BLACK & VEATCH

2023 Electric Generation Integrated Resource Plan

IRP
INTEGRATED RESOURCE PLANNING

Dear friends and neighbors,

I'm pleased to share with you the details of the 2023 version of JEA's electric Integrated Resource Plan (IRP).

I say "version" because long-term planning for the best ways to provide essential energy to our customers and community — **reliably, cost-effectively, and sustainably** — will be an ongoing process. While the specific plan details are very complex, the goals the JEA Board has set for us are simple, clear, and ambitious.

Namely, in less than a decade:

- Our power supply portfolio will be **35 percent clean energy**.
- We will **retire less efficient generating assets**.
- We will lead the way by using 100 percent clean energy to serve JEA facilities.
- We will **increase and enhance energy efficiency programs** to offset growing demands from the ongoing electrification of homes, businesses, and vehicles.

Accomplished together by 2030, these goals will result in an 80 percent reduction in JEA's overall carbon emissions since 2005.

The work we've done over the past months, in collaboration with a diverse group of community stakeholders is just the start of a longer, worthwhile journey to serve you, our customers and owners, in the best way possible as energy technologies evolve. Our planning will continue in an open and transparent manner with you. Your feedback throughout this process has been, and remains, fundamental to its success.
We look forward to maintaining an ongoing dialogue with you on these and other JEA services that are foundational to **a vibrant and healthy Jacksonville and Northeast Florida.**

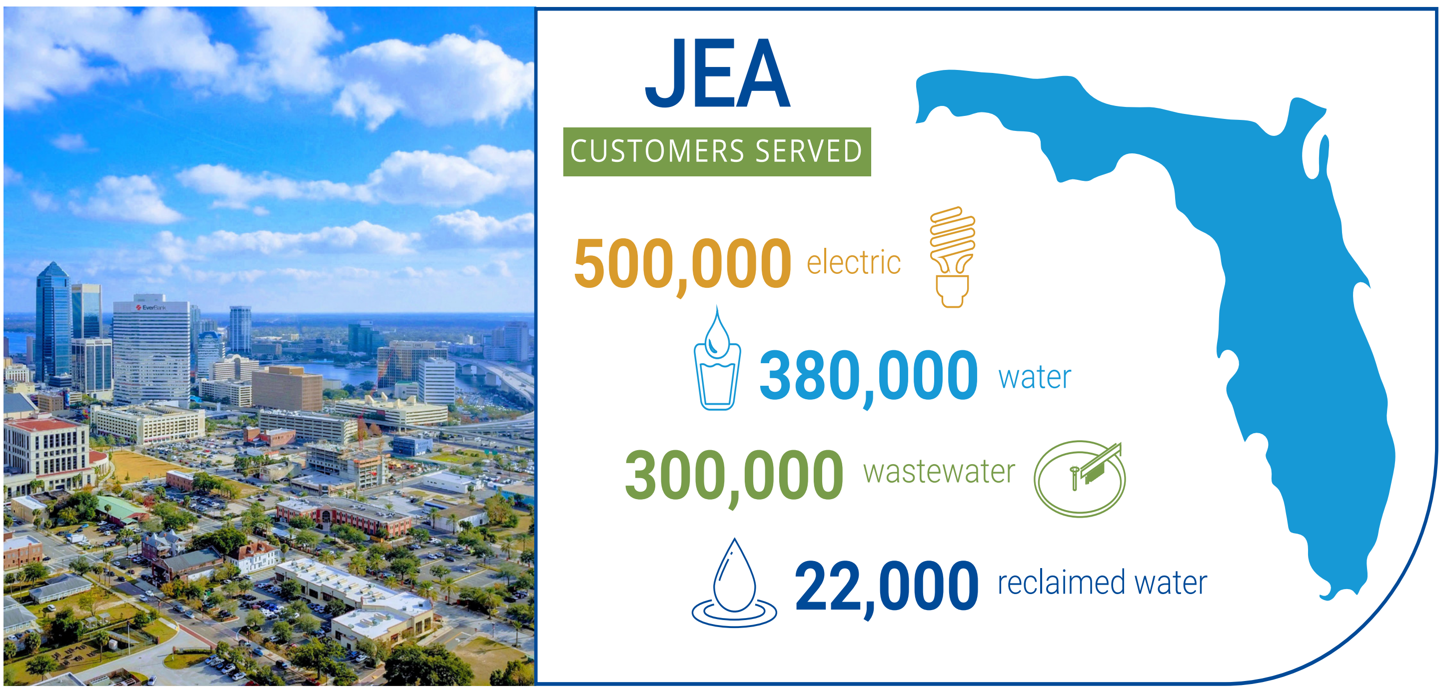
Thank you. It's an honor to serve you.

Jay

Executive Summary

The JEA 2023 Electric Generation Integrated Resource Plan (IRP) was prepared to guide JEA's efforts to continue providing reliable, low-cost power to its customers for decades to come, while balancing affordability, reliability, and environmental sustainability.

JEA benefited at every step of this IRP's development from collaborating with and listening to our community through a group of representative stakeholders. Their input and perspectives helped us better envision future scenarios and fine-tune the economic and engineering processes that are integral to resource planning. As a result, like no other IRP JEA has conducted previously, this 2023 edition combines economics, engineering, and engagement to chart a responsible course forward toward 2030 and beyond.



Overview of JEA

JEA serves an estimated 500,000 electric, 380,000 water, 300,000 wastewater and 22,000 reclaimed water customers. JEA owns and operates an electric system that includes four generating plants, over 745 circuit miles of transmission lines and more than 7,200 miles of distribution lines. JEA also purchases solar energy from several small third-party owned solar resources located across the service territory.

In 2022, the mix of resource types used to supply energy to customers included renewable (1 percent), natural gas fired (59 percent), purchased power (29 percent), and solid fuel fired (11 percent).

Technical Conclusions of the IRP

The IRP involved modeling of multiple scenarios and sensitivities. Each scenario represented a possible future that JEA could experience, and each sensitivity represented a possible singular event that could transpire within one of the scenarios (the Current Outlook scenario). Because it is impossible to predict the future, it isn't reasonable to merely select results from one scenario or sensitivity to determine which resource options to implement. It's more reasonable to identify resource options that appeared most frequently across all the scenarios and sensitivities. In this way, JEA can be confident that the near-term resource options it develops will become and remain valuable additions to the portfolio regardless of which future occurs. Based on modeling six scenarios and six sensitivities (each sensitivity evaluated within one scenario), the IRP results illustrate that in the near-term by the 2030 timeframe[1]. It is highly likely that:

- JEA will require significant firm, reliable capacity to meet projected customer peak demands (plus reserve margin requirements) beginning in the 2029 timeframe when JEA's existing Northside Generating Station Unit 3 is removed from service.
- JEA's system will benefit from increased amounts of solar generation resources in the near-term, subject to siting considerations and electric transmission system improvements that will be necessary to support the additional solar generation. These amounts of solar generation would be in addition to the 5-year purchase of 150 MW of solar photovoltaic (PV) that JEA has recently secured. The most common additions of solar PV across the scenarios and sensitivities are 300 MW in the 2026 timeframe and an additional 975 MW in the 2030 timeframe. The scenarios and sensitivities calling for these additions are illustrated in Figure ES-1 and Figure ES-2 below.
- JEA's system will benefit from retiring Unit 3 at Northside Generating Station.
- JEA's system will benefit from efficient, flexible baseload generation through the addition of advanced-class combined-cycle combustion turbines[2], allowing for the efficient utilization of natural gas (and potentially hydrogen) while providing the JEA system with operational flexibility to reliably integrate increased amounts of intermittent solar energy. The most common addition across the scenarios and sensitivities is a 571 MW natural gas combined cycle in the 2029 timeframe. The scenarios and sensitivities calling for this addition are illustrated in Figure ES-3 below.

Figure ES- 1: Most Common Resource Additions; Solar in the 2026 Timeframe

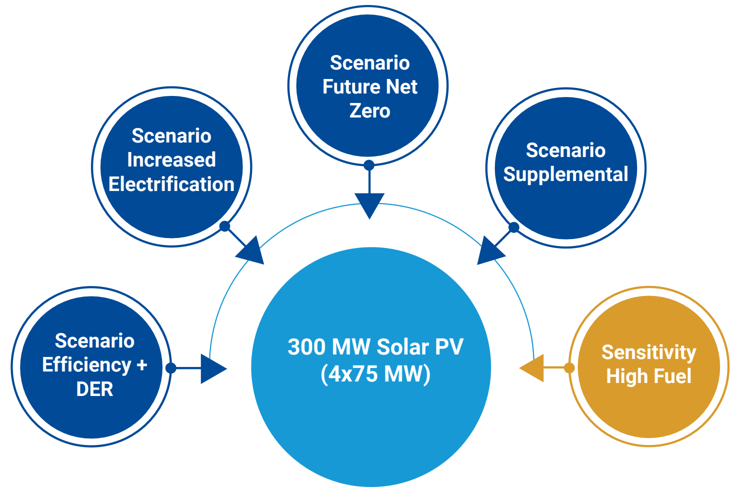
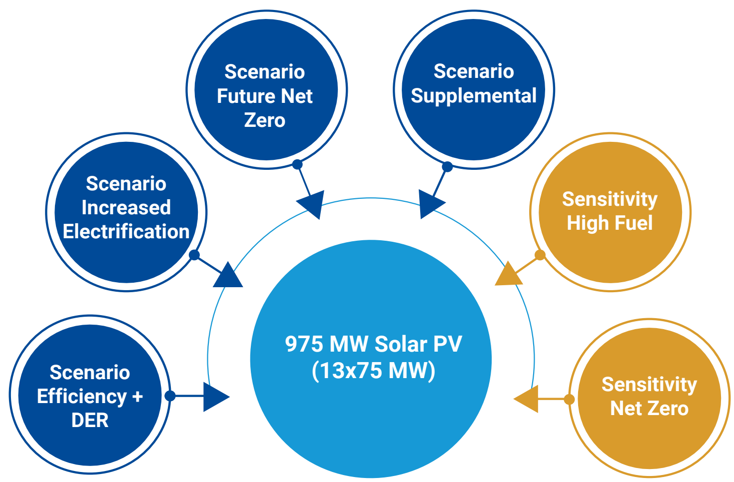


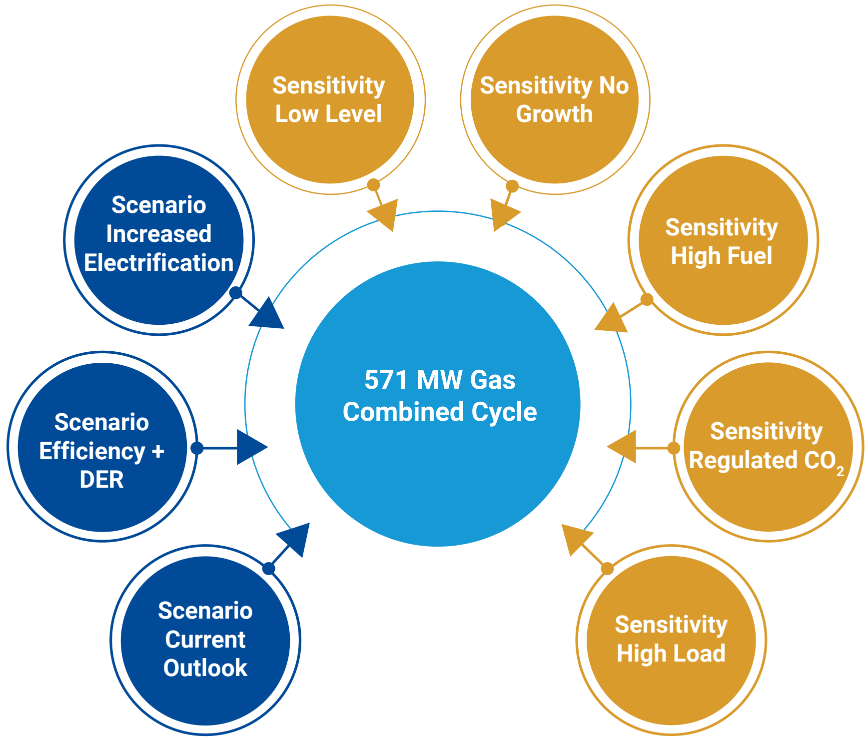
Figure ES- 2: Most Common Resource Additions; Solar in the 2030 Timeframe



The IRP will serve as a compass, guiding JEA in continued provision of reliable and low-cost power to its customers for decades to come.

[1] Although the IRP considered a planning horizon through 2051, longer-term resource decisions will be informed by subsequent studies and resource planning activities, including future IRPs. As such, the findings of the IRP summarized herein are focused on near-term resources that are components of the long-term resource plans identified through the comprehensive scenario and sensitivity analysis approach reflected in the IRP.
[2] A combined cycle configuration is referred to herein as a 1x1 GE 7HA.02 or a 1x1 H Class Gas resource.

Figure ES- 3: Most Common Resource Additions; Gas-Fired Firming in the 2029 Timeframe

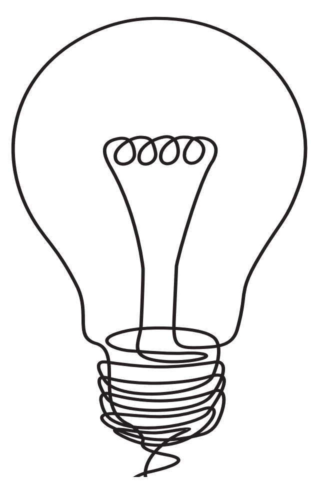


- Several of the scenarios and sensitivities identified economic benefits to adding energy storage in the 2025 timeframe. However, additional sensitivity analyses showed that the benefit is very small because capital cost of these storage resources is relatively high. In future IRPs JEA will continue to evaluate battery resources to determine when storage resources provide needed reliability at the right price point for customers.

IRP Approach

JEA conducted the IRP with ongoing engagement from a diverse cross-section of community leaders through a Stakeholder engagement process. Stakeholders included residential and commercial customers, community partners, environmental group members, neighborhood associations, and municipal representatives. Stakeholders and JEA conducted eight formal meetings, allowing robust discussion, and bringing a variety of social, environmental, and historical considerations from across the community into the decision-making process. Meeting topics and dates were synchronized with planned key IRP development milestones so that Stakeholder feedback could be incorporated immediately. JEA also posted information on its website, allowing the public to follow development of the IRP, ask questions and provide feedback. A summary of the Stakeholder meetings and topics is provided in Table 2-1.

Economic portions of the IRP were developed with industry-standard modeling tools (computer simulations) to evaluate various resources and identify the least-cost resource plans to reliably meet forecasted customer energy requirements for the 2022 through 2051 period considered in this IRP. The evaluations were performed across a



wide range of potential futures, incorporating both scenario and sensitivity analysis methodology to evaluate how variables and considerations impact the future energy needs of JEA customers. Scenario analysis considers a set of changes to multiple variables simultaneously to analyze a potential future. Sensitivity analysis considers changes to one of these variables at a time within a given potential future.

IRP Scenarios

Stakeholders and JEA experts developed six scenarios together, blending reliability, economics, and societal considerations. Stakeholders discussed the scenarios, asked questions, and refined them with JEA over several months and meetings.

The simplest way to view the scenarios is as a wide range of potential futures. Applying modeling to these scenarios, and then continuing to refine the modeling using sensitivity analysis, established the information set that allowed JEA to see more clearly what resource decisions and goals will serve the community best in the near term. The scenarios are summarized in Table ES-1.

IRP Modeling Methodology

The PLEXOS model evaluated resource combinations JEA could use to meet future demand and energy requirements in the 2022-2051 planning horizon. PLEXOS is an industry standard capacity expansion and production cost model that multiple utilities and utility industry professionals use for a variety of analyses. PLEXOS produced least-cost resource plans for the 12 scenarios and sensitivities.
All possible resources had to meet important reliability considerations (i.e. having sufficient firm, dependable capacity to meet forecast peak demands plus reserve margins and JEA customers' energy requirements) while honoring unit operational constraints. Ultimately, the IRP examined commercial technologies including solar PV, battery energy storage systems, and various firming natural gas turbines.

JEA will benefit from increased amounts of solar generation and addition of a new efficient, flexible new advanced-class gas-fired firming resource in the near term.

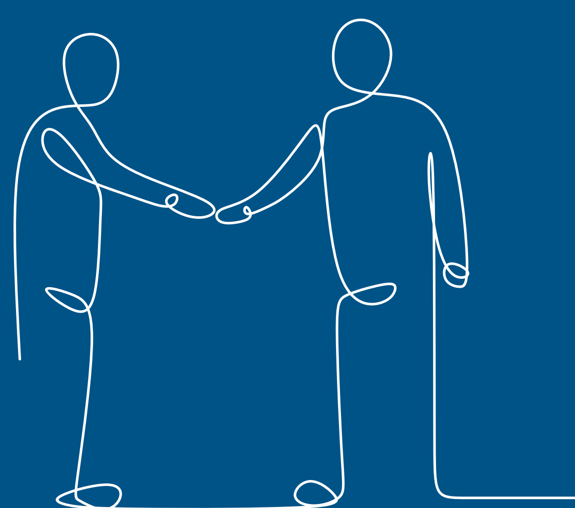


Table ES-1 - Existing and Future Planned Generating Resources

Scenario Name	Description
Current Outlook	Reflects JEA's current outlook (forecasts and projections) related to inflation and escalation rates, customer peak demand and energy requirements (including JEA's current projections related to demand-side management/energy efficiency/conservation, plug-in electric vehicles, electrification, and customer-sited solar), natural gas and solid fuel prices, costs for new generating resources, Northside 3 removed from service in 2029 with all other JEA-owned generating resources continuing to operate for the IRP study horizon[3], no costs for emissions of CO_2, and no targets for percent of energy served by renewable or non-CO_2 emitting resources.
Economic Downturn	Reflects a future with a sustained economic slowdown, driven in part by higher inflation rates and increased fuel prices and commodity costs. Relative to the Current Outlook, inflation and escalation rates are increased, customer peak demand and energy requirements are reduced, fuel prices are increased, and costs to construct new generating resources are increased.
Efficiency + DER	Reflects a future with increased levels of interest and participation in demand-side management and energy efficiency and customer-sited renewable energy resources, and increased interest in plug-in electric vehicles and electrification, driven in part by higher fuel prices. As compared to the Current Outlook, customer peak demand and energy requirements are increased (reductions associated with demand-side management, energy efficiency, and customer-sited renewables do not offset increased energy requirements associated with plug-in electric vehicles and electrification), and fuel prices are increased.
Increased Electrification	Reflects a future with increased levels of interest and adoption of customer-sited renewables, plug-in electric vehicles, and electrification, driven in part by higher fuel costs. As compared to the Current Outlook, customer peak demand and energy requirements are increased (due to increased adoption of plug-in electric vehicles and electrification), fuel prices are increased, and costs to construct new generating resources are increased.
Future Net Zero	Reflects a future in which JEA achieves zero CO_2 emissions from its generating portfolio by the end of the IRP planning period. As compared to the Current Outlook, customer peak demand and energy requirements are increased (reductions associated with demand-side management and energy efficiency and customer-sited renewables do not offset increased energy requirements associated with plug-in electric vehicles and electrification), fuel prices are increased, and there is a cost for emissions of CO_2, JEA's generating portfolio has zero CO_2 emissions by 2050 with interim CO_2 reductions beginning in 2030, through increased utilization of clean energy resources (40 percent clean energy by 2030, increasing to 100 percent clean energy by 2050.
Supplemental	Reflects a future in which JEA achieves zero CO_2 emissions from its generating portfolio by the end of the IRP planning period. As compared to the Current Outlook, customer peak demand and energy requirements are increased (reductions associated with demand-side management and energy efficiency and customer-sited renewables do not offset increased energy requirements associated with plug-in electric vehicles and electrification), fuel prices are increased, and there is a cost for emissions of CO_2, JEA's generating portfolio has zero CO_2 emissions by 2050 with interim CO_2 reductions beginning in 2030, through increased utilization of clean energy resources (40 percent clean energy by 2030, increasing to 100 percent clean energy by 2050.

[3]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, particularly for Northside 3. For Northside 3, which is a less-efficient, aging unit with uncontrolled NOx, PM and SO_2 emissions, the areas of potential future concern include Regional Haze rules, potential changes to NOx emissions, any rules or means limiting future CO_2 emissions, the risk of becoming subject to New Source Performance Standards (NSPS) due to the scope of maintenance required to keep the unit safe and reliable, and the higher cost impacts (due to lower efficiency) of increased natural gas prices. Given all of those considerations, Northside 3 is reflected as being removed from service in 2029 in all scenarios and sensitivities evaluated in this IRP.

2023 Electric Generation Integrated Resource Plan

VOLUME 1

IRP INTEGRATED RESOURCE PLANNING

JEA Building Community

VOLUME 1

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List of Acronyms

AC	Alternating Current
ACC	Air-Cooled Condenser
Bcf/d	Billion Cubic Feet of Natural Gas per day
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
CCCT	Combined Cycle Combustion Turbine
CTG	Combustion Turbine Generator
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resources
DSM	Demand Side Management
EIA	Energy Information Administration
FPSC	Florida Public Service Commission
GEC	Greenland Energy Center
GHG	Green House Gas
GIS	Graphical Information System
GPCM	Gas Pipeline Competition Model
HHV	Higher Heating Value
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITC	Investment Tax Credit
LDC	Local Distribution Company
LCOE	Levelized Cost of Energy
LNG	Liquified Natural Gas
LT	Long Term
LWR	Light Water Reactor
MT	Middle Term
MW	Megawatts
NGS	Northside Generating Station
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
PASA	Projected Assessment of System Adequacy
PEV	Plug-in Electric Vehicle
PLEXOS	Power system modeling software tool from Energy Exemplar
PPA	Power Purchase Agreement
PSS/E	Power System Study/Electric
PTC	Production Tax Credit
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SJRPP	St. Johns River Power Park
SMR	Small Modular Reactor
SOCC	System Operations Control Center
SPRINT	SPRay INTercooling
ST	Short Term
TARA	Transmission Adequacy & Reliability Assessment
UAMPS	Utah Association of Municipal Power Systems

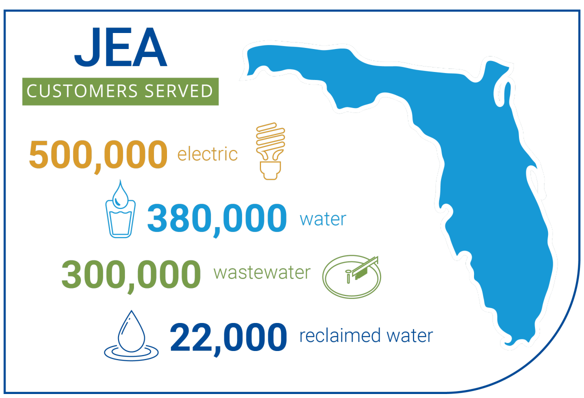
1

Introduction

1. Introduction

1.1. Overview of JEA

JEA was created by the City of Jacksonville to serve those who live in Jacksonville and in the surrounding communities. The sole purpose of JEA's business is to ensure the electric, water and wastewater demands of JEA's customers are met, both today and for generations to come. JEA's goal is to provide reliable services at the best value to JEA's customers while ensuring the areas' precious natural resources are protected.



JEA owns and operates an Electric System with four generating plants, and transmission and distribution facilities, including over 745 circuit miles of transmission lines and more than 7,200 miles of distribution lines. JEA also currently purchases energy from several solar sites located across the service territory, including Jacksonville Solar, a 100-acre site on the City's westside, utilizing 200,000 solar panels. In addition, JEA has contractual arrangements to purchase power from two landfill gas facilities and from Vogtle nuclear Units 3 and 4 as the units begin operating.

JEA's existing and future committed generating resources, including owned and contractual purchase resources, are summarized in Table 1-1 at the end of this section.[1]

1.2. IRP Process

This Integrated Resource Plan (IRP) is a figurative compass that will help guide JEA's energy future. The IRP considered energy generation and supply by balancing affordability, reliability, resilience, and sustainability. JEA currently relies on a diverse fuel mix of petroleum coke, coal, biomass, natural gas, and solar energy. JEA examined how to reduce carbon emissions, increase utilization of renewable energy, and meet the growing needs of JEA's future population.

[1] For purposes of this IRP, "committed" refers to generating resources for which JEA currently has a contract in place.

Integrated resource planning is performed throughout the electric utility industry. The primary goals and key steps in developing an IRP include:

- Comparing future electric system demand with existing generating resources.
- Evaluating new resource options.
- Analyzing solutions.
- Gathering Stakeholder feedback.
- Determining preferred portfolio.
- Developing action plan(s).

An IRP must evaluate both quantitative factors (variables) and qualitative factors (considerations). Variables evaluated in this IRP included:

JEA Load Growth (Customer Demand for Energy)

- Forecast of net energy – how much energy do JEA's customers require aggregated over each year?
- Forecast of net firm peak demand – what is the maximum demand required by JEA's customers in each year?
- Demand-Side Management and Energy Efficiency – what are JEA's customers doing in their homes/business to reduce energy and demand requirements?
- Plug-In Electric Vehicles (PEVs) – how will future adoption of PEVs affect JEA's energy and firm peak demand?
- Electrification – how will future adoption of electric equipment affect JEA's energy and firm peak demand?

Fuel Costs

- Future prices for natural gas.
- Future prices for solid fuel.

Environmental Regulations

- How will costs for emissions of carbon dioxide (CO_2) affect JEA's generating portfolio?
- How will achieving a specific percentage of energy from non-CO_2 emitting resources affect JEA's generating portfolio?

Emerging Generating Technologies

- What types of new generating technologies should be considered?

Customer-Site Generating (Distributed Energy Resources)

- Customer sited renewables, or distributed energy resources – how will JEA's energy and firm peak demand be affected by JEA customers installing solar or other energy resources on their homes/businesses?

Others

- Cost to build new generating resources.
- How long will JEA's existing generating units continue to operate?
- What does it cost to finance construction of new generating resources?

Considerations evaluated in this IRP include the following:

- Affordability.
- Reliability.
- Environmental quality.
- Economic development.
- CO_2 emissions reductions.

The IRP utilized both scenario and sensitivity analysis methodology to evaluate how these variables and considerations impact the future energy needs of JEA's customers. Scenario analysis considers a set of changes to multiple variables simultaneously to analyze a potential future. Sensitivity analysis considers changes to one of these variables at a time within a given potential future.

Scenarios were developed that represent potential futures for JEA over the IRP timeframe (30 years). A scenario must be different enough to illustrate how future outcomes may vary in meaningful ways when compared to other scenarios. Similarly, sensitivities are intended to evaluate how a resource portfolio responds to a change in a single variable (e.g., changes to the load forecast or fuel prices). Combining scenario and sensitivity evaluation provides for a robust analysis of future resource decisions.

1.3. Outline of IRP

The remainder of Volume 1 is organized as follows:

- Chapter 2 presents an overview of the Stakeholder Engagement process that was an integral part of developing the IRP.
- Chapter 3 discusses the load forecast (peak demands and annual energy requirements) and various components thereof and illustrates JEA's projected need for additional capacity evaluated in this IRP.
- Chapter 4 discusses the methodology used to develop fuel price projections reflected in the IRP, and addresses fuel transportation considerations.
- Chapter 5 provides an overview of the new generating resources considered in this IRP, including cost and operating characteristics.
- Chapter 6 presents a levelized cost analysis of the economics of the new generating resources outlined in Chapter 5.
- Chapter 7 discusses the scenarios and sensitivities evaluated in this IRP.
- Chapter 8 discusses the optimal generation expansion and production cost modeling methodology and presents the results of the analyses.
- Chapter 9 presents conclusions based on the analyses performed in this IRP.

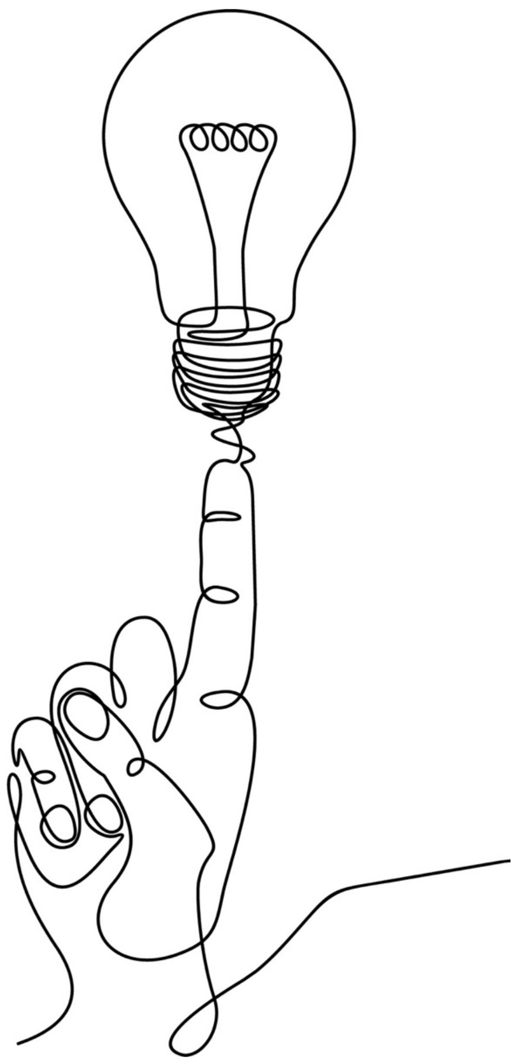


Table 1-1: Existing and Future Committed Generating Resources

Unit Name	Primary Fuel	Net Dependable Summer MW	Net Dependable Winter MW	Owned/ PPA	Commercial Operation Date / PPA Term
Kennedy GT7	Natural Gas	179	191	Owned	2000
Kennedy GT8	Natural Gas	179	191	Owned	2009
Northside ST1	Pet Coke	293	293	Owned	2003
Northside ST2	Pet Coke	293	293	Owned	2003
Northside ST3	Natural Gas	524	524	Owned	1977
Northside GT33-36	Diesel	200	246	Owned	1975
Brandy Branch GT1	Natural Gas	179	191	Owned	2001
Brandy Branch CC4	Natural Gas	596	640	Owned	2005
Greenland Energy Center GT1	Natural Gas	179	191	Owned	2011
Greenland Energy Center GT2	Natural Gas	179	191	Owned	2011
NextEra PPA	System PPA	200	200	PPA	2022 - 2042
Sarasota LFG	LFG	6	6	PPA	2008 - 2026
Trail Ridge LFG	LFG	9	9	PPA	2014 - 2026
Vogtle 3	Nuclear	100	100	PPA	2023 - 2042
Vogtle 4	Nuclear	100	100	PPA	2024 - 2043
Blair Solar	Solar (4 MW AC)	0.7	0	PPA	2018 - 2038
Jax Solar	Solar (12.6 MW AC)	2.0	0	PPA	2010 - 2040
NW Jax Solar	Solar (7 MW AC)	1.1	0	PPA	2017 - 2042
Old Kings Solar	Solar (1 MW AC)	0.2	0	PPA	2018 - 2038
Old Plank Solar	Solar (3 MW AC)	0.5	0	PPA	2017 - 2037
Simmons Solar	Solar (2 MW AC)	0.4	0	PPA	2018 - 2038
Starratt Solar	Solar (5 MW AC)	0.9	0	PPA	2017 - 2037
SunPort Solar	Solar (5 MW AC)	1.0	0	PPA	2014 - 2039

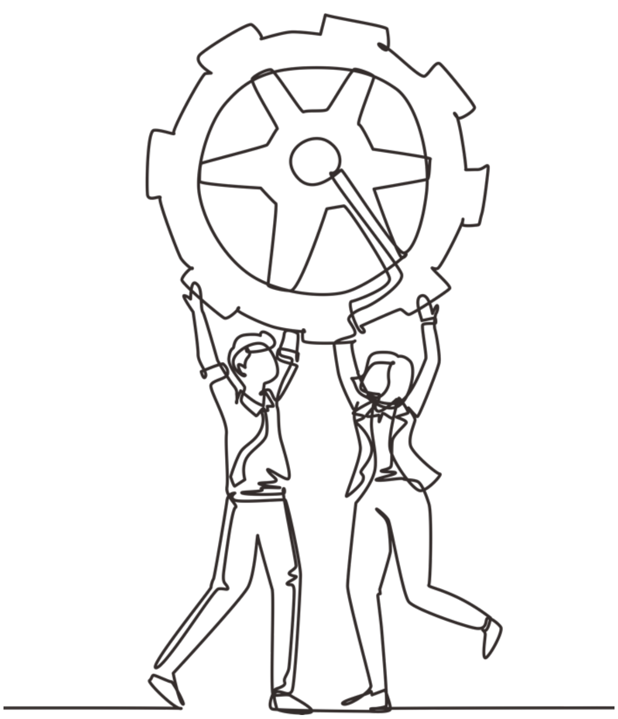
Notes:
GT: Gas Turbine
ST: Steam Turbine
CC: Combined Cycle
LFG: Landfill Gas
PPA: Power Purchase Agreement
PC: Petroleum Coke
MW AC: Megawatts Alternating-Current Basis Solar Nameplate Rating
PPA term for Vogtle 3 and 4 is a planning assumption based on expected online dates when IRP analysis was initiated.
150 MW solar PV PPA not included as it was entered into as IRP was being completed.

2
Stakeholder Engagement

2. Stakeholder Engagement

2.1. Overview of the Process

JEA established a Stakeholder engagement process to inform the 2023 IRP. Engaging with a diverse cross-section of community leaders was extremely helpful and valuable at every step of the way. Stakeholders included residential and commercial customers, community partners, environmental group leaders, neighborhood associations, and municipal representatives.



2.1.1. Objectives

The objectives at the outset for the process included the following:

- Improving the transparency of the JEA resource planning and decision-making processes.
- Educating Stakeholders on the resource planning process and JEA's obligation to provide reliable power.
- Creating opportunities for Stakeholders to provide feedback on the process.
- Encouraging Stakeholders to share what they learn with colleagues and other community members to garner their additional feedback.
- Promoting dynamic and informed dialogue around planning results and subsequent resource decisions.
- Building understanding and support for JEA's resource decisions.

JEA designed the Stakeholder engagement process to be open, transparent and data driven. JEA asked that Stakeholders approach the process with the same intention and encouraged the group to ask questions, make suggestions, and provide data and information.

To facilitate engagement, JEA contracted with Black & Veatch. Black & Veatch retained a local Stakeholder engagement firm, Acuity Design Group, Inc., to support Stakeholder engagement planning, facilitation, and to ensure consideration of lessons learned and best practices from similar efforts across the industry.

2.1.2. Stakeholder Group Formation

JEA carefully considered the diverse viewpoints across our community and worked with community leaders to plan the Stakeholder Engagement process. A letter from Jay Stowe, JEA's Managing Director and CEO, invited the following organizations to participate:

- Baptist Medical Center
- Bethel Baptist Institutional Church
- City of Jacksonville
- Commercial Metals Company
- Downtown Vision, Inc.
- Duval County School Board
- ElderSource
- First Coast Manufacturers Association
- Jacksonville Aviation Authority
- Jacksonville Civic Council
- Jacksonville Transportation Authority
- Jacksonville University
- JAX Chamber
- Jessie Ball DuPont Fund
- Local Initiatives Support Corporation
- Northeast Florida Builders Association
- Northeast Florida Community Action Agency
- North Florida Green Chamber of Commerce
- St. Johns Riverkeeper, Inc.
- Sierra Club Northeast Florida Group
- United Way of Northeast Florida
- University of North Florida

A copy of a Stakeholder invitation letter is shown in Appendix E – Stakeholder Engagement Details.

2.1.3. Stakeholder Resources

Several resources were developed and provided to Stakeholders during the process to support communications and record progress through the process. Key resources include the following:

- Communications Plan.
- IRP specific website page.[1]
- IRP email address for Stakeholders to provide comments.
- IRP Brochure.[1]
- IRP Video.[1]
- Stakeholder Presentations (specific to each meeting).[1]
- Mid-May 2022 Report (provided a recap of the first series of meetings).[1]

The IRP website page identified several key factors to be considered in IRP development. These are shown in Figure 2-1.

2.2. Stakeholder Meetings

Stakeholder engagement occurred primarily through a series of formal meetings. 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. The milestones included development of the Scenarios key forecasts, and supply side options that were foundational to the IRP modeling, final and preliminary modeling results, 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 2-1.

Table 2-1: 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

Further detail on the Stakeholder meetings is provided in Appendix E – Stakeholder Engagement Details, including locations, JEA participants, topics presented, and feedback received from Stakeholders.

In addition to Stakeholder engagement, JEA Board and Board Committee engagement occurred primarily through a series of meetings that occurred during the term of the IRP preparation. A list of the meeting dates and topics is provided in Table 2-2.

Table 2-2: Board and Board Committee Meetings and Topics

Meeting #	Topic and Presenters
January 2022 Board Meeting	Electric Integrated Resource Plan, Laura Schepis, Chief External Affairs Officer
February 2022 Board Meeting	Electric Integrated Resource Plan Update, Raynetta Curry Marshall, Chief Operating Officer and Laura Schepis, Chief External Affairs Officer
July 2022 External Affairs Committee Meeting	Electric Integrated Resource Plan Update, Laura Schepis, Chief External Affairs Officer and Raynetta Curry Marshall, Chief Operating Officer
September 2022 Finance and Operations Committee Meeting	Electric Integrated Resource Plan Update, Raynetta Curry Marshall, Chief Operating Officer
December 2022 Joint Meeting of the Finance & Operations and External Affairs Committees	Electric Integrated Resource Plan (IRP) Scenarios, IRP Project Team
March 2023 Finance and Operations Committee Meeting	Electric Integrated Resource Plan Update, Pedro Melendez, Vice President, Engineering & Construction
March 2023 Board Meeting	Electric Integrated Resource Plan Discussion, Raynetta Curry Marshall, Chief Operating Officer, Pedro Melendez, Vice President, Engineering & Construction
April 2023 Finance and Operations Committee Meeting and External Affairs Committee Meeting	Electric Integrated Resource Plan and Stakeholder Update, Pedro Melendez, Vice President, Engineering & Construction and Laura Schepis, Chief External Affairs Officer
April 2023 Board Meeting	JEA Board formally adopted 2030 goals

Figure 2-1: Key Factors Considered in IRP Development

3

Supplying the Generation Needs of the Community

3. Supplying the Generation Needs of the Community

3.1. Load Forecast

Table 3-1 summarizes the seasonal (winter and summer) peak demand and annual energy forecast for the Current Outlook scenario. Chapter 7 includes discussion of the various scenarios and sensitivities.

JEA load forecasting specialists developed the base forecast and the alternative forecasts used for the scenarios and sensitivities.

For the base forecast, JEA began with its most recent load forecast prepared for its 2022 10 Year Site Plan. That forecast was updated for the IRP to reflect the most recent and best available information concerning economic growth in the service territory, newly identified commercial and industrial loads, and a base level of customer energy efficiency and conservation implementation.

The Black & Veatch Team then developed forecasts of key load components to modify the base forecast to reflect the desired conditions for each scenario. The modifiers included levels of demand side management (DSM), energy efficiency (EE) and load reduction (Conservation). These were prepared using cost estimating and econometric modeling of specific current and future technologies and programs. The modifiers also included forecasts of Plug-In

Table 3-1: Peak Demand and Energy Forecast (Base)

Year	Summer Peak (MW)	Winter Peak (MW)	Net Energy (GWh)
2022	2,693	2,830	12,827
2023	2,710	2,848	12,948
2024	2,726	2,865	13,057
2025	2,740	2,879	13,160
2026	2,751	2,893	13,250
2027	2,759	2,904	13,327
2028	2,767	2,913	13,399
2029	2,774	2,924	13,470
2030	2,783	2,933	13,534
2031	2,792	2,941	13,595
2032	2,797	2,949	13,654
2033	2,804	2,958	13,712
2034	2,809	2,966	13,764
2035	2,815	2,974	13,814
2036	2,824	2,982	13,862
2037	2,829	2,991	13,905
2038	2,832	3,000	13,949
2039	2,838	3,007	13,987
2040	2,841	3,016	14,024
2041	2,849	3,083	14,057
2042	2,868	3,086	14,085
2043	2,878	3,100	14,111
2044	2,889	3,116	14,137
2045	2,897	3,130	14,160
2046	2,914	3,165	14,183
2047	2,937	3,195	14,201
2048	2,954	3,232	14,212
2049	2,963	3,264	14,225
2050	2,987	3,302	14,242
2051	3,024	3,358	14,237

Electric Vehicles (PEVs) market penetration and associated load growth prepared using industry accepted methods to forecast electric vehicle adoption in areas like Jacksonville, and levels of other Electrification. Finally, a forecast of Customer-Sited Renewables (Distributed Energy Resources) was prepared using a comprehensive DER market simulation model factoring in levels of utility incentives, state/federal subsidies, electric rates, and technology costs. JEA then modified the base forecast with different combinations of load growth and the load modifiers as necessary to reflect the desired conditions for each scenario and sensitivity.

The resulting winter peak demand forecasts for each scenario and sensitivity are summarized in Table 3-2 and illustrated on Figure 3-1. Similarly, the resulting annual energy forecasts for each scenario and sensitivity are summarized in Table 3-3 and illustrated on Figure 3-2.

The base forecast was used for both the Current Outlook scenario and most of the sensitivities, except for the high load sensitivity discussed below.

The Supplemental scenario used a forecast based off the Current Outlook scenario but modified by increasing the customer-sited solar and batteries to be equivalent 5 percent of residential load by 2030.

A relatively low load forecast was used for the Economic Downturn scenario. This forecast assumed significantly reduced economic activity in the JEA service area, patterned after the 2008 recession during which JEA experienced very low energy sales for an extended period.

Another load forecast was used for both the Efficiency + DER and the Future Net Zero scenarios. This forecast assumed relatively high levels of DSM/EE/Conservation, PEV load growth, electrification of non-vehicle loads and Customer Sited Renewables (5 percent Residential and 3 percent Commercial by 2030). The net effect was a forecast higher than the base forecast.

The load forecast used for the Increased Electrification scenario reflects the highest loads evaluated in the IRP. This forecast was like the load forecast used for the Efficiency + DER and the Future Net Zero scenarios, except that it reflects lower levels of DSM and Conservation.

The sensitivity analyses considered two load forecasts not evaluated in the Scenarios. The load forecast used for the High Load sensitivity was based on the Efficiency + DER and Future Net Zero scenario load forecast, but also reflects the addition of a potential large customer of approximately 200 MW beginning in 2024. The load forecast used for the No Load Growth sensitivity applied the 2022 load forecast from the Current Outlook scenario across all 30 years of the study horizon.

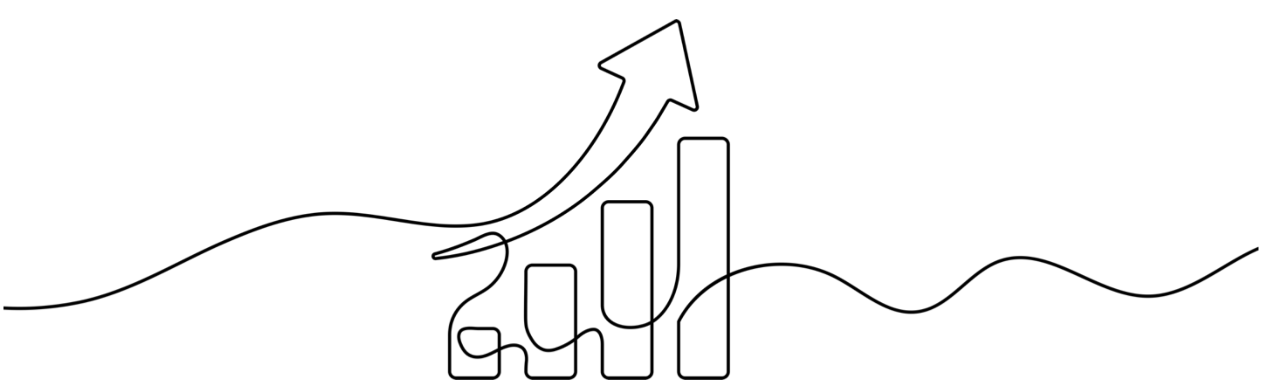


Table 3-2: Scenario and Sensitivity Peak Winter Demand Forecasts (MW)

Year	Current Outlook Scenario	Supplemental Scenario	Economic Downturn Scenario / Low Load Sensitivity	Efficiency + DER Scenario / Future NetZero Scenario	Increased Electrification Scenario	High Load Sensitivity	No Load Growth Sensitivity
2022	2,830	2,830	2,827	2,830	2,830	2,830	2,830
2023	2,848	2,847	2,808	2,837	2,849	2,837	2,830
2024	2,865	2,864	2,801	2,850	2,866	2,850	2,830
2025	2,879	2,878	2,769	2,859	2,881	2,994	2,830
2026	2,893	2,891	2,703	2,867	2,896	3,075	2,830
2027	2,904	2,902	2,694	2,875	2,908	3,082	2,830
2028	2,913	2,910	2,729	2,882	2,921	3,089	2,830
2029	2,924	2,920	2,747	2,894	2,939	3,101	2,830
2030	2,933	2,928	2,765	2,908	2,958	3,115	2,830
2031	2,941	2,935	2,743	2,921	2,977	3,129	2,830
2032	2,949	2,942	2,760	2,935	2,996	3,142	2,830
2033	2,958	2,950	2,772	2,979	3,024	3,187	2,830
2034	2,966	2,956	2,785	3,016	3,073	3,224	2,830
2035	2,974	2,963	2,797	3,079	3,136	3,287	2,830
2036	2,982	2,970	2,809	3,132	3,194	3,340	2,830
2037	2,991	2,978	2,821	3,183	3,251	3,391	2,830
2038	3,000	2,986	2,834	3,251	3,315	3,458	2,830
2039	3,007	2,993	2,845	3,319	3,381	3,527	2,830
2040	3,016	3,001	2,857	3,348	3,428	3,555	2,830
2041	3,083	3,067	2,929	3,381	3,476	3,588	2,830
2042	3,086	3,070	2,936	3,443	3,539	3,650	2,830
2043	3,100	3,082	2,952	3,487	3,593	3,695	2,830
2044	3,116	3,097	2,971	3,548	3,656	3,756	2,830
2045	3,130	3,110	2,988	3,590	3,707	3,797	2,830
2046	3,165	3,144	3,025	3,650	3,769	3,858	2,830
2047	3,195	3,174	3,059	3,700	3,824	3,907	2,830
2048	3,232	3,210	3,101	3,760	3,884	3,967	2,830
2049	3,264	3,241	3,135	3,807	3,937	4,014	2,830
2050	3,302	3,278	3,178	3,866	3,996	4,073	2,830
2051	3,358	3,333	3,238	3,938	4,064	4,145	2,830

Table 3-3: Scenario and Sensitivity Forecast Net Energy (GWh)

Year	Current Outlook Scenario	Supplemental Scenario	Economic Downturn Scenario / Low Load Sensitivity	Efficiency + DER Scenario / Future NetZero Scenario	Increased Electrification Scenario	High Load Sensitivity	No Load Growth Sensitivity
2022	12,827	12,827	12,827	12,827	12,827	12,827	12,827
2023	12,948	12,926	12,229	12,852	12,924	12,852	12,827
2024	13,057	12,996	12,228	12,890	12,998	13,188	12,827
2025	13,160	13,054	12,121	12,925	13,069	14,368	12,827
2026	13,250	13,096	11,864	12,955	13,134	14,534	12,827
2027	13,327	13,122	11,851	12,979	13,195	14,558	12,827
2028	13,399	13,138	12,026	13,015	13,267	14,599	12,827
2029	13,470	13,150	12,128	13,085	13,373	14,664	12,827
2030	13,534	13,148	12,225	13,171	13,495	14,750	12,827
2031	13,595	13,147	12,151	13,271	13,631	14,850	12,827
2032	13,654	13,148	12,247	13,382	13,779	14,966	12,827
2033	13,712	13,158	12,290	13,506	13,937	15,085	12,827
2034	13,764	13,166	12,269	13,633	14,100	15,211	12,827
2035	13,814	13,181	12,467	13,768	14,271	15,347	12,827
2036	13,862	13,197	12,531	13,907	14,447	15,491	12,827
2037	13,905	13,221	12,593	14,044	14,619	15,623	12,827
2038	13,949	13,254	12,652	14,191	14,802	15,770	12,827
2039	13,987	13,292	12,708	14,341	14,988	15,920	12,827
2040	14,024	13,338	12,763	14,500	15,185	16,084	12,827
2041	14,057	13,373	12,813	14,637	15,356	16,216	12,827
2042	14,085	13,392	12,859	14,758	15,513	16,337	12,827
2043	14,111	13,408	12,902	14,870	15,661	16,449	12,827
2044	14,137	13,420	12,944	14,978	15,806	16,562	12,827
2045	14,160	13,434	12,983	15,070	15,933	16,649	12,827
2046	14,183	13,446	13,023	15,160	16,058	16,739	12,827
2047	14,201	13,452	13,059	15,237	16,172	16,816	12,827
2048	14,212	13,448	13,090	15,303	16,275	16,887	12,827
2049	14,225	13,452	13,122	15,360	16,366	16,939	12,827
2050	14,242	13,461	13,157	15,422	16,464	17,001	12,827
2051	14,237	13,472	13,193	15,485	16,562	17,064	12,827

Figure 3-1: Winter Peak Load Forecasts

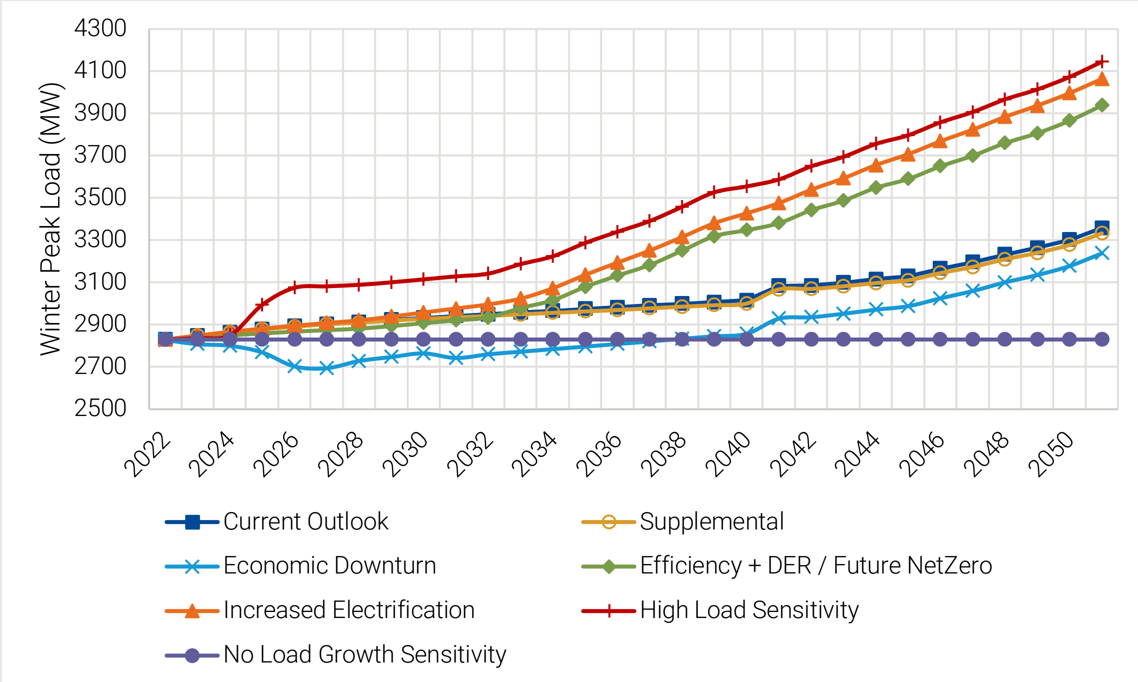
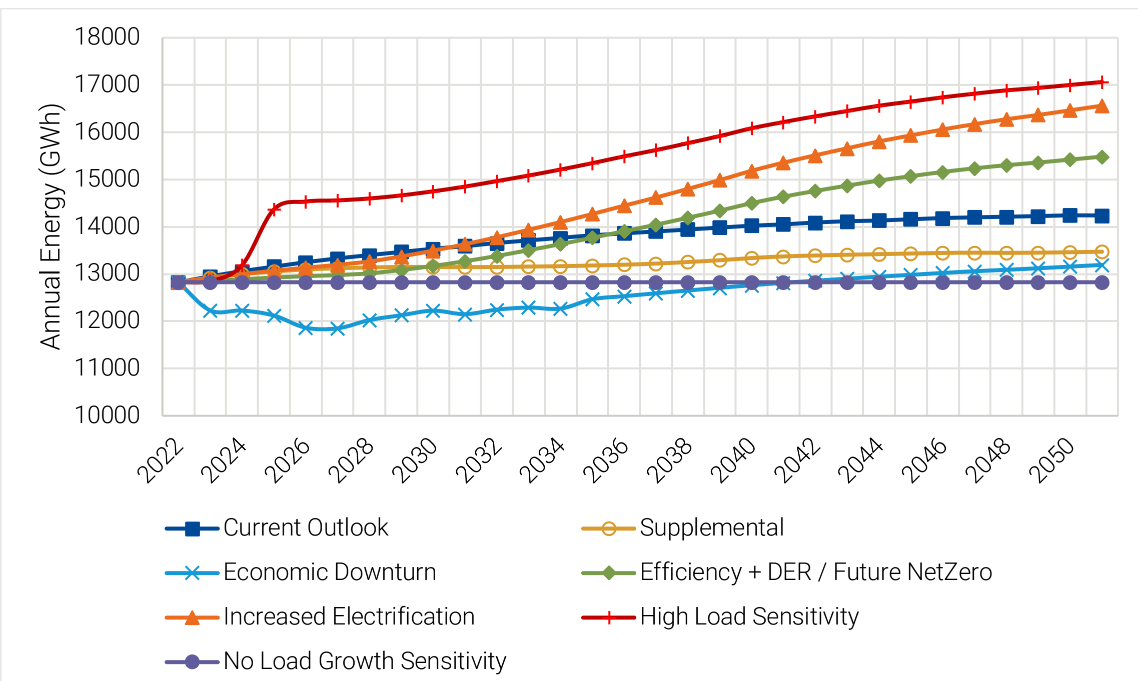


Figure 3-2: Annual Energy Forecasts



3.2. Transportation Electrification Forecasts

Transportation Electrification is already manifesting in JEA's service territory. The IRP Stakeholders discussed its impacts frequently and IRP modeling work focused on it a great deal.

Black & Veatch investigated the potential load impacts from electrical vehicle adoption from both passenger vehicles ("Passenger PEV Forecast") and commercial vehicles ("Commercial On-Road Electrification"). Across the scenarios, the IRP process considered two separate forecasts - base adoption and high adoption.

3.2.1. Base Forecast

JEA developed the base forecast. The base PEV demand and energy forecasts used the historical number of PEVs in Duval County per the Florida Department of Highway Safety and Motor Vehicles and the historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the number of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval population, median household income and number of households from Moody's Analytics. In turn, the number of PEVs was then forecasted using multiple regression analysis of the number of vehicles, disposable income from Moody's Analytics, the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) and JEA's electric rates.

3.2.2. High Adoption Forecasts

Black & Veatch developed the high adoption forecasts to consider passenger vehicles (High Adoption Passenger PEV Forecast) and commercial vehicles (High Adoption Commercial On-Road Electrification Forecast). Both utilized a bottom-up, stock rollover methodology to forecast the adoption rate of electric vehicles in JEA's service territory. The methods and assumptions are outlined in the following sections.

High Adoption Passenger PEV Forecast

The passenger PEV forecast estimates the adoption over the study period for light-duty vehicles only. The methodology Black & Veatch used is outlined on Figure 3-3. An estimate of vehicle growth in JEA's service territory was forecasted first. Next, the adoption rate of both Battery Electric Vehicles (BEVs) and Plug-In Hybrid Vehicles (PHEVs) were forecasted by assuming an s-curve adoption of electric vehicles to replace existing vehicles at the point of replacement. For the purposes of this analysis, adoption was assumed to follow the Florida Department of Transportation's 2021 EV Infrastructure Master Plan Aggressive Scenario, where the study had projected that 35 percent of new sales would be electric by 2040[2]. The forecasted adoption of passenger PEVs is depicted on Figure 3-4, representing a 22 percent compound annual growth rate of electric vehicles through the study period, or 60 percent of all passenger vehicles by 2050.

[2] Florida Department of Transportation EV Infrastructure Master Plan 2021 https://fdotwww.blob.core.windows.net/sitefinity/docs/default-source/planning/fto/fdotevmp.pdf

Figure 3-3: High Adoption Passenger PEV Forecast Methodology

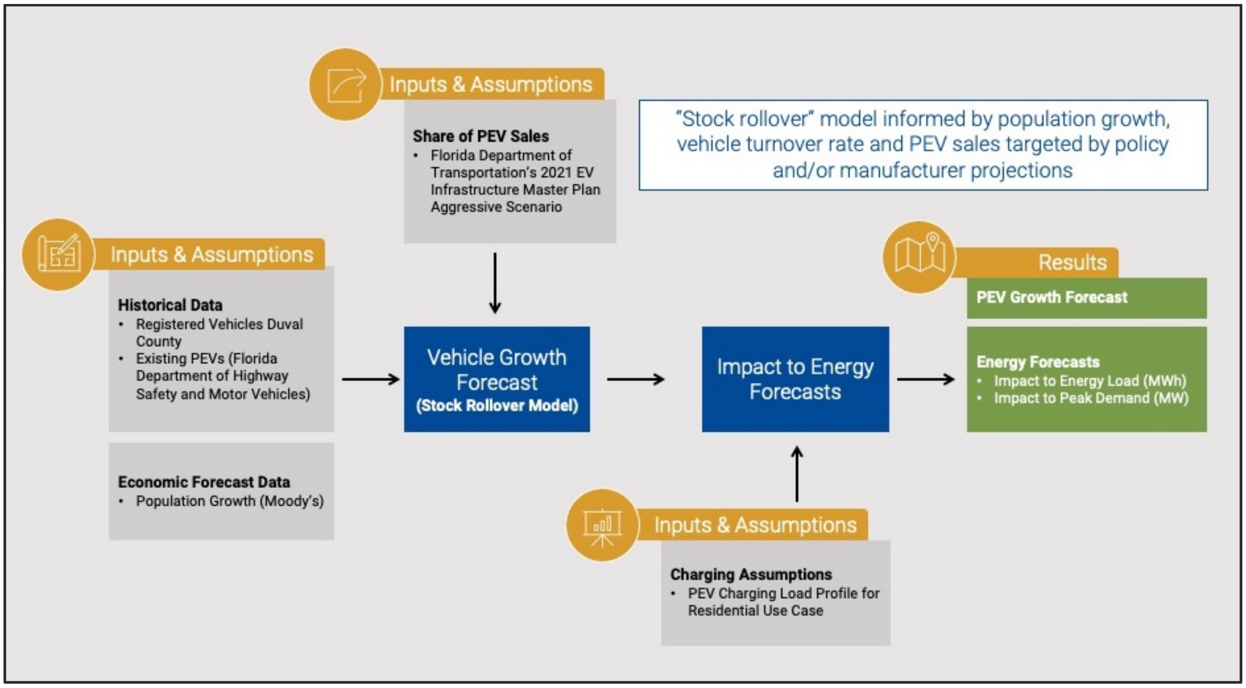
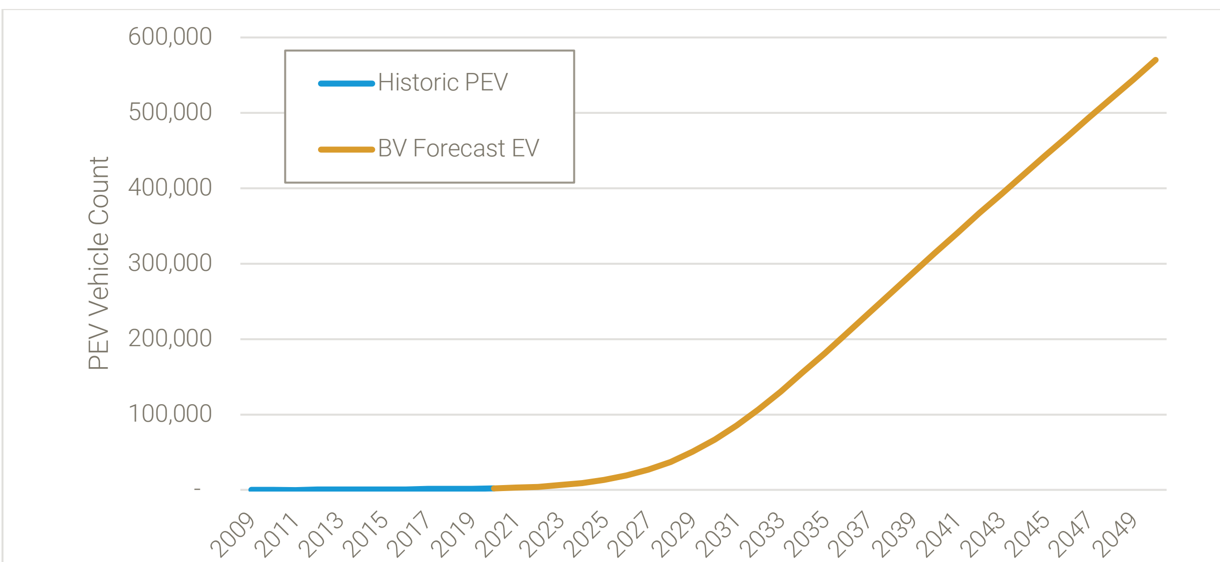
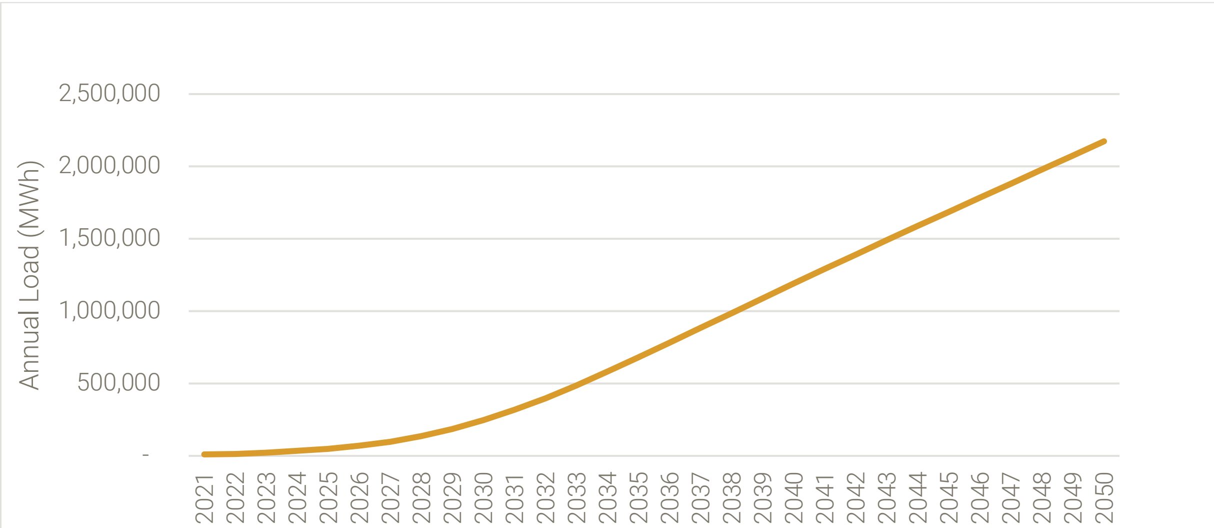


Figure 3-4: High Adoption PEV Forecast by Count



The corresponding impact to load was calculated based on the adoption forecast. The annual vehicle miles travelled per capita was assumed at 10,330 miles over the study period[3] and the charging load profiles were estimated by JEA leveraging prototypical charging profiles for residential charging applications. The resulting load impact is depicted on Figure 3-5.

Figure 3-5: High Adoption Passenger PEV Load Impact (MWh)



High Adoption Commercial On-Road Electrification Forecast

The Commercial On-Road Electrification forecast estimated the adoption of Class 2 to Class 8 commercial vehicles over the study period, including, but not limited to, vehicles such as the following vehicles:

- Light Commercial Trucks.
- Other Buses.
- Single Unit Short-Haul Trucks.
- Single Unit Long-Haul Trucks.
- School Buses.
- Refuse Trucks.
- Combination Long-Haul Trucks.
- Combination Short-Haul Trucks.

Black & Veatch methodology is outlined on Figure 3-6 and, like the passenger PEV forecast, used a stock rollover methodology.

An estimate of vehicle changes in JEA's service territory was first forecasted leveraging Department of Transportation registration data across the classes of vehicles and forecasted according to economic forecast indicators. The vehicle turnover and rate of adoption of electric vehicles to replace conventional vehicles are identified by vehicle economics and vehicle availability of electric models for each vehicle class. Vehicle economics are determined by Black & Veatch's proprietary Total Cost of Ownership model, where the

[3] Jacksonville, FL data from U.S. Department of Transportation Federal Highway Administration https://www.fhwa.dot.gov/ohim/onh00/onh2p11.htm

cost of ownership over the life of an electric vehicle, charging equipment, operating and maintenance costs are evaluated and compared to a conventional diesel or gasoline-fueled truck of corresponding capabilities. An s-curve adoption was employed with electric share of sales reaching measure saturation at the point in which the electric configuration reaches price parity or better than the conventional configuration and varies by vehicle class and site operation.

The forecasted adoption of commercial on-road electric vehicles is depicted on Figure 3-7, representing a 35 percent compound annual growth rate of electric vehicles through the study period, or 62 percent of all commercial trucks by 2050.

The corresponding impact to load was calculated based on the adoption forecast. Annual energy consumption by vehicle application was estimated by JEA by vehicle class and type as described above. Charging load profiles were estimated by JEA leveraging prototypical use and charging profiles according to application, such as direct current fast charging (DCFC), school bus, transit bus, small fleet, medium fleet, and large fleets. The resulting load impact is depicted on Figure 3-8.

Figure 3-6: High Adoption Commercial On-Road Electrification Forecast Methodology

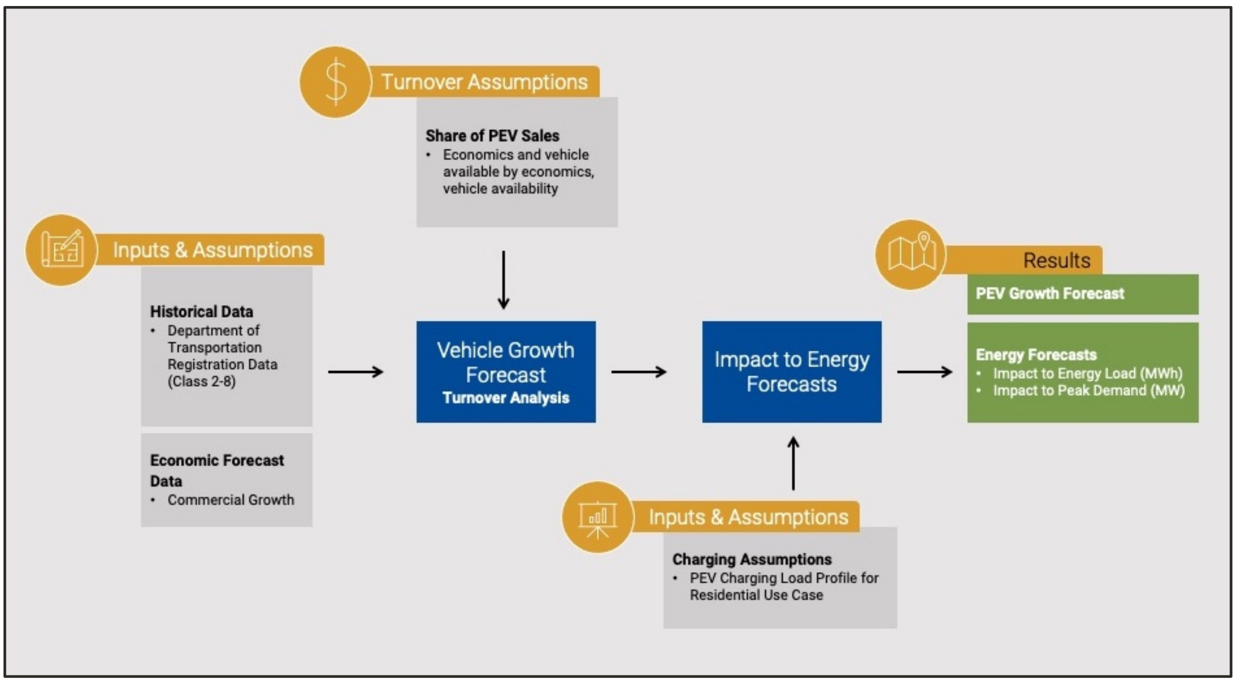


Figure 3-7: High Adoption Commercial On-Road Electrification Forecast by Count

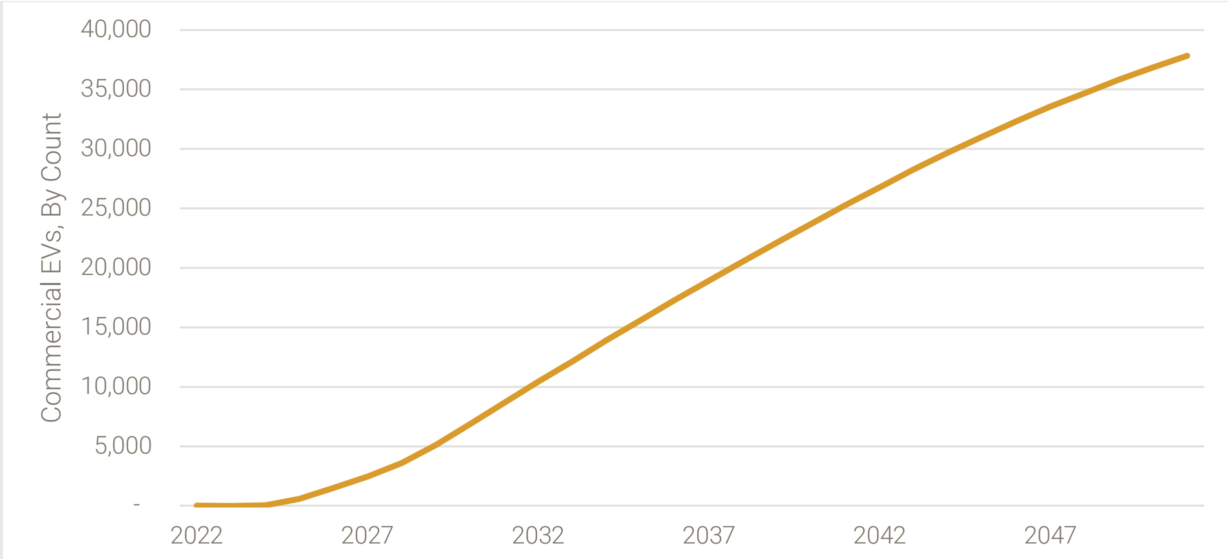
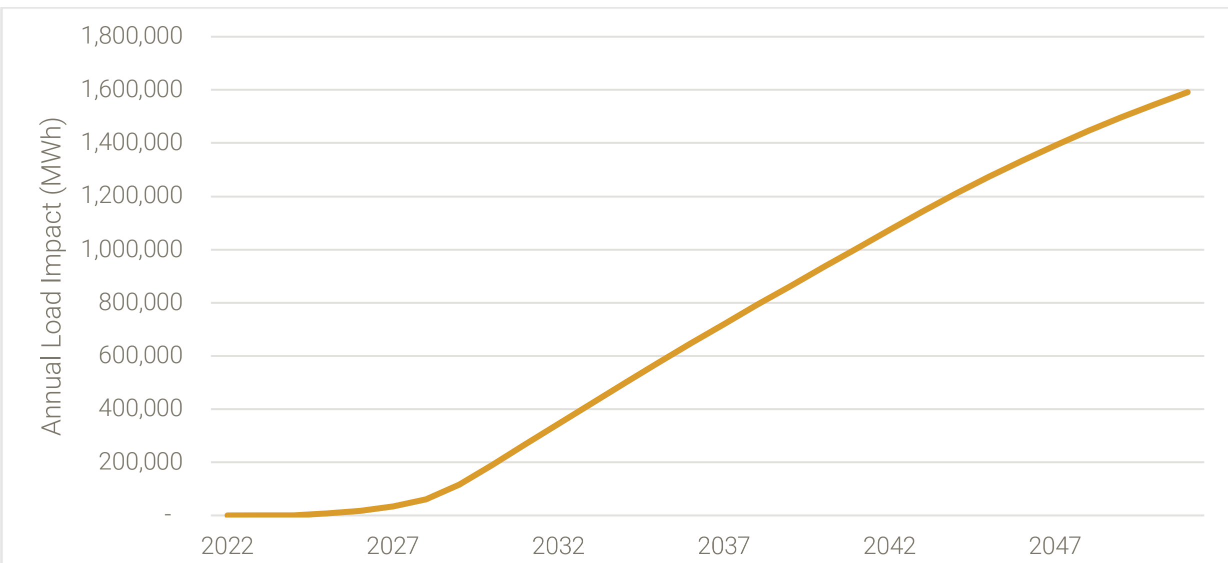


Figure 3-8: High Adoption Commercial On-Road Electrification Load Impact (MWh)



3.3. New Demand-Side Management/Energy Efficiency/Customer-Sited Renewables

Demand-side management (DSM) opportunities provide a reliable, cost-effective resource that contributes to meeting the peak demand and energy requirements of JEA customers.

The Black & Veatch team developed estimates of DSM opportunities in JEA customers' homes and business, including the installation of energy efficiency technologies as well as customer-sited renewables. These DSM resources reduce total consumption and peak demands in JEA's load forecast.

Two scenarios for DSM opportunities included a Current Outlook forecast that aligns with current and planned JEA programs and initiatives, and a High forecast that assumes more aggressive DSM program offerings.

3.3.1. Energy Efficiency

For the energy efficiency Current Outlook forecast, the Black & Veatch team incorporated JEA's portfolio of 11 cost-effective residential and commercial EE programs and the project annual incremental energy savings to estimate future load impacts.

For the energy efficiency High forecast, JEA's programs were assumed to be expanded, with additional funding for more aggressive marketing, outreach, and customer education, as well as customer incentives. The resulting energy impacts are forecasted to double from the Current Outlook on an annual incremental basis. Figure 3-9 summarizes the cumulative impacts over the IRP planning horizon for the EE Current Outlook and High Forecast scenarios.

3.3.2. Customer-Sited Renewables

The focus of the customer-sited renewables analysis was on rooftop solar photovoltaic (PV) and battery storage installations.

With respect to customer-sited solar PV, the analysis accounted for available roof space (including pitched versus. flat roofs, other roof equipment, etc.), PV power density, hourly generation shapes, and AC/DC ratios, among other factors. These technical potential calculations were supplemented by forecasting market adoption of solar PV systems over the IRP forecast horizon. A rigorous hourly economic analysis calculated the point at which it is cost-effective for customers to install a system as a function of $/kW, discount rates, and other costs using the extensive sensitivity analysis capabilities of the modeling software.

With respect to battery storage, the analysis focused primarily on technical potential for paired solar + energy storage systems. The modeling software accounted for the complex economics of a storage technology, which can shift load to reduce energy charges (e.g., through on/off peak period arbitration) or reduce peak demand charges, by utilizing an hourly battery storage dispatch optimization module. This analysis simulates the hourly dispatch of stand-alone or solar-paired storage systems, accounting for electric rate structure, system characteristics, customer load profile, and solar PV generation profile. Figure 3-10 depicts an hourly solar and storage dispatch profile for an illustrative business without net metering.

Like the EE analysis, the customer-sited renewables analysis evaluated two cases as follows:

- The base case was modeled based on current JEA system parameters, available tax credits at the time of the analysis, and current JEA battery storage incentives.

- The high PV case was modeled assuming JEA targets 5 percent of JEA's residential load to be met by rooftop PV by 2030. The analysis adjusted estimated program incentives to align customer adoption rates with this targeted output and incorporated the recently approved extension of the 30 percent Federal Incentive Tax Credit (ITC). The commercial sector PV forecast was then analyzed using similar program incentive assumptions.

Results for each of these cases are shown on Figure 3-11. The forecast load reduction from customer sited renewables under the high PV case was significantly higher than that for the base case.

Figure 3-9: Cumulative Energy Impacts – Energy Efficiency Current Outlook and High Forecast Scenarios

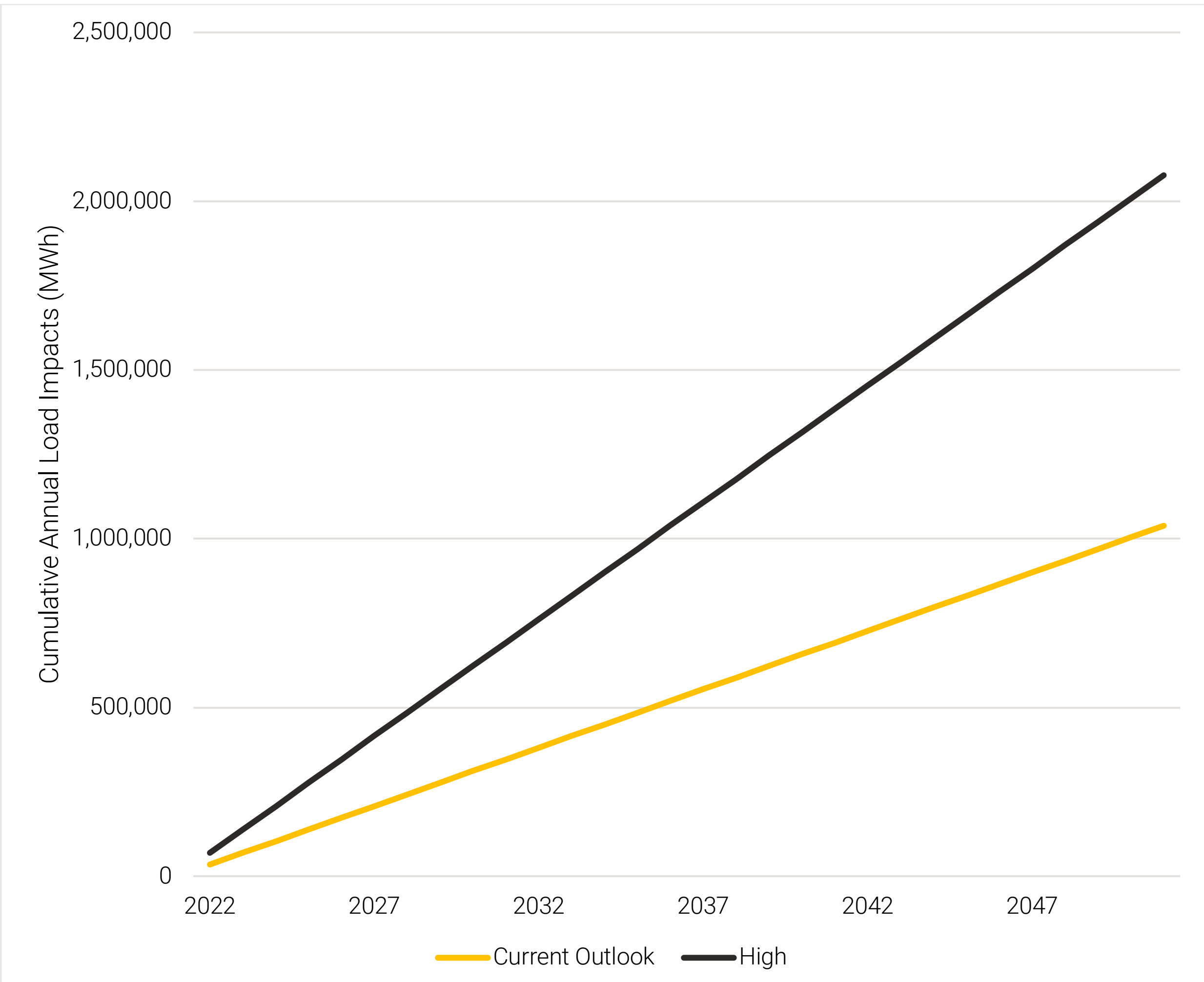


Figure 3-10: Illustrative Optimal Hourly Storage Dispatch

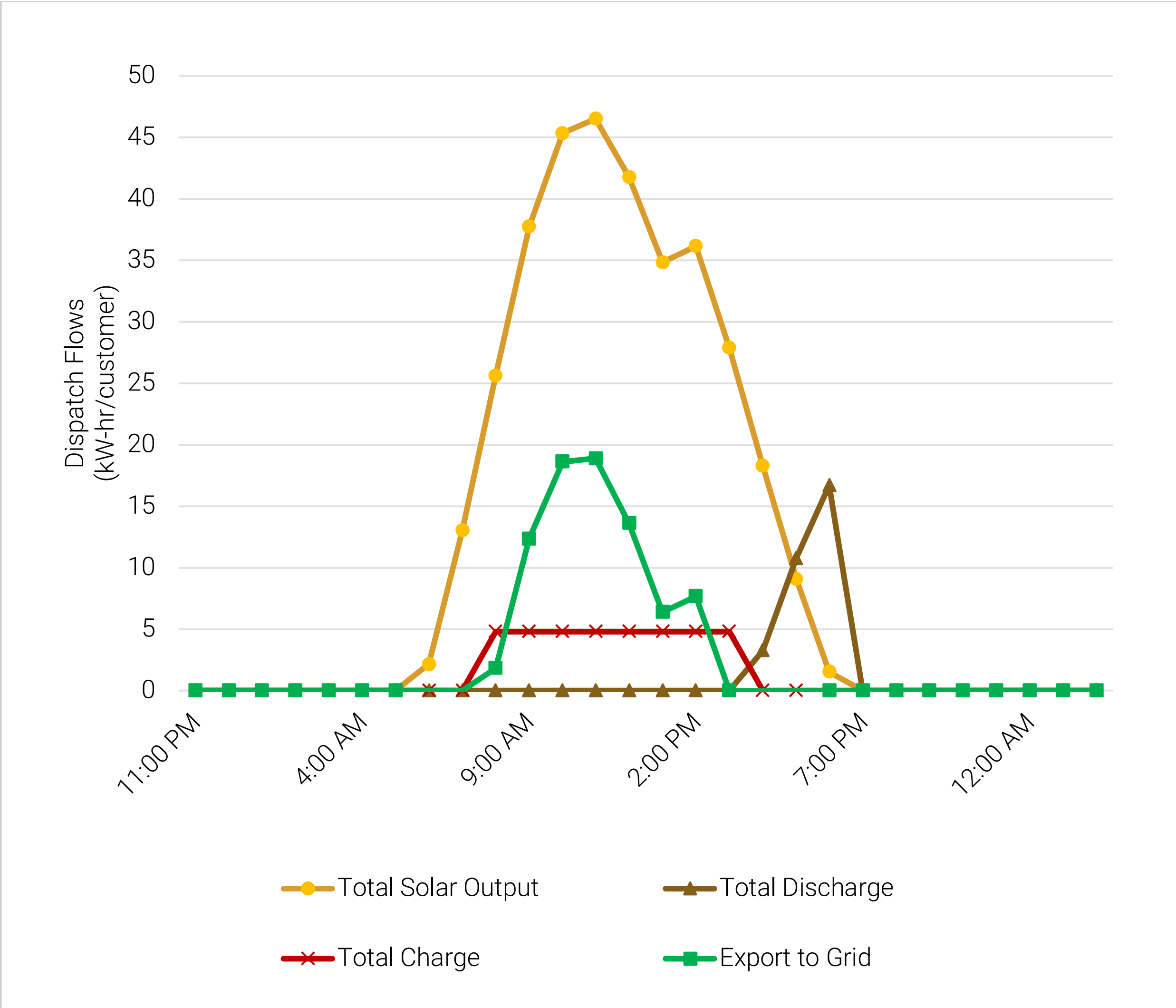
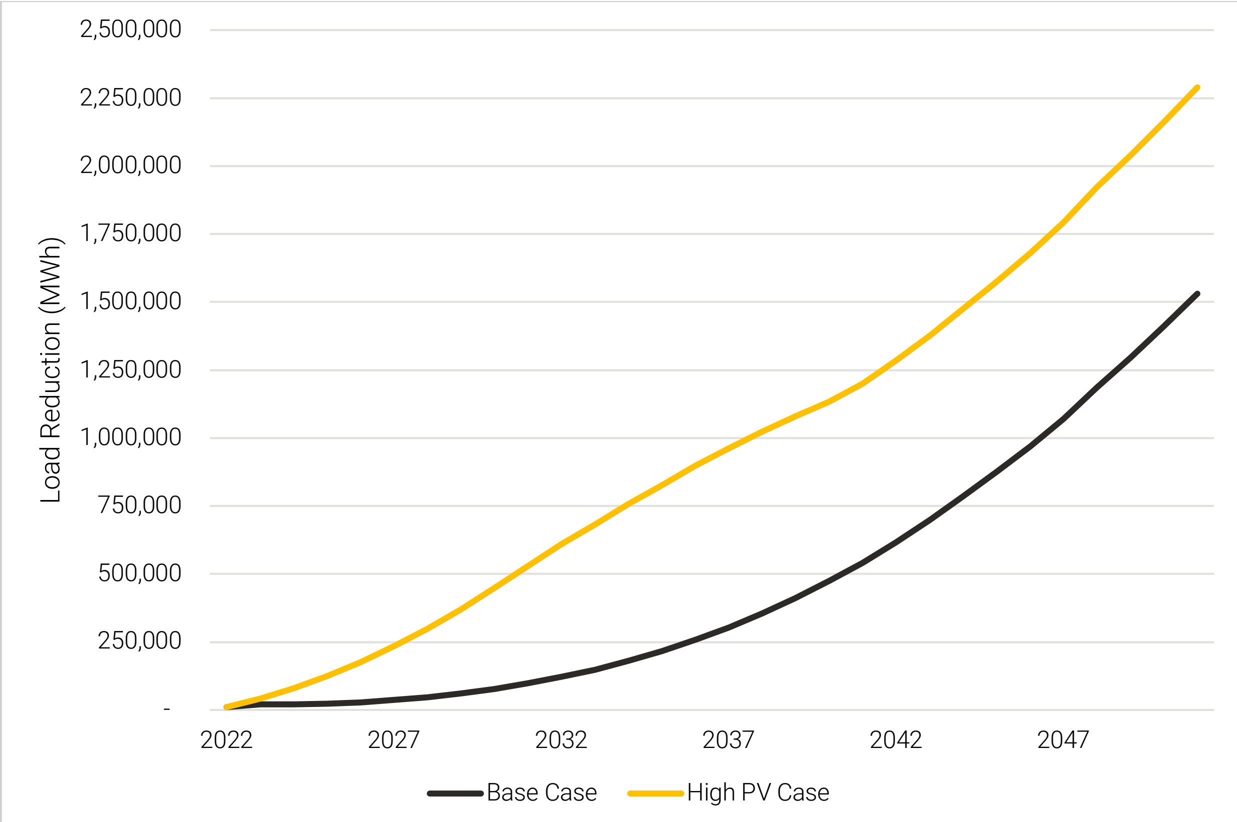


Figure 3-11: Cumulative MWh Load *Reduction* from Solar and Battery Storage



3.4. Capacity Resources

When the IRP began, JEA's existing and planned future generating resources, including owned resources and contractual power purchases, totaled approximately 3,020 MW in the summer and 3,167 MW in the winter. These winter and summer capacity ratings vary over the IRP planning period, as new PPAs (specifically, Vogtle nuclear Units 3 and 4 PPAs) begin and existing PPAs expire, and as Northside 3 is assumed to no longer be operational beginning in the spring of 2029. JEA's projected available summer and winter capacity based on existing and planned generating resources for each year of the IRP planning period is illustrated on Figure 3-12.

3.5. Need for Capacity

The Florida Public Service Commission (FPSC) has established a 15 percent reserve margin for municipal utilities (such as JEA) to help ensure that the utilities have sufficient firm, dependable capacity available to meet forecast peak demand while accounting for uncertainties related to actual peak demand, and the availability of generating resources at time of peak.[4] This reserve margin has been determined to be adequate to meet and exceed the industry standard loss of load probability of 0.1 days per year. JEA's resource planning criteria include having sufficient capacity available to meet forecast peak demand plus the 15 percent reserve margin established by the FPSC for forecasted wholesale and retail firm customer coincident 1-hour peak demand, for both winter and summer seasons.

When considering the differential in forecast peak demand and capacity ratings between winter and summer seasons, JEA's capacity requirements to meet projected peak demand plus reserve margins occur during the winter season[5]. As such, JEA's projected annual winter capacity requirements for each year of the IRP planning period for the Current Outlook scenario are illustrated on Figure 3-13.

Figure 3-13 describes winter capacity provided by JEA's existing and future planned generating resources (including owned resources as well as PPAs) and accounts for JEA's existing interruptible load program as contributing to meeting projected peak demands. As shown on Figure 3-13, JEA was projected to require 430 MW of new capacity to meet peak demand plus reserve margin requirements in the winter of 2030, with this need increasing to 525 MW by the winter of 2040 and more than 1,300 MW by 2051 (the end of the IRP planning period). The magnitudes of JEA's projected capacity requirements vary based on the forecast of peak demand and continued operation of existing generating resources reflected in each scenario and sensitivity evaluated in this IRP.

JEA capacity requirements increase 300% from 2030 to 2051

[4] FPC Section 25-6.035 Adequacy of Resources (1) Each electric utility shall maintain sufficient generating capacity, supplemented by regularly available generating and non-generating resources, in order to meet all reasonable demands for service and provide a reasonable reserve for emergencies. Each electric utility shall also coordinate the sharing of energy reserves with other electric utilities in Peninsular Florida. To achieve an equitable sharing of energy reserves, Peninsular Florida utilities shall be required to maintain, at a minimum, a 15% planned reserve margin.

[5] As illustrated in Table 1-1, winter capacity ratings are higher than summer capacity ratings for combustion turbines and combined cycles, but not for steam turbines (including natural gas, solid fuel, and nuclear generating resources) and solar PV resources do not provide firm capacity during the time of winter peak demand.

Figure 3-12: Summer and Winter Capacity

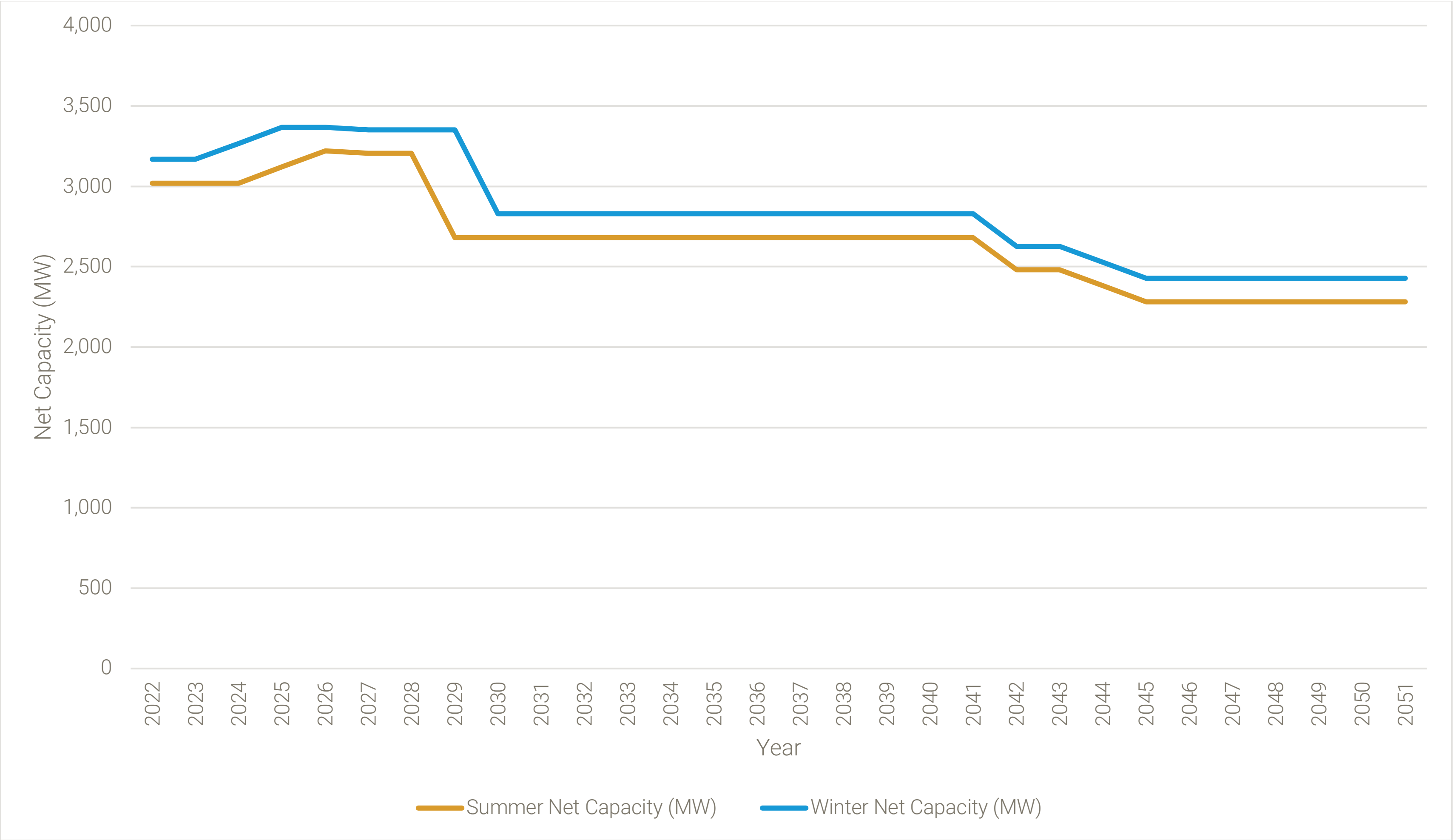
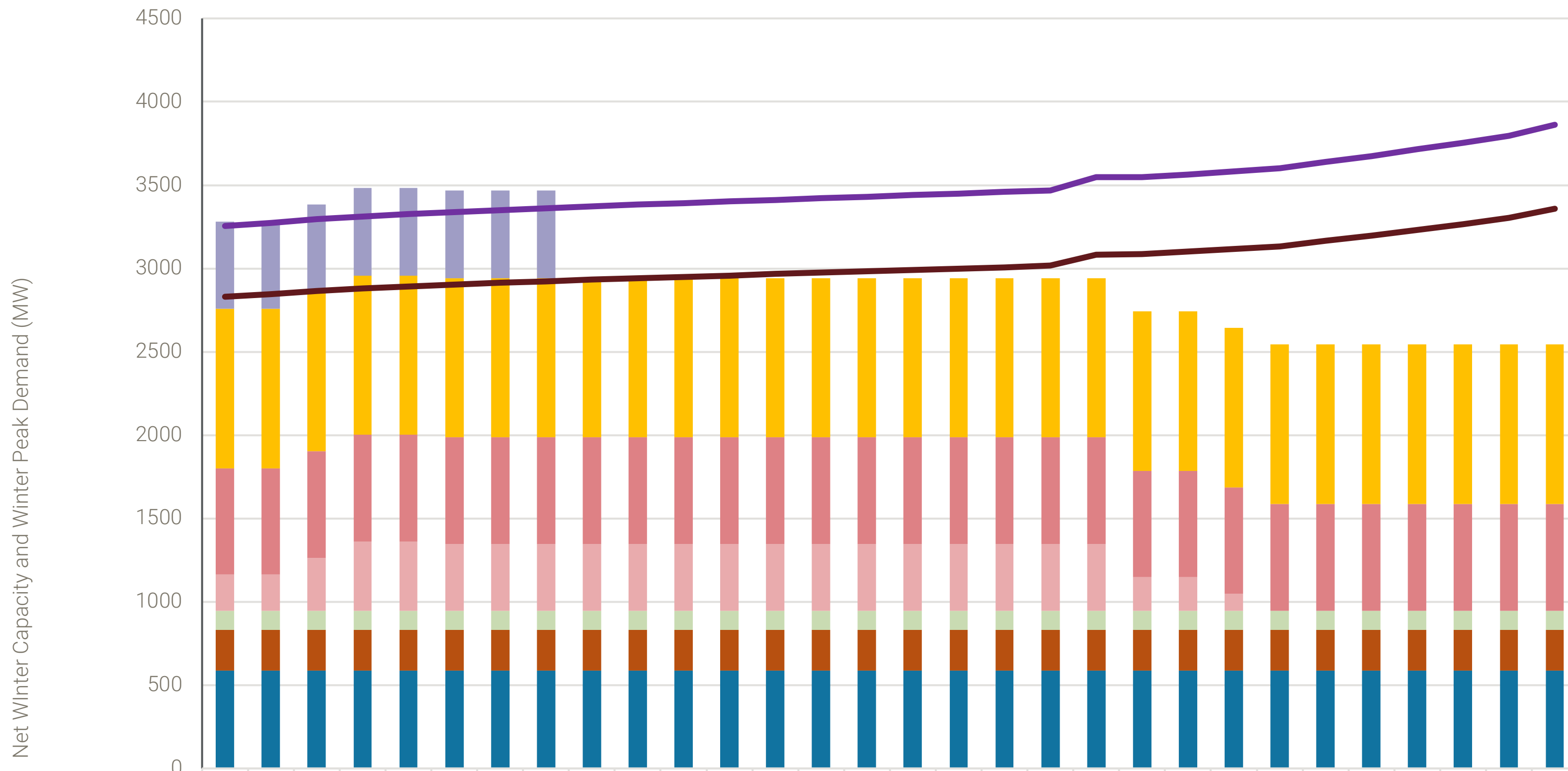


Figure 3-13: Projected Capacity Requirements - Current Outlook Scenario



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
NorthSide ST3	524	524	524	524	524	524	524	524	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas CTs	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956	956
Brandy Branch CC4	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640	640
Contracted PPAs	215	215	315	415	415	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	200	200	100	0	0	0	0	0	0	0
Interruptible Load	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Diesel CTs	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246	246
Northside ST 1 and ST 2	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586	586
Peak Demand	2830	2848	2865	2879	2893	2904	2913	2924	2933	2941	2949	2958	2966	2974	2982	2991	3000	3007	3016	3083	3086	3100	3116	3130	3165	3195	3232	3264	3302	3358
Peak Demand + 15% Reserve Margin	3255	3275	3295	3311	3327	3340	3350	3362	3373	3382	3391	3402	3411	3420	3429	3440	3450	3458	3468	3546	3549	3564	3583	3599	3640	3675	3717	3754	3798	3862

4

Fuel Price Projections

4. Fuel Price Projections

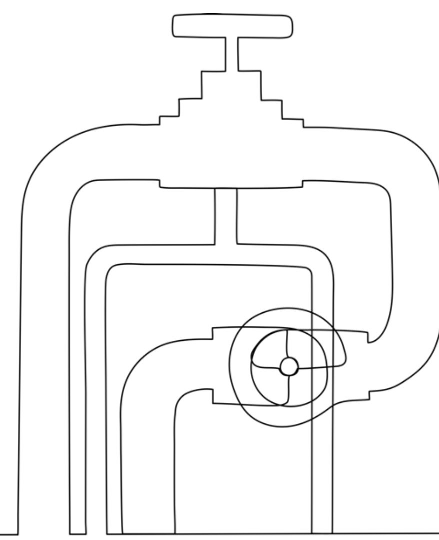
4.1. Natural Gas Fuel Price Forecasts

Figure 4-1 illustrates the natural gas price forecasts utilized for the IRP.

PLEXOS used these forecasts to determine the future operating costs of both the existing JEA gas-fired resources and the potential new gas-fired resource options. The base forecast was used for the Current Outlook and the Supplemental scenarios. The high forecast was used for the Economic Downturn, Efficiency + DER, Increased Electrification and Future Net Zero scenarios.

These forecasts are based on prices for natural gas bought and sold at the Henry Hub, a natural gas pipeline in Louisiana that has access to many of the major gas markets in the United States, including four intrastate and nine interstate pipelines. Because of this access and the large volumes of gas bought and sold, Henry Hub has become the most important natural gas market clearing price point in the U.S. Natural gas contracts across the country are often indexed to the Henry Hub gas price. Therefore, it is also the price that is most useful to forecast for purposes of long-term gas planning and procurement.

Each of the forecasts shown consists of a short-term and a long-term component. The first 3 years are taken from the then-current prices for natural gas bought and sold at Henry Hub as published on the New York Mercantile Exchange, or NYMEX. On the NYMEX, parties can contract for gas delivered at Henry Hub for up to 3 years in the future and therefore these actual prices represent a very strong indicator of prices for the first 3 years of the forecast. Prices for the subsequent years are developed using a complex software model that simulates the supply, consumption, and import/export of natural gas across North America for several years into the future.

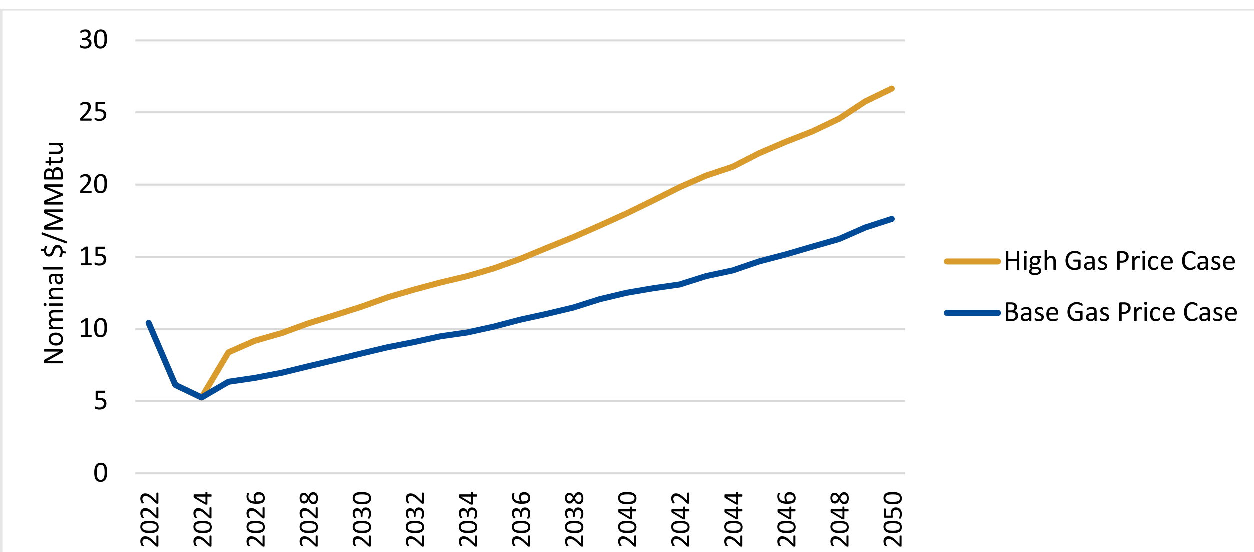


The model, the Gas Pipeline Competition Model (GPCM) is the industry standard for long-term gas price forecasting. The model was customized to reflect current gas market conditions, including relatively high levels of liquefied natural gas (LNG) exports caused by the Russia-Ukraine conflict, a continued limitation of pipeline take-away capacity from the Permian and Marcellus/Utica gas production basins, and higher labor, capital, and E&P (Exploration and Production) costs associated with the current inflationary price environment.

The base forecast assumes Lower 48 LNG export levels will reach 28.8 Bcf/d by 2030 and 37 Bcf/d by 2040. The high gas price forecast increases this by an additional 3.0 Bcf/d of LNG exports by 2027 and 6 Bcf/d by 2030 assuming continuation of the Ukraine/Russia conflict which has led to higher Western European energy imports. The high gas price forecast also assumes a reduction of 4.0 Bcf/d of pipeline take-away capacity from the Marcellus/Utica basins, which restricts low-cost gas supplies from reaching the Gulf Coast. Higher oil and gas exploration and production were assumed in the high price forecast to reflect the current inflated labor and material costs.

On top of these Henry Hub forecasts, the cost of transportation to the JEA gas-fired resource sites was added. This includes high-pressure interstate transportation from Henry Hub to Florida and low-pressure intra-state transportation across the local gas distribution system of Peoples Gas. These forecast costs of interstate and intra-state transportation were developed in close coordination with the JEA fuels group and Peoples Gas, particularly with respect to JEA's existing natural gas transportation arrangements and incremental requirements for firm and interruptible gas delivery.

Figure 4-1: Natural Gas Fuel Forecast Prices at Henry Hub

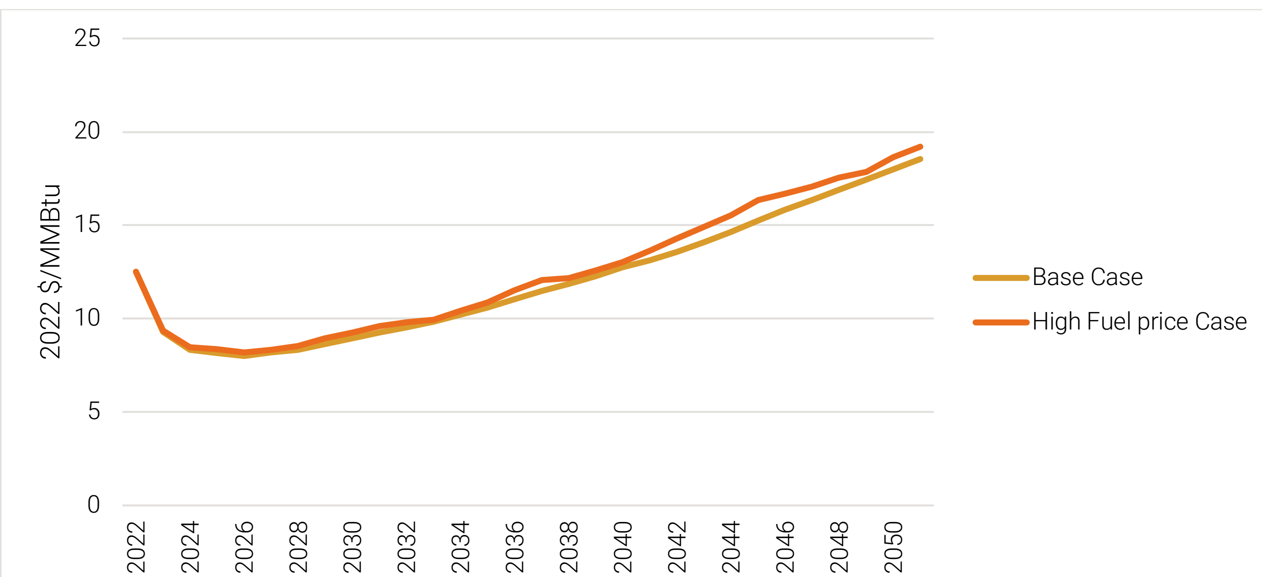


4.2. Northside 1 and 2 Fuel Price Forecasts

Figure 4-2 illustrates the fuel price forecasts for Northside Units 1 and 2 developed for the IRP, both a base and high case forecast. The base forecast was used in both the Current Outlook and the Supplemental scenarios, while the high forecast was used in the Economic Downturn, Efficiency + DER, Increased Electrification and Future Net Zero scenarios.

Fuel for Northside 1 and 2 is referred to as solid fuel because it is composed primarily of petroleum coke (petcoke) and coal with lesser components of natural gas and biomass. Black & Veatch developed this forecast as a blend of individual forecasts of these fuel components. The coal component was based on the coal price forecast provided by the federal Energy Information Agency (EIA) as part of their 2022 Annual Energy Outlook report. The EIA forecast was then modified to reflect current market conditions, including the impact that the Russia-Ukraine conflict has had on near-term coal demand and its potential impact on Lower 48 coal prices. The petcoke component was based on projected delivered coal price adjusted by the historical delivered price relationship between petcoke and coal. The natural gas component was based on the gas price forecast described in Section 4.1. The biomass component was based on a forecast JEA provided, based on JEA's experience procuring biomass and knowledge of the local biomass market. The resulting forecasts show a significant decline in prices between 2022 and 2026 as the current fuel supply chain disruptions and extreme market conditions are expected to relax. This is followed by a consistent increasing price trend thereafter driven primarily by increasing coal mining and delivery costs.

Figure 4-2: Solid Fuel Forecast Prices for Northside Units 1 and 2



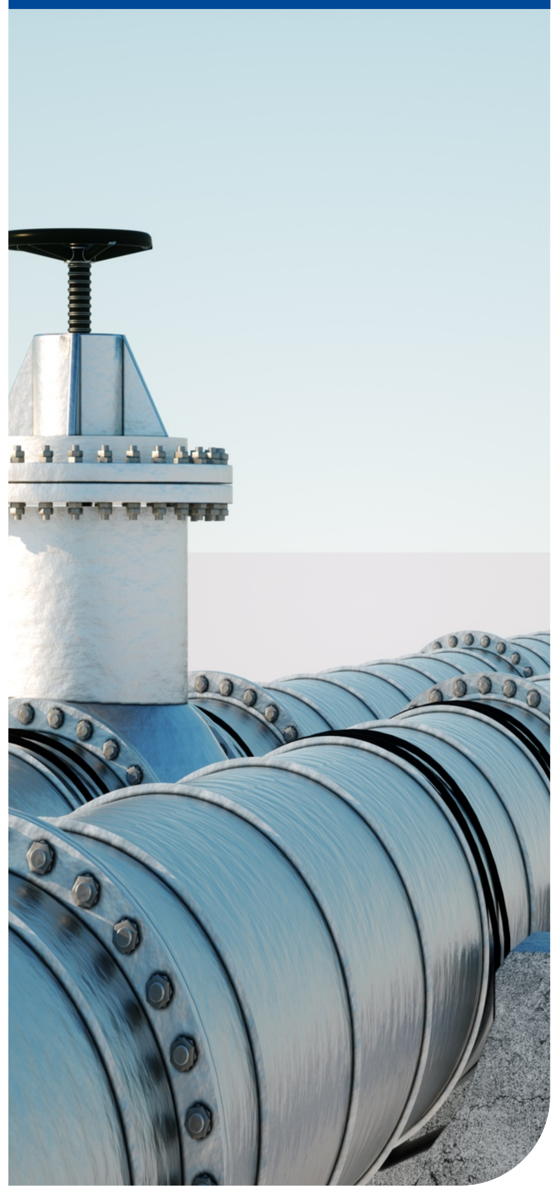
4.3. Natural Gas Delivery

JEA assessed the expected future gas delivery requirements to support addition of new generation at the Northside, SJRPP, and GEC sites in collaboration with Peoples Gas, the local natural gas distribution company (LDC) that serves JEA. The assessment found that physical upgrades of existing gas delivery systems by pipeline looping or compression and/or installation of new gas delivery systems will be required if JEA implements new incremental gas-fired resources at these sites. Order-of-magnitude estimates of capital and operating and maintenance (O&M) costs for the respective natural gas-based solutions were developed. These estimates and other information contributed to PLEXOS modeling to reflect the cost of natural gas delivery to these sites. These estimates are for planning purposes only and do not reflect further analysis that JEA and Peoples Gas may perform for implementation purposes.

For deliveries to Northside and/or SJRPP, JEA and Peoples Gas assessed the feasibility of upgrading an existing low-pressure line owned by Peoples Gas and adding compression at the end of the line as needed to reach operating pressures and flows for each new resource considered.

For deliveries to GEC, Peoples Gas assessed whether modifications to the current system would be sufficient to support combined cycle conversion of the existing simple cycle resources at GEC without any upgrades, as well as the potential upgrades required for new gas fired resources. Peoples Gas performed gas system modeling to forecast the expected scope, cost, and timing of the necessary upgrades.

Upgrades to the existing gas delivery system may be necessary.



5

New Generating Resource Options

5. New Generating Resource Options

5.1. Overview

The IRP considered numerous new generating resource options, including renewable, conventional gas-fired, and nuclear technologies. The range of options was developed throughout the IRP process.

5.2. Renewable and Storage Resource Options

The IRP process considered numerous renewable and storage resource generating options. These included solar, solar plus integrated storage, standalone storage, and biomass resources. Several renewable and storage generating resources were not considered because the general lack of resource potential in Florida and the broader southeastern grid, including on-shore wind, off-shore wind, geothermal, pumped hydro storage and compressed air storage. Detailed descriptions of the options considered are provided in Appendix C – New Generating Resource Options Characterization.

Renewable resources have historically benefited from certain tax benefits under federal law, including investment tax credits (ITCs) and production tax credits (PTCs). During development of the IRP the U.S. Congress passed the Inflation Reduction Act (IRA) which, among other provisions, introduced a new ITC for stand-alone storage resources. Prior to this change, storage resources were not eligible for an ITC unless they were integrated into a solar or other renewable resource and would charge and discharge only energy generated by that renewable resource. Introduction of the new storage ITC effectively eliminated the requirement to integrate storage with solar and therefore the solar plus storage options (Options 2 and 3) were not considered in the detailed PLEXOS modeling described elsewhere in this report.

The IRA also will allow municipal entities such as JEA to receive direct payment of the ITC even though they do not incur income tax. This improves the economics of new JEA owned renewable resources. Further information on how this this provision was addressed in the IRP is provided below under Federal Tax Considerations.

A summary of the renewable and storage options considered is shown in Table 5-1.

Table 5-1: Renewable and Storage Options Considered for the IRP

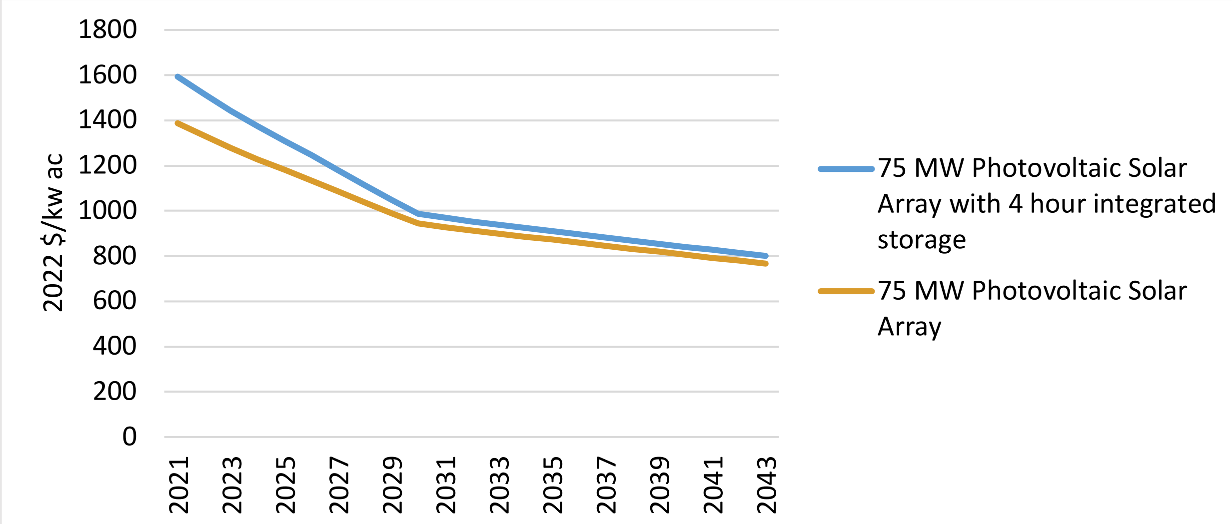
ID	Resource Option	Solar PV Rating (MW)	Battery Rating (MW)	Battery Capacity (MWh)
1	75 MW Photovoltaic Solar Array	75	NA	NA
2	75 MW Photovoltaic Solar Array with 0.5 hour integrated storage	75	37.5	37.5
3	75 MW Photovoltaic Solar Array with 4 hour integrated storage	75	75	300
4	37.5 MW Lithium Ion 1 hour Battery Storage[6]	NA	37.5	37.5
5	75 MW Lithium Ion 4 hour Battery Storage[7]	NA	75	300
6	50 MW Biomass BFB, with SCR, Baghouse, sorbent injection	47	NA	NA

The capital and O&M cost assumptions for these renewable and storage resources were developed by Black & Veatch engineers experienced with design, construction, and operation of solar and storage plants. Capital and operating costs were developed from a conceptual design of the resource. To forecast solar annual energy and degradation for the resource, the engineers simulated its operation at varying operating conditions using the PVSyst suite of solar photovoltaic simulation software that is licensed by Black & Veatch. To estimate capital and operating costs the engineers used an estimating module within the PVSyst software, the results of which are then checked for consistency and completeness against estimates that the engineers have developed or seen elsewhere for similar plant configurations.

The capital cost estimates were developed assuming construction of a solar resource in 2022 based on 2022 costs for solar resource technology, including panels, inverters, and other solar equipment. These capital costs are likely to continue declining for resources constructed in later years due to technology and construction advances. Black & Veatch therefore reduced these estimated costs for solar resources reaching commercial operation in later years. Figure 5-1 illustrates this forecast.

[6] 25 MW 1-hour Battery Storage was also considered.
[7] 50 MW 4-hour Battery Storage was also considered.

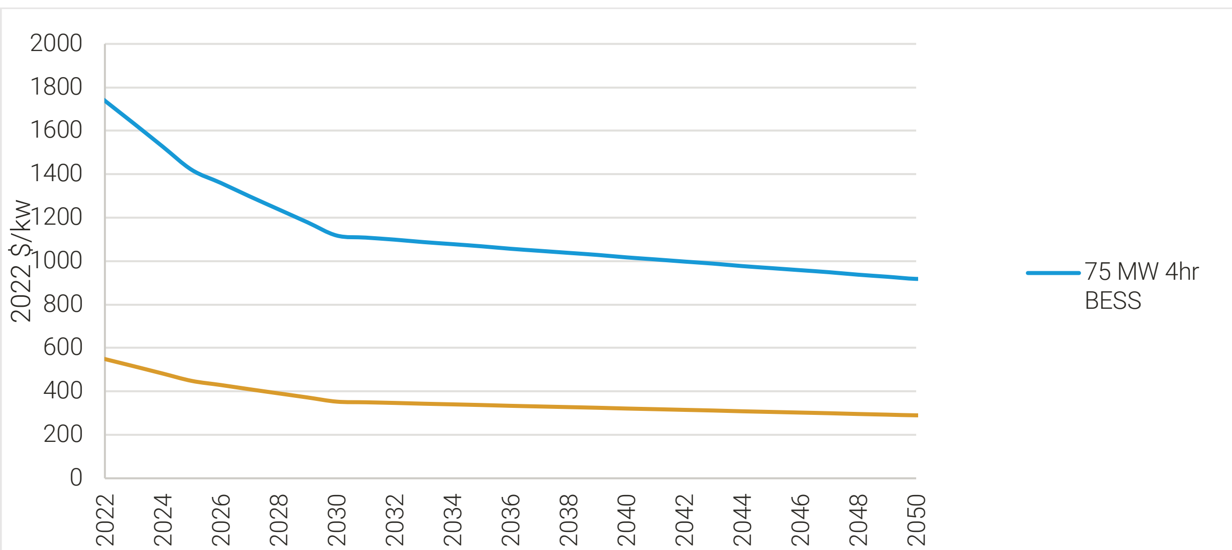
Figure 5-1: Solar Resources - Forecast Capital Costs



5.2.1. Battery Energy Storage Cost Estimating

Like the solar resources, capital cost estimates for storage resources were developed assuming construction of the resource in 2022 based on 2022 costs for battery technology, including metals, modules, inverters, and other battery equipment. These capital costs will likely continue to decline for resources constructed in later years due to advancements in technology and manufacturing and construction methods. Black & Veatch therefore reduced these estimated costs for battery storage resources reaching commercial operation in later years. Figure 5-2 illustrates this forecast.

Figure 5-2: Battery Storage Resources - Forecast Capital Costs



Forecasts are shown for both the 75 MW 4-hour duration and 37.5 MW 1 hour duration battery resources. The forecast was developed by Black & Veatch engineers experienced with actual design, construction, and operation of battery storage resources.

Capital costs are forecast to decline significantly from current levels. This is due to the expected continued decline in capital costs and increasing performance of battery storage resource components (modules, inverters, chilling, etc.). Costs are expected to decline rapidly until 2030 and then less rapidly thereafter as the advancements in technology and reductions in manufacturing costs begin to fade as is typical over the life of new technologies and products.

5.2.2. Federal Tax Credit Considerations

Significant sets of regulations required to implement the IRA were still incomplete during the modeling period of this IRP. Implementing regulations, for instance, that allow JEA to calculate a significant portion of the benefit of using the IRA's mechanisms, were still largely incomplete throughout the duration of this IRP's modeling. Therefore, while the IRA's provisions may provide JEA with additional choices in the near-term for how to construct and fund renewable projects, Black & Veatch did not direct the model to conclude that JEA would use the new IRA provisions.

As mentioned previously, the IRA's new tax provisions make solar and storage resources (Options 1 through 5) eligible for an ITC. The ITC rate is 30 percent and is applicable to the capital cost of the solar components and the storage components of a new solar and new storage resources, respectively. The biomass resource (Option 6) is eligible for a PTC. The PTC rate is $0.026/kWh and is applicable to the energy production from the resource, with the rate escalated for inflation in subsequent years.

Historically, municipal utilities such as JEA have utilized power purchase agreements to obtain solar energy rather than direct ownership of the solar resource. This is primarily because JEA is not a taxpayer and therefore has no taxable income to shelter through use of a tax credit. The value of the ITC is significant, and it has been typical in the industry to have a private taxpaying entity own the solar resource and enter a power purchase agreement (PPA) with the municipal entity and indirectly pass the ITC benefit to the municipal entity in the form of a PPA price that is lower than the cost of energy that the municipal entity would have experienced if it owned the solar resource directly.

In contrast to this typical approach, the recently passed IRA provides, among other things, that municipal entities may now receive the value of the ITC in the form of a cash payment from the federal government rather than an ITC (known as "Direct Pay"). Direct Pay would allow JEA to access the ITC and perhaps eliminate the need for a PPA. However, Direct Pay has an additional eligibility requirement for minimum domestic content where the minimum increases in future years. Commonly referred to as the "domestic content provision," this requirement is intended to encourage the production of steel and iron in the United States, rather than importing it from overseas. Failure to achieve the domestic content requirement results in a reduced ITC benefit to the project owner. At this time there is a great level of uncertainty about whether adequate domestic content will become available and at what cost.[8] Therefore, for purposes of the IRP, Black & Veatch assumed that JEA would not be able to utilize the full benefits of the ITC because of the domestic content requirement and other factors. All solar energy would come through PPAs with private entities. Direct Pay and the choice it may give JEA to contract for renewable energy or build its own resources will continue to be evaluated in future IRPs.

In addition to Direct Pay and domestic content, the IRA introduced a new ITC eligibility requirement to pay prevailing wage to labor used for construction and operation of a new resource. Black & Veatch assumed that the private entity owning the solar resource would choose to meet this requirement. Therefore Black & Veatch's PPA price forecasting described in Subsection 5.2.5 reflects both the ITC and a higher resource capital cost (prevailing wage was not assumed in development of the resource option cost estimate).

The IRA also introduced a new extended timeline for reduction of the ITC and PTC available to new resources. Prior to the IRA, the ITC and PTC were scheduled to reduce to 10 percent no later than the year 2026. Under the IRA, they now begin to phase out to 75 percent, then 50 percent and then 0 percent of their original values in the years following the year in which certain annual greenhouse gas (GHG) emissions reductions are achieved by the U.S. The IRS has not provided guidance as to what year this percent reduction might be achieved, and it is currently very difficult to forecast in what year it might be achieved. Therefore, for purposes of the IRP, Black & Veatch assumed that the reduction will be achieved in 2041 and the ITC and PTC will step down to 75 percent, 50 percent, and 0 percent of their original values in 2042, 2043 and 2044, respectively.

5.2.3. Solar Resource Siting Considerations

In addition to development of the solar resource option cost and performance estimates, a siting analysis was performed to determine the potential location of the new solar resources. A detailed description of the siting analysis is provided in Appendix D, Solar Siting Analysis.

Location of solar resources is important because solar resources are land intensive. About 6-8 acres of land is required for just 1 MW of solar using a common industry assumption. Therefore, scenarios calling for addition of 1,000 MW of new solar would require about 6,000 acres or more of suitable land to be secured for hosting the resources. Securing this amount of land would be a significant effort and would likely require land beyond the JEA service territory due to the sheer magnitude required.

As a first step in the analysis, a systematic search for land parcels that could be developed to support up to 4,000 MW of the new solar resources was performed. This amount of new resources was targeted because it was expected that Scenarios with robust environmental policy goals such as Net Zero could require up to this amount of new solar resources to deliver the energy required.

The land search was done using land data available in a graphical information system (GIS) database for central and northern Florida. These areas were chosen for study because they are expected to have better

[8] For example, at the time of IRP preparation, the IRS had not issued guidance concerning what qualifies as a "component" of a qualified facility, whether or not all steel and iron manufacturing processes of those components must take place in the United States and what constitutes a component made primarily of iron or steel. Even with such guidance, the price of such components from domestic manufacturers must then be forecast which requires significant knowledge of the manufacturing industry and cost/price drivers.

access to transmission capacity now and in the future than areas north of Florida and areas in southern Florida. Black & Veatch looked for parcels with beneficial factors for new solar plant development, including size, proximity to high voltage electric lines, the absence of forests and wetlands, and relatively flat terrain. There were 22 factors in total. Then Black & Veatch developed scoring criteria for each factor, a scale from 0 to 9 of representing how well each parcel satisfies the factor. For example, parcels less than 450 acres received a land factor score of 0 since a minimum of 450 acres would be required for a 75 MW plant based on the 6 acres per MW assumption. Parcels with a high voltage transmission line immediately nearby received a score of 9, whereas those with transmission more than a mile away received a score of 0, and so on for the other factors. Finally, the scores were summed for each parcel and then the parcels were ranked by score.

Results from the land portion of the study reveal that over 100 parcels would be required to host 4,000 MW of the new 75 MW solar resources. Thirty-two (32) of these parcels are in Duval County with the other 68 spread across 23 other counties in northern Florida and the Panhandle. Each of these parcels is large enough to support a 450-acre site for a 75 MW plant. These parcels sum to more than 51,000 acres of land. Acquisition of this much land, either by JEA as direct owner of the plant, or by a third-party plant developer and owner with power sold to JEA, would take many years to accomplish.

With respect to land costs for the new solar resources, it is important to note that new solar resources are in demand by nearly all utilities today. This may result in competition between JEA and other utilities in Florida for the identified solar sites, particularly for those not located in the JEA service territory. This could result in increasing costs for the new solar resources and perhaps limit the total amount of new solar resources that JEA could acquire.

The land cost assumptions that were utilized for the IRP are described in Subsection 5.2.4.

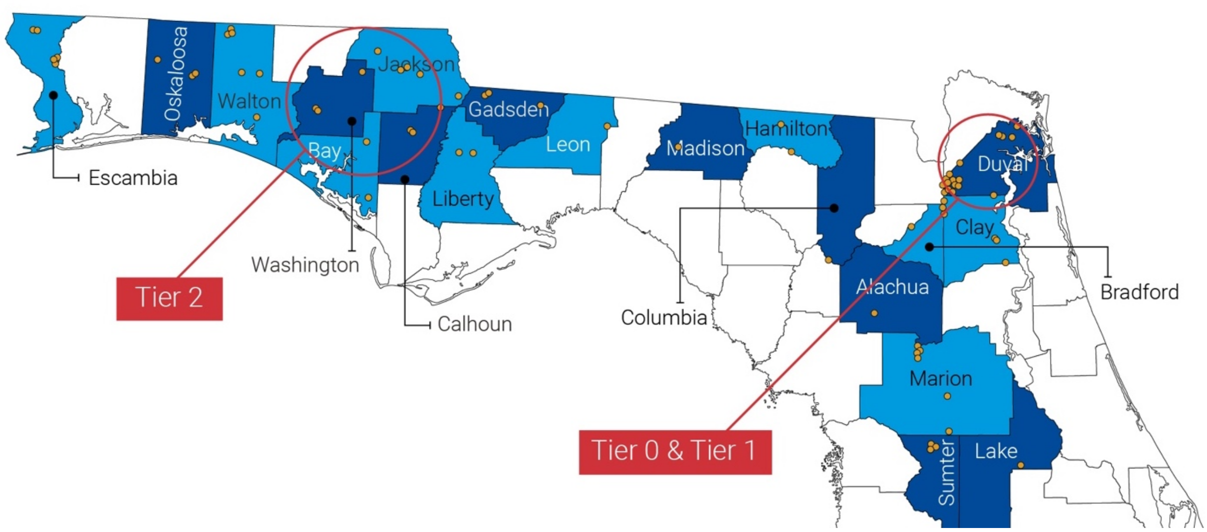
> Nearly all utilities demand new solar resources, resulting in increased competition for land and potentially increasing the costs for, and limiting the amount of, new solar resources that JEA can acquire.

5.2.4. Solar Transmission Considerations

Locating new solar on lands outside the JEA service territory also raises the challenge of electric transmission. JEA would need to secure or construct new remote transmission capacity sufficient to reliably deliver the energy from the remote new solar resources to the JEA service territory. Construction of new transmission is also land intensive and would be a significant effort. One cannot simply assume that large amounts of new solar can be delivered at no cost. The IRP considered the time and cost required to acquire or build the necessary transmission to interconnect and deliver energy from these new solar sites to the JEA service territory.

The transmission analysis began with review of results from the Solar Siting Analysis. The scope of the transmission analysis considered approximately 2,000 MW of the 4,000 MW of sites identified. At that time, it was anticipated that the PLEXOS modeling (then yet to be performed) would likely identify that around 2,000 MW of new solar resource capacity must be added to the generation portfolio particularly for the scenarios that require large amounts of carbon reduction. The transmission analysis scope considered sites outside of Duval County as well as inside given the large amount of land required (approximately 6 to 8 acres per MW). A subset of the sites in Duval County were identified that were relatively highly ranked, in proximity to one another and could collectively support approximately 1,000 MW of solar resources (Tier 1 Solar). Similarly, a subset of sites in the Panhandle area that could collectively support another 1,000 MW of solar resources (Tier 2 Solar) were identified. The transmission analysis also included four of the solar sites that JEA controls in Duval County that could collectively support another 300 MW of solar resources (Tier 0 Solar). The transmission analysis scope therefore included a total of 2,600 MW of potential solar resources. The general location of the Tier 0, Tier 1 and Tier 2 sites are identified on the map on Figure 5-3.

Figure 5-3: Map of Sites Utilized in Transmission Analysis



The transmission analysis was performed by Black & Veatch engineers experienced with planning, design, construction, and operation of transmission facilities. It was performed on the high voltage transmission system of JEA and surrounding areas assuming interconnection of these specific potential new resources using PSS/E and TARA transmission modeling software that Black & Veatch licenses. Load flow and voltage simulations were performed assuming FRCC's standard set of P1 to P7 contingencies. Results of the simulations identified overloads and voltage violations, and the necessary transmission system improvements and voltage support required to mitigate them. Capital costs for the improvements along with a general schedule for their completion were then estimated. The work was performed in consultation with JEA’s Transmission Planning Group.

Results of the transmission analysis showed that new high voltage transmission facilities must be constructed in a phased approach to deliver the solar energy, beginning with interconnection facilities for the Tier 0 resources, then interconnection and transmission facilities for the Tier 1 resources, and then interconnection and transmission facilities for the Tier 2 resources. The time to construct these facilities was also estimated based on experience of both the Black & Veatch engineers and JEA’s Transmission Planning Group. The Tier 0, Tier 1 and Tier 2 solar resources are not expected to be available until 2026, 2030 and 2032, respectively, when the associated interconnection and transmission facilities are necessary. The first year of solar energy delivery from resources in each tier was constrained to be no earlier than the year of expected completion of the facilities.

5.2.5. Solar PPA Price Forecasting

Black & Veatch utilized the solar resource performance and cost estimates along with the assumptions on prevailing wage and ITC to forecast prices for a series of 20-year solar PPAs beginning in each year of the Study Period (the “PPA Price Forecasts”). These forecasts were used in the PLEXOS modeling.

Black & Veatch used a pro-forma financial model that mimics the actual financial modeling that a private party solar developer would perform for a new 75 MW solar project to determine the PPA prices that it must charge to recover costs and earn a profit (the “PPA Model”). This model has been developed and is maintained and used by Black & Veatch on behalf of potential investors in new solar projects to assess future financial results claimed by the private party project developer. The financial assumptions were developed by Black & Veatch consultants that are experienced with financing of solar projects, including the levels of debt and equity required, interest rates, debt service coverage, required return on equity, taxes and tax credits. This includes ITC eligibility and phase out assumptions under the IRA.

PPA prices were forecast for new solar resources at each of three general siting areas that were identified from the Solar Siting Analysis: Tier 0, Tier 1, and Tier 2. Prices were assumed to be in the form of a first-year price in $/MWh escalating thereafter at 3 percent annually. Private party solar developers typically propose escalating price streams to keep the first-year price as low as possible to be competitive. The prices were assumed to be inclusive of all energy, capacity, and environmental attributes associated with the project (all output and attributes purchased by JEA).

Following the expiration of the PPA, each project was assumed to earn revenue for the remainder of its 30-year useful life through continued energy sales to JEA or others (years 21-30). Continued energy sales were estimated based on a long-term energy market price forecast performed by Black & Veatch.

Using the methodology and assumptions described above, Black & Veatch forecasted PPA prices for the generic renewable resources. Figure 5-4 illustrates these forecasts. Please note that for ease of price comparison between tiers and years, Figure 5-4 shows the first year PPA price only. Figure 5-5 shows the first-year price and each subsequent year price for a Tier 0 PPA starting in each year of the forecast period.

Figure 5-4: Solar PPA Resources Forecast First Year Prices

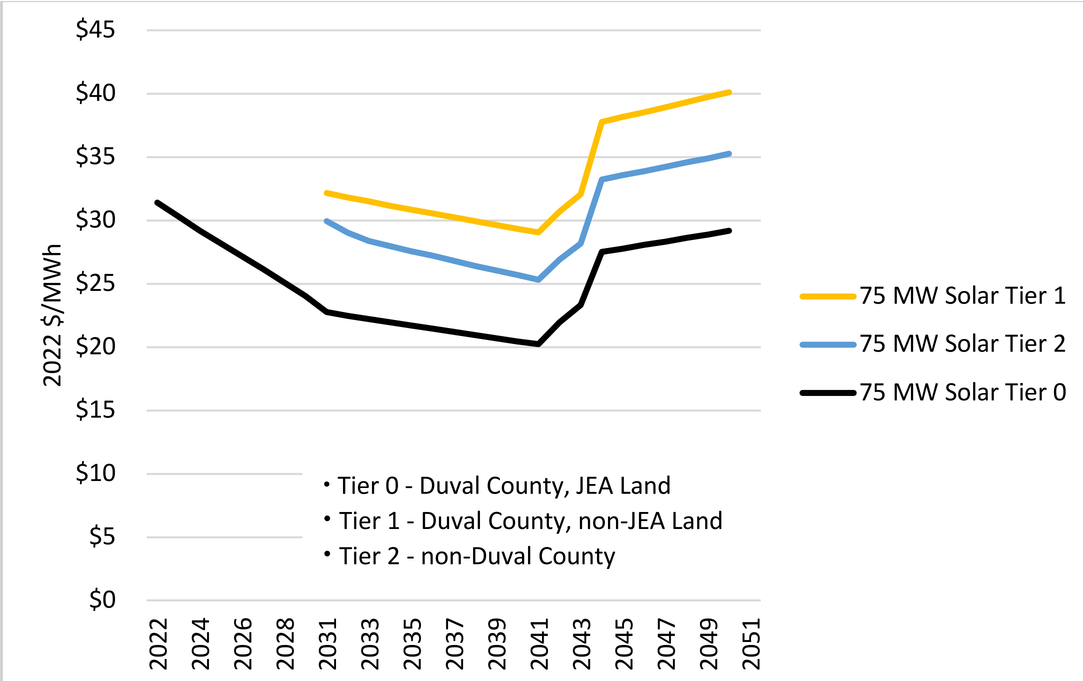
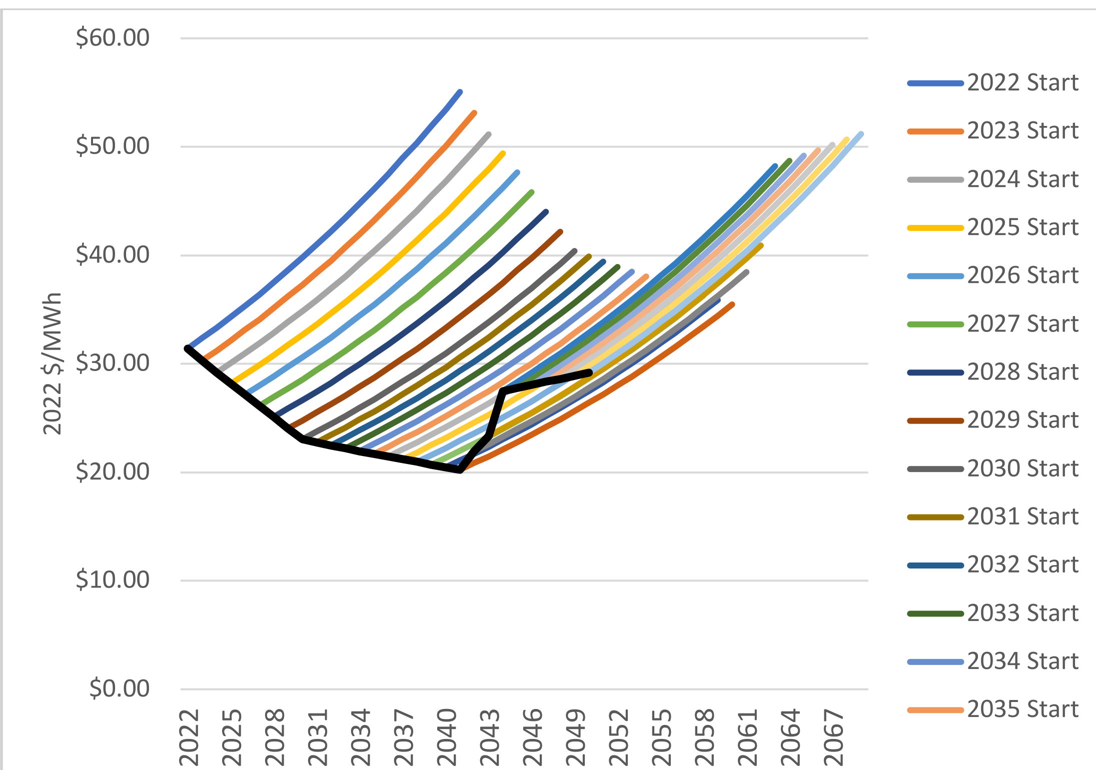


Figure 5-5: Tier 0 Solar Resources PPA Price Streams by Start Year



For clarity, prices are shown in 2022 dollars, which means without inflation. Including inflation in the figure would make it difficult to see the real impact of different cost assumptions between tiers and years. If a Tier 0 solar resource was added to the capacity expansion, the specific PPA price stream for that resource for that start year was included in inflated dollars.

Prices differ by location. The lowest prices would be from the Tier 0 sites that JEA would lease to developers, namely the Deep Creek, Forest Trail, Miller, and Peterson sites. The highest prices would be from the Tier 1 sites that the developers would lease from other landowners. The middle-range stem from the Tier 2 sites the developers would lease from other landowners. The price differences are driven directly by differences in land value that underly the lease rates. Lease rates for the Tier 0 sites are assumed to be 0 since JEA would likely charge low or no lease rates to the developers to avoid giving the lease revenue back in the form of a higher PPA price. Lease rates for the Tier 1 sites are based on a survey of prices for open agricultural land in Duval County, which average around $50,000 per acre. Lease rates for the Tier 2 sites are based on a similar survey of the Panhandle area, which reveals an average of around $7,000 per acre.

It is also important to note that the first year PPA prices are also significantly different from year to year. They decline consistently from the 2020s through 2041 (the Initial Period), when they begin to rise to relatively high levels until 2045 (the Middle Period), and then rise even further through 2051 (the Final Period). The Initial Period decline is driven by an expected continued decline in capital costs and increasing performance of solar PV components (panels, inverters, etc.), which in combination effectively reduces capital costs. The Middle Period increase is due to the expected reduction of the ITC, which effectively raises capital costs. The Final Period increase is due to increasing capital costs for solar PV components as the prior downward trend in costs is expected to reverse and future costs begin to rise.

These PPA prices are for energy delivered at the solar plant boundary, which is typical for PPAs. To reflect the true cost of the solar energy to JEA, the capital costs of the interconnection and transmission facilities for each tier identified in the transmission study were converted into fixed charge rates and added to the respective PPA prices for purposes of the PLEXOS modeling.

Unlike the solar PV resources presented earlier, these capital costs are those that JEA would incur to build and own the resource. JEA would not utilize a PPA arrangement to access the battery resource. It was assumed that JEA would directly own and operate future battery resources because they provide capacity and can be used for a multitude of system reliability purposes such as operating reserves, load following and solar resource balancing, like existing and future new gas-fired resources. These benefits would be more difficult to access under a PPA structure where the private party owner would likely place limits on battery use to preserve the battery for other uses or future users. Also, there is sufficient space at the SJRPP, Northside and GEC sites to accommodate these battery storage resources and therefore JEA does not need to rely on a third party to mitigate the risk of site acquisition.

5.2.6. Biomass Cost Estimating

Cost and performance estimates for a new biomass resource were also developed.

Biomass generating resource estimates in general are highly dependent on the assumed type and quality of biomass fuel to be burned. Black & Veatch, working closely with JEA fuel specialists, determined that woody biomass from forest residues would likely be the most available fuel over the future study period. The composition and moisture content of the woody biomass was based on a fuel composition analysis provided by JEA for biomass fuel burned at Northside Units 1 and 2.

The woody biomass would be chipped and then burned in a bubbling fluidized bed (BFB) technology boiler. Based on the fuel analysis and likely supply available, the biomass resource assumes a single nominal 50 MW unit with 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.

Unlike the solar PV resources presented earlier, the biomass capital and operating costs are those that JEA would incur to build and own the resource. It was assumed that JEA would not utilize a PPA arrangement to access biomass energy but rather directly own and operate a future biomass resource based on its expertise in development and operation of the repowered Northside Units 1 and 2, which consume biomass as a component of the solid fuel stream.

PTC benefits were not considered for the biomass resource. This was because the PTC has the same Direct Pay eligibility requirement as the ITC, including use of minimum domestic content and, as for solar and battery resources there is too much uncertainty as to whether domestic content would be available and at what prices.

5.3. Gas-Fired Resource Options

Numerous gas-fired resource generating options were considered. These included reciprocating engine, standalone combustion turbine, combined cycle combustion turbine and combustion turbine conversion technologies. Detailed information on these resource options is provided in Appendix C – New Generating Resource Options Characterization. A summary of the options is shown in Table 5-2.

Table 5-2: Summary of Gas-Fired Resource Options

ID	Resource Option	Plant Configuration	Average Ambient Net Output[1] (MW)	Heat Rate (Btu/kWh, HHV)
7	2x0 GE LM6000 PF SPRINT	Combustion Turbine	91	9,379
8	1x0 GE LMS100PA+	Combustion Turbine	111	8,818
9	1x0 GE 7FA.05	Combustion Turbine	226	10,080
10	1x0 GE 7HA.02	Combustion Turbine	329	9,256
11	5x0 Wartsila 18V50DF	Reciprocating Engine	89	8,380
12	1x1 GE 7FA.05	Combustion Turbine Combined Cycle	373	6,743

ID	Resource Option	Plant Configuration	Average Ambient Net Output[1] (MW)	Heat Rate (Btu/kWh, HHV)
13	2x1 GE 7FA.05	Two Combustion Turbine Combined Cycle	749	6,715
14	1x1 GE 7HA.02	One Combustion Turbine Combined Cycle	558	6,419
15	2x1 GE 7HA.02	Two Combustion Turbine Combined Cycle	1,119	6,397
16	3x1 GE 7HA.02	Three Combustion Turbine Combined Cycle	1,684	6,378
17	1x1 GE 7HA.02	Same as #14 but Air-Cooled Condenser	552	6,484
18	Conversion of existing GEC CTGs	One Combustion Turbine Combined Cycle	318	6,832
19	Conversion of existing GEC CTGs	Two Combustion Turbine Combined Cycle	638	6,830

Black & Veatch engineers experienced with design, construction and operation of gas-fired power plants developed these estimates. The capacity and heat rate estimates were based on technical information provided by General Electric for their combustion turbine-based power plants, except for the 18V50DF resource, which was based on technical information provided by Wartsila for their reciprocating engine-based power plants. To estimate capacity and heat rate, the engineers developed a conceptual design of each resource and then simulated its operation at varying operating conditions using the Thermoflow suite of thermodynamic simulation software licensed by Black & Veatch. To estimate capital and operating costs, the engineers use an estimating module of the Thermoflow software, and then check results for consistency and completeness against estimates that the engineers have developed or seen elsewhere for similar plant configurations.

Like the battery resources presented earlier, these capital and O&M costs are those that JEA would incur to build, own, and operate the resource. It was assumed that the resource would not be built and owned by a third-party developer with long-term sales to JEA but rather that JEA would directly own and operate future gas-fired resources because they provide capacity and can be used for a multitude of system reliability purposes such as operating reserves, load following and solar resource balancing. These benefits would be more difficult to access under a PPA structure where the private party owner would likely place limits on resource use to preserve the resource for other uses or future users. Also, there is sufficient space at the Power Park and GEC sites to accommodate most of these gas-fired resources, meaning JEA does not need to rely on a third party to mitigate the risk of site acquisition.

5.4. Nuclear Resource Options

For purposes of the IRP, Black & Veatch studied seven different nuclear technologies, including Small Modular Light Water Reactor (SMR LWR) and Advanced non-Light Water Reactor (Advanced Reactor) technologies. Detailed information on these resource options is provided in Appendix C – New Generating Resource Options Characterization. A summary of the options is shown in Table 5-3. Each of these technologies is different that the Large Light Water Reactor technology employed at the Vogtle nuclear plant for which JEA will soon be purchasing 200 MW under a 20-year PPA.

Table 5-3: Summary of Nuclear Resource Options

ID	Technology Type	Resource Option	Plant Configuration	Reactor Rating (MWth)	Plant Output (MWE)
20	Small Modular Light Water Reactor (SMR LWR)	NuScale Power Module™	Four, six, or 12 individual power modules.	160 or 250 per module	50 or 77 per module
21	Small Modular Light Water Reactor (SMR LWR)	General Electric-Hitachi (GEH) BWRX-300	Water-cooled, natural circulation Small Modular Reactor (SMR) with passive safety systems.	870	300+
22	Small Modular Light Water Reactor (SMR LWR)	Holtec SMR-160	SMR designed to produce 160 megawatts of electricity using low enriched uranium fuel.	480	160
23	Advanced Reactor	Kairos Power FHR	Salt-cooled high temperature reactor; higher process temperature allows for industrial heating in addition to power production.	311.1	140
24	Advanced Reactor	TerraPower Natrium Reactor	Sodium fast reactor combined with a molten salt energy storage system.	767 est.	345
25	Advanced Reactor	X-energy Xe-100	Modular and scalable with up to 4 modules per group.	200 per module, 800 per 4 module plant	80 per module, 320 per 4 module plant
26	Advanced Reactor	Terrestrial Energy Integral Molten Salt Reactor (IMSR®)	Molten salt as coolant and fuel that permits lower pressure and high temperature operation.	443	195

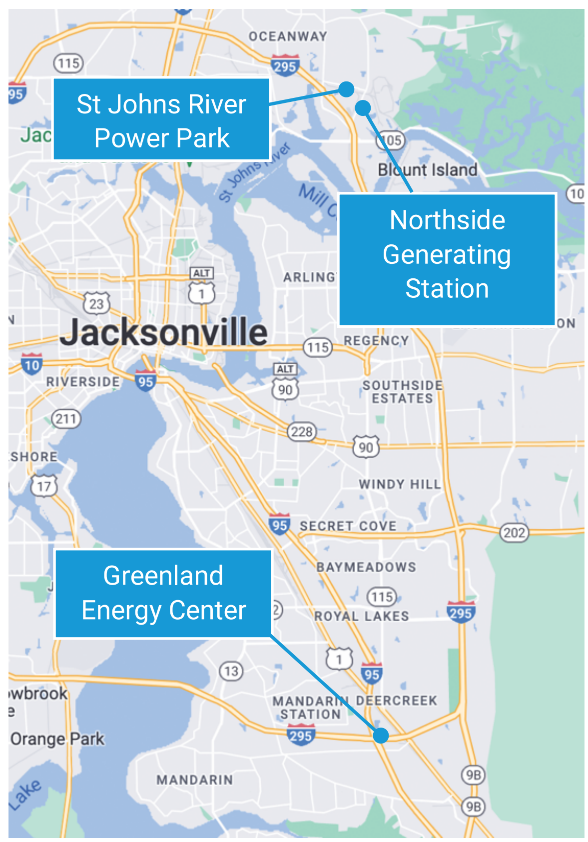
Of the seven nuclear technologies studied, the option considered for the IRP was the SMR LWR or SMR technology under development by NuScale. The NuScale SMR resource consists of 12 individual 77 MW reactor modules with a combined power rating of 924 MW gross. This option was chosen because it is more fully developed relative to the other options. The NRC has issued several approvals and rules advancing the technology, including Standard Design Approval of the NuScale module and certification that NuScale's small modular reactor design meets the NRC safety requirements. In December 2022, NuScale applied to the NRC for standard design approval of its multi-module plant design, which if accepted will allow the company to pursue its first reactor deployment in the mid-2020s. NuScale is planning its first deployment of its SMR technology at a site in Utah in the 2030 timeframe for the Utah Associated Municipal Power Systems (UAMPS).

5.5. Assessment of JEA Existing Sites to Host Resource Options

In addition to development of cost and performance estimates for all the resource options, the available site space at the Greenland Energy Center (GEC), Northside Generating Station (Northside) and St. Johns River Power Park (SJRPP) JEA generating plant sites was assessed to determine which options could be hosted at those sites. This assessment was important because locating new resources at the existing sites avoids the need to secure new sites and the associated acquisition time, permitting time and cost. GEC, Northside and SJRPP were selected because of the general availability of space relative to other JEA generating sites and the general electrical benefit of having new generation on the eastern side of the JEA system rather than the western side. Figure 5-6 below is a map that illustrates the location of these sites.

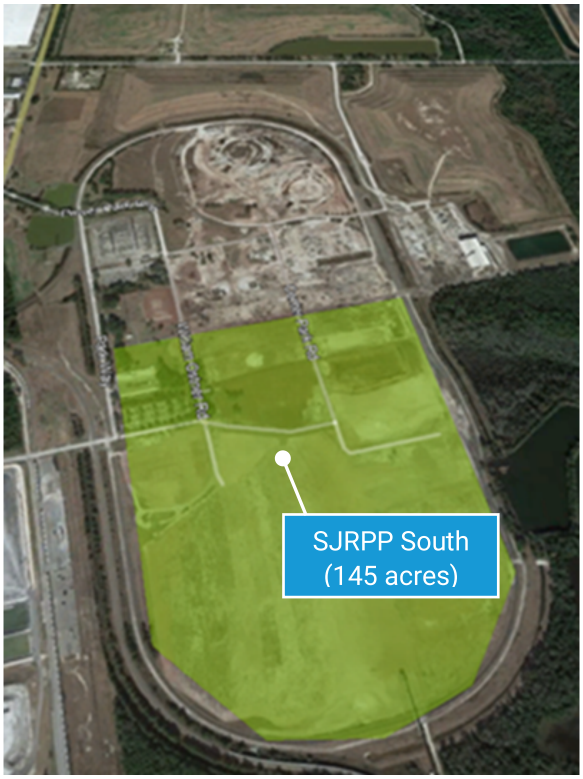
As a first step in the assessment, aerial imagery was used to identify areas at each site that are either currently vacant or could become vacant if existing resources and supporting infrastructure were to be removed in favor of new resources. The areas were then refined based on discussions with JEA engineering and operations staff and other subject matter experts concerning current uses of the areas, dependencies and durations for equipment removal and other factors.

Figure 5-6: Locations of Existing Generating Sites



The available areas identified at SJRPP are shown on Figure 5-7.

Figure 5-7: SJRPP Available Space



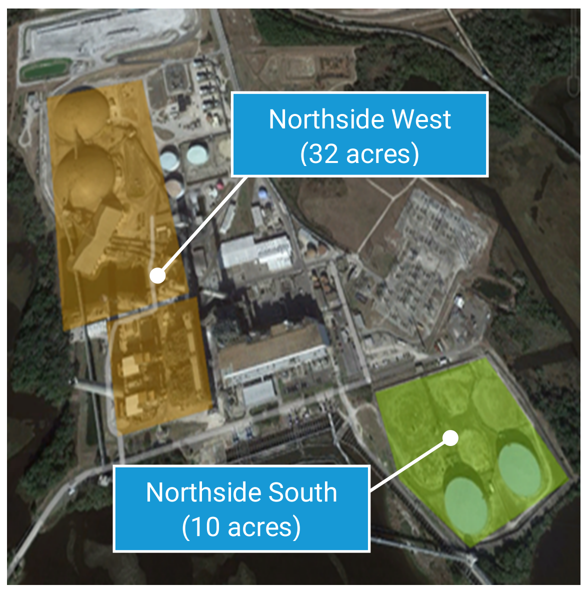
The largest available area is SJRPP South, which is currently vacant and located south of the former St. Johns River Power Park, a 1,252 megawatt coal-fired electric generating plant that was retired in early 2018. This area is generally expected to have fewer buried utilities than the former plant site to the north making it less costly for construction of new resources.

The available areas identified at Northside are shown on Figure 5-8.

The largest area identified is Northside West, which is the site of the existing Northside Units 1 and 2. This area would only be available if Northside Units 1 and 2 are retired and demolished. Demolition was estimated to cost approximately $10 million and take about a year to perform. Therefore, modeling the deployment any of the new resource options at this area would need to factor in the lead time and costs.

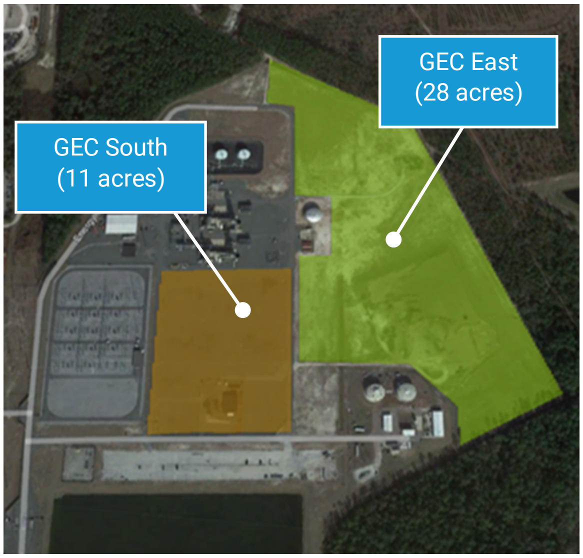
The Northside South area is currently partially occupied by two fuel oil storage tanks that serve Northside Unit 3. This area would only be available if Northside Unit 3 is retired and the fuel oil tanks removed. Therefore, modeling the deployment any of the new resource options at this area would need to factor in the lead time and the costs for tank removal.

Figure 5-8: Northside Available Space



The available areas identified at GEC are shown on Figure 5-9.

Figure 5-9: GEC Available Space



The GEC South area is immediately south of the existing GEC dual unit combustion turbine plant. The area is currently vacant and to date has been reserved for future deployment of steam generators and steam turbines that would be part of a conversion of the existing combustion turbine plant to a combustion turbine combined cycle plant. These conversions are considered in the IRP as new resource Options 17 and 18. Use of this area for any other new resource options would generally preclude the deployment of Options 17 and 18. Therefore, modeling the deployment of any new resource options other than 17 and 18 at this area would need to remove Options 17 and 18 from consideration. The GEC East Area is currently vacant and to date has generally been reserved for addition of new gas-fired resources at GEC.

With these areas defined, the acreage typically required to host each option versus the acreage available within each area was compared. It is important to note that the nuclear SMR option was excluded from this assessment. This is because at the time of IRP preparation the technology was new and therefore the acreage typically required and associated nuclear siting laws and restrictions were unknown.

Results of the comparison show the following:

- The SJRPP, NGS West and GEC West areas are very similar in ability to host potential new resources.
- None of the solar options could be hosted within any of the areas. This is because the acreage required for each (450) exceeds the acreage available (11-145). The solar options must be hosted on new areas elsewhere.
- Any of the battery options could be hosted within any of the areas due to the relatively small acreage required.
- The biomass option could be hosted within SJRPP South only.
- Only the relatively small combustion turbine and reciprocating engine-based options could be hosted within NGS South. The larger combustion turbine based combined cycle options must be hosted within NGS West or SJRPP South.

6

Levelized Cost of Energy Comparisons

6. Levelized Cost of Energy Comparisons

A key step in the IRP process was reviewing the forecast capital and operating costs of each new generating resource option and determining whether any should be eliminated from further consideration due to relatively high forecast capital and operating costs. This filtering accomplishes reducing the number of resource options to be considered in the subsequent very detailed and time intensive PLEXOS capacity expansion and production cost simulation modeling process.

The resource options have a wide range of capital and operating costs. To compare and filter them on a common basis, a levelized cost of energy (LCOE) screening analysis was performed. LCOE for a resource was defined as the present value of its costs over its life divided by the present value of its electric generation output over its life.

Figure 6-1 summarizes the LCOE formula and the key variables.

Cost variables include assumed installation and ongoing capital costs, fixed O&M costs, and variable O&M costs such as fuel. Performance variables include assumed energy production, capacity factor and expected resource life. For renewable resources, assumptions must also be made for degradation rates and component overhaul/replacement costs. Economic variables include assumed ownership, escalation and inflation rates and the discount rate, which is based on the owner's debt and equity capitalization and interest rates.

Economic assumptions utilized for the LCOE analysis are summarized in Table 6-1. These assumptions were based on discussions with JEA economic and financial staff. It is important to note that JEA ownership was assumed for the LCOE analysis. This contrasts with the PLEXOS modeling where third-party ownership of solar resources under long-term energy sales to JEA was assumed (Solar PPAs). JEA ownership of solar was assumed in the LCOE analysis for consistency and comparability of results across the resource types.

It is important to note that these forecasts do not include the effect of the solar and storage ITC or biomass PTC available under the IRA. As described previously under Federal Tax Considerations, for JEA to benefit from the ITC/PTC it would have to satisfy the Direct Pay requirements, which requires use of domestic materials in the resource. Currently, the IRS has not issued guidance on what constitutes domestic materials. It is also very difficult to estimate if domestic production capacity will be sufficient to provide the amounts of domestic materials required for solar, battery storage, and biomass resources and at what prices. Due to this uncertainty, a conservative approach was taken for purposes of this LCOE analysis by assuming that JEA would not benefit from the ITC. Direct Pay will be further assessed in future IRPs. The assumption of no Direct Pay was for this IRP only and does not reflect additional analysis that JEA may subsequently perform.

Figure 6-1: Levelized Cost of Energy (LCOE) Formula

$$\frac{\sum_{t=1}^{n} \frac{I_t+M_t+F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

$$\text{LCOE} = \frac{\text{Present Value of Costs over Lifetime}}{\text{Present Value of Electric Generation over Lifetime}}$$

Where:
I_t : investment expenditures in year t;
M_t : operations and maintenance expenditures in year t;
F_t : fuel expenditures in year t;
E_t : electrical energy generated in year t;
r : discount rate;
n : expected lifetime of system.

Table 6-1: Economic Assumptions for the LCOE Analysis

Parameter	Assumption
Resource ownership	JEA
General inflation rate	3.00%
Construction cost escalation rate	3.00%
Fixed O&M cost escalation rate	3.00%
Non-fuel variable O&M cost escalation rate	3.00%
Interest rate	4.00%
Discount rate (equal to bond interest rate)	4.00%

Cost and performance assumptions utilized for the LCOE analysis of the gas-fired resource options are summarized in Table 6-2. These assumptions are based on the resource characteristics described in Appendix C – New Generating Resource Options Characterization.

Results of the LCOE analysis for the gas-fired new resource options are shown on Figure 6-2. Results are shown for each resource option at a different capacity factor assumption to illustrate the impact of the capacity factor assumption on LCOE.

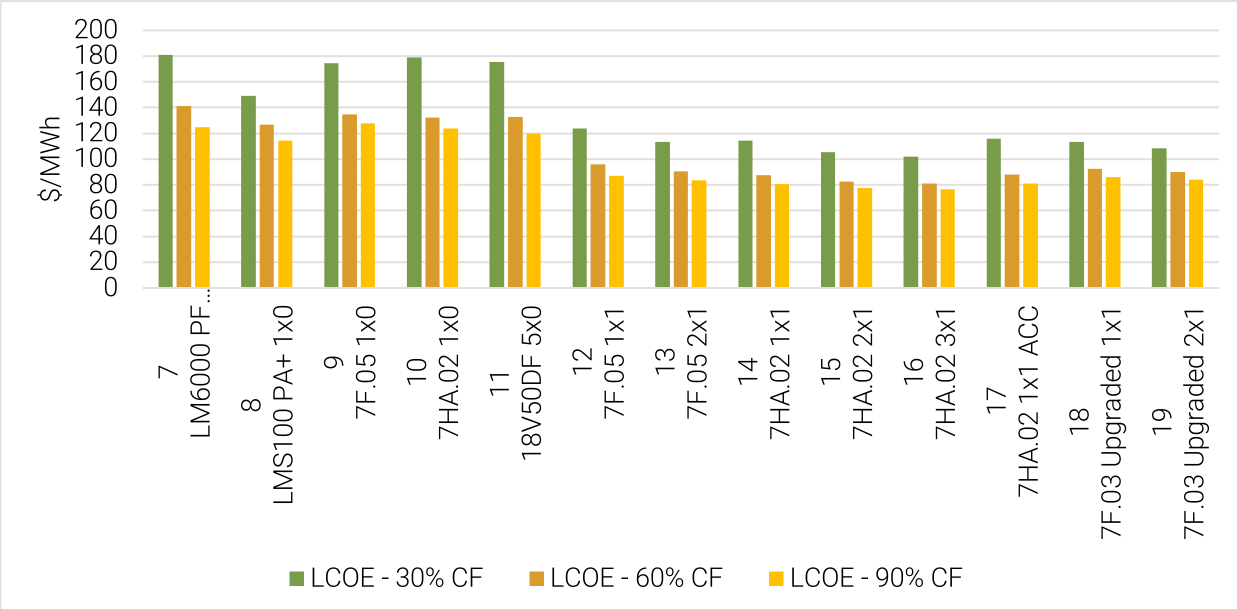
Results for the simple cycle combustion turbine and reciprocating engine resource options (Options 7 through 11) showed they have very similar LCOEs across the different capacity factor levels except for Option 8 the LMS100 PA+ 1x0, which has significantly lower costs. Since there was no one option with relatively high costs, none could be eliminated from further modeling.

Results for the combined-cycle combustion turbine resource options (Options 12 through 19) showed they also have very similar LCOEs and therefore none could be eliminated from further modeling.

Table 6-2: Gas-Fired New Resource Options - LCOE Assumptions

Option	Resource Configuration	Type	Economic Life (years)	Maximum Capacity - Winter (MW)	Maximum Capacity - Summer (MW)	Capital Cost ($/kw at Winter Capacity)	Capacity Factor (%)	Fixed O&M ($/year)	Variable O&M ($/MWh)
7	LM6000 PF SPRINT 2x0	SCCT	20	99.5	76.1	$1,048	30	1,443,087	7.07
8	LMS100 PA+ 1x0	SCCT	20	115.2	91.2	$1,078	30	1,466,707	4.55
9	7F.05 1x0	SCCT	20	235.7	208.7	$464	30	1,931,240	10.25
10	7HA.02 1x0	SCCT	20	346.2	300.1	$503	30	2,039,503	13.69
11	18V50DF 5x0	SCCT	20	89.4	83.8	$1,445	30	2,029,721	9.08
12	7F.05 1x1	CCCT	25	379.5	342.2	$1,175	60	3,804,971	2.43
13	7F.05 2x1	CCCT	25	761.8	687.5	$974	60	4,946,786	2.34
14	7HA.02 1x1	CCCT	25	571.3	518	$919	60	4,126,527	2.48
15	7HA.02 2x1	CCCT	25	1,146.5	1,039.8	$762	60	5,592,219	2.41
16	7HA.02 3x1	CCCT	25	1,724.6	1,563.6	$646	60	7,387,710	2.39
17	7HA.02 1x1 ACC	CCCT	25	566.6	511.2	$973	60	4,133,777	1.8
18	7F.03 Upgraded 1x1	CCCT	25	328.8	297.3	$924	60	3,686,567	2.75
19	7F.03 Upgraded 2x1	CCCT	25	660.3	597.2	$839	60	4,703,331	2.67

Figure 6-2: LCOE Results for Gas-Fired Resource Options



Cost and performance assumptions utilized for the LCOE analysis of the renewable, storage and nuclear resource options are summarized on Table 6-3. These assumptions are based on the resource characteristics described in Appendix C – New Generating Resource Options Characterization, except for capacity factors for the solar plus storage and storage options which are not stated in the Appendix. Capacity factors for the solar plus storage options were calculated based on the hourly energy production profile for the 75 MW solar resource and common assumptions for hours of discharge per day and round-trip efficiency. Capacity factors for the storage options were calculated using common assumptions for hours of discharge per day and round-trip efficiency.

Results of the LCOE analysis for the renewable, storage and nuclear options are shown on Figure 6-3.

Comparing the options that provide energy only (Options 1, 6 and 20), its apparent that the nuclear Option 20 is significantly more costly and therefore was eliminated from further modeling.

With respect to the options that provide shaped energy (Options 2 and 3), Option 3 is significantly more costly and therefore was eliminated from further modeling. Option 3 has a higher LCOE because it has a higher capital cost (due to its larger battery) and a lower capacity factor. The lower capacity factor indicates that for the given solar profile a 4-hour co-located battery is excessive, and a smaller battery size is sufficient.

Although Option 2 was selected for further modeling, it was ultimately removed from further consideration due to passage of the IRA. As described in Section 5.2, the IRA allows for a storage ITC which effectively eliminates the need for solar plus integrated storage resources. Therefore Option 2 was excluded since this resource type is no longer required and because exclusion simplifies the PLEXOS modeling.

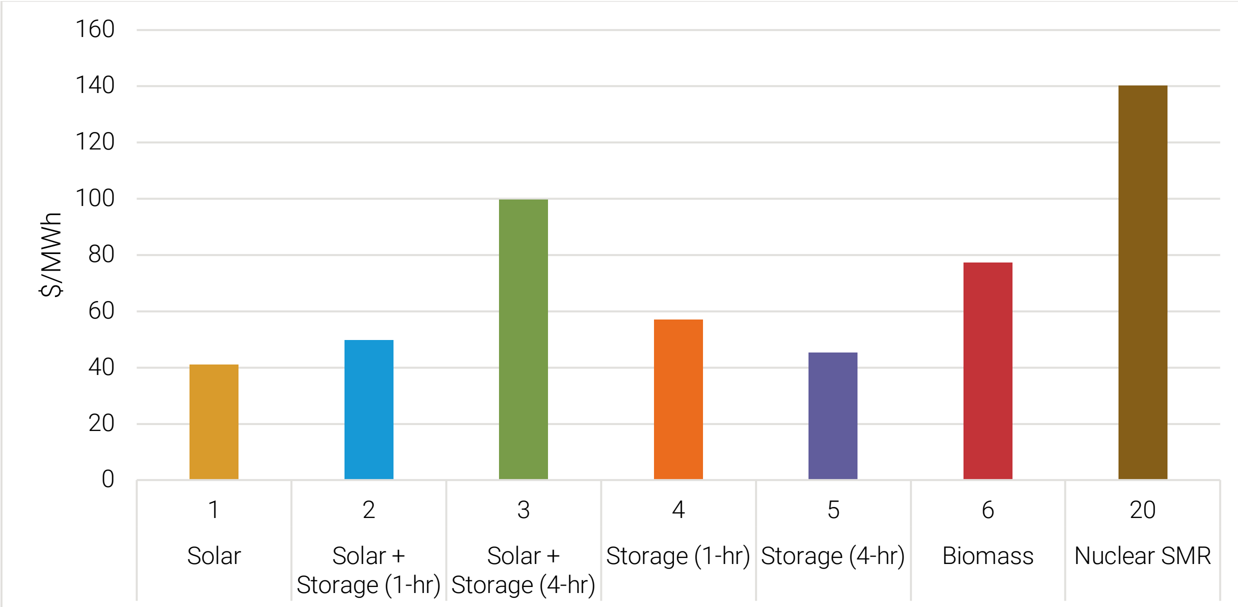
With respect to the storage options (4 and 5), Option 4 (1 hour capacity) is more costly. Although this LCOE analysis shows that the 1-hour BESS is more costly, the subsequent PLEXOS modeling may show it to be less costly particularly if there is a strong need for short-term storage to provide rapid load following and solar intermittency. Therefore the 1-hour BESS was retained for further modeling.

Table 6-3: Renewable, Storage and Nuclear LCOE Assumptions

Option	Resource Configuration	Economic Life (years)	Maximum Capacity (MW-AC)	Capacity Factor (%)	Capital Cost ($/kw at Winter Capacity)	Fixed O&M ($/kWac-year)	Variable O&M ($/MWh)	Degradation Rate (%)
1	Solar	25	74.9	29.9	$1388	7	-	0.5
2	Solar + Storage (1-hr duration)	25	74.9	29.4	$1663	8.22	-	0.5
3	Solar + Storage (4-hr duration)	25	74.9	26	$3134	8.22	-	0.5
4	Storage (1-hr duration)	20	37.5	8.33	$552	2.44	-	-
5	Storage (4-hr duration)	20	74.9	33.33	$1747	8.2	-	-
6	Wood Biomass	25	50	80	$3,562	147.5	8.08	-
20	Small Modular Nuclear Reactor	40	854	95	$2,850	7.05	16.4	-

*Note: For stand-alone storage units, the capacity factor represents 86 percent round trip efficiency.

Figure 6-3: LCOE Results for Renewable, Storage and Nuclear Resource Options



7

Development of Scenarios and Sensitivities

7. Development of Scenarios and Sensitivities

As discussed throughout the IRP Stakeholders Meetings and elsewhere in this IRP, the IRP utilizes both scenario and sensitivity analysis methodology. Scenario analysis considers a set of changes to multiple variables simultaneously to analyze a potential future. Sensitivity analysis considers changes to one of these variables at a time within a given potential future. The scenarios and sensitivities evaluated throughout the IRP are intended to address uncertainties related to the following:

- Projected load growth (both peak demand and annual energy requirements).
- Penetration of plug-in electric vehicles and electrification in general.
- Demand-side management, energy efficiency, conservation, and customer-sited generation (DERs).
- Future environmental regulation and clean energy standards.
- Projected natural gas and solid fuel prices.

Several key considerations were critical to holistic evaluation of scenario results. These include affordability, reliability, environmental impact, economic development, and CO_2 emission reductions.

Affordability was considered by examining the potential cost and rate increases under each scenario to ensure that they are moderate and would not cause undue hardship on customers. Reliability was considered by examining the amount of generating capacity at the time of peak customer demand to ensure that it exceeds the peak by the required reserve margin.

Environmental impact and economic development were considered by examining the location of new resources to help ensure that disadvantaged communities will not bear the brunt of potential increased noise and visual impact and that land use would be consistent with future economic development. CO_2 emission reductions were considered by examining the potential reduction of these emissions relative to the other scenarios.

The following provides a conceptual-level summary of the six scenarios with figures that illustrate the changes to the variables within each scenario as compared to the Current Outlook scenario. Within each figure, the magnitude of variables within the

Current Outlook scenario are indicated as "Base" or "None" while "High" and "Low" represent the magnitude of the variable as compared to the corresponding variable within the Current Outlook scenario. Following discussion of the six scenarios is an overview of the six sensitivities.

7.1. Current Outlook Scenario

The Current Outlook scenario reflects the following:

- Inflation and escalation rates increase as compared to recent rates.
- Load forecast based on:
    - Historical customer usage trends and population projections.
    - Historical customer participation in demand-side management/energy efficiency/conservation/DER.
    - Projections of increased plug-in electric vehicle adoption and electrification based on recent historical observations and projected population growth.
- Natural gas and solid fuel prices in-line with recent historical prices following a period of volatility given current international disruptions to fuel markets.
- No cost for emissions of carbon dioxide (CO_2).
- No specific target for renewable energy/clean energy generation.
- Costs for construction of new generating resource options in-line with current costs.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

7.2. Economic Downturn Scenario

The Economic Downturn scenario represents a future with a sustained economic slowdown, driven in part by higher inflation and fuel and commodity costs, and reflects the following:

- Inflation and escalation rates increase as compared to the Current Outlook.
- Load forecast lower than in the Current Outlook, influenced by a combination of the following:
    - Lower customer usage and population projections than the Current Outlook.
    - No changes to demand-side management, energy efficiency, conservation, DER, or electrification as compared to the Current Outlook.
    - Lower plug-in electric vehicle adoption than the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Costs for construction of new generating resource options increase as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A tabular summary of the differences between the Economic Downturn scenario and the Current Outlook scenario is provided in Table 7-1.

The Current Outlook represents a future based on JEA's current expectations related to customer loads, fuel prices, and existing energy efficiency and generating units plan.

Table 7-1: Differences between the Current Outlook and Economic Downturn Scenarios

Area	Variable	Current Outlook	Economic Downtown
Financial	Interest During Construction and Discount Rate	Base	High
	General Inflation Rate	Base	High
	Capital Cost Escalation Rate	Base	High
Demand	Total Net Energy Requirements Forecast	Base	Low
	Net Firm Peak Demand Forecast	Base	Low
	DSM/EE/Conservation	Base	Base
	PEVs	Base	Low
	Electrification	Base	Base
	Customer-Sited Renewables (DERs)	Base	Base
Environmental Regulations	Carbon Regulations/Cost	None	None
	Clean Energy Standards (CES)	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	High
	Unit Retirements	Base	Base

"Base" represents variables in Current Outlook Scenario
"High" or "Low" represents the magnitude of variables relative to "Base" or "None"

7.3. Efficiency + DER Scenario

The Efficiency + DER scenario represents a future with increasing levels of interest and participation in demand-side management, conservation, energy efficiency, and DER, driven in part by higher fuel costs, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
    - Higher customer usage than the Current Outlook, as increases to PEV adoption and electrification are not offset by increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook, all as discussed below.
    - Increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook.
    - Increased PEV adoption and electrification as compared to the Current Outlook.

- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Lower costs for construction of new generating resource options as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A summary of the differences between the Efficiency + DER scenario and the Current Outlook scenario is provided in Table 7-2.

Table 7-2: Differences between the Current Outlook and Efficiency + DER Scenarios

Area	Variable	Current Outlook	Efficiency + DER
Financial	Interest During Construction and Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	High
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	Clean Energy Standards (CES)	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	Low
	Unit Retirements	Base	Base

"Base" represents variables in Current Outlook Scenario
"High" or "Low" represents the magnitude of variables relative to "Base" or "None"

7.4. Increased Electrification Scenario

The Increased Electrification scenario represents a future with increased levels of interest and adoption of DER and electrification, driven in part by higher fuel costs, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
    - Higher customer usage than the Current Outlook.
    - Increased customer adoption of plug-in electric vehicles, electrification, and DER as compared to the Current Outlook.
    - No changes to demand-side management, energy efficiency, or conservation as compared to the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- No cost for emissions of CO_2.
- No specific target for renewable energy/clean energy generation.
- Increased costs for construction of new generating resource options as compared to the Current Outlook.
- JEA's existing generating units continue to operate until their retirement due to age and condition.

A tabular summary of the differences between the Increased Electrification scenario and the Current Outlook scenario is provided in Table 7-3.

Table 7-3: Differences between the Current Outlook and Increased Electrification Scenarios

Area	Variable	Current Outlook	Increased Electrification
Financial	Interest During Construction & Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	Base
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	CES	None	None
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	High
	Unit Retirements	Base	Base

"Base" represents variables in Current Outlook Scenario
"High" or "Low" represents the magnitude of variables relative to "Base" or "None"

7.5. Future Net Zero Scenario

The Future Net Zero scenario represents a future in which JEA achieves net zero carbon emissions from its generating portfolio by the end of the IRP planning period, and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast higher than in the Current Outlook, influenced by a combination of the following:
    - Higher customer usage than the Current Outlook, as increases to PEV adoption and electrification are not offset by increased customer participation in demand-side management, energy efficiency, conservation, and DER as compared to the Current Outlook, all as discussed below.
    - Increased customer adoption of PEVs, electrification, and DER as compared to the Current Outlook.
    - Increased PEV adoption and electrification as compared to the Current Outlook.
- Natural gas and solid fuel prices increase as compared to the Current Outlook.
- Costs for emissions of CO_2.
- Net-zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of clean energy resources (i.e., 40 percent clean energy by 2030, increasing to 100 percent clean energy by 2050).
- No change to costs for construction of new generating resource options as compared to the Current Outlook.

A summary of the differences between the Future Net Zero scenario and the Current Outlook scenario is provided in Table 7-4.

Table 7-4: Differences between the Current Outlook and Future Net Zero Scenarios

Area	Variable	Current Outlook	Future Net Zero
Financial	Interest During Construction and Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	High
	Net Firm Peak Demand Forecast	Base	High
	DSM/EE/Conservation	Base	High
	PEVs	Base	High
	Electrification	Base	High
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	High
	CES	None	High
Fuel Prices	Natural Gas	Base	High
	Solid Fuel	Base	High
Others	Construction Cost	Base	Base
	Unit Retirements	Base	Base

"Base" represents variables in Current Outlook Scenario
"High" or "Low" represents the magnitude of variables relative to "Base" or "None"

7.6. Supplemental Scenario

The Supplemental scenario was developed to address specific requests from Stakeholders received as part of the Stakeholder Engagement process (discussed in Chapter 2 of this IRP), and reflects the following:

- No changes to inflation and escalation rates as compared to the Current Outlook.
- Load forecast lower than in the Current Outlook Due to increased levels of customer adoption of customer-sited renewables.
- No changes to demand-side management, energy efficiency, or conservation as compared to the Current Outlook.
- No changes to natural gas and solid fuel prices increase as compared to the Current Outlook.
- No costs for emissions of CO_2.
- Net-zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of renewable energy resources (i.e., 30 percent renewable energy by 2030, increasing to 100 percent renewable energy by 2050).
- No change to costs for construction of new generating resource options as compared to the Current Outlook.
- Removal of Northside Generating Station units 1 and 2 by 2030.

A summary of the differences between the Supplemental scenario and the Current Outlook scenario is provided in Table 7-5.

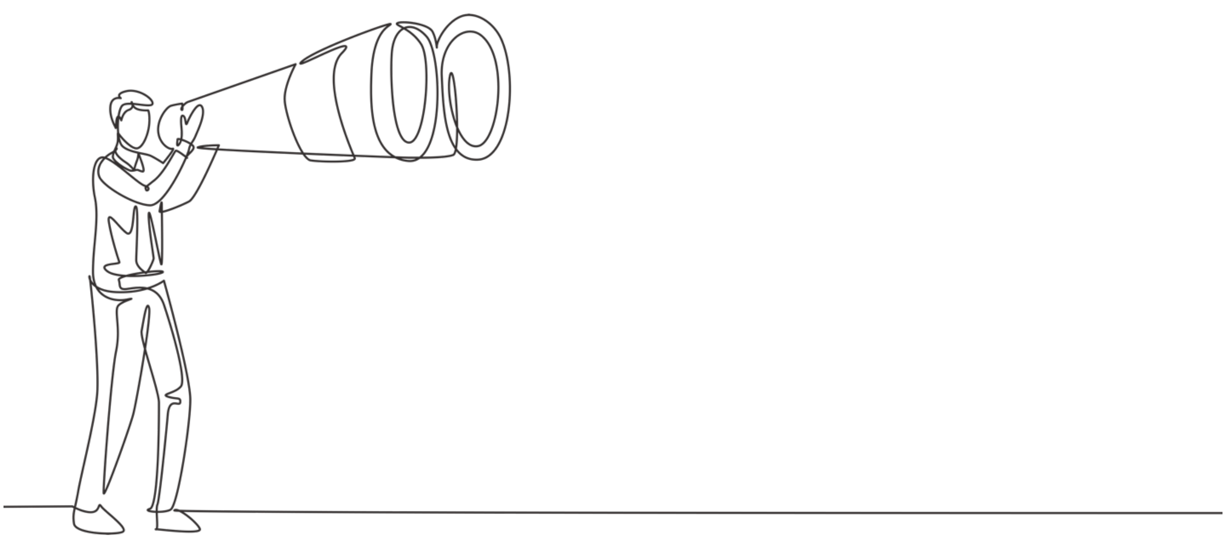


Table 7-5: Differences between the Current Outlook and Supplemental Scenarios

Area	Variable	Current Outlook	Supplemental
Financial	Interest During Construction & Discount Rate	Base	Base
	General Inflation Rate	Base	Base
	Capital Cost Escalation Rate	Base	Base
Demand	Total Net Energy Requirements Forecast	Base	Low
	Net Firm Peak Demand Forecast	Base	Low
	DSM/EE/Conservation	Base	Base
	PEVs	Base	Base
	Electrification	Base	Base
	Customer-Sited Renewables (DERs)	Base	High
Environmental Regulations	Carbon Regulations/Cost	None	None
	CES	None	High
Fuel Prices	Natural Gas	Base	Base
	Solid Fuel	Base	Base
Others	Construction Cost	Base	Base
	Unit Retirements	Base	High

"Base" represents variables in Current Outlook Scenario
"High" or "Low" represents the magnitude of variables relative to "Base" or "None"

7.7. Sensitivities

As discussed throughout the IRP, the IRP evaluated several sensitivities as well as the scenarios that were outlined previously in this chapter. The sensitivities were evaluated within the Current Outlook scenario and, except as noted below, reflect variables that are consistent with those evaluated for the Current Outlook scenario:

- Low Load Sensitivity: Sensitivity that utilizes the forecast annual peak demand and energy requirements load forecast that was reflected in the Economic Downturn scenario.
- No Load Growth Sensitivity: Sensitivity in which the forecast peak demand and annual energy requirements reflected for 2022 in the Current Outlook scenario are held constant for each year of 2023 through 2051 period.
- High Load Sensitivity: Sensitivity based on the load forecast utilized for the Efficiency + DER and Future Net Zero scenarios with the addition of a potential large customer of approximately 200 MW beginning in 2024.
- High Fuel Sensitivity: Sensitivity in which natural gas and solid fuel prices are higher than those in the Current Outlook scenario, reflecting the high price projections included in Chapter 4 of this IRP.
- Regulated CO_2 Sensitivity: Sensitivity in which all CO_2 emissions are assessed a cost of $30/ton beginning in 2030, increasing by 5 percent annually.

- Net Zero Sensitivity: Sensitivity in which there are zero CO_2 emissions from JEA's generating portfolio by 2050 with interim CO_2 reductions beginning in 2030, achieved through increased utilization of clean energy resources (i.e., 40 percent clean energy by 2030, increasing to 100 percent clean energy by 2050).

8

Modeling Results

8. Modeling Results

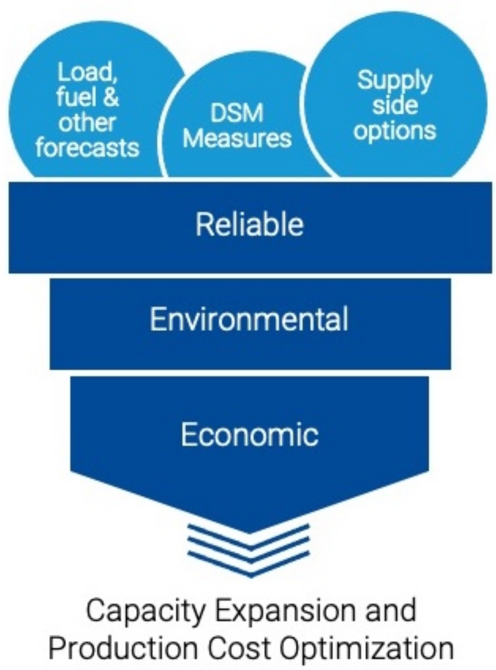
8.1. Overview of PLEXOS

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. PLEXOS was used to evaluate the data discussed in previous sections to produce a least cost resource plan while honoring unit operational constraints and maintaining the ability of the resource plan to serve forecast load requirements in a reliable manner.

PLEXOS was used to develop optimal capacity expansion plans and associated production costs for each of the scenarios and sensitivities.

The evaluations are discussed throughout Chapter 7 of this IRP. While this Chapter presents summary-level information related to the optimal capacity expansion plans, additional details are provided in Appendix A - Detailed PLEXOS Modeling Results. For more details on PLEXOS see Appendix F.

Figure 8-1: PLEXOS Constrained Optimization



8.2. Results

8.2.1. Resource Additions

Summaries of the resource additions associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-2 and Figure 8-3, respectively.

Results of the PLEXOS analysis and determination of the optimal capacity expansion plans for each scenario and sensitivity within different timeframes are illustrated on Figure 8-4 and Figure 8-5, respectively. These results indicate that additional solar generation, additional natural gas-fueled generation, and energy storage resources are the near-term (i.e., by the 2030 timeframe) resource additions that will provide benefits to the JEA system, as these new resources consistently comprise the optimal capacity expansion plans across the range of scenarios and sensitivities evaluated as part of this IRP.

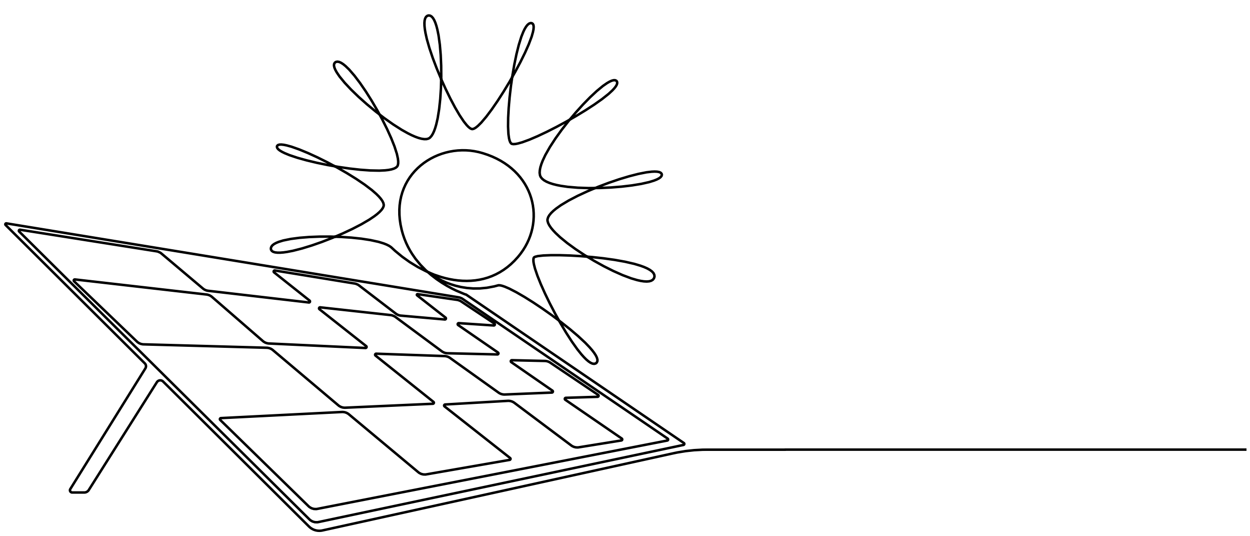


Figure 8-2: Forecast Resource Additions for Each Scenario

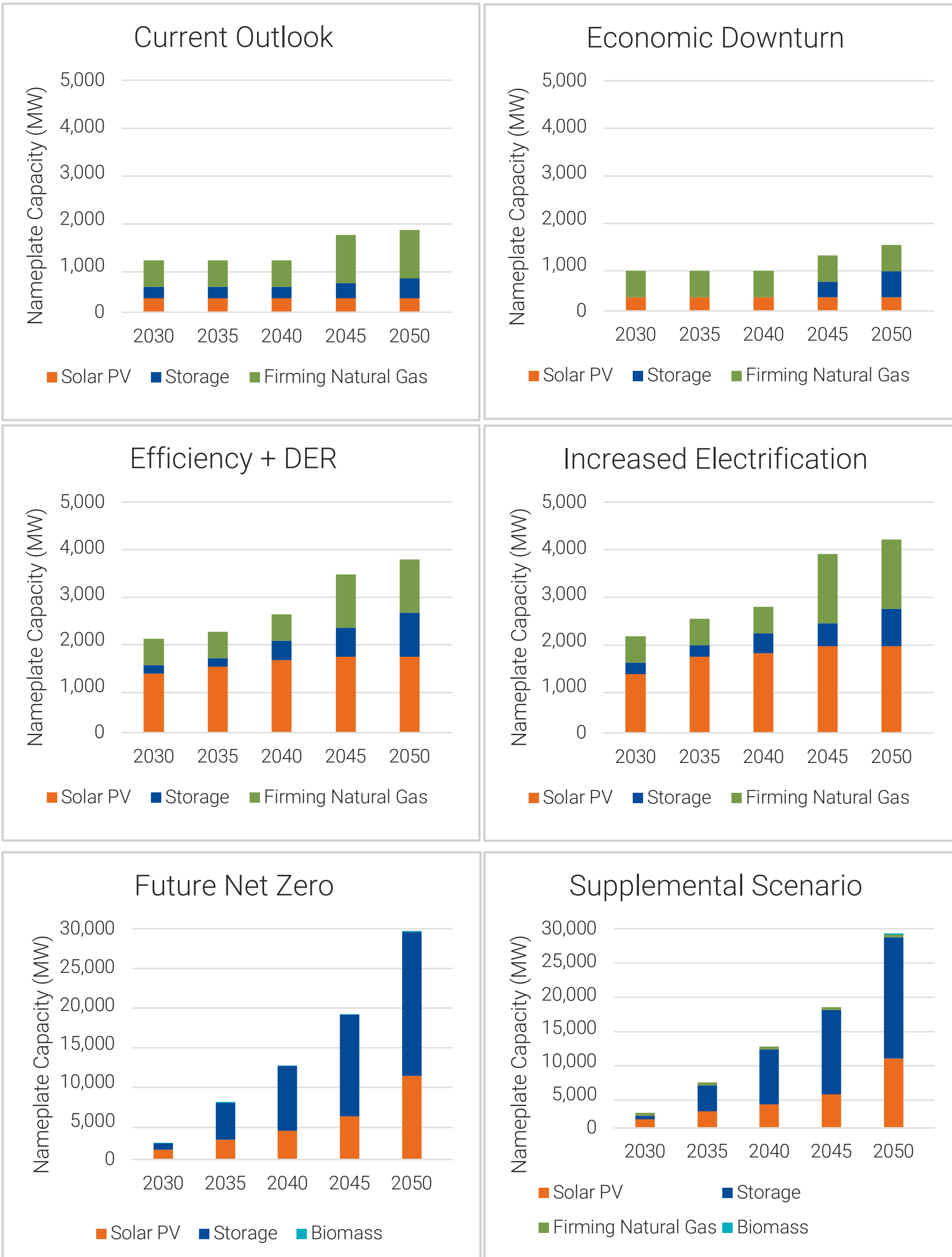


Figure 8-3: Forecast Resource Additions for Each Sensitivity

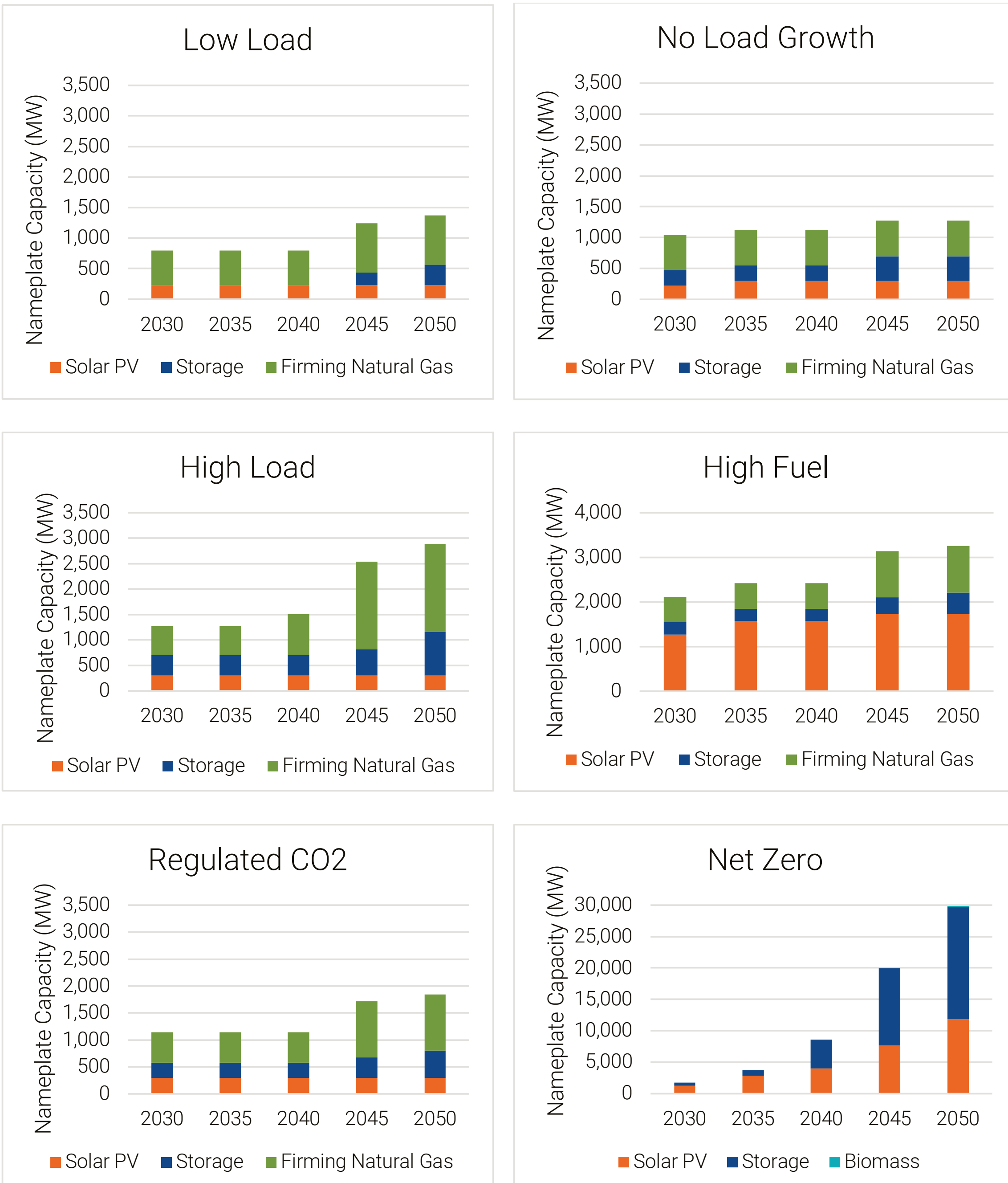


Figure 8-4: Summary of Resource Additions for Each Scenario

Incremental Solar PV Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	300 MW	300 MW	1,275 MW	1,275 MW	1,275 MW	1,275 MW
Additional 2030 – 2040	0 MW	0 MW	300 MW	450 MW	2,475 MW	2,250 MW
Additional 2040 – 2050	0 MW	0 MW	75 MW	150 MW	7,125 MW	6,975 MW
Total Solar PV Additions by 2050	**300 MW**	**300 MW**	**1,650 MW**	**1,875 MW**	**10,875 MW**	**10,500 MW**

Incremental Battery Energy Storage System (BESS) Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	250 MW	0 MW	188 MW	250 MW	824 MW	563 MW
Additional 2030 – 2040	0 MW	0 MW	225 MW	188 MW	7,575 MW	7,750 MW
Additional 2040 – 2050	289 MW	612 MW	612 MW	451 MW	10,325 MW	10,438 MW
Total BESS Additions by 2050	**539 MW**	**612 MW**	**1,025 MW**	**889 MW**	**18,724 MW**	**18,751MW**

Incremental Natural Gas Additions

	Current Outlook	Economic Downturn	Efficiency + DER	Increased Electrification	Future Net Zero	Supplemental
Cumulative 2030	571 MW	571 MW	571 MW	571 MW	0 MW	461 MW
Additional 2030 – 2040	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW
Additional 2040 – 2050	472 MW	0 MW	582 MW	928 MW	0 MW	0 MW
Total Natural Gas Additions by 2050	**1,043 MW**	**571 MW**	**1,153 MW**	**1,499 MW**	**0 MW**	**461 MW**

Figure 8-5: Summary of Resource Additions for Each Sensitivity

Incremental Solar PV Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO_2	Net Zero
Cumulative 2030	225 MW	225 MW	300 MW	1,275 MW	300 MW	1,275 MW
Additional 2030 – 2040	0 MW	75 MW	0 MW	300 MW	0 MW	2,775 MW
Additional 2040 – 2050	0 MW	0 MW	0 MW	150 MW	0 MW	7,800 MW
Total Solar PV Additions by 2050	**225 MW**	**300 MW**	**300 MW**	**1,725 MW**	**300 MW**	**11,850 MW**

Incremental Battery Energy Storage System (BESS) Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO_2	Net Zero
Cumulative 2030	0 MW	250 MW	400 MW	275 MW	275 MW	450 MW
Additional 2030 – 2040	0 MW	0 MW	0 MW	0 MW	0 MW	4,075 MW
Additional 2040 – 2050	388 MW	150 MW	538 MW	289 MW	314 MW	13,414 MW
Total BESS Additions by 2050	**388 MW**	**400 MW**	**938 MW**	**564 MW**	**589 MW**	**17,939 MW**

Incremental Natural Gas Additions

	Low Load	No Load Growth	High Load	High Fuel	Regulated CO_2	Net Zero
Cumulative 2030	571 MW	571 MW	571 MW	571 MW	571 MW	0 MW
Additional 2030 – 2040	0 MW	0 MW	236 MW	0 MW	0 MW	0 MW
Additional 2040 – 2050	236 MW	0 MW	917 MW	471 MW	471 MW	0 MW
Total Natural Gas Additions by 2050	**807 MW**	**571 MW**	**1,724 MW**	**1,042 MW**	**1,042 MW**	**0 MW**

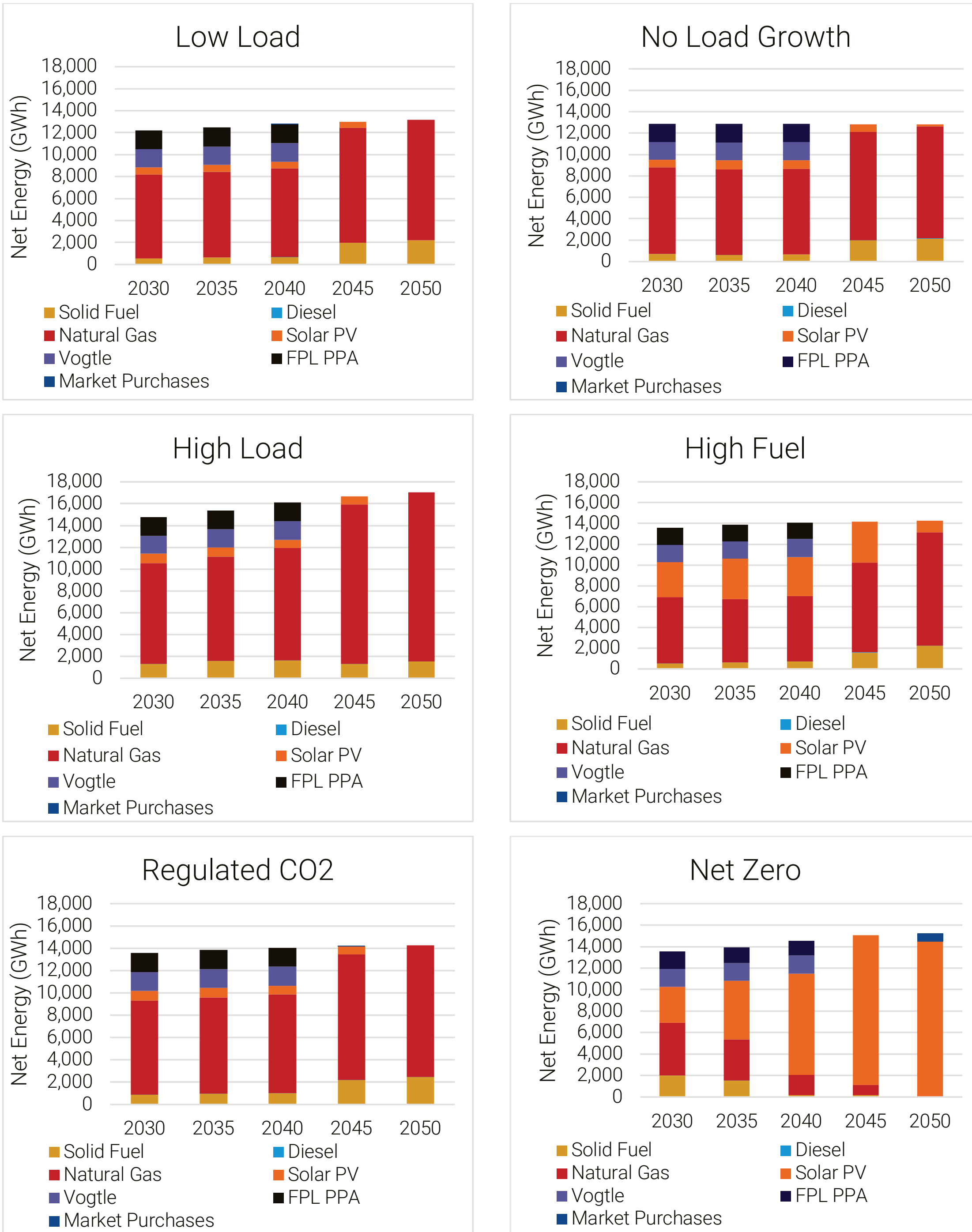
8.2.2. Energy Generation

Summaries of the amount of energy generated by resource/fuel type associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-6 and Figure 8-7, respectively.

These results indicate that, consistent with the magnitude of new resource additions by type (i.e., solar PV and natural gas) discussed in Subsection 8.2.1, forecast energy requirements are projected to be met primarily by a combination of solar and natural gas resources.

Figure 8-6: Projected Energy Generation for Each Scenario

Figure 8-7: Projected Energy Generation for Each Sensitivity



8.2.3. CO_2 Emissions

Summaries of the amount of CO_2 emissions from each generating unit associated with the optimal capacity expansion plan for each scenario and each sensitivity evaluated in this IRP are provided on Figure 8-8 and Figure 8-9, respectively.

These results indicate that, in general, for scenarios and sensitivities that do not include 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), emissions of CO_2 are projected to remain relatively consistent through the 2040 period. An increase in CO2 emissions after 2040 is shown for these scenarios and sensitivities as low and zero emissions PPAs, such as the Vogtle PPA and existing solar PPAs and new solar PPA added early in the IRP planning period, expire. As a point of reference, JEA's CO_2 emissions in the year 2005 were approximately 15,000,000 tons, and the significant decrease in the magnitude of CO_2 emissions shown on Figure 8-8 and Figure 8-9 as compared to 2005 CO_2 emissions illustrates the impact of JEA no longer utilizing various coal-fueled generating units (including Scherer Unit 4 and St. Johns River Power Park Units 1 and 2). Further, the magnitude of the reduction in CO_2 emissions is noteworthy when considering that JEA's number of customers has grown since 2005.

JEA is projected to serve increased customer energy requirements while simultaneously reducing CO_2 emissions by approximately 66 percent when looking at projected CO_2 emissions for 2030.

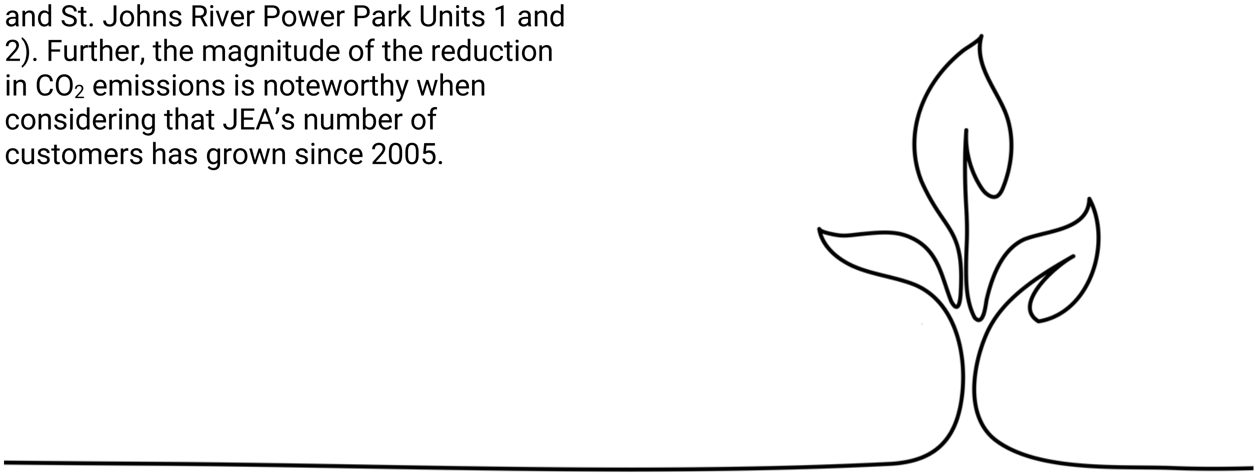


Figure 8-8: Forecast CO_2 Emissions for Each Scenario

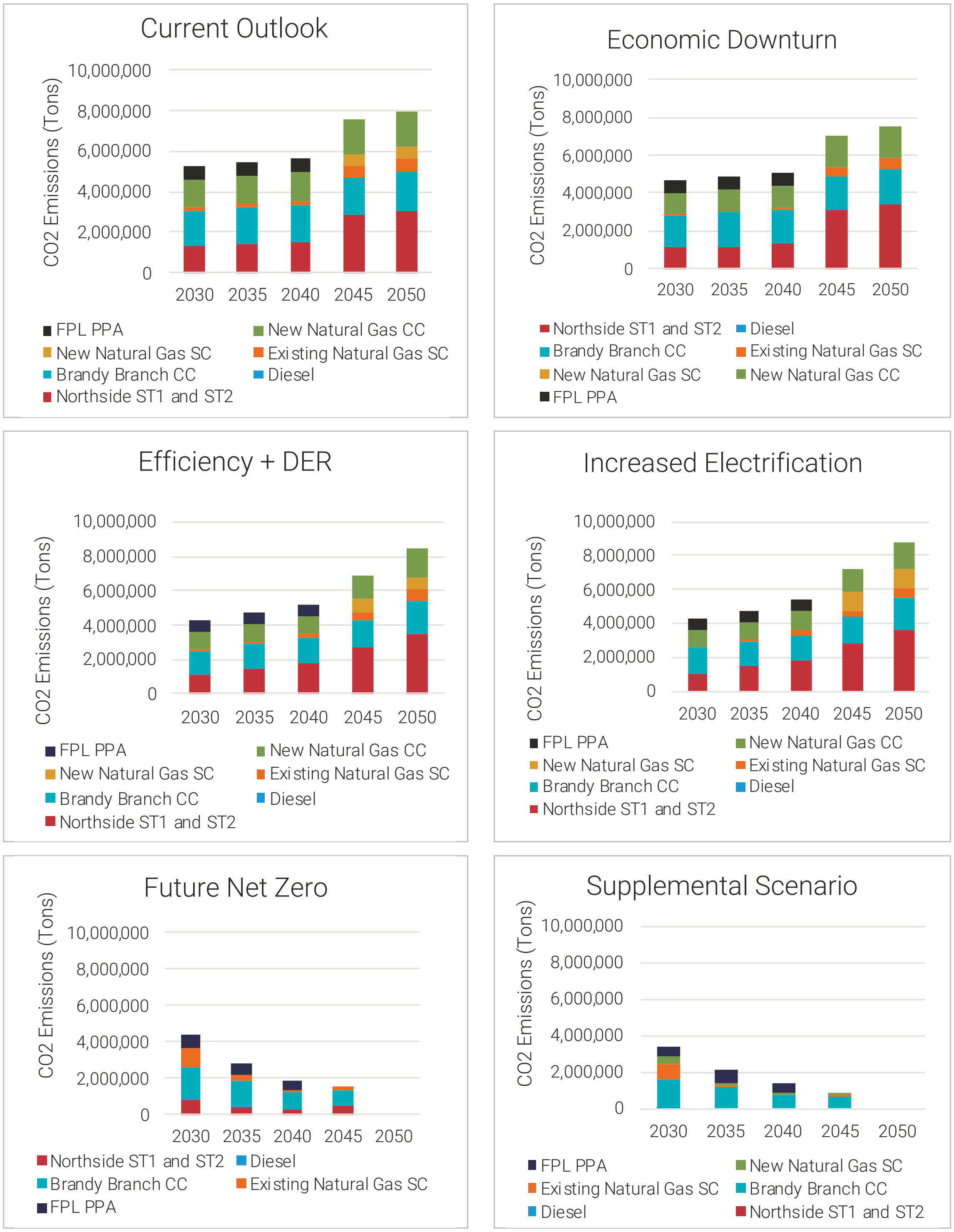


Figure 8-9: Forecast CO_2 Emissions for Each Sensitivity

8.2.4. Cumulative System Costs

Summaries of the cumulative system costs associated with the optimal capacity expansion plan for each scenario and sensitivity evaluated in this IRP are provided on Figure 8-10 and Figure 8-11, respectively. The cumulative system costs represent variable production costs as well as fixed O&M costs for existing generating resources and fixed O&M and capital costs for new generating resources, but do not include debt service costs for existing resources as such costs are costs that do not vary by capacity plan.

Importantly, comparison of cumulative system costs across scenarios or sensitivities may not provide for a meaningful comparison, given differences in variables reflected in the scenarios and sensitivities. However, comparison of the cumulative system costs does provide insight into JEA's costs to continue reliably serving its customers energy requirements for certain scenarios or sensitivities being evaluated. For example, the cumulative system cost by 2050 in the Current Outlook scenario was approximately $40 billion, while the cumulative system cost by 2050 for the Net Zero sensitivity (which reflects the same variables as evaluated in the Current Outlook except for a target of no CO_2 emissions by 2050, with a gradual decline in CO_2 emissions between 2030 to 2050) was approximately $60 billion, or approximately 50 percent higher. This differential in cumulative system costs is consistent with the differential between the Supplemental scenario and the Current Outlook scenario, which are largely similar but differ related to increased residential customer-sited renewables and removal of Northside Units 1 and 2 from service in the Supplemental scenario.

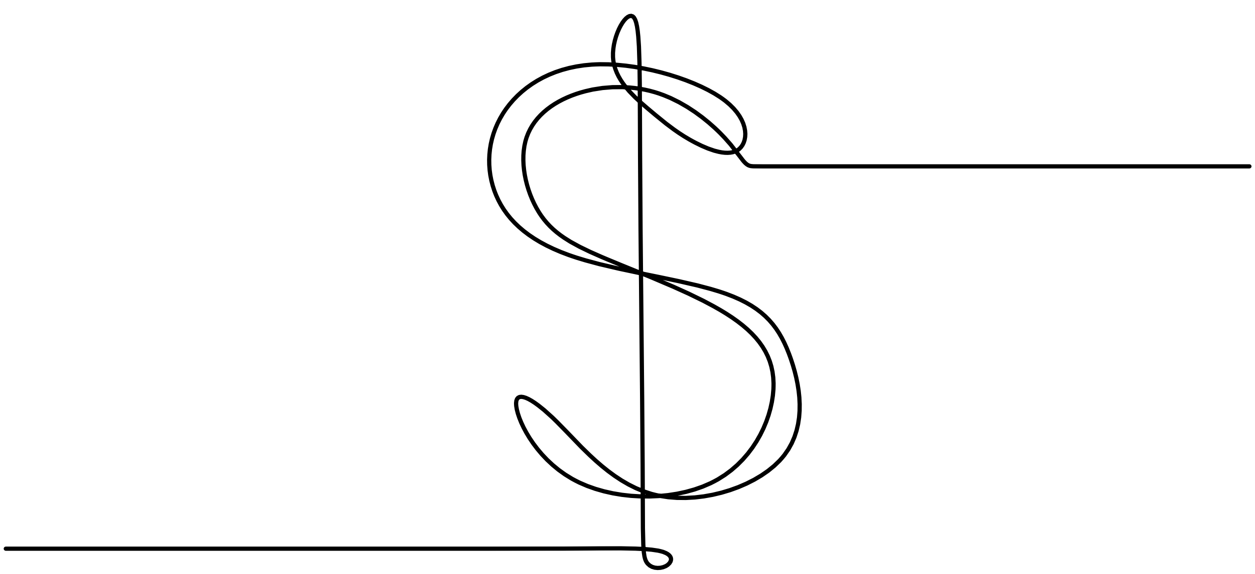


Figure 8-10: Forecast System Costs for Each Scenario

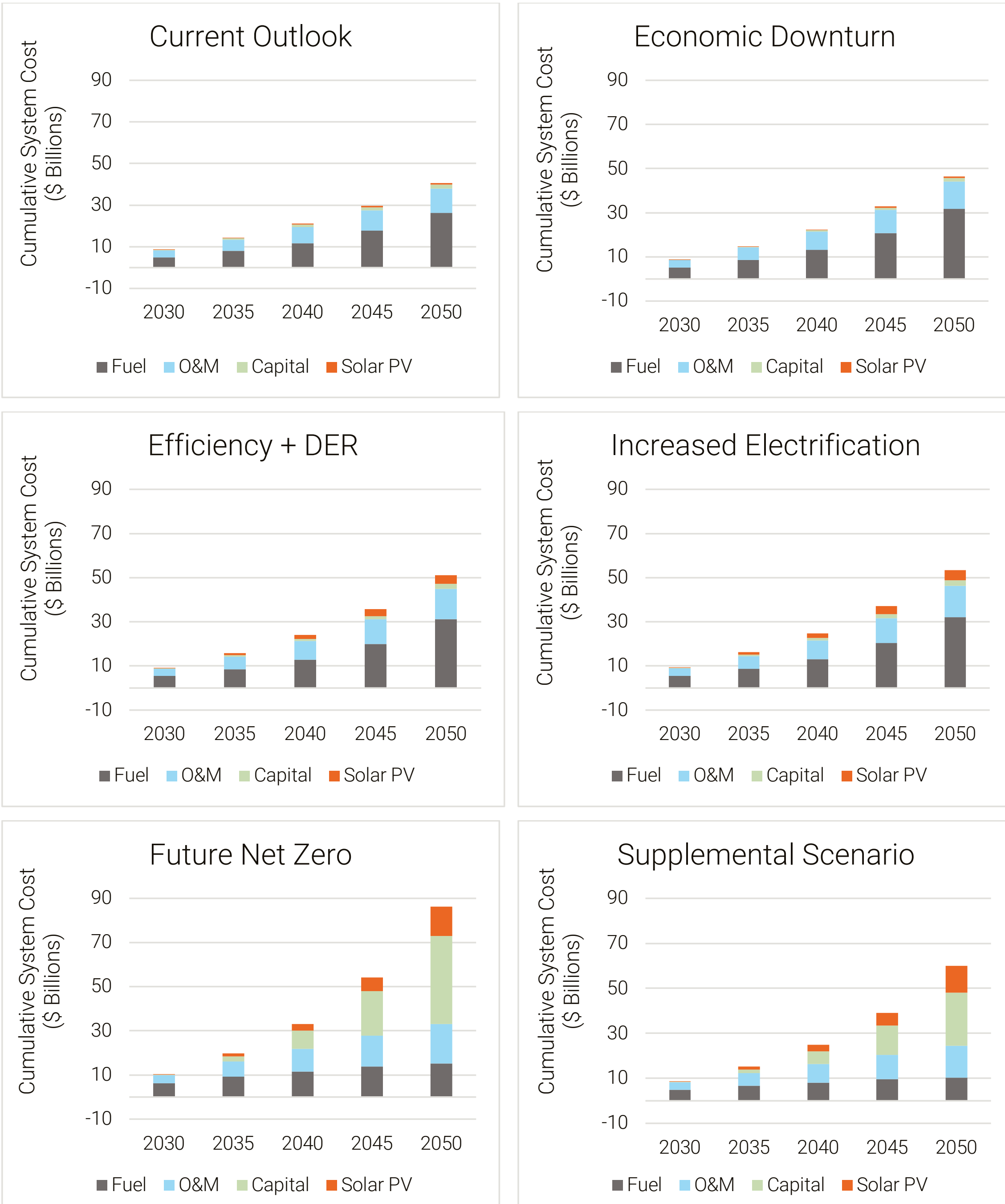
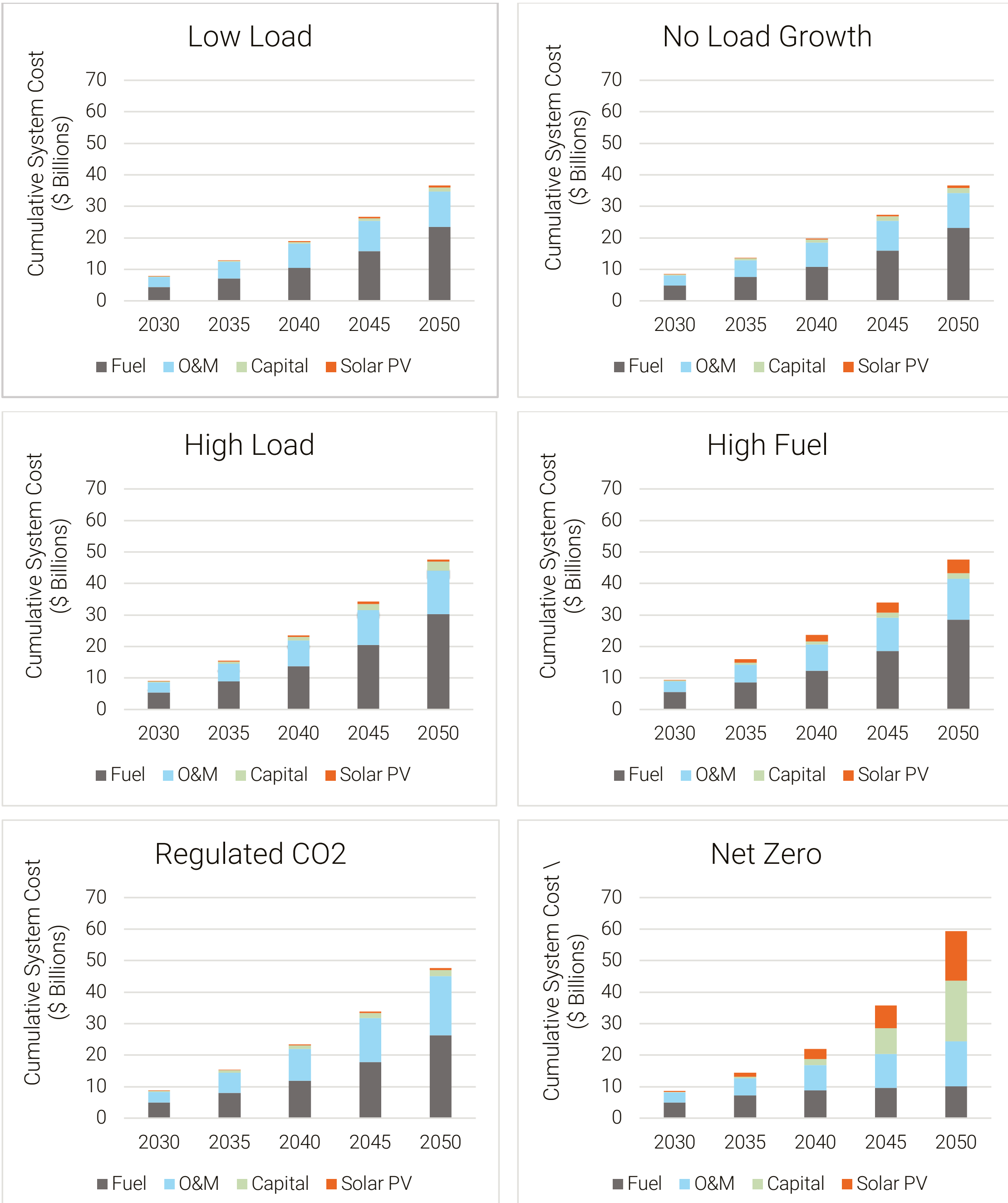


Figure 8-11: Forecast System Costs for Each Sensitivity



9

Conclusions

9. Conclusions

The modeling results show that under every scenario and sensitivity JEA will need to deploy several hundred MW of new solar PV, energy storage and gas-fired generating resource options over the next 30 years to serve growing customer load and compensate for retirement of Northside Unit 3 and the Vogtle PPAs while maintaining a 15 percent generating reserve margin to ensure continued reliable service.

These results will inform JEA as to the resource options it should implement, particularly those that should be implemented within the next 10 years.

The specific resource options identified by the modeling between 2025 and 2030 under each scenario and sensitivity are summarized in Table 9-1 and Table 9-2, respectively.

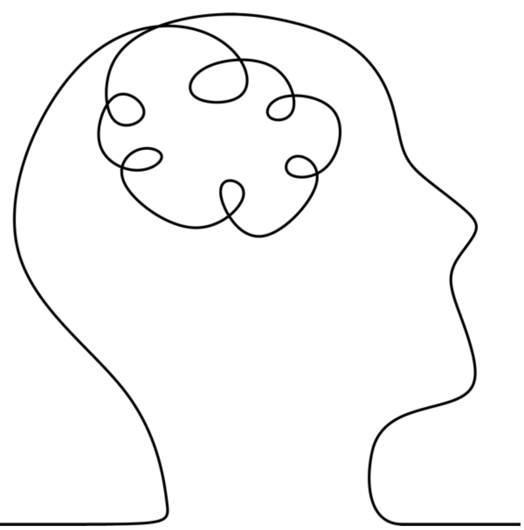


Table 9-1: Resources Identified for 2025-2030 by Scenario

	Scenario					
Year	**Current Outlook**	**Economic Downturn**	**Efficiency + DER**	**Increased Electrification**	**Future Net Zero**	**Supplemental**
2025	100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS		25 MW - 25 MW 1 hr BESS 37.5 MW - 37.5 MW 1 hr BESS 50 MW - 50 MW 1 hr BESS 75 MW - 75 MW 1 hr BESS	50 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS	262 MW - 37.5 MW 1 hr BESS 150 MW - 75 MW 4 hr BESS	225 MW - 75 MW 4 hr BESS
2026	150 MW Solar PV	150 MW Solar PV	300 MW Solar PV	300 MW Solar PV	300 MW Solar PV	300 MW Solar PV
2027						
2028				50 MW - 50 MW 4 hr BESS		
2029	571 MW 1x1 H Class Gas	150 MW Solar PV	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	95 MW Biomass 150 MW - 75 MW 4 hr BESS	346 MW 1X0 H Class Gas 115 MW 1X0 LMS 100 Gas
2030	150 MW Solar PV	571 MW 1x1 H Class Gas	975 MW Tier1 Solar PV	975 MW Tier1 Solar PV	975 MW Tier 1 Solar PV 262 MW - 37.5 MW 1 hr BESS	975 MW Tier 1 Solar PV 338 MW - 37.5 MW 1 hr BESS

Table 9-2: Resources Identified for 2025-2030 by Sensitivity

	Sensitivity					
Year	Low Load	No Growth	High Fuel	Regulated CO_2	NetZero	High Load
2025		100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr 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	300 MW - 37.5 MW 1 hr BESS 150 MW - 75 MW 4 hr BESS	150 MW - 37.5 MW 1 hr BESS 100 MW - 50 MW 4 hr BESS 150 MW - 75 MW 4 hr BESS
2026	75 MW Solar PV		300 MW Solar PV	150 MW Solar PV	225 MW Solar PV	300 MW Tier 1 Solar PV
2027					75 MW Solar PV	
2028						
2029	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas	571 MW 1x1 H Class Gas		571 MW 1x1 H Class Gas
2030	150 MW Solar PV	225 MW Solar PV	975 MW Tier1 Solar PV	150 MW Solar PV	975 MW Tier 1 Solar PV	

Results show a wide range of resource option types and sizes across the scenarios and sensitivities. Additional filtering was necessary to select a reasonable subset of types and sizes for implementation.

As discussed earlier, each scenario represents a possible future for JEA and each sensitivity represents a possible singular event that JEA could experience within the Current Outlook scenario. Because it is impossible to predict the future, it isn't reasonable for JEA to merely select results from one scenario or sensitivity to make a final determination about implementing near term resource options. The more reasonable outcome of an IRP is identifying resource options that appear most frequently across all the scenarios and sensitivities. In this way, JEA can be confident that the resource options it develops in the near term will become and remain valuable additions to the portfolio regardless of which future occurs.

The resource options that appear most frequently across the scenario and sensitivity results shown above are summarized below ("Near-Term Resources").

- 150 MW BESS (2x75 MW 4 hour)
- 300 MW Solar (4x75 MW Tier 0 Solar PV)
- 571 MW Gas (571 MW 1x1 H Class Gas)
- 975 MW Solar (13x75 MW Tier 1 Solar PV)

It is important to note that this list of Near Term Resources was a result of the IRP study only and provides guidance to JEA. It does not reflect further study and determination by JEA of the actual resources that will be implemented.

JEA may need to begin development of these Near-Term Resources as soon as practical. This is particularly true for the 571 MW 1x1 gas-fired resource, which includes a steam turbine component. Any new steam electrical generating facility that generates 75 MW or more requires certification under the Florida Power Plant Siting Act which would require, among other activities, 1) completion of a site certification process with the Florida Department of Environmental Protection, 2) completion of air quality permitting processes with state and local air quality regulatory agencies and 3) completion of a need determination process with the Florida Public Service Commission.[9] These processes must be completed prior to start of construction and typically take several years to complete. While the ultimate size of the gas-fired resource may change as details are finalized, the process described above are still required for such a combined cycle configuration.

Development of the Tier 1 solar resources should also begin soon given that transmission system upgrades will be required to allow delivery of energy from those resources to load. Transmission system upgrades, particularly new transmission lines and towers, will require successful completion of transmission planning, land acquisition and permitting processes. These processes must be completed prior to start of construction and typically take several years to complete.

The Near-Term Resources also include a significant amount of new BESS in the year 2025. This is because BESS appears in five of the six scenarios and five of the six sensitivities evaluated. It appears in the Future Net Zero and Supplemental scenarios and the High Load and Net Zero Sensitivities due to a potential capacity short fall. In the remainder of the scenarios and sensitivities, it appears due to the benefit of variable cost reduction. These determinations are supported by the fact that the BESS does not appear in the Economic Downturn scenario or Low Load sensitivity where both the loads and variable costs are lower. Furthermore, results from additional sensitivity analysis performed on the Current Outlook scenario showed that if PLEXOS was prevented from considering BESS until the early 2030s, total portfolio variable costs drop (a savings). The capital cost of these near-term BESS resources is relatively high and therefore further studies on the size and timing of this BESS resource are warranted to determine if their benefit becomes more significant.

End of Volume 1

[9] Solar PV facilities that generate 75 MW or more would also require certification under the Florida Power Plant Siting Act; as such, solar PV facilities are typically sized at under 75 MW. For purposes of this IRP, the 75 MW solar PV options serve as a proxy for what may ultimately be sized at just under 75 MW.