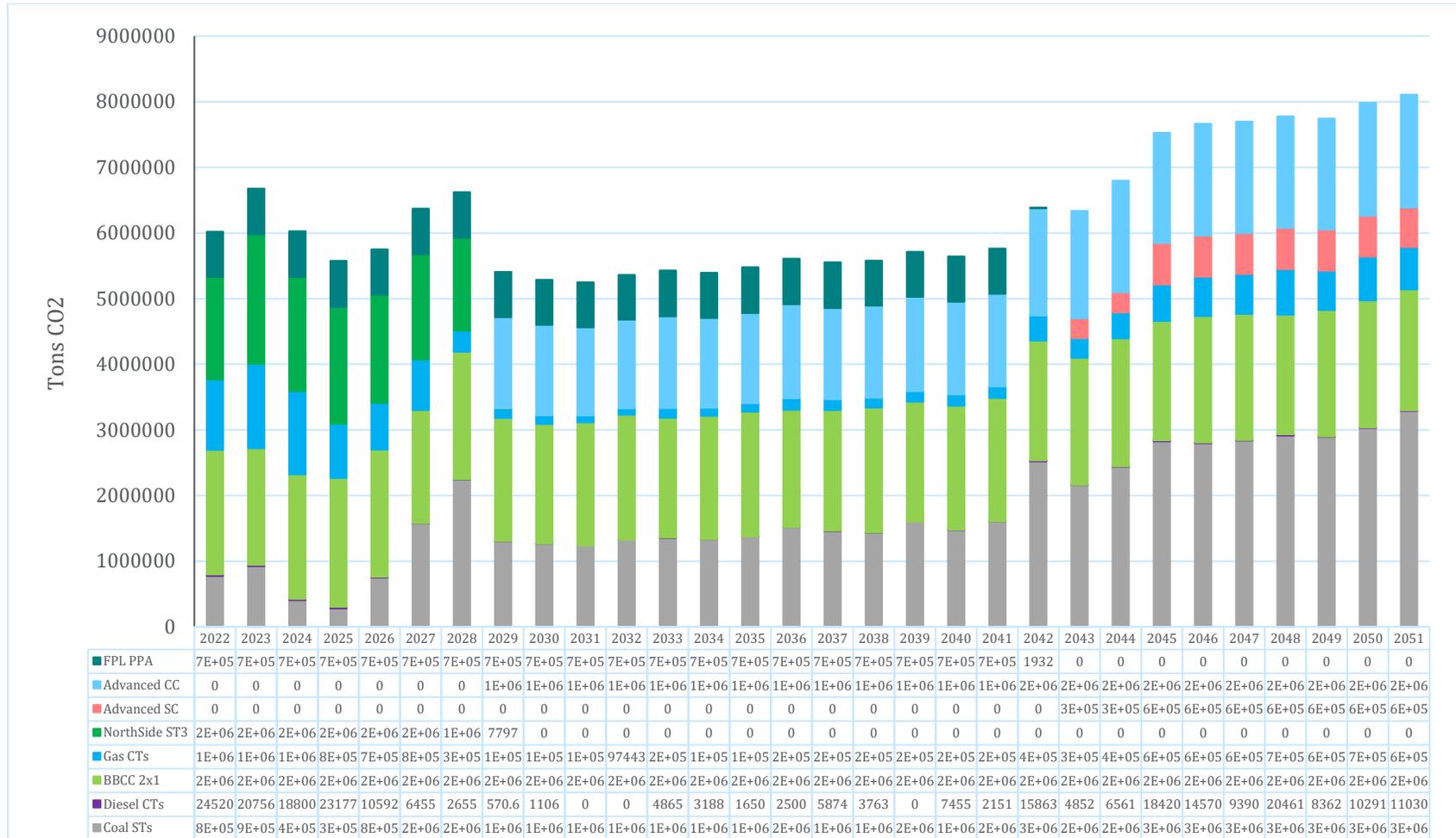
Appendix A – Detailed PLEXOS Modeling Results

Figure A-40 – Net Zero Sensitivity – Annual Energy by Resource



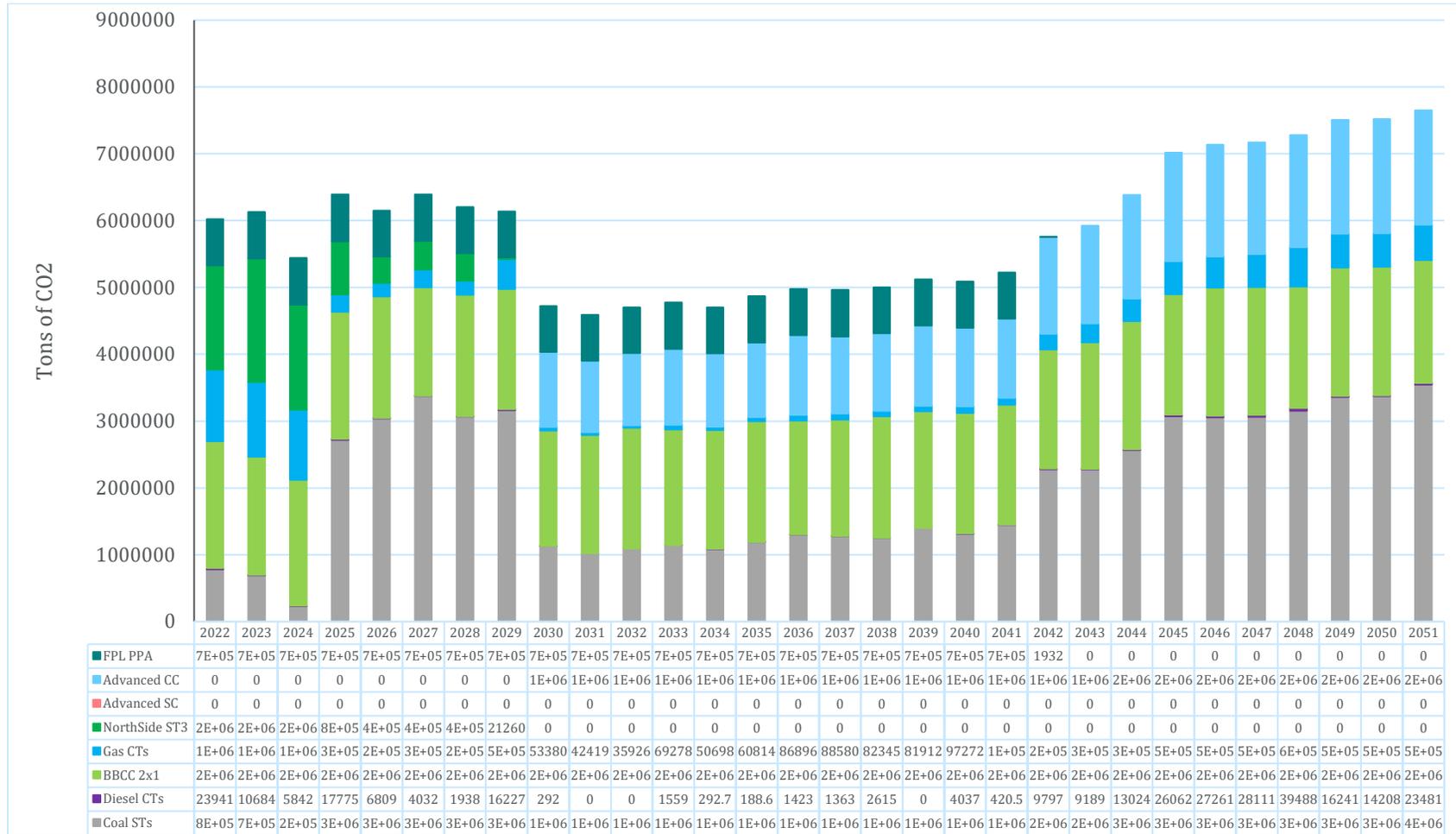
Appendix A – Detailed PLEXOS Modeling Results

Figure A-41 – Current Outlook Scenario - CO<sub>2</sub> Emissions by Resource Type



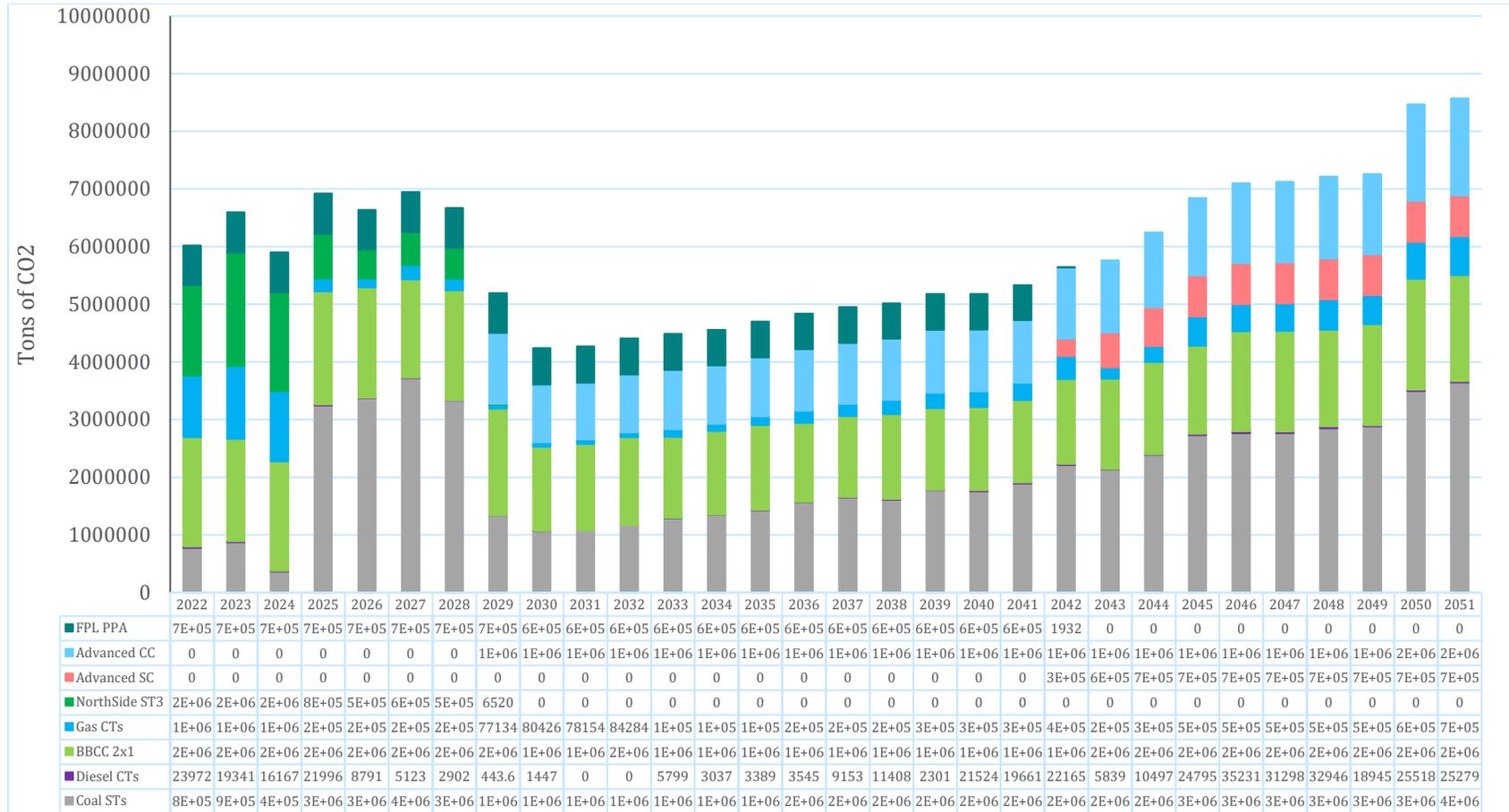
Appendix A – Detailed PLEXOS Modeling Results

Figure A-42 – Economic Downturn Scenario - CO<sub>2</sub> Emissions by Resource Type



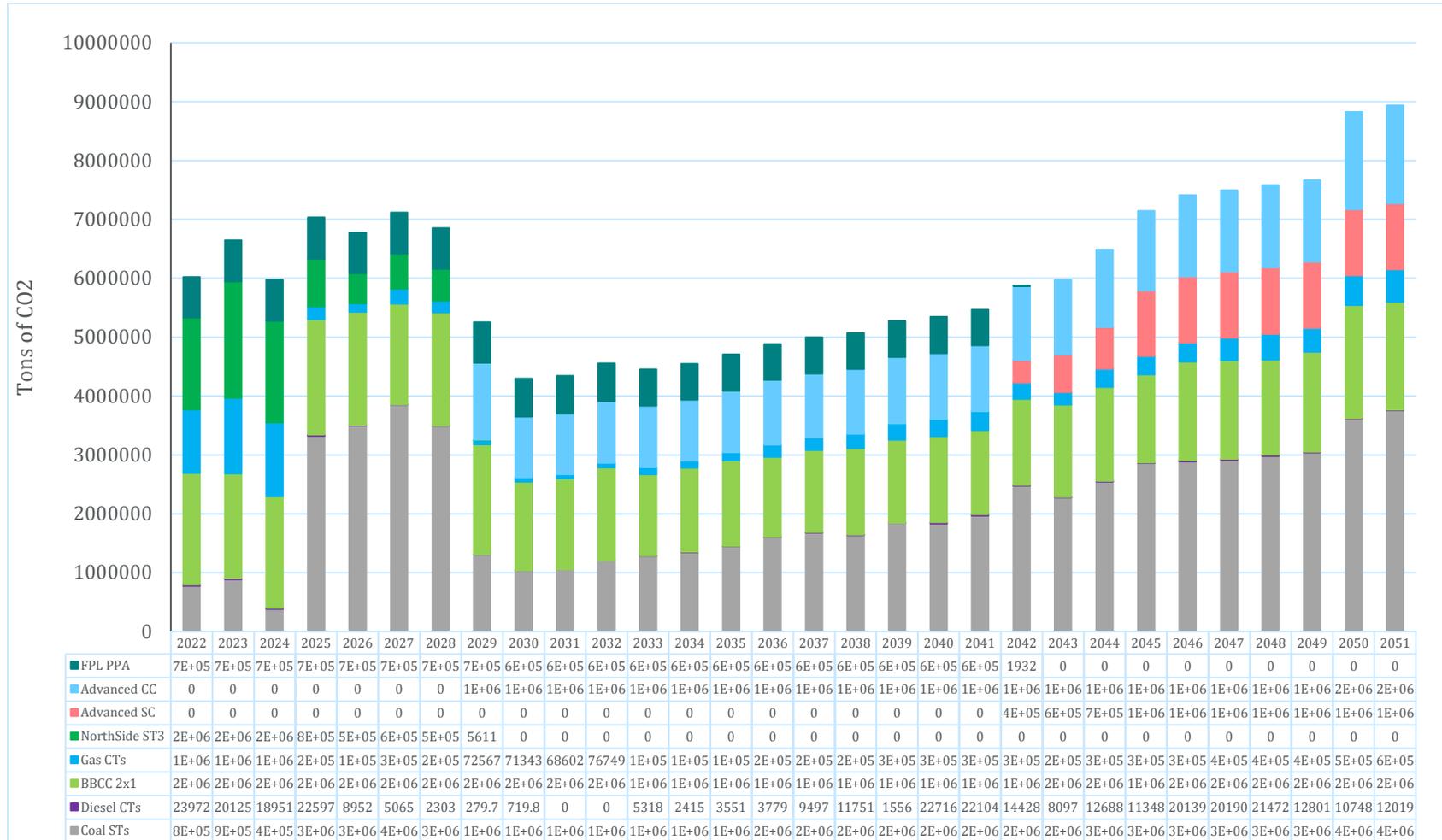
Appendix A – Detailed PLEXOS Modeling Results

Figure A-43 – Efficiency + DER Scenario - CO<sub>2</sub> Emissions by Resource Type



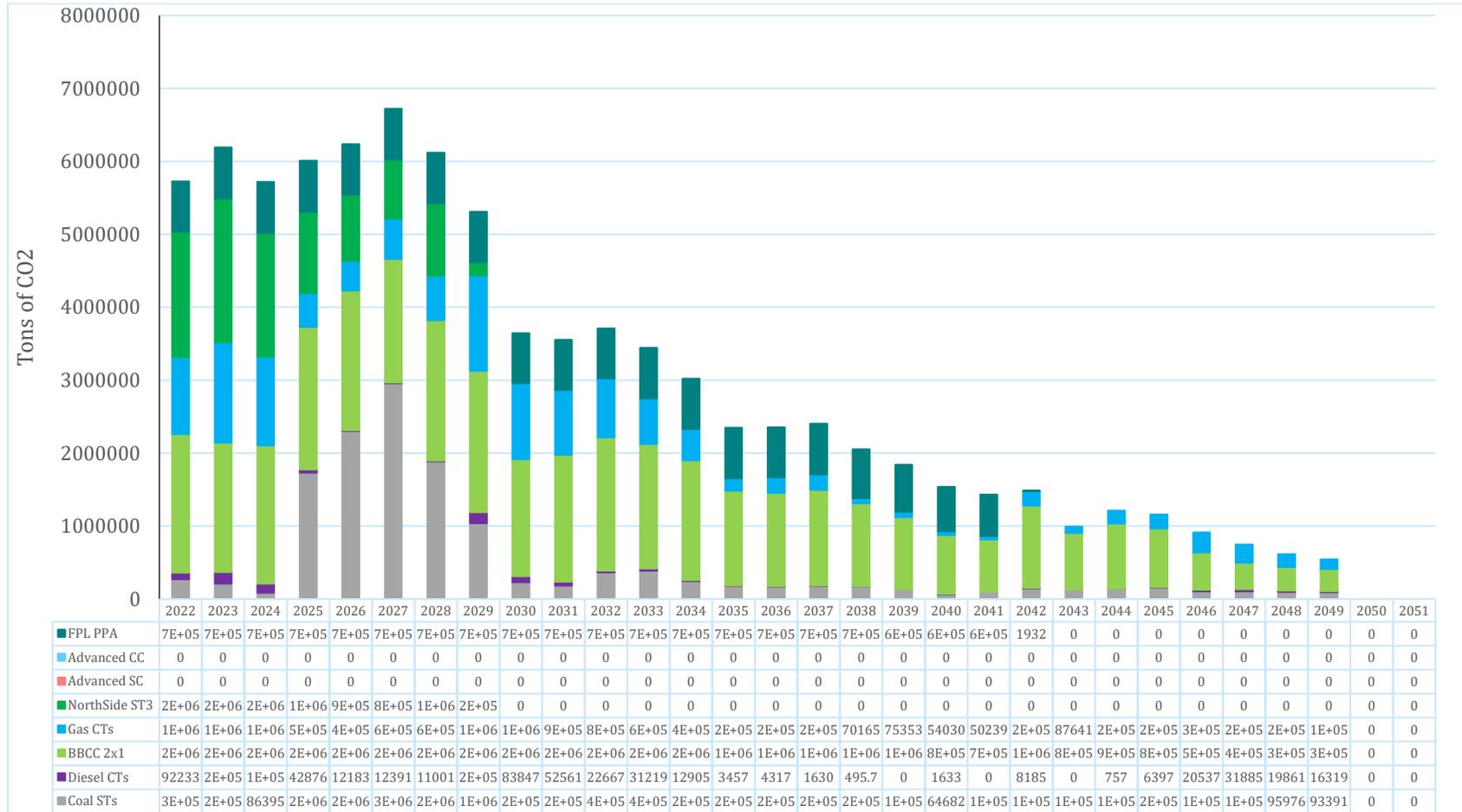
Appendix A – Detailed PLEXOS Modeling Results

Figure A-44 – Increased Electrification Scenario - CO<sub>2</sub> Emissions by Resource Type



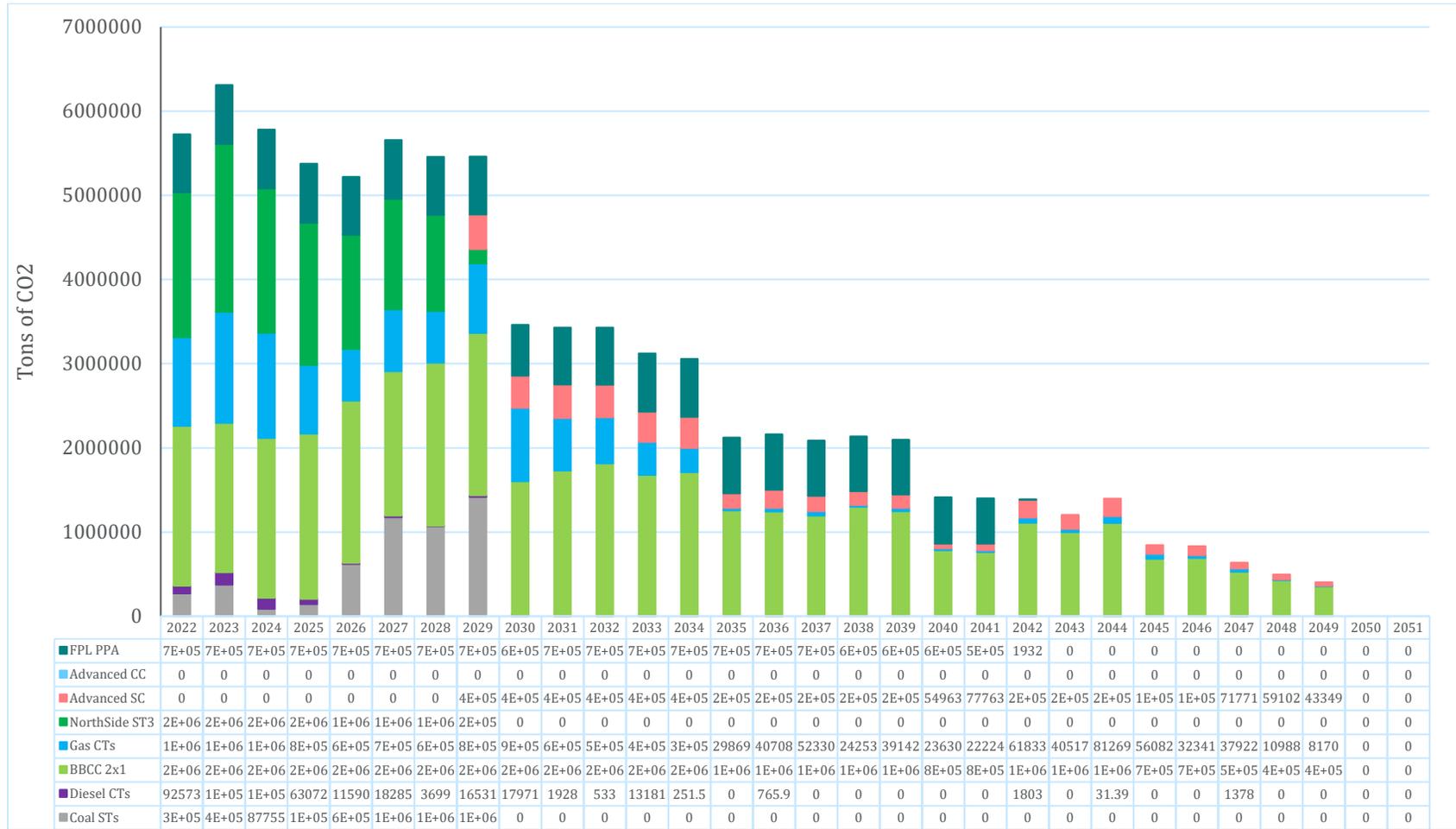
Appendix A – Detailed PLEXOS Modeling Results

Figure A-45 – Future Net Zero Scenario - CO<sub>2</sub> Emissions by Resource Type



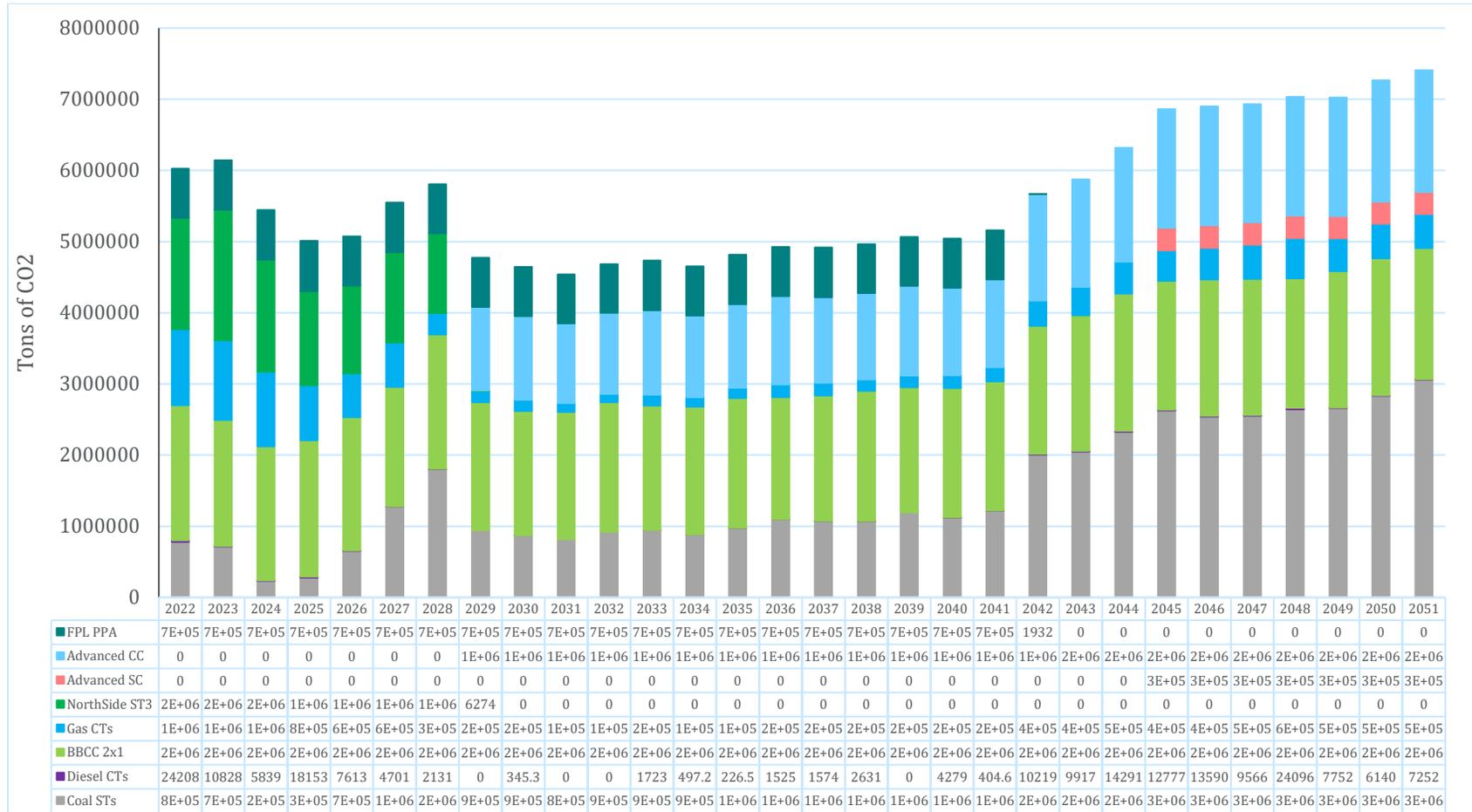
Appendix A – Detailed PLEXOS Modeling Results

Figure A-46 – Supplemental Scenario - CO<sub>2</sub> Emissions by Resource Type



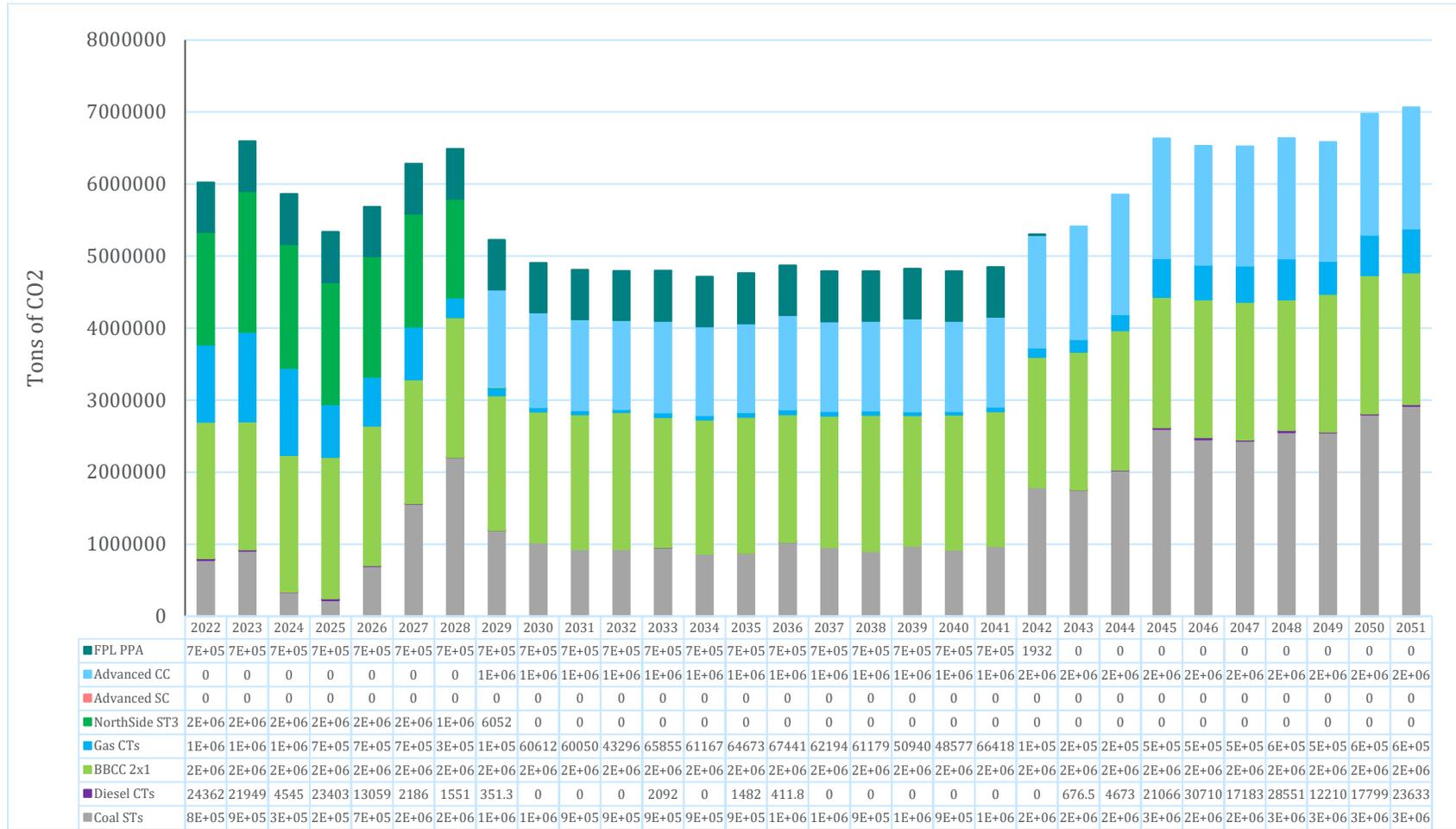
Appendix A – Detailed PLEXOS Modeling Results

Figure A-47 – Low Load Sensitivity - CO<sub>2</sub> Emissions by Resource Type



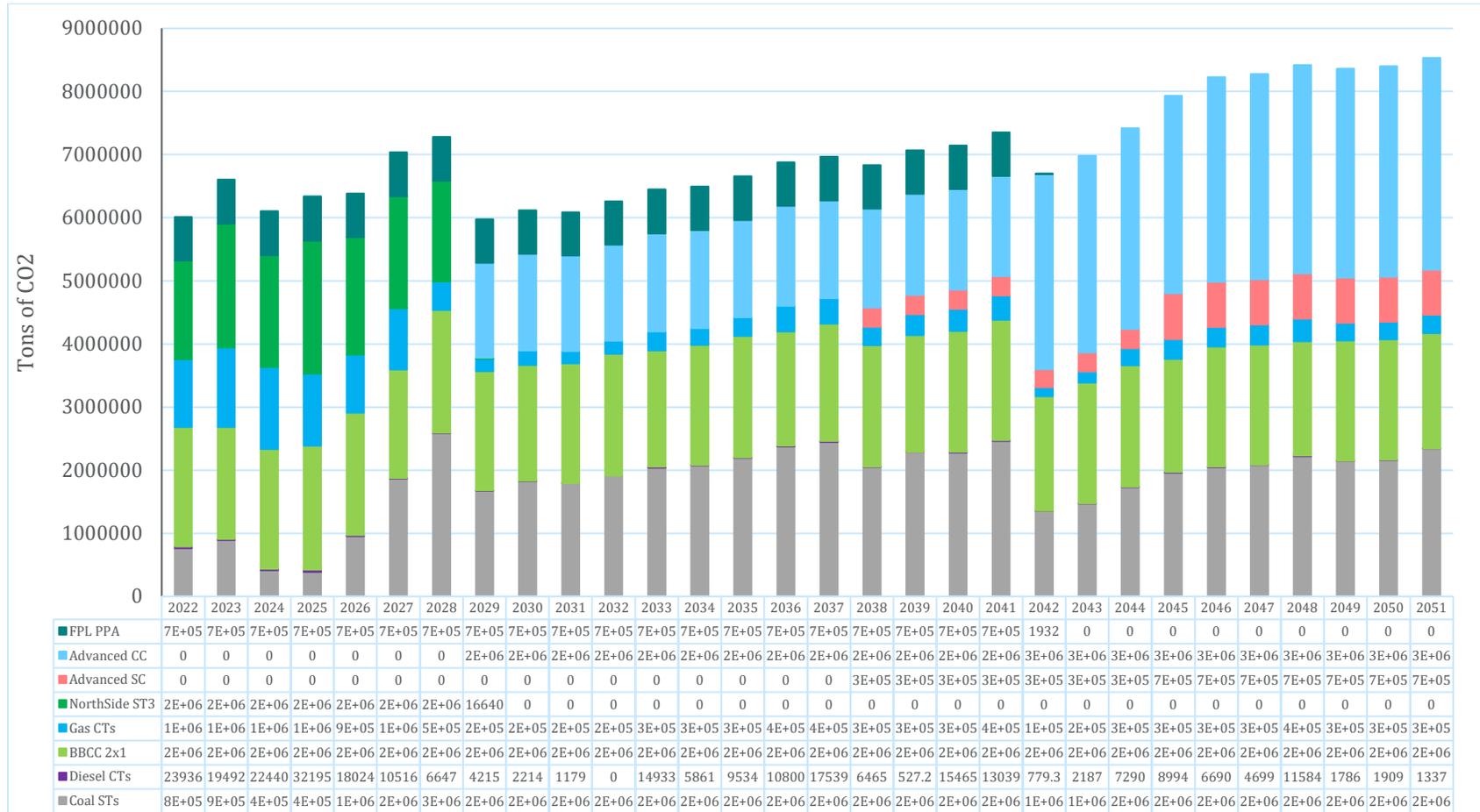
Appendix A – Detailed PLEXOS Modeling Results

Figure A-48 – No Load Growth Sensitivity - CO<sub>2</sub> Emissions by Resource Type



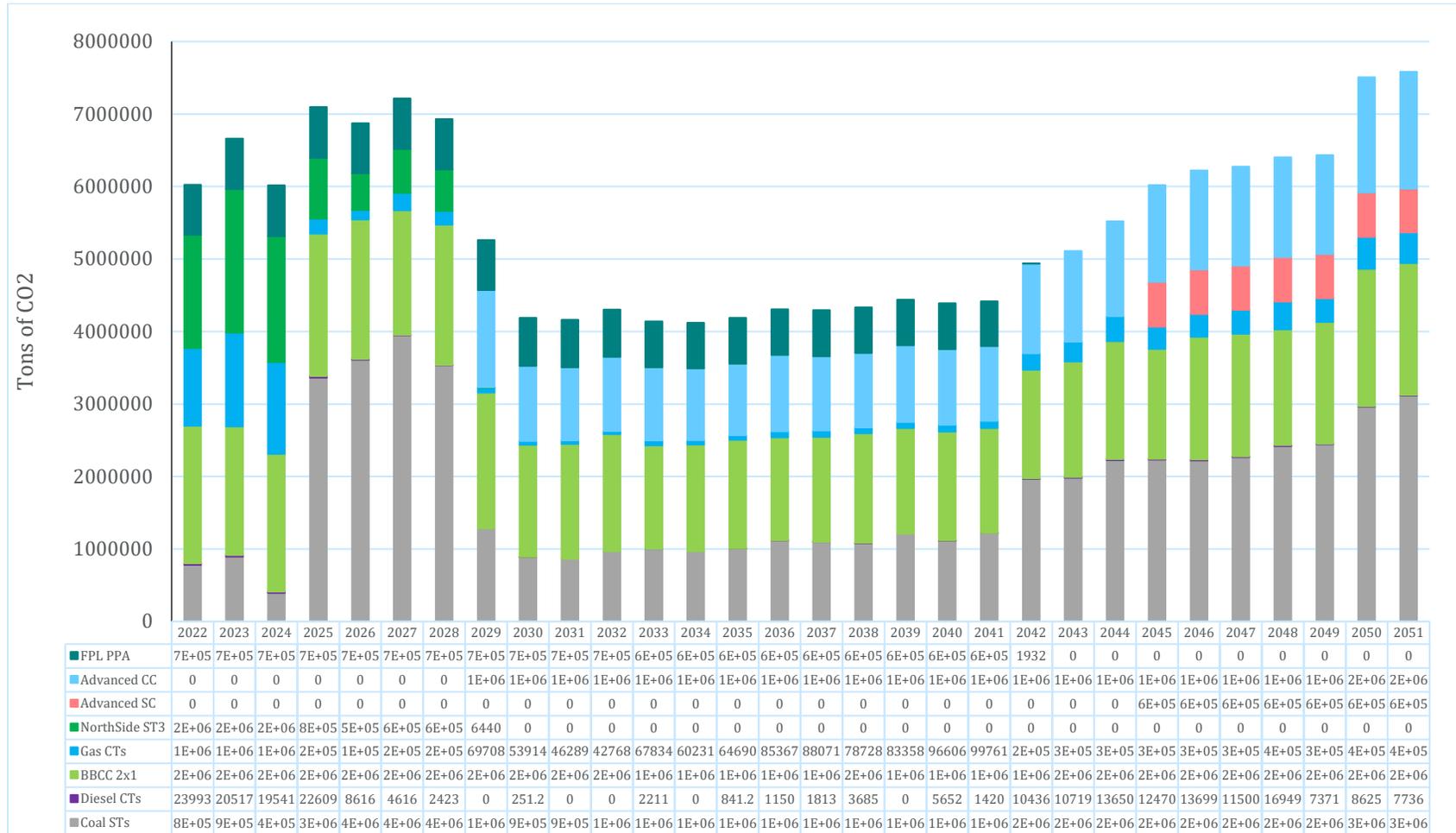
Appendix A – Detailed PLEXOS Modeling Results

Figure A-49 – High Load Sensitivity - CO<sub>2</sub> Emissions by Resource Type



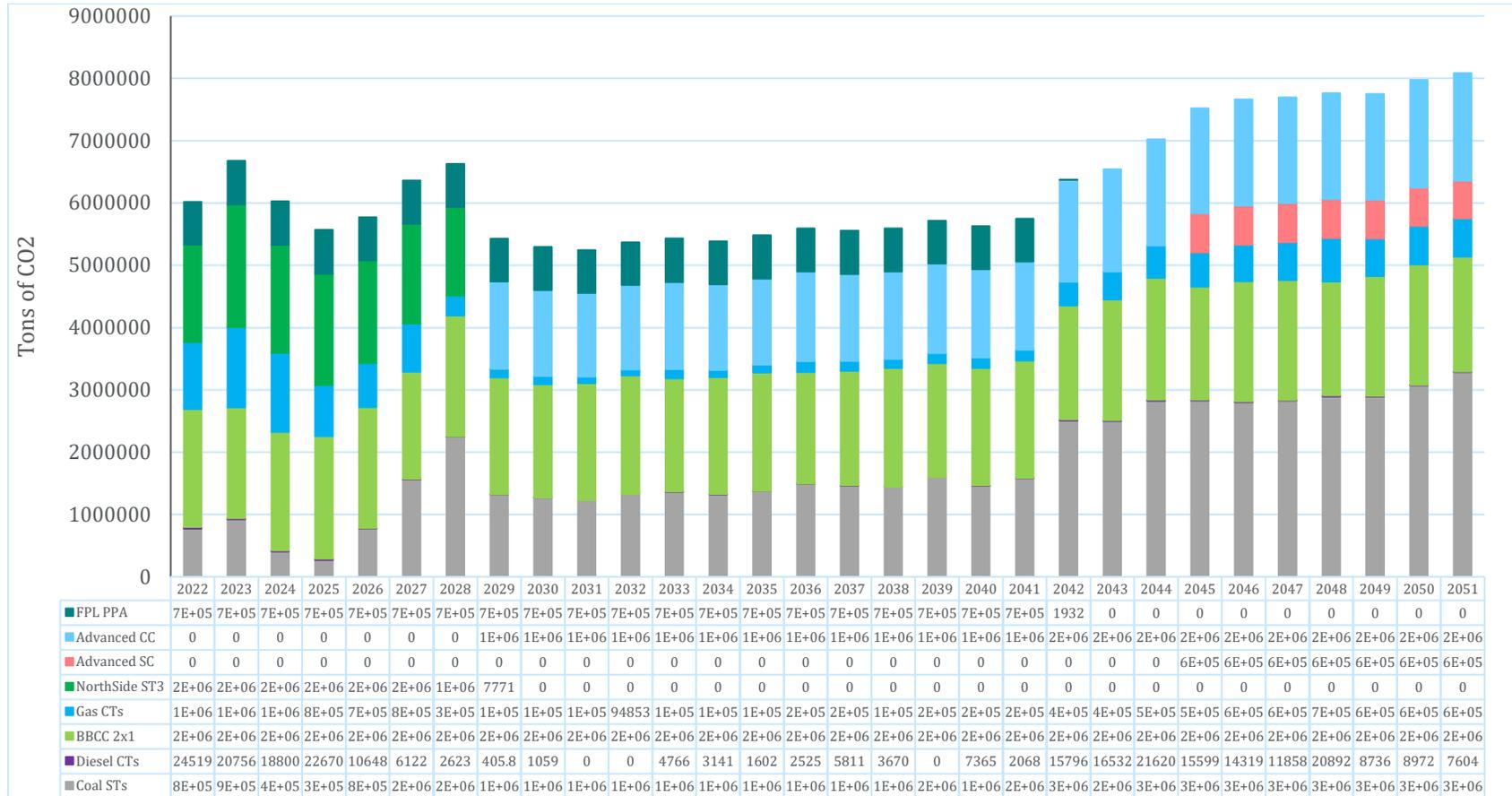
Appendix A – Detailed PLEXOS Modeling Results

Figure A-50 – High Fuel Sensitivity - CO<sub>2</sub> Emissions by Resource Type



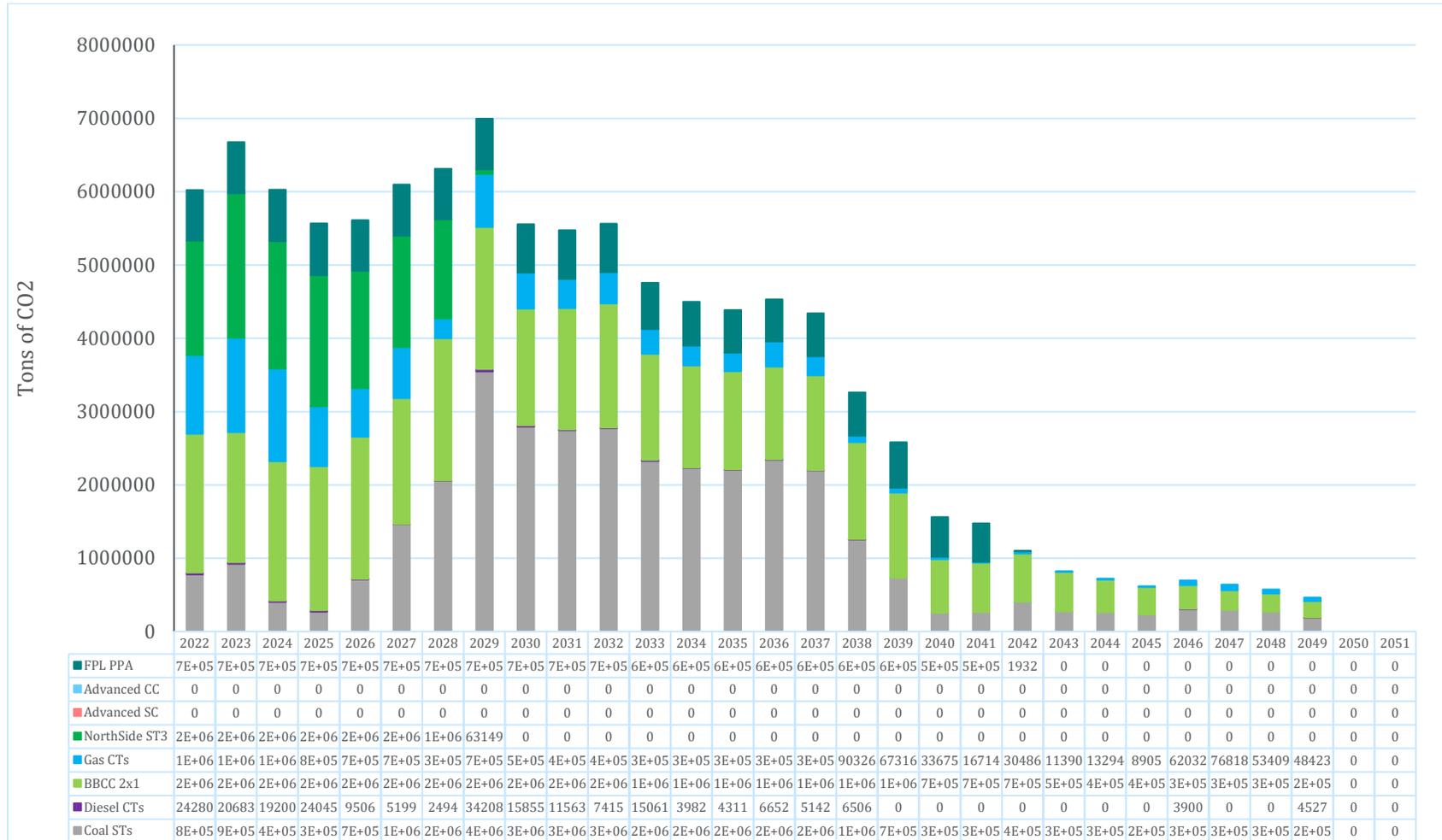
Appendix A – Detailed PLEXOS Modeling Results

Figure A-51 – Regulated CO<sub>2</sub> Sensitivity - CO<sub>2</sub> Emissions by Resource Type



Appendix A – Detailed PLEXOS Modeling Results

Figure A-52 – Net Zero Sensitivity - CO<sub>2</sub> Emissions by Resource Type



Appendix A – Detailed PLEXOS Modeling Results

Table A-7 - Current Outlook Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unreserved Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,483	-	105,662	54,737	41,911	118	969,175	1,023,912	-	-	1,023,912	1,023,911.79
2023	12,948	-	12,943	5	0	550,209	-	188,228	73,618	32,300	145	770,882	844,500	-	-	844,500	1,835,931.29
2024	13,057	-	13,054	3	-	439,883	-	231,266	75,420	27,803	118	699,070	774,490	-	-	774,490	2,551,990.67
2025	13,160	275	13,415	20	-	485,970	-	304,215	79,791	20,169	113	810,467	890,258	31,162	389,378	921,420	3,371,130.03
2026	13,250	266	13,507	9	-	494,093	13,808	260,853	82,356	30,423	118	799,296	881,652	31,162	-	912,814	4,151,407.17
2027	13,327	176	13,502	1	-	547,627	14,151	255,144	177,158	35,009	140	852,071	1,029,228	31,162	-	1,060,390	5,022,970.63
2028	13,399	191	13,590	0	-	566,714	14,503	265,470	86,515	40,451	148	887,286	973,801	31,162	-	1,004,962	5,817,207.08
2029	13,470	278	13,749	-	0	512,813	14,863	252,998	106,436	31,619	49	812,342	918,778	77,854	663,615	996,632	6,574,565.14
2030	13,534	290	13,824	-	0	520,723	28,718	251,522	100,608	37,700	47	838,710	939,319	77,854	-	1,017,172	7,317,803.07
2031	13,595	299	13,894	0	0	544,229	29,432	274,216	102,113	38,843	46	886,766	988,879	77,854	-	1,066,733	8,067,275.31
2032	13,654	290	13,944	-	-	579,983	30,163	262,704	99,807	40,458	49	913,358	1,013,165	77,854	-	1,091,019	8,804,328.33
2033	13,712	309	14,020	1	0	611,299	30,913	275,749	138,991	42,503	50	960,514	1,099,504	77,854	-	1,177,358	9,569,117.59
2034	13,764	305	14,069	-	0	629,364	31,681	300,776	106,900	42,824	49	1,004,695	1,111,595	77,854	-	1,189,449	10,312,043.70
2035	13,814	310	14,124	-	0	660,441	32,468	292,071	104,504	47,435	50	1,032,465	1,136,970	77,854	-	1,214,824	11,041,635.28
2036	13,862	309	14,171	0	0	705,202	33,275	281,269	158,587	51,309	55	1,071,111	1,229,698	77,854	-	1,307,552	11,796,713.90
2037	13,905	321	14,225	1	0	729,045	34,102	294,751	110,586	50,226	53	1,108,177	1,218,763	77,854	-	1,296,617	12,516,679.37
2038	13,949	329	14,278	-	0	768,220	34,949	273,834	137,510	52,106	53	1,129,162	1,266,672	77,854	-	1,344,526	13,234,532.79
2039	13,987	314	14,300	0	0	809,527	35,818	268,285	127,052	59,740	57	1,173,426	1,300,478	77,854	-	1,378,332	13,942,131.72
2040	14,024	328	14,350	1	-	841,703	36,708	283,614	150,102	59,736	54	1,221,816	1,371,918	77,854	-	1,449,772	14,657,779.84
2041	14,057	337	14,394	-	0	874,457	37,620	256,861	141,932	61,801	58	1,230,797	1,372,729	77,854	-	1,450,583	15,346,288.10
2042	14,085	359	14,441	2	0	1,096,340	38,555	274,439	106,619	66,027	88	1,475,449	1,582,069	77,854	-	1,659,923	16,103,855.07
2043	14,111	343	14,454	0	0	1,181,578	39,513	199,216	212,554	63,445	79	1,483,831	1,696,385	94,135	203,434	1,790,520	16,889,595.42
2044	14,137	362	14,498	1	0	1,301,164	40,495	101,308	138,288	67,254	88	1,510,310	1,648,598	97,683	44,342	1,746,282	17,626,448.42
2045	14,160	29	14,185	4	0	1,487,193	41,501	104,295	139,695	102,337	104	1,735,431	1,875,126	83,794	215,823	1,958,920	18,421,233.85
2046	14,183	28	14,209	3	0	1,579,285	19,973	102,097	132,705	105,455	104	1,806,915	1,939,620	83,794	-	2,023,414	19,210,611.02
2047	14,201	43	14,243	0	0	1,632,167	20,469	95,865	138,397	108,819	105	1,857,424	1,995,822	85,676	23,525	2,081,498	19,991,415.89
2048	14,212	58	14,263	6	0	1,711,480	20,978	121,402	151,208	109,941	108	1,963,910	2,115,118	87,592	23,941	2,202,711	20,785,909.88
2049	14,225	67	14,292	0	0	1,773,586	21,499	100,024	170,510	115,237	107	2,010,453	2,180,962	89,546	24,411	2,270,509	21,573,359.86
2050	14,242	79	14,319	2	0	1,891,759	-	109,151	147,647	115,870	112	2,116,892	2,264,539	90,918	17,146	2,355,458	22,358,851.94
2051	14,237	157	14,367	1	0	1,960,155	-	113,347	154,964	110,826	119	2,184,448	2,339,412	101,073	126,883	2,440,485	23,141,396.82
						Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)		Total System Cost (\$1MM)	
						CPWC (\$1MM)	\$14,600.61	\$378.13	\$4,098.67	\$2,070.30	\$930.86	\$1.59	\$20,009.85	\$22,080.15	\$1,061.25		\$23,141.40

Appendix A – Detailed PLEXOS Modeling Results

Table A-8 - Economic Downturn Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,384	-	105,196	54,737	42,095	118	968,792	1,023,529	-	-	1,023,529	1,023,529.19
2023	12,948	-	12,227	3	0	502,750	-	177,925	74,169	31,131	130	711,936	786,105	-	-	786,105	1,772,200.73
2024	13,057	-	12,227	0	-	392,114	-	217,223	76,563	25,707	101	635,144	711,707	-	-	711,707	2,417,740.17
2025	13,160	-	12,104	17	0	548,718	-	295,665	75,251	67,128	131	911,642	986,894	-	-	986,894	3,270,256.00
2026	13,250	-	11,859	5	0	539,552	12,371	254,506	78,467	58,195	119	864,742	943,209	-	-	943,209	4,046,236.47
2027	13,327	-	11,850	0	0	581,028	12,801	243,339	178,553	51,653	131	888,951	1,067,504	-	-	1,067,504	4,882,653.80
2028	13,399	-	12,026	0	0	611,005	13,247	258,998	84,042	50,811	120	934,180	1,018,222	-	-	1,018,222	5,642,466.79
2029	13,470	-	12,125	3	0	631,435	26,024	266,000	87,458	59,316	106	982,882	1,070,340	-	-	1,070,340	6,403,137.67
2030	13,534	-	12,225	-	0	607,987	26,930	248,203	99,630	54,057	41	937,219	1,036,848	58,173	751,875	1,095,021	7,144,290.87
2031	13,595	-	12,151	-	0	626,305	27,867	271,509	101,791	56,862	38	982,582	1,084,372	58,173	-	1,142,545	7,880,785.44
2032	13,654	-	12,247	0	0	670,417	28,837	260,318	99,752	58,221	40	1,017,833	1,117,585	58,173	-	1,175,757	8,602,598.31
2033	13,712	-	12,290	0	0	702,847	29,840	269,857	143,870	62,403	42	1,064,989	1,208,859	58,173	-	1,267,031	9,343,405.25
2034	13,764	-	12,269	0	-	718,032	30,879	295,006	108,762	65,147	40	1,109,105	1,217,867	58,173	-	1,276,040	10,053,951.83
2035	13,814	-	12,467	-	0	768,446	31,953	288,645	106,629	69,927	44	1,159,015	1,265,644	58,173	-	1,323,817	10,756,000.14
2036	13,862	-	12,531	0	0	821,708	33,065	278,700	169,074	72,896	47	1,206,416	1,375,491	58,173	-	1,433,663	11,480,097.40
2037	13,905	-	12,593	-	0	860,836	34,216	287,832	114,775	76,439	46	1,259,369	1,374,144	58,173	-	1,432,317	12,169,066.22
2038	13,949	-	12,652	0	0	917,760	35,407	272,082	146,820	80,385	46	1,305,679	1,452,499	58,173	-	1,510,671	12,861,122.23
2039	13,987	-	12,708	-	0	966,387	36,639	267,961	135,417	88,063	50	1,359,100	1,494,517	58,173	-	1,552,690	13,538,555.55
2040	14,024	-	12,762	1	0	1,020,681	37,914	279,831	163,618	91,582	48	1,430,056	1,593,674	58,173	-	1,651,846	14,224,931.87
2041	14,057	-	12,813	-	0	1,084,615	39,233	255,237	154,918	99,068	52	1,478,205	1,633,123	58,173	-	1,691,296	14,894,235.13
2042	14,085	34	12,891	1	0	1,385,565	40,599	269,532	117,679	112,345	79	1,808,120	1,925,799	63,017	55,840	1,988,815	15,643,798.76
2043	14,111	43	12,943	2	0	1,505,951	42,012	205,851	233,811	115,741	80	1,869,633	2,103,444	64,449	16,510	2,167,893	16,421,947.38
2044	14,137	86	13,028	2	0	1,657,744	43,474	113,872	143,965	123,582	89	1,938,759	2,082,724	70,796	73,163	2,153,520	17,158,127.88
2045	14,160	130	13,103	10	0	1,867,906	44,986	120,004	144,011	123,408	106	2,156,411	2,300,422	77,270	74,631	2,377,692	17,932,236.20
2046	14,183	234	13,249	7	0	1,986,185	22,031	128,359	139,113	121,973	106	2,258,654	2,397,767	91,210	160,692	2,488,977	18,703,988.07
2047	14,201	242	13,299	2	0	2,059,328	22,798	134,783	146,748	125,410	107	2,342,427	2,489,175	91,210	-	2,580,385	19,465,982.84
2048	14,212	281	13,359	12	0	2,162,111	23,591	170,695	165,578	132,279	110	2,488,787	2,654,364	100,949	112,267	2,755,314	20,240,889.26
2049	14,225	353	13,473	2	0	2,291,743	-	120,378	193,378	126,423	115	2,538,659	2,732,037	110,880	114,471	2,842,916	21,002,359.62
2050	14,242	417	13,571	3	0	2,380,686	-	120,849	166,587	125,480	115	2,627,130	2,793,718	120,999	116,646	2,914,716	21,745,885.23
2051	14,237	480	13,641	3	0	2,479,206	-	151,929	176,624	129,060	121	2,760,315	2,936,939	131,421	120,145	3,068,360	22,491,331.98

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 14,796.38	\$ 330.80	\$ 3,706.49	\$ 1,875.52	\$ 1,141.98	\$ 1.40	\$ 19,977.05	\$ 21,852.56	\$ 638.77	\$ 22,491.33

Appendix A – Detailed PLEXOS Modeling Results

Table A-9 - Efficiency + DER Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,364	-	105,232	54,737	41,943	118	968,658	1,023,394	-	-	1,023,394	1,023,394.42
2023	12,948	-	12,848	4	0	544,330	-	186,642	73,618	32,186	143	763,301	836,919	-	-	836,919	1,828,124.52
2024	13,057	-	12,887	2	-	431,976	-	228,487	75,420	26,776	114	687,353	762,773	-	-	762,773	2,533,351.03
2025	13,160	190	13,096	19	-	605,841	-	300,582	77,211	45,613	145	952,181	1,029,391	18,065	225,727	1,047,456	3,464,535.76
2026	13,250	201	13,148	8	0	588,094	27,616	256,340	79,769	52,420	134	924,603	1,004,372	18,065	-	1,022,437	4,338,519.48
2027	13,327	196	13,174	1	-	637,213	28,302	245,258	174,569	50,141	149	961,062	1,135,631	18,065	-	1,153,696	5,286,773.47
2028	13,399	197	13,211	0	0	658,819	29,005	260,400	83,917	56,903	135	1,005,262	1,089,179	18,065	-	1,107,244	6,161,844.18
2029	13,470	171	13,257	0	0	638,225	29,726	250,440	103,844	56,490	49	974,930	1,078,774	64,757	663,615	1,143,531	7,030,833.87
2030	13,534	213	13,384	0	0	513,164	136,412	244,759	98,020	81,920	39	976,293	1,074,313	64,757	-	1,139,070	7,863,141.28
2031	13,595	216	13,487	0	-	543,675	139,802	267,061	99,460	87,440	39	1,038,018	1,137,478	64,757	-	1,202,235	8,707,815.85
2032	13,654	216	13,599	-	0	587,710	143,276	255,650	97,080	90,106	42	1,076,784	1,173,864	64,757	-	1,238,621	9,544,583.97
2033	13,712	216	13,720	1	-	609,403	162,283	269,223	136,206	101,133	46	1,142,089	1,278,295	64,757	-	1,343,052	10,417,004.98
2034	13,764	216	13,848	0	-	637,733	166,316	293,091	104,047	107,850	48	1,205,038	1,309,084	64,757	-	1,373,841	11,275,102.25
2035	13,814	216	13,983	0	-	681,858	170,449	286,650	101,580	114,718	51	1,253,725	1,355,306	64,757	-	1,420,063	12,127,955.07
2036	13,862	216	14,122	1	-	733,390	182,784	274,919	155,586	122,804	55	1,313,952	1,469,538	64,757	-	1,534,295	13,013,971.93
2037	13,905	216	14,257	3	-	782,522	187,326	291,931	107,518	135,015	58	1,396,851	1,504,369	64,757	-	1,569,126	13,885,252.09
2038	13,949	231	14,420	2	-	845,288	191,981	277,061	134,752	140,451	57	1,454,839	1,589,591	66,335	19,725	1,655,926	14,769,364.67
2039	13,987	274	14,615	-	-	897,415	196,752	263,989	125,412	147,809	62	1,506,027	1,631,438	71,169	60,395	1,702,607	15,643,437.59
2040	14,024	303	14,796	7	0	954,562	210,251	296,414	149,231	154,342	62	1,615,632	1,764,863	74,451	41,014	1,839,314	16,551,374.79
2041	14,057	303	14,936	4	0	1,021,019	224,201	275,808	141,043	167,171	67	1,688,266	1,829,310	74,451	-	1,903,761	17,454,980.41
2042	14,085	303	15,056	5	-	1,326,215	229,773	282,484	117,641	174,897	80	2,013,449	2,131,090	90,258	197,509	2,221,348	18,468,774.64
2043	14,111	303	15,172	1	-	1,440,212	235,483	203,061	228,306	182,217	78	2,061,051	2,289,357	117,640	342,153	2,406,997	19,525,045.83
2044	14,137	303	15,279	2	-	1,601,503	241,334	112,641	153,288	199,548	88	2,155,114	2,308,402	117,640	-	2,426,042	20,548,727.45
2045	14,160	226	15,286	10	0	1,828,559	247,332	114,952	149,980	212,850	101	2,403,794	2,553,774	115,216	195,432	2,668,990	21,631,606.81
2046	14,183	312	15,464	8	0	1,989,053	208,359	138,718	145,301	215,708	103	2,551,940	2,697,241	124,358	114,233	2,821,599	22,732,373.06
2047	14,201	427	15,661	4	-	2,063,756	213,536	136,202	153,539	216,894	103	2,630,490	2,784,029	136,281	148,984	2,920,310	23,827,830.57
2048	14,212	566	15,860	10	0	2,157,633	218,843	143,571	170,054	218,191	106	2,738,343	2,908,396	152,377	201,128	3,060,774	24,931,818.71
2049	14,225	561	15,917	4	0	2,253,647	224,281	121,479	189,155	230,491	106	2,830,004	3,019,160	152,377	-	3,171,537	26,031,760.26
2050	14,242	581	15,999	4	0	2,761,161	56,754	150,142	166,640	188,890	127	3,157,075	3,323,715	153,750	17,146	3,477,465	27,191,416.33
2051	14,237	696	16,141	5	0	2,870,343	58,165	155,423	175,012	182,842	131	3,266,904	3,441,916	166,735	162,261	3,608,652	28,348,535.54

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 17,004.44	\$ 2,088.08	\$ 4,142.03	\$ 2,101.16	\$ 1,924.64	\$ 1.62	\$ 25,160.80	\$ 27,261.96	\$ 1,086.58	\$ 28,348.54

Appendix A – Detailed PLEXOS Modeling Results

Table A-10 - Increased Electrification Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,365	-	105,232	54,737	41,957	118	968,672	1,023,409	-	-	1,023,409	1,023,408.70
2023	12,948	-	12,920	5	-	549,046	-	187,681	73,618	32,435	144	769,306	842,923	-	-	842,923	1,833,912.02
2024	13,057	-	12,995	3	-	438,728	-	231,371	75,420	26,837	116	697,052	772,472	-	-	772,472	2,548,105.80
2025	13,160	223	13,272	20	0	617,431	-	301,155	78,856	43,098	150	961,833	1,040,689	27,383	342,156	1,068,072	3,497,618.14
2026	13,250	255	13,381	8	0	601,668	27,616	256,650	81,413	48,448	139	934,520	1,015,933	27,383	-	1,043,316	4,389,448.92
2027	13,327	247	13,441	1	0	654,799	28,302	245,689	176,208	46,314	154	975,257	1,151,466	27,383	-	1,178,848	5,358,376.44
2028	13,399	300	13,567	0	0	678,773	29,005	260,354	86,887	50,106	140	1,018,378	1,105,265	33,952	82,083	1,139,217	6,258,716.37
2029	13,470	293	13,666	-	0	657,536	29,726	251,098	106,799	50,803	48	989,210	1,096,010	85,313	729,976	1,181,323	7,156,424.46
2030	13,534	361	13,856	-	0	528,333	136,412	244,462	100,963	76,138	38	985,382	1,086,346	85,313	-	1,171,659	8,012,544.18
2031	13,595	352	13,983	-	0	562,554	139,802	267,751	102,476	82,136	39	1,052,281	1,154,757	85,313	-	1,240,070	8,883,800.89
2032	13,654	346	14,124	-	0	611,129	143,276	256,458	100,179	89,445	43	1,100,351	1,200,530	85,313	-	1,285,843	9,752,470.24
2033	13,712	384	14,320	2	-	606,955	185,453	268,440	139,368	98,022	46	1,158,915	1,298,283	85,313	-	1,383,596	10,651,228.01
2034	13,764	384	14,484	0	0	637,695	190,062	292,426	107,286	106,637	48	1,226,867	1,334,153	85,313	-	1,419,466	11,537,822.12
2035	13,814	384	14,655	0	0	685,413	194,785	286,948	104,898	112,438	51	1,279,635	1,384,533	85,313	-	1,469,846	12,420,573.62
2036	13,862	384	14,831	1	-	741,641	207,725	275,531	158,990	122,123	56	1,347,076	1,506,066	85,313	-	1,591,379	13,339,555.22
2037	13,905	384	15,001	3	0	794,287	212,887	292,789	110,995	130,913	59	1,430,934	1,541,930	85,313	-	1,627,243	14,243,105.31
2038	13,949	413	15,215	2	1	859,885	218,177	278,234	138,739	135,504	58	1,491,858	1,630,597	88,786	43,394	1,719,383	15,161,098.07
2039	13,987	442	15,430	0	0	917,189	223,599	263,803	129,141	144,781	64	1,549,435	1,678,576	92,330	44,290	1,770,906	16,070,233.91
2040	14,024	456	15,634	7	0	992,149	229,155	299,505	152,671	152,663	65	1,673,538	1,826,208	94,136	22,558	1,920,344	17,018,169.66
2041	14,057	480	15,831	5	0	1,053,242	252,300	280,680	145,288	164,468	69	1,750,759	1,896,047	97,248	38,886	1,993,294	17,964,271.68
2042	14,085	480	15,991	2	0	1,342,593	258,569	278,529	126,623	180,020	88	2,059,799	2,186,423	126,491	365,406	2,312,914	19,019,855.29
2043	14,111	480	16,140	1	-	1,485,574	264,995	208,737	232,756	182,548	83	2,141,937	2,374,693	144,400	223,778	2,519,093	20,125,317.91
2044	14,137	480	16,284	2	0	1,656,394	271,580	119,260	157,852	200,446	93	2,247,773	2,405,626	144,400	-	2,550,026	21,201,314.92
2045	14,160	173	16,101	4	-	1,903,484	278,329	109,575	165,468	230,728	106	2,522,221	2,687,689	148,972	399,289	2,836,661	22,352,223.18
2046	14,183	173	16,227	4	-	2,072,372	240,126	129,404	158,717	233,803	108	2,675,813	2,834,530	148,972	-	2,983,502	23,516,151.34
2047	14,201	197	16,367	2	-	2,166,672	246,093	134,673	165,020	240,705	109	2,788,253	2,953,273	152,471	43,714	3,105,744	24,681,168.03
2048	14,212	351	16,620	6	0	2,270,645	252,209	142,660	181,718	240,894	112	2,906,519	3,088,237	172,597	333,566	3,260,834	25,857,315.85
2049	14,225	360	16,724	2	0	2,379,973	258,476	131,070	201,143	259,405	113	3,029,037	3,230,179	174,078	18,509	3,404,258	27,037,968.83
2050	14,242	475	16,937	2	0	2,871,222	91,799	141,922	181,471	215,278	132	3,320,353	3,501,824	187,947	173,289	3,689,770	28,268,424.16
2051	14,237	591	17,115	1	0	2,995,339	94,080	150,068	190,030	208,481	137	3,448,104	3,638,134	202,231	178,487	3,840,365	29,499,842.55

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 17,499.21	\$ 2,334.74	\$ 4,148.18	\$ 2,175.98	\$ 1,946.30	\$ 1.67	\$ 25,930.10	\$ 28,106.07	\$ 1,393.77	\$ 29,499.84

Appendix A – Detailed PLEXOS Modeling Results

Table A-11 - Future Net Zero Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,785	41	-	199	-	5,803	1,014,751	54,737	15,890	76,628	1,091,380	-	-	1,091,380	1,091,379.87
2023	12,948	-	12,782	70	-	154	-	6,210	886,950	73,618	13,691	93,673	980,623	-	-	980,623	2,034,286.82
2024	13,057	-	12,838	52	-	208	-	6,403	803,438	75,420	14,456	96,487	899,925	-	-	899,925	2,866,318.33
2025	13,160	298	13,186	37	-	237	-	6,536	956,489	73,581	10,173	90,527	1,047,017	33,976	424,544	1,080,993	3,827,317.12
2026	13,250	321	13,267	10	-	254	27,616	6,691	926,235	76,129	10,618	121,307	1,047,542	33,976	-	1,081,519	4,751,803.84
2027	13,327	306	13,282	3	-	267	28,302	6,704	975,529	170,925	12,224	218,422	1,193,951	33,976	-	1,227,927	5,761,070.53
2028	13,399	307	13,320	1	-	278	29,005	6,897	1,033,240	80,257	13,958	130,396	1,163,636	33,976	-	1,197,612	6,707,561.02
2029	13,470	418	13,453	50	-	295	29,726	7,092	1,263,522	100,978	14,086	152,177	1,415,699	56,454	311,680	1,472,153	7,826,276.14
2030	13,534	682	13,827	26	-	293	136,412	7,283	1,105,762	95,539	24,112	263,639	1,369,401	68,995	187,527	1,438,396	8,877,297.98
2031	13,595	1,109	14,375	6	-	298	139,802	7,495	1,099,253	97,289	16,908	261,792	1,361,045	137,520	887,067	1,498,565	9,930,169.91
2032	13,654	1,364	14,745	1	-	308	143,276	7,701	1,089,990	95,216	12,746	259,247	1,349,238	225,779	1,133,645	1,575,017	10,994,195.08
2033	13,712	1,826	15,325	7	-	318	177,730	7,925	1,064,589	134,678	11,551	332,202	1,396,791	411,698	2,353,933	1,808,489	12,168,955.10
2034	13,764	2,250	15,881	2	-	333	213,517	8,161	998,021	102,856	11,804	336,671	1,334,692	616,094	2,584,814	1,950,786	13,387,410.48
2035	13,814	3,293	17,061	0	-	349	290,495	8,385	813,380	100,738	11,231	411,197	1,224,576	755,911	1,777,869	1,980,487	14,576,839.85
2036	13,862	3,500	17,407	0	-	367	305,813	8,597	836,901	155,104	11,205	481,087	1,317,988	887,926	1,680,388	2,205,914	15,850,700.04
2037	13,905	3,510	17,554	0	-	381	313,412	8,824	879,551	107,408	12,073	442,099	1,321,650	1,011,098	1,569,898	2,332,749	17,145,992.55
2038	13,949	4,215	18,406	-	-	261	371,209	5,027	773,302	134,638	11,456	522,591	1,295,893	1,162,399	1,921,369	2,458,292	18,458,494.84
2039	13,987	4,693	19,034	-	-	137	414,278	830	736,256	124,496	11,267	551,008	1,287,264	1,310,011	1,875,283	2,597,276	19,791,866.62
2040	14,024	5,425	19,926	-	-	273	467,624	4,850	678,219	147,875	10,245	630,867	1,309,086	1,537,451	2,872,749	2,846,537	21,196,997.30
2041	14,057	5,918	20,555	-	-	151	514,145	437	642,158	140,050	10,851	665,634	1,307,792	1,813,992	3,486,288	3,121,784	22,678,728.43
2042	14,085	5,902	20,660	-	-	460	526,921	9,123	889,732	105,085	12,051	653,641	1,543,373	2,097,821	3,577,351	3,641,194	24,340,521.87
2043	14,111	7,400	22,270	-	-	162	684,331	282	618,677	199,345	11,901	896,021	1,514,698	2,354,521	3,238,365	3,869,218	26,038,464.95
2044	14,137	7,525	22,503	-	-	249	701,336	2,426	633,371	124,418	13,264	841,693	1,475,064	2,726,064	4,673,361	4,201,127	27,811,153.31
2045	14,160	8,309	23,346	-	-	510	809,902	9,576	611,819	122,490	12,939	955,417	1,567,236	2,856,538	1,661,136	4,423,773	29,605,994.72
2046	14,183	9,998	25,153	5	-	525	988,073	9,863	550,195	116,190	13,656	1,128,308	1,678,503	3,177,773	4,044,751	4,856,276	31,500,532.11
2047	14,201	10,750	25,973	13	-	547	1,195,799	10,159	510,504	121,769	12,024	1,340,298	1,850,803	3,490,035	3,932,631	5,340,837	33,503,969.86
2048	14,212	11,236	26,475	64	-	573	1,431,072	10,464	428,969	134,411	10,571	1,587,091	2,016,060	3,968,303	6,006,935	5,984,363	35,662,465.24
2049	14,225	11,439	26,771	28	-	599	1,619,121	10,778	399,555	153,619	9,819	1,793,936	2,193,490	4,216,199	3,097,533	6,409,689	37,885,451.59
2050	14,242	11,702	26,065	1,059	-	6	1,771,794	18	89,169	130,773	0	1,902,591	1,991,761	4,736,324	6,499,125	6,728,084	40,129,116.12
2051	14,237	11,711	26,098	1,062	-	6	1,815,823	19	88,951	136,049	-	1,951,897	2,040,848	4,711,689	-	6,752,537	42,294,326.72

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 5.15	\$ 6,296.87	\$ 116.60	\$ 15,303.93	\$ 1,963.22	\$ 225.96	\$ 8,607.80	\$ 23,911.73	\$ 18,382.60	\$ 42,294.33

Appendix A – Detailed PLEXOS Modeling Results

Table A-12 - Supplemental Scenario - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,785	41	0	835,287	-	163,837	55,273	16,187	115	1,015,425	1,070,698	-	-	1,070,698	1,070,698.32
2023	12,948	-	12,862	64	-	567,004	-	301,038	78,004	13,573	136	881,750	959,754	-	-	959,754	1,993,538.79
2024	13,057	-	12,940	57	-	458,365	-	333,151	80,945	14,317	112	805,946	886,891	-	-	886,891	2,813,519.30
2025	13,160	282	13,291	45	-	488,023	-	343,345	85,964	9,883	106	841,356	927,320	27,937	349,087	955,258	3,662,739.88
2026	13,250	315	13,403	8	-	462,520	27,616	260,982	89,865	10,377	99	761,594	851,459	27,937	-	879,396	4,414,451.46
2027	13,327	274	13,390	6	-	513,309	28,302	265,266	186,156	11,990	114	818,981	1,005,136	27,937	-	1,033,074	5,263,562.84
2028	13,399	308	13,445	0	-	523,636	29,005	266,616	97,177	13,396	101	832,754	929,931	27,937	-	957,869	6,020,580.49
2029	13,470	242	13,390	2	-	562,513	29,726	282,261	114,174	21,878	69	896,446	1,010,621	58,265	378,954	1,068,886	6,832,845.80
2030	13,534	504	13,522	131	-	421,351	136,412	280,329	66,642	27,638	17	865,747	932,389	70,342	150,904	1,002,731	7,565,531.55
2031	13,595	1,067	14,207	7	-	419,735	139,802	283,272	80,298	19,788	14	862,610	942,908	131,097	759,153	1,074,005	8,320,113.23
2032	13,654	1,328	14,465	12	-	437,728	143,276	269,443	94,399	16,649	13	867,109	961,508	193,142	775,270	1,154,650	9,100,153.28
2033	13,712	1,837	14,994	1	-	406,089	177,730	288,528	109,702	15,048	12	887,407	997,109	262,471	866,289	1,259,580	9,918,352.54
2034	13,764	1,924	15,090	-	0	405,860	182,147	298,931	134,089	13,935	11	900,883	1,034,972	370,521	1,350,115	1,405,493	10,796,219.23
2035	13,814	3,280	16,461	-	-	262,673	282,235	277,529	159,562	11,565	5	834,007	993,569	480,789	1,377,835	1,474,358	11,681,680.16
2036	13,862	3,361	16,558	-	0	286,135	289,249	267,343	186,653	11,235	6	853,967	1,040,620	593,160	1,404,116	1,633,780	12,625,147.55
2037	13,905	3,399	16,620	-	-	280,801	304,646	273,497	214,263	12,042	6	870,992	1,085,255	707,869	1,433,326	1,793,124	13,620,805.75
2038	13,949	3,478	16,732	-	-	301,693	312,216	253,527	243,875	11,169	5	878,611	1,122,486	824,955	1,463,026	1,947,441	14,660,560.36
2039	13,987	3,575	16,867	-	-	309,488	328,436	252,371	275,073	11,681	5	901,982	1,177,055	944,457	1,493,217	2,121,512	15,749,687.96
2040	14,024	4,935	18,273	-	-	187,514	439,920	246,517	308,492	10,705	3	884,660	1,193,151	1,066,189	1,521,070	2,259,340	16,864,961.65
2041	14,057	5,021	18,394	-	-	196,128	459,577	228,172	342,142	11,233	3	895,114	1,237,256	1,190,409	1,552,168	2,427,665	18,017,234.46
2042	14,085	4,982	18,374	-	0	328,253	470,998	228,175	362,527	14,012	6	1,041,444	1,403,971	1,317,097	1,583,012	2,721,068	19,259,094.43
2043	14,111	5,612	19,020	-	-	295,355	554,860	154,370	401,331	14,309	5	1,018,899	1,420,230	1,446,352	1,615,083	2,866,582	20,517,046.90
2044	14,137	5,738	19,159	-	-	356,789	568,648	53,451	442,661	15,527	6	994,421	1,437,082	1,577,959	1,644,466	3,015,041	21,789,259.53
2045	14,160	6,781	19,613	602	-	230,192	739,015	13,348	475,645	12,040	3	994,598	1,470,242	1,684,267	1,677,442	3,154,509	23,069,127.06
2046	14,183	7,470	20,826	89	-	226,683	874,792	13,087	519,507	13,429	3	1,127,994	1,647,502	1,821,192	1,710,916	3,468,693	24,422,338.73
2047	14,201	8,033	21,424	61	-	179,088	1,065,612	12,512	565,233	12,826	3	1,270,040	1,835,273	1,960,835	1,744,890	3,796,108	25,846,322.79
2048	14,212	8,491	21,870	69	-	146,719	1,268,285	8,059	614,442	10,742	2	1,433,807	2,048,249	2,104,866	1,799,714	4,153,115	27,344,306.62
2049	14,225	9,293	22,739	6	-	123,781	1,482,786	6,398	669,124	10,257	1	1,623,223	2,292,347	2,245,713	2,138,876	4,538,060	28,918,181.08
2050	14,242	9,738	22,512	687	-	15,441	1,738,874	3,771	758,529	-	-	1,758,086	2,516,615	2,472,257	3,080,101	4,988,872	30,581,857.35
2051	14,237	9,677	22,454	667	-	16,645	1,782,085	4,065	778,907	-	-	1,802,795	2,581,702	2,502,402	1,135,829	5,084,104	32,212,082.65

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 7,082.30	\$ 5,754.83	\$ 4,078.05	\$ 3,999.94	\$ 245.31	\$ 0.83	\$ 17,161.32	\$ 21,161.26	\$ 11,050.83	\$ 32,212.08

Appendix A – Detailed PLEXOS Modeling Results

Table A-13 - Low Load Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,420	-	105,489	54,737	42,326	119	969,353	1,024,090	-	-	1,024,090	1,024,089.56
2023	12,948	-	12,227	3	-	502,441	-	177,746	73,618	31,605	130	711,922	785,540	-	-	785,540	1,772,222.87
2024	13,057	-	12,227	0	-	391,467	-	216,816	75,420	25,263	102	633,648	709,068	-	-	709,068	2,415,368.33
2025	13,160	-	12,104	17	-	424,157	-	297,604	73,581	30,230	88	752,079	825,661	-	-	825,661	3,128,605.13
2026	13,250	-	11,859	5	-	421,593	6,755	255,925	76,129	38,784	93	723,150	799,279	-	-	799,279	3,786,173.61
2027	13,327	-	11,850	1	0	462,486	6,990	248,371	170,924	44,959	113	762,919	933,843	-	-	933,843	4,517,864.37
2028	13,399	-	12,026	0	0	485,558	7,245	261,281	80,257	51,509	119	805,712	885,969	-	-	885,969	5,178,988.41
2029	13,470	-	12,128	-	0	449,454	7,484	249,732	100,192	36,875	37	743,583	843,775	46,692	663,615	890,467	5,811,826.68
2030	13,534	-	12,225	-	0	456,330	20,948	247,950	94,369	41,723	35	766,986	861,356	46,692	-	908,047	6,426,428.95
2031	13,595	-	12,151	-	0	468,647	21,676	270,867	95,718	42,751	33	803,973	899,691	46,692	-	946,383	7,036,476.16
2032	13,654	-	12,247	0	0	502,686	22,466	259,390	93,234	46,499	36	831,077	924,311	46,692	-	971,003	7,632,587.66
2033	13,712	-	12,290	0	0	528,366	23,206	268,624	132,278	47,872	37	868,105	1,000,383	46,692	-	1,047,075	8,244,790.55
2034	13,764	-	12,269	0	0	538,654	24,011	293,680	100,020	49,074	35	905,452	1,005,473	46,692	-	1,052,165	8,830,675.13
2035	13,814	-	12,467	-	0	577,136	24,842	286,840	97,455	52,799	38	941,656	1,039,111	46,692	-	1,085,803	9,406,499.39
2036	13,862	-	12,531	0	0	618,028	25,745	276,392	151,349	56,368	42	976,575	1,127,924	46,692	-	1,174,616	9,999,760.39
2037	13,905	-	12,593	-	0	639,307	26,591	285,347	103,188	58,650	41	1,009,935	1,113,122	46,692	-	1,159,814	10,557,650.95
2038	13,949	-	12,652	0	0	677,865	27,509	268,387	129,929	60,157	41	1,033,959	1,163,888	46,692	-	1,210,580	11,112,231.59
2039	13,987	-	12,708	-	0	716,082	28,459	264,482	119,282	65,384	45	1,074,452	1,193,734	46,692	-	1,240,426	11,653,425.34
2040	14,024	-	12,762	1	0	746,336	29,490	274,948	142,125	67,239	43	1,118,057	1,260,182	46,692	-	1,306,874	12,196,458.52
2041	14,057	-	12,813	-	0	777,961	30,455	250,731	133,781	71,767	46	1,130,960	1,264,741	46,692	-	1,311,433	12,715,437.00
2042	14,085	24	12,882	1	0	984,092	31,504	260,918	98,982	80,611	72	1,357,197	1,456,179	49,577	36,053	1,505,756	13,282,940.60
2043	14,111	38	12,938	2	0	1,066,014	32,588	196,184	193,125	85,699	74	1,380,560	1,573,684	51,320	21,775	1,625,004	13,866,223.40
2044	14,137	82	13,023	3	0	1,177,874	33,765	102,125	118,967	88,659	83	1,402,505	1,521,473	56,643	66,512	1,578,116	14,405,702.07
2045	14,160	81	13,062	3	0	1,336,787	34,866	82,233	129,113	92,387	94	1,546,368	1,675,481	73,915	215,823	1,749,396	14,975,255.37
2046	14,183	81	13,101	2	0	1,405,069	22,746	86,430	122,045	96,901	92	1,611,237	1,733,282	73,915	-	1,807,197	15,535,609.26
2047	14,201	77	13,136	0	0	1,457,840	23,526	81,175	127,177	100,832	93	1,663,466	1,790,643	73,915	-	1,864,558	16,086,218.39
2048	14,212	91	13,176	5	0	1,535,241	24,374	112,158	139,701	101,586	97	1,773,455	1,913,156	75,236	16,502	1,988,392	16,645,435.30
2049	14,225	152	13,274	0	0	1,588,156	25,167	83,676	160,411	107,684	96	1,804,779	1,965,190	83,564	104,064	2,048,754	17,194,190.63
2050	14,242	216	13,373	1	0	1,698,745	-	86,298	139,159	100,704	101	1,885,848	2,025,007	92,051	106,042	2,117,057	17,734,238.45
2051	14,237	284	13,449	1	0	1,770,200	-	89,807	146,135	98,385	108	1,958,499	2,104,633	100,792	109,223	2,205,425	18,270,038.38

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 11,285.62	\$ 253.00	\$ 3,588.16	\$ 1,719.62	\$ 878.35	\$ 1.21	\$ 16,006.33	\$ 17,725.95	\$ 544.08	\$ 18,270.04

Appendix A – Detailed PLEXOS Modeling Results

Table A-14 - No Load Growth Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,456	-	105,556	54,737	42,060	119	969,191	1,023,928	-	-	1,023,928	1,023,928.05
2023	12,948	-	12,817	10	0	541,934	-	188,889	73,618	32,583	143	763,550	837,167	-	-	837,167	1,828,896.67
2024	13,057	-	12,856	1	-	424,950	-	217,639	75,420	26,479	113	669,182	744,602	-	-	744,602	2,517,322.95
2025	13,160	278	13,079	25	-	464,167	-	303,551	79,791	19,029	106	786,852	866,643	31,162	389,378	897,805	3,315,468.51
2026	13,250	260	13,076	11	-	492,275	-	263,198	82,356	27,185	117	782,775	865,132	31,162	-	896,294	4,081,624.05
2027	13,327	173	13,000	0	0	538,540	-	250,228	177,158	32,466	137	821,372	998,530	31,162	-	1,029,692	4,927,955.54
2028	13,399	181	13,038	-	-	554,812	-	263,410	86,515	37,098	144	855,464	941,979	31,162	-	973,141	5,697,043.01
2029	13,470	270	13,097	-	0	495,122	-	252,073	106,436	30,593	45	777,832	884,268	77,854	663,615	962,121	6,428,176.26
2030	13,534	285	13,112	-	0	483,971	20,282	248,714	100,608	34,173	39	787,180	887,788	77,854	-	965,642	7,133,761.09
2031	13,595	278	13,105	-	-	503,205	20,786	272,392	102,113	34,963	36	831,383	933,496	77,854	-	1,011,350	7,844,322.14
2032	13,654	280	13,137	-	0	520,968	28,229	260,151	99,807	39,128	36	848,512	948,319	77,854	-	1,026,173	8,537,568.02
2033	13,712	283	13,110	-	0	542,099	28,880	269,803	138,991	38,222	37	879,041	1,018,032	77,854	-	1,095,886	9,249,434.36
2034	13,764	279	13,105	-	0	554,503	29,596	293,967	106,900	38,726	34	916,826	1,023,726	77,854	-	1,101,580	9,937,477.92
2035	13,814	285	13,111	-	0	578,692	30,328	288,412	104,504	44,210	35	941,677	1,046,181	77,854	-	1,124,035	10,612,544.10
2036	13,862	281	13,138	-	0	615,843	31,130	274,735	158,587	45,586	39	967,333	1,125,921	77,854	-	1,203,775	11,307,694.00
2037	13,905	280	13,107	-	0	629,053	31,845	282,784	110,586	46,833	37	990,551	1,101,137	77,854	-	1,178,991	11,962,345.89
2038	13,949	279	13,106	-	0	662,474	32,630	264,020	137,510	48,222	35	1,007,381	1,144,891	77,854	-	1,222,745	12,615,179.57
2039	13,987	281	13,108	-	0	693,867	33,434	263,517	127,052	51,300	37	1,042,156	1,169,208	77,854	-	1,247,062	13,255,387.78
2040	14,024	281	13,138	-	-	720,052	34,314	267,238	150,102	50,305	36	1,071,944	1,222,046	77,854	-	1,299,900	13,897,055.17
2041	14,057	281	13,108	-	0	745,254	35,098	248,655	141,932	52,637	37	1,081,681	1,223,614	77,854	-	1,301,468	14,514,787.03
2042	14,085	294	13,121	-	0	937,105	35,960	242,692	106,619	49,770	63	1,265,590	1,372,209	77,854	-	1,450,063	15,176,577.01
2043	14,111	295	13,122	-	0	1,013,491	36,842	178,577	200,515	47,730	63	1,276,702	1,477,217	77,854	-	1,555,071	15,858,994.42
2044	14,137	316	13,172	1	0	1,121,447	37,807	84,026	125,209	51,364	72	1,294,716	1,419,925	77,854	-	1,497,778	16,490,990.12
2045	14,160	58	12,880	5	0	1,285,919	38,667	86,376	116,079	84,657	92	1,495,711	1,611,790	53,932	90,461	1,665,722	17,166,817.22
2046	14,183	58	12,866	19	0	1,324,533	39,611	107,821	108,871	91,174	88	1,563,226	1,672,098	53,932	-	1,726,029	17,840,178.26
2047	14,201	58	12,881	4	0	1,364,582	40,578	85,118	113,861	94,022	87	1,584,386	1,698,247	53,932	-	1,752,179	18,497,449.95
2048	14,212	58	12,904	10	0	1,435,617	41,636	110,448	125,867	95,244	91	1,683,037	1,808,904	53,932	-	1,862,836	19,169,354.66
2049	14,225	58	12,883	2	0	1,476,761	42,578	79,858	144,474	100,543	90	1,699,831	1,844,305	53,932	-	1,898,236	19,827,694.41
2050	14,242	58	12,881	4	0	1,617,831	10,655	96,741	120,980	100,463	99	1,825,789	1,946,769	53,932	-	2,000,701	20,494,883.02
2051	14,237	58	12,855	2	0	1,685,390	10,908	111,060	125,626	102,708	103	1,910,169	2,035,795	53,932	-	2,089,726	21,164,956.71

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 13,061.29	\$ 339.53	\$ 3,980.46	\$ 1,994.94	\$ 829.22	\$ 1.40	\$ 18,211.89	\$ 20,206.83	\$ 958.12	\$ 21,164.96

Appendix A – Detailed PLEXOS Modeling Results

Table A-15 - High Load Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	-	821,347	-	105,331	54,737	40,990	118	967,785	1,022,522	-	-	1,022,522	1,022,521.90
2023	12,948	-	12,848	4	0	543,916	-	186,697	73,618	31,968	143	762,724	836,342	-	-	836,342	1,826,697.06
2024	13,057	-	13,183	5	-	447,617	-	235,237	75,420	26,853	120	709,826	785,246	-	-	785,246	2,552,701.44
2025	13,160	247	14,571	44	-	564,428	-	316,711	81,039	21,308	136	902,583	983,623	37,044	462,873	1,020,666	3,460,070.01
2026	13,250	242	14,763	12	-	556,244	27,549	270,580	83,610	32,451	137	886,961	970,571	37,044	-	1,007,615	4,321,383.24
2027	13,327	146	14,701	3	-	608,605	28,233	262,324	178,415	40,492	159	939,813	1,118,228	37,044	-	1,155,272	5,270,932.31
2028	13,399	175	14,772	1	-	629,005	28,982	272,510	87,779	44,023	169	974,689	1,062,468	37,044	-	1,099,512	6,139,892.27
2029	13,470	338	15,002	-	0	564,340	29,650	259,005	107,699	34,991	61	888,048	995,747	83,736	663,615	1,079,483	6,960,210.27
2030	13,534	356	15,106	0	0	602,457	30,384	256,548	101,874	37,694	65	927,149	1,029,022	83,736	-	1,112,758	7,773,291.74
2031	13,595	385	15,235	-	0	632,293	31,136	279,445	103,411	38,517	64	981,455	1,084,866	83,736	-	1,168,602	8,594,335.69
2032	13,654	406	15,373	-	-	675,908	31,958	267,108	101,141	42,574	68	1,017,616	1,118,757	83,736	-	1,202,493	9,406,696.67
2033	13,712	394	15,476	3	0	721,508	32,692	293,013	140,353	49,487	73	1,096,773	1,237,126	83,736	-	1,320,862	10,264,703.32
2034	13,764	404	15,613	3	0	746,169	33,498	309,644	108,298	54,267	73	1,143,650	1,251,948	83,736	-	1,335,684	11,098,967.43
2035	13,814	414	15,759	1	0	792,917	34,322	307,448	105,937	57,541	77	1,192,306	1,298,242	83,736	-	1,381,978	11,928,947.60
2036	13,862	416	15,906	1	-	857,066	35,225	298,549	160,059	63,982	84	1,254,905	1,414,964	83,736	-	1,498,700	12,794,409.33
2037	13,905	401	16,015	9	0	896,439	36,030	317,948	112,090	69,551	86	1,320,055	1,432,145	83,736	-	1,515,881	13,636,124.03
2038	13,949	398	16,168	1	0	953,127	36,914	291,322	150,579	67,474	75	1,348,912	1,499,490	97,780	175,484	1,597,270	14,488,919.36
2039	13,987	406	16,326	-	0	1,016,094	37,819	283,689	140,256	75,840	83	1,413,525	1,553,781	97,780	-	1,651,560	15,336,786.22
2040	14,024	412	16,492	4	0	1,071,496	38,809	309,875	163,480	83,679	83	1,503,942	1,667,422	97,780	-	1,765,202	16,208,139.32
2041	14,057	415	16,629	3	0	1,124,727	39,691	289,850	155,418	85,241	89	1,539,598	1,695,016	97,780	-	1,792,796	17,059,076.23
2042	14,085	376	16,712	-	0	1,238,918	40,660	267,343	251,876	115,812	55	1,662,788	1,914,664	166,348	974,541	2,081,013	18,008,823.19
2043	14,111	361	16,810	0	0	1,342,417	41,652	206,232	346,151	125,552	60	1,715,913	2,062,063	166,348	-	2,228,412	18,986,725.11
2044	14,137	384	16,945	1	0	1,472,354	42,738	113,898	271,638	122,250	69	1,751,309	2,022,947	166,348	-	2,189,295	19,910,509.97
2045	14,160	40	16,686	4	0	1,649,212	43,703	110,148	277,165	136,663	79	1,939,805	2,216,970	163,907	432,371	2,380,877	20,876,494.67
2046	14,183	157	16,895	1	0	1,787,521	-	112,505	273,204	125,312	82	2,025,420	2,298,625	175,598	146,083	2,474,223	21,841,742.23
2047	14,201	232	17,048	0	0	1,856,119	-	112,786	280,652	125,455	83	2,094,442	2,375,095	183,624	100,286	2,558,719	22,801,560.63
2048	14,212	335	17,218	4	0	1,945,069	-	130,599	296,643	133,672	88	2,209,427	2,506,070	195,758	151,621	2,701,829	23,776,081.19
2049	14,225	448	17,386	0	0	2,027,272	-	114,828	318,467	135,652	85	2,277,836	2,596,303	208,131	154,598	2,804,434	24,748,705.25
2050	14,242	564	17,565	0	0	2,105,123	-	119,194	298,816	142,430	85	2,366,832	2,665,649	220,738	157,535	2,886,387	25,711,250.35
2051	14,237	655	17,679	-	0	2,190,991	-	121,742	307,071	148,141	91	2,460,965	2,768,036	233,724	162,261	3,001,760	26,673,769.00

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 16,647.37	\$ 410.70	\$ 4,273.45	\$ 2,657.36	\$ 1,155.35	\$ 1.75	\$ 22,488.61	\$ 25,145.97	\$ 1,527.80	\$ 26,673.77

Appendix A – Detailed PLEXOS Modeling Results

Table A-16 - High Fuel Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,381	-	105,232	54,737	42,116	118	968,848	1,023,585	-	-	1,023,585	1,023,584.68
2023	12,948	-	12,943	5	-	550,561	-	188,024	73,618	32,201	145	770,930	844,548	-	-	844,548	1,835,649.79
2024	13,057	-	13,054	3	-	442,007	-	231,938	75,420	27,035	117	701,098	776,517	-	-	776,517	2,553,583.76
2025	13,160	257	13,397	20	0	624,704	-	301,346	80,004	41,502	152	967,704	1,047,708	32,175	402,043	1,079,883	3,513,595.88
2026	13,250	302	13,544	8	-	609,945	27,549	256,398	82,569	45,250	142	939,284	1,021,853	32,175	-	1,054,028	4,414,583.67
2027	13,327	295	13,622	0	0	664,989	28,233	245,416	177,371	41,800	157	980,595	1,157,966	32,175	-	1,190,142	5,392,793.61
2028	13,399	313	13,713	0	0	689,454	28,982	260,806	86,730	47,025	143	1,026,410	1,113,140	32,175	-	1,145,315	6,297,952.98
2029	13,470	301	13,771	-	-	664,130	29,650	251,169	106,650	47,580	47	992,577	1,099,227	78,867	663,615	1,178,094	7,193,207.90
2030	13,534	370	13,904	-	-	523,443	136,332	243,828	100,823	71,111	34	974,747	1,075,570	78,867	-	1,154,437	8,036,743.80
2031	13,595	365	13,961	-	0	550,143	139,716	267,350	102,333	75,050	33	1,032,292	1,134,625	78,867	-	1,213,493	8,889,327.74
2032	13,654	354	14,009	-	0	589,574	143,237	255,743	100,033	81,709	36	1,070,299	1,170,332	78,867	-	1,249,199	9,733,242.14
2033	13,712	375	14,086	0	-	576,114	177,629	264,055	139,222	87,872	37	1,105,707	1,244,929	78,867	-	1,323,796	10,593,154.83
2034	13,764	382	14,146	-	-	595,259	182,037	288,195	107,137	92,415	36	1,157,942	1,265,079	78,867	-	1,343,946	11,432,579.62
2035	13,814	383	14,198	-	0	627,804	186,553	281,747	104,747	96,781	37	1,192,921	1,297,668	78,867	-	1,376,536	12,259,291.22
2036	13,862	384	14,246	0	-	672,578	191,239	269,948	158,837	103,736	40	1,237,540	1,396,377	78,867	-	1,475,245	13,111,208.35
2037	13,905	381	14,286	0	-	705,901	195,920	279,531	110,841	106,646	40	1,288,038	1,398,879	78,867	-	1,477,746	13,931,748.22
2038	13,949	377	14,325	-	-	754,660	200,777	263,735	137,772	110,961	40	1,330,173	1,467,945	78,867	-	1,546,812	14,757,603.93
2039	13,987	386	14,373	-	-	793,836	205,754	257,943	127,320	120,503	43	1,378,079	1,505,399	78,867	-	1,584,267	15,570,924.07
2040	14,024	394	14,417	1	-	838,263	210,918	270,434	150,377	125,430	41	1,445,085	1,595,462	78,867	-	1,674,330	16,397,420.28
2041	14,057	394	14,450	-	-	868,452	233,527	244,472	142,214	134,604	44	1,481,098	1,623,312	78,867	-	1,702,180	17,205,346.91
2042	14,085	394	14,477	2	0	1,133,502	239,313	251,971	106,908	159,579	68	1,784,433	1,891,341	78,867	-	1,970,208	18,104,524.30
2043	14,111	394	14,502	3	0	1,241,520	245,241	188,358	200,810	164,851	69	1,840,039	2,040,850	78,867	-	2,119,717	19,034,727.48
2044	14,137	431	14,565	3	0	1,376,554	251,386	91,026	126,712	173,737	78	1,892,781	2,019,493	83,639	59,623	2,103,132	19,922,155.22
2045	14,160	38	14,196	3	-	1,633,230	257,536	79,276	140,006	194,029	83	2,164,153	2,304,159	86,008	431,647	2,390,167	20,891,909.09
2046	14,183	38	14,219	2	0	1,774,790	219,147	85,391	133,023	195,871	83	2,275,282	2,408,304	86,008	-	2,494,313	21,864,994.07
2047	14,201	38	14,239	0	-	1,838,244	224,593	84,142	138,242	203,079	84	2,350,143	2,488,385	86,008	-	2,574,393	22,830,692.20
2048	14,212	53	14,261	4	0	1,922,817	230,174	97,965	151,049	210,404	89	2,461,449	2,612,498	87,924	23,941	2,700,423	23,804,705.54
2049	14,225	67	14,292	0	-	1,998,238	235,894	81,448	170,347	228,920	89	2,544,589	2,714,936	89,878	24,411	2,804,813	24,777,461.33
2050	14,242	82	14,322	1	0	2,466,581	68,655	98,069	147,647	176,970	107	2,810,383	2,958,030	91,869	24,875	3,049,899	25,794,533.86
2051	14,237	197	14,407	0	0	2,540,030	70,362	98,863	155,631	179,724	111	2,889,090	3,044,722	104,854	162,261	3,149,576	26,804,449.93

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 15,850.62	\$ 2,182.30	\$ 3,940.70	\$ 2,063.30	\$ 1,701.90	\$ 1.50	\$ 23,677.01	\$ 25,740.31	\$ 1,064.14	\$ 26,804.45

Appendix A – Detailed PLEXOS Modeling Results

Table A-17- Regulated CO<sub>2</sub> Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unserviced Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdown (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,484	-	105,663	54,737	41,739	118	969,004	1,023,741	-	-	1,023,741	1,023,741.30
2023	12,948	-	12,943	5	0	550,210	-	188,230	73,618	32,307	145	770,892	844,510	-	-	844,510	1,835,769.85
2024	13,057	-	13,054	3	-	439,884	-	231,266	75,420	27,774	118	699,041	774,461	-	-	774,461	2,551,802.57
2025	13,160	280	13,420	20	-	485,852	-	303,871	80,004	19,424	112	809,260	889,264	32,175	402,043	921,439	3,370,958.63
2026	13,250	265	13,506	9	-	494,133	13,511	260,914	82,569	30,956	119	799,633	882,202	32,175	-	914,378	4,152,572.61
2027	13,327	178	13,505	1	0	547,494	13,846	254,613	177,371	34,744	140	850,838	1,028,209	32,175	-	1,060,384	5,024,131.25
2028	13,399	190	13,590	0	0	566,725	14,213	265,452	86,730	40,888	148	887,427	974,157	32,175	-	1,006,332	5,819,450.27
2029	13,470	289	13,759	-	0	512,666	14,541	252,890	106,650	33,098	49	813,244	919,894	78,867	663,615	998,762	6,578,427.15
2030	13,534	299	13,834	-	0	520,505	28,649	251,443	100,823	38,061	158,836	997,494	1,098,316	78,867	-	1,177,184	7,438,583.86
2031	13,595	306	13,901	0	-	544,036	29,359	274,219	102,333	38,956	165,256	1,051,825	1,154,159	78,867	-	1,233,026	8,304,891.80
2032	13,654	299	13,953	0	0	579,873	30,136	262,690	100,033	41,455	177,603	1,091,757	1,191,790	78,867	-	1,270,658	9,163,302.70
2033	13,712	314	14,025	1	0	611,124	30,829	275,646	139,222	42,230	188,629	1,148,458	1,287,680	78,867	-	1,366,547	10,050,985.82
2034	13,764	313	14,077	-	0	629,084	31,591	300,716	107,137	42,171	196,377	1,199,939	1,307,076	78,867	-	1,385,944	10,916,642.31
2035	13,814	318	14,132	-	0	660,322	32,370	292,022	104,747	47,710	209,935	1,242,359	1,347,106	78,867	-	1,425,973	11,773,044.93
2036	13,862	317	14,179	0	0	704,955	33,224	281,307	158,837	50,628	224,813	1,294,927	1,453,764	78,867	-	1,532,631	12,658,101.36
2037	13,905	327	14,231	1	-	728,838	33,984	294,734	110,841	50,343	234,611	1,342,510	1,453,351	78,867	-	1,532,219	13,508,887.98
2038	13,949	338	14,287	-	0	767,936	34,820	273,691	137,772	52,849	247,901	1,377,196	1,514,968	78,867	-	1,593,836	14,359,849.98
2039	13,987	321	14,308	0	0	809,358	35,675	268,273	127,320	60,285	266,132	1,439,723	1,567,043	78,867	-	1,645,911	15,204,816.55
2040	14,024	338	14,361	1	0	841,421	36,612	283,575	150,377	58,251	275,118	1,494,976	1,645,353	78,867	-	1,724,221	16,055,940.42
2041	14,057	345	14,402	-	-	874,003	37,445	256,702	142,214	60,917	295,084	1,524,152	1,666,366	78,867	-	1,745,233	16,884,302.22
2042	14,085	368	14,451	2	0	1,096,108	38,362	274,318	106,908	66,090	343,554	1,818,133	1,925,341	78,867	-	2,004,208	17,798,996.70
2043	14,111	363	14,469	5	0	1,183,044	39,300	211,329	200,810	70,699	370,113	1,874,485	2,075,295	78,867	-	2,154,163	18,744,315.72
2044	14,137	412	14,544	6	0	1,303,842	40,327	118,983	126,712	71,073	417,187	1,951,411	2,078,123	83,639	59,623	2,161,762	19,656,482.77
2045	14,160	38	14,195	4	0	1,484,441	41,240	99,851	140,006	100,693	469,066	2,195,291	2,335,296	86,008	431,647	2,421,305	20,638,869.86
2046	14,183	35	14,216	3	0	1,577,739	20,291	101,800	133,023	105,854	501,925	2,307,609	2,440,632	86,008	-	2,526,640	21,624,566.38
2047	14,201	38	14,239	0	0	1,633,253	20,786	99,684	138,242	110,603	529,294	2,393,621	2,531,863	86,008	-	2,617,871	22,606,573.91
2048	14,212	53	14,258	6	0	1,711,555	21,327	122,002	151,049	108,541	560,643	2,524,068	2,675,118	87,924	23,941	2,763,042	23,603,173.38
2049	14,225	62	14,287	0	0	1,773,263	21,809	100,639	170,347	117,992	587,531	2,601,234	2,771,581	89,878	24,411	2,861,459	24,591,574.71
2050	14,242	141	14,382	1	0	1,887,141	-	106,344	149,161	107,296	635,007	2,735,787	2,884,948	98,364	106,042	2,983,312	25,590,442.14
2051	14,237	211	14,420	0	0	1,956,829	-	106,699	156,690	102,578	675,602	2,841,708	2,998,398	109,156	134,844	3,107,554	26,586,883.67

	Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdown (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)	Total System Cost (\$1MM)
CPWC (\$1MM)	\$ 14,596.41	\$ 376.61	\$ 4,107.12	\$ 2,064.15	\$ 931.43	\$ 3,443.49	\$ 23,455.05	\$ 25,519.20	\$ 1,067.68	\$ 26,586.88

Appendix A – Detailed PLEXOS Modeling Results

Table A-18 - Net Zero Sensitivity - Cumulative Present Worth Costs (CPWC)

YEAR	Energy					Production Cost											Cumulative Present Worth Cost (CPWC)
	Native Load (GWh)	Battery Load (GWh)	Generation (GWh)	Unservd Energy (GWh)	Dump Energy (GWh)	Fuel Cost (\$000)	Solar PPA Costs (\$000)	Plant O&M Costs				Variable Production Costs (\$000)	Total Production Cost (\$000)	Unit Additions Annualized Capital Costs (\$000)	Unit Additions Capital Costs (\$000)	Total System Cost (\$000)	
								Variable Cost (\$000)	Fixed Cost (\$000)	Start and Shutdo wn (\$000)	Emission Cost (\$000)						
2022	12,827	-	12,818	8	0	821,439	-	105,553	54,737	41,832	119	968,943	1,023,680	-	-	1,023,680	1,023,679.60
2023	12,948	-	12,943	5	-	550,184	-	188,141	73,618	32,533	145	771,003	844,620	-	-	844,620	1,835,814.66
2024	13,057	-	13,054	3	-	440,113	-	231,689	75,420	27,603	118	699,523	774,943	-	-	774,943	2,552,292.67
2025	13,160	287	13,427	20	-	486,205	-	305,125	79,794	18,942	113	810,385	890,179	32,674	408,274	922,853	3,372,705.92
2026	13,250	269	13,511	9	-	480,792	20,704	259,121	82,363	29,342	114	790,072	872,435	32,674	-	905,109	4,146,397.06
2027	13,327	172	13,499	1	-	520,115	27,857	252,170	177,169	35,993	132	836,268	1,013,438	32,674	-	1,046,112	5,006,224.62
2028	13,399	193	13,592	0	-	538,514	28,452	264,125	86,532	40,000	138	871,230	957,762	32,674	-	990,436	5,788,980.68
2029	13,470	211	13,671	10	-	595,244	28,961	287,547	89,103	43,202	124	955,078	1,044,181	32,674	-	1,076,855	6,607,301.71
2030	13,534	397	13,928	3	-	456,499	135,475	262,752	83,120	61,736	94	916,556	999,676	32,674	-	1,032,351	7,361,630.19
2031	13,595	500	14,094	1	-	468,667	138,684	281,149	86,381	62,028	91	950,619	1,037,001	41,427	109,374	1,078,428	8,119,319.57
2032	13,654	510	14,164	0	-	500,114	142,019	265,104	83,910	64,096	92	971,425	1,055,335	41,427	-	1,096,762	8,860,252.67
2033	13,712	1,013	14,722	3	-	436,846	207,114	278,489	133,061	60,027	78	982,554	1,115,615	87,075	570,377	1,202,690	9,641,496.97
2034	13,764	1,043	14,806	1	-	419,389	251,302	289,513	101,097	62,110	74	1,022,388	1,123,485	87,075	-	1,210,559	10,397,608.75
2035	13,814	1,067	14,880	1	-	417,962	321,078	281,943	98,825	67,313	73	1,088,369	1,187,194	87,075	-	1,274,269	11,162,901.57
2036	13,862	1,064	14,924	2	-	455,844	328,929	273,166	153,009	70,129	77	1,128,144	1,281,153	87,075	-	1,368,228	11,953,019.18
2037	13,905	1,265	15,170	0	-	449,362	345,067	279,017	109,583	69,570	72	1,143,088	1,252,671	106,840	246,969	1,359,510	12,707,906.90
2038	13,949	2,456	16,404	1	-	365,140	361,782	258,129	166,256	51,631	42	1,036,726	1,202,983	237,984	1,638,694	1,440,967	13,477,250.86
2039	13,987	3,550	17,537	-	-	299,270	387,496	245,060	190,136	42,837	26	974,689	1,164,825	385,709	1,845,866	1,550,534	14,273,253.37
2040	14,024	5,139	19,163	-	-	174,446	500,302	243,614	260,556	28,313	10	946,684	1,207,240	586,002	2,502,728	1,793,243	15,158,448.38
2041	14,057	5,593	19,649	-	-	164,011	521,186	223,396	303,160	27,164	10	935,767	1,238,927	797,238	2,639,456	2,036,165	16,124,898.72
2042	14,085	6,590	20,674	-	-	182,569	648,543	210,407	321,308	29,994	14	1,071,527	1,392,836	1,012,792	2,693,419	2,405,628	17,222,795.80
2043	14,111	7,302	21,414	-	-	143,743	788,135	141,263	471,252	28,885	10	1,102,035	1,573,288	1,232,630	2,746,941	2,805,917	18,454,126.66
2044	14,137	8,179	22,316	-	-	128,250	957,990	35,110	455,153	25,469	9	1,146,827	1,601,980	1,456,921	2,802,594	3,058,902	19,744,846.77
2045	14,160	8,976	23,136	-	-	114,269	1,137,727	3,644	508,668	22,444	8	1,278,093	1,786,760	1,669,067	3,059,102	3,455,828	21,146,967.00
2046	14,183	10,078	24,261	-	-	135,186	1,300,168	11,712	565,637	15,363	11	1,462,440	2,028,077	1,902,019	2,910,802	3,930,096	22,680,181.67
2047	14,201	10,401	24,602	-	-	126,874	1,489,435	4,476	637,702	13,271	10	1,634,067	2,271,769	2,139,619	2,968,889	4,411,388	24,334,967.49
2048	14,212	10,567	24,760	19	-	115,306	1,717,323	3,929	677,760	13,970	9	1,850,537	2,528,297	2,199,186	744,315	4,727,483	26,040,119.77
2049	14,225	11,143	25,364	4	-	104,208	1,942,982	13,120	742,333	10,966	7	2,071,284	2,813,617	2,340,303	1,763,299	5,153,920	27,827,584.73
2050	14,242	11,191	24,692	742	-	9,202	1,913,345	2,248	814,447	-	-	1,924,795	2,739,242	2,602,422	3,344,627	5,341,664	29,608,909.29
2051	14,237	11,241	24,744	707	-	10,132	1,960,891	2,475	838,305	-	-	1,973,498	2,811,803	2,546,494	162,261	5,358,297	31,327,054.84
						Fuel Cost (\$1MM)	Solar Cost (\$1MM)	Variable Cost (\$1MM)	Fixed Cost (\$1MM)	Start and Shutdo wn (\$1MM)	Emission Cost (\$1MM)	Variable Production Costs (\$1MM)	Total Production Cost (\$1MM)	Unit Additions Capital Costs (\$1MM)		Total System Cost (\$1MM)	
						\$ 7,160.01	\$ 7,263.49	\$ 3,718.27	\$ 3,867.52	\$ 706.37	\$ 1.37	\$ 18,849.51	\$ 22,717.03	\$ 8,610.02		\$ 31,327.05	

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## Appendix B – Environmental Assessment

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# B Environmental Assessment

## B.1 Introduction

JEA's generation fleet is subject to numerous environmental regulatory programs and requirements. While most of the environmental regulatory programs and requirements applicable to JEA generating units have already been addressed, a few recently proposed and finalized programs in various stages of administrative transition and judicial review could have impacts on future operations. The following sections provide a summary of the applicability of air, water and waste programs and permitting requirements, as well as the associated potential compliance risks associated with continued operation of the existing fossil fuel-fired generating units.

## B.2 Assessment of Carbon, Air, Water, and Other Environmental Considerations

The following subsections outline the current and impending regulatory programs and requirements related to carbon, air, water, and other environmental concerns.

### B.2.1 Carbon Assessment

#### B.2.1.1 Clean Power Plan/Affordable Clean Energy Rule

On August 3, 2015 the United States Environmental Protection Agency (EPA) released its final Clean Power Plan (CPP) rulemaking to establish standards for performance for greenhouse gas (GHG) emissions from existing electric generating units (EGUs) (i.e., EGUs for which construction was commenced prior to January 8, 2014) under Section 111(d) of the Clean Air Act (CAA). In the final CPP rule, the EPA set emission performance rates, phased in over the period from 2022 through 2030, for two subcategories

of affected fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

The final CPP rule required each state to submit a final plan that outlines how the state will meet its goal by September 2016. However, on February 9, 2016 the U.S. Supreme Court issued an order to stay (suspend) the CPP until legal challenges to the rule could be resolved in federal court(s). In September of 2016, the District of Columbia (D.C.) Circuit Court of Appeals heard oral arguments on the legal challenges to the CPP. Following the hearings, however, the D.C. Circuit subsequently granted a petition from the new Trump Administration to hold the prior CPP litigation in abeyance pending the outcome of EPA's announced intentions to reconsider the CPP rule.

EPA published a proposal to repeal the CPP in its entirety on October 16, 2017. Then on August 21, 2018 EPA released an alternative proposal to revise the CPP. Entitled the Affordable Clean Energy (ACE) rule, this latest proposal seeks to reduce carbon dioxide (CO<sub>2</sub>) emissions solely through heat rate improvements at existing fossil fuel-fired utility boiler EGUs. Units 1, 2, and 3 at Northside Generating Station and Scherer Unit 4, which is no longer in operation, are the only units in JEA's portfolio that would have been subject to regulation under ACE as the rule was proposed.

As with the CPP, the ACE rule proposed to regulate existing power plants under Section 111(d) of the CAA by establishing performance standards based on the Best System of Emission Reduction (BSER). In contrast to the CPP, however, and in accordance with EPA's most recent interpretation of its authority under the CAA, the ACE rule focused on only those measures that could be implemented "within the fence line" of existing EGU facilities. Consistent with that approach, EPA proposed that BSER is to be limited to heat rate improvement measures at existing coal-fired

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EGUs. Instead of setting numeric limits, EPA’s ACE rule provided emission guidelines that states were to use in developing their individual State Implementation Plans (SIP) to regulate CO<sub>2</sub> emissions from EGUs within their jurisdictions. These guidelines included a list of “candidate technologies” and measures to achieve heat rate improvements.

However, on January 19<sup>th</sup>, 2021 the D.C. Circuit Court vacated the ACE rule, with instructions for the EPA to “consider the question afresh.” Key takeaways of the vacated ACE rule are as follows:

- The D.C. Circuit rejected the Trump Administration’s contention that—no matter the circumstances—Section 111 of the Clean Air Act unambiguously limits the “best system of emission reduction” to emissions-reducing measures operating at the physical source.
- The court’s decision clears the way for the Biden EPA to issue a replacement rule regulating CO<sub>2</sub> emissions from existing power plants, potentially again considering generation shifting and other measures to more aggressively target power sector emissions.
- President Biden’s choice for EPA Administrator, Michael Regan, testified that he views the opportunity as a “clean slate” for the Agency to chart next steps under Section 111(d).

On June 30, 2022, the U.S. Supreme Court issued their ruling regarding the CPP/ACE rule and in essence, limited EPA’s authority to set standards on climate-changing greenhouse gases (GHG) emissions from existing power plants. The ruling surmised that for issues of major national significance; i.e., how people will get their energy, a regulatory agency must have clear statutory authorization from Congress to take certain actions and not rely on its general agency authority. Should any replacement rule

still be issued by the EPA; it is unknown what type of requirements would be proposed at this time. With the current make-up of the Congress, it is anticipated any new legislature pertaining to limiting GHG emissions from existing power plants is unlikely to be proposed.

### **B.2.1.2 Florida Statewide Renewable Energy Goal**

On April 21, 2022 the Commissioner of Agriculture and Consumer Services announced a new statewide renewable energy goal. This new goal seeks to increase the amounts of renewable energy used by the state to at least 40 percent by 2030 with an ultimate goal of 100 percent by 2050. However, under state law, the Public Service Commission (PSC) has the authority to force the utilities to meet these goals, and the PSC has been historically less aggressive in boosting standards for renewable energy. As such, it is unknown at the time this report was written how this might affect the portfolio requirements for JEA.

### **B.2.1.3 Clean Future Act**

On March 2, 2021 representative Frank Pallone introduced H.R. 1512 also known as the Clean Future Act (CFA or H.R. 1512). H.R. 1512 creates requirements and incentives to reduce GHG emissions. In general, the bill establishes an interim goal that would reduce GHG emissions to levels that are 50 percent below 2005 values by the year 2030. The bill also sets a national goal to cut GHG emissions to a net zero level by 2050. The bill states that each federal agency must develop plans on how these levels can be achieved.

The bill goes on to state that by 2023, all retail electricity suppliers must provide an increasing percentage of electricity that produces “zero-emission electricity”. The bill then states that by the year 2035, retail electricity suppliers must provide electricity that produces “zero-emissions” or show an alternative way to obtain compliance. The bill does indicate that retail

## Appendix B – Environmental Assessment

electricity suppliers may obtain credits under a trading program that allows them to buy, sell, and trade credits to show compliance.

The bill establishes multiple requirements, programs, and incentives that are to be used to reduce or eliminate GHG emissions. A bullet list of some of these “other” requirements, programs, and incentives are listed below:

- Increasing energy efficiency in buildings, homes, and appliances;
- Supporting clean transportation, including electric vehicles and related charging infrastructure;
- Issuing greenhouse gas standards for certain vehicles, engines, and aircraft;
- Promoting manufacturing and industrial decarbonization, including through buy-clean programs;
- Supporting environmental justice efforts; and
- Reducing methane, plastics, and super pollutants.

It is unclear whether the CFA bill will advance in the U.S. House of Representatives and become law. It is likely that the CFA will face challenges within the U.S. House of Representatives and possibly the U.S. court system going forward.

### B.2.1.4 45Q Tax Code

Congress added Section 45Q to the Internal Revenue Code in 2008 in an effort to incentivize additional investments in carbon capture and sequestration projects. In its original form, Section 45Q provided a tax credit for each metric ton of qualified carbon dioxide captured and either disposed of in secure geological storage or used for certain purposes, such as use in oil or natural gas extraction processes. However, the original code made available such credits only for the first 75 million tons of qualified carbon dioxide captured by all projects and each project was required to capture at

least 500,000 metric tons of qualified carbon dioxide in a single taxable year.

The Bipartisan Budget Act of 2018 established a number of important changes to Section 45Q that made these credits more attractive to investors. It expanded Section 45Q to include carbon oxide in addition to the previously allowed carbon dioxide. The amendment eliminated the 75 million ton program limitation on the overall credits available in the market and it lowered thresholds for the amount of carbon that would have to be captured in a given year.

The amendment also clarified the credits would be available for 12 years, beginning when the carbon capture equipment is placed in service, in addition to increasing the value of Section 45Q credits. For taxpayers who dispose of qualified carbon oxide (includes certain types of carbon dioxide and carbon oxide) in secure geological storage spaces, a tax credit worth \$22.66 per metric ton was available for 2017 and increasing linearly until reaching \$50 per metric ton in 2026. A tax credit worth \$12.83 per metric ton was available for 2017 and increasing linearly until reaching \$35 per metric ton in 2026 for taxpayers who capture and then use qualified carbon oxide for certain activities. After 2026, the amount of the credit is subject to an inflation-adjusted increase. Lastly, the amendment clarifies that the taxpayer who owns the carbon capture facility does not need to own the facility that emits the qualified carbon oxide that is being captured to be eligible for the tax credits under Section 45Q.

### B.2.1.5 Geologic Review for Carbon Sequestration

Compliance with the Safe Drinking Water Acts requires that all injection occurs below the underground source of U.S. drinking water (USDW), although EPA may grant exceptions. A USDW is an aquifer or part of an aquifer that is currently used as a drinking water source or contains fewer than 10,000 milligrams per

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liter (mg/L) total dissolved solids (40 CFR 146.3). Due to the presence of the Upper and Lower Floridan Aquifers at depths ranging from approximately 600 to 2000 feet below land surface (bls), potentially suitable geologic formations in the study area should be deeper than approximately 3,000 feet bls. If found to be suitable, the target reservoir formation will need to have a thick and extensive seal (i.e. geologic formation above the injection zone that has confining characteristics), have sufficient porosity, and be sufficiently permeable to permit injection at high flow rates without requiring excessively high pressure.

In Florida, there are numerous facilities that dispose municipal and industrial wastes using injection wells. These waste fluids are generally injected into permeable zones in the lower Floridan aquifer (LFA), in a zone commonly known as the Boulder Zone. The Boulder Zone is widely encountered in central and south Florida, making it suitable for an injection zone. In contrast, the Boulder Zone is not encountered in the northern portion of Florida. The permeable saline zones of the Cedar Keys formation and the Lawson Limestone are an alternative often studied in central Florida and could serve as an option in northern Florida. In Polk County for example, wastes are injected into the permeable zone of the Lower Cedar Keys Formation and Lawson Limestone, which are overlain by a thick sequence of impermeable anhydrites and dolomites positioned well below any USDW.

Although not explored in detail in this current assessment, the Lawson Limestone appears to be an attractive option for sequestering CO<sub>2</sub> below depths of 3,000 feet bls. Sequestering CO<sub>2</sub> below this depth with overlying confining geologic formations (i.e., the Cedar Keys) will decrease the likelihood of upward/lateral migration and protect the local USDW. Another advantage of using the Lawson Limestone as carbon storage reservoir is that the pressure-temperature (PT) conditions at that depth

would ensure that the CO<sub>2</sub> remains in a supercritical state, thereby occupying less pore space than a gas. Further, CO<sub>2</sub> density is high enough to allow efficient pore filling and to decrease the buoyancy difference compared with in-situ fluids.

The Southeast Regional Carbon Sequestration Partnership, or SECARB, performed a study between 2003 and 2005, sparked by a research program launched by the U.S. Department of Energy (DOE). The researchers took a macro-level, dimensional, geographic identification approach to identify areas and particular geologic formations with sequestration potential. Data sets were composed using publicly available data that revealed three primary types of geologic sinks capable of storage (saline formations, coal seams and oil and gas reservoirs).

In the southeastern area of the region that include South Carolina, Georgia, and Florida, SECARB identified minimal opportunities for storage as part of the recovery of coal bed methane (CBM), oil or gas. Based on available data, the potential geological setting suitable for CO<sub>2</sub> sequestration were determined to be sedimentary brine or saline formations and offshore.

### **B.2.1.5.1 Sedimentary Saline Geologic Formations**

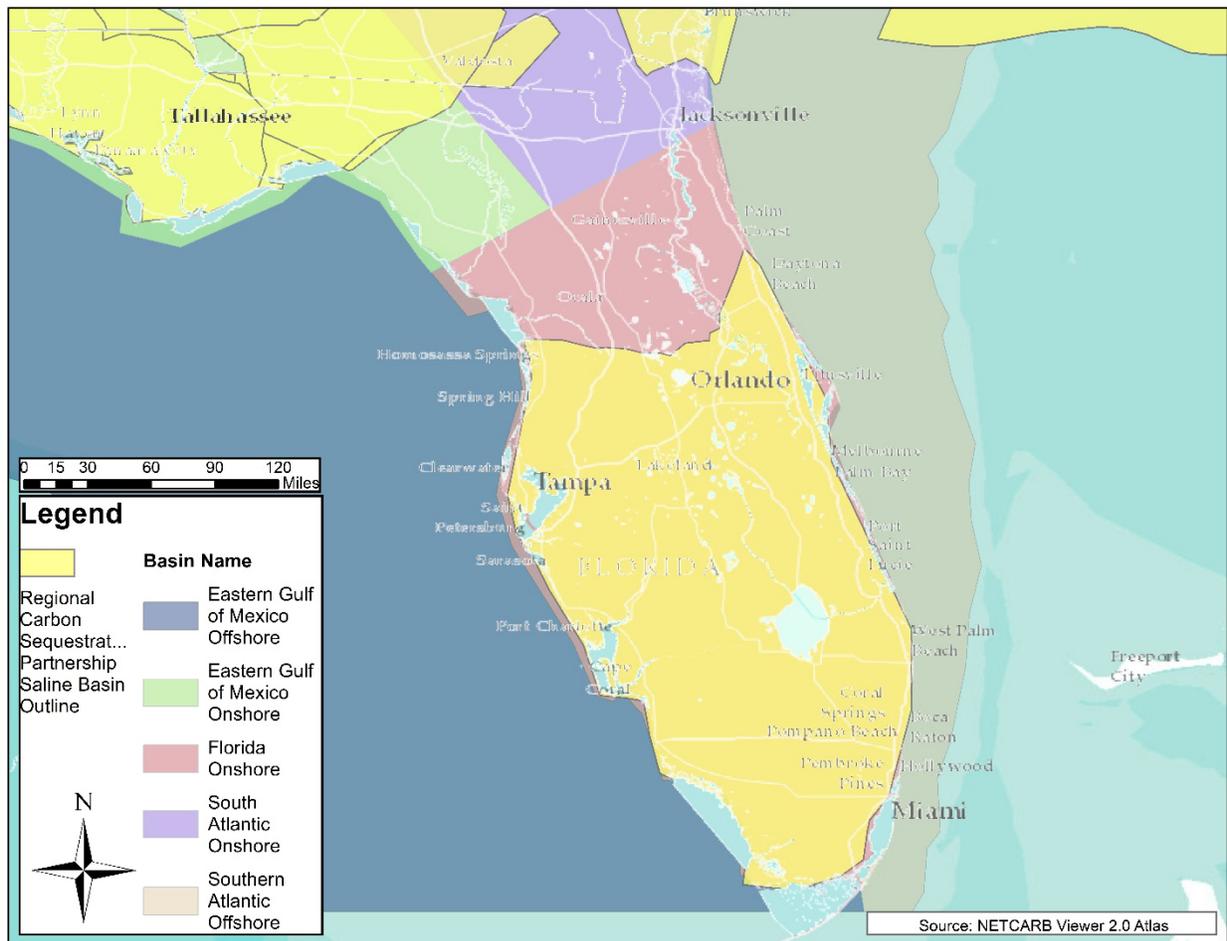
The sedimentary geologic basins and saline basins (studied) are shown in Figure B-1. Within the area of interest, sedimentary saline geologic formations such as the Cedar Keys and Lawson Limestone appear to contain an extensive lateral porous area with saline conditions that is capped by an anhydrite and dolomite impermeable sequence that is approximately 500 feet thick. Although the extent of the potential reservoir capacity is currently unknown, in previous reports it has been described that the southwestern portion of Florida used to be a great back-barrier reef area while the deposition and formation of the Cedar

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Keys and Lawson occurred, indicating that these units of carbonates and evaporates have the potential to be laterally extensive. In this case, the upper part of the Cedar Keys formation provides competent confinement due to its thick sequence of dolostone with interbedded anhydrite, while the lower portion near the base of the Cedar Keys formation and the

Lawson Limestone could serve as a potential injection zone based on the increased permeability in these zones. In addition, the EPA determined that a saline formation suitable to sequester CO<sub>2</sub> must have a minimum 10,000 part per million (ppm) of total dissolved solids, which in this case, the permeable zones of the Cedar Keys and Lawson Limestone have.

Figure B-1 - Sedimentary Basins and Saline Basins Suitable for CO<sub>2</sub> Sequestration



**B.2.1.5.2 Offshore**

In regions where limited onshore geologic storage exists, offshore geologic storage could serve as an alternative option. Currently, the U.S. is studying the potential of offshore geologic storage for a safe and long-term capture zone able to sequester CO<sub>2</sub> efficiently.

The process of sequestering CO<sub>2</sub> in an offshore geologic setting involves obtaining the CO<sub>2</sub> from a stationary emission source, using a sub-sea pipeline or an ocean tanker to transport the CO<sub>2</sub> from the source to an injection system, and injecting it into a deep geologic formation below the sea bottom capable of retaining and

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isolating the CO<sub>2</sub> from the ocean water. However, when considering this option, there are numerous aspects like storage potential and the lack of experience in offshore CO<sub>2</sub> storage and monitoring that still need to be evaluated to close the knowledge gap for CO<sub>2</sub> to be injected safely in offshore geologic formations.

Assessments of potential CO<sub>2</sub> offshore geologic sequestration are ongoing by various research groups. The Bureau of Ocean Energy Management (BOEM) of the U.S. Department of Interior (DOI) acts as the authority under the Energy Policy Act of 2005 and is in the process of putting together rules to regulate carbon sequestration projects in the outer continental shelf, but as of now, no guidance or regulations exist for offshore applications (Nemeth 2006).

Listed below are some advantages of offshore CO<sub>2</sub> storage:

- Site located safely away from heavily populated onshore areas
- If on Federal lands, it minimizes issues when obtaining surface and mineral owner rights (single entity pore space owner)
- Typically injected into saline formations which reduces contamination potential to any USDW
- Similar chemistry and salinity from formation fluid and sea water (30,000 to 40,000 ppm total dissolved solids)
- Could utilize existing design and infrastructure from oil and gas facilities and right-of-ways
- Serves as potential storage of CO<sub>2</sub> to many large stationary emission sources along coastlines that have limited options for onshore CO<sub>2</sub> storage

While enormous opportunity exists for sequestering onshore CO<sub>2</sub> sources in offshore storage reservoirs, several key challenges remain to be solved before offshore storage can provide a viable alternative for onshore energy

providers. These limitations include a high cost of implementation relative to onshore storage operations, unproven compatibility with existing oil and gas (O&G) infrastructure, lack of accurate / current cost data for O&G equipment, and the source-to-sink matching challenges associated with the disparate locations of carbon sources and offshore storage locations.

### B.2.1.5.3 Geologic Confinement

Because the density of CO<sub>2</sub> is less than that of water, the CO<sub>2</sub> will tend to float. Therefore, an adequate seal, or “trap”, in the geologic unit overlying the target reservoir is a key component for the success of the carbon sequestration project. The seal must contain the buoyant column of CO<sub>2</sub> as well as be laterally continuous across the trap. Trapping mechanisms are typically stratigraphic or structural. Stratigraphic traps are those that rely on a change in lithology, such as a thick shale bed overlying more permeable units. Structural traps include anticlines, faults, and salt domes.

In the case of Duval County, the anhydrite and dolomitic beds of the Cedar Keys formation may serve as the geologic confinement necessary to protect the overlying potable water sources of the Upper and Lower Floridan Aquifers. To determine whether the Cedar Keys formation can function as an adequate stratigraphic trap for safe and effective sequestration of CO<sub>2</sub> in the underlying target reservoir, extensive upfront geological and geophysical studies will be required during the initial phases of any potential future assessment for suitability. These studies would need to assess the thickness, lateral extent, permeability, and other hydrogeologic and hydrogeochemical properties of the target storage reservoir and confining units.

### B.2.1.5.4 Conclusion

Based on a high-level geologic review of the potential for carbon sequestration in the Jacksonville area, the Mesozoic carbonate

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sediments of the Lawson Limestone (~3,000 ft bls) appear to have marginal to good prospect for carbon sequestration. Factors that will influence the acceptability of the Lawson Limestone for injection of CO<sub>2</sub> include the injectability and hydrogeochemical compatibility of the Lawson Limestone as well as the permeability and lateral continuity of the anhydrite and dolomitic beds of the Cedar Keys formation, which would need to serve as the geologic trapping mechanism to prevent upward/lateral migration of sequestered carbon.

While unproven as of yet, carbon sequestration in offshore basins utilizing existing oil and gas infrastructure may be an alternative option for Jacksonville area carbon sources in the future. However, several economic, regulatory, and logistical challenges must be addressed before the opportunity offered by offshore carbon sink reservoirs can be realized.

### B.2.2 Air Assessment

The following subsection outlines the current and impending regulatory programs and requirements related to air pollutant emissions from the JEA generation units.

#### B.2.2.1 New Source Review & Title V Air Operation Permits

Federal and State regulations require that an air construction permit be obtained to authorize construction of new emissions units or modifications to existing emissions units. The construction permitting process entails New Source Review (NSR), which begins with an analysis to determine the applicability of major source permitting requirements under the provisions of Prevention of Significant Deterioration (PSD), for those sources located in areas that are in attainment of the National Ambient Air Quality Standards (NAAQS) or unclassifiable, or Non-Attainment NSR (NA NSR) for those sources located in areas not in attainment of the NAAQS for one or more

pollutants. Duval County, Florida, where all of JEA's existing generating assets are situated, is currently designated as attainment or unclassifiable for all criteria pollutants. Compliance with the various NAAQS is determined on an annual basis, and as such, the attainment status of a given county is certainly subject to change in the future.

Should JEA undertake any installations/modifications in the future that trigger PSD and/or NA NSR (i.e., major source permitting), a construction permit will first need to be obtained. EPA has recently proposed changes to how NSR applicability is determined for major modifications (see project accounting memo).

Air permitting in Florida is under the jurisdiction of the Florida Department of Environmental Protection (FDEP). The EPA has given the FDEP authority to implement and enforce the federal CAA provisions and state air regulations under its approved SIP.

Each of the currently operating JEA generation assets is authorized by a Title V Air Operation Permit. These permits establish terms and conditions which the permitted facility must operate under, including operational requirements/restrictions, monitoring and reporting requirements, and emission limits. JEA maintains compliance with the terms and conditions of their various Title V Air Operation Permits. Additionally, the current terms and conditions do not present any significant risks of non-compliance or necessity to incur additional costs to maintain compliance in the future.

Concurrent with Northside Generating Station (NGS) Units 1 and 2 being converted to circulating fluidized bed (CFB) boilers, JEA entered into a Community Commitment to reduce overall sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), and particulate matter (PM) emissions from Units 1, 2, and 3 by 10 percent relative to previous annual emissions. These limits, in tons per year (tpy), which are now

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included in the NGS Title V Air Operation Permit are listed in Table B-1.

Based on the current operation of NGS Units 1, 2, and 3, the SO<sub>2</sub> and PM emissions are well below their limits. The annual NO<sub>x</sub> limit requires more careful management to ensure compliance. Based on facility NO<sub>x</sub> CEMS data from 2016-2020, annual NO<sub>x</sub> emissions have been within the prescribed limit. The emissions data and the annual operating hours of each unit is included in Table B-2.

Assuming future operation remains consistent with recent past operation, these emission limits should have no impact on operations at NGS. However, should market conditions dictate increased dispatch of the units in the future, operations (including the use of the existing selective non-catalytic reduction systems on NGS Units 1 and 2), will need to be managed carefully in order to maintain compliance with the annual NO<sub>x</sub> emission limit.

**Table B-1 - Northside Generating Station Community Commitment Emission Limits**

Pollutant	Cumulative Annual Limit – Units 1, 2, and 3 (tpy)
NO <sub>x</sub>	3,600
SO <sub>2</sub>	12,284
PM	881

**Table B-2 - Annual Cumulative Facility Emissions Northside Generating Station**

Year	PM <sup>[1]</sup> , tpy	SO <sub>2</sub> <sup>[2]</sup> , tpy	NO <sub>x</sub> <sup>[2]</sup> , tpy	Unit ID	Annual Hours of Operation <sup>[2]</sup>	Percent of Full Year Operation
2016	355	3,041	2,555	1A	6,312	72
				2A	7,780	89
				3	5,857	67
2017	326	1,485	1,923	1A	4,762	54
				2A	3,239	37
				3	5,025	57
2018	59	2,473	2,714	1A	7,825	89
				2A	4,308	49
				3	7,126	81
2019	45	1,917	2,864	1A	8,007	91
				2A	1,790	20
				3	6,591	75
2020	54	2,318	3,212	1A	7,420	85
				2A	4,760	54
				3	7,907	90

**NOTES [ ]:**

1. Data obtained from the facility's annual air emissions reports. For PM, these values represent the entire facility, not just Units 1, 2, and 3.
2. Data obtained from the U.S. EPA's Clean Air Markets database.

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### B.2.2.2 National Ambient Air Quality Standards

The EPA has set NAAQS for six principal pollutants, which are called “criteria” air pollutants. Geographical areas (in this case counties) in Florida are designated for each pollutant as attainment, non-attainment, or unclassifiable based on actual air quality measurements and/or modeling. As noted above, currently, Duval County Florida is designated as attainment or unclassifiable for all the criteria pollutants.

The CAA requires that EPA periodically review the various NAAQS and promulgate revised standards if scientific evidence indicates that a revision is necessary. In 2010, EPA established new 1-hour standards for SO<sub>2</sub> and NO<sub>x</sub> which has presented compliance challenges as a result of the short (one hour) averaging period. Of specific concern, the 1-hour SO<sub>2</sub> NAAQS Data Requirements Rule (DRR) required states to either monitor ambient air or conduct air dispersion modeling to demonstrate compliance with 1-hour SO<sub>2</sub> NAAQS. Again, Duval County is designated as attainment/unclassifiable for the 1-hour SO<sub>2</sub> and NO<sub>x</sub> NAAQS.

In order to proactively ensure compliance with the 1-hr SO<sub>2</sub> NAAQS violations, JEA has implemented operating restrictions on NGS Unit 3 that apply to oil-fired operations. Future revisions to these standards to make them more stringent could potentially change the attainment designation of Duval and/or surrounding counties, which could further impact the operation of the JEA fleet should the Florida Department of Environmental Protection (FDEP) take steps to mitigate short term NO<sub>x</sub> and/or SO<sub>2</sub> emissions from fossil fuel-fired electric generating facilities.

EPA is required to review the standards every five years and, if appropriate, revise existing air quality criteria to reflect advances in scientific

knowledge on the effects of the pollutant on public health and welfare. On April 6, 2018, EPA issued their final decision to retain the current NO<sub>x</sub> national ambient air quality standard (NAAQS). On February 25, 2019, EPA issued their final decision to retain the existing primary 1-hour SO<sub>2</sub> NAAQS.

In 2015, EPA finalized an 8-hour standard of 70 parts per billion (ppb) for ozone. On December 23, 2020, EPA completed their review and decided to retain the existing ozone NAAQS. In 2012, EPA finalized the 24-hour standard of 35 µg/m<sup>3</sup> for fine particulate matter, 24-hour standard of 150 µg/m<sup>3</sup> for particulate matter, the primary annual standard of 12.0 µg/m<sup>3</sup> for fine particulate matter, and the secondary annual standard of 15.0 µg/m<sup>3</sup> for fine particulate matter. On December 7, 2020, EPA announced it would retain the existing primary and secondary NAAQS for particulate matter. However, the new Biden Administration issued an executive order on January 20, 2021, in which it called for the review of several environmental regulations that were recently finalized. This includes the review of the ozone NAAQS, as well as the particulate NAAQS. EPA, under the Trump Administration, altered the review process, including but not limited to, alterations to the make-up of the Clean Air Scientific Advisory Committee, which is an independent committee of experts that assists EPA in reviewing the NAAQS. On June 10, 2021, EPA announced that it will reconsider the previous decision to retain the particulate matter NAAQS, as EPA believes there is available scientific evidence and technical information which indicates the current standards may not be adequate to protect public health and welfare.

On January 6, 2023, EPA announced it proposed rule to revise the primary annual PM<sub>2.5</sub> standard from its current level of 12.0 µg/m<sup>3</sup> to within the range of 9.0 to 10.0 µg/m<sup>3</sup>. While this proposed rule did not revise the 24-hour standard, EPA will accept comments on

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retaining the current existing 24-hour standard. As this is a proposed rule, any requirements in the final rule cannot be assessed at this time. Nonetheless, should the proposed rule be finalized as-is, the revised annual standard should not pose any concern for facilities located in Duval County, Florida.

A review of the current design values for ozone and fine particulate matter was undertaken. Based on the 2018-2020 data for Florida's Air Quality System, the design values for Duval County are 60.3 ppb and 19.6  $\mu\text{g}/\text{m}^3$  for ozone and fine particulate matter (24-hour), respectively. Including current 2021 data would alter the designs to 60.0 ppb and 20.1  $\mu\text{g}/\text{m}^3$  for ozone and fine particulate matter (24-hour), respectively. Continued awareness of any potential changes to the NAAQS will be necessary to determine if any changes would have any effect on the existing JEA assets or any permitting activities for any future potential new facilities.

### B.2.2.3 Acid Rain Program

The Acid Rain Program (ARP) is aimed at achieving major emission reductions of  $\text{SO}_2$  and  $\text{NO}_x$ , the primary precursors of acid rain.  $\text{NO}_x$  reductions are achieved by imposing emission limits on various types of coal-fired boilers regulated under the ARP.  $\text{SO}_2$  reductions, on the other hand, are achieved via a cap-and-trade program. Regulated emission units (i.e., fossil fuel-fired combustion devices that serve a generator capable of producing 25 megawatts (MW) of electricity for sale to the grid) are required to surrender allowances for each ton of  $\text{SO}_2$  emitted annually.

JEA will continue to be required to surrender ARP allowances to cover the units' ARP compliance obligation into the future. Regulated units that were constructed prior to 2001 are allocated allowances annually. Sources constructed after 2001 are not provided an allocation of allowances, and must purchase them from government accounts, auctions

and/or the open market. Compliance obligations over and above annual allocations can either be covered by banked allowances in owner-held accounts or obtained from the open market. JEA's current compliance strategy is to rely on banked allowances to cover the fleet's annual compliance obligation. ARP allowances are currently trading at less than \$0.50 per ton. Assuming that allowance prices don't increase dramatically, in the event that JEA is required to obtain at least a portion of its ARP compliance obligation in the future, it should not represent a significant operational cost.

### B.2.2.4 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) is EPA's cap and trade program aimed at curbing cross-state transport of  $\text{NO}_x$  and  $\text{SO}_2$  emissions in the eastern U.S. Ultimately, the purpose of the rule is to reduce the number of PM less than 2.5 microns ( $\text{PM}_{2.5}$ ) and ozone nonattainment areas caused by cross-state air pollution from the power sector. Affected units under CSAPR are required to surrender allowances for both annual  $\text{NO}_x$  and  $\text{SO}_2$  emissions and/or ozone season (May through September)  $\text{NO}_x$  emissions. For each affected unit, a given state allocates allowances for each regulated pollutant and compliance period. Any surplus allowances can be banked and held for future compliance and/or sold on the open market. Should a facility's emissions be in excess of its annual allocation, the deficit is required to be covered by banked allowances and/or allowances purchased on the open market.

As originally designed, CSAPR was intended to reduce  $\text{NO}_x$  emissions in order to help achieve attainment of the 1997 ozone standard. EPA issued an update to CSAPR in 2016 to incorporate the more stringent 2008 ozone standard. This update removed Florida from the requirement to participate in the ozone season  $\text{NO}_x$  emissions program. As such, facilities in Florida are no longer required to participate in CSAPR.

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As of this writing, seasonal CSAPR NO<sub>x</sub> allowances are trading for approximately \$2,425 per ton while annual NO<sub>x</sub> allowances are trading for approximately \$8.50 per ton. SO<sub>2</sub> allowances are trading for approximately \$2.31 per ton.

### B.2.2.5 Visibility and Regional Haze Rule

On June 2, 1999, the U.S. EPA issued regulations to improve visibility, or visual air quality, in 156 national parks and wilderness areas (i.e., Class I areas) across the country. The rule calls for state and federal agencies to work together to achieve a goal to return Class I areas to pristine conditions by 2064 and requires that states assess “reasonable progress” towards the goal every ten years. The first state plans were due in December 2007 and the next review due in 2018 has been extended to 2021. To the extent that states are not meeting the glide path towards compliance, revised plans to accelerate compliance in order to get back on track with compliance goals are required.

The initial emission reduction initiative to achieve compliance with the Regional Haze Program is known as Best Available Retrofit Technology (BART). BART represents the most effective control for visibility impairing pollutants that is also environmentally friendly, technologically feasible, and cost effective. BART can be applied to 26 different industrial sources, including coal-fired power plants, built between 1962 and 1977. In 2005, the EPA provided an amendment to the Regional Haze Program that provided states with guidelines for developing SIPs to determine which sources of visibility impairing pollutants, including NO<sub>x</sub>, SO<sub>2</sub>, and PM, will need to install BART. A BART determination in 2010 determined that no further controls would be needed for Northside Generating Station Unit 3.

FDEP has provided a notice in regard to the EPA guidance on the second implementation period (2019-2028) and requested comments be received by July 9, 2021. A public hearing was

also conducted on July 15, 2021. Incidentally, JEA submitted an application requesting the establishment of an SO<sub>2</sub> emission limit for Boiler No. 3 and a conditional fuel oil sulfur content limit for the purpose of complying with Regional Haze Program. The new condition in the permit will impose an SO<sub>2</sub> emission limit of 3,500 pounds per hour on a 24-hour block average basis as determined by CEMS, which will become effective January 1, 2022. The specific condition for the fuel sulfur content will prohibit JEA from purchasing fuel oil with a sulfur content of greater than 1.0 percent by weight. Based on existing CEMS data for Unit No. 3, the maximum 24-hour block average was 2,583; 509; and 863 pounds per hour for 2018, 2019, and 2020, respectively.

### B.2.2.6 National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) are established under Section 112 of the CAA. The list of regulated hazardous air pollutants (HAPs) was set forth in the Clean Air Act Amendments of 1990. The EPA identified a list of source categories (e.g., electric utility boilers, industrial boilers, combustion turbines, reciprocating internal combustion engines) that included major sources of HAPs (i.e., those sources emitting 10 tpy or more of any one HAP or 25 tpy of any combination of HAPs) and area sources of HAPs (i.e., those sources that are not major sources). Once the various source categories were identified, EPA issued Maximum Achievable Control Technology (MACT) standards for each listed source category according to a prescribed schedule. MACT standards are required to be reevaluated every eight years to determine if additional controls are necessary to reduce health and environmental risks below acceptable levels.

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### **B.2.2.6.1 40 CFR 63 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units**

The most significant MACT standard for coal-fired power plants is known as the Mercury and Air Toxics Standard (MATS). The MATS rule, which was finalized by EPA in December of 2011, established a MACT standard in the form of numerical limits for emissions of mercury, no-mercury metallic HAPs, and acid gas HAPs from coal and oil-fired power plants with a capacity greater than 25 MW. Additionally, MATS established work practice standards for emissions of organic HAPs such as dioxins and furans. Under the MATS rule, affected units can comply with the non-mercury metallic HAPs standards by meeting a surrogate particulate matter emissions limit, a total metals limit, or individual emission limits for ten different metallic HAPs, such as lead, arsenic, and various others. Compliance with acid gas limits can be demonstrated by meeting either a hydrogen chloride limit or a SO<sub>2</sub> limit. Power plants that choose to demonstrate compliance with the acid gas limits by meeting a SO<sub>2</sub> limit must be equipped with add-on FGD systems.

Power plants regulated by MATS were required to demonstrate compliance with the rule by April 16, 2015 unless a one-year extension from the state permitting agency was granted for the “installation of controls”. An additional year long extension could be granted by the U.S. EPA for sources that could demonstrate that their operation was critical to grid reliability.

Units 1 and 2 at Northside Generating Station are regulated under the MATS rule and are currently in compliance. Unit 3 at Northside Generating Station is currently exempt from emission limits under MATS given that fuel oil combustion is limited by JEA to 10 percent of the average annual heat input on a rolling three year average basis and 15 percent of the annual heat input during any one of those calendar

years. Although EPA has recently announced its intention to revisit portions of the MATS rulemaking, it is not expected that any new requirements or additional impacts to the JEA fleet will result in the foreseeable future.

However, given that NESHAPs such as MATS are required to be reviewed periodically, there is at least some possibility that EPA could increase the stringency of the MATS limits, thus requiring a greater degree of control for compliance.

### **B.2.2.6.2 40 CFR 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines**

On March 5, 2004, the EPA published the final NESHAP for stationary combustion turbines. This rule, found at 40 CFR §63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of HAPs. Northside Generating Station is classified as a major source of HAPs.

The CT MACT has been stayed by the EPA for natural gas-fired combustion turbines, however, there are still requirements under the rule for lean premix and diffusion flame oil-fired combustion turbines. According to the Northside Generating Station Draft Title V Renewal (issued August 10, 2018) the four combustion turbines at Northside Generating Station are not subject to regulation under Subpart YYYY. In addition, since Brandy Branch, Kennedy, and Greenland are classified as area (rather than major) sources of HAPs, the combustion turbines at these facilities are not subject to the Subpart YYYY requirements.

On April 12, 2019, EPA released a proposed rule to amend the CT MACT, specifically to address period of startup, shutdown, and malfunction (SSM) and to remove the stay of the effectiveness of the standards for new lean premix and diffusion flame gas fired turbines. However, a final rule was issued in the Federal

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Register, which did not finalize the stay, but did require an operational standard in lieu of a numeric emission limit during periods of SSM; specifically, startup shall be limited to 1 hour for simple cycle operations and limited to 3 for combined cycle operation. EPA is reviewing a new petition (August 2019) to delist the stationary combustion turbines source category from regulation under CAA section 112. EPA is delaying taking final action on the stay until a determination regarding the source category delisting petition has been made. Should the source category not be delisted and the stay is removed, there is potential impact on the turbines at Northside unless they can demonstrate compliance with the formaldehyde limit of 91 ppbv.

### **B.2.2.6.3 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines**

On June 15, 2004, the EPA established national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. This rule has since been amended several times, with the most recent amendment on January 30, 2013. The stationary RICE MACT is applicable to the various emergency diesel generators and diesel fire pumps at the JEA facilities. Given that these engines are classified as emergency units under the rule, the requirements for each of these units are generally limited to recording keeping and reporting requirements and maintenance practices.

### **B.2.2.7 New Source Performance Standards**

The CAA of 1970 authorized the EPA to establish technology-based emissions standards that apply to specific categories of stationary emissions sources that the EPA has determined

“causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.” These standards, known as New Source Performance Standards (NSPS), apply to new, modified, and reconstructed stationary sources and regulate emissions of several pollutants including, but not limited to, the six criteria pollutants.

The CAA allows the EPA to identify specific facilities within a source category that should be regulated by NSPS and also allows the designation of subcategories. NSPS can be established for specific types of equipment located within a facility or for an entire facility belonging to a regulated source category. Generally, a particular NSPS will regulate facilities or equipment within a facility based on the type of unit, size of unit, material handled, and date of construction, modification, or reconstruction.

NSPS are designed to establish minimum control requirements for all facilities within a source category based on the emissions limitations and reductions that are achieved in practice at the time of the rulemaking. The CAA requires the EPA to review each NSPS every eight years in order to determine if the emission limits, controls, and other requirements need to be revised based on technological advancements and/or other changes affecting a particular industry.

### **B.2.2.7.1 40 CFR Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators**

EPA finalized NSPS Subpart D on December 19, 1995. The rule has been amended several times with the most recent amendment dated June 13, 2007. The rule regulates emissions of particulate matter, SO<sub>2</sub>, and NO<sub>x</sub> from fossil-fuel-fired steam generating units with a heat input of more than 250 MMBtu/hr that commenced construction or modification after August 17, 1971, except for those sources that are applicable to NSPS Subpart Da or Subpart

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KKKK. Compliance with these limits ensures compliance with NSPS Subpart D by default. This rule should have limited future impact on the JEA fleet unless EPA makes significant changes.

### **B.2.2.7.2 40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Generating Units**

EPA finalized NSPS Subpart Da on June 13, 2007. The rule regulates emissions of PM, SO<sub>2</sub>, and NO<sub>x</sub>, from electric utility steam generating units that were constructed, modified, or reconstructed after September 18, 1978 and are capable of combusting more than 250 MMBtu/hr of fossil fuel. Units 1 and 2 at Northside Generating Station are currently the only units in JEA's fleet that are regulated under Subpart Da and are operating in compliance with the limits of the rule. This rule should have limited future impact on the boilers unless EPA makes changes to the rule.

### **B.2.2.7.3 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines**

EPA finalized NSPS Subpart GG on September 10, 1979. The rule has been amended several times with the most recent amendment dated February 27, 2014. The rule regulates SO<sub>2</sub> and NO<sub>x</sub> emissions from stationary gas turbines with a heat input greater than 10 MMBtu/hr that commenced construction, modification, or reconstruction after October 3, 1977. Gas turbines that are subject to NSPS Subpart KKKK are not subject to Subpart GG. The combustion turbines at Northside generating station were constructed prior to 1977 and, as such, are not applicable to Subpart GG. Subpart GG is, however, applicable to Unit 7 at Kennedy and Unit 1 at Brandy Branch. Given that new and/or modified combustion turbines are now regulated by NSPS Subpart KKKK, this rule should have no significant future impacts on the JEA fleet.

### **B.2.2.7.4 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines**

The final rule for Subpart KKKK was published in the Federal Register on July 6, 2006 with an amendment to the rule finalized on March 20, 2009. Subpart KKKK is applicable to stationary combustion turbines with a peak load heat input greater than 10 MMBtu/hour that commenced construction, modification, or reconstruction after February 18, 2005. The rule contains emission limits for NO<sub>x</sub> and SO<sub>2</sub>. NSPS Subpart KKKK is applicable to the combustion turbines at Greenland Energy Center and the combined cycle units at Brandy Branch Generating Station. These units are currently in compliance with the applicable emission limits. Should any new combustion turbines be installed at new or existing facilities or should any changes be made to any of the combustion turbines currently subject to Subpart GG that constitute a modification under the definition in 40 CFR Part 60, then NSPS Subpart KKKK could have future impacts on the JEA fleet. Otherwise, the future impacts of this rule should be minimal unless significant changes are made.

### **B.2.2.7.5 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

On July 11, 2006, the U.S. EPA published Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Subpart IIII applies to the various emergency diesel-fired RICE generators and fire pumps operating at JEA facilities. This rule should have minimal impact on future operations barring the installation of any non-emergency compression ignition RICE generators.

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### **B.2.2.7.6 40 CFR 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units**

On October 23, 2015, the U.S. EPA published Standards of Performance for greenhouse gas emissions for electric generating units which commenced construction after January 18, 2014 or reconstruction/modification after June 18, 2014. The rule regulates carbon dioxide (CO<sub>2</sub>) emissions from new, modified, and reconstructed steam generating units, integrated gasification combined cycle (IGCC) units, and fossil fuel-fired stationary combustion turbines which have a base loading rating greater than 250 mmBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. For stationary combustion turbines, the rule stipulates separate emission standards based on the type of fuel combusted and the operation of the unit (i.e., base-loaded machines vs. peak-shaving machines). Black & Veatch notes that it can be difficult for SCCTs to meet these baseload CO<sub>2</sub> emission limits. However, if the SCCTs are operated as a “peaking” unit; i.e., limited number of hours of operation in the year, the SCCTs would be subject to a less onerous emission limit and may be able to achieve this limit. To meet the requirements of this rule, the hours of operation would need to be limited based on the efficiency of the turbine.

### **B.2.2.7.7 40 CFR 60 Subpart Y – Standards of Performance for Coal Preparation Plants**

The final rule for NSPS Subpart Y was published in the Federal Register on October 8, 2009. The rule regulates particulate emissions from coal handling facilities constructed after October 27, 1974 and before April 28, 2008. Subpart Y is applicable to the crusher house and fuel silo dust collectors at Northside Generating Station. This rule is expected to have a minimal impact on future operations.

### **B.2.2.7.8 40 CFR 60 Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The final rule for NSPS Subpart OOO was published in the Federal Register on April 28, 2009. The rule regulates particulate emissions from mineral processing plants and is currently applicable to the limestone handling system at Northside Generating Station. This system is currently complying with the requirements of Subpart OOO. This rule is expected to have minimal impacts on future operations.

## **B.2.3 Water Assessment**

### **B.2.3.1 Clean Water Act 316(b) Cooling Water Intake**

EPA published its final Phase II 316b rule regulating cooling water intakes at existing facilities in August 2014. The rule establishes national requirements applicable to the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the Best Technology Available (BTA) for minimizing adverse impacts of impingement and entrainment. Existing power generation facilities, as well as manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) from surface waters of the U.S. and use at least 25 percent of the water exclusively for cooling purposes are subject to the rule.

The final rule established seven alternatives for meeting the impingement requirements – including use of modified traveling screens, reducing through screen design or actual flow velocities, utilizing closed cycle cooling systems, operating existing offshore velocity cap, or meeting a 24 percent mortality standard on a rolling 12-month basis. Although compliance with entrainment requirements are to be made on a site specific, case-by-case basis, since Northside withdraws over 125 MGD it is required to conduct extensive characterization studies to establish the appropriate BTA. In

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order to establish the appropriate BTA, affected facilities are required to conduct and submit certain data, studies and plans for compliance (outlined in Table B-3) to the National Pollutant Discharge Elimination System (NPDES) permitting authority (here the FDEP) for review and approval as part of the next NPDES permit renewal application.

JEA's Northside Generating Station is the only facility that is subject to the final Phase II 316b rule, as a result of once-through cooling water being drawn from the St. Johns River in amounts greater than 2 MGD with >25 percent of this withdrawn water used for cooling purposes. Because its actual intake flow is greater than 125 MGD, the facility is subject to the additional entrainment study requirements of this rule.

**Table B-3 - Cooling Water Intake Structure Data and Studies**

Regulation	Description
40 CFR 122.21 r(2)	Source Water Physical Data
40 CFR 122.21 r(3)	Cooling Water Intake Structure Data
40 CFR 122.21 r(4)	Source Water Baseline Biological Characterization Data
40 CFR 122.21 r(5)	Cooling Water System Data
40 CFR 122.21 r(6)	Chosen Method(s) of Compliance with Impingement Mortality Standard
40 CFR 122.21 r(7)	Entrainment Performance Studies
40 CFR 122.21 r(8)	Operational Status of each generating unit that uses cooling water
40 CFR 122.21 r(9)	Entrainment Characterization Study-
40 CFR 122.21 r(10)	Comprehensive Technical Feasibility and Cost Evaluation Study
40 CFR 122.21 r(11)	Benefits Valuation Study
40 CFR 122.21 r(12)	Non-water Quality Environmental and Other Impacts Study
40 CFR 122.21 r(13)	Peer Review

The previous NPDES permit, which was issued as a combined permit for both the Northside Generating Station and the St. Johns River Power Park, expired on May 8, 2017. JEA submitted an application for renewal of the NPDES in November 2016. Since that submittal the St Johns River Power Park has been demolished and no longer needs to be included in the permit. Currently the permit is still under review by the FDEP. JEA has recently completed the following:

- Entrainment sampling was conducted at Northside from March 2018 to March

2020 to complete the required 2 years of baseline characterization.

- Baseline Entrainment Characterization (r9) report was drafted and submitted to JEA for review
- Baseline data was used to estimate reductions in entrainment mortality associated with mechanical draft cooling towers (MDCT) and fine-mesh screens (FMS) (2020)
- Preliminary benefits valuations (Veritas) and subsequent fine-tuning of the biological models were completed in 2021

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- Biological models have been revised and draft benefits valuations for MDCT and FMS are currently under final review (Veritas)

As noted above the NPDES permit has yet to be issued by the FDEP. The schedule for submission of 316b materials is still anticipated to be at the end of this next permit cycle (4.5 years following issuance).

As the permit has yet to be issued, JEA has adequate time to complete the 316(b) submittals. The next steps in the process are below:

- Finalize the engineering and cost evaluations for the three technologies (MDCT, FMS and variable frequency drives (VFD))
- Estimate mortality reductions associated with VFD and include in benefit valuations
- Develop social cost estimates for each technology (Veritas)
- Develop r(10) – Comprehensive Technical Feasibility and Cost Evaluation Study
- Develop r(11) – Benefits Valuation Study

In accordance with a previous agreement between the FDEP and the FCG Environmental Committee, a condition will be included in the renewal permit setting forth a timeline for discussion and submittal of the relevant §122.21r data requirements. JEA has several options to consider in selecting a preferred method of compliance, including a combination of upgrading of existing screen systems, shutting down units, and cooling tower installations.

The feasibility of these options will be assessed and costs determined concurrent with completion of the outstanding §122.21r studies. Once the studies and preferred solutions are submitted to the FDEP, the agency will

determine the appropriate BTA for the Northside cooling water intake, and will set the schedule for implementing the upgrades and final compliance deadlines.

### B.2.3.2 Effluent Limit Guidelines

The final steam electric effluent limit guidelines (ELG) rule establishing more stringent technology-based wastewater discharge standards for steam electric generation plants was published on November 3, 2015. Changes include new standards for wet flue gas desulfurization (WFGD), flue gas mercury control, gasification, and landfill leachate water streams that were previously included under low volume wastes. Additionally, the rules establish a zero discharge standard for fly ash and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

These ELG standards are to be used by the NPDES permitting authority (FDEP in Florida) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities. All new ELG limits were not to apply until a date determined by the permitting authority to be “no sooner than” November 1, 2018, but no later than December 31, 2023. Subsequently EPA released a final rule on September 12, 2017 extending the “no sooner than” compliance deadline for bottom ash and WFGD effluents to November 1, 2020. FDEP has not issued a renewal of the NPDES permit yet, so currently there are no new ELG requirements enacted at this time. To address the only ELG requirement that applies to NGS (Combustion residual leachate – CRL), FDEP and JEA have agreed to implement a new internal monitoring location (sump 11) to sample the combined leachate and contact stormwater discharged from the BSA ponds. The CRL ELG limits would apply at that monitoring location.

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No additional treatment measures are anticipated to be necessary to meet the ELG limits.

Currently JEA does not have any other effluents that are affected by the ELG rulemaking revisions - as a result of its dry ash handling systems, and absence of WFGD, landfill and gasification at its generation facilities. JEA remains in compliance with the existing ELGs that have already been incorporated into its NPDES permits.

### B.2.3.3 Other Water Considerations

#### B.2.3.3.1 NPDES Groundwater Discharge Decision

On April 23, 2020, the U.S. Supreme Court opined that the reach of the Clean Water Act (CWA) includes regulation of indirect groundwater discharges to surface water. The ruling concluded that a NPDES permit is required “where there is a direct discharge from a point source into navigable waters or where there is a functional equivalent of a direct discharge.” The decision by the supreme court is counter to an Interpretative Statement issued by the USEPA in April 2019 which concluded that the release of pollutants to groundwater is excluded from the Clean Water Act and regulation is left to the states and the EPA under different statutes. In its ruling the court recognized that the primary factors to determine if an NPDES permit would be required for a groundwater discharge would be travel, time, and distance from the point of discharge to the waterway. Other factors that could be used to determine CWA and NPDES authority include:

- The nature of material through which the pollutant travels
- Extent of dilution or chemical change of the pollutant

- Amount of pollutant entering the navigable water relative to the amount discharged
- The area over which, or the means by which, a pollutant enters the waters
- The degree to which the pollutant can be identified.

Furthermore a guidance document titled “Applying the Supreme Court’s *County of Maui v. Hawaii Wildlife Fund* decision in the Clean Water Act Section 402 National Pollutant Discharge Elimination System Permit Program” was issued on January 21, 2021 and then rescinded on September 15, 2021, stating it was issued without proper deliberation within EPA or with other federal partners. The EPA reverts back to guidance provided in the Supreme Court ruling and listed above as guiding factors to determine if groundwater discharge is jurisdiction under the CWA. The EPA in the September 15, 2021 memo states that the Office of Water will be evaluating appropriate next steps and will continue to apply site-specific, science-based evaluations to determine whether a discharge from a point source through groundwater requires a NPDES Permit under the CWA.

Groundwater discharges at the Northside Generation Station could potentially be considered “functionally equivalent” to a direct discharge and hydrologically connected to nearby surface waters. FDEP Currently regulates groundwater discharges and standards under Florida Administrative Code (FAC) 62-520 Ground Water Classes, Standards and Exemptions but potentially could require an NPDES permit in the future. Absent further guidance from EPA or FDEP, this ruling leaves uncertainty and significant risk for facilities that fail to obtain a NPDES permit for potentially covered groundwater discharges, or at least disclose them during the permitting process.

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### B.2.3.4 Florida Assumption of U.S. Army Corp of Engineers Clean Water Act Section 404 Permitting

#### B.2.3.4.1 Background

On Dec. 22, 2020, the U.S. EPA published the approval of Florida’s State Clean Water Act Section 404 Program in the Federal Register, and the FDEP began administering the State 404 Program on that date.

In 2018, Florida’s legislature passed a bill that gave FDEP authority to begin the public rulemaking process to assume the federal dredge and fill permitting program under section 404 of the federal CWA within certain waters of the US. The rulemaking process was completed on July 21, 2020. Through this process, Chapter 62-331, FAC, “State 404 Program,” was created to bring in the requirements of federal law not already addressed by the existing Environmental Resource Permitting (ERP) program. Minor changes were also made to the ERP rules in Chapter 62-330, FAC, to facilitate assumption. Florida submitted its assumption package to the EPA on Aug. 20, 2020.

State assumption of the 404 program provides a streamlined permitting procedure where both federal and state requirements are addressed by state permits. The State 404 Program is a separate program from the existing ERP program, and projects within state-assumed waters require both an ERP and a State 404 Program authorization. As noted by the FDEP, approximately 85 percent of review requirements overlap between programs, and this assumption eliminates duplicated federal and state reviews.

#### B.2.3.4.2 Permit Process

The State 404 Program is responsible for overseeing permitting for any project proposing dredge or fill activities within state assumed waters. Such projects include, but are not limited to: utility projects; environmental

restoration and enhancement; linear projects; governmental development; and in-water work within assumed fresh water bodies. Retained waters generally include traditional navigable waters, such as larger navigable rivers, coastal waters, and wetlands adjacent to such waters up to a 300-foot administrative boundary. Assumed waters include all other waters of the U.S. (WOTUS), and in Florida, this generally consists of inland features, such as smaller rivers, streams, creeks, lakes, and their adjacent wetlands. JEA should utilize FDEP resources, including an online geographic information system (GIS) tool that FDEP has developed, to determine whether the U.S. Army Corp of Engineers (USACE) or the state agency (in Florida, the FDEP) will issue a 404 permit for a project.

If a project will result in discharges of dredged or fill material in retained waters, the 404 application generally should be submitted to the USACE. If the proposed project impacts only assumed waters (and does not impact retained waters), FDEP will generally process the application. In Florida, even if most WOTUS impacts from a proposed project will occur within assumed waters, if the project impacts any retained waters, the 404 permit will be processed by the USACE for all WOTUS impacts.

FDEP’s 404 program adopted a general permit process that is similar to the USACE nationwide permit (NWP) program, and FDEP has also assumed management of seven USACE Regional General Permits. The state program, however, is based on the USACE 2017 NWPs (not the 2021 modifications). Therefore, there are some key differences. For example, the USACE 2021 modifications of the NWP 12 for utility lines into NWPs specific to the type of utility (e.g., telecommunication, oil and natural gas, or water). FDEP has established one state general permit for “Utility Line Activities.” The state general permit authorizes activities related to the construction, maintenance, repair, and removal of any type of utility line, provided the

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activity does not result in the loss of greater than ½-acre of state-assumed waters. FDEP has also assumed administration of seven USACE regional general permits (RGPs) in state-assumed waters, including SAJ-13 (Aerial Transmission Lines) and SAJ-14 (Sub-aqueous Utility and Transmission Lines in Florida). In some circumstances, the conditions of a USACE RGP may be preferable to the state general permit.

Within 10 days of the determination that the application is "administratively complete," FDEP will publish the public notice. Copies of the public notice will be distributed to the relevant and appropriate parties and commenting agencies. This triggers interagency coordination with the State Historical Preservation Officer (SHPO) and the Tribal Historical Preservation Officer (THPO), the Florida Fish and Wildlife Conservation Commission (FWC), U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), Florida's Water Management Districts (WMDs) and EPA. A commenting agency may submit questions or comments for FDEP to include in a Request for Additional Information (RAI). A commenting agency may also provide comments to EPA and request that EPA object to a proposed activity. FDEP will forward the applicant's response to the RAI to each commenting agency for review, if applicable. Additional conditions may be included in the final authorization based upon the recommendation of a commenting agency to avoid or minimize potential adverse effects due to the project.

The EPA will continue to play a role in the process and under the federal regulations, unless EPA has waived review, FDEP will provide EPA with the public notice for the proposed activity. EPA may choose to comment, condition or object to the proposed activity. EPA is prohibited from waiving review of permit applications for discharges with reasonable potential for affecting endangered or threatened species. Within 30 days of receipt of

the public notice, EPA may notify FDEP of its intent to comment on the proposed activity. If EPA does not notify FDEP of an intent to comment, FDEP will make a final permit decision to issue or deny the permit 60 days after the end of the public comment period and after the application is technically complete. When EPA notifies FDEP of an intent to comment, FDEP will provide EPA 90 days to comment on the proposed activity. When necessary, FDEP may use the RAI to communicate any of EPA's comments or concerns with the applicant. FDEP will make a final agency action to issue or deny the permit after receiving EPA's comments (and RAI response). FDEP may choose to add EPA's conditions and make a final permitting decision to issue or deny the permit within 90 days of receipt of the objection or condition.

### **B.2.3.4.3 Permit Issuance Challenges**

FDEP's permitting actions are subject to review. Because the issuance of the new 404 permits is a state action, parties may initiate an administrative proceeding by written petition to FDEP. If the petition identifies disputed issues of material facts, the petition will be referred to the Florida Division of Administrative Hearings (DOAH) for the assignment of an administrative law judge (ALJ) for a hearing. The DOAH hearing includes live witnesses and discovery (with the burden of proof on the petitioner). Upon completing the hearing, the ALJ submits to FDEP a recommended order consisting of findings of fact, conclusions of law and a recommended disposition. FDEP then issues a final order. Prior to the FDEP assumption, challenges to a 404 permit would have to be brought in federal court. Such federal challenges are record review cases based on the deferential standards of the Administrative Procedure Act. One possible result of the assumption is that there will be more challenges as they move to the state process. However, one major benefit is that assumption by the state will eliminate challenges under the National Environmental Policy Act (NEPA).

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On December 30, 2022 the EPA and USACE announced a final rule addressing a pre-2015 definition of “waters of the United States” (WOTUS). This final rule was issued to clarify the definition of WOTUS which has been changed via court decisions and final rules issued by the EPA and USACE in 2015, 2019 and 2020. The following are considered WOTUS under the 2022 rule:

- Traditional Navigable Waters
- Territorial Seas
- Interstate Waters
- Impoundments
- Tributaries
- Adjacent Wetlands

Additional Waters (Do not meet the categories above but qualify under the relatively permanent standard or the significant nexus standard.)

The Relatively Permanent Standard is a test that provides important efficiencies and clarity for regulators and the public by readily identifying a subset of waters that will virtually always significantly affect paragraph (a)(1) waters. To meet the relatively permanent standard, the waterbodies must be relatively permanent, standing, or continuously flowing waters connected to paragraph (a)(1) waters or waters with a continuous surface connection to such relatively permanent waters or to paragraph (a)(1) waters.

The Significant Nexus Standard is a test that clarifies if certain waterbodies, such as tributaries and wetlands, are subject to the Clean Water Act based on their connection to and effect on larger downstream waters that Congress fundamentally sought to protect. A significant nexus exists if the waterbody (alone or in combination) significantly affects the chemical, physical, or biological integrity of traditional navigable waters, the territorial seas, or interstate waters.

There will likely be court and regulatory challenges to this new rule and close attention should be paid to the evolving regulatory environment regarding this rule and the definition of WOTUS.

### B.2.4 Other Environment Considerations

#### B.2.4.1 Coal Combustion Residuals

The Coal Combustion Residuals (CCR) rule published in April 2015 under 40 CFR 257, establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule is intended to address risks from coal ash disposal, such as leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly accessible website.

The CCR rule contains specific requirements that are to be met in order to continue operation of landfills and surface impoundments (CCR units) at active coal-fired power generation facilities. These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

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Existing CCR units were to demonstrate compliance with the first four criteria by deadlines staged over 2015-2018 (with one aquifer locational standard deadline recently extended to 2020). Failure to meet or document these items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR allows two options: (1) leave the CCR in place and install a defined final cover system or (2) remove the CCR and decontaminate the unit.

Although the St. John’s River Power Park has ceased operations, its CCR by-products storage area is subject to the EPA rule. JEA has timely demonstrated compliance with the relevant CCR rule requirements to date. The Area A landfill has already been closed, and JEA plans on closing the Area B Phase 1 in place once receipt of CCR or removal of CCR for beneficial use no longer occurs. JEA has filed and posted a Closure Plan outlining the methods and timing of the Area B Phase 1 area closure.

Because Northside Generation Station fires a combination of fuels, the majority (>50 percent on a heat input or mass basis) being natural gas and petroleum coke, the CCR rule does not apply to management of these combustion by-products at the facility per 40 CFR 257.50(f).

It is worth noting that a recent August 21, 2018 decision by the federal D.C. Circuit Court of Appeals vacated and remanded several provisions of the CCR rule regarding unlined, clay-lined surface impoundments, and those located at inactive (legacy) plants. On August 28, 2020, EPA published its final rule in the Federal Register (85 Fed. Reg. 53,516), entitled “Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to Closure Part A: Deadline to Initiate Closure” (Part A Rule). The Part A Rule amends several regulatory provisions that govern coal combustion residuals and includes amendments

that require certain CCR units (unlined or clay-lined surface impoundments and units failing the aquifer separation location restriction) to cease waste receipt and initiate closure “as soon as technically feasible” but no later than April 11, 2021. The final Part A Rule becomes effective on September 28, 2020.

### B.2.4.2 Polyfluoroalkyl Substances (PFAS) Review

#### B.2.4.2.1 PFAS Contamination in Florida and the Jacksonville Area

Existing per- and polyfluoroalkyl substances (PFAS) contamination is documented at multiple sites in the vicinity of JEA operations, Jacksonville International Airport, and at three Navy Facilities (Naval Air Stations Cecil Fields and Jacksonville, and Naval Outlying Field Jacksonville). Also, FDEP is currently overseeing cleanup at 5 industrial sites in or near Jacksonville. Local news media has extensively reported on PFAS issues in the Jacksonville Area. It should be noted however, that during their preliminary analysis of PFAS in drinking water at 3 U.S. Navy facilities near Jacksonville, the U.S. Navy found no detectable levels of PFAS in JEA-supplied drinking water.

PFAS contamination has been documented, reported on, and studied throughout Florida – especially in the vicinities of Miami, Tampa Bay, Jacksonville, and military facilities on the emerald coast. The widespread occurrence of PFAS in drinking water and environmental media throughout the state has prompted state environmental (FDEP) and public health (Florida Department of Health (FDH)) officials to investigate its occurrence, and to develop and implement strategies to assess and mitigate the impacts of PFAS contamination – including the development of screening and provisional target cleanup levels in a variety of media, and execution of projects to sample well systems and perform pilot studies of cleanup technologies.

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### B.2.4.2.2 Federal and State PFAS Regulatory Considerations

The regulatory status affecting the PFAS family of chemicals is complex for several reasons, including: 1) Over 2,000 PFAS compounds have been identified, although PFAS regulation has so far focused on less than 10 of the most prevalent congeners (this is dynamic and expanding); 2) PFAS regulations are being developed across nearly every environmental regulatory regime (RCRA; Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); CWA; Safe Drinking Water Act (SDWA); CAA; NEPA; Toxic Substances Control Act (TSCA); etc.) – but on much different timetables, and 3) non-statutory factors are applying pressure to minimize or stop using PFAS chemicals (i.e. public pressure / media / several billion dollars in legal settlements), all while the properties of PFAS chemicals make them indispensable in many consumer and industrial products, and in firefighting flammable liquids (especially petroleum hydrocarbons).

Currently, Florida is monitoring and managing impacts from PFAS contamination through FDEP and through FDH. The Florida program comprises: 1) use of the EPA lifetime drinking water health advisory level (HAL) for perfluorooctanoic acid (PFOA) and/or perfluorooctane sulfonic acid (PFOS) of 70 ng/L as a basis for assuring safety of drinking water sources and as a basis for developing screening and provisional cleanup standards in environmental media, 2) investigation of targeted industrial cleanup sites (federal facilities, airports, dry cleaners, and state-led cleanup sites) for PFAS contamination, and 3) development of a coordinated approach to PFAS issues (PER AND POLYFLUOROALKYL SUBSTANCES (PFAS) DYNAMIC PLAN, FDEP DWM, Aug 21). If JEA has any cleanup sites where aqueous film-forming foam (AFFF) or other PFAS-containing substances are stored or used, they may eventually have to sample environmental media for PFAS compounds. If

PFAS compounds are found in any environmental media associated with JEA facilities or cleanup sites, it is likely that current cleanup regulations (i.e., the FDEP Cleanup Program) would be invoked to guide the investigation and potential cleanup, even though promulgated cleanup standards do not yet exist.

Federal regulations and federal regulatory activity might also significantly impact the use of PFAS compounds and the steps required to mitigate impact from PFAS released into the environment. To date, EPA has not established enforceable national drinking water limits for any PFAS substance. EPA has, however, issued notices of proposed rulemaking to develop drinking water limits for PFOA and PFOS (and possibly perfluorobutane sulfonic acid (PFBS)). A national drinking water limit will require the entire country to evaluate the concentration of these two compounds in drinking water, and to implement treatment systems and permit limits to achieve the drinking water limits. In addition, the next round of Unregulated Contaminant Monitoring Rule sampling will include all 29 PFAS that are within the scope of EPA Methods 533 and 537.1 – indicating potential future maximum contaminant levels (MCLs) for many more PFAS.

On 22 June 2020 the EPA issued a final rule (85 CFR 37354), which clarified reporting requirements for entities that use or have used certain PFAS. The rule mandated that, starting with the July 2021 Toxic Release Inventory (TRI) Report, 172 PFAS compounds (threshold limit 100 pounds each) must be listed. The de minimis level is 1 percent for all listed PFAS, except PFOA (CASRN: 335-67-1), which has a de minimis level of 0.1 percent. It is possible that AFFF kept on-site for fire response in bulk fuel storage areas could exceed TRI reporting levels. Also, EPA has indicated they will be seeking to add more PFAS compounds to the TRI reporting list, and to eliminate some existing reporting exemptions.

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Regulations governing cleanup of PFAS-contaminated sites are being developed. EPA has publicly stated plans to 1) designate PFOA and PFOS as hazardous substances under CERCLA, 2) add PFOA, PFOS, PFBS, and GenX as RCRA Hazardous Constituents under 40 CFR 261, and 3) initiate rulemaking to broadly clarify that states can require clean-up of any emerging contaminant that meets the RCRA statutory definition of a hazardous waste. If JEA has any sites where AFFF has been stored or used, for example (by any JEA or municipal fire department firefighting or training activities), these sites should be considered for screening environmental media for PFAS contamination to understand potential future liability. The hazardous substance/constituent designations of PFAS compounds will also affect due diligence / all appropriate inquiries, meaning that property values could be affected, and any buying or selling of property should consider including PFAS sampling in the Phase I Environmental Assessment (note: “consider including” until CERCLA or RCRA designations are law, in which case PFAS analysis will be required wherever it may exist).

EPA is also moving ahead aggressively to investigate, and in some cases limit the discharge of PFAS in industrial water through the NPDES system and the development of new effluent limit guidelines. At this time the focus of this regulatory activity is on targeted industries, but the work will (along with a large amount of research on eco-toxicity of PFAS in surface water and sediment) likely have a broad impact on all NPDES permits in the future. JEA may want to consider evaluating whether and which PFAS substances are present in any wastewater streams or other discharges.

Although EPA has indicated it may seek to designate some PFAS as hazardous air pollutants, at this time they are still “building the technical foundation necessary to evaluate and potentially propose PFAS air emissions under the CAA”.

### B.2.4.3 Environmental Justice

Environmental justice (EJ) has been defined as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.

Fair treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.

Meaningful involvement means:

- People have an opportunity to participate in decisions about activities that may affect their environment and/or health;
- The public's contribution can influence the regulatory agency's decision;
- Community concerns will be considered in the decision making process; and
- Decision makers will seek out and facilitate the involvement of those potentially affected.

Executive Order 12898, signed on February 11, 1994, directed federal agencies to develop environmental justice strategies to help federal agencies address disproportionately high and adverse human health or environmental effects of their programs on minority and low-income populations. On February 27, 2012, federal agencies, led by the Council on Environmental Quality (CEQ) and the EPA, released environmental justice strategies, implementation plans, and progress reports outlining the steps that agencies will take to protect certain communities facing health and environmental risks. These strategies constitute a significant increase in the integration of environmental justice into federal decision-making and programs.

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Incorporation of environmental justice analysis in siting and expansion of power generation projects should be considered in siting analyses. For there to be a significant concern that low-income or minority population areas may receive a disproportionate share of negative impacts from a facility, the following factors generally need to be met: 1) high percentages of minority and low income populations would need to be present in close proximity to the site, 2) negative cultural, economic, or health impacts on such populations would need to be expected, and 3) minority and low-income areas would be expected to bear a disproportionate share of negative impacts from the facility. The EPA has created the EJSCREEN Mapping tool to help provide a high-level look at EJ data for siting and preliminary screening purposes. EJSCREEN allows users to access environmental and demographic information for locations in the U.S. and compare their selected locations to the rest of the state, EPA region, or the nation.

The tool may help users identify areas with:

- Minority and/or low-income populations
- Potential environmental quality concerns
- A combination of environmental and demographic indicators that is greater than usual
- Other factors that may be of interest

An EJSCREEN review as well as other census and available socioeconomic data should be analyzed in siting and expansion of future facilities.

### B.2.4.4 Climate Justice

The draft legislation of the CLEAN Future Act has provisions related to EJ. The main concern for existing facilities is a provision which could potentially require agencies to not allow a permit to be renewed for a major source in an overburdened census tract after January 1,

2025. An overburdened census tract is defined as:

- Has been identified within the National Air Toxics Assessment published by the Administrator as having a greater than 100 in 1,000,000 total cancer risk: or
- Has been determined to have an annual mean concentration of PM<sub>2.5</sub> of greater than 8 micrograms per cubic meter ( $\mu\text{g}/\text{m}^3$ ), as determined over the most recent 3-year period for which data are available.

Secondly, after the date of enactment of the CLEAN Future Act, no permit shall be granted by a permitting authority for a proposed major source that would be in an overburdened census tract. The potential impact of this rule, if enacted, would be enormous as a large percentage of the U.S., including most industrial areas, has an annual mean PM<sub>2.5</sub> concentration greater than the 8  $\mu\text{g}/\text{m}^3$  threshold, meaning that no permitting of major sources in those areas would be allowed, and no permit could be renewed after January 2025. It is unlikely that legislation as stringent as these provisions in the CLEAN Future Act will be enacted in the near future, however one should pay close attention to the evolution of this Act and the other proposed EJ legislature.

Current EJSCREEN data suggests that the areas around Northside, Brandy Branch, and Greenland Energy Center are less than the 100 in 1,000,000 total cancer risk, but above the 8  $\mu\text{g}/\text{m}^3$  annual PM<sub>2.5</sub> concentration.

### B.2.4.5 Climate Resiliency Discussion

Climate change impacts can be assessed by looking at multiple parameters. The impacts and associated risks most relevant to the project are discussed in this section and include temperature increases, sea-level rise, ocean acidification and increased variability and intensity of rainfall, wind, and severe weather events. This discussion is a summary of third-

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party reviews and data and does not constitute a specific projection for this assessment.

The primary data source for the global information discussed in this section is Climate Change 2021: The Physical Science Basis, Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC 2021). The key source of data for climate change impacts specific to the southeastern U.S. is the Coupled Model Intercomparison Project, Phase 6 (CMIP6), which was used to inform the IPCC's Sixth Assessment Report (AR6) and is overseen by the World Climate Research Program.

To illustrate possible climate futures, multiple scenarios were assessed in the IPCC report and CMIP6 data, all with varying levels of future GHG emissions. The results presented in this section will cover the best- and worst-case scenarios, representing net negative GHG emissions and GHG emissions that roughly double from current levels by 2050, respectively.

### B.2.4.5.1 Increased Temperatures

According to the IPCC 2021 report, the global surface temperature has risen by 1.09 degrees Celsius (°C) across the globe from 1850-1900 to 2011-2020 with human-induced warming contributing 1.07°C of the increase. Around Jacksonville, average temperatures have increased by around 0.44°C (0.8 °F) within the last 30 years.<sup>1</sup>

Increased temperatures will result in significant consequences for human health, agriculture, ecosystems, and water resources. As related to the proposed Project, higher temperatures will increase the demand for water, and result in higher cooling and air conditioning

requirements as well as a fall in efficiency for thermal power generation.

### B.2.4.5.2 Sea Level Rise

Global mean sea level (GMSL) has increased by 0.20 meters between 1901 and 2018 because of ocean expansion due to water temperature warming and melting of glaciers and ice sheets. Since 1928 sea level has risen an average of 2.76 millimeters (0.11 inches) per year near Jacksonville, Florida.<sup>2</sup>

Sea level rise is expected to accelerate in the coming years with median model levels of 0.20-0.24 additional meters by 2050 and 0.44-0.83 total additional meters by 2021 at Fernandina Beach, Florida. These projection tools encompass multiple levels of Global Warming.<sup>3</sup>

### B.2.4.5.3 Impacts of Increased Variability and Intensity of Rainfall, Wind and Extreme Weather Events

Areas in northeast Florida have experienced slight increases in overall annual precipitation since the early 1900's. Heavy single rainfall events have also shown an increase since the early 1900's.<sup>4</sup> Future annual rainfall and heavy precipitation projections associated with climate change for northeast Florida are not clear overall, however tropical activity and associated rainfall is expected to increase during hurricane season going forward.<sup>5</sup> Additional heavy rainfall events have the potential to cause property and road infrastructure damage. In addition, if runoff levels increase, the likelihood of natural disasters such as floods would rise.

<sup>1</sup> United States Global Climate Change Research Program, national temperature map. Jacksonville, Florida area

<sup>2</sup> Sea Level Trends – National Oceanic and Atmospheric Association Tides and Currents Fernandina Beach, Florida

<sup>3</sup> IPCC Sixth Assessment Sea Level Projection Tools

<sup>4</sup> United States EPA, Climate Change Indicators: Annual Rainfall and Heavy Precipitation

<sup>5</sup> Geophysical Fluid Dynamics Laboratory, Princeton University. Supported by NOAA and based on IPCC AR6 Projections.

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### B.2.4.5.4 Ocean Acidification

Ocean Acidification is caused by excess CO<sub>2</sub> dissolving in the ocean, the additional CO<sub>2</sub> changes the composition of the ocean and causing the seawater to become more acidic. Globally, upper ocean stratification has increased in the last 50 years and seawater pH has declined, with human influence the main driver. Under all scenarios, ocean acidification and associated reductions in the saturation state of calcium carbonate are forecast to increase this century.

As the climate has warmed, the ocean has become more stratified, inhibiting the necessary mixing of heat, oxygen, and CO<sub>2</sub> from the surface to be transported into the deeper ocean levels. Per the 2021 IPCC report, stratification, acidification, deoxygenation, and

marine heatwave frequency will continue to increase throughout this century.

Increased acidity can cause further damage to ocean ecosystems also harmed by ocean temperature rise. With a more stratified ocean, oxygen that is absorbed at the surface does not mix as easily with the cooler waters below, causing it to become more difficult for marine life to flourish.

### B.2.4.5.5 Climate Risks and Recommended Mitigation Measures

Climate change contributes to an increased risk on the natural environmental, public health and infrastructure. The climate change impacts discussed in the previous section will lead to different degrees of risks to JEA's assets around Jacksonville. These potential risks and mitigation measures are summarized in Table B-4.

**Table B-4 - Climate Risks and Recommended Mitigation Measures**

Key Risk	Climate Drivers	Recommended Mitigation Measures
Flooding and Water Damage	Increased Precipitation, Increased Thunderstorm Severity, Sea Level Rise	<ul style="list-style-type: none"> <li>Elevate water-sensitive equipment to address high water levels, incorporating projected rather than historic sea level rise and flood heights</li> <li>Storm-harden energy infrastructure</li> <li>Develop a flood risk management plan</li> <li>Develop effective storm water pollution control measures and ensure proper secondary containment is designed with climate change impacts considered</li> <li>Ensure drainage capacity can handle increases in precipitation and sea level/river level rise (Northside and Kennedy)</li> <li>Ensure flood design loads consider sea level/river level rise (Northside and Kennedy)</li> </ul>
Increased Sediment Load from Rivers	Increased Precipitation	<ul style="list-style-type: none"> <li>Perform due diligence to properly understand the maintenance dredging that could be required due to increased sediment load from rivers (Northside and Kennedy)</li> <li>Develop a sediment monitoring plan to plan dredging procedures and avoid disruptions, delays, or costly large-scale dredging efforts (Northside and Kennedy)</li> </ul>
Partial or Full Power Disruption	Increased Precipitation, Sea-Level Rise, Increased Thunderstorm Intensity	<ul style="list-style-type: none"> <li>Build redundancy into facilities</li> <li>Provide back-up power supply and distributed generation, capable of responding to disruptions</li> </ul>

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Key Risk	Climate Drivers	Recommended Mitigation Measures
Increased Energy Demands and Lower Power Plant Efficiency	Increased Temperature, Sea-Level Rise	<ul style="list-style-type: none"> <li>Seek efficient solutions and plan accordingly for the increase in energy that may be required for treatment, drainage, and pumping</li> <li>Counter the effect of increased ambient temperatures with advanced cooling technologies, including design elements such as additional cooling to intake air.</li> </ul>
Risk associated with structural damage	Increased Ambient Temperature, Increased Thunderstorm Intensity	<ul style="list-style-type: none"> <li>Optimize structure design by employing building, storage, and transmission material that can withstand high heat, and severe winds.</li> </ul>

### B.2.4.6 Assessment of Cooling Tower Blowdown Versus Wastewater Treatment

Evaluation of injection wells for cooling tower blowdown versus wastewater treatment due to salinity or sodium concerns is discussed in the following subsections.

#### B.2.4.6.1 Brandy Branch

Based on a review of information provided by JEA, there are indications of a fairly consistent and low constituent concentration discharge stream from the facility. The samples were not analyzed for salinity, sodium and chlorides, and as such a determination as to the level of salinity in the water cannot be made.

Comparing the sample analyses to the cooling water discharge requirements found in information provided by JEA, there were no constituents in exceedance found. Likewise, a review of the NPDES permit application also did not find any constituents in exceedance. Based on these findings, we see no reason to treat the wastewater prior to discharge or else bypass and send to an injection well.

#### B.2.4.6.2 Northside

This analysis is based on a review of information provided by JEA. Based on this review, no analysis was found showing the effluent characteristics with regards to salinity, sodium or chlorides, nor any restrictions. However, a daily maximum value for chemical oxygen demand (COD) of 750 mg/L is a bit concerning

as this level of COD, if continuous and coupled with adequate nutrients, could sustain a biological mass leading to biofouling issues. Further understanding of the main cause of this level of COD would help indicate the appropriate level of treatment.

Further review of the documents provided by JEA indicates the cooling system is a “once-through” system. These systems typically require very large flows of water and evaporation is negligible, so no significant change in water chemistry occurs and treatment needs are negligible with the exception of chlorination.

#### B.2.4.6.3 Costs

A high-level cost, rough order of magnitude cost estimate for well development is approximately \$1 million. Additionally, approximately \$550,000 would be estimated for the cost to purchase and install a high flow high head well pump. The approximate cost for any desalination or seawater reverse osmosis (RO) system is \$10 per 1,000 gallons throughput.

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**B.3 Environmental Considerations for New Sites and Gas Delivery Options**

Northside option (i.e., new generation, retirement, life extension), as well as the options for the existing and potential new sites for future JEA generating units.

The following subsections assess the environmental considerations specific to the

**B.3.1 Socioeconomics**

**Table B-5 - Socioeconomic Assessment**

Site	Proximity to Existing Roadways	Proximity to Sensitive Receptors	Resident Displacement
North Jax	Nearest Interstate is I-295 roughly 0.45 miles away.	No sensitive receptors are in the immediate 1 mile area.	No resident displacements would be required.
Northside Generating Station New Generation	Nearest Interstate is I-295 roughly 0.45 miles away.	No sensitive receptors are in the immediate 1 mile area.	No resident displacements would be required.
Greenland Energy Center	Nearest Interstate or highway is US-1 roughly 0.5 miles away.	The closest sensitive receptors are residential structures 1,650 feet to south of the property and new apartments that are 0.3 miles to the east. Newer development to the east could be as close as 200 feet to the property line.	No resident displacements would be required.
Brandy Branch Generation Station	Nearest Interstate or highway is US-90 roughly 1 miles away.	The closest sensitive receptors is a residential structure and dairy farm 2,800 feet to south of the property.	No resident displacements would be required.

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**B.3.2 Land Use**

**Table B-6 - Land Use Assessment**

Site	Site Ownership	Land Use Compatibility	Environmental Justice and Site Risks
North Jax	Site owned by JEA	No land use compatibility concerns.	<ul style="list-style-type: none"> <li>• Low Environmental Justice Risk</li> <li>• High Potential for contaminated soil and water on the site.</li> </ul>
Northside Generating Station New Generation	Site owned by JEA	No land use compatibility concerns.	<ul style="list-style-type: none"> <li>• Low Environmental Justice Risk</li> <li>• High Potential for contaminated soil and water on the site.</li> </ul>
Greenland Energy Center	Site owned by JEA	No land use compatibility concerns.	<ul style="list-style-type: none"> <li>• Low Environmental Justice Risk</li> <li>• Potential for contaminated soil and water on the site.</li> <li>• Potential for additional development restrictions due to nearby residential and commercial development</li> </ul>
Brandy Branch Generation Station	Site owned by JEA	No land use compatibility concerns.	<ul style="list-style-type: none"> <li>• Low Environmental Justice Risk</li> <li>• Potential for contaminated soil and water on the site.</li> </ul>

**B.3.3 Air Quality – Proximity Review**

**B.3.3.1 Proximity to Nonattainment/Maintenance Areas**

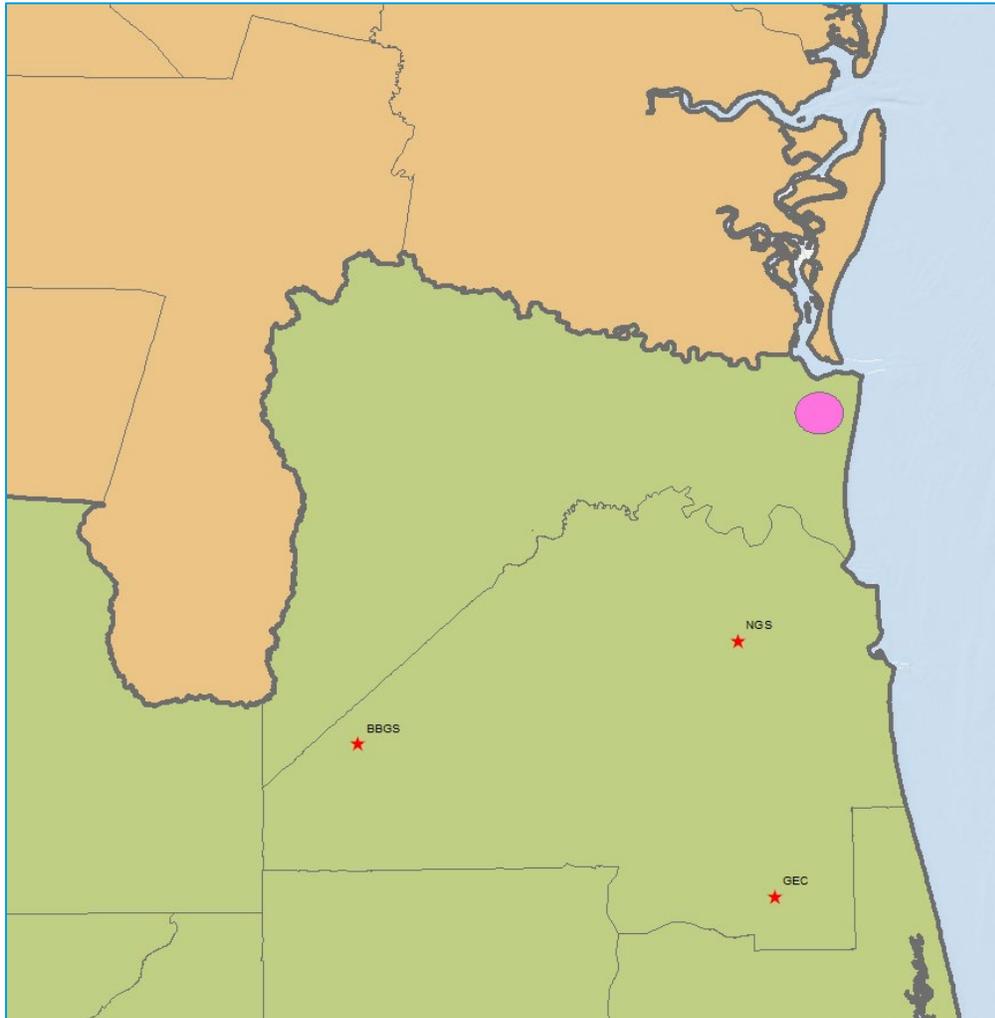
Nonattainment areas are those areas not meeting the NAAQS. Locating adjacent to or near a nonattainment area or maintenance area (i.e., an area previously in nonattainment) can have permitting implications via specific state regulations. This is due to the fact that often times states recognize that if an area is considered to be in nonattainment or

maintenance that nearby sources of air pollution contribute to the attainment status and certain measures/precautions must be taken upon the surrounding source in order to bring the area back into attainment or continue its maintenance of the air quality standards.

The nearest nonattainment area is a 2010 1-Hour SO<sub>2</sub> area located in northeast Nassau County. The non-attainment area is located sufficiently far from the proposed locations as to not pose a concern. Figure B-2 illustrates the location of the non-attainment area.

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Figure B-2 - Nearby Non-Attainment Areas



### B.3.3.2 Proximity to Class I Areas

Class I areas are geographical areas of special national or regional natural, scenic, recreational, or historic value for which the NSR PSD air permitting regulations provide special protection. The existence of Class I areas near the site can pose significant permitting hurdles as the modeling required to be performed often results in very restrictive operation or extreme controls upon a plant. Based on guidance from the Federal Land Managers, a source located more than 50 kilometers (km) from a Class I area will have negligible impacts with respect to all Class I air quality related values if its total

SO<sub>2</sub>, NO<sub>x</sub>, PM less than 10 microns (PM<sub>10</sub>), and sulfuric acid (H<sub>2</sub>SO<sub>4</sub>) annual emissions (in tons per year, based on the 24-hour maximum allowable emissions) divided by the distance (in km) from the Class I area is 10 or less. For those sites located within 50 km of a Class I area, an analysis using a steady-state model following the EPA modeling guidelines would be necessary.

The study sites have five Class I areas within a 300 km radius. The Class I areas and the distance from the sites are listed in Table B-7 and depicted in Figure B-3. Based on emissions for a state-of-the-art combined cycle system,

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negligible impacts should occur for both the Northside and Greenland Energy Center locations. Since the Brandy Branch site is located within 50 km of the Okefenokee Wilderness area, an air dispersion modeling

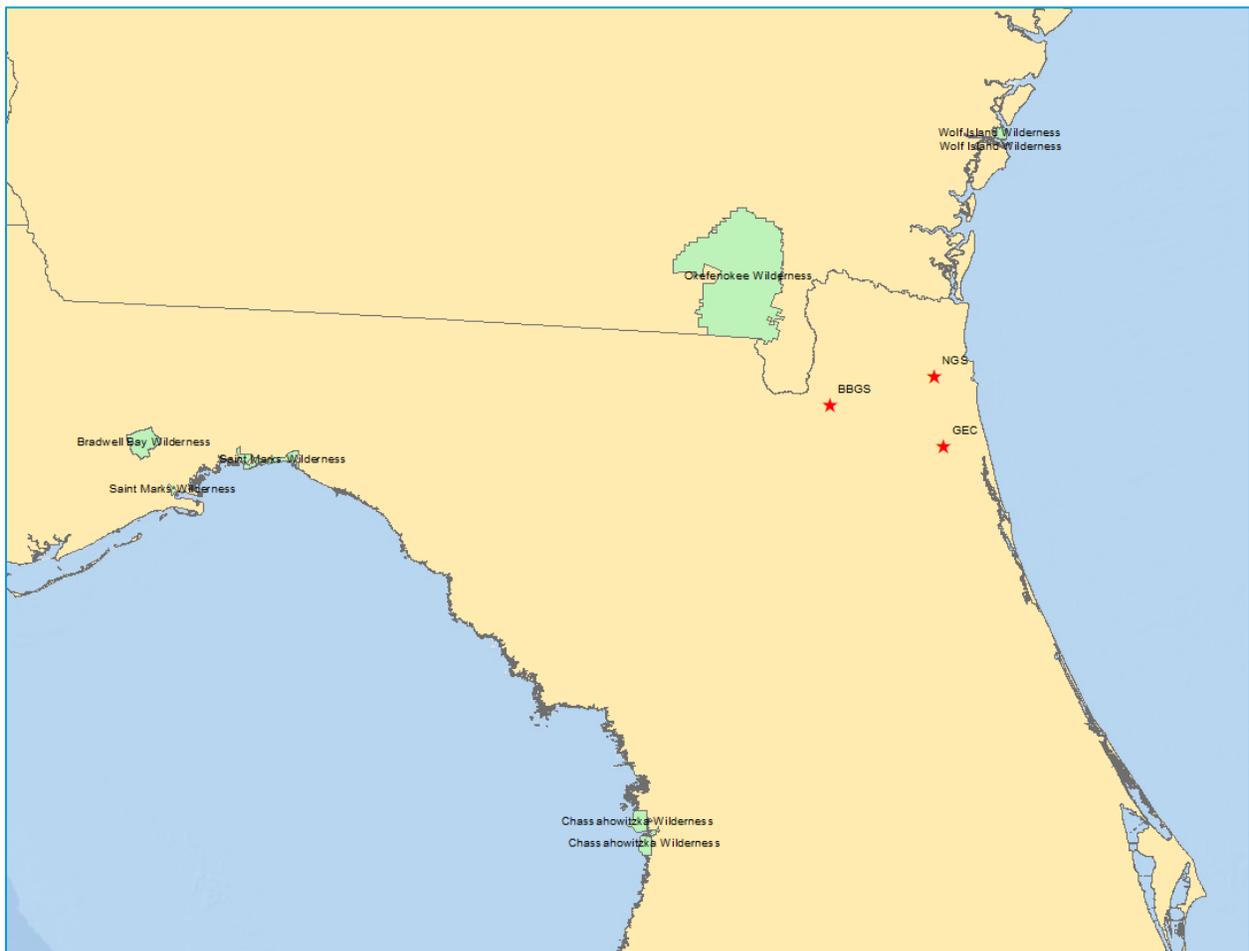
analysis would be required to determine the effects a proposed facility’s emissions would have on the Class I area.

**Table B-7 - Class I Areas Proximity to JEA Facilities**

Class I Area	Northside	BBGS	GEC
Okefenokee Wilderness	60.03	33.63	76.11
Wolf Island Wilderness	100.65	125.03	128.46
Chassahowitzka Wilderness	211.14	184.58	188.62
Saint Marks Wilderness	235.06	196.22	236.66
Bradwell Bay Wilderness	284.25	245.71	286.67

All distances are in units of kilometer.

**Figure B-3 - Nearby Class I Areas**



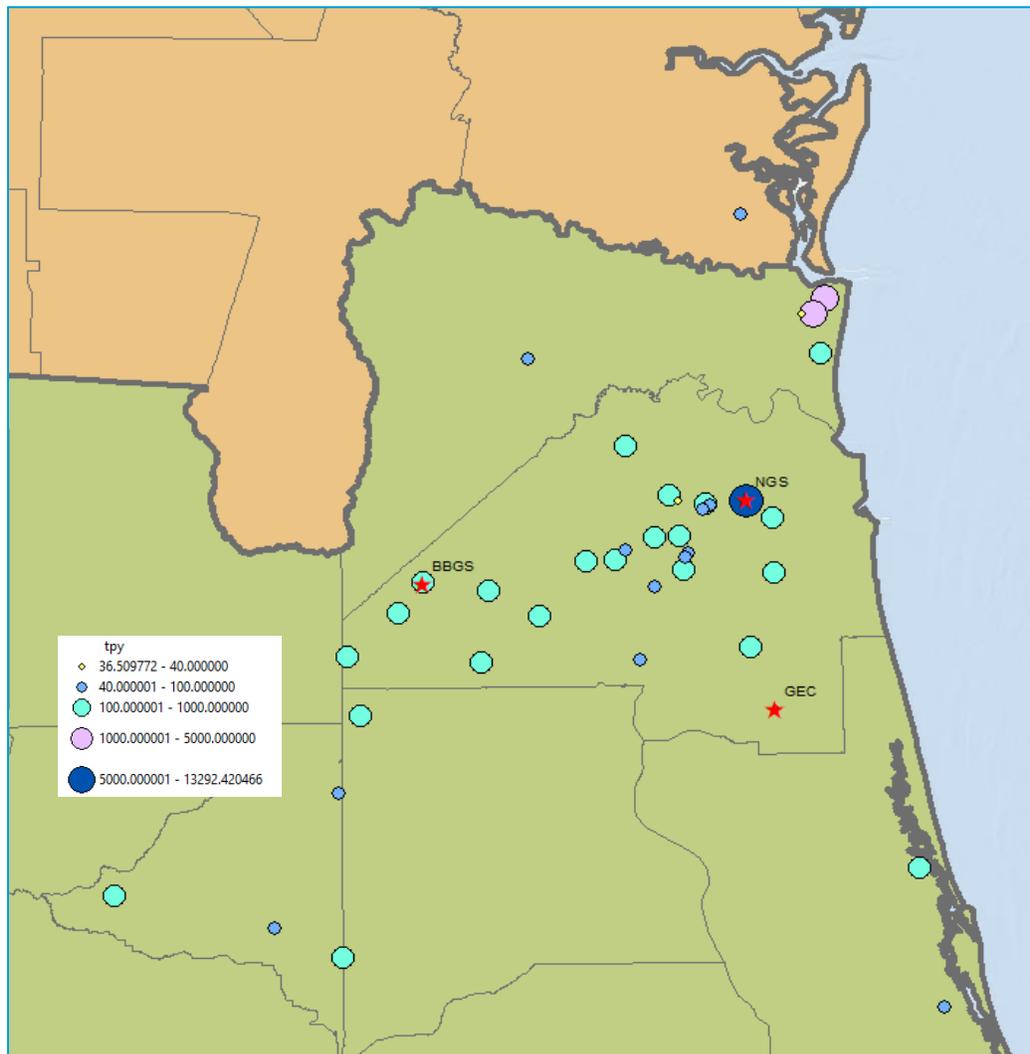
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### B.3.3.3 Proximity to Nearby Sources

With sources of the magnitude considered in this assessment, it is often pertinent to understand if there are any large sources of air pollution located nearby. Should the air quality modeling demonstrate a need for interactive cumulative source modeling, the existence of large nearby sources of air pollution may pose a significant hurdle due to the reduced air quality room available to the proposed source. This review looked for those facilities which emit more than 100 tpy of any criteria pollutant and is located within 50 km of the proposed site locations.

According to the EPA's 2017 National Emission Inventory, there are 24 facilities that emit more than 100 tpy of any criteria pollutant and is located within 50 km. Figure B-4 illustrates the location of the large emitters. Locating near large emission sources can pose a hurdle for permitting activities, however, it is not a necessity as there are options available (design changes, etc.) to allow the permitting process to continue forward.

**Figure B-4 - Nearby Emission Sources**



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B.3.4 Permitting Considerations

Table B-8 - Permitting Considerations

Site	Air Quality Permit Ability	Environmental Permit Ability
North Jax	High- Air Quality Permitting for new generation at the North Jax site would likely require a modification of the Northside Generation Station permit since it would likely be considered a single source.	High- Already developed and cleared site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water. Additionally, a new cooling water intake structure or reuse system would need to be implemented.
Northside Generating Station New Generation	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water, or expansion of the project area which could cause impacts to wetlands and species. Additionally, a new cooling water intake structure or reuse system would likely need to be implemented.
Greenland Energy Center	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	High- Air Quality Permitting for new generation at the site would require a modification of the existing permit.	High- Already developed site with limited wetlands, species or historical impacts likely. Potential constraints could be remediation of contaminated soils and surface and ground water, or expansion of the project area which could cause impacts to wetlands and species. Additionally, a new cooling water intake structure or reuse system would likely need to be implemented.

B.3.5 Ecology

Table B-9 - Ecology Assessment

Site	Potential for Threatened and Endangered Species Habitat	Potential for Wetlands/Waters of the US
North Jax	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Northside Generating Station New Generation	Low- Already developed site with limited wetlands, species or historical impacts likely. Expansion of the project area which could cause impacts to wetlands and species.	Low- Already developed site with limited wetlands, species or historical impacts likely. Expansion of the project area which could cause impacts to wetlands and species.
Greenland Energy Center	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.

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B.3.6 Culture Resources

Table B-10 - Culture Resource Assessment

Site	Potential for Threatened and Endangered Species Habitat	Potential for Wetlands/Waters of the US
North Jax	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Northside Generating Station New Generation	Low- Already developed site with limited wetlands, species or historical impacts likely.	Low- Already developed site with limited wetlands, species or historical impacts likely.
Greenland Energy Center	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.
Brandy Branch Generation Station	Low - Already developed site with limited wetlands, species or historical impacts likely.	Low - Already developed site with limited wetlands, species or historical impacts likely.

B.3.7 Technical Considerations Site Development Factors

Table B-11 - Technical Considerations

Site	Site Development	Site Expansion	Wastewater Disposal Options	Water Availability
North Jax	Already developed site with limited wetlands, species or historical impacts likely.	Site is already cleared and the site of a generating station. Additional constraints may include remediation of contaminated soils and waters.	High- Could use existing infrastructure to tie into Northside Water Intake System	High- Could use existing infrastructure to tie into Northside Water Intake System
Northside Generating Station New Generation	Already developed site with limited wetlands, species or historical impacts likely.	Limited space for expansion. Existing facilities could be retooled and modernized. Additional constraints include contaminated soil and water remediation.	High- Could use existing infrastructure. Other options to comply with new state regulations regarding waste water discharges will need to be evaluated.	High- Could use existing infrastructure. Updates would need to be made to intake structures to comply with 316(b) requirements
Greenland Energy Center	Already developed site with limited wetlands, species or historical impacts likely.	Space on site for expansion or addition of units. However, nearby development and sensitive receptors may limit expansion.	High- Could use existing infrastructure	High- Could use existing infrastructure

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Site	Site Development	Site Expansion	Wastewater Disposal Options	Water Availability
Brandy Branch Generation Station	Already developed site with limited wetlands, species or historical impacts likely.	Limited space on the already developed site area. However, JEA owns some adjacent property which if developed, would require additional permitting and potential wetlands, species or historical impacts.	High- Could use existing infrastructure	High- Could use existing infrastructure

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## Appendix C - New Generating Resource Options Characterization

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### C New Generating Resource Options Characterization

#### C.1 Background and Methodology

JEA directed Black & Veatch to characterize several new generating resource options that JEA could implement in the future to serve customer load (Resource Options). The range of Resource Options was developed through discussions between JEA and the B&V Team and are focused on those that were most relevant and most likely to be viable for JEA. The Resource Options included solar photovoltaic (PV) systems with and without battery storage, biomass, hydrogen, and firming resources consisting of natural gas-fired frame combustion turbine generators (CTGs), aeroderivative CTGs, compression ignition reciprocating internal combustion engines (RICEs), and nuclear generating technologies. This report summarizes the Resource Options and the methodologies, assumptions and results of their characterization.

Characterization of the Resource Options was based on order-of-magnitude estimates of capital costs, O&M costs, energy production profiles for the renewable resources, and thermal performance and stack emissions for gas-fired power plants operating in both simple cycle (SC) and combined cycle (CC) configurations.

The characterization was performed by Black & Veatch leveraging their experience with similar generation options, including both recent

studies and recent project installations. Where applicable, Black & Veatch has incorporated recent performance and cost data provided by major Original Equipment Manufacturers (OEMs). This information has been adjusted using engineering judgment to provide values that are considered representative for potential projects that may be implemented by JEA.

This report is structured to first describe at a high level the type and size of the Resource Options studied. A more detailed description of each Resource Option is then provided including the key assumptions as to the technology, features, location and other factors which are used for the performance and cost estimating (the design basis). The results of the estimating are then provided.

The resulting information and data presented herein are preliminary, screening-level characteristics suitable for the initial evaluation of the Resource Options as part of the IRP process. If a Resource Option is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development.

#### C.2 Solar, Solar plus Storage, and Storage Resources

The solar, solar plus storage and storage Resource Options that were studied along with their typical utility system use type are summarized in Table C-1 below:

## Appendix C - New Generating Resource Options Characterization

Table C-1 – Solar, Solar plus Storage, and Storage Resource Options Studied

ID	Resource Option	Plant Configuration	Battery Type	Solar PV Rating (MW)	Battery Rating (MW)	Battery Capacity (MWh)
1	75 MW Photovoltaic Solar Array	No integrated battery storage	N/A	75	N/A	N/A
2	75 MW Photovoltaic Solar Array with 0.5 hour integrated storage	Integrated battery storage (37.5 MW capacity, 37.5 MWh Energy), used for load firming / smoothing, using cell type battery technology	Lithium Ion	75	37.5	37.5
3	75 MW Photovoltaic Solar Array with 4 hour integrated storage	Integrated battery storage (74.9 MW, up to 4 hours of capacity) for peak shifting to 3-7pm, using cell type battery	Lithium Ion	75	75	300
4	37.5 MW Battery Storage 1 hour	Battery storage (25 MW, 25 MWh) used for load firming / smoothing using cell type battery technology	Lithium Ion	N/A	25	25
5	Battery Storage 4 hour	Battery storage (50 MW, up to 4 hours of capacity) used for peak shifting to 3-7pm using cell type battery technology	Lithium Ion	N/A	50	200

Load firming / smoothing means the ability to manage ramp rates when output from a solar array has a large drop in output (greater than 50 percent) or long-term deviation from the facility rated output (greater than 30 minutes). These resources will also provide the ability to eliminate minor (less than 50 percent) and / or short-term (less than 30 minutes) output deviations.

Peak shifting means charging the battery during periods of low demand and discharging during periods of high demand. This will typically occur during the evening ramp down in output as the sun sets with the battery providing firm supply until the stored energy is depleted.

## C.2.1 Solar PV

### C.2.1.1 Technology Overview

Solar PV modules can be classified into either thin-film or crystalline silicon. First Solar is the largest thin-film module supplier while crystalline silicon is the most common type manufactured by global suppliers. Within crystalline silicon, the technology is further classified into mono- and poly-crystalline. Mono-crystalline silicon provides greater efficiencies and therefore higher wattage modules than poly-crystalline but is generally more expensive (on a cost per Watt of dc power [\$ / Wdc] basis). However, industry demand is to reduce overall project costs and higher wattage modules support reduced Balance of System costs, therefore the industry is converging, and now most major suppliers of

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## Appendix C - New Generating Resource Options Characterization

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silicon cells utilize the same technologies for high-end modules. Additionally, larger cells are being used to increase overall module wattage, with a corresponding increase in overall module size. Suppliers are beginning to consolidate production lines and eliminate older product lines (lower wattage and / or mono-facial) to streamline production as much as possible, therefore reducing cost while increasing module output. A further artifact of this convergence is that there is no discernible performance difference (efficiency and degradation) among suppliers at the 50 percent probability (i.e., P50) level of confidence at which projects are typically evaluated.

The latest major technology trend is the increase of bi-facial modules. These modules are similar to the mono-facial modules, but with a clear back panel; either clear glass or plastic is used on the back of the panel allowing light reflected from the ground to also enter the cells, resulting in additional energy. Bi-facial modules are only now being installed in significant quantities, so long-term performance history is not available.

In recent years, the widespread adoption of the most advanced cell and module technologies and production methodologies has driven a rapid increase in module wattage and decline in costs. This rate is anticipated to decrease, but the trend is likely to continue for the foreseeable future. Further, new advances in technology (such as a switch to n-type cells) will continue to drive further efficiency gains while reducing output degradation over time.

Fixed racks and single-axis trackers (SATs) are currently the most common types of racks used for solar projects. Over the last few years, the trend has been toward SATs for all projects except for projects located in areas with high wind loads (i.e., greater than 120 mph), typically coastal areas subject to tropical storms and hurricanes. In those areas, fixed racks are the

only option as SATs are not available to meet the high wind loads.

The major advantage to fixed racks is the lower procurement and installation cost (as much as 20 percent less than trackers) as well as low operating and maintenance costs as there are no moving parts (as much as 30 percent less than SATs). However, there is a significant energy production reduction (as much as 30 percent) when compared to SATs.

SATs have become popular due to the large gain in production over fixed racks and the declining price as the products have matured. The specific type of SAT commonly available today is the Horizontal Single-Axis Tracker where the modules are laid flat relative to the ground and follow the sun from east-to-west throughout the day. Other versions of SATs are available, but not at the quantities needed in utility scale systems. Most SAT systems also have the capability of adaptive or intelligent sun tracking options that can help recover lost energy due to east and west sloped project sites from increased row-on-row shading and also during overcast sky conditions. Adaptive tracking energy gains can be as much as 1 to 2 percent depending on site topography and cloudy / clear sky ratios.

SATs use either an independent-row drive (i.e., each row has a motor driven actuator) or central driveline system (i.e., one motor drives multiple rows). Independent-row drives provides more flexibility in design, improved site access, and a single drive failure affects fewer modules. However, independent-row drives do have more parts that can fail and are generally more expensive to maintain. The central driveline system, with its fewer components is generally less expensive to maintain. However, the driveline restricts access between rows and a single failure affects more site DC capacity. Independent-row drive is more common within the industry as only one significant manufacturer (Array Technologies,

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Inc., or ATI) uses the driveline approach. The decision between these two methods usually comes down to total installed cost.

Historically, SATs were available in a one-in-portrait (1p) configuration where the long axis of the module was oriented east-to-west across the torque tube. Now, two-in-portrait (2p) SATs are available where the long axis of two modules, one on either side of the torque tube, are oriented east-to-west. This configuration allows for more modules to be driven by a single actuator, fewer posts are required to support the same quantity of modules, and there are fewer parts to install, therefore reducing overall installation costs. However, with the increasing size and weight of modules, the 2p configuration requires more steel in the torque tubes and other design accommodations that have reduced the cost advantages compared to 1p.

Inverters convert the DC energy to AC for supply to the grid. On utility scale projects, the standard approach is to use large central inverter skids, consisting of the inverter(s) and step-up transformer on a single steel base. Central inverter skid options are available from multiple suppliers in the 3.6-4.5 MVA range, with the largest available up to 7 MVA. The larger inverter skids are actually multiple large inverter modules tied together and sharing a single step-up transformer.

Generally, larger inverters are more cost-effective. However, there is a point of diminishing returns; if an inverter is too large, the number of modules wired to a single inverter drive the cost of the DC collection system up and the cost efficiency of the inverter is more than offset. With the current range of module sizes (450 to 550W), the most commonly applied range of inverter is the 3.6 to 4.5 MVA range.

### C.2.1.2 Study Basis

The study basis for these Resource Options includes the following:

The technical characteristics for the Solar PV Resource Option are based on a 75 MWac / 105 MWdc project in Jacksonville, Florida. The solar cost and performance estimates reflect the following assumptions:

- Use of the best available technology
- Azimuth of 180°
- Panel tilt of 0°
- Single-axis tracking. With a maximum tracker angle of + / -50°.
- Crystalline-silicon, bi-facial modules
- The estimated annual solar resource is 1,674 kWh / m<sup>2</sup> / year and is based on Global Horizontal Irradiance; derived from NSRDB (Jacksonville Airport TMY2). The first year estimated generation is 196,600 MWh (ac), and the net capacity factor (ac) is 29.9 percent. Both values are based on an energy simulation result with a standard annual degradation of 0.5 percent.
- The selected site is generally flat, cleared of trees, rectangular, and contiguous.
- The selected site has no nearby features (e.g., trees or tall buildings) that can cause shading of the solar modules.
- The selected site is close to the point-of-interconnect or at an existing facility with existing interconnection facilities.
- The battery energy storage system (BESS) is AC-coupled and co-located near the PV collector substation.
- Capacity is limited to 75 MW to avoid the more stringent permitting process in Florida.

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- BESSs were evaluated at 1- and 4-hour durations, representing the typical minimum and maximum application of the commercially mature lithium-ion technology.
- BESSs are assumed to be containerized and modular for easy scalability.

It will be necessary to refine the study basis in a subsequent resource planning step if specific sites are identified for solar development to account for additional variables (e.g., land use conditions, presence of environmental resources such as wetlands or waterbodies, and distance of the site from transmission resources). Study basis parameters for the storage selected solar Resource Options characterized are summarized in Table C-1.

### C.2.1.3 Capital and O&M Costs

The capital costs for the solar PV Resource Option are summarized in Table C-2. The costs assume owner's cost as 20 percent of EPC cost. Equipment costs include modules, inverters, trackers, and electrical / structural balance of system.

In estimating the O&M cost per kW-year, it was assumed that the solar project would be built with equipment from top tier manufacturers and that module washing would not be

performed. Black & Veatch considered annual O&M costs, as well as major equipment corrective maintenance. The values in Table C-2 are exclusive of asset management and non-technical costs (e.g., taxes and lease payments) and assumes that buildings with not require heating and cooling. Some variables that can impact the O&M price forecasting, but are currently unknown, are agreement scopes, EPC warranty term and terms, major equipment warranties term and terms, plant layout specifics, and number of inverters.

The anticipated major maintenance corrective costs are dependent on the scope of major equipment repair and replacement included within the base service fee of the O&M agreement. Assuming that no major equipment repair or replacement is included in the base fee, Table C-4 includes reasonable major maintenance assumptions (inverters, modules, transformers, trackers) for a 25-year project duration. Black & Veatch notes that these are budgeted spend amounts, and that tracker, module, and transformer replacement do not necessarily need to be modeled as reserves.

**Table C-2 - Solar PV Resource Option Capital Cost Estimate**

Component	Price (\$ / Wdc)	Price (\$ / WAc)
Equipment	\$0.602	\$0.843
Installation	\$0.125	\$0.175
Engineering	\$0.007	\$0.010
Overhead, Construction Management, Profit	\$0.132	\$0.185
Total EPC Cost	\$0.867	\$1.213
Owner's Cost	\$0.17	\$0.243
Total Installed Cost: \$ / Wdc	\$1.04	\$1.456

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**Table C-3 - Solar PV Resource Option O&M Cost Estimate**

Description	Period	Cost	
Includes 0 module wash per year; excludes asset management, major equipment corrective maintenance, interconnection costs, non-technical costs (tax / leases), includes preventative / corrective maintenance	Years 1-10	\$5 / kWdc / year	\$7 / kWac / year
	Years 11-25	\$6 / kWdc / year	\$8.40 / kWac / year

**Table C-4 - Solar PV Resource Option Major Maintenance Corrective Cost Estimate**

Maintenance	Years 0-5	Years 6-10	Years 11-25
Nominal Major Equipment Overhaul / Replacement Cost	\$0 / kWdc	\$2 / kWdc	\$4 / kWdc
	\$0 / kWac	\$2.80 / kWac	\$5.60 / kWac

### C.2.2 Energy Storage

#### C.2.2.1 Technology Overview

Although it is not a generation resource, energy storage can perform many of the same applications as a traditional generator by using stored energy from the grid or from other generation resources such as solar. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable energy integration applications. Utility scale energy storage applications with their brief descriptions are provided below:

- **Electric Energy Time-Shift (Arbitrage):** The use of energy storage to purchase energy when prices are low and shift that energy to be sold when prices are higher (during peak times).
- **Electric Supply Capacity:** The use of energy storage to provide system capacity during peak hours.
- **Frequency Regulation:** The use of energy storage to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- **Spinning Reserve:** The use of energy storage that is online and synchronized to supply generation capacity within 10 minutes.
- **Non-Spinning Reserve:** The use of energy storage that is offline but can be ramped up and synchronized to supply generation capacity within 10 minutes.
- **Voltage Support:** The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- **Variable Energy Resource Capacity Firming:** The use of energy storage to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- **Variable Energy Resource Ramp Rate Control:** Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.
- **Transmission and Distribution Upgrade Deferral:** The use of energy storage to avoid or defer costly transmission and distribution upgrades.

Some of the applications listed above such as Ramp Rate Control or Capacity Firming are location specific and require nearby renewable

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energy sources such as utility scale solar or wind generation, whereas applications such as Electric Energy Time-Shift or Frequency Regulation can be location independent and be performed at different locations on the grid.

Applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control / smoothing are examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems. Electric Supply Capacity, Electric Energy Time-Shift, and Transmission and Distribution Upgrade Deferral are examples of energy applications.

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The main

components of a battery are the positive electrode (cathode), the negative electrode (anode), and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.<sup>6</sup> Batteries store direct current (DC) charge, so power conversion is necessary to interface a battery with an alternative current (AC) power system.

BESSs employ multiple (up to several thousand) batteries that are connected in series and / or parallel and are charged via an external source of electrical energy. The BESS discharges this stored energy to provide a specific electrical function.

A fully operational BESS comprises of an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a Battery Management System (BMS) and a Site or BESS Controller and is summarized in Table C-5.

**Table C-5 - BESS Components**

Component	Definition
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components, and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bi-directional converter that changes AC to DC and DC to AC. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be comprised of various BMS units at the cell, module, and system level. The BMS monitors and manages the battery state of charge (SOC) and charge and discharge of the ESS.
BESS / Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS / Site Controller.

<sup>6</sup> T. B. Reddy, "Linden's Handbook of Batteries," 4th Edition, November 2010.

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When considering different energy storage technologies, there are several key performance parameters to understand:

- **Power Rating:** The rated power output (MW) of the entire ESS.
- **Energy Rating:** The energy storage capacity (MWh) of the entire ESS.
- **Discharge Duration:** The typical duration that the BESS can discharge at its power rating
- **Response Time:** How quickly an ESS can reach its power rating (typically in milliseconds).
- **Ramp-rate:** how quickly an energy storage system can change its power output, typically in MW / min
- **Charge / Discharge Rate (C-Rate):** A measure of the rate at which the ESS can charge / discharge relative to the rate at which will completely charge / discharge the battery in one hour. A one-hour charge / discharge rate is a 1C rate, while a 2C rate completely charges / discharges the ESS in 30 minutes.
- **Round Trip Efficiency:** The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS and transformer efficiencies.
- **Depth of Discharge (DOD):** The amount of energy discharged as a percentage of ESS overall energy rating.
- **State of Charge (SOC):** The amount of energy an ESS has charged relative to its energy rating, noted as a percentage.
- **Cycle Life:** Number of cycles before ESS reaches 80 percent of initial energy rating. The cycle life typically varies for as a function of the DOD.

Battery types employed within energy storage systems typically include lithium ion (Lithium-ion), flow, lead-acid, or sodium sulfur (NaS) batteries. Lithium-ion batteries are the dominant component in battery energy storage, and the demonstrated experience is increasing. Lithium-ion batteries are anticipated to be a major industry component in the years to come and are well suited for both power and cycling applications as well as some energy applications.

Sodium-ion batteries are very similar to lithium-ion and were recently introduced by a major battery manufacturer. They exhibit some advantages over lithium-ion (such as lower flammability and greater material availability) that offset the disadvantages to lithium-ion (lower energy density). The sodium-ion battery market is anticipated to rapidly increase, and stationary battery applications could migrate rapidly from lithium to sodium over the next few years.

Redox flow battery installations are more limited; however, redox flow batteries are also projected to likely have a considerable market share for large stationary applications in the future and are best suited for energy applications that require longer durations of discharge. As large-scale applications of flow batteries have not been demonstrated, these applications are not considered further in this Characterization of Resource Options report.

Lithium-ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode.

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The battery cells are integrated to form modules. These modules are then strung together in series and / or parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

Lithium-ion battery energy storage systems are typically used for both power and energy applications. The primary strength of lithium-ion batteries is the strong cycle life. For shallow, frequent cycles, which are common for power applications, lithium-ion systems demonstrate good cycle life characteristics. Additionally, lithium-ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- **Excellent Cycle Life:** Lithium-ion technologies have superior cycling ability to other battery technologies such as lead acid.
- **Fast Response Time:** Lithium-ion technologies have a fast response time which is typically less than 100 milliseconds.
- **High Round Trip Efficiency:** Lithium-ion energy conversion is efficient and has around 94 percent round trip efficiency (DC-DC).
- **Versatility:** Lithium-ion solutions can provide many relevant operating functions.
- **Commercial Availability:** There are many top tier lithium-ion vendors.
- **Energy Density:** Lithium-ion solutions have a high energy density to meet space constraints.

Over the last two years, significant Lithium-ion battery capacity has been installed in the United States and around the world. According to Bloomberg New Energy Finance (NEF) estimates, more than 75 GWh of capacity will

be installed around the world by the end of 2021. System sizes of 100MWh and larger are common, with GWh systems coming on-line and continuing to advance in the planning stages.

O&M activities for Lithium-ion energy storage systems typically involve annual scheduled maintenance. During this maintenance, visual inspection of the system components and status check is performed as well as expendable parts such as filters are replaced. Software updates regarding BMS can be applied during this maintenance period.

Different lithium-ion vendors employ different lithium-ion chemistry for their product. Each chemistry composition is slightly different in terms of its performance characteristics, namely, cycle life, charge rate capabilities, and energy density. They also vary in terms of the typical applications (which are primarily dictated by the performance parameters) they perform and their relative safety characteristics.

The main types of lithium-ion chemistries are shown in Table C-6 as well as the associated strengths and weaknesses of the chemistries. It should be noted that the chemistries listed are relevant chemistries for grid scale energy storage. The source of the information is from Battery University, Linden's Handbook of Batteries, and Black & Veatch experience.

Black & Veatch maintains a database of more than 80 energy storage providers in the industry. Of these, there are a significant number of lithium-ion suppliers. Black & Veatch's recent EPC experience has allowed us to narrow the long list of suppliers to the top tier candidates. The top tier lithium-ion battery suppliers Black & Veatch frequently engages are listed in Table C-7.

## Appendix C - New Generating Resource Options Characterization

Table C-6 - Lithium-Ion Chemistries for Energy Storage

Chemistry	Cycle Life <sup>1</sup>	Charge Rate	Specific Energy <sup>7</sup>	applications	Safety
Lithium Manganese Oxide (LMO)	4000 – 5000 cycles	0.25C to 3C	100-150 Wh / kg	Both power and energy applications	Good
Lithium Nickel Manganese Cobalt Oxide (NMC)	4000 – 5000 cycles	0.25C to 3C	150-220 Wh / kg	Often have separate power and energy cells	Good
Lithium Iron Phosphate (LFP)	3000 – 5000 cycles	0.25C to 2C. 4C with power cells.	90-120 Wh / kg	Often have separate power and energy cells	Very good
Lithium Nickel Cobalt Aluminum Oxide (NCA)	3000 (better at shallow DODs)	0.5C to 3C	200-260 Wh / kg	Often have separate power and energy cells	Good
Lithium Titanate (LTO)	5000 – 10000 cycles	1C to 6C	50-80 Wh / kg	Power applications	Good

Notes:

1. Cycle life is based on cycles to reach 80 percent initial energy storage capacity at 1 C rate. DoD for each cycle is assumed to be around a full DOD, or 90 percent.

Table C-7 - Lithium-Ion Battery Storage Providers

Chemistry	Manufacturer
Lithium Manganese Oxide (LMO)	Samsung SDI
Lithium Nickel Manganese Cobalt Oxide (NMC)	LG Chem
Lithium Iron Phosphate (LFP)	CATL, FHR
Lithium Nickel Cobalt Aluminum Oxide (NCA)	Saft, Tesla
Lithium Titanate (LTO)	Toshiba

<sup>7</sup> Battery University, "BU-205: Types of Lithium-ion," [http://batteryuniversity.com/learn/Article/types\\_of\\_lithium\\_ion](http://batteryuniversity.com/learn/Article/types_of_lithium_ion), October 2018.

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### C.2.2.2 Battery Energy Storage Augmentation

Due to the continuous degradation of Lithium-ion batteries, the overall system capacity will decline over time. Some system owners account for this degradation in the pro forma and plan to do no augmentation. Other strategies include an initial overbuild of capacity or installation of additional capacity at planned intervals (i.e., 1-, 3-, or 5-year intervals).

With an initial overbuild of capacity, enough additional capacity is installed to offset the total expected degradation over the design life of the battery system. This has the advantage of not requiring work to be performed in the future on an operational asset and there is no cost uncertainty in regard to future cost of installation or equipment.

Alternatively, additional capacity can be installed at planned intervals. These intervals can be of any duration, but most are no less than annual, with 3- to 5-year intervals typical. Initially, sufficient capacity will be installed to offset expected degradation between install and the scheduled augmentation. Advantages of this method include reduced initial cost, the ability to take advantage of future technology advances, and expected cost reductions in batteries. A disadvantage of this approach is

that costs are less certain (though likely to decline, there is still some uncertainty in that forecast), and system availability may be impacted during installation of additional capacity.

### C.2.2.3 Capital and O&M Costs

Cost parameters for the different battery storage options are provided in Table C-8 and Table C-9. The costs assume that an overbuild of capacity will be installed in year 1 such that the battery will still meet the Facility Energy Rating in year 10 after accounting for degradation and round trip efficiency losses. After year 10, an annual degradation loss of approximately 1.0 percent can be expected for typical usage scenarios. Because no augmentation/capacity management of the battery is planned for the first year no costs for same are included in the Fixed O&M costs. It is assumed that buildings will not require heating or cooling. Auxiliary power for the cooling of the batteries is netted out of the energy produced (i.e., it is assumed auxiliary power is provided by the batteries themselves and the batteries are then oversized to compensate for this load). When paired with solar, the costs below would be in addition to the solar cost.

**Table C-8 - Battery Energy Storage for the Solar plus Storage Resource Options**

Location	Application	Rating (MW)	Size (MWh)	Battery Technology
Greenfield 74.9 MW Solar Facility	Load firming / smooth	37.5	37.5	Cell Battery
Greenfield 74.9 MW Solar Facility	Peak Shifting	74.9	300.0	Cell Battery
Existing Site	Load firming / smooth	25.0	25.0	Cell Battery
Existing Site	Peak Shifting	50.0	200.0	Cell Battery

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**Table C-9 - Representative Costs for Energy Storage Systems**

	Parameter			
	37.5 MW Battery Storage 1 Hour	25 MW Battery Storage 1 Hour	50 MW Battery Storage 4 Hour	75 MW Battery Storage 4 Hour
Facility Power Rating, MW	37.5	25	50	75
Facility Energy Rating, MWh	37.5	25	200	300
ESS Cost <sup>1</sup> (\$M)	\$11.99	\$7.99	\$63.84	\$95.77
PCS Cost (\$M)	\$2.25	\$1.50	\$3.00	\$4.50
Balance of System Direct Cost <sup>2</sup> (\$M)	\$2.34	\$1.67	\$7.80	\$11.58
Balance of System Indirect Cost <sup>3</sup> (\$M)	\$2.13	\$1.66	\$4.46	\$5.66
Installed EPC Costs <sup>4</sup> (\$M)	\$18.71	\$12.82	\$79.11	\$117.51
EPC Cost per kW (\$)	\$499	\$513	\$1,582	\$1,567
EPC Cost per kWh (\$)	\$499	\$513	\$396	\$392
Fixed O&M Costs \$ / kW-yr <sup>5</sup>	2.44	2.44	8.20	8.20
Notes:				
1. Inclusive of containerization				
2. Direct costs are inclusive of balance of system electrical, civil, interconnection, SCADA, equipment, and labor				
3. Indirect costs are inclusive of engineering and project management, builder's insurance bonding and warranty. Sales tax, EPC markup, and development costs are not considered.				
4. Installed costs are based on 2021 COD				
5. Battery replacement and capacity maintenance not included in Fixed O&M Cost				

### C.3 Biomass Resources

The biomass Resource Options that were studied are summarized in Table C-10.

#### C.3.1.1 Technology Overview

Biomass power generating resources are those where plant (wood, energy crops and waste from forests, yards, or farms) or animal material

is used as fuel to produce electricity or heat. The biomass Resource Options that was studied was a 50 MW biomass burning wood waste.

Biomass firing for power generation is both a well-established technology as well as an increasingly popular option for generators looking to reduce or eliminate carbon emissions.

**Table C-10 – Biomass Resource Options Studied**

ID	Resource Option	Plant Configuration	Duty	Net Output (MW)	Annual Capacity Factor (%)	Annual Number of Starts
6	50 MW Biomass	BFB, with SCR, Baghouse, sorbent injection	Base	47.403	80	5
Notes						
1. Net Output value based on ambient conditions of 80°F and relative humidity of 60 percent.						

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During the next phases of project development, a biomass resource assessment can be performed to identify and quantify the currently available biomass resources in the anticipated location that could potentially be used for this new generating asset. In addition to looking at currently available resources, other potential sources that could be developed as fuel sources are considered, but not evaluated in detail on a quantitative basis in this study. At this time it is understood that JEA's focus of the study was on woody biomass.

Forest residues are remnants of forest clearing and thinning operations and include treetops, branches and stumps. Forest residues are produced by commercial logging and forest management practices. This resource category comprises a very large volume of material, but can be quite dispersed geographically. The amount of forest residue available for use as biomass fuel depends primarily on the cost to collect/remove the material and distance from the point of extraction to the end-use point.

The woody biomass fuel anticipated by JEA for this option will be an un-treated pine originating from the southeastern US. The woody biomass will be chipped to size required by the BFB and will be stored outdoors. Suppliers have noted that this general fuel criteria is estimated to be about 45% moisture on average but may be as high as 60% moisture during rainy weather. A BFB combustion system is recommended to effectively fire this fuel.

BFB units feature a furnace equipped with a bed of solid, inert material in the bottom of the unit. Pressurized air is blown upward through the bed, fluidizing it to the point of "bubbling" operation. Fuel is introduced into this bubbling bed where it is combusted under low temperature. Because of the low temperature in the furnace, fluidized bed units often produce lower NO<sub>x</sub> compared with traditional suspension fired units. BFBs are well suited for

high moisture fuels and do not require as finely milled fuel particles as suspension fired units. The low bed temperatures also allow for some in-bed sorbent injection and may, therefore, not require additional scrubbing of the flue gas post-combustion.

### C.3.1.2 Study Basis

The study basis for the biomass resource option includes the following:

- The design is based on a single nominal 50 MW biomass-fired bubbling fluidized bed (BFB) unit. The unit has standard emissions control technology to meet U.S.-based requirements. The performance estimates are based on high level heat balances and combustion calculations, and the installed cost estimates are based on rough order of magnitude pricing from vendors.
- The unit will fire wood chips based on a composition analysis provided by JEA. The woody biomass fuel anticipated by JEA will be an un-treated pine originating from the southeastern US. The woody biomass will be chipped to size required by the BFB and will be stored outdoors.
- This generating unit evaluated in this scenario would include combustion air fans, fluidizing fans, air heater, boiler, emissions controls, stack, and other balance of plant equipment. At this time, air emissions limits have not been established yet for this project. Boiler vendors were requested to include a "typical" scope for emissions controls equipment. The bidder carried in this estimate has included sorbent injection, a selective catalytic reduction (SCR) system, and a baghouse.

A summary of the estimated capital and O&M costs are provided in Table C-11 and Table C-12.

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### C.3.1.3 Capital and O&M Costs

**Table C-11 - Summary of Biomass Overnight EPC Capital Cost Estimates**

ID	Resource Option	EPC Cost (\$M)
6	50MW Biomass	178.075

**Table C-12 - Summary of Biomass Screening-Level Non-Fuel O&M Cost Estimates**

Supply Side Option	Unit	50MW Biomass
Supply Side Option ID	--	6
Case Number	--	6
Annual Capacity Factor	%	80
Starts Per Year	Count	5
Number of Full Time Equivalent Personnel	Count	44
Reference Year for Cost Estimates	Year	2021
Net Plant Output (Note 1)	MW	47.403
Annual Net Generation	MWh / year	332,200
Fixed Costs, Annual	\$1000 / year	7,375
Variable Costs, Annual	\$1000 / year	2,685
Total O&M Costs, Annual	\$1000 / year	10,061
Fixed Costs, Annual	\$ / kW-year	155.59
Variable Costs, Annual	\$ / MWh	8.08

Notes:

1. Net Output value based on ambient conditions of 80°F and relative humidity of 60 percent.

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### C.4 Natural Gas-Fired Resources

#### C.4.1 Technology Overview

##### C.4.1.1 F-Class and Advanced Class Combustion Turbines

F-class combustion turbine technologies provide a demonstrated operating record in the United States and around the world. GE's 7F fleet includes over 900 units, and these units have compiled over 45 million operating hours. The latest iteration of the F-class combustion turbine offered by GE is the 7F.05.

Advanced class machines offer the highest efficiency among frame combustion turbines, with CC efficiencies exceeding 60 percent. For large-scale gas-fired applications (i.e., with SC output greater than 250 MW) at 60 Hz, GE offers an advanced class combustion turbine option, the 7HA.02.

The purpose of using only GE CTGs as the basis for these resource options is to provide a consistent comparison within typical combustion turbine technology classes and is not intended to be an implicit recommendation of GE CTGs. This approach helps to minimize the cost and duration of IRP modeling versus modeling of CTGs from several different manufacturers. If one of these GE CTG based Resource Options is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development, including consideration of CTGs from other manufacturers. For example, if an advanced class GE 7HA.02 CTG option is selected, JEA should also consider and evaluate comparable advanced-class CTGs offered by Mitsubishi Power Americas (MPA) and Siemens as well as GE.

##### C.4.1.1.1 GE 7F.05

The 7F.05 is an air-cooled frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low nitrogen oxide (NO<sub>x</sub>) (DLN) combustors. The 7F.05 is GE's fifth-generation 7F machine. Advancements integrated into the 7F.05 design include a redesigned compressor with three variable stator stages and a variable inlet guide vane for improved turndown capabilities. The 7F.05 was introduced in 2009, and the first unit shipped in 2013.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 megawatts per minute (MW / min) ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes (excluding purge).
- Natural gas interface pressure requirement of 435 pounds per square inch gauge (psig) at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.
- DLN combustion with CTG NO<sub>x</sub> emissions of 9 parts per million (ppm) on natural gas.
- Capable of turndown to 45 percent of full load.
- High exhaust temperature increases the difficulty of implementing post-combustion NO<sub>x</sub> emissions controls (i.e., SCR).

Cost and performance characteristics have been developed for the following GE 7F.05 combustion turbine configurations:

- 1x0 SC natural gas-fired GE 7F.05 combustion turbine facility.

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- 1x1 CC natural gas-fired GE 7F.05 combustion turbine facility.
- 2x1 CC natural gas-fired GE 7F.05 combustion turbine facility.

### C.4.1.1.2 GE 7HA.02

The GE 7HA.02 is an air-cooled frame CTG with a single shaft; 14-stage axial compressor; 4-stage axial turbine; and can-annular DLN combustor. The machine includes a single inlet guide vane stage and three variable stator vane stages to vary compressor geometry for part load operation. The 7HA.02 represents one of the largest and most advanced frame CTG technologies from GE, with the 7HA.03 CTG being the largest and most recent CTG from GE. The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.02 uses the DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system, which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees; providing stable operations; and allowing for increased fuel variability.

Besides the 7HA.03 CTG, the 7HA.02 is the newest 60Hz combustion turbine technology offered by GE. GE has sold 59 7HA.02 gas turbines around the world with 34 of those in commercial operation and 8 more being commissioned, as of November 2021. The first four 7HA.02 gas turbines entered commercial operations at two separate Exelon sites in Texas in June 2017. The total 7HA fleet, including 7HA.01 and 7HA.02, has more than 780,000 hours and almost 6,000 starts. The 7HA.02 fleet leader has over 32,000 operating hours.

Key attributes of the GE 7HA.02 include the following:

- High availability.
- 60 MW / min ramp rate.

- Capable of turndown to approximately 25 percent of full load (ambient temperature dependent).
- Natural gas interface pressure requirement of approximately 540 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.
- DLN combustion with CTG NO<sub>x</sub> emissions of 25 ppm on natural gas.

Cost and performance characteristics have been developed for the following advanced class combustion turbine configurations:

- GE 7HA.02
  - 1x0 SC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 2x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 3x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.

### C.4.1.2 Aero-derivative Combustion Turbines

Aero-derivative CTGs were derived from aerospace jet turbine technology. An aero-derivative CTG is generally a two- or three-shaft turbine with a variable-speed compressor and power turbine. The variable-speed drive is advantageous for part-load efficiency because airflow is reduced with the lower speed.

Turbine inlet temperatures in aero-derivative CTGs are generally higher than in frame CTGs. Aero-derivatives generally offer higher efficiencies than frame CTGs. Furthermore, aero-derivative CTGs are smaller and lighter for a given power output and can be started more rapidly because of the inherently low inertia. The faster start times allow for less fuel consumption during startup. This feature allows the machine to more easily follow load for peaking applications. Aero-derivative CTGs are

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available in sizes ranging from single digits up to approximately 100 MW. The machines with the largest market share are in the range of 40 to 60 MW.

Aeroderivative CTGs have higher compressor pressure ratios than frame CTGs resulting in much higher fuel gas pressure requirements. This higher-pressure requirement can result in the need for onsite fuel gas compressors.

### C.4.1.2.1 GE LMS100

The LMS100 is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor (LPC) section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor (HPC) section. A mixture of compressed air and fuel is combusted in a single annular combustor (SAC). Hot flue gas then enters the two-stage high pressure turbine (HPT). The high-pressure turbine drives the high-pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine (IPT), which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine (LPT) drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to / from the intercooler and the external heat exchanger. NO<sub>x</sub> emissions are minimized utilizing water injection (for the LMS100PA+) or the use of Dry Low Emission (DLE) combustion technology (for the LMS100PB+).

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high-pressure turbine are

derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 MW / min ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 850 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.

The LMS100 is available in several configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and DLE in lieu of water injected combustion for applications when water availability is limited.

Cost and performance characteristics have been developed for the following GE LMS100 combustion turbine configuration:

- 1x0 SC natural gas-fired GE LMS100PA+ combustion turbine facility.

### C.4.1.2.2 GE LM6000

The LM6000 was introduced in 1991, and the LM6000 family of gas turbines has accumulated more than 37 million operating hours with over 1,200 units produced. The baseline LM6000 is a derivative of the CF6-80C2 (Commercial Aircraft) flight gas turbine, and more recently,

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the CF6-80E1. Models currently commercially offered by GE include the LM6000PC, LM6000PG, LM6000PF, and LM6000PF+.

The LM6000 employs a 5-stage LPC and a 14 stage HPC, an annular combustor, two-stage air-cooled HPT, and a five-stage LPT. All stages of the LPC and six stages of the HPC feature variable-geometry inlet guide vanes. The LPT drives both the LP compressor and the generator load.

The LM6000 SPRINT (SPRay INTERcooling) configuration increases power output of the engine by injecting air-atomized demineralized water droplets into the compressor to cool the air flow as the water evaporates on its way through the compressor, increasing power by approximately 9 percent at ISO conditions.

The LM6000PC and LM6000PG employ SAC combustion systems. The LM6000PC was introduced in 1997 after approximately 1 million operating hours on models PA / PB. The LM6000PG and PH engines were announced in 2008. Upgrades of LM6000PG, relative to the LM6000PC design, include upgraded materials and increased rotor speed (with addition of a gearbox) to increase power output.

The LM6000PF and LM6000PF+ employ DLE combustion systems. GE introduced the LM6000PF in 2005. The LM6000PF is an upgrade of the LM6000PD. The LM6000PF was the first LM6000 model to employ DLE1.5 technology, which utilized improved combustor design to achieve NO<sub>x</sub> emissions of 15 ppm. In 2016, GE announced an upgrade of the LM6000PF: the LM6000PF+. Like the LM6000PG, the LM6000PF+ operates at increased rotor speeds to allow for greater airflow and firing temperature. Additional modifications allow for greater airflow and firing temperature, increasing power output relative to the LM6000PF. In April of 2017, an LM6000PF+ unit was placed into demonstration at a utility host site.

Key attributes of the GE LM6000 include the following:

- High full and part load efficiency.
- High availability.
- 50 MW / min ramp rate.
- 5-minute fast start to full power (excluding purge).
- Capable of turndown to 25 percent of full load (50 percent for DLE).
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 640 psig at the CTG inlet, downstream of the filters and regulating skid.
- Dual fuel capable.

Cost and performance characteristics have been developed for the following GE LM6000 combustion turbine configuration:

- 1x0 SC natural gas-fired GE LM6000PF SPRINT combustion turbine facility.

### C.4.1.3 Reciprocating Internal Combustion Engines

A reciprocating internal combustion engine (RICE) resource option utilizes a utility-size spark-initiated or compression initiated gas-fueled piston driven engine as the prime mover for the generating facility. A reciprocating engine is a heat engine that uses the expansion of hot gases to convert the linear movement of the piston into the rotating movement of a crankshaft to generate power.

Modern reciprocating engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE units are characterized by the type of combustion utilized: spark-ignited or compression-ignited, also known as diesel. The spark-ignited engine is based on the Otto

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thermodynamic cycle and uses a spark plug to ignite an air-fuel mixture injected at the top of the cylinder.

The size and power of a reciprocating engine is a function of the volume of fuel and air combusted. Therefore, the size of the cylinder, the number of cylinders, and the engine speed determine the amount of power the engine generates. The output of reciprocating engine generator sets is currently limited to approximately 20 MW. In a power plant, multiple units are grouped together in a power block to provide generating capacity in standardized sizes. Reciprocating engine power plants are highly efficient with SC efficiencies of 40 to 49 percent (LHV), generally surpassing the performance of SC CT power plants. The biggest concession with reciprocating engines is the operation and maintenance costs often make them less appealing in life-cycle cost analyses.

Many RICE units use a compressed air start system in which compressed air is used to initiate rotation of the crankshaft. RICE units can start quickly (approximately two hours after shutdown) and require a minimal amount of electricity and fuel during startup.

The technology selected to represent the RICE options was the Wartsila 18V50DF in SC configuration. Consideration of only the Wartsila RICE for this resource option is not intended to be an implicit recommendation of the Wartsila RICE. If this resource options is selected for implementation as a result of the IRP, further investigation, and refinement of these estimates is recommended in subsequent stages of planning and development, including consideration of RICE from other manufacturers.

The Wartsila 18V50DF reciprocating engine is a turbocharged, four-stroke compression-ignited dual fuel engine. The DF is always started on liquid fuel and requires a small amount of liquid pilot fuel even during natural gas operation to

maintain combustion. The 18V50DF utilizes 18 cylinders in a “V” configuration. Each cylinder has a bore diameter of 500 millimeters (19-11 / 16 inches) and a stroke of 580 millimeters (22-13 / 16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. Currently there are approximately 260 18V50DF engines in operation around the world used for power generation, and at least another forty sold to date, with initial commercial operations starting in 2004.

For this characterization, it is assumed that engine heat is rejected to the atmosphere using an air-cooled heat exchanger, or “radiator.” An 18V50DF power plant utilizing air cooled heat exchangers requires very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO<sub>x</sub> reduction.

Key attributes of the Wartsila 18V50DF include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge); purge is performed during the shutdown sequence.
- Each engine is capable of turndown to 40 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or outage schedule.
- Natural gas interface pressure requirement of 75 psig.
- Dual fuel capable.

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Cost and performance characteristics have been developed for the following Wartsila 18V50DF RICE configuration:

- 5x0 SC natural gas-fired Wartsila 18V50DF RICE facility.

### C.4.2 Study Basis

There were twelve (12) gas-fired combustion turbine generator (CTG) based Resource Options studied including four simple cycle (SC) options and eight combined cycle (CC) options. The SC options are expected to operate as peaking resources while the CC options are expected to operate as intermediate / base duty resources.

The gas-fired Resource Options include those using current, commercial large frame CTGs as the prime movers. Consideration was made for backup fuel oil firing capability to mitigate gas supply interruptions during operations. The following CTGs manufactured by General Electric (GE) were used as the basis for the characterization of these options:

- GE 7FA.05 (in both SC and CC configurations)
- GE 7HA.02 (in both SC and CC configurations)
- GE LMS100 (in SC configuration)
- GE LM6000 (in SC configuration)
- Existing GE 7F.03 SC units upgraded to include a 7FA.05 compressor and advanced gas path (AGP) upgrade, and converted from SC to CC configuration

The study basis utilized to evaluate the gas-fired Resource Options includes the following:

- Gas-fired Resource Options will be constructed at either the existing Greenland Energy Center (GEC) or at a brownfield location currently referenced as the North Jax site.
- The GEC site was originally designed for an ultimate buildout of two 2x1 F-Class

CTG units in CC configuration plus one SC CTG. There are currently two 7FA.03 SC CTGs in SC configuration on the site along with service water, fire water, control room, fuel oil storage, electrical substation, gas supply line, and other common site equipment already constructed.

- The North Jax site is anticipated to be parceled out from the now-retired St. Johns River Power Park (SJRPP) site which is owned by JEA. The potential site is anticipated to be cleared and restored to level ground with no site infrastructure in place except the original SJRPP substation. There is also a low-pressure gas line to the site, formerly used for startup burners.
- CTGs and RICE technology will be dual fuel capable, with natural gas as the primary fuel and Ultra Low Sulfur No. 2 distillate as the secondary fuel.
- For CC Resource Options:
  - CTG(s) will be located outdoors in a weather-proof enclosure; the CTGs will be close-coupled to a three-pressure heat recovery steam generator (HRSG). Ancillary CTG skids will also be located outdoors in weather-proof enclosures.
  - The steam turbine will be located outdoors in a weather-proof enclosure.
  - A generation building will house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility already exists at GEC but may need to be expanded.
  - Wet surface condenser with a mechanical draft cooling tower-based heat rejection systems (WMDCT) will be utilized. To

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- demonstrate the impacts of utilizing an air-cooled condenser (ACC) based dry heat rejection system, an ACC option will be considered for the 1x1 7HA.02 CC Resource Option.
- Oxidation catalysts and selective catalytic reduction (SCR) will be utilized to meet current market Best Available Control Technology (BACT) stack emission rate targets.
  - Supplemental HRSG duct firing will be included.
  - Conventional start times will be achievable and black start capability will be provided.
  - Note that CC units constructed in the state of Florida (over 80MW steam) are subject to regulation under the Florida Power Plant Siting Act (PPSA), which is regulated by the Florida Public Service Commission (PSC). The minimum duration for completing this regulatory process is three years.
  - For SC Resource Options:
    - The CTG / RICE will be located outdoors in a weather-proof enclosure. Ancillary CTG / RICE skids will also be located outdoors in weather-proof enclosures.
    - A generation building will house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility already exists at GEC but may need to be expanded.
  - Fast-start capability along with black start capability will be provided.
  - Frame type CTGs will meet New Source Performance Standards (NSPS) through good combustion practices and will not have oxidation catalysts or SCR.
  - Aeroderivative type CTGs will meet NSPS through good combustion practices and will also have oxidation catalysts and SCR.
  - RICE technology will meet NSPS through good combustion practices, oxidation catalysts and SCR.
  - Note that peaking technologies are not regulated by the Power Plant Siting Act (PPSA) and therefore permitting duration is approximately 18 months total.
  - At the GEC facility, upgrades (proposed by PGS) are sufficient to support the frame CTGs and RICE, but fuel gas compression costs are included in the capital cost of the aeroderivative CTGs.<sup>8</sup> At the North Jax site, upgrades (proposed by PGS) would be required for all options except for the RICE option, and fuel gas compression costs are included in aeroderivative CTG capital costs.<sup>9</sup>
- Study basis parameters for the selected gas-fired Resource Options are summarized in Table C-13 and Table C-14 below.

<sup>8</sup> Because of the structure of the existing supply contract for the GEC site, incremental costs for increased delivery or pressure from the Peoples Gas System (PGS) owned Seacoast Pipeline to the JEA-owned GEC Lateral serving the GEC have been captured in the IRP as a transportation cost adder to the GEC unit fuel forecast price, rather than as a capital cost added to the unit construction cost or Owner's Cost.

<sup>9</sup> Pressure and flow to the NGS and SJRPP sites, and to the proposed adjacent or co-located North Jax site via the existing supply system co-owned by JEA and PGS are limited. Costs to serve the potential upgrades from the PGS system have been captured in the IRP as a transportation cost adder to the NGS and SJRPP unit fuel forecast price, rather than as a capital cost added to the unit construction cost or Owner's Cost.

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Table C-13 - Study Basis Parameters for Gas-Fired Peaking Resource Options

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output <sup>1</sup> (MW)	Annual Capacity Factor (%)	Annual Number of Starts
7	2x0 GE LM6000 PF SPRINT	Combustion Turbine: GE LM6000 PF SPRINT AQC: SCR, CO Catalyst	Peaking	91	10	250
8	1x0 GE LMS100PA+	Combustion Turbine: GE LMS100PA+, with dry interstage cooling AQC: SCR, CO Catalyst	Peaking	111	10	250
9	1x0 GE 7FA.05	Combustion Turbine: GE 7F.05 AQC: Good Combustion Practices	Peaking	226	10	250
10	1x0 GE 7HA.02	Combustion Turbine: GE 7HA.02 AQC: Good Combustion Practices	Peaking	329	10	250
11	5x0 Wartsila 18V50DF	Reciprocating Engine: Wartsila 18V50SG AQC: SCR, CO catalyst	Peaking	89	11	250

Notes

1. Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70 percent, with no inlet chilling.

Table C-14 - Study Basis Parameters for Gas-Fired Intermediate / Base Resource Options

ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output <sup>1</sup> (MW)	Annual Capacity Factor (%)	Annual Number of Starts
12	1x1 GE 7FA.05	Combustion Turbine: GE 7F.05 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	373	35 / 80	325 / 5

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ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output <sup>1</sup> (MW)	Annual Capacity Factor (%)	Annual Number of Starts
13	2x1 GE 7FA.05	Combustion Turbine: GE 7F.05 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	749	35 / 80	325 / 5
14	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	558	35 / 80	325 / 5
15	2x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	1,119	35 / 80	325 / 5
16	3x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	1,684	35 / 80	325 / 5

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ID	Resource Option	Plant Configuration	Duty	Average Ambient Net Output <sup>1</sup> (MW)	Annual Capacity Factor (%)	Annual Number of Starts
17	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Air-Cooled Condenser	Intermediate / Base	552	35 / 80	325 / 5
18	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor / AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor / AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	318	35 / 80	325 / 5
19	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor / AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor / AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15 percent STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate / Base	638	35 / 80	325 / 5

## Notes

1. Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70 percent, with no inlet chilling.
2. Output for Resource Option ID options 17 and 18 is total capacity, not incremental capacity associated with the conversion.

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### C.4.2.2 Non-fuel Operating & Maintenance Estimating Basis

Black & Veatch developed non-fuel O&M cost estimates for each Resource Option under consideration. Non-fuel O&M cost estimates were developed as representative estimates based on previous Black & Veatch experience with projects of similar design and scale, and relevant vendor information available to Black & Veatch. Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components:

- Fixed O&M costs include labor, routine maintenance, and other expenses (e.g., training, office, and administrative expenses).
- Non-fuel Variable O&M costs include outage maintenance (including the costs associated with Long Term Service Agreements [LTSA] or other maintenance agreements), parts and materials, water usage, chemical usage, and equipment.
- Non-fuel Variable O&M costs exclude the cost of fuel (e.g., natural gas).

Additional assumptions regarding O&M cost estimates include the following:

- SC facilities are assumed to operate in peaking service, while CC facilities are

assumed to operate in intermediate duty service or base-load service.

Assumed annual operating profiles for SC and CC facilities are summarized in Table C-16.

- Plant staffing assumptions are summarized in Table C-17 for the various facility configurations under consideration.
- Labor rates for O&M staff were assumed based on Black & Veatch experience with similar facilities in the southeastern United States.
- All major maintenance for CTG / RICEs is assumed to be conducted under an LTSA with the OEM. LTSA costs were estimated based on confidential and proprietary recent LTSA proposals (provided to Black & Veatch) for the CTG / RICEs under consideration.
- All plant water consumption (including cooling water) was assumed to be sourced from the local water utility (JEA). Water rates were assumed to be \$2.50 per 1,000 gallons.
- Cost for additional plant consumables based on Black & Veatch experience with similar facilities in the region.
- All non-fuel O&M cost estimates are presented in mid-year 2021 United States dollars.

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Table C-15 - Potential Owner’s Costs for a Power Generation Project

<p><b>Project Development</b></p> <ul style="list-style-type: none"> <li>•Site selection study</li> <li>•Land purchase / rezoning for greenfield sites</li> <li>•Transmission / gas pipeline right-of-way</li> <li>•Road modifications / upgrades</li> <li>•Demolition</li> <li>•Environmental permitting / offsets</li> <li>•Public relations / community development</li> <li>•Legal assistance</li> <li>•Provision of project management</li> </ul>	<p><b>Spare Parts and Plant Equipment</b></p> <ul style="list-style-type: none"> <li>•Combustion and steam turbine materials, supplies, and parts</li> <li>•HRSG and / or boiler materials, supplies, and parts</li> <li>•SCR and CO catalyst materials, supplies, and parts</li> <li>•Balance-of-plant equipment / tools</li> <li>•Rolling stock</li> <li>•Plant furnishings and supplies</li> <li>•Recip. engine materials, supplies, and parts</li> </ul>
<p><b>Plant Startup / Construction Support</b></p> <ul style="list-style-type: none"> <li>•Owner’s site mobilization</li> <li>•O&amp;M staff training</li> <li>•Initial test fluids and lubricants</li> <li>•Initial inventory of chemicals and reagents</li> <li>•Consumables</li> <li>•Cost of fuel not recovered in power sales</li> <li>•Auxiliary power purchases</li> <li>•Acceptance testing</li> <li>•Construction all-risk insurance</li> </ul>	<p><b>Utility Interconnections</b></p> <ul style="list-style-type: none"> <li>•Natural gas service</li> <li>•Gas system upgrades</li> <li>•Electrical transmission (including switchyard)</li> <li>•Water supply</li> <li>•Wastewater / sewer</li> </ul>
<p><b>Owner's Contingency</b></p> <ul style="list-style-type: none"> <li>•Unidentified project scope increases</li> <li>•Unidentified project requirements</li> <li>•Costs pending final agreements (i.e., interconnection contract costs)</li> </ul>	<p><b>Owners Project Management</b></p> <ul style="list-style-type: none"> <li>•Preparation of bid documents and the selection of contractors and suppliers</li> <li>•Performance of engineering due diligence</li> <li>•Provision of personnel for site construction management</li> </ul>
<p><b>Financing</b></p> <ul style="list-style-type: none"> <li>•Financial advisor, lender’s legal, market analyst, and engineer</li> <li>•Interest during construction</li> <li>•Loan administration and commitment fees</li> <li>•Debt service reserve fund</li> </ul>	<p><b>Taxes/Advisory Fees/Legal</b></p> <ul style="list-style-type: none"> <li>•Taxes</li> <li>•Market and environmental consultants</li> <li>•Owner’s legal expenses</li> <li>•Interconnect agreements</li> <li>•Contracts (procurement and construction)</li> <li>•Property</li> </ul>

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**Table C-16 - Annual Operating Profile Assumptions for Gas-fired Facilities**

CT Facility Configuration	Annual Number of Starts	Annual Number of Hours	Annual Capacity Factor
SC CT / RICE Facility	250	876 / 1,000	10% / 11.4%
CC CT Facility	325 / 5	3,066 / 7,008	35% / 80%

**Table C-17 - Plant Staffing Assumptions for Facilities**

CT Facility Configuration	Plant Staffing (FTEs)
1x0 SC CT	9
1x1 CC CT	17
2x1 CC CT	19
3x1 CC CT	23
5x0 Simple Cycle RICE	13
Utility Scale Solar & Solar + BESS	0.5
Biomass	44

### C.4.2.3 Duct Firing Considerations

All duct firing represents a trade-off between increased output and operational flexibility achieved at the expense of worse heat rate, plant footprint, and operational complexity. The level of duct firing can be sized based on material temperature limits, transmission limits, or operational goals. The relevant Resource Options are duct fired to an output corresponding to 15 percent of steam turbine (STG) unfired output to allow for future gas turbine upgrades. CTG manufacturers regularly iterate their technology and offer increased performance on existing units. For example, a 10 percent increase in output may be realized following upgrades made available at the first major inspection (typically between 50,000 and 65,000 hours of operation). However, these CTG upgrades require large engineering and capital cost efforts to resize the rest of the plant if one sizes the STG and balance-of-plant (BOP) cycle (pumps, pipes, condenser, etc.) only for the original CTG exhaust energy.

Sufficient margin for future CTG upgrades can be incorporated by sizing the level of duct firing

output 15 percent higher than unfired STG output. This intermediate-range planning avoids large rework on the STG and BOP. Even after a CTG upgrade, the duct firing allows flexibility in operation such as on hot days when the CTG output falls due to high ambient temperature.

### C.4.2.4 Black Start Considerations

A black start system allows the starting of a primary generator with no grid connection. Generally, black start systems consist of some number of small diesel or natural gas generators. They are sized for the minimum required starting loads, which can vary based on plant features.

Large frame CTGs can draw significant electrical load for their static frequency converter starting mechanisms, in addition to critical loads such as oil pumps and vent fans. Minimal gas compression and BOP equipment needs also need assessed. Finally, proper load sequencing and electrical design can bring up sequentially larger pieces of equipment—for example, starting one of the CTG / HRSG trains in a 3x1, then sequentially bringing the other trains online.

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### C.4.2.5 Wet vs. Dry Cooling Considerations

CC power plants require large heat rejection systems for proper operation. For a CC power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower (WMDCT) is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature, which results in a greater thermal efficiency of the bottoming cycle. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. For example, operation of a 2x1 7F.05 CC would require approximately 2,000 to 3,000 gallons per minute (gpm) of water during full load operation, depending on ambient conditions.

In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet

mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC, which results in a lower bottoming cycle efficiency compared to wet cooling methods. The reduction in cycle efficiency results in reduced plant output, and increased plant heat rate (less electrical output for the same amount of fuel used).

Cost and performance characteristics have been developed for the following dry cooling configuration:

- 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility with ACC.

O&M costs required to maintain an air-cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water usage and water treatment chemicals would likely offset the additional maintenance cost. Table C-18 provides a summary comparison for a typical CC operating during hot day conditions. The performance difference during average day conditions would be reduced.

**Table C-18 - Typical CC Wet versus Dry Cooling Comparison**

Variable	Wet Surface Condenser / Wet Mechanical Draft Cooling Tower	Air Cooled Condenser
Capital Cost	Base	+3 to +5 percent
Net Plant Output	Base	-1.5 to -2.0 percent
Net Plant Heat Rate	Base	+1.5 to +2.0 percent

## Appendix C - New Generating Resource Options Characterization

### C.4.3 Summary of Capital, Owners, and O&M Cost Estimates

Black & Veatch developed order-of-magnitude capital and owners cost estimates for generic gas-fired power plants constructed within the state of Florida, considering the Resource Options in this Characterization of Resource Options report. Estimates are based on similar studies and project experience and have been adjusted using engineering judgement.

### C.4.3.1 Overnight EPC Capital Cost Estimates

Overnight EPC cost estimates have been prepared considering the estimating basis defined in Section 2. Screening-level estimates of EPC capital costs for both GEC and North Jax are included in Table C-19 and Table C-20. Owner's costs have been included in these tables as well.

**Table C-19 - Summary of GEC Gas-Fired Overnight EPC Capital and Owner's Cost Estimates**

ID	Resource Option	EPC Cost (\$M) (Typical Greenfield)	EPC Cost (\$M) (Site-Specific)	Owner's Cost (\$M)	Total EPC + Owner's Cost (\$M)	Optional Adder for Black Start (\$M)
7	2x0 GE LM6000 PF SPRINT	92.7	89.7	14.6	104.3	0.50
8	1x0 GE LMS100PA+	109.9	106.9	17.3	124.2	1.25
9	1x0 GE 7F.05	97.1	94.1	15.3	109.4	6.25
12	1x0 GE 7HA.02	153.9	149.9	24.2	174.1	6.25
19	5x0 Wartsila 18V50DF	112.7	111.2	18.0	129.2	N/A
10	1x1 GE 7F.05	391.1	384.1	61.7	445.8	6.25
11	2x1 GE 7F.05	605.1	596.1	145.6	741.7	6.25
13	1x1 GE 7HA.02	460.5	452.5	72.6	525.1	6.25
14	2x1 GE 7HA.02	676.5	666.5	206.8	873.3	6.25
15	3x1 GE 7HA.02	885.6	873.6	240.0	1,113.6	6.25
16	1x1 GE 7HA.02	483.1	475.1	76.2	551.3	6.25
17	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor / AGP upgrade	269.9	261.9	42.1	304.0	6.25
18	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor / AGP upgrade	487.1	477.1	76.5	553.6	6.25

## Appendix C - New Generating Resource Options Characterization

**Table C-20 - Summary of North Jax Gas-Fired Overnight EPC Capital and Owner's Cost Estimates**

ID	Resource Option	EPC Cost (\$M) (Typical Greenfield)	EPC Cost (\$M) (Site-Specific)	Owner's Cost (\$M)	Total EPC + Owner's Cost (\$M)	Optional Adder for Black Start (\$M)
7	2x0 GE LM6000 PF SPRINT	92.7	92.7	20.2	112.9	0.50
8	1x0 GE LMS100PA+	109.9	109.9	23.0	132.9	1.25
9	1x0 GE 7F.05	97.1	97.1	20.9	118.0	6.25
12	1x0 GE 7HA.02	153.9	153.9	30.0	183.9	6.25
19	5x0 Wartsila 18V50SG	112.7	112.7	23.4	136.1	N/A
10	1x1 GE 7F.05	391.1	391.1	68.0	459.1	6.25
11	2x1 GE 7F.05	605.1	605.1	102.2	707.3	6.25
13	1x1 GE 7HA.02	460.5	460.5	79.1	539.6	6.25
14	2x1 GE 7HA.02	676.5	676.5	113.6	790.1	6.25
15	3x1 GE 7HA.02	885.6	885.6	147.1	1,032.7	6.25
16	1x1 GE 7HA.02	483.1	483.1	82.7	565.8	6.25

The scope of these cost estimates includes all facility generation equipment up to the high-side of the generator step-up transformers. The cost estimates presented include dual fuel systems (to allow operation on either natural gas or distillate oil fuels) for the CTG and RICE options.

Within a given estimate, EPC capital costs may be divided into two categories: direct EPC costs and indirect EPC costs. Direct EPC costs include the costs associated with the purchase and installation of major equipment and balance of plant (BOP) equipment. Indirect costs include costs such as engineering, construction management, construction indirects<sup>10</sup>, pre-operational plant startup and testing, bonding and insurance, and EPC contractor contingency and profit.

<sup>10</sup> Construction indirect costs encompass a variety of items including construction supervision, purchase of small tools and consumables, site services, construction safety program (including development and compliance),

### C.4.3.2 Non-Fuel O&M Cost Estimates

Non-fuel O&M cost estimates have been prepared considering the estimating basis defined in Section 4.3. Estimates of annual non-fuel O&M costs are heavily dependent upon operating profile assumptions such as the number of annual operating hours and the number of annual starts.

For resource planning or general comparison purposes, it is often useful to consider O&M costs on various normalized bases. Fixed O&M costs may be evaluated on a \$ / kW-year basis, while variable O&M costs may be evaluated on a \$ / MWh basis. Given the operating profiles defined for Resource Options in Table C-16, screening-level estimates of non-fuel O&M costs and normalized O&M costs for each Resource Option are presented in Table C-21, Table C-22 and Table C-23.

installation of temporary facilities and utilities, rental of construction equipment, and heavy haul of construction materials and equipment.

## Appendix C - New Generating Resource Options Characterization

Table C-21 - Summary of Screening-Level Non-Fuel O&amp;M Cost Estimates for Resource Options 7,8,9,10,11, 12 and 19

Resource Option	Unit	2x0 GE LM6000 PF Sprint	1x0 GE LMS100PA+	1x0 GE 7F.05	1x0 GE 7HA.02	5x0 Wartsila 18V50DF	1x1 GE 7F.05	1x1 GE 7F.05	2x1 GE 7F.05	2x1 GE 7F.05
Resource Option ID	--	7	8	9	12	19	10	10	11	11
Case Number	--	7	8	9	12	19	10A	10B	11A	11B
Annual Capacity Factor	%	10%	10%	10%	10%	11%	35%	80%	35%	80%
Starts Per Year	Count	250	250	250	250	250	325	5	325	5
Number of Full Time Equivalent Personnel	Count	9	9	9	9	13	17	17	19	19
Reference Year for Cost Estimates	Year	2021	2021	2021	2021	2021	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	91	111	226	329	89	373	373	749	749
Annual Net Generation	MWh / year	79,817	97,485	198,257	288,095	89,237	1,144,056	2,614,985	2,297,812	5,252,142
Fixed Costs, Annual	\$1000 / year	1,443	1,467	1,931	2,040	2,030	3,805	3,805	4,947	4,947
Variable Costs, Annual	\$1000 / year	564	443	2,032	3,944	810	4,766	6,342	9,357	12,305
Total O&M Costs, Annual	\$1000 / year	2,007	1,910	3,963	5,984	2,840	8,571	10,147	14,304	17,252
Fixed Costs, Annual	\$ / kW-year	15.84	13.18	8.53	6.20	22.71	10.20	10.20	6.60	6.60
Variable Costs, Annual	\$ / MWh	7.07	4.55	10.25	13.69	9.08	4.17	2.43	4.07	2.34
Notes:										
1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.										
2. Different case with the same Resource Option ID represents different capacity factors.										

## Appendix C - New Generating Resource Options Characterization

Table C-22 - Summary of Screening-Level Non-Fuel O&amp;M Cost Estimates for Resource Options 13, 14, 15 and 16

Resource Option	Unit	1x1 GE 7HA.02	1x1 GE 7HA.02	2x1 GE 7HA.02	2x1 GE 7HA.02	3x1 GE 7HA.02	3x1 GE 7HA.02	1x1 GE 7HA.02	1x1 GE 7HA.02
Resource Option ID	--	13	13	14	14	15	15	16	16
Case Number	--	13A	13B	14A	14B	15A	15B	16A	16B
Annual Capacity Factor	%	35%	80%	35%	80%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5	325	5	325	5
Number of Full Time Equivalent Personnel	Count	17	17	19	19	23	23	17	17
Reference Year for Cost Estimates	Year	2021	2021	2021	2021	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	558	558	1,119	1,119	1,684	1,684	552	552
Annual Net Generation	MWh / year	1,709,870	3,908,274	3,432,057	7,844,701	5,163,372	11,801,993	1,692,677	3,868,977
Fixed Costs, Annual	\$1000 / year	4,127	4,127	5,592	5,592	7,388	7,388	4,134	4,134
Variable Costs, Annual	\$1000 / year	8,298	9,677	16,416	18,938	24,520	28,194	7,110	6,963
Total O&M Costs, Annual	\$1000 / year	12,424	13,804	22,008	24,530	31,908	35,582	11,244	11,097
Fixed Costs, Annual	\$ / kW-year	7.40	7.40	5.00	5.00	4.39	4.39	7.49	7.49
Variable Costs, Annual	\$ / MWh	4.85	2.48	4.78	2.41	4.75	2.39	4.20	1.80
Notes:									
1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.									
2. Different cases with the same Resource Option ID represent different capacity factors.									

## Appendix C - New Generating Resource Options Characterization

Table C-23 - Summary of Screening-Level Non-Fuel O&amp;M Cost Estimates for Resource Options 17 and 18

Resource Option	Unit	Conversion of Existing GEC CTGs to 1x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 1x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 2x1 GE 7F.03 with .05 Compressor / AGP Upgrade	Conversion of Existing GEC CTGs to 2x1 GE 7F.03 with .05 Compressor / AGP Upgrade
Resource Option ID	--	17	17	18	18
Case Number	--	17A	17B	18A	18B
Annual Capacity Factor	%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5
Number of Full Time Equivalent Personnel	Count	17	17	19	19
Reference Year for Cost Estimates	Year	2021	2021	2021	2021
Net Plant Output (Note 1)	MW	318	318	638	638
Annual Net Generation	MWh / year	973,762	2,225,741	1,956,108	4,471,104
Fixed Costs, Annual	\$1000 / year	3,687	3,687	4,703	4,703
Variable Costs, Annual	\$1000 / year	4,658	6,125	9,173	11,943
Total O&M Costs, Annual	\$1000 / year	8,345	9,811	13,876	16,647
Fixed Costs, Annual	\$ / kW-year	11.61	11.61	7.37	7.37
Variable Costs, Annual	\$ / MWh	4.78	2.75	4.69	2.67
Notes:					
1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for CC units.					
2. Different cases with the same Resource Option ID represent different capacity factors.					

## Appendix C - New Generating Resource Options Characterization

### C.5 Nuclear Generation Resources

A nuclear generating plant can provide both carbon-free baseload energy and, if contractually provided, the flexibility to adjust generation to compensate for variable grid demands and variable renewable generation.

The range of potential nuclear resource options includes both traditional large light water reactors (LLWRs) and new small modular reactor (SMR) technologies. However, only the SMR technologies were considered for the IRP. This is primarily because JEA has already committed to purchase a large amount of power from a new nuclear resource that utilizes the LLWR technology, namely 200 MW from the new Vogtle 3 and 4 nuclear generating units that utilize the AP1000 technology at 1,117 MW each. It's also because while LLWRs are still being constructed internationally, LLWRs are becoming less common in the United States due to the large capital cost and extended construction schedules. Vogtle is the only new LLWR scheduled to enter service in the region within the next 10 years. SMR based resources include those using the light water reactors typically less than 300 MWe and non-light water micro-reactors that are typically less than 10 MWe. These would be less capital-intensive than LLWRs and could be pursued by JEA in the future either directly or by participating in an ownership opportunity or in a PPA with a nuclear utility developer.

#### C.5.1.1 Large Light Water Reactors

LLWRs are the most prevalent of the current nuclear operating fleet in the United States. LLWRs in the United States consist of both Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs). While the current operating fleet is composed of Generation III (Gen III) reactors, which have active safety components and require emergency diesel generators for support of the active safety equipment, any new LLWRs constructed in the future would be Generation III+ (Gen III+)

reactors that have passive safety features. Gen III+ reactors rely on passive safety features, such as gravity drainage and passive heat transfer. Active systems are used to back-up the passive safety features but do not have to be safety related. Because of the added passive safety features, the Gen III+ reactors are typically an order of magnitude safer (in terms of core damage frequency or CDF) than the current fleet of Gen III reactors.

There are several LLWR technologies that have been licensed by the NRC, including the Gen III Advanced Boiling Water Reactor (ABWR), the Gen III+ Advanced Power Reactor 1400 (APR1400), the Gen III+ Advanced Passive 1000 (AP1000), and the Gen III+ Economic Simplified Boiling Water Reactor (ESBWR). The two primary Gen III+ LLWR technologies that are licensed by the NRC and have been issued Combined Licenses (COLs) are the Westinghouse AP1000 and the General Electric-Hitachi Nuclear Energy ESBWR. Any new LLWRs built in the United States in the next 15 to 20 years would likely be either AP1000 or ESBWR units.

##### C.5.1.1.1 Westinghouse AP1000

The AP1000® Plant is a two-loop pressurized water reactor (PWR) that uses a simplified approach to safety. With a gross power rating of 3,415 megawatt thermal (MWt) and a nominal net electrical output of 1,110 megawatt electric (MWe), the AP1000® Plant, with a 157-fuel-assembly core, is suitable for new baseload generation.

Simplifications in overall safety systems, normal operating systems, the control room, construction techniques, and instrumentation and control systems provide a plant that is easier and less expensive to build, operate and maintain. Plant simplifications yield fewer components, cable, and seismic building volume, all of which contribute to considerable savings in capital investment, and lesser operation and maintenance costs. At the same

## Appendix C - New Generating Resource Options Characterization

time, the safety margins for the AP1000® Plant have been increased over currently operating plants.

The AP1000® PWR is comprised of components that incorporate many design improvements distilled from 50 years of operating nuclear power plant experience. The reactor vessel and internals, steam generator, fuel and pressurizer designs are improved versions of those found in currently operating Westinghouse-designed PWRs. The reactor coolant pumps are canned-motor pumps, the type used in many other industrial applications where reliability and long life are requirements.

Note, while AP1000 units have been constructed and are in operation in China, the two units at the Vogtle site in Georgia are still in the final stages of construction and start-up testing. Two AP1000 units that were being built at the V.C. Summer site in South Carolina have stopped construction due to cost overruns.

### C.5.1.1.2 General Electric-Hitachi ESBWR

The Economic Simplified Boiling Water Reactor (ESBWR) is a 1,520 MWe Generation III+ boiling water reactor. Certified by the NRC in 2014, the ESBWR has the lowest core damage frequency (industry standard measure of safety) of any Generation III or III+ reactor and can safely cool itself with no AC electrical power or human action for more than seven days.

Using natural circulation, the ESBWR has 25 percent fewer pumps and mechanical drives than existing active safety plants. The ESBWR is projected to have the lowest operating, maintenance, and staffing costs per megawatt hour of any LLWR reactor technology currently available.

### C.5.1.2 Small Modular Reactors

SMRs can be subdivided into Generation III+ (Gen III+) light water reactors (LWRs) and Generation IV (Gen IV) advanced reactors. Gen III+ reactors are similar to the existing (large) Gen III reactors that are operating in the fleet

but have reduced capacity and advanced features that are incremental improvements from existing technology. Therefore technology risks with Gen III+ SMRs are expected to be limited. Gen IV reactors are different from the existing fleet and may have technology risks that could impact the long-term operability of new designs. It is assumed that Gen III+ SMRs can be economically implemented with commercial operation dates (CODs) beginning in 2030 and Gen IV advanced reactors (both SMRs and micro-reactors) can be economically implemented with CODs beginning in 2035. JEA would need to initiate project work at a minimum of eight years ahead of the planned COD. For example, assuming a desired 2035 COD, JEA would need to begin development in 2027. If JEA pursues incremental nuclear capacity additions through a PPA, this full development timeline would be different.

The following SMR nuclear generation options were considered as Resource Options:

- Small Modular Reactor (LWR Designs)
  - NuScale Power Module™
  - General Electric-Hitachi (GEH) BWRX-300
  - Holtec SMR-160
- Nuclear Advanced Reactors (non-LWR Designs)
  - Kairos Power FHR
  - TerraPower Sodium Reactor
  - X-energy Xe-100
  - Terrestrial Energy Integral Molten Salt Reactor (IMSR®)
- Nuclear Advanced Micro-Reactors (non-LWR Designs)
  - Oklo Power LLC
  - General Atomics
  - HolosGen
  - NuGen
  - Westinghouse eVinci
  - X-energy

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Early adoption of SMRs may include added First of a Kind (FOAK) design / development costs from the reactor OEMs that would increase the cost of these Resource Options. Waiting for the nuclear Resource Options to mature further would reduce implementation costs, solidify the supply chain, and provide more schedule certainty. The time that this takes will depend on the market demand for nuclear technology. The primary driver hindering SMR development has been low natural gas prices.

Gen III+ SMRs are all light water reactors and use conventional BWR or PWR fuel like the existing fleet. The following provides a technology overview of three SMRs that would be available for a 2030 COD.

### C.5.1.2.1 NuScale

NuScale originally developed the integral PWR (iPWR) to be a standalone reactor with a capacity of approximately 50 MWe. To take advantage of greater economies of scale, NuScale has designed a plant around having multiple reactor modules that can be operated depending upon the load requirements. NuScale's scalable design (power plants that can house up to four, six, or 12 individual power modules) offers the benefits of carbon-free energy and reduces the financial commitments associated with gigawatt sized nuclear facilities. A fully factory fabricated NuScale Power Module™ (NPM) generates a gross output of 50 (or 77) MWe using a safer, smaller, and scalable version of pressurized water reactor technology (the greater output resulted from NuScale uprating the reactor power to improve the \$ / MW capital cost ).

- Original power module = 160 MWth, 50 MWe
- Each NPM-20 module = 250 MWth, 77 MWe (gross)
- Up to 12 modules in a single Reactor Building
- NPM 4-Module Plant – 308 MWe

- NPM 6-Module Plant – 462 MWe
- NPM 12-Module Plant – 924 MWe

### C.5.1.2.2 GEH BWRX-300

The BWRX-300 is a 300+ MWe water-cooled, natural circulation SMR with passive safety systems. As the tenth evolution of the Boiling Water Reactor (BWR), the BWRX-300 represents the simplest BWR design since GE began developing nuclear reactors in 1955.

The BWRX-300 is based on the NRC-licensed, 1,520 MWe ESBWR and is designed to provide clean, flexible baseload electricity generation that is competitively priced and estimated to have the lifecycle costs of typical natural gas combined-cycle plants targeting \$2,250 / kW for NOAK (nth of a kind) implementations.

The BWRX-300 has the following benefits and features:

- Mitigates loss-of-coolant accidents (LOCA) enabling simpler passive safety
- Projected to have reduced capital cost per MW when compared with typical water-cooled SMR
- Steam condensation and gravity allow BWRX-300 to cool itself for a minimum of seven days without power or operator action
- Uses existing GNF2 fuel that is the primary BWR fuel in the current operating fleet, therefore, no fuel development program is required

### C.5.1.2.3 Holtec SMR-160

The Holtec SMR-160, developed by Holtec International, is a small modular reactor designed to produce 160 megawatts of electricity using low enriched uranium fuel. The SMR-160 is a pressurized water reactor (PWR) with passive safety systems. The reactor, steam generator, and spent fuel pool are located in containment with the reactor core well below grade. The SMR-160 was sized so that it would

## Appendix C - New Generating Resource Options Characterization

be possible to use either conventional cooling towers or air-cooled condensers for sites that have limited water.

### C.5.1.2.4 Study Basis

The study basis parameters for the SMR LWR Resource Options are summarized in Table C-24. Each SMR LWR Resource Option is in the pre-application stage with the United States Nuclear Regulatory Commission (NRC). Both the NuScale Power Module™ and the GEH BWRX-300 designs have a licensing advantage because

the NPM-20 is the updated version of the NuScale design that has gone through the design certification process and the BWRX-300 is a derivative SMR plant based on the larger ESBWR LWR design that has been through design certification. All three of the SMR LWR Resource Options below are also currently in the Canadian Nuclear Safety Commission (CNSC) Vendor Design Review (VDR) process. Therefore, the three SMR LWR Resource Options can be deployed in a broader North American fleet that could provide both capital and operational savings.

**Table C-24 - Study Basis Parameters for Small Modular Reactor Resource Options**

ID	Resource Option	Plant Configuration	Plant TYPE	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
20	NuScale Power Module™	Four, six, or 12 individual power modules.	Gen III+ iPWR	160 or 250 per module	50 or 77 per module	NRC (design certification)
21	General Electric-Hitachi (GEH) BWRX-300	Water-cooled, natural circulation Small Modular Reactor (SMR) with passive safety systems.	Gen III+ BWR	870	300+	NRC (pre-application)
22	Holtec SMR-160	Small modular reactor designed to produce 160 megawatts of electricity using low enriched uranium fuel.	Gen III+ PWR	480	160	NRC (pre-application)

### C.5.1.3 Advanced Reactors

The Gen IV or advanced reactors are still in development, with the technology developers working on the reactor technology, fuel technology, and nuclear licensing. While there are two technologies that were selected for the Department of Energy (DOE) Advanced Reactor Demonstration Project (ARDP) with a goal for a 2028 COD, a more likely date for commercially available reactors would be 2035.

#### C.5.1.3.1 Kairos Power FHR

The Kairos Power fluoride salt-cooled high temperature reactor (KP-FHR) is a novel advanced reactor technology that is cost

competitive with natural gas in the United States electricity market and to provide a long-term reduction in cost. Higher process temperature allows for industrial heating in addition to power production. The KP-FHR plant uses accident tolerant TRISO fuel to provide a high-degree of fuel safety. Use of TRISO fuel in the FHR plant also eliminates the complicated chemical processing plant that is required for more conventional Molten Salt Reactor (MSR) plants.

#### C.5.1.3.2 TerraPower Sodium Reactor

The TerraPower Sodium™ technology consists of a cost-competitive sodium fast reactor

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combined with a molten salt energy storage system. This combination will provide clean, flexible energy and stability, and integrate into power grids. TerraPower and GE-Hitachi Nuclear Energy developed the Natrium technology with a 345 MWe sodium fast reactor. The integral salt storage allows the unit to produce a peak of 500 MWe for a period of 5.5 hours when needed to help balance renewables or supply peak demands.

### C.5.1.3.3 X-energy Xe-100 Reactor

X-energy's reactor designs are based on HTGR technology — a Gen-IV reactor technology with a proven operational pedigree. The Xe-100 plant is modular and scalable with up to 4 modules per group and is helium cooled with TRISO fuel.

### C.5.1.3.4 Terrestrial Energy Integral Molten Salt Reactor

The Integral Molten Salt Reactor (IMSR®) uses a molten salt as coolant and fuel. Molten salts are thermally very stable, which permits lower pressure and high temperature operation.

When a molten salt coolant and molten salt fuel are used in combination, the reactor has the potential to incorporate the characteristics of passive and inherent reactor safety. Operating at greater than 44 percent thermal efficiency, an IMSR® power plant generates 195 megawatts of electricity with a thermal-spectrum, graphite-moderated, molten-fluoride-salt reactor system. It uses standard nuclear fuel, comprising standard-assay low-enriched uranium (less than 5 percent <sup>235</sup>U), critical for near-term commercial deployment. The IMSR® does require a chemical processing plant to remove the “spent” nuclear fuel from the molten salt.

### C.5.1.4 Micro-Reactors

Like the Gen IV or advanced reactors, micro-reactors are still in development, with the technology developers working on the reactor

technology, fuel technology, and nuclear licensing. Several Gen IV developers are developing the same technology in both SMR and micro-reactor sizes to address different segments of the industry.

Some of the early micro-reactors are being developed for DoD applications and may take advantage of High Assay Low-Enriched Uranium (HALEU) fuel or higher enriched fuels. Micro-reactors at DoD facilities will have inherent security and security response capabilities that non-DoD facilities would not have and therefore may be able to use higher enriched fuel. Micro-reactors may be connected to the grid, but also can serve in micro grids to supply power to more remote areas or as backup power sources for critical power infrastructure needs. Some of the designs are intended to be a form of nuclear battery that can provide remote power for a period of 10 or more years before replacement. While there are several technology developers that are actively pursuing the development of micro-reactors for remote locations and for DoD applications, not all of these technology developers may be successful in the marketplace. However, the need for reliable remote power and green reliable power for DoD applications will lead to development and eventual commercialization. These advanced micro-reactors should be available commercially starting in 2035.

Because of the wide range in Gen IV technologies, a technology overview will not be presented for each of the five micro-reactor Resource Options. By 2035, there should be several commercially available and economically viable options in the <10 MWe size range that could be deployed to meet energy needs in JEAs generation fleet. It would also be possible to purchase power or to partner with others on the development of these micro-reactors.

## Appendix C - New Generating Resource Options Characterization

### C.5.2 Study Basis

Study basis parameters for the Advanced Reactor Resource Options are summarized in Table C-25. All have received some level of funding and / or have current customer interest. The four SMR advanced reactor Resource Options represent the most probable advanced reactor designs that could be

developed by a utility in the United States market based on the current development and licensing status. All four of the advanced reactor Resource Options are in the pre-application stage with the NRC. The X-energy and Terrestrial Energy advanced reactor Resource Options are also currently in the CNSC VDR process.

**Table C-25 - Study Basis Parameters for Advanced Reactor Resource Options**

ID	Resource Option	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
23	Kairos Power FHR	Salt-cooled high temperature reactor; Higher process temperature allows for industrial heating in addition to power production.	Gen IV FHR	311.1	140	No Pre-Application Status with NRC
24	TerraPower Natrium Reactor	Sodium fast reactor combined with a molten salt energy storage system.	Gen IV Sodium Cooled Fast Reactor	767 est.	345	No / Pre-Application Status with NRC
25	X-energy Xe-100	Modular and scalable with up to 4 modules per group.	Gen IV HTGR	200 per module 800 per 4 module plant	80 per module 320 per 4 module plant	No / Pre-Application Status with NRC
26	Terrestrial Energy Integral Molten Salt Reactor (IMSR®)	Molten salt as coolant and fuel that permits lower pressure and high temperature operation.	Gen IV MSR	443	195	No / Pre-Application Status with NRC

#### C.5.2.1 Advanced Micro-Reactors

Study basis parameters for the nuclear Advanced Micro-Reactor Resource Options are summarized in Table C-26. Note, some of the early micro-reactors are being developed for Department of Defense (DoD) applications and may use High Assay Low-Enriched Uranium (HALEU) fuel or higher enriched fuels. Micro-reactors at DoD facilities will have inherent security and security response capabilities that non-DoD facilities would not have and therefore may be able to use higher enriched fuel. Micro-

reactors may be connected to the grid, but also can serve in micro grids to supply power to more remote areas or as backup power sources for critical power infrastructure needs. Some of the designs are intended to be a form of nuclear battery that can provide remote power for a period of 10 or more years before replacement. While there are several technology developers that are actively pursuing the development of micro-reactors for remote locations and for DoD applications, not all of these technology developers may be successful in the marketplace. However, the need for reliable

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remote power for DoD applications will lead to the development and eventual commercialization of the technology. These

advanced micro-reactors are anticipated to be available commercially beginning in 2035.

**Table C-26 - Study Basis Parameters for Advanced Micro-Reactors**

ID	Resource Option	Plant Configuration	Plant Type	Reactor Rating (MWth)	Plant Output (MWE)	Licensed
27	Oklo Power LLC	Heat is transported using heat pipes that function as thermal superconductors.	Sodium-cooled fast reactor	4	1.5	COL Application submitted to NRC
28	General Atomics	Modular autonomous system	Gas-cooled reactor	N/A	10	No / Pre-Application Status with NRC
29	HolosGen	Distributable modular nuclear power generator	Liquid metal	N/A	3 per module 13 in Holos Quad plant	No
30	NuGen	Compact and versatile configuration	Fission fuel core integrated into jet engine	N/A	1-3	No
31	Westinghouse eVinci	Micro reactor	Solid Core Heat Pipe Reactor	N/A	1-5	No / Pre-Application Status with NRC
32	X-energy	Mobile Microreactor Project – Xe Mobile	HTGR	N/A	1 to 5	No / Pre-Application Status with NRC

### C.5.3 General Assumptions

#### C.5.3.1 General Site Assumptions

In addition to the study basis parameters provided in the tables above, general site assumptions employed by Black & Veatch for these Resource Options include the following:

- The site has sufficient area available to accommodate construction activities including office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive

lands. The project site will require neither mitigation nor remediation.

- Pilings are assumed under major equipment and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, service, and fire water will be supplied from the local water utility.

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- Cooling water, if required, will be supplied from the local water utility, and is expected to be municipal reclaim water with well water backup.
- Wastewater disposal will utilize local sewer systems or existing JEA infrastructure.

### C.5.3.2 Capital Cost Estimating Basis

Screening-level capital cost estimates were developed for each of the Resource Options evaluated. The capital cost estimates were developed based on Black & Veatch's experience on projects either serving as engineering, procurement, and construction (EPC) contractor or as owner's engineer (OE). Capital cost estimates are market-based and are based on recent and on-going experiences. The market-based numbers were adjusted based on technology and configuration to arrive at capital cost estimates developed on a consistent basis and reflective of current market trends.

The estimates presented herein have been developed using recent historical and current project pricing and then adjusted to account for differences in region, project scope, technology type, and cycle configuration. The basic process flow is as follows:

- Leverage confidential and proprietary information, including in-house database of project information from EPC projects recently completed and currently being executed as well as EPC pursuits currently being bid and our knowledge of the market from an OE perspective to produce a list of potential reference projects based primarily on technology type and cycle configuration.
- Review differences in region and scope.
- Exclude references that differ significantly from study basis.
- Adjust the remaining references by categorizing into several cost categories

and accounting for differences such as major equipment pricing, labor, and commodities escalation.

- Scale the remaining reference projects by generating a scaling curve and compare. That scaling curve forms the basis for the screening-level capital cost estimates and is ultimately used to arrive at the EPC capital cost estimate.

The estimating process described above maximizes the value of past experiences and reduces bias resulting from project outliers such as differences in scope and location with the objective of providing current market pricing for generic power projects in and around the JEA service territory.

Capital cost estimates are based on site development, under fixed, lump sum EPC contracting. Cost estimates are overnight estimates (i.e., excluding escalation and finance costs) and are presented on a mid-year 2021 United States dollars basis. EPC cost estimates are based on Black & Veatch's knowledge of current market trends.

Financing fees and interest during construction will be captured as part of the fixed charge rate that will be applied during the LCOE screening and other analysis of the Resource Options in the IRP and are therefore not included in the capital cost estimates developed as part of this Characterization of Resource Options report. Land costs, supporting infrastructure (e.g., gas delivery upgrades, transmission upgrades, and water and wastewater upgrades), taxes, project management costs, and OE costs, are considered to be Owner's Costs and need to be added to the EPC cost estimates to arrive at a total installed cost. A listing of potential Owner's Costs is provided in Table C-15. Owner's Cost percentages are estimated for the North Jax site and the GEC site, and applied to capital costs as appropriate. Typically, Owner's Costs may be equivalent to 20 to 50 percent of the project's EPC contract cost.

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### C.5.4 Summary of Capital and O&M Cost Estimates

Developers of new generation focus on both cost and schedule certainty from a reactor technology; however, costs for new nuclear can vary significantly. When reviewing new build cost data, the most significant issue is the relatively low amount of input data as very few new reactors have been built in the United States. Cost data from international projects is available, but it is not likely to represent what the cost of new nuclear will be in the United States. In international countries that have continued to build new nuclear in a repetitive manner, state-sponsored or state-controlled supply chains and construction entities have assisted in the delivery of the units. In the United States, consistency in the cost and schedule certainty of new nuclear is important and will need to be developed through execution and repeat projects. The global push to decarbonization may assist with having more repeat projects to improve learning and future delivery performance.

LLWR plants have significant capital costs. Not only is the nuclear technology expensive but the BOP and site infrastructure costs to support the large plants are also expensive. The previous target for LLWR plants during the early 2000s was \$4500 / kW; however, recent LLWR construction has not been able to achieve this target. Most new plant construction has resulted in cost overruns nearly doubling the original cost of the units. This is evidenced by capital costs of approximately \$9,000 / kW for recent LLWR AP1000 nuclear plant projects in Georgia and South Carolina. As a result, the AP1000 units in South Carolina have been cancelled due to these cost overruns. The AP1000 units in Georgia at the Vogtle site are in construction and costs are likely to go up further due to delays. The final cost for the Vogtle units will likely be more than \$9,000 / kW before they are fully commercial.

LCOE values for LLWR range from \$100 / MWh on the lower end to values of \$160-180 / MWh on the upper end.

Capital costs and LCOE values for SMRs and advanced reactors can be estimated; however, actual as-built and actual operating values are not available. The following provides information on anticipated costs for various SMR and advanced reactor technology. Advertised capital costs and LCOE values should be reviewed carefully to understand the cost assumptions that went into development. Nth-of-a-kind (NOAK) figures are often presented that make optimistic assumptions about cost savings for NOAK units that may or may not be realized.

NuScale NPM-20 has an NOAK overnight capital cost of approximately \$3,600 / kW, backed by AACE Class IV cost estimates. The cost estimate for NuScale increased from \$1,200 / kW, an early preconceptual cost estimate, to \$5,078 / kW (2014\$) in Fluor's estimates prior to the uprating to the NPM-20 size. The target LCOE for NuScale's first 12-module power plant is \$65 per megawatt hour. [Reference: NuScale website] An estimate of the NuScale NOAK LCOE is in the range of \$51 / MWh–\$54 / MWh calculated using NuScale's design estimates.

For the BWRX-300, the NOAK overnight capital cost is in the range of \$4,000 / kW. The BWRX-300 LCOE is in the range of \$44–\$51 / MWh. This LCOE was calculated for the NOAK BWRX-300 using GE-Hitachi's (GEH's) design-to-cost and target pricing input.

A cost summary for SMR advanced reactors is provided in Table C-27. The average costs below are reasonable for NOAK costs. FOAK and early plants will be higher as discussed previously. Costs for micro-reactors on a per kW or per MWh basis may be greater than this due to the smaller output; however, some of the micro-reactors will have low BOP costs and lower operational costs, which may bring the levelized costs down. Limited data are available to support validation of these cost values for micro-reactors.

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**Table C-27 - Cost Summary for SMR Advanced Reactors**

Cost	Average	Minimum	Maximum
Capital Cost Total	\$3,782 / kW	\$2,053 / kW	\$5,855 / kW
Operating Cost Total	\$21 / MWh	\$14 / MWh	\$30 / MWh
Levelized Cost of Electricity	\$60 / MWh	\$36 / MWh	\$90 / MWh

The average levelized cost of electricity (LCOE) of \$60 / MWh from the Energy Options Network (EON) study participants is 39 percent less than the \$99 / MWh expected by the United States Energy Information Agency for PWR nuclear plants entering service in the early 2020s.

An important consideration in the cost review of nuclear plants is that they are expected to have a minimum design / operating life of 60 years. Similar to the existing operating fleet, many of the LWR SMRs and the advanced reactors would be capable of additional life extension, likely out to 80 years. This is significantly longer than the operational life of other generation technologies.

## C.6 Hydrogen

### C.6.1.1 Technical Characteristics

Hydrogen is a versatile chemical substance globally used across numerous industries and is being considered to be a leading low-carbon fuel for power generation. Currently, hydrogen is primarily used in refining, petrochemical, and commodity chemical industries. However, it is also being used to a minor extent as a transportation fuel in fuel cell electric vehicles and has been used for long-duration energy storage applications. The hydrogen value chain is depicted in Figure C-1 below to demonstrate the wide variety of feedstocks, production processes, and end uses for hydrogen.

The most common forms of hydrogen are “green” hydrogen generated from electrolysis

and “blue” hydrogen generated from steam methane reforming (SMR) coupled with carbon capture, utilization, and storage (CCUS) technologies.

#### C.6.1.1.1 Electrolysis

Electrolysis is the process of splitting water into hydrogen and oxygen using electricity in an electrochemical cell. Electrolyzers come in a variety of capacities and chemistries, but the fundamental concept remains the same. Electrolyzers have electrodes (i.e., anodes and cathodes) separated by an electrolyte. The combination of electrodes and electrolyte vary by the type of chemical reactions taking place. Unlike SMR, electrolyzers are considered “green” sources of hydrogen when the electricity consumed is provided by a renewable energy resource. Instead of using carbon as an energy carrier, electrolysis-derived hydrogen uses the splitting and combining of water. There are two primary types of electrolyzers: proton exchange membrane (PEM) and alkaline water electrolysis (AWE).

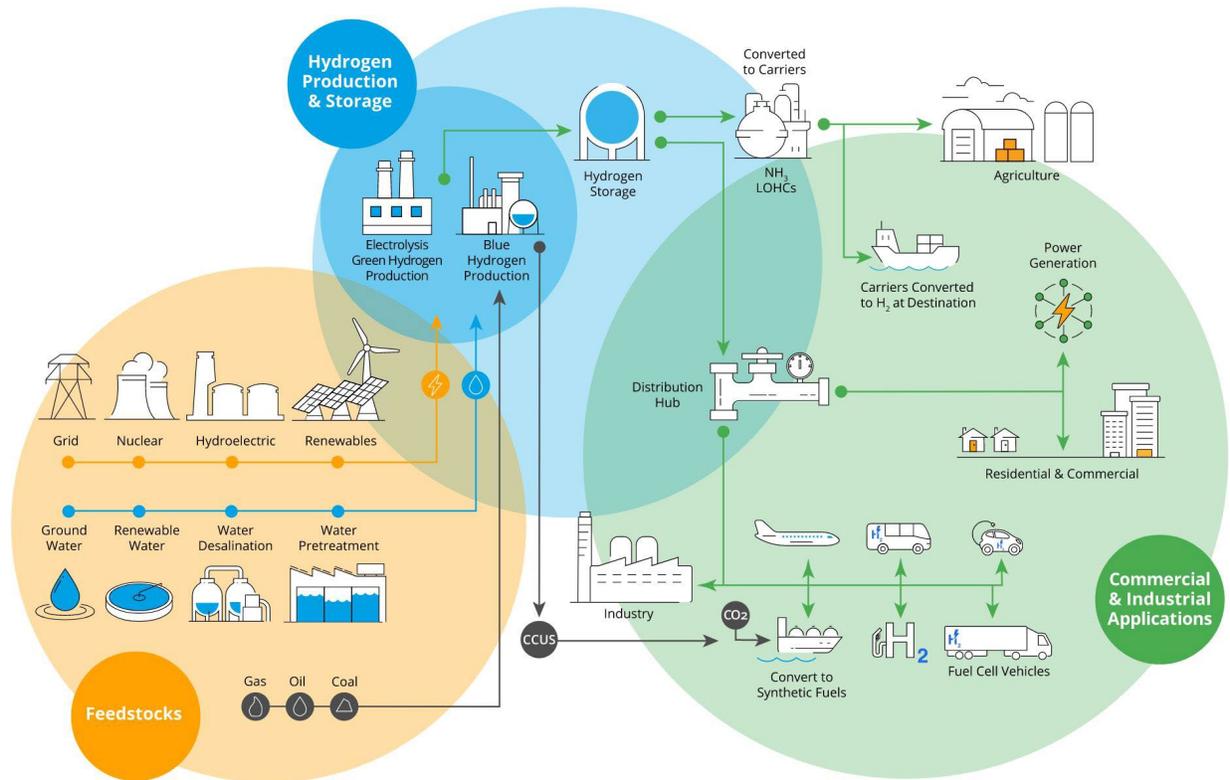
PEM electrolyzers exchange a proton through the electrolyte between the electrodes. In a PEM electrolyzer, water is split into oxygen and hydrogen, with the hydrogen ions traveling from the anode to the cathode and exiting out the cathode side of the stack. Oxygen, in turn, exits out of the anode side of the stack. Recent research and development initiatives have optimized the catalytic activity of the cell while minimizing the amount of expensive electrocatalysts, thereby lowering the cost.<sup>11</sup>

<sup>11</sup> Vichard, L., et al. “Degradation Prediction of PEM Fuel Cell Based on Artificial Intelligence.” International Journal

of Hydrogen Energy, vol. 45, no. 29, 16 Apr. 2020, pp. 14953–14963., doi:10.1016 / j.ijhydene.2020.03.209.

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Figure C-1 – Illustration of the Hydrogen Value Chain



AWEs fundamentally function similarly to PEM electrolyzers; however, the ion transported in the electrolyte is  $\text{OH}^-$  and travels from the cathode to the anode. The hydrogen then exits out the cathode side of the stack and the oxygen exits out of the anode side of the stack. Because AWEs have a lower current density, they also require a larger footprint compared to PEMs. However, the technology is considered more mature for large-scale hydrogen production.<sup>12</sup>

#### C.6.1.1.2 Steam Methane Reforming

In an SMR process, natural gas reacts with steam over a catalyst and in presence of heat to produce syngas, which is subsequently cleaned/upgraded (via water-gas shift and pressure swing adsorption) to hydrogen. The process can

generate large quantities of hydrogen that are typically utilized in production of various petrochemicals and ammonia for fertilizers. Waste heat from the burner flue gas is recovered for feed pre-heating and boiler feed water heating and steam production. Heat for steam production is also recovered from the process gas exiting the reactor in a waste heat boiler.

SMR processes also generate large amounts of carbon dioxide emissions and without carbon capture and storage (CCS) can be counterproductive to electric utility industry efforts of generating low-carbon electricity via hydrogen fuel blending and co-firing solution (i.e., the carbon intensity of “gray” hydrogen from SMR is roughly 80 to 90 percent higher

<sup>12</sup> Brauns, Jörn, and Thomas Turek. “Alkaline Water Electrolysis Powered by Renewable Energy: A Review.”

Processes, vol. 8, no. 2, 2020, p. 248., doi:10.3390/pr8020248.

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## Appendix C – New Generating Resource Options Characterization

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than that of fossil-based natural gas). SMR is the most common approach for hydrogen production at scale in the industry, although autothermal reforming and partial oxidation technologies (or combinations thereof) are also used in some cases for lower cost hydrogen.

### C.6.1.1.3 Hydrogen Storage and Transportation

Because hydrogen is typically produced and consumed on-demand, there is a need to store the hydrogen for later use in power generation/energy storage applications. Hydrogen is the lightest molecular element; therefore, it can be challenging to store large quantities. Methane is approximately eight times denser than hydrogen at standard conditions on a gravimetric basis, so the pressures and temperatures required to store hydrogen in an economical manner are more extreme than that of natural gas.

Compressed hydrogen storage is the most common method of storage for industrial hydrogen consumers. Depending on the amount of hydrogen being stored, pressures can range from 2,000 to 10,000 psig with the high end of this range more suitable for small cylinders used in the transportation sector rather than large bulk tanks for industrial users. Depending on the pressure and storage volume, many smaller vessels may be more economical than one large bulk tank. Hydrogen also presents an issue with leakage. Some compressed storage applications may require special materials to line the inside of the vessel to prevent leakage.

Hydrogen liquefaction is more energy intensive than compressed storage. The storage volumes for liquefied hydrogen would be much less than the storage volumes for compressed for the same mass. However, liquefied hydrogen requires more complex auxiliary equipment and

requires cryogenic temperatures, boil-off compressors, and other ancillaries. An additional consideration with the liquefaction equipment is the thermal cycling and ramp time.

Geological formations such as salt caverns, rock caverns, and depleted gas fields provide an opportunity to store large volumes of hydrogen in existing features. Conceptually, hydrogen is compressed and stored in an existing geological formation and then withdrawn for later use. Salt caverns provide the most suitable geological storage feature followed by rock caverns and then depleted gas fields as the least suitable of the three. Depending on the geological feature, upgrades such as a liner may need to be added to prevent leakage. Another consideration associated with geological storage is contamination from substances such as methane or water. Additional clean up equipment may be required depending on the geographic location and the hydrogen user quality requirements.

Pipelines are the most cost-efficient way to transport large quantities of hydrogen over long distances. There are currently approximately 1,600 miles of hydrogen pipelines installed in the United States, primarily in the Gulf Coast region, which are predominantly owned / operated by major industrial gas companies. Hydrogen pipelines are considered mature technologies and can typically cost approximately up to 10 percent more than a traditional natural gas transmission pipeline. For dry hydrogen service, the use of carbon steel is acceptable for the typical temperatures/pressures associated most electrolysis projects. In instances where corrosive contaminants or condensate are present, a stainless-steel pipeline material would be selected instead, which can increase costs.<sup>13</sup>

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<sup>13</sup> Chen, Tan-Peng. "Hydrogen Delivery Infrastructure Options Analysis." DOE Hydrogen Program, FY 2006

Annual Progress Report; March 2007, US Department of Energy, Mar. 2007, [www.hydrogen.energy.gov/pdfs/progress07/iii\\_a\\_1\\_chen.pdf](http://www.hydrogen.energy.gov/pdfs/progress07/iii_a_1_chen.pdf).

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One option is to blend hydrogen in the existing natural gas pipeline network, which includes more than 400,000 miles of infrastructure. It is estimated that at typical pressures and diameters associated with natural gas pipelines, approximately 21 tons of hydrogen could be stored per linear mile. Hydrogen is generally limited to 5 to 10 percent blending throughout most of the United States, primarily due to safety and pipeline integrity concerns. While greater percentages may be possible if natural gas pipelines and supporting infrastructure are converted for use with hydrogen, these costs and the required modifications are the subject of significant research and development.<sup>14</sup>

### C.6.1.2 Hydrogen-Fueled Resource Options

The use of hydrogen as a fuel has not yet been implemented for utility scale power generation and therefore, specific hydrogen fuel Resource Options have not been evaluated for this Characterization of Resource Options report. Additional information regarding the use of hydrogen, including costs relative to natural gas units, is provided below to reflect the current state of hydrogen as a supply-side option.

Hydrogen can be utilized directly in fuel cell power generation equipment and is currently being developed for 100 percent firing in RICE / CTG equipment, although most CTG OEMs have only achieved up to approximately 60 percent hydrogen by volume with natural gas (or as part of a biogas / syngas stream fed directly to a CTG). In many cases, Black & Veatch anticipates that hydrogen co-firing will be limited to 35 percent by volume in existing plants to avoid costly modifications to the CTG island. Some of the technical challenges in hydrogen firing and / or co-firing in traditional power plants include:

- Rate of change in Wobbe index and associated monitoring equipment
- Design of mixing drum and blending skid
- Replacement of combustors, including premixing devices (e.g., flashback, fluid dynamics / pressure fluctuations, combustion stability, etc.)
- Higher density exhaust gas and air quality control implications
- Increased nitrogen oxide production
- Hazardous gas detection
- Hazardous area classification

Beyond the energy conversion system itself, hydrogen can cause embrittlement in piping, which is typically constructed from low strength carbon steel designed for lower operating stress (i.e., lower pressures or thicker pipe walls). Pressures greater than 650 psig and temperatures greater than 400°F have been demonstrated to accelerate the effects of embrittlement, particularly in high strength carbon steels and harder steels that may be present in an existing power plant. Fully welded piping is preferred for hydrogen with very limited number of flanges. In many cases, stainless steel piping is used in high cleanliness applications, such as gas turbine fuel piping; however, 304 stainless steel is more likely to embrittle while 316 stainless is the preferred grade due to better performance and greater resistance to the degradation mechanism. Additionally, firing 100 percent hydrogen can change pipe velocities by factor of 3.5 relative to natural gas on a calorific value basis and at same pressure / temperature conditions, thus plant fuel gas piping areas must increase to maintain velocity conditions. Pipe sizing impacts stress analysis, pipe hangers, pipe racks, OEM enclosures and requires the evaluation of specialty equipment in some cases.

<sup>14</sup> Domptail, Kim, et al. Pipeline Research Council International Inc., 2020, Emerging Fuels - Hydrogen State of the Art, Gap Analysis, and Future Project Roadmap.

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Hydrogen has a higher flame temperature than that of natural gas; therefore, blending hydrogen into the fuel will result in the CTG burning at a higher temperature. This higher temperature correlates directly to a higher production of nitrogen oxide emissions (e.g., at 35 percent hydrogen in natural gas, nitrogen oxide emissions are estimated to increase by 20 percent). Steam can be injected into the CTG to reduce burner temperature and prevent increased nitrogen oxide emissions, but at a cost to efficiency. Alternatively, increased ammonia feed to the selective catalytic reduction unit may be required to keep nitrogen oxide emissions within the limits of the plant's air permit. However, other criteria air pollutants are expected to improve as a result of firing higher percentages of hydrogen.

From a decarbonization perspective, it is important to note that carbon dioxide emissions are not proportionally decreased by an increase in volumetric hydrogen in the fuel. Because carbon emissions are measured on a mass basis, consideration for the mass of carbon displaced by hydrogen needs to be accounted. In general, co-firing of hydrogen with natural gas up to 35 percent by volume is only anticipated to result in an approximate 15 percent reduction in GHG emissions. Greater reductions in GHG emissions will only be possible when RICE / CTG manufacturers are able to achieve suitable performance / reliability using higher blends of hydrogen with natural gas, up to 100 percent hydrogen.

### C.6.1.3 Capital and O&M Costs

Capital, O&M, and levelized costs associated with different types of power generation with

hydrogen, similar to liquid and gaseous low-carbon fuels, can vary substantially depending on the production capacity, storage / transportation requirements, and range of feedstock (i.e., natural gas, electricity, water, etc.) costs. For co-firing hydrogen in an existing power plant up to 35 percent hydrogen by volume (corresponding to an LHV of 666 BTU / scf or 75 percent of the volumetric energy density of pure natural gas), these systems should be modeled in the same manner (e.g., capacity, capital / O&M costs, heat rate, etc.) as traditional natural gas fueled plants with the main difference being in fuel pricing. However, it may be warranted to also include a \$5 / kW increase in capital cost and 10 percent increase in variable O&M costs to account for minor modifications in air quality control equipment and associated reagent consumption.

For a greenfield power generation station with 100 percent hydrogen fueling, the capital, O&M, and levelized costs are not yet well understood, given that these facilities have not been constructed or operated to-date. However, in the near term, a 10 percent increase in capital cost would be considered (relative to natural gas fueled plant) and 25 percent increase in variable O&M costs to account for differences in air quality control equipment differences and associated reagent consumption as well as additional regulatory requirements associated with this significant quantity of hydrogen.

With respect to hydrogen production and on-site storage fuel pricing, estimates are shown in United States dollars per MMBTU in Table C-28.

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**Table C-28 - Hydrogen Production and Storage Fuel Pricing**

Fuel Type (Notes 1,2)	Minimum	Maximum
Green Hydrogen, 2021-2030	\$55.00	\$70.00
Green Hydrogen 2030+	\$10.00	\$24.00
Blue Hydrogen, 2021-2030	\$18.00	\$35.00
Blue Hydrogen, 2030+	\$17.00	\$26.00
Hydrogen Storage (All Options)	\$2.00	\$40.00

All pricing is provided in 2021 \$ / MMBTU.  
Pricing based on Black & Veatch analysis and market data.

### C.6.1.4 Development Timeline

Large quantities of low-carbon hydrogen are not yet available to enable large-scale hydrogen power generation applications. This is anticipated to remain the case at least through 2030 while the industry continues to ramp up to address this emerging market and CTG manufacturers continue to pursue the research and development needed to enable 100 percent hydrogen fueled systems. The price of “blue” hydrogen is anticipated to fall faster over the next 10 years than the price of “green” hydrogen, primarily driven by economies of scale in the CCUS industry. However, the availability of low-cost electrolysis equipment coupled with low-cost, abundant electricity from interconnected renewable energy resources are expected to drive low prices for “green” hydrogen in the 2030 to 2045 timeframe and beyond.

### C.6.1.5 Conclusions

The following are the major conclusions for hydrogen fuels:

- Hydrogen can be produced via numerous pathways and has utility across many different end use applications. Most of the focus on low-carbon hydrogen is with respect to hydrogen produced via steam methane reforming coupled with CCUS or

produced via water electrolysis using renewable energy resources.

- Co-firing of hydrogen with natural gas in existing power plants is anticipated to be limited to 35 percent by volume, which only corresponds with a 15 percent reduction in GHG emissions and 20 percent increase in nitrogen oxide emissions. Pursuit of such a project in the near-term is feasible but could be expensive relative to other decarbonization options.
- Hydrogen can be used in at large scales and is anticipated to be feasible in purpose-built 100 percent hydrogen fueled power generation stations beyond the 2030 timeframe.

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## Appendix D – Remote Solar Siting

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### D Remote Solar Siting

#### D.1 Background and Methodology

Black & Veatch performed a high-level siting study to identify potential sites for development of new solar electric generation facilities for Jacksonville Electric Authority (JEA) throughout the State of Florida. JEA is developing an Integrated Resource Plan (IRP), which evaluates various options for future power generation, including replacement of existing coal-generated power. In this study, Black & Veatch identifies and evaluates potential sites for development of future solar power generation for JEA. The following analysis provides a summary of potential sites for solar development identified using geographic information system (GIS) datasets for various siting factors, including environmental considerations and infrastructure access. Renewable energy generation, including solar generation, is an efficient and reliable energy generation resource that reduces carbon dioxide emissions and can effectively supplement and/or replace fossil fuel generation and is critical in the pursuit of decarbonization objectives.

The objective of this solar siting study is to assist JEA in identifying potential sites for development of approximately 4,000 Megawatts (MW) of new solar assets to replace current fossil fuel generation and support future community growth. Development of 4,000 MWs of solar generation would involve the use of approximately 24,000 to 32,000 acres of land (assuming 6 to 8 acres per MW of energy production). A certain amount of overbuild and storage is recommended to provide useful replacement generation. This study focuses on parcels capable of generating approximately 75 MW of energy to facilitate project approval and minimize timely and costly permitting processes.

When selecting sites for development, it is essential to define what resources are required to support the project, availability and cost of the land, and accessibility of a reliable electric transmission system. Though it may require investment in transmission upgrades, selection of geographically diverse new solar production sites may be prudent as it can mitigate intermittency challenges and risk of loss from environmental disasters, such as tornados, flooding and hurricanes.

In the following study, potential locations for new solar generation facilities were identified through a high-level GIS analysis. The study evaluated parcels of land across the entire State of Florida and scored each parcel for feasibility of development utilizing 22 different environmental and technical criteria. Sites were scored and ranked for having desirable development criteria. The following sections discuss the GIS-analysis method and results. Results were evaluated and summarized by county since the following study is a high-level evaluation of more than 100 potential development sites and was completed in support of the IRP.

This report did not evaluate any specific parcels or aggregate parcels that may currently be owned or considered for development by JEA and/or the City of Jacksonville. Likewise, the analysis did not consider whether the identified potential sites are available for purchase or lease. To mitigate real estate concerns, this study only evaluated sites consisting of a single parcel to minimize real estate discussions with multiple owners. Additional analyses in later phases of the site selection process should consider other real estate hurdles and/or opportunities, including opportunities for sites composed of multiple parcels.

#### D.2 Florida Regulatory Framework

Construction and operation of new commercial scale solar facilities in the State of Florida are subject to several federal, state and local

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## Appendix D – Remote Solar Siting

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permits, which may be applicable depending upon the project location, size and design specifications. When selecting a site, or sites, for development, it is important to consider what permits/approvals will be required because they can significantly impact project schedule and costs.

At the current siting phase of this project, Black & Veatch recommends JEA consider a Florida-specific regulatory requirement, which has an applicability threshold based upon production of the new generation facility. Pursuant to the Florida Electrical Power Plant Siting Act (PPSA) (Fla. Stat §403.501), solar power plants with a capacity at or above 75 MW are subject to a rigorous Florida Public Service Commission (FPSC) need determination review and permitting process. The PPSA is the state's centralized process for licensing large power generation facilities. Under this framework, one certification replaces all local and state permits. This certification grants approval for the location of the power plant and its associated facilities, such as a natural gas pipeline supplying the plant's fuel, rail lines for bringing coal to the site, roadways and electrical transmission lines carrying power to the electrical grid. To avoid triggering this review process a best practice is to limit each project (or phase) below 75 MW.

### D.3 Environmental GIS Analysis

#### D.3.1 GIS Analysis Procedure

Black & Veatch's Environmental team regularly provides siting and routing services to a variety of electric utility clients. Our solar siting studies are designed to screen, evaluate, score, and rank potential site locations for future solar development.

Our team of regulatory professionals, engineers, GIS specialists, biologists and archaeologists identify and analyze environmental issues and site constraints before capital decisions are made. Analysis of

environmental and sensitive resources can not only identify opportunities to streamline project timelines and minimize project environmental compliance and permitting costs, but can reduce project development costs as well.

Using data from GIS tools, desktop research, online resources, and, if applicable, conceptual design considerations, potential sites are evaluated based on specific scoring criteria to identify optimal candidate sites. Scoring criteria emphasize critical aspects of the siting region and potential sites based on environmental suitability for constructing commercial-scale solar electric generating facilities. Criteria may include features such as to proximity to existing infrastructure like electric transmission lines, substations, natural gas pipelines, railways, and highways; permitting requirements; and site condition/constructability considerations, such as land cover, topography, soil conditions, floodplains, wetlands, global horizontal irradiance (GHI), parcel size, and property ownership.

For the following study, site selection criteria were defined to identify, evaluate and score each potential site for development of solar generating facilities. Best professional judgment was used to select the relative desirability of each criterion. Scores for each criterion were ordered with 9 being most desirable and 1 or 0 being least desirable for proposed site development. Site selection criteria are defined in Attachment A, Solar Site Selection Scoring Criteria. Potential sites identified through this process have higher scores, and are thus ranked higher for site selection since they have been defined as having favorable conditions for ease of design, constructability, and environmental permitting/approvals.

Note the following GIS analysis was based upon high-level publicly available datasets. A high-level GIS analysis can identify absence/presence and proximity of various constraints and

## Appendix D – Remote Solar Siting

resources, and serves as useful first step in the site selection process.

### D.3.2 GIS Analysis Results

The following section summarizes results of the GIS analysis.

Florida is mostly flat with generally gentle slopes in areas (i.e., >15%), making ideal ground conditions for solar development. Much of the landscape is characterized by rivers, small waterways and wetlands, which are often associated with flood risk and additional permitting hurdles; therefore, identification and avoidance of these features is recommended during the site selection process. Florida is also characterized by forested areas with dense vegetation which can make solar development challenging. Due to the geography of the siting region, this study utilized land cover as an initial siting criterion. A majority of the identified candidate sites are characterized by agricultural, pastureland or grassland land cover. Sites with forested areas are still eligible for development, but are slightly less desirable due to the cost of tree removal and potential permitting challenges.

Black & Veatch performed a high-level GIS analysis siting study to identify candidate sites for development of new solar generation of up to 4,000 MW. The GIS analysis identified 101 candidate sites in 24 counties in Florida, including 32 candidate sites in Duval County (refer to Attachment B, Florida Solar Siting Overview Map). A summary of the candidate sites identified by GIS analysis by county is found in Table D-1 below. The 101 candidate sites include a total of 51,583 acres of real estate with a total of 43,627 buildable acres (i.e., non-wetland acres). Maps illustrating the total number of sites and total number of acres identified for solar development in each county can be found in Attachment C. If all non-wetland space could be developed, these 101 sites would yield between 5,453 and 7,271 MW assuming it would take 6 to 8 acres to yield 1 MW of production. This exceeds the

4,000 MW generation goal of this study; however, it is likely there will be other site development constraints and setbacks when designing each site, as well as real estate challenges.

Twenty-one (21) of the 101 candidate sites are greater than 600 acres in size, and thus may be capable of producing 74.9 MW of power. Larger sites can be developed in smaller phases, if necessary, to stay below the 75 MW threshold. There is also the ability to aggregate smaller sites to achieve the 74.9 MW goal.

All of the 101 identified potential sites are feasible for development of new large scale solar generation facilities based upon available GIS data. All candidate sites have the following favorable site conditions/characteristics:

- Composed of a single parcel of 200 acres or larger
- Transmission lines within 1 mile
- Highway/interstate within 10 miles
- Railroad within 20 miles
- Substation within 2 miles
- Slopes of 15% or less
- No designated scenic, natural, recreational or wildlife areas onsite
- Approximately 200 acres or more of non-wetland area for development
- Approximately 200 acres or more of non-floodplain area for development
- No seismic activity concerns onsite
- No federal superfund sites recorded onsite
- No federal National Register of Historic Places (NRHP) properties onsite
- No known threatened or endangered species areas intersecting the site
- Medium to low risk of natural disasters (based on history of frequent natural disasters, such as forest fires, tornados, etc.)

## Appendix D – Remote Solar Siting

- No lands owned by The Nature Conservancy (TNC) onsite

Of the 101 potential sites, the minimum distance to Jacksonville city center is 7.5 miles, the maximum distance is 348 miles, and the average distance is 129 miles.

All sites are located within 3 miles of a major highway. The average distance to a major

highway is 0.5 miles; however, several sites are located immediately adjacent to a major highway.

All sites are located less than 2 miles from an existing substation. The average distance to a substation is 0.8 miles; however, at least 9 sites are located immediately adjacent to an existing substation and an additional 12 sites are within 0.25 miles of a substation.

**Table D-1 - Summary of Potential Sites Identified for Solar Production in each Florida County**

County	Total Number of Parcels	Total Estimated Production at 6 acres/MW	Total Estimated Production at 8 acres/MW	Total Land Area (Acres)	Total Non-Wetland Area (Acres)
Alachua	1	47	35	280	280
Bay	2	148	111	1,063	889
Bradford	1	39	29	280	231
Calhoun	3	152	114	1,073	915
Clay	4	393	295	2,553	2,360
Columbia	2	83	63	500	500
Duval	32	3,229	2,422	25,523	19,373
Escambia	6	367	275	2,394	2,204
Gadsden	3	172	129	1,094	1,033
Hamilton	2	89	67	552	535
Hernando	1	133	33	265	264
Highlands	2	87	65	536	523
Jackson	7	361	271	2,247	2,164
Lake	3	141	106	856	845
Leon	1	183	32	281	253
Liberty	2	147	110	963	879
Madison	2	79	59	493	474
Marion	6	369	276	2,276	2,212
Okaloosa	3	239	179	1,551	1,432
Orange	1	325	65	559	518
Polk	1	359	25	219	203
Sumter	3	133	99	797	796
Walton	8	465	349	3,174	2,791
Washington	5	326	244	2,054	1,955
<b>Total</b>	<b>101</b>	<b>8,065</b>	<b>5,453</b>	<b>51,583</b>	<b>43,627</b>

Note: The table includes total estimated energy production, total area (acres) and total buildable area (i.e., non-wetland area).

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## Appendix D – Remote Solar Siting

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Based upon GIS analysis, 70 parcels were identified as having favorable slope (i.e., 1 to 9%) across a majority of the site. The remaining 31 parcels have pockets of slopes slightly less favorable, <1% and/or 10 to 15%, slopes, but would not prevent development.

During visual analysis of the candidate sites, it was noted that some candidate sites were located adjacent to other candidate sites. These may pose favorable opportunities to aggregate sites to minimize construction costs, transmission upgrades and future maintenance needs. Sites would be selected and developed in phases, preferably no more than 450 acres at a time, thus targeting approximately 75 MW of energy generation.

### D.4 Conclusions and Recommendations

Florida is rich with solar energy potential, and there is a legislative push to move electric utilities towards renewables. However, due to limited land availability, land-grab challenges could be encountered when multiple companies develop solar at the same time.

Environmental regulations require facilities be built to minimize impact to wetlands and environmentally sensitive areas. This siting study has assisted with the initial step in that process. Through continued thoughtful planning, ecologically sensitive areas that should be preserved and protected will be identified and potentially restored, where possible. Considerations for stormwater management, as well as long term erosion and sediment control, should also be considered when selecting sites for development.

#### D.4.1 GIS Results

The GIS analysis identified 101 candidate sites in 24 counties in Florida, including 32 candidate sites in Duval County. The 101 candidate sites include a total of 51,583 acres of real estate with a total of 43,627 buildable acres. If all non-

wetland space could be developed, these 101 sites would yield between 5,453 and 7,271 MW assuming 6 to 8 acres/MW. This exceeds the 4,000 MW generation goal of the study.

#### D.4.2 Site Selection

Selection of sites for solar development should involve a multi-faceted approach, including consideration of high-level GIS data to determine feasibility of development, site availability, including purchase and lease options, electric transmission accessibility and upgrades requirements, and current and future customer needs, among other factors. Solar development of selected candidate sites will likely encounter two foreseeable challenges, including competition for desirable development sites and transmission upgrades to deliver solar energy from remote locations.

This high-level GIS analysis identifies sites that are feasible for solar development; however, it does not confirm availability, account for line loss, or interconnection agreement requirements. If a site has an estimated production greater than 75 MW, phased construction is recommended to expediate the state approval process.

Recently Environmental Justice (EJ) concerns have been raised at newly proposed solar facilities in Florida, due to their proximity to vulnerable communities. This concern could lead to growing community opposition to the development of a project and the denial of special or conditional use permits through jurisdictions. To mitigate or avoid this issue, we recommend consideration of EJ factors and proximity of community resources, such as residences, during site selection. Solar facilities can provide environmental enhancement using native, pollinator friendly plant species, protection of wildlife corridors, reduction in water use, and improvements in stormwater quality. Local economies can benefit as well through career opportunities, providing a use for unused or abandoned land which can

## Appendix D – Remote Solar Siting

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improve the aesthetic value, property value, and overall quality of life of a community which can potentially offset some of the local or EJ concerns.

### D.4.3 Recommended Next Steps

Once JEA selects sites for the first phase of solar development, Black & Veatch recommends an evaluation of local, state, and federal environmental regulatory and permitting requirements for the selected sites. A permitting evaluation will provide insight regarding the permits that will be required for construction and operation of the facility, as well as a timeline and cost estimate. This initial assessment is critically important to help ensure likely permits and approvals are identified, and that project information required for applications are developed in time to support the application schedule.

Desktop and/or onsite studies such as wetland delineation, protected species surveys, and cultural resources surveys, and initiation of applicable agency consultations, are also recommended to support the permitting process. Onsite studies can be utilized to ground-truth GIS data, update current site conditions, and identify opportunities to avoid and/or minimize impact to environmental resources through site design, and thus simplify permitting obligations. Black & Veatch has the expertise to perform many of these services and/or offer consultation on the next steps required to bring these solar projects to fruition.

## Appendix D – Remote Solar Siting

### Attachment A. Solar Site Selection Scoring Criteria

This attachment summarizes the environmental and technical evaluation criteria used to evaluate the siting region to identify potential sites for development. Best professional judgment was used to select the relative desirability of the criteria. Scores are ordered with 9 being most desirable and 1 or 0 being least desirable. If any criteria have site features that must be avoided for solar project development, these are noted as exclusions.

Following GIS analysis for each criterion, best professional judgement was used to apply assumptions for some criteria to ensure alignment with project needs and to arrive at a manageable list of candidate sites meeting the most favorable development conditions. Any assumptions applied are identified in the project summary report.

#### A. Land Cover

- Ideal: agricultural, scrub/shrub, grassland, pasture, cultivated, barren land
- Data Source: Online sources.
- Analysis Notes: None
- Scoring
  - 9: Agricultural, grassland, pastureland, barren
  - 3: Forested
  - 1: Developed (industrial/commercial, residential)
  - 0: Open water, Wetlands
- Exclusion: None

#### B. Proximity to existing transmission lines

- Ideal: Transmission lines along site (transecting okay especially if owned by client)
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest transmission line provided.

- Scoring
  - 9: Transect/border site
  - 3: <0.5 miles away
  - 1: 0.5 to 1 mile away
- Exclusion:>1 mile away

#### C. Proximity to Highway/Interstate

- Ideal: Access nearby (<1 mile)
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest highway/interstate provided.
- Scoring
  - 9: Border site and up to 1 mile away
  - 3: >1 mile and up to 10 miles away
  - 1: >10 and up to 20 miles away
- Exclusion: Transect site and >20 miles from highway or interstate

#### D. Proximity to Railroad

- Ideal: Near railroad but not onsite to avoid ROW agreements
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest railroad provided.
- Scoring
  - 9: <10 miles from site
  - 3: 10 to 20 miles away
  - 1: >20 miles
- Exclusion: Transect site

#### E. Proximity to existing substation

- Ideal: Existing substation within 1 mile of site.
- Data Sources: Online sources.
- Analysis Notes: Distance to nearest substation provided.
- Scoring
  - 9: Existing substation within 1 mile of site
  - 3: Existing substation located >1 mile, but less than 2 miles from site
  - 1: No existing substation within 2 miles of site; therefore, project must construct new substation.
- Exclusion: None

## Appendix D – Remote Solar Siting

### F. Potential Site Size

- Ideal: Prefer contiguous parcels of same owner at least 200 acres, but larger the better.
- Data Sources: Online sources, Pivvot
- Analysis Notes: None
- Scoring
  - 9: >800 acres
  - 3: 500-800 acres
  - 1: 200-499 acres
- Exclusion: Less than 200 acres

### G. Topography

- Ideal: less than 10% slope. A minimum 1-2% slope is preferred over 0% slope for drainage purposes.
- Data Source: Online sources.
- Analysis Notes: Topography score based on majority of parcel being of that slope category.
- Scoring
  - 9: 1-2% slope
  - 3: 3-9% slope
  - 1: <1% slope or 10-15%
- Exclusion: greater than 15% slope

### H. Proximity to Designated Scenic, Natural, Recreational, or Wildlife Areas

- Definition: Parks, state or federal forests, monuments, recreational areas, wildlife areas, wilderness/wilderness study areas, wild and scenic rivers, and scenic transportation routes.
- Ideal: Outside of designated area and greater than 1 mile to avoid any indirect impacts that may complicate permitting (and/or require studies).
- Data Source: State and federal natural resource agency websites.
- Analysis Notes: None
- Scoring
  - 9: No designated areas within 1 miles of site.
  - 3: Designated areas present within 1 mile of site (but not onsite).
- Exclusion: Designated areas onsite.

### I. Proximity to population center

- Ideal: Just outside of large population center
- Data Sources: Online sources and maps. Use ESRI population density areas as high-level review.
- Analysis Notes: None
- Scoring
  - 9: 0-15 miles away (just outside and within 15 miles)
  - 3: 16-30 miles away
  - 1: 31-50 miles away
- Exclusion: Inside Population Center

### J. Wetlands/Waters of the US

- Definition: Jurisdictional waters of the US
- Data Source: NWI maps, online sources.
- Analysis Notes: Subtract acreage of jurisdictional wetland/waters onsite from total site size to determine how many acres of non-wetland area, i.e., usable for development, are onsite.
- Scoring
  - 9:  $\geq$ 400 acres of non-regulated wetlands/waters development area onsite
  - 3: 200-399 acres of non-regulated wetlands/waters development area onsite
  - 1: < 200 acres of non-regulated wetlands/waters development area onsite
- Exclusion: None

### K. Flood Potential

- Ideal: Outside floodplain, upland location to minimize flooding risk
- Data Sources: Online sources.
- Analysis Notes: Subtract acreage of FEMA 100-year floodplain onsite from total site size to determine how many acres of non-floodplain area, i.e., usable for development, are onsite.

## Appendix D – Remote Solar Siting

- Scoring
    - 9:  $\geq$ 400 acres of non-100-year floodplain development area onsite
    - 3: 200-399 acres of non-100-year floodplain development area onsite
    - 1:  $<$ 200 acres of non-100-year floodplain development area onsite
  - Exclusion: None
- L. Global Horizontal Irradiance (GHI)
- Definition: GHI measures the total solar resource on a horizontal plane. Composed of three components: direct beam, diffuse horizontal irradiance and ground reflected radiation. Long term average of annual sum. Assume higher GHI is associated with higher solar resource, and therefore, yield.
  - Ideal:  $>$ 5.0 kWh/m<sup>2</sup>/day (FL);  $>$ 4.5 kWh/m<sup>2</sup>/day (GA)
  - Data Sources: Online sources and maps.
  - Analysis Notes:
  - Scoring
    - 9:  $>$ 5.0 kWh/m<sup>2</sup>/day
    - 3: 4.5 – 4.9 kWh/m<sup>2</sup>/day
    - 1:  $<$ 4.5 kWh/m<sup>2</sup>/day
  - Exclusion: None
- M. Proximity to airports
- Ideal: Greater than 3.8 miles from airports (FAA notification required for tall structures within 20,000 feet, i.e., 3.8 miles, of public or military airport.)
  - Data Sources: Online sources.
  - Analysis Notes: Prefer  $>$ 3.8 miles but at least  $>$ 1 mile. Do not remove any sites due to airport proximity – just influences FAA notices, glare studies, lighting requirements, etc.
  - Scoring
    - 9:  $>$ 3.8 miles away
    - 3: 3.8-1 miles away
    - 1:  $<$ 1 mile away
  - Exclusion: None
- N. Existing Oil & Gas Activity
- Ideal: Avoid areas with heavy oil and gas activity
  - Data Sources: Online sources. Note that data is high level.
  - Analysis Notes: None
  - Scoring
    - 9: Oil and gas lines  $>$ 0.25 mile away
    - 3: Oil and gas lines adjacent (i.e., bordering and up to  $<$ 0.25 mile away)
    - 1: Oil and gas lines transecting site
  - Exclusion: None
- O. Seismic Zone
- Definition: Potential for seismic activity. Fault zone.
  - Data Sources: Online sources.
  - Analysis Notes: None
  - Scoring
    - 9: No seismic activity concerns.
    - 3: Medium probability of seismic activity.
    - 1: High probability of seismic activity.
  - Exclusion: None
- P. Potential for Hazardous Material Contamination
- Definition: Proximity to Superfund site (NPL – National Priority List, EPA)
  - Data Source: [https://services.arcgis.com/cJ9YHowT8TU7DUyn/ArcGIS/rest/services/Superfund\\_National\\_Priorities\\_List\\_\(NPL\)\\_Sites\\_with\\_Status\\_Information/FeatureServer](https://services.arcgis.com/cJ9YHowT8TU7DUyn/ArcGIS/rest/services/Superfund_National_Priorities_List_(NPL)_Sites_with_Status_Information/FeatureServer)
  - Analysis Notes: None
  - Scoring
    - 9: No Superfund (NPL) sites located within parcel.
    - 1: Superfund (NPL) site located within parcel.
  - Exclusion: None

## Appendix D – Remote Solar Siting

### Q. Soil Corrosivity

- Definition: Degree that conditions onsite could accommodate construction and installation work. Use steel and concrete corrosivity ratings for soil.
- Ideal: low corrosivity soils
- Data Sources: USDA soils survey.
- Analysis Notes: Both Steel and Concrete Corrosivity
- Scoring
  - 9: Favorable Conditions: low corrosivity soils
  - 3: Moderate Challenges: moderate corrosivity soils
  - 1: Significant Challenges: high corrosivity soils
- Exclusion: None

### R. Depth to Restrictive Layer

- Ideal: Deep, >80 inches
- Data Sources: USDA soils survey.
- Analysis Notes: None
- Scoring
  - 9: > 80 inches
  - 1: < 80 inches
- Exclusion: None

### S. Cultural Resources

- Definition: Historic sites listed in the National Register of Historic Places (NRHP). Note this is not a cultural resources desktop review evaluating potential project impacts to known and/or unknown cultural resources, but rather an emphasis on available GIS data for known/listed federal sites. Does not include state-listed resources or confidential resources that must be requested from SHPO by a professional archaeologist.
- Data Source: Online sources (NPS website)
- Analysis Notes: None
- Scoring
  - 9: No listed resources onsite or within 1 mile of site. [resources >1 mile]

- 3: No listed resources onsite but resource located within 1 mile of site.

- 1: Listed resource onsite

- Exclusion: None

### T. Documented Threatened and Endangered Species

- Definition: Critical habitat area. Species (or habitats) that are federally listed as endangered or threatened. This is not a biological desktop review but rather a high-level review based on publicly available data.
- Data Source: Online sources, USFWS IPaC
- Analysis Notes: 3 and 1 are essentially the same permitting result; therefore, prefer score of 9, but note that absence of intersecting area does not necessarily mean no threatened or endangered species or habitat may exist onsite. Would need to be confirmed with consultation and onsite investigation.
- Scoring
  - 9: No known threatened or endangered species areas intersecting parcel.
  - 3: Threatened species area intersects parcel.
  - 1: Endangered species area intersects parcel.
- Exclusion: None

### U. Historical Natural Disasters

- Ideal: Avoid areas with history of frequent natural disasters such as forest fires, tornados, etc.
- Data Source: NOAA data for past 20 years.
- Analysis Notes: None
- Scoring
  - 9: Low risk of natural disasters based on historical activity.

## Appendix D – Remote Solar Siting

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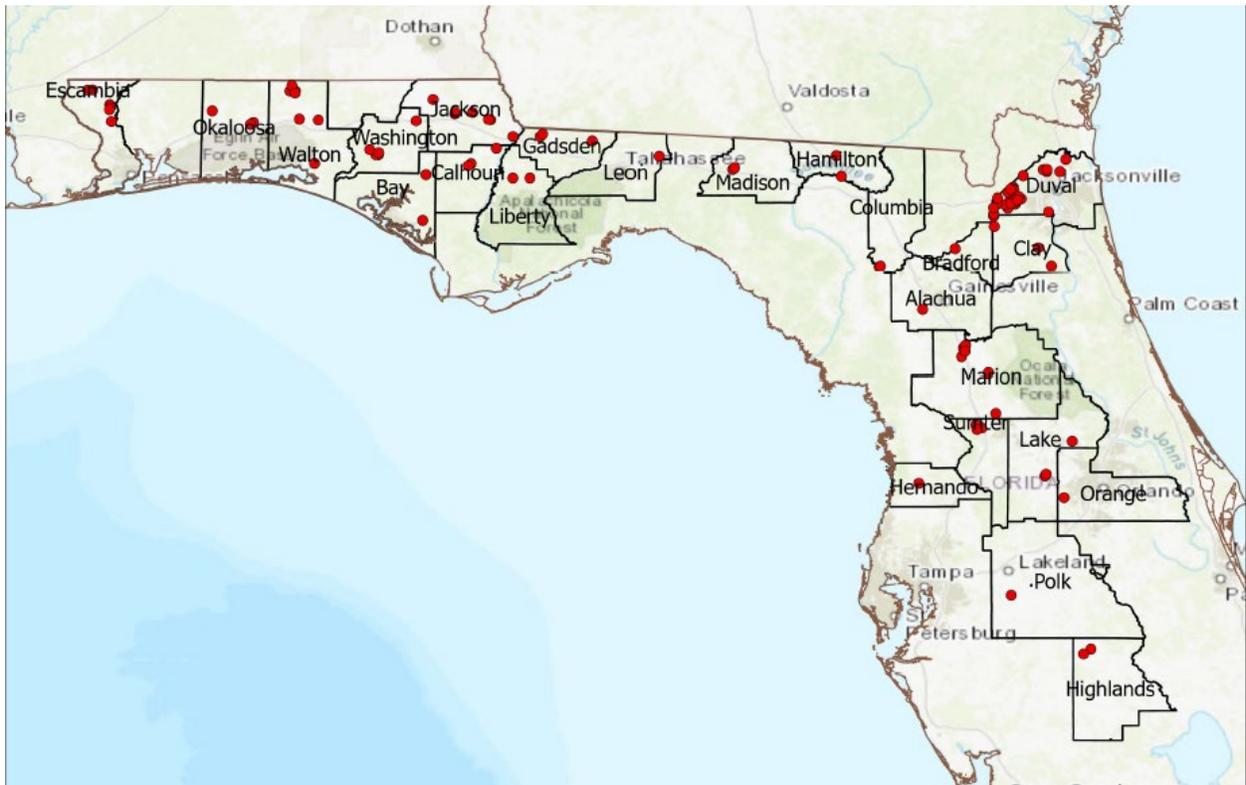
- 3: Medium risk of natural disasters based on historical activity.
- 1: High risk of natural disasters based on historical activity.
- Exclusion: None

### V. The Nature Conservancy

- Definition: TNC lands including conservation easements, deed restrictions, agreements, leases, permits, access right of ways, right of way tracts and transfers/assists.
- Data Source: The Nature Conservancy data, [tnclands.tnc.org](https://tnclands.tnc.org)
- Analysis: None
- Scoring
  - 9: No TNC resources onsite. (no)
  - 0: TNC resource onsite. (yes)
- Exclusion: None

Appendix D – Remote Solar Siting

Attachment B. Florida Solar Siting Overview Map





## Appendix E – Stakeholder Engagement Details

### E Stakeholder Engagement Details

Stakeholder engagement occurred primarily through a series of formal meetings that occurred during the term of the IRP preparation. The topics and dates for the meetings were synchronized with planned key milestones of the IRP development so that feedback from the Stakeholders could be incorporated immediately into the IRP rather than after the fact. The milestones included development of the Scenarios, development of the key forecasts and supply side options that were foundational to the IRP modeling, the preliminary results of the modeling, the final results of the modeling, and identification of the most common near-term resources for possible implementation by JEA. A list of the meeting dates and topics is provided in Table E-1.

**Table E-1 Stakeholder Engagement Meetings and Topics**

Meeting #	Topic
1. January 2022	Introduction to JEA and the IRP Process
2. February 2022	Planned Scenarios
3. March 2022	Key Forecasts
4. June 2022	New Resource Options
5. September 2022	Preliminary PLEXOS Modeling Results
6. November 2022	Updated PLEXOS Modeling Results
7. February 2023	Final PLEXOS Modeling Results and Implementation Plan
8. May 2023	Final IRP and Implementation Plan

## Appendix E – Stakeholder Engagement Details

Figure E-1 – Stakeholder Invitation Letter



Building a more reliable and sustainable community

November 24, 2021

Over the course of 2022, JEA will develop an Integrated Resource Plan (IRP) to help guide operations of the electric system that serves our community for the next twenty-plus years.

In order to properly weigh the many factors that go into serving Northeast Florida with reliable and sustainable power at a reasonable cost, we need input from a diverse set of area stakeholders. Therefore, we are forming a Stakeholder Advisory Committee to advise our IRP process. Because of your leadership role in Jacksonville and Northeast Florida, I would like to invite you to participate as a member of this Committee.

This letter provides you with some background information about the IRP, plans for convening the Committee, and contact information for learning more. I appreciate your consideration of this invitation and hope that you will add your voice to this important endeavor.

### JEA's Integrated Resource Plan

The 2022 IRP will result in a comprehensive approach for meeting the forecasted energy demands of our community. JEA is responsible for looking at a range of operational, environmental, and technological considerations, while balancing the needs of a diverse set of residential, commercial, and government customers in a rapidly growing region.

As we prepare for the 2022 IRP, the Committee's review and feedback will give us valuable advice and perspectives. The IRP will consider several scenarios while addressing the following essential requirements and trends:

- System reliability, resiliency and resource adequacy
- Carbon emission reduction goals and future potential requirements
- Retirement or replacement of aging generation resources
- Integration of planned and future utility-scale solar facilities

- Land requirements and site locations for new resources
- Distributed energy resources, demand-side management, and energy efficiency
- Electric vehicle and other electrification technology
- New and emerging supply-side resource technologies
- Population growth and economic development in Northeast Florida

### IRP Stakeholder Advisory Committee Roles and Responsibilities

The Committee will be invited to a series of eight meetings with JEA leaders and external subject matter experts. The meetings will provide Committee members with informational briefings about the planning considerations listed above and invite you, as a representative of your organization, to share perspectives and ask questions.

Committee participants will be asked to:

- Participate in meetings beginning in January 2022 and concluding in January 2023. These meetings will be approximately 90 minutes long and conducted in person with virtual attendance options.
- Represent your organization's interests
- Review background materials provided in advance of meetings
- Engage in positive, productive communication with other participants, the facilitator, and project staff
- Communicate disagreement respectfully
- Provide advice and input on how JEA can engage other community members on IRP matters

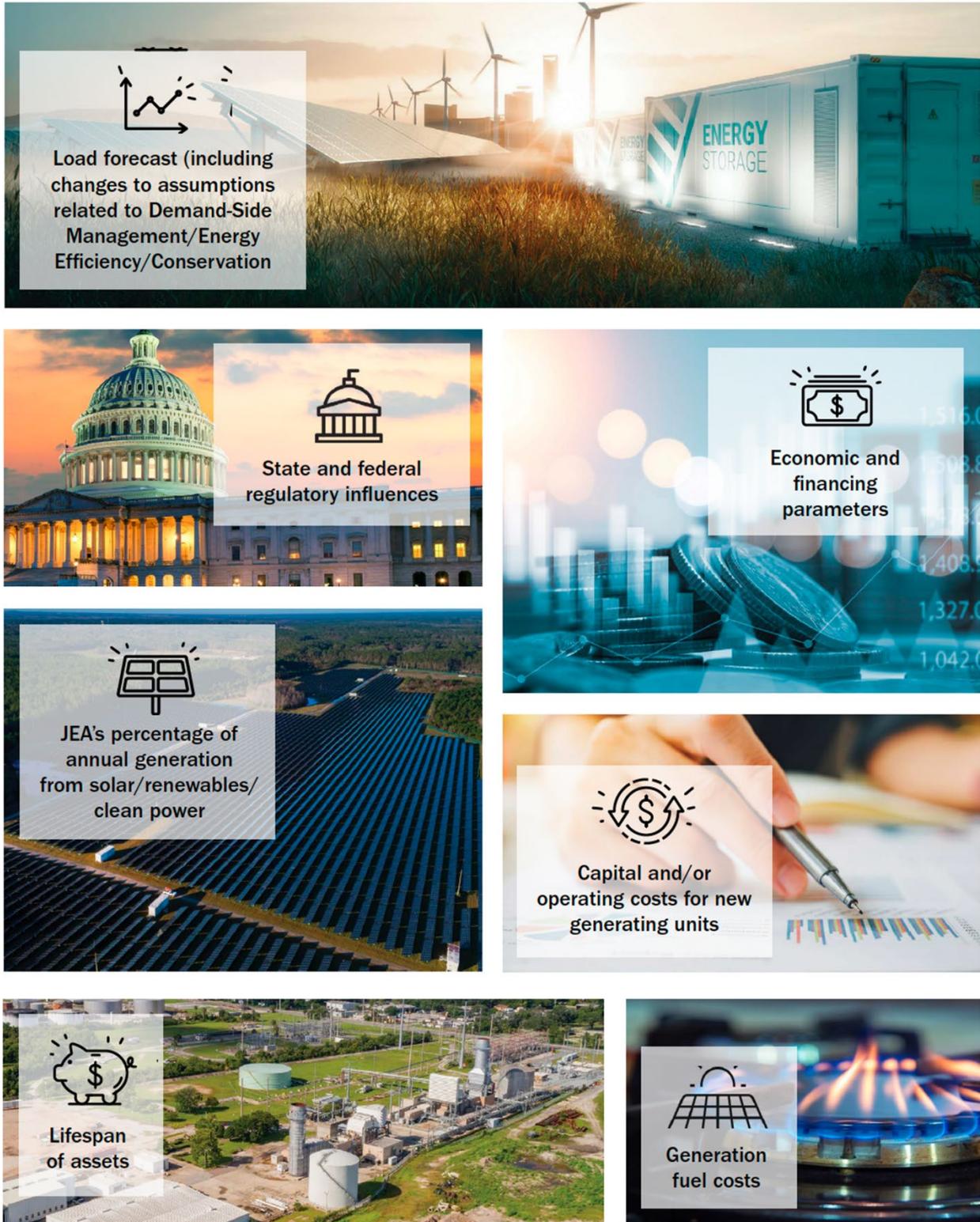
Please feel free to contact Laura Schepis, our Chief External Affairs Officer with questions about this invitation as well as your suggestions for the Stakeholder Advisory Committee. She can be reached at [schela@jea.com](mailto:schela@jea.com). You can also reply to [IRP@jea.com](mailto:IRP@jea.com) with your response regarding participation. We look forward to partnering with you as we undertake this critically important initiative for our community.

Sincerely,

Jay C. Stowe  
Managing Director and CEO

Appendix E – Stakeholder Engagement Details

Figure E-2 – Key Factors Considered in IRP Development



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## Appendix E – Stakeholder Engagement Details

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Meeting #1 was held at the JEA headquarters and focused on introducing Stakeholders to JEA and the IRP process. Presenters included Jay Stowe (Managing Director and CEO); Raynetta Curry Marshall, P.E., (Chief Operating Officer); Ricky Erixton (Vice President of Electric Systems); Laura Schepis (Chief External Affairs Officer); and Brad Kushner (IRP Lead from Black & Veatch). The presentation included an overview of JEA's electric system, including historical and projected electric customer demands, historical number of customers, and historical and projected carbon emissions associated with JEA's electric generation. Key utility industry trends relevant to the IRP were also presented along with key drivers for the IRP. A preliminary timeline for completion of the IRP and future Stakeholder meetings was also covered. Stakeholder comments during and after the meeting were primarily about accounting for carbon emissions, the impact of limited battery material availability and disposal requirements, and environmental justice considerations.

Meeting #2 was held at the JEA headquarters and focused on introducing Stakeholders to the multiple planning scenarios that were going to be studied as a foundation for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Cantrece Jones (Stakeholder Lead from Black & Veatch); and Brad Kushner (IRP Lead from Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Several planning concepts were then presented. These included IRP variables (considered quantitatively; fuel cost, environmental regulations, cost of generating technologies, etc.) and IRP considerations (considered qualitatively; affordability, environmental justice, economic development and CO<sub>2</sub> emissions reductions). The concepts also included scenarios and sensitivities. A scenario is a set of simultaneous changes to

multiple variables that are modeled simultaneously to reflect a potential future, whereas a sensitivity is a change to one variable within a potential future to test the sensitivity of results to that variable. The preliminary list of scenarios planned for the IRP were then presented, including Current Outlook, Economic Downturn, etc., along with the key characteristics of each.

Meeting #3 was held at the JEA headquarters and focused on presenting the key forecasts that had been or were planned to be developed for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer), Laura Schepis (Chief External Affairs Officer); Melinda Fischer (Electric Generation Planning Manager); Brian Phippen (DSM/EE Program Manager); Felise Man (Electric Vehicle Lead for Black & Veatch); Jim Herndon (DSM/EE Lead for Black & Veatch); and Brad Kushner (IRP Lead for Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Forecasts were then presented concerning future JEA loads, electric vehicles, JEA's existing DSM/EE programs, potential new DSM/EE and customer-sited generation. The proposed scenarios were then revisited with a discussion of how different variables within each proposed scenario would change relative to the proposed Current Outlook scenario. Throughout the presentation, Stakeholder feedback was welcomed and addressed as the presentation progressed. Stakeholders were encouraged to share what they would like to see at upcoming Stakeholder meetings and how the Stakeholder experience could be improved. The Stakeholders were informed that a written report on IRP activities would be provided in mid-May given the time between the March and scheduled June meeting.

Meeting #4 was held at the JEA system operations control center (SOCC) and was focused on the new resource options that had

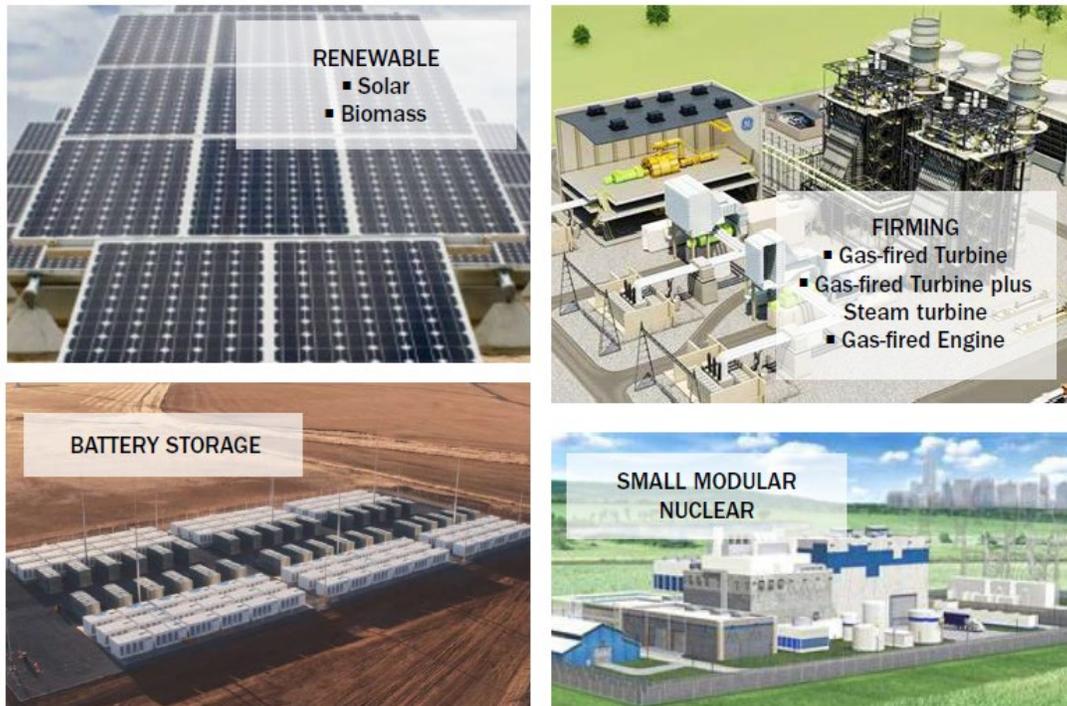
## Appendix E – Stakeholder Engagement Details

been or were planned to be developed for the IRP. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Garry Baker (Senior Director, Energy Operations); Brad Kushner (IRP Lead for Black & Veatch); Paul Maxwell (IRP Manager for Black & Veatch); and Darren Bishop (Resource Option Lead for Black & Veatch). The meeting began with a brief visual overview of the SOCC floor, including the various operating desks and their function. A recap of the prior Stakeholder meeting was then presented, including key takeaways and post-meeting comments received from Stakeholders. The focus then shifted to the new resource options that were being studied. These included renewables (solar, solar plus storage, standalone storage, battery storage), natural gas-fired firming (gas turbine, reciprocating engine, combined cycle, and combined cycle conversion), and advanced nuclear (small modular reactor). An illustration of the new resource options presented is shown on Figure E-3.

Hydrogen as a potential future fuel was also discussed. More detail was then presented on the solar options, particularly the large land need for new solar resources and the transmission to bring the solar energy to JEA loads. The availability of space at the existing JEA GEC, Northside and SJRPP sites to host the renewable and gas-fired options was also presented. The presentation then shifted to the upcoming planned scenario modeling and some sample results.

Meeting #5 was held at the JEA headquarters and was focused on presenting preliminary IRP modeling results from the PLEXOS modeling tool. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); and Brad Kushner (IRP Lead for Black & Veatch). A photograph taken during the meeting is shown on Figure E-4.

**Figure E-3 – Presentation of New Resource Options**



Appendix E – Stakeholder Engagement Details

Figure E-4 – Photograph of Meeting #5



The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. The focus then shifted to presentation of preliminary modeling results for the Current Outlook scenario and a sensitivity with assumptions similar to the planned Future Net Zero scenario. Results were also presented for a similar but special sensitivity that had been run in response to Stakeholder comments received prior to the meeting (Riverkeepers Sensitivity). These sets of results were intended to serve as “bookends” to illustrate how the type, quantity and timing of new resource additions could vary widely across the scenarios when the scenario modeling is completed.

Meeting #6 was held at the JEA Conservation Center and was focused on presenting updated PLEXOS modeling results. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Pedro Melendez (Vice President of Planning, Engineering & Construction); Brad

Kushner (IRP Lead for Black & Veatch); and Paul Maxwell (IRP Manager for Black & Veatch).

The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Some key changes that had been made to the IRP modeling assumptions since the prior meeting were then discussed. The changes included promotion of the Riverkeepers Sensitivity to a full scenario (the “Supplemental Scenario”). This new scenario replaced the Efficiency + DER + Lower Emissions Scenario because that scenario was judged to be not significantly different than the other scenarios. Other changes included modeling of the expanded investment tax credit (ITC) provisions under the recently passed federal Inflation Reduction Act (IRA), which caused reduction of the solar PPA price forecasts and elimination of the solar plus storage resource options. Changes also included reduced energy storage costs due to expected future technology improvements and performance degradation. Modeling assumptions for each of

## Appendix E – Stakeholder Engagement Details

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the scenarios was then presented along with detailed modeling results. Resulting forecasts for each scenario across the entire JEA system included the type and capacity of existing and added new resource options that would be added, the energy that would be produced, the amount of CO<sub>2</sub> emissions that would be produced, and the total capital and operating costs to JEA. In addition to these detailed results, an analysis across the results was presented that identified the resources that appeared most frequently across all the scenarios for the first 10 years of the planning period (“Most Common Resources”). This analysis should prove useful to JEA and Stakeholders as they consider which resources to begin implementing in the near term to regardless of which potential future (which scenario) will occur.

Meeting #7 was held at the JEA headquarters and was focused on presenting final PLEXOS modeling results. Presenters included Raynetta Curry Marshall, P.E. (Chief Operating Officer); Laura Schepis (Chief External Affairs Officer); Pedro Melendez (Vice President of Planning, Engineering & Construction); and Brad Kushner (IRP Lead for Black & Veatch). The meeting began with a recap of the prior Stakeholder meeting, including key takeaways and post-meeting comments received from Stakeholders. Some key changes that had been made to the IRP modeling since the prior meeting were then discussed. The key changes included increased PPA prices for the Tier 0 solar resources due to increased cost estimates of electrical transmission interconnections based on more detailed transmission system analysis and discussions with JEA transmission planning staff. The changes also included performance of six sensitivities off the Current Outlook scenario to address questions that Stakeholders had raised about the scenario modeling results presented during the prior meeting. Results for the six scenarios and the six sensitivities were presented in a similar format to results presented at the prior meeting.

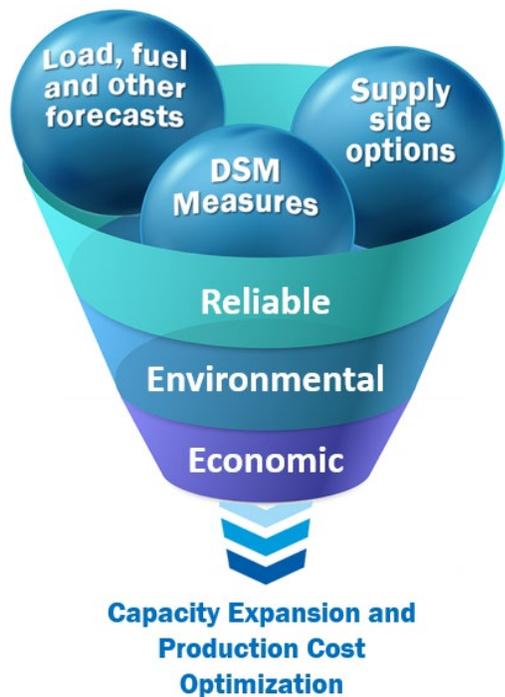
Meeting #8 will be held in May 2023 and will focus on presentation of the final IRP report to Stakeholders and the general public.

## Appendix F – Overview of PLEXOS

### F Overview of PLEXOS

Black & Veatch utilized PLEXOS to evaluate the combination of resources available to JEA to meet future demand and energy requirements in the 2022-2051 planning horizon. PLEXOS is an industry standard, capacity expansion and production cost model used by multiple utilities and other utility industry professionals to perform a variety of analysis..

**Figure F-1 - PLEXOS Constrained Optimization**



PLEXOS is an industry preferred model for a variety of reasons such as its ability to run scenario analysis as well as its optionality. PLEXOS has the flexibility to modify granularity, chronology, and performance targets so that the model will produce the lowest cost solution in a reasonable amount of time. The PLEXOS model performs its evaluation in four phases: Long Term (LT), Projected Assessment of System Adequacy (PASA), Middle Term (MT) and Short Term (ST). These phases can be utilized together or independently depending on the user's needs. Black & Veatch utilized all four phases for the purpose of the JEA IRP. Each

Phase of the model passes the solution to the next phase.

The LT is responsible for capacity expansion. Capacity expansion refers to finding the optimal combination of existing generating resources, generation new builds, transmission upgrades, and retirements that minimizes the net present value of the total costs over the long-term planning horizon while adhering to all the constraints applied on the model. The LT was set to evaluate the entire 30-year planning horizon in one step and every day in the planning horizon was evaluated with full chronology, meaning each period of the day followed the one before it as opposed to a load distribution curve. This is important when evaluating renewables or storage resources, where the operation of these assets is time-period sensitive.

The PASA phase calculates several reliability indices and schedules planned outages. This phase of the model was only used in the JEA IRP to provide scheduled maintenance for the new generation assets.

The MT phase pre-solves the optimization problem for the ST. The MT is particularly important for items that require planning across multiple days or longer periods of time. The MT is crucial for optimizing storage, fuel supply and emissions constraints. The MT was set to evaluate an entire year per step, this was necessary given the annual constraints associated with the Future Net Zero scenario and sensitivity as well as the Supplemental scenario.

The ST model is the final and most detailed phase of the model and produces the final hourly production cost. The ST is set to evaluate 1 day per step and each hour is evaluated individually. The ST model builds on all the outputs of the other phases to produce the detailed hourly production cost.

## Appendix F – Overview of PLEXOS

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The fundamental objective of PLEXOS in developing the optimal capacity expansion plans within each scenario and sensitivity is to minimize the net present value of costs (systemwide production costs as well as fixed O&M and capital costs associated with new generating resource additions) over the IRP time horizon while maintaining system reliability. The model is required to carry sufficient capacity to meet annual peak demand plus reserve margin requirements and meet the annual energy requirements of the JEA system. For scenarios and sensitivities in which there are annual targets for percent of generation from renewable and/or clean energy resources (i.e., the Future Net Zero and Supplemental scenarios, and the Net Zero sensitivity), the optimal capacity expansion plans are determined by considering economic and reliability while meeting the annual targets for renewable and/or clean energy generation).

Appendix F – Overview of PLEXOS

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END OF VOLUME 2