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VOLUME 4

SUPPLY-SIDE RESOURCE ANALYSIS

THE EMPIRE DISTRICT
ELECTRIC COMPANY D/B/A LIBERTY
(“LIBERTY-EMPIRE”)

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SUPPLY-SIDE RESOURCE ANALYSIS

Commission Rule 20 CSR 4240-22.040, Supply-Side Resource Analysis, provides in part as follows:

PURPOSE: This rule establishes minimum standards for the scope and level of detail required in supply-side resource analysis.

SECTION 1 EXISTING SUPPLY-SIDE RESOURCES

(1) The utility shall evaluate all existing supply-side resources and identify a variety of potential supply-side resource options which the utility can reasonably expect to use, develop, implement, or acquire, and, for purposes of integrated resource planning, all such supply-side resources shall be considered as potential supply-side resource options. These potential supply-side resource options include full or partial ownership of new plants using existing generation technologies; full or partial ownership of new plants using new generation technologies, including technologies expected to become commercially available within the twenty (20)-year planning horizon; renewable energy resources on the utility-side of the meter, including a wide variety of renewable generation technologies; technologies for distributed generation; life extension and refurbishment at existing generating plants; enhancement of the emission controls at existing or new generating plants; purchased power from bi-lateral transactions and from organized capacity and energy markets; generating plant efficiency improvements which reduce the utility's own use of energy; and upgrading of the transmission and distribution systems to reduce power and energy losses. The utility shall collect generic cost and performance information sufficient to fairly analyze and compare each of these potential supply-side resource options, including at least those attributes needed to assess capital cost, fixed and variable operation and maintenance costs, probable environmental costs, and operating characteristics.

This Section describes the existing supply-side generation resources included in the Empire District Electric Company d/b/a Liberty ("Liberty-Empire" or "the Company") system to meet Liberty-Empire's current customer energy and capacity needs. Section 1.1 provides a high-level overview of Liberty-Empire's existing generation resource fleet. Section 1.2 describes the history, operating characteristics, and emissions controls (if relevant) of each existing resource in more detail. Sections 1.3 and 1.4 provide an overview of planned or completed operating improvements and upgrades to existing plants.

Pursuant to 20 CSR 4240-22.040(1), Liberty-Empire also identified various potential supply-side resource options that could reasonably be used to meet future customer energy and capacity obligations. Following the discussion of Liberty-Empire's existing generation resource fleet in Section 1, the identification and analysis of these potential supply-side resource options is discussed in more detail in Section 2.

1.1 Overview of Existing and Committed Supply-Side Resources

Liberty-Empire's fleet of existing and committed supply-side resources includes both fully or jointly owned resources and resources for which Liberty-Empire has power purchase agreements ("PPA"). The existing owned resource fleet consists of a variety of fuel and ownership types, including partial ownership shares in two coal-fired plants, several wholly owned natural gas-fired combustion turbines ("CT"), a wholly owned natural gas-fired combined cycle ("CC") unit, a partial ownership share in a natural gas-fired combined cycle unit, a hydroelectric facility, and three wind facilities. Additionally, Liberty-Empire meets its customer needs with long-term PPAs for coal and wind units. Table 4-1 provides a summary of the existing generating facilities owned or contracted by Liberty-Empire. The unit ratings represent summer operating capacity ratings (unless otherwise specified) during the 2025 IRP analysis and reflect Liberty-Empire's ownership share of jointly owned units. Units are re-rated from time to time as routine capability tests are performed.

Table 4-1 – Liberty-Empire Existing Supply-Side Resources – Owned and Contracted

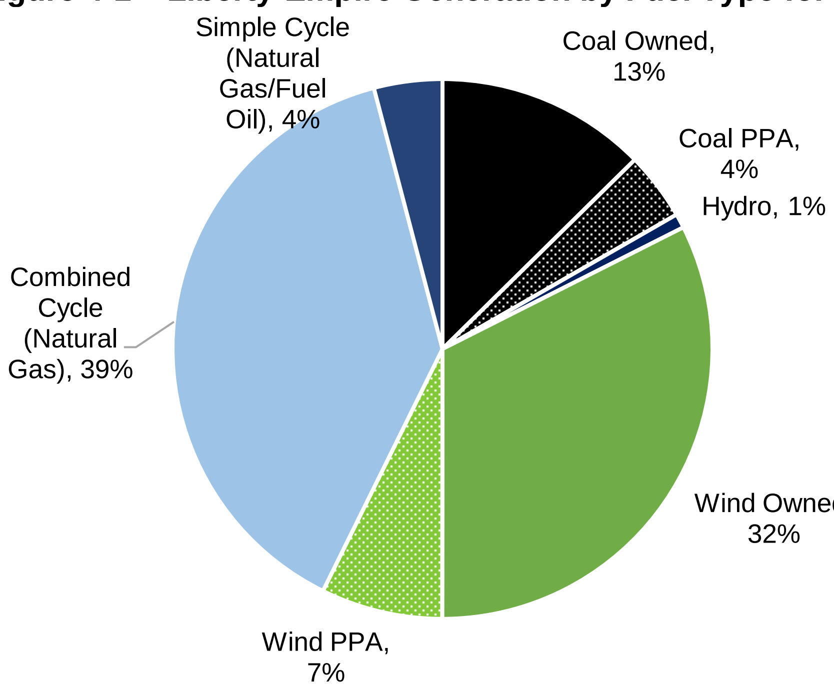
Owned Resources	Fuel Type	COD	State	% Owned	Summer Operating Capacity (MW)	Winter Operating Capacity (MW)
Iatan 1	Coal	1980	MO	12%	84	84
Iatan 2	Coal	2010	MO	12%	108	108
Plum Point (Owned)	Coal	2010	AR	7.52%	50	50
Riverton 10 CT	Natural Gas/Oil	1988	KS	100%	13	15
Riverton 11 CT	Natural Gas / Oil	1988	KS	100%	15	15
Riverton 12 CC	Natural Gas	2016	KS	100%	254	283
Riverton 13 CT	Natural Gas	2026	KS	100%	13	13
Riverton 14 CT	Natural Gas	2026	KS	100%	13	13
Empire Energy Center 1 CT	Natural Gas / Oil	1978	MO	100%	81	95
Empire Energy Center 2 CT	Natural Gas / Oil	1981	MO	100%	80	80
Empire Energy Center 3 CT	Natural Gas / Oil	2003	MO	100%	40	55
Empire Energy Center 4 CT	Natural Gas / Oil	2003	MO	100%	43	58
State Line CT	Natural Gas / Oil	1995	MO	100%	93	113
State Line CC	Natural Gas	2001	MO	60%	300	329
Ozark Beach	Hydro	1913	MO	100%	16	16
North Fork Ridge	Wind	2020	MO	100%	149	149
Kings Point	Wind	2021	MO	100%	149	149
Neosho Ridge	Wind	2021	KS	100%	301	301
Firm Solar Build	Solar	2028	MO	100%	175	175
Total Owned Capacity:					**1,802**	**1,900**
Long Term PPAs	**Fuel Type**		**State**		**Summer Operating Capacity (MW)**	**Winter Operating Capacity (MW)**
Plum Point	Coal	2010	AR		50	50
Elk River Wind Farm	Wind	2005	KS		150	150
Meridian Way Wind Farm	Wind	2008	KS		105	105
Total Contracted Capacity:					**305**	**305**

Capacity Sales	Fuel Type		State		Summer Operating Capacity (MW)	Winter Operating Capacity (MW)
MJMEUC Capacity Sale[1]	Capacity		n/a		-78	-78
Total Capacity Sales:					**25**	**78**

As of the beginning of the 2025 IRP analysis period, 14% of Liberty-Empire's total owned and contracted summer operating capacity is from coal-fired units, 44% from natural gas-fired units, and 42% from hydro and wind units.

A summary of Liberty-Empire's historical generation by fuel type for 2023 is shown in Figure 4-1 and summarized in Table 4-2. In 2023, 17% of Liberty-Empire's generation was supplied by coal, 43% by natural gas, and 41% by carbon-free sources, including wind and hydro.[2]

Figure 4-1 – Liberty-Empire Generation by Fuel Type for 2023



[1] The 25MW MJMEUC Capacity Sale PPA that begins in June 2025 is an amended and restated contract to the original 78 MW MJMEUC capacity sale that began in 2020. Due to summer/winter timing considerations, the PPA is shown as 78 MW in this table.

[2] Note that as of March 1, 2014, the Southwest Power Pool ("SPP") Integrated Marketplace allows Liberty-Empire to buy generation from and sell generation to participants throughout the SPP region on an hourly basis.

Table 4-2 – Liberty-Empire Generation by Fuel Type for 2023

Type	Generation in 2023 (MWh)	% of Liberty-Empire's total generation 2023
Coal Owned	821,553	13%
Coal PPA	264,940	4%
Total Coal	1,086,493	17%
Hydro	55,746	1%
Wind Owned	2,111,745	32%
Wind PPA	474,102	7%
Total Carbon-Free	2,641,593	41%
Combined Cycle (Natural Gas)	2,511,216	39%
Simple Cycle (Natural Gas/Fuel Oil)	266,407	4%
Total Natural Gas	2,777,623	43%
Total System MWh (Net System Output)	**4,783,011**	**100%**

1.1.1 Baseline Retirement and PPA Expiration Dates

Table 4-3 summarizes the "baseline" retirement and PPA expiration dates for the existing supply-side resources in Liberty-Empire's portfolio included in the 2024 IRP analysis. The retirement date represents the resource's age-based end of life for wholly or majority-owned resources owned by Liberty-Empire. For resources for which Liberty-Empire is a minority owner, the retirement date represents the planned retirement date indicated by the joint and majority owners. PPA expiration dates represent the assumed contract expiration date with no assumed extensions for IRP purposes.

Table 4-3 – Base Retirement and PPA Expiration Dates

Owned Unit Name	Commercial Online Year	Age of Facility As of 2025 (Years)	Baseline IRP Retirement Year
Iatan 1	1980	45	2039
Iatan 2	2010	15	n/a
Plum Point (Owned)	2010	15	n/a
Riverton 10 CT	1988[1]	54[1]	2026
Riverton 11 CT	1988[1]	54[1]	2026
Riverton 12 CC	2007 & 2016[2]	18 & 9	n/a
Riverton 13 CT	2026	n/a	n/a
Riverton 14 CT	2026	n/a	n/a
Empire Energy Center 1 CT	1978	47	2035
Empire Energy Center 2 CT	1981	44	2035
Empire Energy Center 3 CT	2003	22	n/a
Empire Energy Center 4 CT	2003	22	n/a
State Line CT	1995	30	n/a
State Line CC	1997 & 2001[3]	28 & 24	n/a
Ozark Beach	1913	112	n/a
North Fork Ridge	2020	5	n/a
Kings Point	2021	4	n/a
Neosho Ridge	2021	4	n/a
Firm Solar Build	2028	n/a	n/a
Long-Term Power Purchases and Sales	**PPA Start Year**	**PPA Term (Years)**	**Expected PPA Expiration Year**
Plum Point	2010	30	2040
Elk River Wind Farm	2005	20	2025
Meridian Way Wind Farm	2008	20	2028
MJMEUC Capacity Sale[4]	2020	7	2027

Notes:
1. Riverton 10 and 11 were installed at Liberty-Empire in 1988, but the equipment was manufactured in 1967.
2. Combustion turbine Riverton 12 was installed in 2007. The steam cycle addition (combined cycle conversion) was completed in 2016.
3. One of the gas turbines at State Line CC was installed in 1997. The other gas turbine and the steam turbine were installed in 2001.
4. 25 MW MJMEUC Capacity Sale PPA that begins in 2025 is an amended and restated contract to the original MJMEUC capacity sale that began in 2020.

1.1.2 Long-Term Emissions Considerations

Algonquin Power & Utilities Corp. has a goal of net zero by 2050 for scope one and scope two emissions in its business operations.[3] A significant portion of Liberty-Empire's generation comes from its two existing natural gas CC units, Riverton 12 and the State Line CC. In addition to "baseline" retirement assumptions, which assume that both CCs operate beyond 2050, Liberty-Empire also evaluated earlier retirement years for these units in this 2025 IRP to assess the economic feasibility and cost impact of achieving long-term net zero carbon emissions by 2050.[4] Although 2050 is outside the planning horizon of this twenty-year IRP, Volume 6 discusses the development of Liberty-Empire's net zero alternative plans.

1.2 Description of Power Plants Owned or Contracted by Liberty-Empire

This Section describes in more detail the history and key operating characteristics of each existing resource in Liberty-Empire's generation portfolio.

1.2.1 Iatan Generation Station

Liberty-Empire owns a 12% undivided minority interest in the approximately 700 MW, coal-fired Iatan Generation Station near Weston, Missouri, a 3% interest in the site, and a 12% interest in certain common facilities. Liberty-Empire is entitled to 12 % of the unit's available capacity and must pay for that percentage of the unit's operating costs. Iatan Generation Station consists of two units, Iatan Unit 1 ("Iatan 1") and Iatan Unit 2 ("Iatan 2"). For this IRP, Liberty-Empire's ownership share of Iatan 1's capacity is assumed to be 84 MW.

[3] Scope 1 emissions refer to direct greenhouse gas emissions from sources controlled or owned by Liberty-Empire. Scope 2 emissions refer to indirect greenhouse gas emissions associated with the purchase of electricity. Scope 3 emissions result from activities from assets not owned or controlled by the reporting organization. For Liberty-Empire, emissions associated with the owned portion of Plum Point and Iatan 1 and 2 are scope 3, while those from other portfolio resources are scope 1 and 2.

[4] To achieve net zero carbon emissions by *2050*, Liberty-Empire would likely need to retire Riverton 12 in 2045 and State Line CC in 2050 and replace them with carbon-free resources or retrofit these CCs to run entirely on a clean fuel like green hydrogen. While it is currently uncertain whether the existing CCs could feasibly operate on 100% hydrogen, Liberty-Empire assumed the technical capability would arise in the long term solely for IRP analysis and testing purposes. The costs associated with performing this hydrogen retrofit on the existing CCs are documented in Sections 2 and 4.

Iatan 1 is equipped with a Selective Catalytic Reduction ("SCR") system for the removal of NO_X, a wet scrubber for the removal of SO_2, a fabric filter baghouse for the removal of particulate matter ("PM"), and a powder-activated carbon system for the removal of mercury. These additions, undertaken to comply with Environmental Protection Agency ("EPA") regulations and to meet the requirements for an air permit for Iatan 1, were completed in 2009. Evergy Metro, the majority owner of the plant, has indicated that the unit is expected to retire in 2039.

Liberty-Empire also owns a 12% undivided interest in the Iatan 2 unit, which is assumed to be 108 MW for the purposes of this IRP. The air quality control systems ("AQCS") (SCR, scrubber, fabric filter) constructed with the relatively new Iatan 2 unit comply with recent and anticipated air quality regulations.

1.2.2 Plum Point (Owned and PPA)

The Plum Point Energy Station ("Plum Point") is a nominal 670 MW, sub-critical, coal-fired generating facility near Osceola, Arkansas. Liberty-Empire owns 7.52% (approximately 50 MW) of the project. In addition, Liberty-Empire has a 30-year PPA for an additional 50 MW of capacity that began on September 1, 2010, and expires on August 31, 2040. Plum Point has an SCR for NO_X removal, a dry scrubber for SO_2 control, combustion controls for volatile organic compounds ("VOC") mitigation and a fabric filter baghouse to remove PM.

1.2.3 Riverton 10, 11, 12, 13, and 14

Liberty-Empire's Riverton Generating Plant is located in Riverton, Kansas, and consists of two existing natural gas-fired CT units ("Riverton 10 and 11") and a natural gas-fired CC unit ("Riverton 12" or "Riverton CC").

Riverton 10 and 11 are powered by natural gas as a primary fuel but can use fuel oil as a backup fuel. **[redacted]

[redacted]** However, Riverton 10 and 11 rely on equipment manufactured in 1967, much earlier than installed at Liberty-Empire (1988). Given the age of the equipment, Liberty-Empire expects to retire both Riverton 10 and 11 in 2026.[6] Riverton 13 and 14 will directly replace the units at the site. These new units will be two Siemens SGT-400 13.5 MW industrial gas combustion turbines with dual-fuel **[redacted]** capability in compliance with NERC reliability standards, taking advantage of Riverton 10 and 11's existing interconnection rights at the site.

Riverton 12 is a natural gas-fired Siemens V84.3A2 CT with a Siemens steam turbine/generator with a summer rating of 254 MW. The combustion turbine was initially installed at the Riverton site in 2007. In 2016, the CT was converted into a CC with the addition of the steam turbine, heat recovery steam generator ("HRSG"), cooling tower, and balance of plant equipment.

1.2.4 State Line 1 and CC

Liberty-Empire's State Line Power Plant is located west of Joplin, Missouri, and consists of State Line 1 ("State Line 1"), a CT with a summer generating capacity of 93 MW, and a CC ("State Line CC" or "SLCC") with a summer generating capacity of approximately 500 MW (total plant not company share)[7]. All units at the State Line Power Plant burn natural gas as a primary fuel, with State Line Unit 1 able to burn fuel oil as a backup. Burning fuel oil requires water injection for emissions control. State Line 1 and SLCC have dry low NO_X burners and an SCR on each HRSG.

State Line CC is a Siemens natural gas-fired CC unit consisting of two combustion turbines (CTs 2-1 and 2-2) with an HRSG on the back of each CT. Steam from the HRSGs is fed into a single steam turbine (ST 2-3). The original CT for SLCC was installed in 1997

[5] **[redacted].**

[6] In the 2019 IRP, Liberty-Empire assumed an age-based retirement date of 2033 for both Riverton 10 and 11. However, the 2033 retirement date assumption from the 2019 IRP was based on the date Riverton 10 and 11 were installed at the Liberty-Empire system (1988). The primary equipment used at Riverton 10 and 11 is actually of 1960s vintage.

[7] Liberty-Empire owns a 60% share of approximately 300 MW, as described in the next paragraph.

as a simple cycle unit. The combined cycle additions (the additional CT, ST, and HRSGs) were built in 2001 in partnership with Evergy of Topeka, Kansas. Liberty-Empire owns a 60% share of the total SLCC (approximately 300 MW) and is the operator. The CC can operate in two modes:

1. 1 x 1 mode (one CT and the steam turbine) with a capacity of 150 MW (Liberty-Empire's share)
2. 2 x 1 mode (two CTs and the steam turbine) with a total summer capacity of about 300 MW (Liberty-Empire's share)

SLCC completed combustion turbine upgrade projects in 2021. Additional information on the SLCC upgrades can be found in Section 1.4 ("Existing Plant Upgrades").

1.2.5 Energy Center

Liberty-Empire has four CT peaking units at the Empire Energy Center facility in Jasper County, Missouri, near the town of Sarcoxie, with an aggregate summer operating capacity of approximately 240 MW. Empire Energy Center Units 1 and 2 ("Energy Center 1 and 2" or "EC 1 and 2") are simple cycle frame CTs and were installed in 1978 and 1981, respectively. Empire Energy Center Units 3 and 4 ("Energy Center 3 and 4" or "EC 3 and 4") are aeroderivative CTs installed in 2003. These peaking units operate primarily on natural gas and can burn fuel oil. All units undergo routine maintenance with regular inspections, and equipment is refurbished as needed. All of the CTs use water injection to control NO_X. Based on the age of the units, Liberty-Empire plans to retire Energy Center Units 1 and 2 by 2035.

1.2.6 Ozark Beach

Ozark Beach, Liberty-Empire's hydroelectric generating plant, is located on the White River at Forsyth, Missouri, and comprises four 4-MW units with a total generating capacity of 16 MW. These units have been updated periodically to continue contributing to Liberty-Empire's renewable portfolio. Liberty-Empire began the renewal process for the FERC license in 2016. Once relicensing is complete, the renewed license will not expire for 30 years. The hydroelectric plant backed up the White River and created Lake Taneycomo in southwestern Missouri.

1.2.7 Wind Facilities

On June 19, 2019, the Missouri Public Service Commission voted unanimously to grant Liberty-Empire certificates of convenience and necessity ("CCNs") to build and acquire three wind farms: North Fork Ridge, Kings Point, and Neosho Ridge. These projects are expected to provide significant customer savings over the long term. The savings are primarily based on wind production costs and the ability of all projects to take advantage of federal Production Tax Credits. The three wind farms will also provide sustained community benefits to the regional economy and address the potential tightening environmental regulations on existing thermal units. Additionally they will provide energy sales hedges especially during periods of high fuel costs, offsets the expenses of operating an aging generation fleet, and meet the customer demand for renewable energy.

1.2.7.1 North Fork Ridge and Kings Point

North Fork Ridge Wind Farm and Kings Point Wind Farm are wind farms with about 150 MW each and 69 turbines (for a total of about 300 MW for both). North Fork Ridge Wind Farm is located in Barton and Jasper counties in Missouri, and Kings Point Wind Farm is in Dade, Jasper, and Lawrence counties in Missouri.

Liberty-Empire partnered with Tenaska and Steelhead, Vestas' development arm in North America, to develop and construct both projects. In October 2019, Tenaska elected to terminate its participation in the projects. Liberty, a holding company that is an indirect parent to Liberty-Empire, agreed to purchase Tenaska's interests in the project and continue developing and constructing the projects with Steelhead.

Construction activities for North Fork Ridge Wind Farm and Kings Point Wind Farm began in December 2019 and continued through the first quarter of 2021. Kings Point Wind Farm experienced construction delays due to issues with turbine component deliveries caused by government measures in countries where components were manufactured in response to the COVID-19 public health emergency.

North Fork Ridge Wind Farm ultimately began commercial operations in December 2020, and Kings Point Wind Farm began commercial operations in April 2021. Both projects are qualified for and receive the full value of the Production Tax Credits available to the project.

1.2.7.2 Neosho Ridge

Neosho Ridge Wind Farm is a 300 MW wind farm with 139 turbines in Neosho County, Kansas. Liberty-Empire partnered with Apex Clean Energy and Steelhead to develop and construct the Neosho Ridge Wind Farm.

Engineering and construction work at the Neosho Ridge Wind Farm began in the fall of 2019. It included modifying public roads, building access roads and turbine foundations, installing underground electrical connection lines, foundation work for substations and operations buildings, and building gen-tie lines. Like Kings Point, Neosho Ridge also experienced construction delays due to issues with turbine component deliveries caused by government measures in response to the COVID-19 public health emergency in countries where components were manufactured. The project began commercial operations in May 2021 and qualifies for the full value of the Production Tax Credits available to the project.

1.2.8 Utility-Scale Solar Build

Empire is currently in discussions for contracting a utility-scale solar farm, consistent with the Company’s previous preferred plan. This IRP models a proxy for the project with an installed capacity of 175 MW and in-service date of late 2028. However, given the changing dynamics surrounding the SPP’s resource adequacy construct, evolving market dynamics, and the timing of this filing, it is not certain that this project will proceed, and an update will be provided during the next IRP Annual Update.

1.2.9 Wind PPAs

1.2.9.1 Elk River Wind PPA

On December 10, 2004, Liberty-Empire entered into a 20-year contract with PPM Energy to purchase all the energy generated at the Elk River Wind Farm in Butler County, Kansas. This wind farm began commercial operation on December 15, 2005. The facility consists of 100 1.5-MW turbines for a total generating capacity of 150 MW. Liberty-Empire has contracted to purchase all of the project's output. This contract will expire in mid-December 2025. Liberty-Empire can extend the contract term for up to five years after the end of the 20-year contract period.

1.2.9.2 Meridian Way Wind PPA

In June 2007, Liberty-Empire signed a contract with Horizon Wind Energy to buy wind energy from the Cloud County Wind Farm, LLC, which receives energy from the 105-MW Meridian Way Wind Farm in Cloud County, Kansas, near Concordia. The contract expires in December of 2028. The facility began commercial operation on December 15, 2008.

1.2.10 MJMEUC Capacity Sale

Liberty-Empire entered into a five-year power purchase agreement with the Missouri Joint Municipal Electric Utility Commission (“MJMEUC”) for a capacity and energy sale beginning June 1, 2020, and ending May 31, 2025. The capacity sale is based on a “slice of Liberty-Empire system” approach, with a total capacity sale of 78 MW during the agreement period. An amended and restated contract for a capacity sale of 25 MW will begin May 31, 2025, and run through June 1, 2027. The MJMEUC agreement also enables MJMEUC to receive payment from SPP for energy sold into the market from Liberty-Empire resources allocated to MJMEUC by this agreement. MJMEUC compensates Liberty-Empire for the capacity and for their allocated portion of the fuel costs, startup costs, an additional amount per unit of energy, and some transmission costs as described by the agreement.

1.3 Generating Plant Efficiency Improvements to Reduce Energy Use

Liberty-Empire continually evaluates generating resource efficiency improvement opportunities through which Liberty-Empire can reduce its overall auxiliary load at existing power plants and reduce its use of energy. Potential improvement projects for reducing auxiliary loads depend on the fuel and power plant type. A few examples of projects that may reduce the utility's use of energy at existing power plants are as follows:

- On-line condenser cleaning systems;
- Duct leakage reduction;
- Insulation improvements.

The coal-fired power plants within Liberty-Empire's power supply portfolio recently underwent plant upgrades or are relatively newer constructions. Newer coal plants, like Iatan 2 and Plum Point, are typically designed to reduce auxiliary load consumption to make the unit significantly more efficient. During recent upgrade projects, such as the environmental upgrades at Iatan 1, utilities typically take the opportunity to implement additional efficiency projects. Due to the age of the newly constructed units, the recent upgrades at Iatan 1, and the uncertain future of coal-fired generation in general, few plant efficiency projects remain at the coal facilities that have not already been implemented.

Liberty-Empire does not necessarily operate all of the units within its power supply portfolio and does not control the improvements implemented at those plants. The Company evaluates potential improvement projects for the plants that Liberty-Empire operates as part of its regular operations and maintenance program. A list of the plant improvement projects that Liberty-Empire has implemented over the years has been regularly provided to the Commission as part of the FAC filings.

Liberty-Empire will continue to explore cost-effective generating plant efficiency improvements that reduce the utility's energy use.

1.4 Existing Plant Upgrades

Liberty-Empire continually examines potential upgrades to existing plants. As described previously in this Section, recently completed upgrades at Liberty-Empire's existing plants include:

1. Riverton 12 (a CT) was converted to a CC unit in 2016. See Section 1.2.3 for more details.

2. New pollution control systems were installed at the Iatan 1 unit. A scrubber, SCR, fabric filter, and powder-activated carbon system were installed at Unit 1 in 2009. See Section 1.2.1 for more details.

3. Turbines at State Line CC were upgraded in 2021. These projects consisted of both combustion turbines being upgraded to the FD3 level which will add about 70 additional MW (42 MW Liberty-Empire's share) to the existing winter capacity of the unit, and 36 MW (22 MW Liberty-Empire's share) to the summer capacity after completing the necessary SPP studies. In addition, efficiency increases are expected via heat rate improvements. Liberty-Empire's normal, ongoing maintenance program at each of its plants addresses critical operational and mechanical issues to ensure the longevity of the units. See Section 1.2.4 for more details.

SECTION 2 ANALYSIS OF POTENTIAL SUPPLY-SIDE RESOURCE OPTIONS

(2) The utility shall describe and document its analysis of each potential supply-side resource option referred to in Section (1). The utility may conduct a preliminary screening analysis to determine a short list of preliminary supply-side candidate resource options, or it may consider all of the potential supply-side resource options to be preliminary supply-side candidate resource options pursuant to sub-section (2)(C). All costs shall be expressed in nominal dollars.

2.1 Overview of Supply-Side Resource Option Analysis

Pursuant to 20 CSR 4240-22.040(1) and 20 CSR 4240-22.040(2), Liberty-Empire considered a wide range of potential supply-side resource options for inclusion in its future portfolio resource mix, then narrowed the range down to a subset of feasible and commercially viable options to be evaluated in the fuller integrated portfolio analysis in conjunction with demand-side resources.

Liberty-Empire began with a broad list of all potential resource types that it could reasonably expect to use, develop, implement, or acquire, including plants utilizing existing generation technologies, new generation technologies, emerging technology types expected to become commercially viable within the 20-year IRP horizon, distributed resources, any available existing resource upgrades or life extensions, and purchased power from SPP. This initial list of all potential supply-side resource options is described and documented in Section 2.2.

Liberty-Empire then used a screening process to narrow the broader list of resource options to only those that were likely feasible to develop and operate in the Company's service territory. The process and results of the feasibility screening are described and documented in Section 2.3.

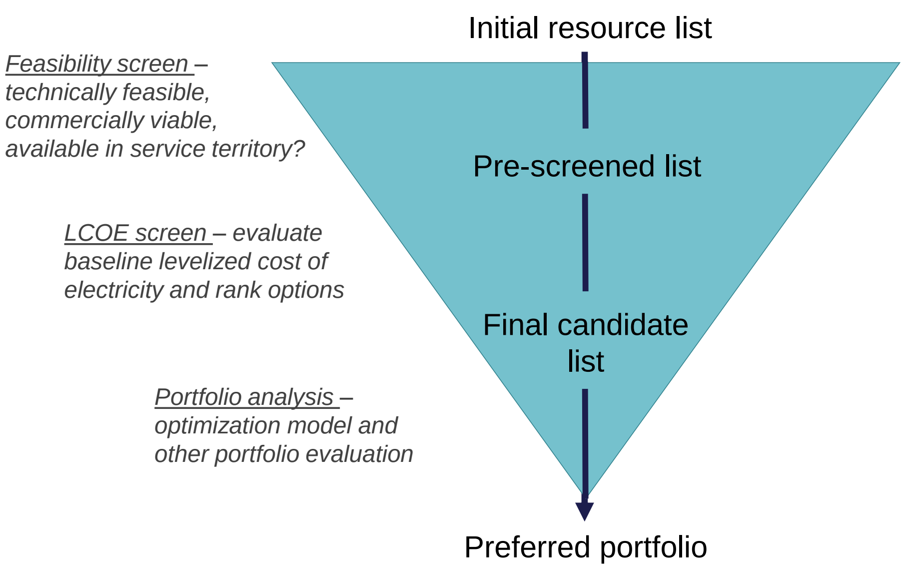
After the identification of the feasible supply-side resource options, planning-level cost and operating assumptions for each of the feasibility-screened resource options were collected and developed by Liberty-Empire's IRP consultant, Charles River Associates

("CRA"), with review and input by experts from a third-party engineering firm, Black and Veatch. Cost and operating estimates for the resource options were developed using a market scan approach for cost and operational parameters. Using the cost and operating parameters from this market scan analysis, Liberty-Empire evaluated the levelized cost of electricity ("LCOE") and levelized cost of capacity of the feasible resource options to determine whether any options were commercially unviable relative to other resources under consideration. The commercial viability screening is described in more detail in Section 2.3. The cost and performance assumptions developed for the resource options are described and documented in Section 4 of this volume.

Based on the results of the two rounds of screening analyses, as well as considerations for probable environmental costs of each potential supply-side resource option, Liberty-Empire ultimately identified a "shortlist" of potential supply-side resource options, representing the preliminary supply-side candidate resource options to be included in the integrated resource planning analysis described in Volume 6. The final list of supply-side candidate resource options is shown in Section 2.6.

An illustration of the supply-side option resource screening process is shown in Figure 4-2.

Figure 4-2 – Supply-Side Resource Screening Approach



2.2 All Potential Supply-Side Resource Options

Pursuant to 20 CSR 4240-22.040(1), Liberty-Empire began with a broad list of all potential resource types that it could reasonably expect to use, develop, implement, or acquire, including plants utilizing existing generation technologies, new generation technologies, emerging technology types expected to become commercially viable within the 20-year IRP horizon, distributed resources, any available existing resource upgrades or life extensions, and purchased power from SPP. The potential supply-side resource options selected for further investigation are as follows:

1. Carbon Capture and Storage ("CCS") – natural gas-fired combined cycle with CCS, retrofit CCS on existing combined cycle or supercritical coal
2. Natural gas-fired simple cycle – Aeroderivative CT and F-class frame CT
3. Natural gas-fired combined cycle – 1 x 1 H Class
4. Natural gas-fired reciprocating engines ("RICE")*
5. Traditional nuclear and small modular nuclear reactor
6. Wind – on-shore and off-shore, including re-powering of existing assets
7. Biomass – wood waste and poultry waste
8. Landfill gas
9. Solar photovoltaic ("PV")*
10. Energy storage – lithium-ion battery*, vanadium redox flow battery, molten salt, Energy Vault concrete block gravity storage, compressed air, iron air, CO_2 storage
11. Combined heat and power ("CHP")*
12. Hydrogen – retrofit on existing gas-fired combined cycle units and new simple cycle combustion turbine
13. Supercritical carbon dioxide power cycle plant

*Denotes a resource option evaluated as both a distributed and utility-scale energy resource.

2.3 Feasibility Screening

A Feasibility screening was conducted to pre-screen resources based on various criteria, including screening criteria including cost, technical feasibility, commercial viability, and deliverability. The size and location of Liberty-Empire were considered to assess the suitability of each resource. This is summarized in Table 4-4.

Based on Liberty-Empire's size and location, the initial feasibility screen eliminated the following supply-side resource options from consideration:

Table 4-4 – Resources Screened Out During Feasibility Screen and Reason for Elimination

Resource	Reason for Elimination
Offshore wind	Absence of the resource type in the region
Re-powering of existing wind assets	Feedback from project owners currently contracted with Liberty-Empire indicates that they are not considering re-powering opportunities at this time
CHP Options	Given the uncertainty regarding feasible sites within Liberty-Empire's service territory and the lack of potential partners that have shown interest in pursuing CHP relationships with Liberty-Empire
Traditional nuclear	Given the large size of the option (~1,000 MW) and the inability to assume with confidence that Liberty-Empire would have access to a partial ownership interest in a new development in any proximity to its service territory
Biomass and landfill gas	Limited access to a reliable source of fuel near the Liberty-Empire service territory
Supercritical carbon dioxide power cycle plant	The technology is nascent, with only a single pilot project currently operational. It remains costly and is unlikely to be available for utility deployment in the near to medium term.
Carbon Capture and Storage	Engineering complexity of capture and transportation, lack of natural geology for storage, and scarcity of operating examples to draw upon.
Compressed Air	Engineering complexity of development and operation and lack of natural geology
Molten Salt Energy Storage	Scarcity of operating examples of molten salt energy storage to draw upon
Iron Air Storage	Early stages of commercial deployment make it hard to gauge scalability and economic viability. Round trip efficiency is lower than Li-Ion, though the longer duration can offset that
CO_2 Storage	Deployment remains mostly at the demonstration phase—no large-scale deployment makes it challenging to model from a cost and operations perspective

2.4 Cost Ranking Screening

(A) Cost rankings of each potential supply-side resource option shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the potential supply-side resource option using the utility discount rate.

The second supply-side resource option screening involved calculating the LCOE, defined as the net present value of the unit cost of electricity over the lifetime of the generating resource of the various supply-side resource candidates, and ranking them to determine whether any options were commercially unviable relative to other resources under consideration. Pursuant to 20 CSR 4240-22.040(2)(A), the LCOE was based on the assumed variable costs of generation plus the installed capital costs and fixed operations and maintenance ("O&M") costs for the potential resource options, levelized and discounted over the lifetime of the asset using the utility's discount rate. The levelized cost of capacity associated with only capital and fixed costs was also applied as a second measure of economic viability.

The remainder of this Section summarizes the results of the LCOE and levelized cost of capacity analyses. The cost and operating assumptions used to calculate these are summarized at a high level and described and documented in more detail in Section 4 of this volume.

2.4.1 Summary of Cost and Operating Parameter Assumptions for LCOE Analysis

After identifying the feasible supply-side resource options, planning-level cost and operating assumptions for each of the remaining resource options were collected and developed by CRA with review and input by experts from a third-party engineering firm, Black and Veatch. Cost and operating estimates for the resource options were developed using a market scan approach for cost and operational parameters. The market scan approach involved in-depth research into recent cost data points from a variety of sources, including public reports, other utility IRP filings and Requests for Proposals, proprietary subscription-based data sources, and Liberty-Empire's and Black and Veatch's internal view based on actual and recent project estimates. The results of the market research findings were used to develop current cost estimates for the technologies and projections for cost changes over time. A summary of the costs and operating parameters for each potential feasibility-screened supply-side resource option was analyzed in the LCOE screening.

The estimates reflect all-in costs for each resource option, including engineering, procurement, construction ("EPC"), land, base interconnects, ownership, and contingency costs. Cost estimates reflect the 2025 IRP Base Case assumptions for all resources. However, "Low" and "High" Case assumptions were also developed with Black and Veatch input and incorporated into the 2025 IRP risk analysis. The average annual expected capacity factors for non-dispatchable renewable resources are based on expectations for renewable availability in the region. The capacity factors for dispatchable resources are based on initial, screening-level dispatch simulations of the SPP market using the 2025 IRP Base Case market and fuel price inputs.

Table 4-5 – Costs and Analysis Descriptors of Potential Supply-Side Resource Options

Dollars in 2023$	**Gas CC**	**CT - Aero**	**CT - Frame**	**RICE**	**Dist. Rice**
Size (MW)	627	54	240	50	2
2024 Full Load Net Heat Rate (Btu/kWh)	6,399	9,224	9,768	8,298	9,403
2024 Installed Capital Cost ($/kW)	1,134	1,800	948	1,900	2,850
2030 Installed Capital Cost ($/kW)	1,085	1,713	902	1,808	2,713
2035 Installed Capital Cost ($/kW)	1,044	1,641	864	1,732	2,598
2024 Fixed O&M ($/kW-year)	17.80	21.00	11.21	15.00	26.00
2024 Firm Gas Delivery ($/kW-year)	27.05	38.44	41.73	34.95	38.96
2024 Ongoing Capex ($/kW-year)	3.86	4.66	1.24	4.66	4.66
2024 Variable O&M ($/MWh)	2.41	15.00	5.51	6.86	16.00
2024 Avg. Expected Capacity Factor (%)	67.0%	5.0%	2.0%	5.1%	5.1%

Dollars in 2023$	**Utility Scale Solar**	**Onshore Wind**	**Dist. Solar PV**
Size (MW)	50	100	5
2024 Full Load Net Heat Rate (Btu/kWh)	N/A	N/A	N/A
2024 Installed Capital Cost ($/kW)	1,900	1,884	3,225
2030 Installed Capital Cost, ($/kW)	1,438	1,623	2,441
2035 Installed Capital Cost, ($/kW)	1,053	1,517	1,788
2024 Fixed O&M ($/kW-year)	19.30	33.00	18.26
2024 Ongoing Capex ($/kW-year)	0.00	20.82	0.00
2024 Variable O&M ($/MWh)	N/A	N/A	N/A
2024 Avg. Expected Capacity Factor (%)[8]	21.0%	40.0%	15.0%

Dollars in 2023$	**H_2 CC Retrofit[9]**	**Hydrogen CT[10]**	**Small Modular Reactor**
Size (MW)	627	54	300
2035 Full Load Net Heat Rate (Btu/kWh)	6,399	9,224	10,421
2035 Capital Cost ($/kW)	91	1,684	6,923
2035 Fixed O&M ($/kW-yr)	16.35	20.68	132
2035 Ongoing Capex ($/kW-yr)	3.86	3.86	3.28
2035 Variable O&M ($/MWh)	2.80	19.50	3.35
2035 Avg. Expected Capacity Factor (%)	51.0%	51.0%	90.0%

2.4.2 LCOE Analysis

Using the cost and operating parameters from the market scan analysis, Liberty-Empire evaluated the levelized cost of electricity and levelized cost of capacity of the feasible resource options to determine whether any options were commercially unviable relative to other resources under consideration. When evaluating the LCOE, Liberty-Empire accounted for all installed capital, interconnection, FOM, firm gas delivery, ongoing capex, VOM, fuel, and emission costs for all resource options. For each dispatchable resource option, capacity factor estimates were developed through screening-level dispatch analysis of the SPP market. For renewables, nuclear, hydrogen-fueled, and storage resources, Liberty-Empire accounted for potential tax benefits associated with Liberty-

[8] Paired solar + storage system capacity factor represents generation calculated as a proportion of total system capacity, including the storage component.

[9] Hydrogen capacity factor is not based on economic dispatch, and instead represents estimate of dispatch level required to provide sufficient clean energy to replace CC output and provide sufficient output for peak service for CT for net zero portfolios in combination with spare capacity for load following. Assumes 100% green hydrogen fuel.

[10] Ibid.

Empire's assumptions for federal tax credits and accelerated MACRS tax depreciation rules. The Inflation Reduction Act ("IRA"), signed into law in August 2022, includes several provisions to expand clean energy generation across the U.S. power sector. The IRA expands and extends several key federal tax credits for various electricity sector technologies and introduces new tax credits for certain emerging technologies.

Most notably, the IRA extended the investment tax credit ("ITC"). It expanded its applicability to storage, extended the production tax credit ("PTC") by expanding its applicability to solar, and introduced new or expanded tax credits for clean hydrogen production and technology-neutral clean energy. Assuming prevailing wage and apprenticeship requirements are met, the PTC provides a tax credit of $30/MWh in 2024$ (paid over the first 10 years of operation) that grows with inflation, while the ITC offers a tax credit worth 30% of the capital investment in a qualifying project. The clean hydrogen production tax credit (45V) provides $3 per kg of clean hydrogen produced for the first 10 years of operation. Additionally, the IRA offers several bonus credits if a project is located in an "energy community" or uses domestic content. For the purposes of the LCOE analysis, CRA assumed no bonus credits.

Table 4-6 – Tax Credit Schedule [11]

In Service Year	Clean Energy PTC	Clean Energy ITC	Hydrogen 45V	Zero Emission Nuclear PTC
	$0.30/kWh		$/kg	$0.30/kWh
2024	100%	30%	$3.00	100%
2025	100%	30%	$3.00	100%
2026	100%	30%	$3,00	100%
2027	100%	30%	$3.00	100%
2028	100%	30%	$3.00	100%
2029	100%	30%	$3.00	100%
2030	100%	30%	$3.00	100%
2031	100%	30%	$3.00	100%
2032	100%	30%	$3.00	100%
2033	100%	30%		100%
2034	100%	30%		100%
2035	100%	30%		100%
2036	75%	22.5%		75%
2037	50%	15%		50%
2038+	0%	0%		0%

In addition to federal tax credits, renewable resources can also take advantage of accelerated depreciation for tax purposes. Nuclear and fossil fuel-fired resources can generally be depreciated for tax purposes on 20 or 15-year schedules, while renewables and storage resources can take advantage of 7 or 5-year schedules. Tables 4-6 summarize these tax depreciation schedules and the book-life depreciation schedules for all resource options.

[11] Dollar amounts are real 2023. Represents the incentives assumed to be available in the year a project enters into service. Reflects the potential safe harboring of investment at an earlier time.

Table 4-7 – Depreciation and Tax Life Assumptions

Technology	Tax Life	Book Life
Gas CC	20	30
Gas CT - Frame	15	30
RICE	15	30
Distributed RICE	15	30
Gas CT - Aero	15	30
Solar PV	5	30
Onshore Wind	5	30
Distributed Solar	5	30
4-hr Li-Ion	7	30*
8-hr Li-Ion	7	30*
10-hr Li-Ion	7	30*
Distributed Storage	7	30
Flow Battery 8-hr	7	30
Gravity Storage	7	30
Small Modular Reactor	15	40
Hydrogen CT	20	30
Hydrogen on Existing CC	15	30

*Note: Lithium-ion battery life assumes one complete refurbishment/replacement of cells. The augmentation costs associated with this are included in ongoing capex assumptions.

Expectations for the cost of fuel and emissions over time significantly influence the LCOE. Probable environmental costs are summarized in Section 2.5.4. The projected fuel costs over time are summarized in Table 4-8. CRA internally represents natural gas prices as the 2025 IRP Base Case. The forecast for green hydrogen is based on SPP power and gas prices.

Table 4-8 – Delivered Fuel Projections used in LCOE Analysis for Select Years (2023$/MMBtu)
****Confidential in its Entirety****

[redacted]

In addition to the LCOE, each resource type was evaluated based on its levelized capacity cost. The levelized cost of capacity calculation considers only fixed costs and is required for the resource to be available to operate during peak demand. These costs include capital, FOM, ongoing capex, and firm gas delivery, levelized over the lifetime of the generating resource. The unit capacity is de-rated to account for forced outages, and the most recent guidance on proposed SPP accreditation represents the amount of the nameplate capacity that is “firm” or available to operate during system peak hours occulting in summer months.

Figure 4-3 and Figure 4-4 summarize the results of the levelized cost analysis for select years, 2025 and 2035, in dollars per MWh for LCOE (on the y-axis) and dollars per kW-year summer accredited capacity (ACAP) for the levelized cost of capacity (on the x-axis), all in nominal terms. Each graphic represents the projected cost for a resource that would enter into service in the indicated year. A resource in the lower left quadrant of the graphic has both a low levelized cost of electricity and low levelized cost of capacity relative to other resources; meanwhile, a resource in the upper right quadrant has both a high levelized cost of electricity and a high levelized cost of capacity relative to other resources. For graphical purposes, the supply-side resources are categorized into three major groups: natural gas-fired (blue), renewable (green), and clean baseload resources (red). Renewable resources include wind, solar, and hybrid systems paired with storage. Clean baseload resources offer carbon-free generation with dispatch control or non-intermittent output, namely hydrogen-fired resources and nuclear SMR. The clean baseload resources were considered only for the longer-term net zero portfolios, described in more detail in Volume 6 of this IRP.

Due to their lower expected capacity factors (approximately 2-5% under Liberty-Empire’s Base Case market environment), the LCOE values of gas peaking options (simple cycle CT and RICE) tend to be higher than those of a combined cycle since fixed costs are spread across a lower number of megawatt hours. Although RICE options have higher capital costs than other peaking resource types, their lower heat rates and higher capacity factors result in an LCOE between aeroderivative and frame CT. Frame CT offers the lowest levelized cost of capacity of all gas options, owing primarily to its relatively low capital cost.

When tax incentives are incorporated, wind and solar resources are the lowest LCOE options in the initial years of the planning period. Over time, the expected costs of wind and solar increase due to tax credit phase-outs but remain substantially lower than the other resource options as their capital costs are expected to decline in real dollar terms, reflecting expectations for technological advancement and efficiency improvements relative to other technologies.

Solar cost projections are like wind costs over time and have the potential to decline in real dollar terms in a high technological advancement scenario. Furthermore, solar resources may offer more capacity value to Liberty-Empire than wind resources in the summer months, given their greater availability during summer days when the SPP system realizes its system peak.[12]

In 2035 and beyond, the commercial availability of hydrogen-fired gas CCs and nuclear SMR will provide an opportunity to supply clean energy with stable output. SMR's low fuel cost and high capacity factor allow for a lower LCOE than hydrogen options. The lower capital cost of hydrogen relative to SMR makes it a comparatively more economical source of capacity. Still, due to the high cost of hydrogen fuel, it is a higher-cost energy source.

[12] Conversely, wind resources offer more capacity value than solar resources in the winter months. Although system peak occurs during summer, Empire peak occurs during winter months where reserve margin requirement is also expected to be higher than that of summer, as discussed in Volume 6.

Figure 4-3 – LCOE and Levelized Cost of Capacity Projections (2025)

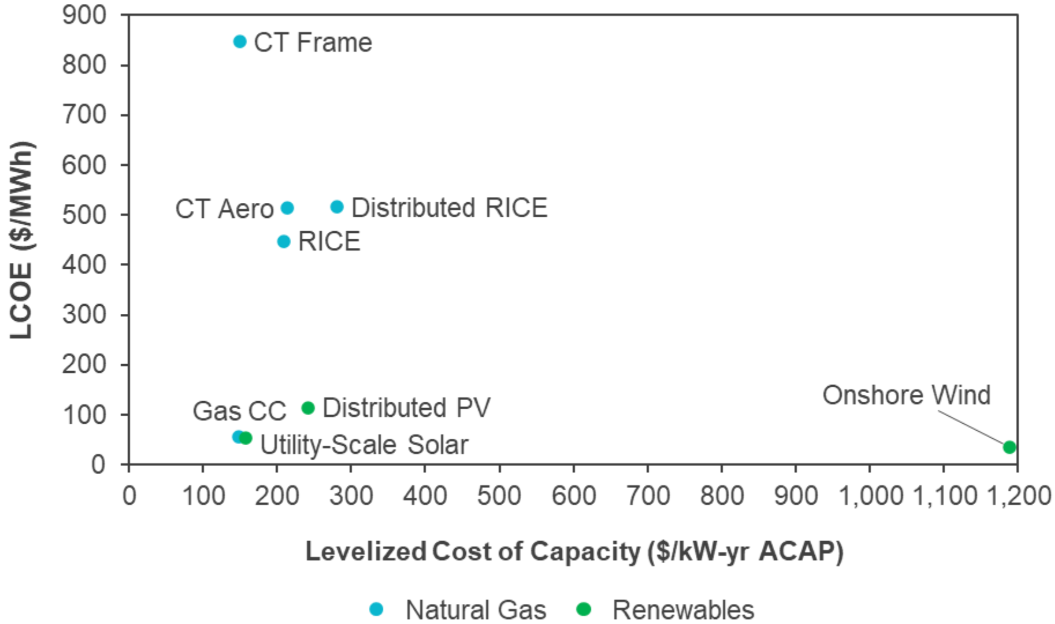
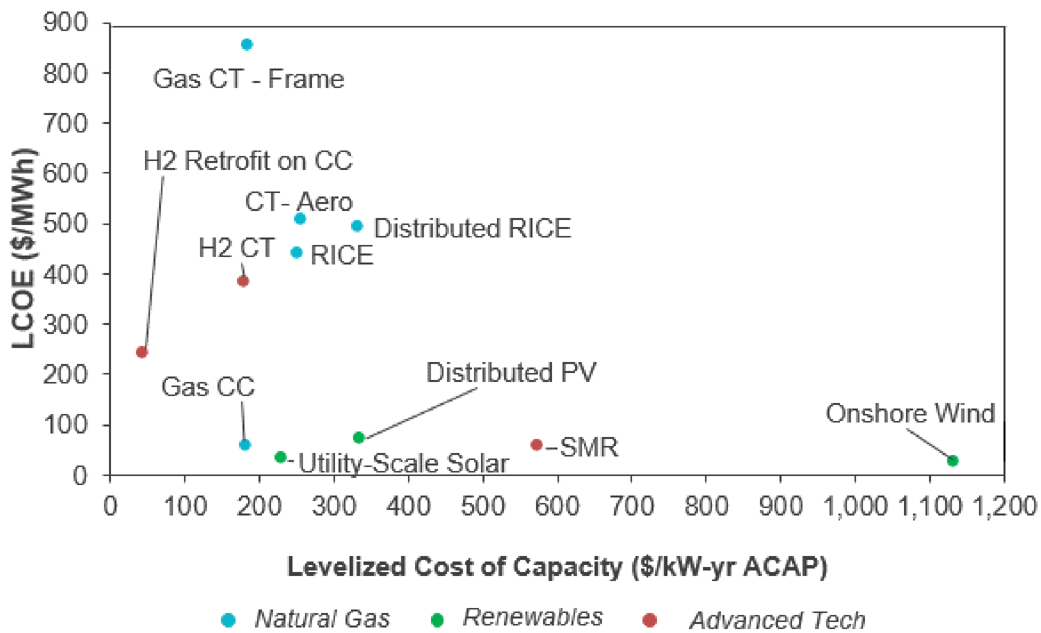


Figure 4-4 – LCOE and Levelized Cost of Capacity Projections (2035)



Overall, the supply-side candidate resource options show a wide range of costs. Other than fixed-tilt solar PV, Liberty-Empire determined that all generation technology types should advance to the next analysis phase due to a wide range of economic and performance benefits for the Liberty-Empire system. These benefits can be summarized as follows:

- Energy – Wind, solar, CCGT gas, and SMR offer low cost of levelized energy.
- Capacity – Hydrogen Retrofits and Hydrogen CTs, along with gas options including CCGT, CT have the lowest LCOC.
- Clean baseload/dispatchable – For net zero evaluation, hydrogen, SMR, and advanced storage technologies offer various energy and capacity value levels.
- Locational – Distributed options, including solar, RICE, and storage, are at a cost premium to their utility-scale counterparts; however, they may provide benefits associated with avoided distribution-level expenditures.

2.4.3 Storage Resource Screening

In addition to generation resources, Liberty-Empire believes that with observed rapid cost reductions and growing availability of commercially viable options, storage is an important asset class to be considered as part of the 2025 IRP. Unlike typical generating resources, storage resources do not provide net energy to the grid but shift energy during the day or even across a week to peak or high-priced hours. Because storage resources do not produce net generation, they cannot be appropriately evaluated in the traditional LCOE framework. Thus, Liberty-Empire assessed and screened storage options based on round-trip efficiency, charging, discharging time, and depth of discharge. These planning-level estimates were reviewed by Black and Veatch and are summarized in Table 4-9.

Table 4-9 – Preliminary Storage Parameters

Parameter	Lithium-Ion 4-hr	Lithium-Ion 8-hr	Flow	Gravity
Size (MW)	50	50	30	30
Assumed First Year of Availability	2027	2027	2035	2035
2025 Installed capital cost (2023$/kW-yr)	1,437	2,622	n/a	n/a
2030 Installed capital cost (2023$/kW-yr)	1,205	2,145	n/a	n/a
2035 Installed capital cost (2023$/kW-yr)	1,112	1,967	2,348	6,500
2040 Installed capital cost (2023$/kW-yr)	1,019	1,789	2,017	6,500
FOM (2023$/kW-yr)	26.06	45.00	16.11	65.00
Ongoing capex (2023$/kW-yr)	41.43	68.30	-	-
Round trip efficiency (%)	90%	90%	70%	80%
Storage duration (Hours)	4	8	8	8

Based on these operating parameters, Liberty-Empire analyzed the levelized costs of the three potential storage resources over a long-term planning period. The levelized cost of each technology on an installed capacity (ICAP) basis is summarized in Figure 4-5. Flow battery and gravity storage are shown beginning in 2035, reflecting their later assumed commercial availability given the limited current supply chain and few operating examples at scale. The estimated ELCC capacity credit that each technology is expected to qualify for under 2025 IRP Base Case market assumptions is shown in Table 4-10. The resulting levelized cost of capacity on a summer ACAP basis is shown in Figure 4-6.

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Figure 4-5 – Levelized Cost of Storage Options (ICAP)

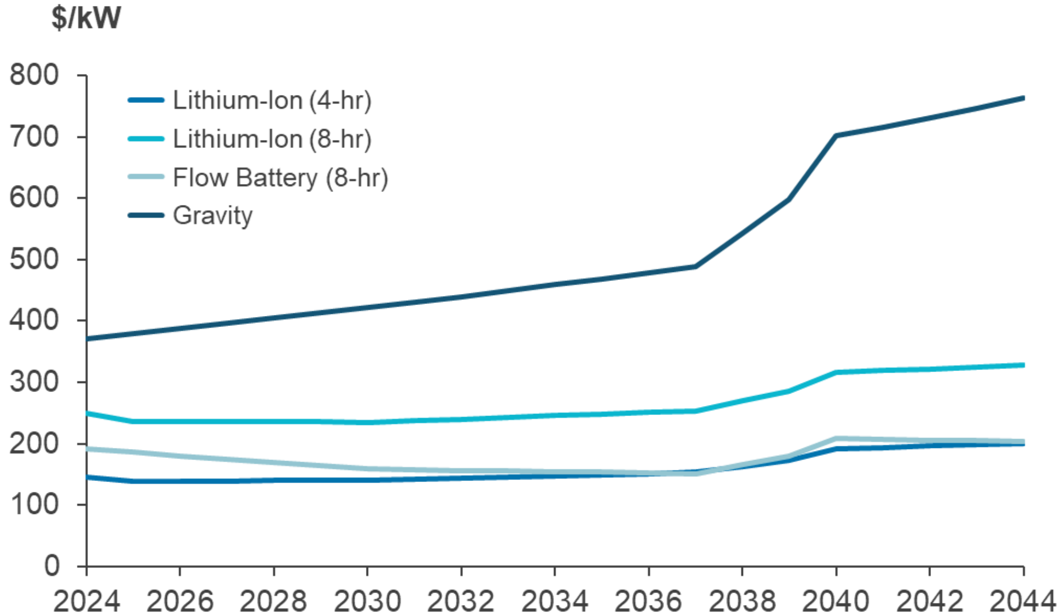
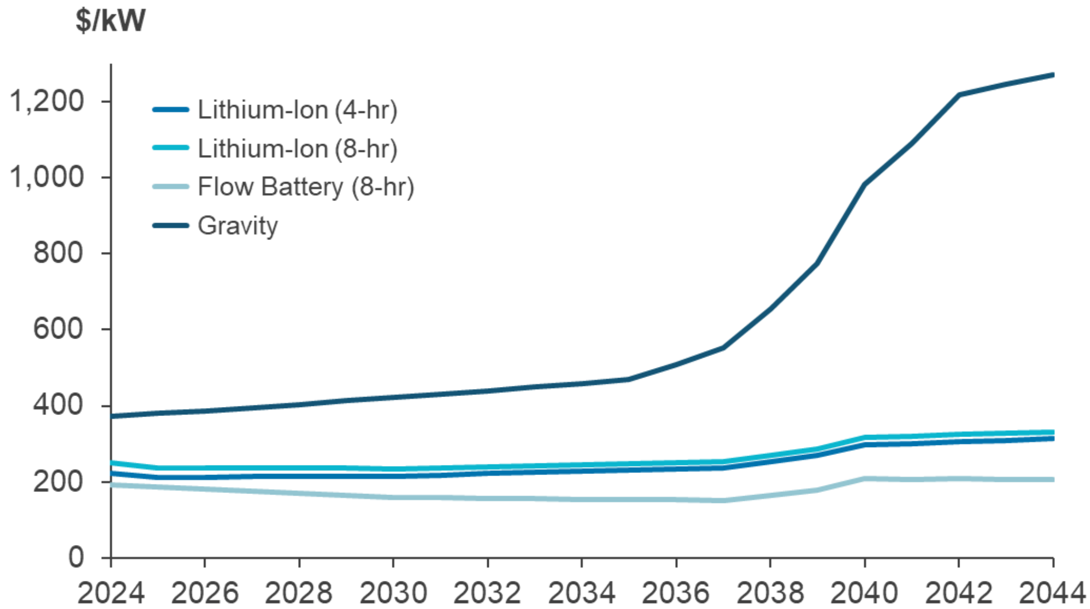


Table 4-10 – Storage Option ELCC (Capacity Credit)

	Lithium-Ion (4-hr)		Lithium-Ion (8-hr)	Flow (8-hr)	Gravity (8-hr)	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2024	65%	50%	100%	77%	100%	100%
2025	65%	49%	100%	77%	100%	100%
2026	65%	49%	100%	77%	100%	100%
2027	65%	49%	100%	77%	100%	100%
2028	65%	49%	100%	77%	100%	100%
2029	65%	48%	100%	77%	100%	100%
2030	65%	48%	100%	77%	100%	100%
2031	65%	47%	100%	77%	100%	100%
2032	65%	47%	100%	76%	100%	100%
2033	65%	46%	100%	77%	100%	100%
2034	65%	46%	100%	77%	100%	100%
2035	65%	45%	100%	77%	100%	100%
2036	65%	45%	100%	77%	100%	100%
2037	65%	44%	100%	77%	100%	100%
2038	65%	44%	100%	77%	100%	100%
2039	65%	43%	100%	77%	100%	100%
2040	65%	43%	100%	77%	100%	100%
2041	64%	42%	100%	77%	100%	100%
2042	64%	42%	99%	76%	99%	99%
2043	64%	42%	99%	76%	99%	99%
2044	64%	41%	99%	76%	99%	99%

Figure 4-6 – Levelized Cost of Storage Options (ACAP)



Based on this screening analysis, Liberty-Empire found that lithium-ion batteries are cost-competitive with standard generation resources on a capacity basis. However, the value of the capacity is likely to erode over time as more storage is added to the system. Relative to other storage resources, lithium-ion batteries' high flexibility and efficiency also provide significant value opportunities across multiple SPP markets, with additional long-term energy arbitrage opportunities and ancillary service value potential associated with the expected growth of intermittent resource capacity in the market.[13]

The screening analysis also demonstrated that flow batteries and gravity storage are expected to be competitive with lithium-ion in the longer term due largely to the longer duration configuration of these technologies, which allows them to provide more capacity value for deployment during peak demand. Liberty-Empire will consider the development of flow batteries for 2035 and beyond and gravity storage only for net zero portfolios in

[13] While ancillary service value is not included in the LCOE analysis, Liberty-Empire did include estimates in the integrated resource planning stage and the critical uncertain factor analysis. See Section 5.5 of this volume for details.

the same time frame. Liberty-Empire will continue evaluating emerging storage technologies as markets evolve and potential use cases are further identified.

In addition to peak load-shifting value, energy arbitrage value, and capacity value, storage resources also have the potential to provide a host of ancillary services, such as frequency regulation and spinning reserves. Thus, Liberty-Empire also assessed and incorporated the ancillary service value of storage resources (as well as thermal resources) in the integrated resource analysis based on potential SPP market revenues in the spinning reserve, regulation up, and regulation down markets.

2.4.4 Distributed Resource Screening

Distributed solar and RICE resources have been found to have a capital cost premium of up to 50% compared to their utility-scale counterparts. In contrast, distributed battery storage is more comparable to the utility-scale alternative. However, Liberty-Empire determined that it is not appropriate to eliminate any feasible distributed resource options through an LCOE approach since they may provide benefits to the system associated with avoided distribution-level expenditures on Liberty-Empire's system, as further described in Section 2.4.4.1. Therefore, the distributed resource options for solar, battery storage, and reciprocating engines have been preserved as candidate resource options.

2.4.4.1 Avoided Distribution Upgrade Costs

Positioning a distributed energy resource in an area with historically high congestion or delivery costs could benefit Liberty-Empire's system and customers by injecting energy at the load site rather than transmitting it across various delivery systems. While determining the exact value of such benefits is complex, it can be estimated by quantifying the ability of distributed energy resources to defer certain distribution system upgrade costs.

Currently, Liberty-Empire has not identified any specific distribution investment projects located within any established areas that can be specifically targeted for DSM programs, and therefore for DSM analysis purposes, conservatively assumed a zero avoided cost of distribution capacity. However, to assess the value of distributed energy resources, such as distributed solar and distributed storage (paired or unpaired), Liberty-Empire previously identified a set of planned and/or representative distribution upgrade projects that could be deferred if transformer current was reduced. Assuming that distributed solar and storage resources can be placed at specific sites on the distribution grid to avoid system upgrades, Liberty-Empire incorporated the value of these representative upgrade projects as offsets to the capital and fixed costs of distributed solar and storage resources. Based on the identified representative distribution upgrade projects, Liberty-Empire could avoid approximately **[redacted]** in project capital costs and **[redacted]** per year in fixed O&M costs by installing at least **[redacted]** of firm distributed capacity at one representative site, and avoid approximately **[redacted]** in project capital costs and **[redacted]** per year in fixed O&M costs by installing at least **[redacted]** of firm distributed capacity at another representative site. At present, no definitive projects which could be offset by DSM have been included within the next 3 years of planned CapEx investment.

Future intersections of resource costs paired with infrastructure/labor cost increases may provide additional benefits that are not quantifiable. Additionally, a multiplying effect may arise if DER aggregation facilitated by FERC Order 2222 materializes to a level that could impact load centers.

2.5 Probable Environmental Costs of Potential Supply-Side Resource Options

(B) The probable environmental costs of each potential supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental legal mandates that may be imposed at some point within the planning horizon. The utility shall identify a list of environmental pollutants for which, in the judgment of the utility decision-makers, legal mandates may be imposed during the planning horizon which would result in compliance costs that could significantly impact utility rates. The utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that legal mandates requiring additional levels of mitigation will

be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation cost for each identified pollutant.

Liberty-Empire is subject to various federal, state, and local laws and regulations with respect to air and water quality and with regard to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping, and reporting, as well as remediation of contaminated sites and other environmental matters. Liberty-Empire operates its generating facilities in compliance with environmental laws and regulations. Environmental laws or regulations imposed during the planning period may impact air emissions, water discharges, or waste material disposal. The rest of this Section briefly discusses these pollutants that could result in compliance costs that may affect utility rates. Liberty-Empire is not able to estimate compliance costs accurately for any new requirements.

2.5.1 Air Emission Impacts

2.5.1.1 EPA Greenhouse Gas Rule

In the spring of 2024, the EPA issued a final version of its Greenhouse Gas (GHG) rule under Section 111 of the Clean Air Act for coal, oil, and natural gas-fired power plants. The EPA aims to cut carbon emissions from power plants by setting stringent limits on new, modified, and existing coal- and gas-fired plants. New gas-fired turbines face phased standards: base load units require 90% CO_2 capture by 2032, while intermediate and low-load units must meet efficiency and low-emission fuel standards. Existing coal-fired steam units with long-term operation plans (post-2039) also need 90% capture by 2032, while medium-term units (2032-2039) must co-fire 40% natural gas by 2030. Units retiring by 2032 are exempt. Standards for oil and natural gas-fired units focus on efficiency by load type, supporting a shift to cleaner energy sources. Ultimate implementation remains uncertain, particularly given the June 30, 2022, Supreme Court decision in West Virginia v. EPA, which specifically limited the EPA's ability to regulate carbon dioxide emissions from power plants on the basis that the original CPP had overstepped authority granted under the Clean Air Act.

2.5.1.2 National Ambient Air Quality Standards

The Clean Air Act ("CAA") requires the EPA to set National Ambient Air Quality Standards ("NAAQS") for four air pollutants associated with fossil-fuel generation, including particulate matter, ground-level ozone, sulfur dioxide (SO_2), and nitrogen oxides (NO_X). These air pollutants are regulated by setting human health-based or environmental-based criteria for permissible levels.

2.5.1.3 Particulate Matter

The EPA strengthened the PM standard in 2013 and again in 2024. The Jasper County (Missouri) area is currently in attainment of the PM NAAQS. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the Jasper County area will remain in attainment of a future revision of the standard. Future non-attainment of revised standards could require additional reduction technologies, emission limits, or both on fossil-fueled units.

2.5.1.4 Ozone

In 2015, the EPA strengthened the NAAQS for ground-level ozone. The Jasper County area is currently attaining the 2015 Ozone NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional NO_X reduction technologies, emission limits, or both on fossil-fueled units.

2.5.1.5 Sulfur Dioxide

In 2010, the EPA strengthened the NAAQS for SO_2. The Jasper County area is currently attaining the 2010 SO_2 NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional SO_2 reduction technologies, emission limits, or both for fossil-fueled units.

2.5.1.6 Nitrogen Oxides

In 2010, the EPA strengthened the NAAQS for NO_X. The Jasper County area is currently attaining the 2010 NO_X NAAQS. No additional emission control equipment is currently needed to comply with this standard. Future non-attainment of revised standards could result in regulations requiring additional NO_X reduction technologies, emission limits, or both for fossil-fueled units.

2.5.1.7 Cross-State Air Pollution Rule

In 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR"), requiring eastern and central states to significantly reduce power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states. The CSAPR Update Rule took effect in 2017 with more stringent ozone-season NO_X emission budgets for electric generating units ("EGUs") in many states to address significant contribution and maintenance issues concerning the ozone NAAQS established in 2008. In 2021, the EPA issued new amended budgets for 12 states, although Missouri and Kansas were not impacted. No additional emission control equipment is currently needed to comply with this rule. The Company complies through a combination of trading allowances within or outside its system and changes in operations as necessary. Future strengthened ozone, NO_X, or SO_2 standards could result in additional cross-state rule updates requiring additional trading of allowances, emission reduction technologies or reduced generation on fossil-fueled units.

In 2022 the Missouri Department of Natural Resources ("MDNR") proposed revisions to the Missouri State Implementation Plan ("SIP"). This revision is a supplement to the SIP-Interstate Transport Provisions for the 2015 Ozone Standard. The EPA's response to the MDNR SIP revision was proposed denial. In addition, the EPA also proposed implementing the Good Neighbor Federal Implementation Plan ("FIP") to assure that the

26 states identified in the proposal (including Missouri) do not significantly contribute to problems attaining and maintaining the 2015 Ozone NAAQS in downwind states. The Good Neighbor FIP would impose more stringent NO_X ozone season compliance requirements for Missouri EGUs. Should the Good Neighbor FIP become applicable, additional emission control equipment could be needed to comply with this rule. In lieu of adding control equipment to comply with the Good Neighbor FIP, the Company could also comply through a combination of trading allowances within or outside its system and changes in operations, as necessary. The proposed Good Neighbor FIP has the potential to move Missouri sources from the Group 2 NO_X ozone season trading program to Group 3 NO_X ozone season trading program. Pricing per ton emitted is much higher in the Group 3 trading program (fall of 2022 Group 3 NO_X ozone season allowances have cost as much as $35,000 each). Future strengthened ozone, NO_X, or SO_2 standards could result in additional cross-state rule updates requiring additional trading of allowances, emission reduction technologies or reduced generation on fossil-fueled units. The Eighth U.S. Circuit Court of Appeals granted the Missouri Attorney General's request for a stay, preventing the EPA from imposing this regulation on Missouri sources until the appeals process plays out.

2.5.1.8 Regional Haze

In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule. These amendments apply to the provisions of the Regional Haze Rule that require emission controls known as best available retrofit technology ("BART") for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze.

The pollutants that reduce visibility include $PM_{2.5}$ and compounds that contribute to $PM_{2.5}$ formation, such as NO_X, SO_2, volatile organic compounds, and ammonia under certain conditions. Under the 1999 Regional Haze Rule, states must set periodic goals for improving visibility in natural areas. As states work to reach these goals, they must develop regional haze implementation plans that contain enforceable measures and strategies for reducing visibility-impairing pollution.

The Regional Haze Rule directs state air quality agencies to identify whether visibility-reducing emissions from sources subject to BART are below the state's limits or whether retrofit measures are needed to reduce emissions. It also directs these agencies to file Regional Haze plans with the EPA for approval.

Future visibility progress goals could result in additional SO_2, NO_X, and PM controls or reduction technologies on fossil-fired units.

2.5.1.9 Mercury and Air Toxics Standards (MATS)

In 2011, the EPA finalized a rule to reduce emissions of toxic air pollutants from power plants. These MATS for power plants reduced emissions from new and existing coal and oil-fired electric EGUs. Control equipment was installed at Liberty-Empire facilities to comply with this rule. No additional emission control equipment is currently needed to comply with this standard. It is not known whether the rule will be strengthened in the future. Future rule strengthening could require additional reduction technologies, emission limits, or both on coal and oil-fired units.

2.5.2 Water-Related Impacts

Liberty-Empire operates under the Kansas and Missouri National Pollutant Discharge Elimination System (“NPDES”) plans implemented in response to the Federal Clean Water Act (“CWA”). Liberty-Empire operates its generation facilities in compliance with applicable regulations, and all facilities have received necessary discharge permits.

2.5.2.1 Clean Water Act Section 316(b)

On September 17, 2018, the Kansas Department of Health and Environment (“KDHE”) issued a Certificate of Determination stating that the Riverton Generating Station cooling water intake structure (“CWIS”) complies with Section 316(b) of the CWA. The location, design, construction, and capacity of the CWIS reflect the best technology available (“BTA”) for minimizing adverse environmental impacts. Iatan 2 and Plum Point also meet the BTA standard. Future modifications at the Iatan 1 facility could range from flow velocity reductions, traveling screen modifications, or installing a closed-cycle cooling tower retrofit.

2.5.2.2 Surface Impoundments

Liberty-Empire owns and maintains a coal ash impoundment at the former and closed Asbury Power Plant site. Additionally, Liberty-Empire owns a 12 percent interest in a coal ash impoundment at the Iatan Generating Station and a 7.52 percent interest in a coal ash impoundment at Plum Point. Future closure of all surface impoundments is anticipated.

Effluent Limitation Guidelines ("ELGs") for Steam Electrical Power Generating Point Sources are currently incorporated into all facilities' wastewater discharge permits. The EPA rule defines bottom ash transport water, fly ash transport water, and scrubber wastes as wastewaters that cannot be discharged after December 21, 2023.

2.5.3 Coal Combustion Residuals

In compliance with the EPA's final rule to regulate the disposal of coal combustion residuals ("CCRs") as non-hazardous solid waste under subtitle D of the Resource Conservation and Recovery Act, the former Riverton Plant impoundment was closed as a CCR landfill in 2014 in accordance with Kansas Department of Health and Environment regulations.

Final closure of the other existing ash impoundment at the Iatan Generating Station has been accounted for in Liberty-Empire's Asset Retirement Obligation ("ARO"). In December 2016, The Missouri Department of Natural Resources ("MDNR") granted Liberty-Empire a Utility Waste Disposal Area Construction Permit that could be used for CCR waste disposal. Construction of the landfill is not expected as Liberty-Empire closed the Asbury impoundment by leaving all accumulated CCR in place.

2.5.4 Assigning Environmental Probabilities

Under 20 CSR 4240-22.040(2)(B), Liberty-Empire evaluated the probable environmental costs of new supply-side resource options associated with potential CO_2 emissions.

Although several legislative and executive actions related to carbon emissions have been attempted over the last decade, there is currently no price on carbon and no binding emission limits at the federal level. At the time of the development of Liberty-Empire's 2025 IRP assumptions, the Biden Administration's Inflation Reduction Act (IRA), which afforded certain tax credits to clean energy resources, had been in effect for 2 years. Additionally, the Environmental Protection Agency (EPA) proposed its Greenhouse Gas (GHG) Standards and Rules for Fossil Fuel-Fired Power Plants aimed at reducing GHG emissions. However, no policies directly regulating carbon emissions were signed into law as of June 2024.

Given several previous federal proposals to regulate carbon emissions, Liberty-Empire's Base Case incorporates a modest price on carbon emissions of $13/short ton starting in 2031, which can be seen as a proxy for several different potential pathways for legislative action or executive regulation (not explicitly a carbon tax). CRA's analysis suggests that pricing between $13-20/ton (in real 2023$) between 2031 and 2044 would achieve 60-70% reduction in SPP carbon emissions by 2044 relative to a recent historical year baseline, depending on other market factors and dynamics. Such a carbon price would likely result in significant additional coal-to-gas switching nationwide and pressure a significant percentage of the existing coal fleet nationwide to retire by 2044. The price would also improve renewable and other clean energy generation economics.

Assuming 2025 IRP Base Case CO_2 price assumptions, Table 4-11 presents the levelized environmental cost expectations for the Base Case over the twenty-year planning period due to CO_2 emissions. Although NO_x and SO_2 emission costs were also modeled in the 2025 IRP analysis, given the minor cost impact of these resources, they are excluded from this table.

Table 4-11 – Probable Environmental Costs

Technology	Levelized Probable Environmental Costs – Emissions-based ($/MWh)
Gas CC	6.98
RICE	9.09
CT – Aero	10.11
CT – Frame	10.71
Hydrogen CT	0
Hydrogen Retrofit CC	0
Small Modular Nuclear	0
Utility Scale Solar	0
Onshore Wind	0
Dist. Solar PV	0
Dist. RICE	10.31

2.6 Selection of Preliminary Supply-Side Candidate Resource Options

(C) The utility shall indicate which potential supply-side resource options it considers to be preliminary supply-side candidate resource options. Any utility using the preliminary screening analysis to identify preliminary supply-side candidate resource options shall rank all preliminary supply-side candidate resource options based on estimates of the utility costs and also on utility costs plus probable environmental costs.

Based on the feasibility and cost ranking screening analyses described previously in this Section, Liberty-Empire identified a final list of technologies representing the preliminary supply-side future candidate resource options to be included in the 2025 integrated planning analysis. The final list of candidate supply-side resource options is as follows:

- Natural gas-fired simple cycle – Aeroderivative CT and F-class frame CT;
- Natural gas-fired combined cycle – 1 x 1 H Class;
- Natural gas-fired reciprocating engines (“RICE”)*;
- Small modular nuclear reactor;
- Onshore Wind;

- Solar photovoltaic ("PV")*;
- Energy storage – lithium-ion battery*, vanadium redox flow battery, Energy Vault concrete block gravity storage; and
- Hydrogen – retrofit on existing gas-fired combined cycle units and new simple cycle combustion turbine.

*Denotes a resource option evaluated as both a distributed and utility-scale energy resource.

2.6.1 Potential Supply-Side Resource Option Table

1. Provide a summary table showing each potential supply-side resource option and the utility cost and the probable environmental cost for each potential supply-side resource option and an assessment of whether each potential supply-side resource option qualifies as a utility renewable energy resource; and

Pursuant to 20 CSR 4240-22-040(2)(C) and 20 CSR 4240-22-040(2)(C)(1), Table 4-12 summarizes the expected utility-levelized cost of electricity for each potential supply-side resource option at select time periods. Table 4-11 presents the levelized environmental cost expectations. As discussed in Section 2.4.3 storage resources were excluded from these tables because they could not be appropriately evaluated on a traditional LCOE basis.

Table 4-12 – LCOE by Supply Side Resource at Select Periods in Time

Technology		Levelized Cost of Electricity (Nominal $/MWh)		
		2025	**2030**	**2035**
Natural Gas	Reciprocating Engine (RICE)	448	449	443
	Distributed RICE	516	504	492
	Gas CC	56	59	61
	CT - Aero	514	516	509
	CT - Frame	846	861	853
Renewable	Onshore Wind	37	32	31
	Utility Scale Solar	53	44	35
	Distributed Solar PV	114	93	72
Clean Baseload	Small Modular Nuclear	-	68	59
	Hydrogen CT	361	367	386
	Hydrogen Retrofit CC	226	231	244

2.6.2 Elimination of Potential Supply-Side Resource Options

2. Explain which potential supply-side resource options are eliminated from further consideration and the reasons for their elimination.

As discussed in Sections 2.3 and 2.4, Liberty-Empire performed two rounds of screening analyses to narrow its initial list of all potential supply-side resource options to a final list of preliminary options to be included in the fuller integrated portfolio analysis.

Based on the feasibility screen, Liberty-Empire eliminated the following supply-side resource options from consideration:

Table 4-13 – Resources Eliminated in Feasibility Screen

Resource	Reason for Elimination
Offshore wind	Absence of the resource type in the region
Re-powering of existing wind assets	Feedback from project owners currently contracted with Liberty-Empire indicates that they are not considering re-powering opportunities at this time
CHP Options	Given the uncertainty regarding feasible sites within Liberty-Empire's service territory and the lack of potential partners that have shown interest in pursuing CHP relationships with Liberty-Empire
Traditional nuclear	Given the large size of the option (~1,000 MW) and the inability to assume with confidence that Liberty-Empire would have access to a partial ownership interest in a new development in any proximity to its service territory
Biomass and landfill gas	Limited access to a reliable source of fuel near the Liberty-Empire service territory
Supercritical carbon dioxide power cycle plant	The technology is nascent, with only a single pilot project currently operational. It remains costly and is unlikely to be economically viable in the near term.
Carbon Capture and Storage	Engineering complexity of capture and transportation, lack of natural geology for storage, and scarcity of operating examples to draw upon.
Compressed Air	Engineering complexity of development and operation and lack of natural geology
Molten Salt Energy Storage	Scarcity of operating examples of molten salt energy storage to draw upon
Iron Air Storage	Early stages of commercial deployment make it hard to gauge scalability and economic viability. Round trip efficiency is lower than Li-Ion, though the longer duration can offset that
CO_2 Storage	Deployment remains mostly at the demonstration phase—no large-scale deployment makes it challenging to model from a cost and operations perspective

Based on the cost screen, Liberty-Empire only eliminated one option: gravity storage. Gravity storage has benefits as long-duration energy storage to help address many grid challenges, such as renewable intermittency peak load management. However, the cost in the LCOE analysis was considerably high, so Liberty-Empire determined that it should be eliminated from further consideration. Despite a wide range of costs for the remaining resource types, all options proceeded to the final candidate list due to a wide range of economic and performance benefits for the Liberty-Empire system, including energy, capacity, clean baseload, and locational. Hydrogen and SMR options were considered less mature technologies and thus were assumed to be first commercially available in 2035 and beyond to provide a combination of relatively large amounts of clean energy and stable output and were considered for inclusion only in the “net zero” portfolios. Further discussion of the net zero alternative plan development can be found in Volume 6.

Detailed descriptions and documentation of the cost and operating parameters assumed for each of the final candidate supply-side resource options can be found in Section 4.1.

SECTION 3 INTERCONNECTION AND TRANSMISSION REQUIREMENTS OF PRELIMINARY CANDIDATE OPTIONS

(3) The utility shall describe and document its analysis of the interconnection and any other transmission requirements associated with the preliminary supply-side candidate resource options identified in sub-section (2)(C).

3.1 Interconnection and Transmission Constraints Analysis

(A) The analysis shall include the identification of transmission constraints, as estimated pursuant to 4 CSR 240-22.045(3), whether within the Regional Transmission Organization's (RTO's) footprint, on an interconnected RTO, or a transmission system that is not part of an RTO. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the preliminary supply-side candidate resource options under consideration, that the costs of the transmission system investments associated with preliminary supply-side candidate resource options, as estimated pursuant to 4 CSR 240-22.045(3), are properly considered and to provide an adequate foundation of basic information for decisions to include, but not be limited to, the following:

1. Joint ownership or participation in generation construction projects;

2. Construction of wholly-owned generation facilities;

3. Participation in major refurbishment, life extension, upgrading, or retrofitting of existing generation facilities;

4. Improvements on its transmission and distribution system to increase efficiency and reduce power losses;

5. Acquisition of existing generating facilities; and

6. Opportunities for new long-term power purchases and sales, and short-term power purchases that may be required for bridging the gap between other *supply options, both firm and non-firm, that are likely to be available over all or part of the planning horizon.*

Liberty-Empire is a member of SPP and is thus reliant on SPP's determination of transmission capacity expansion requirements. As a member of SPP, Liberty-Empire is assigned a cost-sharing allocation of all lines built in the SPP footprint. SPP conducts three studies directly associated with transmission planning: large generation interconnect studies, aggregate transmission service studies, and the SPP integrated transmission plan ("ITP"). The large generation interconnection study determines if any modifications are needed to connect a new generator to the transmission system. The aggregate transmission service studies determine system upgrades required to grant transmission service from a generation source to a load source. The ITP is an annual planning cycle that assesses SPP's regional transmission needs in the long- and near-term to create a cost-effective, flexible, and robust transmission network to improve access to the region's diverse generating resources. Liberty-Empire actively participates in SPP transmission planning processes through committee membership, meetings, and working group attendance, as well as participation as a customer and a transmission owner in developing and implementing all of SPP's transmission studies and other avenues.

Liberty-Empire modeled a transmission cost adder for each alternative resource examined in this IRP. For Liberty-Empire's 2025 IRP, Liberty-Empire assigned transmission costs on a dollar-per-kilowatt basis for each candidate resource examined in this IRP. There are various costs for gas, solar, wind, and storage. Other advanced technologies, such as hydrogen and small modular reactors, were treated similarly to new gas interconnection costs. The generator interconnection cost estimate is described in more detail in Section 4.3.

3.2 New Supply-Side Resources Output Limitations

(B) This analysis shall include the identification of any output limitations imposed on existing or new supply-side resources due to transmission and/or

distribution system capacity constraints, in order to ensure that supply-side candidate resource options are evaluated in accordance with any such constraints.

Liberty-Empire cannot provide a generic list of transmission upgrades needed to interconnect any given generation source within the SPP footprint physically. Each request for Generator Interconnection ("GI") must be submitted to the SPP Generation Interconnection process, as defined in the SPP transmission tariff. This process examines the specific location proposed for generator interconnection and its unique technical characteristics and determines the necessary transmission upgrades for that unique interconnection, as SPP requires.

SECTION 4 SUPPLY-SIDE CANDIDATE RESOURCE OPTIONS

4.1 Supply-Side Candidate Resource Options for Integration

(4) All preliminary supply-side candidate resource options which are not eliminated shall be identified as supply-side candidate resource options. The supply-side candidate resource options that the utility passes on for further evaluation in the integration process shall represent a wide variety of supply-side resource options with diverse fuel and generation technologies, including a wide range of renewable technologies and technologies suitable for distributed generation.

(A) The utility shall describe and document its process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis.

Liberty-Empire's process for identifying and analyzing potential supply-side resource options and preliminary supply-side candidate resource options and for choosing its supply-side candidate resource options to advance to the integration analysis is described and documented in Sections 2.2 through 2.6.

As discussed in Section 2.6, the following supply-side candidate options were identified for inclusion in the integration process:

- Natural gas-fired simple cycle – Aeroderivative CT and F-class frame CT;
- Natural gas-fired combined cycle – 1 x 1 H Class;
- Natural gas-fired reciprocating engines ("RICE")*;
- Small modular nuclear reactor;
- Onshore Wind;
- Solar photovoltaic ("PV")*;

- Energy storage – lithium-ion battery*, vanadium redox flow battery, Energy Vault concrete block gravity storage; and
- Hydrogen – retrofit on existing gas-fired combined cycle units and new simple cycle combustion turbine.

**Denotes a resource option evaluated as both a distributed and utility-scale energy resource.*

The remainder of this Section describes and documents the cost and performance assumptions developed for the resource options as used in the LCOE analysis described in Section 2.4.2 and the integrated planning analysis described in Volume 6. Planning-level cost and operating assumptions for all feasible resource options were collected and developed by Liberty-Empire's IRP consultant, CRA, with expert review and input from a third-party engineering firm, Black and Veatch. Cost and operating estimates for the resource options were developed using a market scan approach for cost and operational parameters. The market scan approach involved in-depth research into recent cost data points from a variety of sources, including public reports, other utility IRP filings and Requests for Proposals, proprietary subscription-based data sources, and Liberty-Empire's and Black and Veatch's internal view based on actual and recent project estimates. The results of the market research findings were used to develop current cost estimates for the technologies and projections for cost changes over time.

4.1.1 Simple Cycle Technologies

A simple cycle gas CT plant utilizes natural gas to produce power in a gas turbine generator. Gas turbine manufacturers continue to develop high-temperature materials and cooling techniques to allow higher turbine firing temperatures, resulting in increased efficiency. Typically, CTs are used for peaking power due to their fast load ramp rates and relatively low capital costs. Typical simple cycle plants operate with natural gas as the operating fuel. The ability to operate on fuel oil is often also required in case the power demand exists when the natural gas supply does not.

Frame turbines are industrial turbines designed specifically for land-based power generation or mechanical drive applications typically used in intermediate to peaking applications. In simple cycle configurations, these machines typically have higher heat rates when compared to aeroderivative engines; however, their capital cost per unit of capacity is also typically lower. Aeroderivative turbines are considered a mature technology and have been used in power generation applications for decades. These machines are commercially available from several vendors, including General Electric ("GE"), Siemens, and Mitsubishi Power. The combustion turbine assumptions are summarized in Table 4-14.

Table 4-14 – Combustion Turbine Performance Parameters

Parameter	Aeroderivative CT	Frame CT
Earliest Feasible Year of Installation	2031[14]	2031[15]
Lead Time in Years (includes development and construction)	3	3
Equivalent Forced Outage Rate	5%	5%
ISO Net Output, Full Load MW	54	240
Full Load Net Heat Rate, Btu/kWh	9,224	9,768
Minimum Load Net Heat Rate, Btu/kWh	12,100	10,896
Capital cost, 2025 (2023$/kW)	n/a	n/a
Capital cost, 2030 (2023$/kW)	n/a	n/a
Capital cost, 2035 (2023$/kW)	1,739	915
Fixed O&M (2023$/kW-year)	21.00	11.21
Variable O&M (2023$/MWh)	15.00	5.51
Ongoing capex (2023$/kW-year)	4.66	1.24
CO_2 Emissions (lbs/MMBtu, HHV)	119	119

[14] Can be commissioned by 2029 with provision of existing interconnection at Kings Point wind site, new solar sites, or with provision of the Expedited Resource Addition Study (ERAS) recently endorsed by SPP which creates a one-time study process to expedite the interconnection of new generation projects to meet resource adequacy needs.

[15] May be commissioned by 2029 with provision of the Expedited Resource Addition Study (ERAS) recently endorsed by SPP, which creates a one-time study process to expedite the interconnection of new generation projects to meet resource adequacy needs.

4.1.2 Combined Cycle Technologies

The basic principle of the combined cycle gas turbine ("CCGT") plant is to utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator, and also to use the hot exhaust gases from the gas turbine to produce steam in a HRSG. This steam is then used to drive a steam turbine and generator to produce electric power. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

Using gas and steam turbine cycles (Brayton and Rankine) in a single plant to produce electricity results in high conversion efficiencies. Combined cycle facilities have heat rates that have, in recent history, been in the 6,500 Btu/kWh range. In the 2025 IRP, a greenfield 1 x 1 H-class CC option was included in the candidate resource option list. Operating parameters for such a resource are summarized in Table 4-15.

Table 4-15 – Combined Cycle Performance Parameters

Parameter	Combined Cycle Gas Turbine
Earliest Feasible Year of Installation	2031[16]
Lead Time in Years (includes development and construction)	5
Equivalent Forced Outage Rate	5%
ISO Net Output, Full Load MW	630
Full Load Net Heat Rate, Btu/kWh	6399
Minimum Load Net Heat Rate, Btu/kWh	7300
Capital cost, 2025 (2023$/kW)	n/a
Capital cost, 2030 (2023$/kW)	n/a
Capital cost, 2035 (2023$/kW)	1099
Fixed O&M (2023$/kW-year)	17.80
Variable O&M (2023$/MWh)	2.41
Ongoing capex (2023$/kW-year)	3.86
CO_2 Emissions (lbs/MMBtu, HHV)	119

[16] May be commissioned by 2029 with provision of the Expedited Resource Addition Study (ERAS) recently endorsed by SPP which creates a one-time study process to expedite the interconnection of new generation projects to meet resource adequacy needs.

4.1.3 Reciprocating Engine Technologies

The reciprocating, or piston, engine, often referred to as a RICE, operates on the four-stroke Otto cycle for the conversion of pressure into rotational energy. Many different vendors offer reciprocating engines, and they are becoming more popular due to their quick start times and operational flexibility. There are slight differences between manufacturers in engine sizes and other characteristics, but all largely share the common characteristics of quick ramp rates and start-up.

The Wartsila 10V50DF (natural gas-fired, dual fuel) reciprocating engine, or similar, was evaluated in this assessment as a potential candidate in blocks of three engines. In addition to these utility-scale estimates, a distributed resource option as a single 2 MW engine was also included. The parameters for both reciprocating engine options are summarized in Table 4-16.

Table 4-16 – Reciprocating Engine Performance Parameters

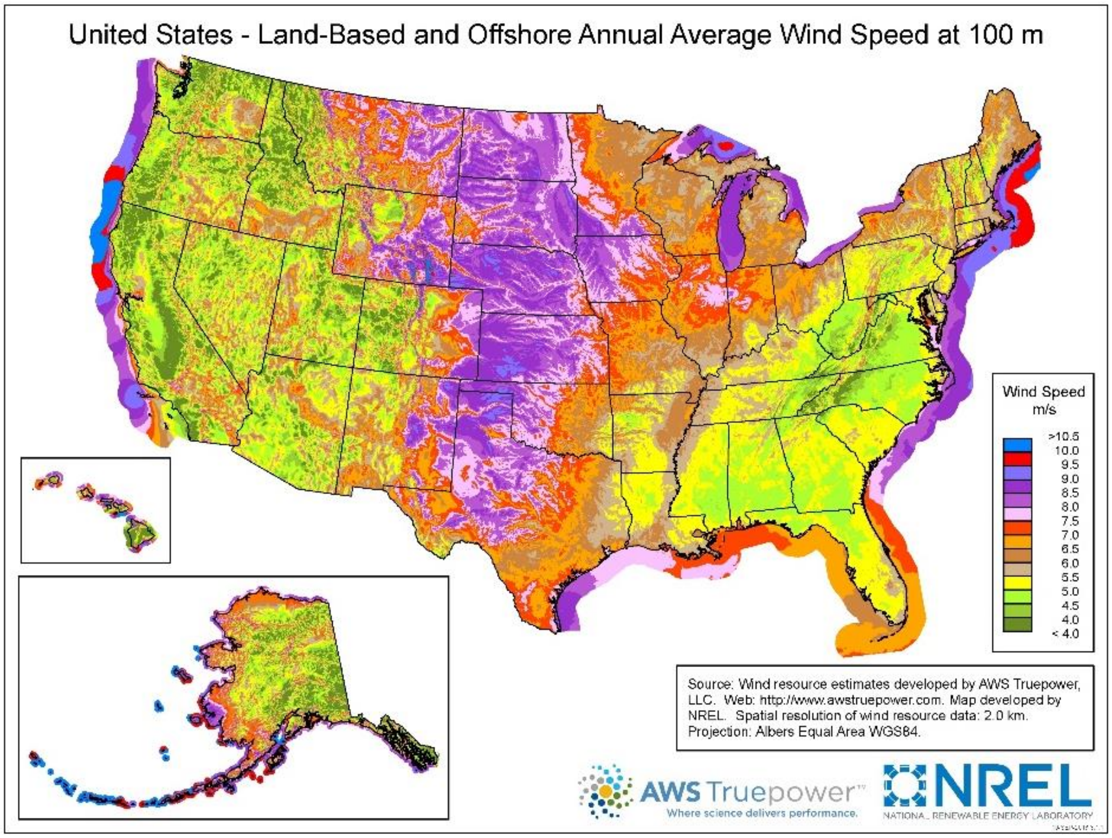
Parameter	Reciprocating Engines – Utility Scale (3 Engines)	Reciprocating Engines – Distributed
Earliest Feasible Year of Installation	2031[17]	2031
Lead Time in Years (includes development and construction)	3	3
ISO Net Output, Full Load MW	50	2
Full Load Net Heat Rate, Btu/kWh	8,298	9,403
Minimum Load Net Heat Rate, Btu/kWh	11,348	11,825
Capital cost, 2025 (2023$/kW)	n/a	n/a
Capital cost, 2030 (2023$/kW)	n/a	n/a
Capital cost, 2035 (2023$/kW)	1,835	2,753
Fixed O&M (2023$/kW-year)	15.00	26.00
Variable O&M (2023$/MWh)	6.86	16.00
Ongoing capex (2023$/kW-year)	4.66	4.66
CO_2 Emissions (lbs/MMBtu, HHV)	119	119

[17] Can be commissioned by 2029 with provision of existing interconnection at Kings Point wind site, new solar sites, or with provision of the Expedited Resource Addition Study (ERAS) recently endorsed by SPP which creates a one-time study process to expedite the interconnection of new generation projects to meet resource adequacy needs.

4.1.4 Wind

Wind energy systems use the kinetic energy from the wind to spin a large turbine rotor, which in turn spins an electromagnetic generator shaft to produce electricity. The power output from a wind turbine depends largely on the wind speed and how often it blows. The SPP region has some of the strongest winds in the U.S., as shown in Figure 4-7, making it an optimal region to deploy wind energy systems.

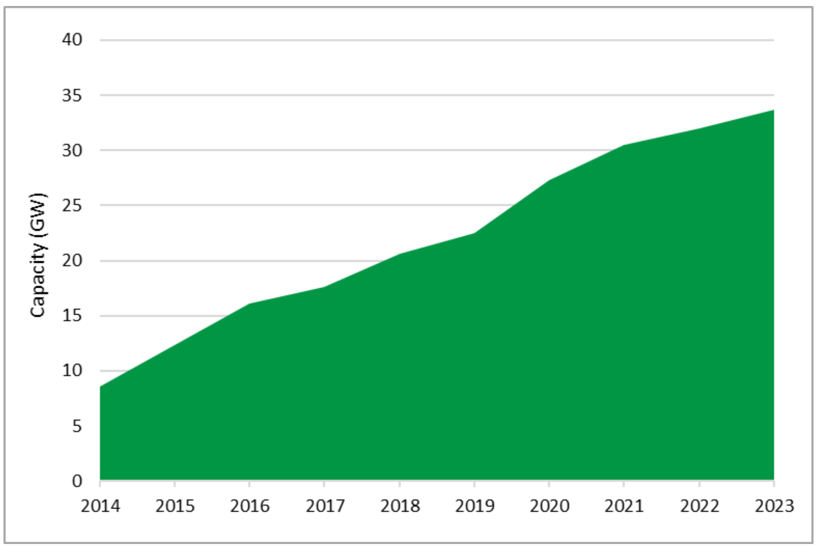
Figure 4-7 – Wind Speeds Across the U.S. (Source: NREL)



SPP has a relatively large number of wind energy systems. In 2024, wind generation accounted for 38% of total generation throughout the year in SPP. In February 2017, SPP became the first RTO in the U.S. to serve more than 50% of its load at a given time with wind energy. SPP has since reliably met as much as 88% of its instantaneous load with wind.

The past decade has seen a rapid deployment of wind systems in the region. In 2009, wind energy systems had a combined total capacity of 3,400 MW, which has increased almost ten times to 33,725 MW by the end of 2023, as displayed in Figure 4-8.[4] Since 2022, wind generation has surpassed both coal and gas and is now the largest source of energy production in the SPP region. SPP credits its successful and rapid deployment of wind to the region's high wind speeds, consolidated balancing authority responsibilities, and robust transmission system. Generally, wind energy systems have become a more competitive resource nationwide due to improvements in system designs such as larger rotor diameters, higher turbine heights, more aerodynamic designs, permanent-magnet direct-drive drivetrains, and stronger, lighter-weight materials, as well as decreases in system component costs.

Figure 4-8 – SPP Installed Wind Capacity 2014-2023



Wind resources have continually been low-cost energy resources, especially when incorporating the benefits of federal tax credits. Cost and performance estimates for the wind option in the 2025 IRP are shown in Table 4-17. Note that all cost estimates are provided before consideration of federal tax credits. The details of federal tax incentives and modeling assumptions included in the 2025 IRP analysis are summarized in Section 2.4.2.

[4] Southwest Power Pool (SPP). State of the Market 2023. 2024. https://www.spp.org/

Table 4-17 – Wind Performance Parameters

Parameter	Wind
Earliest Feasible Year of Installation	2029
Lead Time in Years (includes development and construction)	3.5
ISO Net Output, Full Load MW	100
Typical Capacity Factor, 2023	44%
Capacity Credit towards Peak[18]	24% – Winter, 14% – Summer
Capital cost, 2025 (2023$/kW)	n/a
Capital cost, 2030 (2023$/kW)	1,852
Capital cost, 2035 (2023$/kW)	1,731
Fixed O&M (2023$/kW-year)	33.00
Ongoing capex (2023$/kW-year)	20.82

4.1.5 Solar

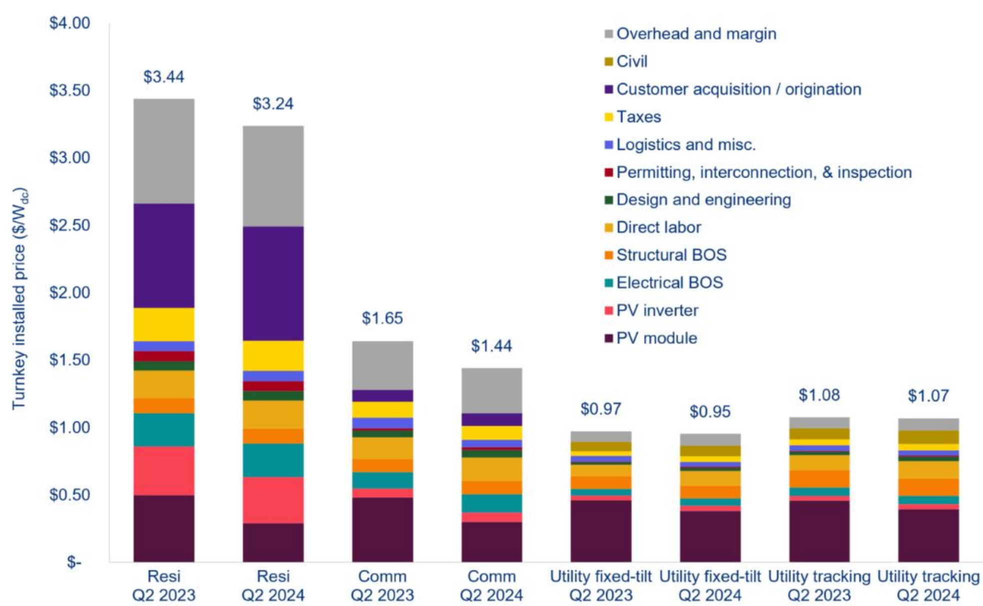
Solar energy is converted into electricity with solar panels, which are made up of PV cells. Today, most PV cells are made from crystalline silicon or thin-film semiconductor material. Silicon cells tend to convert sunlight to electricity more efficiently but are more costly to manufacture. Thin-film materials are less costly to manufacture but also less efficient. Some PV systems use a tracking system that orients the panels towards the sun to capture more solar radiation throughout the day. The downside of trackers is that they require systems to have less dense configurations and cost more to install and maintain over their lifetime. Thus, for a tracker to make economic sense, the net gains from increased electricity production must exceed the added installation and maintenance cost net of tax credits. In this analysis, specific solar technology has not been specified between fixed tilt and tracking allowing for the flexibility for various solar technologies in the procurement process post-IRP. Liberty-Empire has also found this to be the case in its screening analysis. PV systems are also increasingly including battery storage to compensate for the intermittent nature of solar energy, taking advantage of declining

[18] Represents 2027 value. Liberty-Empire assumes decline in wind ELCC to 22% for winter while remaining at 14% for summer by 2044 based on guidance from a recent SPP ELCC study and the level of wind penetration in the market from CRA's market modeling. More information about CRA's modeling approach can be found in Volume 6.

prices for storage technologies, the ITC benefit, existing interconnection, and storing direct current electricity not from the grid.

Over the past decade, the cost of developing PV systems has dropped substantially with improved technology, new materials, and lower installation costs. However, in Q2 2024, PV system prices declined across all segments as module costs dropped significantly, despite higher costs for the balance of system and labor costs. Distributed generation modules have decreased 40% year-over-year. Utility-scale solar also fell for the first time in two years. The year-over-year change in U.S. solar PV installed prices by market segment is shown in Figure 4-9. In the 2025 IRP, Liberty-Empire assumes that capital costs remain flat in real terms until 2025 and then continue to decline thereafter, as presented in the capital cost tables earlier in this Section.

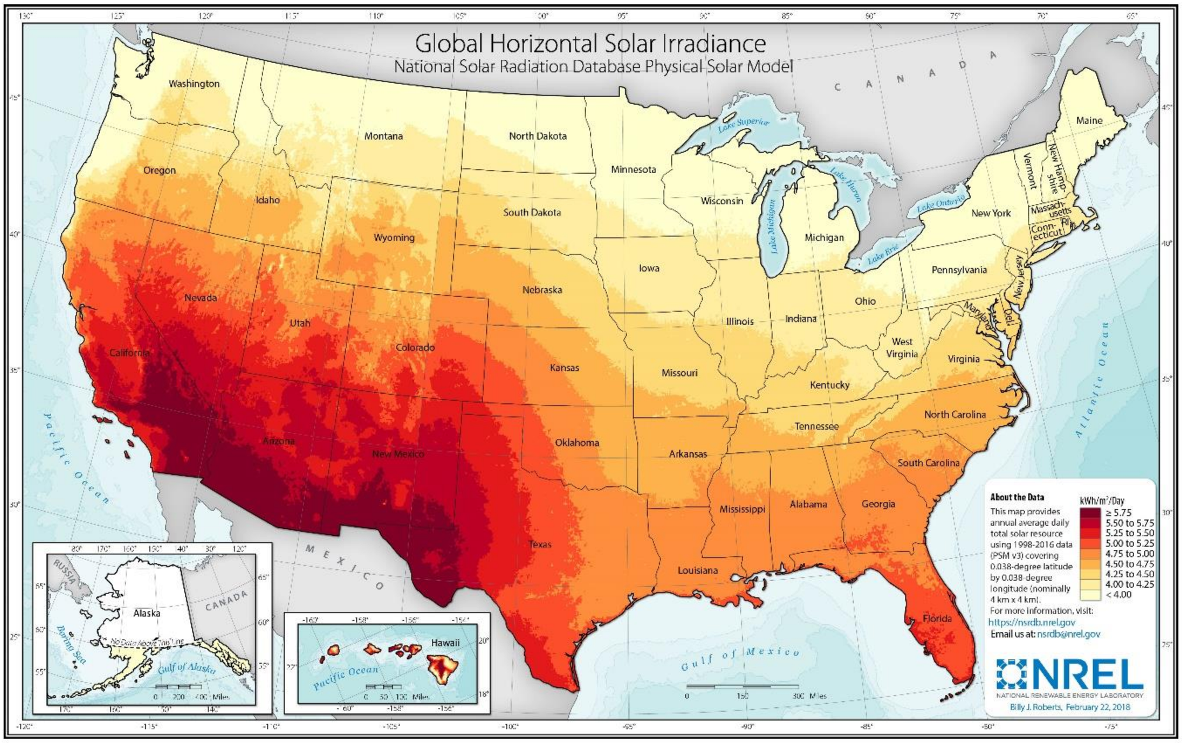
Figure 4-9 – Modeled US National Average System Prices by Market Segment, Q2 2023 and Q2 2024 (Source: SEEIA)[19]



[19] Solar Energy Industries Association (SEIA)/Wood Mackenzie Solar Market Insight Report Q3 2024. https://seia.org/research-resources/solar-market-insight-report-q3-2024/

Solar irradiation is generally the strongest in the Southwest and weakest in the Northeast. The irradiation levels in the SPP region fall roughly in the middle of these two extremes, leaving Liberty-Empire with a roughly average level of solar irradiation relative to the rest of the nation. Figure 4-10 presents nationwide solar irradiation levels.

Figure 4-10 – Global Horizontal Solar Irradiance in the U.S. (Source: NREL)



Cost and performance estimates for the solar PV options are shown in Table 4-18. As with the wind estimates, all cost estimates are provided prior to consideration of federal tax credits and their potential impact on Liberty-Empire's capital cost contribution. The details of federal tax incentives and modeling assumptions included in the 2025 IRP analysis are summarized in Section 2.4.2.

Table 4-18 – Solar PV Single Axis Tracking Performance Parameters

Parameter	Solar PV – Utility Scale	Solar PV – Community Scale
Earliest Feasible Year of Installation	2027	2027
Lead Time in Years (includes development and construction)	2	2
ISO Net Output, Full Load MW	50	5
Typical Capacity Factor	21%	15%
Capacity Credit towards peak[20]	34% – Winter, 60% – Summer	34% – Winter, 60% – Summer
Capital cost, 2025 (2023$/kW)	n/a	n/a
Capital cost, 2030 (2023$/kW)	1,637	2,779
Capital cost, 2035 (2023$/kW)	1,199	2,035
Fixed O&M (2023$/kW-year)	19.30	18.26
Ongoing capex (2023$/kW-year)	0.00	0.00

Although the modeling assumes a 2-year development lead time, the GIA process at SPP has recently taken longer.

4.1.6 Nuclear Small Modular Reactor

Small Modular Reactors ("SMR") are a new type of nuclear fission technology utilizing smaller reactor designs, module factory fabrication, and passive safety features. Key features of an SMR include:

- Small physical footprints;
- Limited on-site preparation, leading to faster construction time and scalability;
- Siting flexibility including sites previously occupied by other technologies; and
- Passive safety features, allowing the reactor to safely shutdown in an emergency without requiring human interventions.

[20] Represents 2027 value. Liberty-Empire assumes declines in solar ELCC to 6% for winter and 13% for summer by 2044 based on guidance from a recent SPP ELCC study and the level of solar penetration in the market from CRA's market modeling. More information about CRA's modeling approach can be found in Volume 6.

SMR can be an alternative for providing baseload electricity without CO_2 emissions. Its siting flexibility and improved safety features allow it to be sited closer to demand centers, reducing transmission investments.

SMR is still in the early stages of development, and uncertainties remain regarding the technology's cost, performance, and availability. The cost assumptions for this IRP represent Nth-of-a-Kind ("NOAK"), reflecting an assumption that Liberty-Empire's development of SMR would occur after other similar projects were underway or operating. Table 4-19 This table shows the cost and performance estimates for SMR. It assumes that SMR will be available for commercial deployment starting in 2035 for net zero portfolios.

Table 4-19 – Small Modular Reactor Performance Parameters

Parameter	Small Modular Reactor
Earliest Feasible Year of Installation	2035
Lead Time in Years (includes development and construction)	5
Equivalent Forced Outage Rate	5%
ISO Net Output, Full Load MW	300
Full Load Net Heat Rate, Btu/kWh	10,421
Capital cost, 2035 (2023$/kW)	8,520
Fixed O&M (2023$/kW-year)	142.65
Variable O&M (2023$/MWh)	3.07
Ongoing capex (2023$/kW-year)	57.82
CO_2 Emissions (lbs/MMBtu, HHV)	0

4.1.7 Hydrogen

Hydrogen ("H_2") can be utilized for combustion by installing a greenfield combustion turbine or combined cycle plant designed for hydrogen use or retrofitting an existing hydrogen-enabled CC plant. Hydrogen CCs operate on the same principle as the NGCC systems discussed in Section 4.1.2 but with some differences in operating characteristics, including:

- Energy density: H_2 is one-third less energy-dense than natural gas. Using hydrogen as a fuel will require a fuel accessory system configured to provide three times higher fuel flow rates into the turbine relative to using natural gas;
- Flame speed: H_2 has about 4.5 times the flame speed of natural gas. The combustion systems have to be configured specifically for hydrogen to prevent the flame from propagating upstream;
- Flammability: H_2 is more flammable than natural gas. The enclosure and ventilation system have to be designed to limit the concentration of hydrogen; and
- Flame temperature: H_2 burns at a higher temperature than natural gas, resulting in higher NO_X emissions. A selective catalytic reduction system is required to reduce NO_X emissions.

H_2 can play multiple roles within an electricity system. It can provide storage capacity during periods of high renewable generation and, depending on H_2 prices, cycling capabilities for intermediate loads or generation capacity during periods of high electricity demand. As a gas turbine technology, hydrogen can also provide system services such as inertia, frequency response, voltage support, and regulating reserves.

Cost and performance estimates for new H_2 CC and H_2 CC retrofits are shown in Table 4-20. The variable operating cost for an H_2 CC is estimated to be two to three times the estimate for an NGCC, reflecting additional costs for maintaining a system with high levels of water and steam injection for emission control.

For purposes of the 2025 IRP, hydrogen will be available starting in 2035 for net zero portfolios based on statements by major power equipment providers committing to providing 100% H_2-enabled turbines by the early-to-mid 2030s.

Table 4-20 – Hydrogen Resources Performance Parameters

Parameter	Hydrogen CT	Hydrogen Retrofit on CC
Earliest Feasible Year of Installation	2035	2035
Lead Time in Years (includes development and construction)	5	5
Equivalent Forced Outage Rate	5%	5%
ISO Net Output, Full Load MW	54	627
Full Load Net Heat Rate, Btu/kWh	9,224	6,399
Minimum Load Net Heat Rate, Btu/kWh	12,100	7,300
Capital cost, 2035 (2023$/kW)	1,847	120
Fixed O&M (2023$/kW-year)	22.05	18.68
Variable O&M (2023$/MWh)	19.50	3.13
Ongoing capex, 2035 (2023$/kW-year)	3.86	3.86
CO_2 Emissions, lbs./MMBtu (HHV)	0	0

4.1.8 Storage Resources

Decreased prices and improvements in manufacturing capacity have played important roles in the expansion of battery storage in recent years. Simultaneously, ongoing changes to industry regulation that allow or will allow stored energy resources to participate in wholesale electricity markets, like SPP's Integrated Marketplace, are likely to increase their value. U.S. battery storage capacity has been increasing since 2021 and grew by 66% in 2024 if developers bring all planned energy storage systems online as scheduled. By then, developers aim to boost U.S. battery capacity to over 30 GW, surpassing the capacities of petroleum liquids, geothermal, wood and wood waste, and landfill gas.[5]

Lithium-ion batteries currently represent the industry standard option for utility-scale storage technology. These resources involve the transfer of lithium ions between electrodes during charging and discharging. The exact chemistry of a lithium-ion battery varies. Generally, the cathode is made of lithiated metal oxides or phosphates, and the anode is made of carbon or lithium titanate. The resulting electrodes are lightweight.

[5]https://www.eia.gov/todayinenergy/detail.php?id=64705

Lithium is a highly reactive element, which means it can store a significant amount of energy in its atomic bonds and has high energy efficiency.

In the past few years, lithium-ion manufacturing factories, including Tesla's Gigafactories, have rapidly built out to meet the demand for batteries in EV applications, typically lithium-ion due to their lightweight and high energy efficiency. Production costs have fallen significantly as a result of this increase in scale. Although lithium-ion batteries have a higher up-front cost than other alternatives like lead-acid batteries, they generally have important advantages over lead-acid batteries, such as their superior volumetric energy density and gravimetric energy density, meaning that they are smaller and lighter. Lithium-ion batteries are also more resilient and, thus, have longer life cycles and are less likely to be harmed if discharged too quickly or if extreme weather occurs.

As discussed in Section 2.4.3, Liberty-Empire has identified a lithium-ion battery option as the best benchmark for potential storage resource additions in the short to medium term. Cost and performance estimates for the lithium-ion battery options are shown in Table 4-21. As with the standalone wind and storage estimates, all cost estimates are provided before consideration of federal tax credits and their potential impact on Liberty-Empire's capital cost contribution. The details of federal tax incentives and modeling assumptions included in the 2025 IRP analysis are summarized in Section 2.4.2.

Table 4-21 – Lithium-Ion Battery Performance Parameters

Parameter	Lithium-Ion Battery – Utility Scale 4 hr	Lithium-Ion Battery – Utility Scale 8 hr	Lithium-Ion Battery – Distributed Scale
Earliest Feasible Year of Installation	2027	2027	2027
Lead Time in Years (includes development and construction)	1.5	1.5	1
ISO Net Output, Full Load MW	50	50	1
Storage duration (hours)	4	8	4
Round-trip efficiency (%)	90%	90%	90%
Capital cost, 2025 (2023$/kW)	n/a	n/a	n/a
Capital cost, 2030 (2023$/kW)	1,470	2,646	n/a
Capital cost, 2035 (2023$/kW)	1,356	2,427	1,800
Fixed O&M, 2023 (2023$/kW-year)	26.06	45.00	7.48
Ongoing capex, 2023 (2023$/kW-year)*	41.43	68.30	20.00

*Note that the ongoing capex assumes full replacement of cells after 15 years.

As discussed in Section 2.4.3 Liberty-Empire will consider vanadium redox flow batteries and gravity concrete block storage only for longer-term net zero portfolios.

Vanadium flow batteries store energy in vanadium-based electrolytes that can transfer electrons back and forth between four different oxidation states, causing charge and discharge. The electrolytes are dissolved in water and stored in two tanks connected by an iron-selective membrane. During discharge, an electrolyte produces DC power that is converted to AC power using converters and controllers. Electrolytic fluid is then regenerated using DC power from the converter during a charge. Flow batteries are already commercially deployed, but their supply chain is not as mature as lithium-ion batteries. Key benefits of flow batteries include siting flexibility, long-duration capability, and no degradation during their lifetime.

The Energy Vault concrete block gravity storage system uses electric motors to lift 35-ton concrete blocks and stack them to form a tall tower. The stored potential energy involved in lifting the blocks is converted to electricity by dropping the stacked blocks one by one by a tether. To date, Energy Vault has only built one energy storage system: a 5-MW commercial demonstrator project in Switzerland. However, given the modularity, simple underlying technology, operations, and significant investment activity in Energy Vault over the 2020-2021 period, Liberty-Empire evaluated this technology as a viable option for longer-term net zero portfolios available for 2035 and beyond.

Cost and performance estimates for flow battery and gravity storage options are shown in Table 4-22.

Table 4-22 – Flow and Gravity Storage Performance Parameters

Parameter	Flow Battery	Gravity
Earliest Feasible Year of Installation	2035	2035
Lead Time in Years (includes development and construction)	1.5	1.5
ISO Net Output, Full Load MW	50	50
Storage duration (hours)	8	8
Round-trip efficiency (%)	70%	80%
Capital cost, 2035 (2023$/kW)	3,840	6,500
Fixed O&M, 2035 (2023$/kW-year)	16.11	65.00
Ongoing capex (2023$/kW-year)	0	0

4.2 Elimination of Preliminary Supply-Side Resources Due to Interconnection or Transmission

(B) The utility shall indicate which, if any, of the preliminary supply-side candidate resource options identified in sub-section (2)(C) are eliminated from further consideration on the basis of the interconnection and other transmission analysis and shall explain the reasons for their elimination.

None of the preliminary supply-side candidate resource options were eliminated from consideration based on interconnection or transmission analysis.

4.3 Interconnection Cost for Supply-Side Resource Option

(C) The utility shall include the cost of interconnection and any other transmission requirements, in addition to the utility cost and probable environmental cost, in the cost of supply-side candidate resource options advanced for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3).

For the purposes of Liberty-Empire's 2025 IRP, Liberty-Empire assigned transmission costs on a dollar-per-kilowatt basis for each candidate resource examined in this IRP. The interconnection cost estimate for the Liberty-Empire region was derived from a survey of the latest available data from Berkeley Labs[21]. Interconnection costs differ by location, with projects in the northern SPP region generally reporting higher costs than those in the southern region, although these regional trends are not very strong. Many recent projects have been withdrawn from the transmission queue due to scarcity and prohibitive interconnection costs. In the current environment and in the face of significant uncertainty, Liberty-Empire deemed this cost level representative of the marginal project local to Liberty-Empire's service territory.

In addition to location and project-specific factors, interconnection costs vary greatly based on the generation type. Gas, solar, and storage have similar costs, but wind energy is almost double that of the other resource types. For the purposes of this IRP, other advanced baseload technologies will be subject to the same interconnection costs as gas. This includes hydrogen—new and conversions, and SMR technology. Advanced long-duration storage will receive the storage interconnection costs. Interconnection costs by resource type are summarized in Table 4-23.

Table 4-23 – 2024 Interconnection Costs by Resource Type

Resource Type	Interconnection Cost (2023$/kW)
Gas	91
Solar	103
Wind	219
Storage	108

Resources that utilize the interconnection capacity of retiring units at existing sites and resources co-located at existing sites to utilize surplus or unused interconnection capacity would avoid paying this interconnection cost.

[21] Berkeley Lab gathered interconnection cost data from 845 projects in the Southwest Power Pool (SPP) territory, covering studies conducted between 2002 and 2023 with the most refined cost estimates. https://emp.lbl.gov/publications/generator-interconnection-cost-0

4.3.1 Co-Location at Existing Sites

For the 2025 IRP, Liberty-Empire considered the ability to co-locate new resources at the following existing sites: North Fork Ridge Wind Farm, Kings Point Wind Farm, and Neosho Ridge Wind Farm. Based on land and siting availability at these sites, Liberty-Empire assumed that solar and/or lithium-ion battery storage resources could be co-located at North Fork Ridge and Neosho Ridge Wind Farms up to the amount of the interconnection availability while these facilities are still in operation, with 2027 being the first feasible in-service year. Kings Point Wind Farm is located near the Energy Center gas generation site, giving it access to gas infrastructure and making it well-suited for co-location of gas generation to make use of spare interconnection. Co-location of new gas units at Kings Point will also allow for a shorter development timeline, with commissioning for the first available year moved up to 2029 from 2031 for greenfield sites. Co-located resources also avoid paying generator interconnection costs and provide both energy and capacity value to the portfolio by selling generation into the market and/or serving Liberty-Empire load during times of interconnection availability.

To determine the amount of solar and/or paired storage resources that could be co-located at the existing wind sites of Neosho Ridge and North Fork Ridge, CRA developed an optimization model that considered as inputs the expected 8760 wind generation profile at each site, the expected 8760 solar generation profile, key operational parameters for a storage asset (e.g., duration, efficiency, etc.), the capital costs to build and operate the new solar and storage assets, the value of capacity of the new solar and storage assets, and the hourly market power price defining the value of the generation. For each wind site, the optimization model evaluated the optimal ICAP MW amount of solar and storage that could be co-located at the site, defined as the combined amount of solar and storage that, in conjunction with output from the wind resource, would maximize the value of the site over the 30-year life of the project. The model limited wind and solar curtailment such that the NPV of the lost value of curtailed energy over the 30-year life of the project was below the interconnection costs listed in Section 3.1 (i.e., the cost of interconnecting a resource at a greenfield site). It was found that solar exclusively was the preferred resource for colocation at these sites.

For the co-location of gas at the existing Kings Point wind site, CRA considered smaller gas generation technologies, including RICE and aeroderivative CT, which could fit within the available spare interconnection at the site. CRA utilized the Aurora model, evaluating operations of these gas co-location options to take into account reduced gas unit output at times where the combined output of wind resource and gas would exceed total interconnection.

The results of the analysis are shown in Table 4-24. For IRP modeling purposes, the solar ICAP values represent the maximum co-located capacity which would be more economic than new greenfield development. The gas ICAP value at Kings Point represents the maximum co-located capacity subject to constraints of gas block size and capacity accreditation potential at the site. [22]

Table 4-24 – Co-Location Results at Wind Sites

Site	Wind ICAP MW	Solar ICAP MW[23]	Gas ICAP MW
Neosho Ridge	301	118	n/a
North Fork Ridge	149	138	n/a
Kings Point	149	n/a	100

Based on these modeling parameters, co-located resource options were made available to be optimally selected without the cost of new interconnection in the integrated portfolio modeling described in Volume 6. Reduced value for any curtailment of output was also taken into account in this analysis.

[22] 150 MW total interconnection at North Fork of which 43 MW is utilized by the existing wind for capacity accreditation, leaving 107 MW available for a gas resource. Liberty-Empire also considered co-location of gas at any new greenfield solar sites. Solar development location is relatively flexible and can be positioned near existing gas infrastructure as provision for gas colocation. Relatively low capacity accreditation of solar allows for a 2:1 ratio of installed capacity of solar to gas without impeding capacity accreditation of both resources.

[23] A higher quantity of solar is economically accommodated at North Fork than at Neosho because the wind profile at North Fork is less coincident and more complimentary with solar.

SECTION 5 SUPPLY-SIDE UNCERTAIN FACTORS

(5) The utility shall develop and describe and document ranges of values and probabilities for several important uncertain factors related to supply-side candidate resource options identified in Section (4). These cost estimates shall include at least the following elements, as applicable to the supply-side candidate resource option:

5.1 Fuel Forecasts

(A) Fuel price forecasts, including fuel delivery costs, over the planning horizon for the appropriate type and grade of primary fuel and for any alternative fuel that may be practical as a contingency option;

For purposes of the 2025 IRP, Liberty-Empire developed a set of coal price and natural gas price forecast ranges for use in the portfolio analysis for existing and new resources. This Section describes the existing natural gas-fired and coal-fired resources and fuel requirements in Liberty-Empire's existing portfolio, followed by a description and documentation of the fuel price ranges developed for this IRP.

5.1.1 Existing Coal and Natural Gas-Fired Unit Fuel Requirements

Coal Fuel Requirements

As discussed previously in Section 1.2**,** Liberty-Empire holds minority ownership shares in coal-fired resources at the Iatan and Plum Point facilities. Liberty-Empire's ownership share at the Iatan plant is 12% (approximately 84 MW of Unit 1 and 108 MW of Unit 2). Evergy is the plant's operator responsible for arranging its fuel supply. The PRB coal burned at Iatan is transported by rail by the Burlington Northern and Santa Fe ("BNSF") Railway Company. Liberty-Empire owns, through an undivided interest, 7.52% (approximately 50 MW) of the coal-fired Plum Point Energy Station, along with a PPA representing 50 MW of output from the plant. Plum Point Services Company, LLC ("PPSC"), the project management company acting on behalf of the joint owners, is responsible for arranging its fuel supply. Liberty-Empire has a 15-year lease agreement, which expired in 2024, for 54 railcars for Liberty-Empire's ownership share of Plum Point. This agreement is in the process of renewal. In December 2010, Liberty-Empire entered another 15-year lease agreement for an additional 54 railcars associated with the Plum Point PPA that expires in 2026. Both of these lease agreements will be incorporated into a new agreement at that time.

Natural Gas Fuel Requirements

As discussed previously in Section 1.2 Liberty-Empire owns natural gas-fired resources at three locations: the Riverton, Energy Center, and State Line generation facilities. The Riverton facility consists of a combined cycle unit (Riverton 12) fueled entirely by natural gas and two small simple cycle natural gas-fired units (Riverton 10 and 11) with dual fuel capability with fuel oil.[24] The Energy Center generation facility consists of four natural gas-fired turbines that can also burn fuel oil as a backup fuel. Finally, the State Line facility has a natural gas-fired combustion turbine (State Line 1) to burn fuel oil and the jointly-owned natural gas-fired SLCC. In 2023, fuel consumption at the Energy Center was 96.35% natural gas on a generation basis and 96.40% at State Line 1. In 2024, fuel consumption at the Energy Center was 87.4% natural gas on a generation basis and 96.39% at State Line 1.

Liberty-Empire has firm transportation agreements with Southern Star Central Pipeline, Inc., which are set to expire on May 1, 2035. These agreements provide for the transportation of natural gas to State Line Combined Cycle (SLCC). Additionally, Liberty-Empire has firm transportation agreements to supply Riverton Unit 12, and Energy Center Units 1-4, also through May 1, 2035. These transportation agreements offer the flexibility to supply a portion of the natural gas needed for State Line 1, the Energy Center facility, or the Riverton facility, based on Liberty-Empire's needs.

Most of Liberty-Empire's physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged a few years into the future following Liberty-Empire's Risk

[24] As discussed in Section 1, Riverton 10 and 11 will be replaced by units 13 and 14 in 2026.

Management Policy to lessen the volatility in Liberty-Empire's fuel expenditures and gain predictability.

5.1.2 Coal Price Forecast

Figure 4-11 and Table 4-25 summarize the delivered fuel price forecast for Southern PRB coal associated with Iatan and Plum Point Energy Center.

Figure 4-11 – Coal Price Forecast for Southern PRB Coal (Iatan and Plum Point Delivered)

****Confidential in its Entirety****

[redacted]

Table 4-25 – Coal Price Forecast for Southern PRB Coal (Iatan and Plum Point Delivered)
****Confidential in its Entirety****

[redacted]

Coal price forecasts for Liberty-Empire's jointly-owned units were based on the operator's most recent 5-year fuel projection in the near term, which incorporates the most recent coal contracts at each plant for those years. In the medium to longer term, the coal price forecasts were escalated based on forecasted growth rates for PRB coal costs as developed by Horizons Energy, combined with transportation adders for Liberty-Empire's coal units.

For the 2025 IRP, Liberty-Empire did not develop high or low scenario forecasts for PRB coal prices for two primary reasons. First, Liberty-Empire's coal-fired resources consist only of Iatan and Plum Point, which are minority-owned and not operated by the

Company. Second, Liberty-Empire does not plan to consider any new coal resources in the portfolio in the future.

5.1.3 Natural Gas Forecast

For the 2025 IRP, Liberty-Empire contracted with its IRP consultant, CRA, to develop a set of market fundamentals-based natural gas price scenario forecasts (Base Case, High Case, and Low Case) for use in the portfolio analysis for both existing and new natural gas-fired resources. Natural gas prices were developed by CRA using a set of fundamental market models, including the Natural Gas Fundamentals ("NGF") model, which produces bottom-up natural gas price and production projections in North America. Inputs to NGF include the latest views from public sources (e.g. EIA and PGC) on natural gas demand by sector, production forecasts, drilling costs, and oil prices under various fundamental potential market conditions. These inputs are further described later in this Section.

CRA also forecasted seasonal and regional prices over the long-term using the Gas Pipeline Competition Model ("GPCM") model, blended with market forwards over the near term to maintain consistency with observed market prices.

Figure 4-12 and Table 4-26 show the forecasted Henry Hub natural gas prices for the Base, High, and Low Case scenarios every month. Figure 4-13 and Table 4-26 show the monthly forecasted Southern Star Delivered natural gas prices for the Base, High, and Low Case scenarios.

NP

Figure 4-12 – Forecasted Base, High, and Low Natural Gas Prices (Henry Hub)
****Confidential in its Entirety****

[redacted]

Figure 4-13 – Forecasted Base, High, and Low Natural Gas Prices (Southern Star Delivered)
****Confidential in its Entirety****

[redacted]

Table 4-26 – Forecasted Base, High, and Low Natural Gas Prices (Henry Hub and Southern Star)
****Confidential in its Entirety****

[redacted]

5.1.4 Natural Gas Price Forecasting Methodology

Liberty-Empire's 2025 IRP natural gas price forecasts are driven by several key market assumptions regarding the major supply and demand dynamics in the North American natural gas market. Figure 4-13 provides a high-level overview of CRA's natural gas price development approach over the study horizon. Figure 4-14 provides an overview of the key inputs that drive CRA's fundamental forecast in its Natural Gas Fundamentals ("NGF") model.

Figure 4-13 – Overview of CRA's Natural Gas Price Development Approach

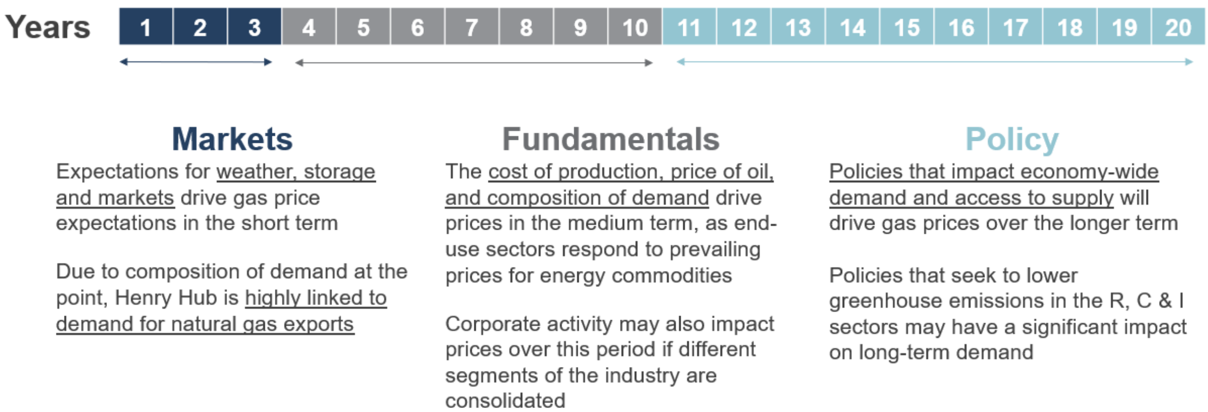
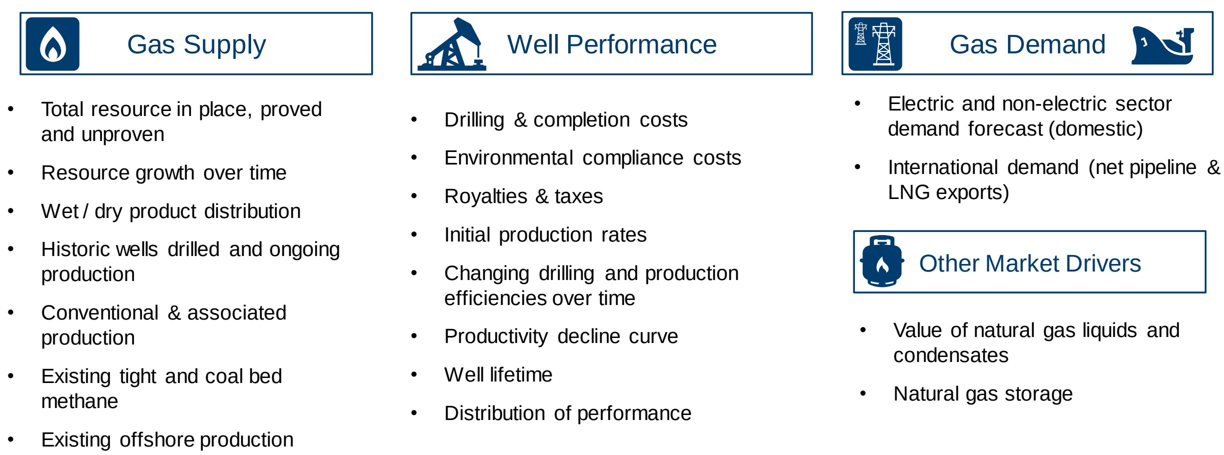


Figure 4-14 – Overview of CRA's NGF Model Inputs



5.1.5 Natural Gas Price Forecast – Base Case Drivers

CRA's Base Case natural gas price forecast is based on a fundamental evaluation of key supply and demand side drivers, as described in more detail below.

Resource Size

In developing long-term estimates for natural gas resource size, CRA relied on the Potential Gas Committee (PGC) "minimum" value as the starting value for recoverable shale reserves. The resource base grew steadily until the PGC "most likely" value was reached in 2050. The minimum value is based on a 100% probability that the resource is recoverable, and the most likely value adds additional resources with reasonable assumptions about source rock, yield factor, and reservoir conditions.

Well Productivity

Natural gas well productivity assumptions are important drivers of ultimate production efficiency, especially since the bulk of the natural gas resource is currently unproven, meaning that the geology of that resource is currently unknown. In developing assumptions for this variable, CRA generated productivity distributions for each production basin based on drilling data in regions that producers expected to have favorable geology. CRA's view is that historical data is biased towards higher-producing sub-regions since the completed wells that produce gas do not reflect a random sampling of the underlying geology in each basin. Therefore, to reflect the expectation that the remaining resource is more likely to be lower quality over time as the premium acreage is depleted, CRA assumes a "Poor Heavy" productivity distribution for future undiscovered resources in the Base Case.

Well Costs

CRA develops drilling cost assumptions by evaluating reported costs from major producers within a supply region. In the last 5 years, producers reported improvements in drilling and O&M costs across most but not all shale basins, and CRA broadly assumes that these improvements will continue over time.

For going forward costs, CRA relies on the EIA's AEO projections for drilling and O&M cost improvements. EIA's approach incorporates annual improvements to key well inputs that account for ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources from historical time periods. Drilling costs are expected to decline by 1% per year for tight oil and shale gas formations and decline by 0.25% per year for all other basins. Equipment and operating costs are expected to decline by 0.5% per year for tight oil and shale gas formations and decline by 0.25% per year for all other basins.

Domestic Demand

CRA relies on the AEO's projections for residential, commercial, industrial, and transport demand to project domestic natural gas demand growth. It also developed an independent electric sector demand forecast using its hourly Aurora dispatch model for the United States. Electric sector demand is expected to be relatively flat throughout the forecast horizon. The AEO's growth expectations for other sectors are also relatively flat, with some growth expected in the industrial sector over time.

Exports - LNG and to Mexico

CRA develops projections for natural gas exports to Mexico via pipeline and to other international markets through LNG by reviewing estimates published by sources like the AEO and analyzing specific export projects under development.

While several LNG export projects are now online or under construction due to softening prices and increased competition, CRA expects that few currently proposed projects will be completed after the Calcasieu Pass and Golden Pass come online in 2023 and 2024. CRA's Reference Case projection for LNG exports will grow to under 20 bcf/day by 2024.

While CRA expects that exports to Mexico will also increase over time, actual exports to Mexico are not keeping pace with the expansion of cross-border export capacity. Numerous pipeline projects in Mexico have faced construction delays, and completed projects operate below capacity. For example, the 1.1 Bcf/d Comanche Trail pipeline has been utilized only 10% on average since completion in June 2017, and the 1.4 Bcf/d Trans-Pecos pipeline completed in 2017 currently has operated at 10-15% of total capacity since completion. Therefore, in the Reference Case, CRA projects modest additional growth in export volume but expects pipeline capacity to continue underutilizing.

Base Case Natural Gas Price Forecast Summary

As a part of its commodity price development process, CRA blends short-term gas price forwards with the fundamental forecast to capture current market dynamics. During forecast development, natural gas spot prices and short-term forwards saw significant lows, driven by a supply surplus and historically high storage inventories. While CRA incorporated the effect of the lower spot prices in its near-term forecast, increased demand, especially from LNG exports, is expected to lead to price recovery over the long term.

CRA's long-term Base Case price forecast was developed based on each of the supply-demand inputs discussed above and is shown in Figure 4-15. The Base Case expects prices to recover marginally from current forward levels over the next few years and then reach about $7/MMBtu (nominal) over the long term. A summary of the key drivers of the Base Case Henry Hub and regional forecasts follows:

- Increased discipline in shale drilling programs has brought production growth more in line with demand growth. Natural gas producers have not immediately responded to higher gas prices with increased production, and prices will remain somewhat elevated in the next couple of years relative to recent history.
- CRA's Base Case view reflects expectations for continued industry consolidation.
- LNG and pipeline exports to Mexico grow over time and combine with strong domestic demand to increase prices modestly over the forecast period as the lowest-cost production regions are exhausted.
- Expectations for downward price pressure driven by improvements in drilling and O&M costs are expected to be moderated by lower domestic oil prices and associated gas volumes.
- Policy shifts at FERC will add cost and schedule to pipeline expansions, although a new pipeline certificate policy has not been implemented. In the Base Case, limited pipeline expansion is assumed in states that have withheld permits for pipeline expansions. This has caused a slight widening of the basis between supply basins and market hubs.

Figure 4-15 illustrates the Base Case for Henry Hub and Southern Star in Nominal$/MMBtu.

Figure 4-15 – Base Gas Natural Gas Price Forecast
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[redacted]

5.1.6 Natural Gas Price Forecast – High Case Drivers

Under the High Case, natural gas prices rise faster over the forecast period under growing international demand. Producers are expected to realize fewer drilling efficiency and cost improvements over time, and LNG exports will grow. These factors drive Henry Hub natural gas prices up to $13/MMBtu (nominal) long-term. Figure 4-16 illustrates the High Case for Henry Hub and Southern Star in nominal$/MMBtu.

Figure 4-16 – High Case Natural Gas Price Forecast
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[redacted]

5.1.7 Natural Gas Price Forecast – Low Case Drivers

Under the Low-Case view, long-term prices remain flat or fall modestly due to a more favorable view of the long-term resource base. Exploration and drilling efficiency improvements advance more rapidly due to artificial intelligence than in the Base-Case view, while domestic demand is tempered by environmental regulation. These factors keep Henry Hub's natural gas prices below $8/MMBtu (nominal) long-term. Figure 4-17 illustrates the Low Case for Henry Hub and Southern Star in nominal$/MMBtu.

Figure 4-17 – Low Case Natural Gas Price Forecast
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[redacted]

5.1.8 Natural Gas Risk Management Policy

Liberty-Empire works diligently to mitigate the price volatility associated with changes in natural gas pricing. In 2001, Liberty-Empire developed and implemented a Risk Management Policy (“RMP”) to manage this volatility. The policy was revised and formally adopted on July 19, 2019. The RMP minimizes Liberty-Empire’s exposure to the impacts of fluctuating natural gas prices. Under the current policy, forward contracts are the preferred fixed price instruments though occasionally financial hedges have been utilized under specific conditions. Under the new advanced procurement strategy, authorized vehicles include Forward Physical Index Contracts and Forward Physical Fixed Contracts triggered by historical pricing levels. The natural gas hedging policy also addresses how far in the future advanced procurement may take place and for which months the hedging may apply. This approach is intended to protect customers from volatility in the marketplace and provide the ability to procure natural gas in advance when pricing indicates economic value as defined by the price matrix described in the RMP. In addition, the approach protects against volatility in local natural gas supply, ensuring the supply management group will have the required natural gas available to meet budgeted native load targets. Of note, the Company's fuel procurement group can request waivers from the Risk Management Oversight Committee ("RMOC"), as necessary, to keep in line with changing market conditions. Liberty-Empire has currently established the price on the following quantities of natural gas for the upcoming calendar years in Table 4-27.

Table 4-27 – Liberty-Empire Natural Gas Hedges
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[redacted]

5.2 Capital Costs of Supply-Side Candidate Options

(B) Estimated capital costs including engineering design, construction, testing, startup, and certification of new facilities or major upgrades, refurbishment, or rehabilitation of existing facilities;

The capital costs modeled for each resource option assume an EPC contracting strategy. Each option includes an allowance for typical owner's expenses, an on-site switchyard, transmission interconnect, natural gas interconnect, and water interconnect, as applicable. Ranges for high and low capital costs were developed for candidate supply-side resources as part of the more extensive process of developing cost and operational parameters. These ranges are shown in Table 4-28.

Table 4-28 – Capital Cost Ranges over Time for Candidate Supply Side Options

Capital Costs (2023$/kW)						
Case	**Year**	**Combined Cycle**	**Combustion Turbine-Frame**	**Combustion Turbine-Aero-derivative**	**RICE - Utility Scale**	**RICE - Distributed**
Base	2025	1,125	940	1,786	1,885	2,827
Base	2030	1,085	902	1,713	1,808	2,713
Base	2035	1,044	864	1,641	1,732	2,598
Low	2025	989	799	1,607	1,659	2,488
Low	2030	951	767	1,542	1,591	2,387
Low	2035	913	734	1,477	1,524	2,286
High	2025	1,307	1,062	1,928	2,111	3,166
High	2030	1,262	1,019	1,850	2,025	3,038
High	2035	1,218	976	1,772	1,940	2,910

Case	Year	Utility Scale Solar	Distributed Solar	Li-Ion Storage - Utility-Scale – 4hr	Li-Ion Storage - Utility-Scale – 8hr	Li-Ion Storage - Utility-Scale – 10hr	Distributed Storage	Wind
Base	2025	1,823	3,094	1,437	2,622	3,321	1,577	1,766
Base	2030	1,438	2,441	1,205	2145	2,702	1322	1,623
Base	2035	1,053	1,788	1,112	1,967	2,473	1,220	1,517
Low	2025	1,570	2,664	828	1,633	1,740	909	1,431
Low	2030	1,154	1,958	652	1,286	1,370	716	1,230
Low	2035	737	1251	595	1,174	1,251	653	1,147
High	2025	2,295	3,895	2,150	3,489	4,459	2,360	2,067
High	2030	1,988	3,375	1,748	2,803	3,573	1,918	1,992
High	2035	1,682	2,854	1,688	2,707	3,451	1,852	1,917

Capital Costs (2023$/kW)						
Case	Year	H_2 CC Retrofit	H_2 CT	Small Modular Nuclear	Flow Battery (8-hr)	Gravity Storage
Base	2035	91	1,684	6,923	2,348	6,500
Base	2039	87	1,624	5,858	2,079	6,500
Base	2043	83	1,565	5,112	1,841	6,500
Low	2035	69	1,549	4,430	2,067	5,330
Low	2039	66	1,494	3,612	1,830	5,330
Low	2043	62	1,440	3,204	1,620	5,330
High	2035	145	1,902	10,522	2,607	8,775
High	2039	138	1,835	9,193	2,308	8,775
High	2043	132	1,768	8,196	2,043	8,775

5.3 Fixed and Variable Costs of Supply-Side Candidate Options

(C) Estimated annual fixed and variable operation and maintenance costs over the planning horizon for new facilities or for existing facilities that are being upgraded, refurbished, or rehabilitated;

The tables in the previous Sections include Base Case O&M costs for the candidate options. Depending on the technology being evaluated, costs are broken out into fixed, variable, and significant maintenance costs.

5.4 Emission Allowance Forecasts

(D) Forecasts of the annual cost or value of emission allowances to be used or produced by each generating facility over the planning horizon;

5.4.1 CO_2 Prices

Although several legislative and executive actions related to carbon emissions have been attempted over the last couple of decades, there is currently no price on carbon and no binding emission limits at the federal level. As of the time of the development of Liberty-Empire’s 2025 IRP assumptions, the Biden Administration had begun to take executive actions related to carbon emission reductions and had introduced several climate-related legislative proposals as part of its overall infrastructure package. However, as of March 2025, no policies directly regulating carbon emissions were signed into law.

Given a history of federal proposals to regulate carbon emissions, Liberty-Empire's Base Case incorporates a modest price on carbon emissions of $13-14/short ton starting in 2031, which can be seen as a proxy for several different potential pathways for legislative action or executive regulation (not explicitly a carbon tax). CRA's analysis suggests that pricing between $13-20/ton (in real 2023$) between 2031 and 2044 would achieve 60-70% reduction in SPP carbon emissions by 2044 relative to a recent historical year baseline, depending on other market factors and dynamics. Such a carbon price would likely result in significant additional coal-to-gas switching nationwide and pressure a significant percentage of the existing coal fleet nationwide to retire by 2044. The price would also improve renewable and other clean energy generation economics.

Liberty-Empire also evaluated the EPA GHG Standards, referenced in Section 2.5.1.1, which were modeled as the high-carbon stringency forecast, serving as an alternative to carbon pricing.[25] The plan involves retiring all coal by 2032. Additionally, new combined cycle gas turbine and simple cycle gas turbine units are capped at 40% and 20% capacity factors, respectively, while existing gas units remain unchanged.

Finally, Liberty-Empire also evaluated a Low-Case carbon scenario, which assumes no carbon price through the horizon. A zero-carbon regulation policy could result from either less stringent environmental regulation at the federal level or environmental regulation that does not directly regulate carbon emissions. Figure 4-18 shows the projected CO_2 costs ($/short ton) for all scenarios in nominal and real 2020 dollars.

[25] The current EPA GHG Standards will test the most stringent possibility of the EPA. It is understood that this ruling has received pushback, will likely continue to face legal challenges, and the final rule may change over time.

Figure 4-18 – CO_2 Price Forecast
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[redacted]

5.4.2 NO_X and SO_2 Prices

Several state and federal statutes regulate NO_X and SO_2, along with many other pollutants, complicating price projections for the costs of emissions, the limits on the emissions themselves, and the projected future emissions levels. Figure 4-19 presents the SO_2 price forecast for the state of Missouri. Figure 4-20 displays an annual price forecast for NO_X.

Figure 4-19 – SO_2 Group 1 (MO) Price Forecast
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[redacted]

Figure 4-20 – NO_X Annual Price Forecast
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[redacted]

5.5 Power Prices

Based on the three fuel price scenarios, the two carbon price scenarios, and the EPA rule scenarios, Liberty-Empire developed nine permutations of power market outcomes and resulting market power price trajectories for the integrated resource planning analysis.

Power prices were determined using the Aurora market model through long-term capacity expansion ("LTCE") power market modeling. The nine power price scenarios, summarized for SPP South Hub, are shown in Figure 4-21 annually.

Figure 4-21 – SPP South Hub All Hours Power Prices
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[redacted]

The Base Gas & Base Carbon power scenario was used as the price input for the simulation of day-ahead dispatch for Liberty-Empire's alternative resource portfolios for the Base Case. The remaining eight scenarios were used in the Critical Uncertainty analysis.

Because the core Aurora market and portfolio model is fundamentally based on a day-ahead hourly simulation, Liberty-Empire performed additional analysis to estimate the incremental value streams that flexible resources can achieve by participating in markets beyond day-ahead energy. To do this, CRA employed its proprietary Energy Storage Operations ("ESOP") model, an optimization model that computes revenues through participation in energy and ancillary service markets with five-minute granularity. Given simulated energy and ancillary service pricing information, ESOP solves optimal dispatch decisions unique to a price-taking resource's technological characteristics and a regional market's participation rules. Liberty-Empire evaluated the potential ancillary service value and sub-hourly energy revenue that highly flexible, fast-ramping supply-side resources (e.g., storage and gas peaking) could provide in these markets through simulation of co-optimized unit dispatch in sub-hourly energy and ancillary service markets.

For the 2025 IRP, the SPP five-minute real-time markets for energy, reg-up, reg-down, and spinning reserves were evaluated, with a focus on the performance of 4-hour lithium-ion battery storage, 8-hour flow battery storage, gravity storage, CT – aeroderivative, CT – frame, and RICE to evaluate specific tradeoffs of these capacity-advantaged resource options in Liberty-Empire's portfolio. CRA estimated real-time sub-hourly energy and ancillary service price forecasts based on historical relationships between day-ahead energy and real-time energy and ancillary service prices. These relationships were used to "shape" each of CRA's nine day-ahead power price scenarios into 5-minute real-time energy price projections for use in ESOP. While long-term market developments (e.g., market rules changes, actual real-time prices, SPP storage, and renewable capacity buildouts) are highly uncertain, CRA's modeling provided a reasonable estimate for this value.

Liberty-Empire assumed that units operated in the market according to assumed asset-specific characteristics reviewed by Black & Veatch (e.g., ramp rates, cycle limits, etc.). Liberty-Empire developed ESOP results for each of the power market outcome scenarios and each of the technology types described previously. The incremental real-time sub-hourly energy and ancillary service value was then included to offset costs for portfolio optimization and revenue requirement modeling.

5.6 Leased or Rented Facilities Fixed Charges

(E) Annual fixed charges for any facility to be included in the rate base or annual payment schedule for leased or rented facilities and

Liberty-Empire has no leased or rental facilities.

5.7 Interconnection or Transmission Costs for Supply-Side Candidates

(F) Estimated interconnection costs or other transmission requirements associated with each supply-side candidate resource option.

As discussed in Section 4.3 in the Base Case, interconnection costs for all supply-side candidate resource options vary by resource. Gas, solar, and storage have similar costs, but wind energy is almost double that of the other resource types. For the purposes of this IRP, other advanced baseload technologies will be subject to the same interconnection costs as gas. This includes hydrogen—new and conversions, and SMR technology. Advanced long-duration storage will receive the storage interconnection costs. The base case costs are forecasted, assuming a 2% annual growth rate.

The high case represents a scenario where system-wide renewable build-out accelerates and interconnection becomes scarcer. This results in a cost level reflective of the upper end of observed SPP interconnection projects. This is represented by an annual growth rate of 10%. The low case represents a lower interconnection demand and cost levels associated with the lower end of observed SPP projects and assumed a growth rate of -5%. The assumed 2025 interconnection cost by resource for potential high and low interconnection costs are shown in Figure 4-22.

Figure 4-22 – Generator Interconnection Cost in 2025
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[redacted]