PUBLIC UTILITIES ENERGY AND TECHNOLOGY INTERIM COMMITTEE

NOVEMBER 15, 2023

FINAL REPORT FOR FEASIBILITY OF INTERMOUNTAIN POWER PLANT

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Study for Feasibility of the Intermountain Power Plant
For the Utah Office of Energy Development, Contract No. 236352, Amendment 1

INTRODUCTION

This Report is submitted in response to the scope of work in Contract No. 236352, Amendment 1 and to fulfill the requirements of House Bill 425 ("HB 425"), the 'Study for Feasibility of the Intermountain Power Plant ("IPP").'[1] Jackson Walker LLP led a qualified, multi-disciplined team to accomplish a comprehensive and professional study. In addition to the Jackson Walker team of environmental and regulatory experts, the team includes subcontractors that have decades of experience in electricity markets, transmission analysis, and carbon reduction technologies. For purposes of this Final Report, we refer to this group of experts as the 'IPP Study Team.' Therefore, the IPP Study Team respectfully submits the enclosed Final Report. Earlier this year, the Utah Legislature passed HB 425, entitled "Energy Security Amendments." The bill was sponsored by Representative Ken Ivory and co-sponsored by Senator Derrin Owens and signed into law by Governor Spencer Cox on March 14, 2023. HB 425 enacted or amended various statutes, including Section 79-6-303 of the Utah Code, which codifies the Utah Legislature's findings concerning the retirement of the coal-fired electrical generation facilities at the IPP. Such findings include that:

- "the state has invested substantial resources in the development of affordable, dispatchable, and secure energy resources within the state," and
- the early retirement of electrical generation facilities providing such energy resources "is a threat to the health, safety, and welfare of the state's citizens."[2]

The Legislature broadly authorizes the Office of the Attorney General to "*take any action necessary* to defend the interest of the state with respect to electricity generation" where a forced retirement of an electrical generation facility is threatened, including that it may file an action in court or participate in administrative proceedings.[3]

HB 425 also enacted Section 11-13-319 of the Utah Code, which directs the Utah Office of Energy Development ("UOED") to conduct this study regarding the continued operation of the IPP. The Study is to include an evaluation of the viability of the IPP under ownership of the state, or in a public private partnership.[4] The Study is also to "identify the steps necessary for the state to obtain first right of refusal for ownership of a project entity's existing coal-powered electrical generation facility."[5] An analysis of the state ownership issue is provided herein.

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[1] The term "Power Plant" is used because that phrase was used by the Legislator in HB 425. However, in several instances throughout this report the phrase, "Power Project" is used as appropriate.

[2] *See* Utah Code Sec. 79-6-303.

[3] *See* Utah Code Sec. 79-6-303 (emphasis added).

[4] Utah Code Sec. 11-13-319(g).

[5] Utah Code Sec. 11-13-319(h).

The IPP Study Team is honored to have been selected by the UOED to conduct this study and has worked earnestly for several months to assess background documentation, conduct interviews, perform legal and technical research, and evaluate the economics surrounding the IPP situation.

A report in preliminary form was provided to the Public Utilities, Energy, and Technology ("PUET") Interim Committee during its scheduled hearing on September 18, 2023. The IPP Study Team has expanded and refined the analysis including completing technical evaluations, conducting follow-up interviews and analyzing responses to information requests.

This report documents the IPP Study Team's evaluation which addresses a wide range of legal, technical, and economic issues surrounding the IPP situation in response to the Utah Legislature's PUET Interim Committee direction to fully assess the potential options associated with the IPP. At the request of the PUET Interim Committee, this Final Report will be presented at the scheduled PUET Interim Committee hearing at the capitol in Salt Lake City on November 15, 2023.

To allow readers to track this Final Report in the order of the tasks described in the RFP, this report is organized as follows:

Task:	**Description:**
Task 1	Regulatory Analysis
Task 2	Technology Analysis
Task 3	Transmission Analysis
Task 4	Economic Development & Economic Interest Analysis
Task 5	Asset and Liability Analysis
Task 6	Ownership and Structure Analysis
Task 7	Energy Security, Reliability, and Resilience for the Southwestern States Analysis

For the reader who opts to read this report one Task at a time (or the reader who is re-reviewing the report after initially reviewing it in full), it might be more useful to review the tasks in the following order:

TASK 1 – Regulatory Analysis

Excerpt from Contract No. 236352, Amendment 1

> *UCA 11-13-319.1(a): "evaluate all environmental regulations and permits to be filed to continue operation of a project entity's existing coal-powered electrical generation facility;"*
>
> *"Evaluate state and federal environmental regulations and permit requirements necessary to keep IPP operational as currently constituted. This includes an analysis of ongoing federal efforts to promulgate new regulations for coal-fired generation (NAAQS, OTR, CCR, ELG, MATS, Regional Haze, etc.), their potential effect on efforts to keep IPP operational, and strategies to overcome any potential regulatory hurdles."*

Analysis

What follows is our regulatory analysis of the key regulations cited as drivers for retirement over the course of the past few years. In each section, we provide a brief background on the regulatory program in question, our assessment of IPP's current regulatory status under each program, and a brief discussion of options that still remain for eliminating each regulatory hurdle to continued operation of the coal-fired units at IPP. Some references are made to options that might have existed and were not exercised, as well as regulatory compliance choices that have been made that will make it more difficult or costly to secure appropriate regulatory approvals for continued operation of the coal units in light of the construction of the new natural gas/hydrogen project. However, it is beyond the scope of this study to provide a full critique of past actions so we have not dwelled on such issues except to the extent that they inform what options may still exist.

Note that each of the federal regulatory standards discussed below is the subject of extensive litigation wherein states, including the State of Utah, and members of the regulated community are pursuing legal options to stop and ultimately overturn each of the programs discussed because the Environmental Protection Agency (EPA) lacks statutory authority to impose the requirements they currently intend. Where appropriate, a short discussion in each of the subsections below is included to discuss the status and import of the pending litigation.

1. Coal Combustion Residual Rule

a. Federal Regulatory Setting

On April 17, 2015, EPA finalized national minimum criteria for the disposal of Coal Combustion Residual ("CCR") as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("2015 CCR Rule").[6] These by-products are generated from the combustion of coal by electric utilities and independent power producers for the generation of electricity and include fly ash,

[6] 80 Fed. Reg. 21,302 (April 17, 2015).

bottom ash, boiler slag, and flue gas desulfurization materials. The CCR regulations are codified in 40 CFR Part 257, Subpart D. The 2015 CCR Rule regulated existing and new CCR landfills and existing and new CCR surface impoundments (as well as lateral expansions of these CCR units). The minimum criteria included location restrictions, design and operating criteria, groundwater monitoring and corrective action, and closure and post-closure requirements. The 2015 CCR Rule was amended in July 2018 and November 2020,[7] and a number of rule proposals are pending.

The major criteria in the CCR Rule include (1) restrictions on the siting of CCR units; (2) standards for the design of CCR units, such as liner requirements; (3) operating conditions; (4) structural integrity requirements for surface impoundments; (5) groundwater monitoring and corrective action requirements; (6) closure requirements; and (7) recordkeeping and reporting requirements.

Under the CCR Rule, a CCR surface impoundment that does not meet certain location standards has an obligation to close. Specifically, if the CCR surface impoundment does not meet the location standards of § 257.60, which requires that the base of the CCR surface impoundment be located no less than five feet above the upper limit of the uppermost aquifer, then CCR and non-CCR waste streams cannot be placed into the unit after April 11, 2021, and the unit must close. For CCR surface impoundments that do not meet the location standards of §§ 257.61 through 257.64, the unit must cease accepting CCR and non-CCR waste streams within six months of making that demonstration and must commence closure. Furthermore, unless an extension is requested as explained herein, under the CCR rules, the owner or operator of an existing unlined[8] CCR surface impoundment had to cease placing CCR and non-CCR waste streams no later than April 11, 2021, and either retrofit or close the CCR unit in accordance with the rules.[9]

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[7] 83 Fed. Reg. 36,435 (July 30, 2018) and 58 Fed. Reg. 72,506 (November 12, 2020).

[8] An "existing CCR surface impoundment" is a "CCR surface impoundment that receives CCR both before and after October 19, 2015, or for which construction commenced prior to October 19, 2015, and receives CCR on or after October 19, 2015." 40 CFR § 257.53. An unlined CCR surface impoundment is a CCR surface impoundment that does not meet composite liner requirements of § 257.70(b), or alternative composite liner requirements of § 257.70(c). 40 CFR § 257.71(a).

[9] The deadlines that are currently in the federal CCR rule were established in the August 2020 amendment to the 2015 CCR Rule. 85 Fed. Reg. 53,516, 53,535 (August 28, 2020). The brief history of the development of the deadlines is as follows: In July 2018, EPA issued a final rule amending several parts of the 2015 CCR Rule. 83 Fed. Reg. 36,435 (July 30, 2018). As relevant to this discussion, the rule extended the deadlines for two categories of CCR surface impoundments to cease receipt of waste and to initiate closure when closing for cause: (1) unlined CCR surface impoundments with an exceedance of a groundwater protection standard for any constituent listed on Appendix IV to 40 CFR Part 257; and (2) CCR surface impoundments that failed to meet the location criteria in § 257.60(a) (requiring either a minimum of five feet between the unit base and the uppermost aquifer or a demonstration that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the unit and the uppermost aquifer). These deadlines were extended until October 31, 2020. The July 2018 final rule was challenged by *Waterkeeper Alliance*, who also requested an expedited review of the October 31, 2020, deadline. *See Waterkeeper Alliance Inc, et al* v. *EPA*, No. 18–1289 (D.C. Cir. 2018). On March 13, 2019, the Court granted EPA's request to remand the July 2018 rule.

In December 2019, EPA issued a proposed rule to address the remand of the July 2018 rule. In the rule proposal, for all unlined CCR surface impoundments, EPA proposed to revise the deadline to cease receipt of waste under § 257.101(a)(1) from October 31, 2020, to August 31, 2020, based on its analysis of the average time needed to obtain alternative disposal capacity. 84 Fed. Reg. 65944, 65951 (December 2, 2019). In issuing the final rule in August 2020 (the "2020 CCR Rule"), EPA recalculated the timeframes and established April 11, 2021, as the deadline for CCR units to cease receipt of CCR and non-CCR waste streams. 85 Fed. Reg. 53,516, 53,535 (August 28, 2020). This

The CCR rules allow for these timeframes to be extended. For unlined CCR surface impoundments, the timeframes can be extended if the owner/operator complies with the alternative liner demonstration provisions in § 257.71(d), or the alternative closure procedures in § 257.103.[10] The alternative closure procedures in § 257.103 can be established by making a demonstration pursuant to either § 257.103(f)(1) or § 257.103(f)(2).

Demonstration under § 257.103(f)(1). A demonstration under § 257.103(f)(1) is entitled "development of alternative capacity is technically infeasible." Among other things, and as the name suggests, this alternative requires a demonstration to EPA that no alternative disposal capacity is available on-site or off-site. The regulations spell out, in some detail, the components of such a request, which includes the submittal of a detailed schedule of the fastest technically feasible time to complete the measures that are necessary for alternative capacity to be available. Requests for additional time to operate a CCR surface impoundment under § 257.103(f)(1) must be submitted to EPA for approval no later than November 30, 2020. Submission of a complete demonstration results in the tolling of the deadline to cease receipt of waste until EPA issues a decision.

Under the § 257.103(f)(1) option, the deadline can be extended to October 15, 2023, or October 15, 2024, if the surface impoundment is an "eligible unlined CCR surface impoundment." This means that the CCR surface impoundment can continue receiving CCR and non-CCR waste to a maximum of October 15, 2023 (or October 15, 2024, if an "eligible unlined CCR surface impoundment") but must cease receiving any such waste streams beyond those dates.

Demonstration under § 257.103(f)(2). Section 257.103(f)(2) is entitled "permanent cessation of a coal-fired boiler(s) by a date certain." Under this provision of the CCR Rule, a CCR surface impoundment may continue to receive CCR and/or non-CCR waste streams if the facility ceases operation of the coal-fired boiler(s) and completes closure of the impoundment within the timeframes provided in the rule. The timeframes depend on the size of the CCR surface impoundments. For CCR surface impoundments that are 40 acres or smaller, the coal-fired boiler(s) must cease operation and the surface impoundment must complete closure no later than October 17, 2023. For CCR surface impoundments that are greater than 40 acres, the complete closure date is October 17, 2028. For CCR surface impoundments to continue to receive CCR waste streams under § 257.103(f)(2), a facility must demonstrate that no alternative disposal capacity is available on-site or off-site. However, contrary to the demonstration under § 257.103(f)(1), EPA explained that "it would be illogical to require facilities [ceasing power generation] to construct new capacity to manage CCR and non-CCR waste streams." EPA again reiterated in the preamble to the final rule that "[i]n contrast to the provision under § 257.103(f)(1), the owner or operator does not need to develop alternative capacity because of the impending closure of the coal-fired boilers. Since the coal-fired boilers will shortly cease power generation, it would be illogical to require these facilities to construct new capacity to manage CCR and non-

discussion is relevant because the deadlines in the current version of the CCR rule are different than what was originally promulgated in 2015.

[10] 40 CFR § 257.101(a)(3). A pre-requisite to qualifying under the alternate liner demonstration provisions in § 257.71 is that the CCR surface impoundment is in detection monitoring (meaning that groundwater protection standards have not been exceeded). 40 CFR § 257.71(d)(2). As explained below, the CCR surface impoundments at the IPP do not qualify for the alternate liner demonstration provisions of § 257.71, and therefore, this option will not be discussed.

CCR waste streams." Thus, unlike a filing under § 257.103(f)(1), under a § 257.103(f)(2) filing, an owner/operator does not need to consider new construction or the development of new alternative disposal capacity (such as constructing a new CCR surface impoundment or new wastewater treatment facility). Requests for additional time to operate a CCR surface impoundment under § 257.103(f)(2) had to have been submitted to EPA for approval no later than November 30, 2020. Submission of a complete demonstration results in the tolling of the deadline to cease receipt of waste until EPA issues a decision.

The rules allow for the transfer between site-specific alternatives – either transfer from § 257.103(f)(1) to § 257.103(f)(2) or vice versa. The rules specifically provide that an "owner or operator authorized to continue operating a CCR surface impoundment … may at any time request authorization to continue operating the impoundment pursuant to another paragraph of subsection (f) by submitting the information in paragraph (f)(4)(i) or (ii) of this section." In the preamble to the 2020 CCR Rule, EPA explained this allowance for a transfer between the alternatives as follows:

> EPA agrees with the commenters that a situation may arise where a facility needs to change course due to unexpected business decisions and that there should be a process for a facility to switch between the site-specific alternative closure provisions. Therefore, EPA is adding regulations at § 257.103(f)(4) to allow the transfer between site-specific alternatives. The process of obtaining approval will be the same as it would be under the initial application for approval.[11]

b. State Regulatory Setting

On September 1, 2016, the State of Utah enacted its state CCR regulations that were substantially identical to the federal 2015 CCR Rule and reflected the same standards and timelines.[12]

On December 16, 2016, the Water Infrastructure Investment for the Nation Act ("WIIN Act") was signed into law. The WIIN Act gives EPA authority to approve state programs addressing CCR units. The Act authorizes EPA to approve a state program so long as the state program is determined to be "at least as protective as" the CCR Rule codified in 40 CFR Part 257. In terms of timing, no later than 180 days after the date the state submits evidence of a permit program or other system of prior approval, EPA, after public notice and an opportunity for public comment, shall approve, in whole or in part, the state program if it determines that the state program meets the federal criteria or is at least as protective. If approved, the state program operates in lieu of the federal CCR program. States that do not submit evidence of a state program to EPA, or whose submitted program is rejected or withdrawn by EPA, will become subject to a federal permit program, once promulgated. The criteria in 40 CFR Part 257 apply to CCR units unless a state permit from an approved state CCR program or a federal permit has been issued.

The EPA is currently working with the State of Utah on a state permit program to operate in lieu of the federal CCR program, however, the state has yet to submit its application to EPA as

[11] 85 Fed. Reg. 53516, 53553 (August 28, 2020).

[12] Utah Admin. Code R315-319.

additional revisions to its regulations are required. It may be a year from now until EPA approval is obtained. Accordingly, as it stands today, all CCR units in Utah are subject to the federal CCR Rule codified in 40 CFR Part 257 and the state CCR rules.[13] Thus, certain existing CCR units are dually regulated.

Under the state CCR rule, unless an alternative closure procedure under Subsection R315-319-103 is pursued, an unlined CCR unit that has contaminated the groundwater must cease receiving CCR and non-CCR wastewater within six months of making that determination.[14] As noted, an alternative closure procedure is allowed under the rules. Utah regulations are structured after the federal CCR rules and similarly have a "no alternative disposal capacity" path (similar to a § 257.103(f)(1) filing) and a "permanent cessation of coal-fired boiler(s)" path (similar to a § 257.103(f)(2) filing).[15] Under Utah's "no alternative disposal capacity path" if no alternative capacity is identified within five years after the initial certification, the CCR unit shall cease receiving CCR and close the unit.[16] The Utah "permanent cessation of coal-fired boiler" path has the same deadlines as the federal regulations; that is, for a CCR surface impoundment that is 40 acres or smaller, the coal-fired boiler shall cease operation and the CCR surface impoundment shall have completed closure no later than October 17, 2023, and for a CCR surface impoundment that is larger than 40 acres, the coal-fired boiler shall cease operation, and the CCR surface impoundment shall complete closure no later than October 17, 2028.[17] Under the Utah regulations, the alternative deadline path is self-implementing, meaning no state approval is required.[18]

c. Intermountain Power Service Corporation's CCR Units

The IPP, owned by the Intermountain Power Agency ("IPA") and operated by Intermountain Power Service Corporation ("IPSC"), has three CCR units: (1) Combustion By-Products Landfill ("CB Landfill"); (2) Bottom Ash Basin; and (3) Waste Water Basin.

On September 9, 2016, IPSC submitted an application to the Utah Department of Environmental Quality ("UDEQ") for a permit to operate the above-referenced coal combustion units under Utah's CCR rule. UDEQ, Division of Waste Management and Radiation Control ("DWMRC") issued Permit No. SW419 for IPSC's CCR units on November 23, 2020. The CCR units are subject to both the state CCR rule and issued permit. As the State of Utah does not have an EPA-approved CCR program, its CCR rules do not operate in lieu of the federal CCR rule; in other words, the federal CCR rules apply to IPP's CCR units.

Despite having been constructed in compliance with applicable state liner requirements governing such units, the Bottom Ash Basin and the Waste Water Basin are considered unlined surface

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[13] Utah Admin. Code R315-319. The state regulations do not operate in lieu of the federal program because EPA has yet to approve the State's CCR program. Accordingly, CCR units are subject to dual regulations.

[14] Utah Admin. Code R315-319-101(a)(1).

[15] Utah Admin. Code R315-319-103(a) and (b).

[16] Utah Admin. Code R315-319-103(a)(3).

[17] Utah Admin. Code R315-319-103(b)(2) and (b)(3).

[18] The regulations were structured as such given the applicability of the federal CCR rules, and the requirement under the federal CCR rules to submit a petition to EPA for approval if these paths are pursued.

impoundments under the CCR Rule as they do not meet the liner requirements of § 257.70(b) or (c). The plant's documentation of impoundment liner can be viewed here: https://ccr.ipsc.com/IPSC/CCRUnit/DownloadFile/2025663?tab=First. According to the federal CCR rules, these units must cease receiving CCR and non-CCR waste streams by April 11, 2021, unless a petition pursuant to § 257.103 is made.

The CCR units at the IPP appear to have impacted groundwater at the site. There are exceedances for arsenic and lithium (both of which have elevated background concentrations throughout the area) and molybdenum at the southwest boundary of the Bottom Ash Basin; and arsenic and lithium at the southern and western boundaries of the Waste Water Basin. Total dissolved solids ("TDS") has also been detected downgradient of the two impoundments, and is used as the leading indicator of impacted groundwater quality. The 2022 Annual Groundwater Monitoring and Corrective Action Summary Report can be found here: https://ccr.ipsc.com/IPSC/CCRUnit/DownloadFile/8968563?tab=First. The selected remedy for addressing impacted groundwater is groundwater recovery and removal from the subsurface and subsequent evaporation of groundwater containing CCR constituents. The Selection of Remedy Report can be found here: https://ccr.ipsc.com/IPSC/CCRUnit/DownloadFile/8949712?tab=First.

On September 12, 2018, IPSC submitted notification of its intent to comply with the alternative closure requirements, and in that filing, it communicated its intent to shut down the boilers at the plant: https://ccr.ipsc.com/IPSC/CCRUnit/DownloadFile/8390407?tab=First.

Following the September 12, 2018, Notification of Intent to Comply with the Alternative Closure Requirements, IPSC states that it has taken steps towards shuttering the IPP's coal units, including contracting with the engineering firm Sargent & Lundy to complete a conceptual decommissioning cost study for the coal units, which is expected to guide decommissioning going forward. The IPSC also retained the engineering firm Stantec to prepare a detailed report evaluating closure alternatives for the CCR units.

On November 30, 2020, IPSC submitted its site-specific alternative deadline to initiate closure under 40 CFR § 257.103(f)(2) for the Bottom Ash Basin and Waste Water Basin at the Intermountain Generation Facility.[19] In the submittal, IPSC requested that both surface impoundments be allowed to continue to receive CCR and non-CCR waste streams after April 11, 2021, and complete closure no later than October 17, 2028.[20] It also stated that it planned cessation of the coal-fired boilers at the facility in July 2025. The EPA deemed the application complete on January 11, 2022, but has not issued a decision. According to the rules, the submittal of a complete application tolls all deadlines.

In its submittal, IPSC explained that due to a potential loss of existing customers, a weak market for coal-fueled electricity and environmental regulatory issues that impact the project's economic viability, they will cease electricity generation using coal in 2025. The IPSC also stated that the facility is moving forward with plans to develop new natural gas and hydrogen-fueled electricity

[19] IPSC's Notification of Intent to Comply with Site-Specific alternative to Initiation of Closure can be found here: https://ccr.ipsc.com/IPSC/CCRUnit/DownloadFile/8940946?tab=First.

[20] The Bottom Ash Basin is 101 acres.

generation at the project site and that power sales contracts require that the coal units be replaced with natural gas-fired power blocks by July 1, 2025.

Accordingly, pursuant to its petition to EPA, IPSC has committed to shutting down the coal-fired boilers and completing closure by October 17, 2028. The EPA has yet to make a decision on IPSC's submittal and is not bound to provide the latest requested date.

d. Extending the Life of the Power Plant

Under its filing to EPA pursuant to 40 CFR § 257.103(f)(2), IPSC committed to shutting down the boilers by July 2025. However, the regulatory requirement is that the coal-fired boilers must be shut down and the CCR surface impoundment must complete closure no later than October 17, 2028. Therefore, if for example, it takes one year to complete the closure of an impoundment, then a facility can presumably operate its boilers until October 2027 and still meet the "complete closure" deadline of October 17, 2028. Accordingly, while IPSC has stated in its CCR filing that it will cease operating the boilers by July 2025, the CCR rules do not mandate that the boilers be shut down by that date. Significantly, if IPSC wants to extend the life beyond July 2025, it should submit a supplemental filing to better account for the needed time to operate the boilers. Under the current filing, IPSC runs the risk of not being provided the October 17, 2028 date by EPA,[21] and thus being forced to cease operating the boilers by July 2025. Accordingly, IPSC could presumably extend the life of the boilers beyond July 2025, but it should supplement its filing under § 257.103(f)(2). It should be understood that, under this scenario, the life of the boilers can only be extended up to a time that will allow completion of closure of the surface impoundments by October 17, 2028.

Another path that could have been pursued is the filing of a petition under § 257.103(f)(1). However, that path is no longer a viable option. A brief explanation of this path and why it is not practical is as follows: § 257.103(f)(4) allows for transfer between site-specific alternatives – a transfer between (f)(2) and (f)(1) and vice versa. EPA explained that it made this option to transfer between alternatives available because a situation may arise where a facility may want to change course due to business decisions. The ability to transfer between a § 257.103(f)(2) filing to a § 257.103(f)(1) filing, and vice versa, was promulgated to provide this flexibility to facilities. However, under the (f)(1) filing (which is not dependent on the cessation of the use of coal-fired boilers), the surface impoundments must cease receiving wastewaters by no later than October 17, 2023, or October 17, 2024 if the surface impoundment is an "eligible unlined surface impoundment." Given the above-referenced impacts to groundwater at the site, the IPP would not qualify as an "eligible unlined CCR surface impoundment," and therefore, the October 2024 deadline is not available. If the surface impoundment at the plant must cease receiving wastewaters by October 17, 2023, then in essence the plant must be shut down by then. Had IPSC converted its filing to an (f)(1) filing some time ago, then it would have potentially had sufficient time to construct a CCR-complaint surface impoundment by the October 17, 2023 deadline, thus not forcing the shutdown of the plant. That, however, was not done and a filing under (f)(1) at this

[21] For example, EPA may conclude that IPSC has not properly demonstrated that it will need over 3 years (from July 2025 to October 2028) to complete closure of the surface impoundments.

time will not extend the life of the plant because, practically speaking, the time for that option has passed.

Another option is for a third party to acquire the facility and construct a CCR compliant surface impoundment, or alternatively convert the system to a dry handling system and continue the use of the coal-fired boilers beyond IPSC's filings. In each instance, the surface impoundments must be closed no later than October 2028 (or prior to that date, if EPA makes a final determination with a more aggressive closure deadline).[22] This option should be explored and could be a viable path to extending the life of the power plant.

Significantly, the plant's life can be extended if a technology that does not rely on the combustion of coal for the generation of electricity is used to produce electricity. Converting to a combustion process that does not produce CCR would negate any additional CCR compliance costs.

Finally, any legal uncertainties created by EPA actions or interpretations that might hinder the above-referenced options, including filing under § 257.103(f)(2), could potentially be resolved through legal action against EPA as the IPP Study Team is confident that the statute and regulations support the availability of the options described.

Key Takeaways: It may be possible for IPSC to extend the life of the boilers beyond July 2025. To do that, however, a supplemental filing with EPA is recommended. Under this scenario, the life of the boilers can only be extended up to a time that will allow completion of closure of the surface impoundments by October 17, 2028. Another potential option to extend the life of the coal-fired plant is for a third party to acquire the facility and construct a CCR compliant surface impoundment, or alternatively convert the system to a dry handling system and continue the use of the coal-fired boilers beyond IPSC's filings. In each instance, the non-compliant surface impoundments must be closed no later than October 2028. There are legal uncertainties with each of these options.

2. Air Permitting

The UDEQ's Division of Air Quality issues air permits needed for coal plants to construct and operate. On June 22, 2022, the Division of Air Quality approved IPA's application to amend its air permit to authorize the construction of the hydrogen/natural gas combustion turbine project.[23] The permit requires IPA to shut down the coal units upon the new combustion turbines becoming operational, as follows:

> *"The equipment listed in Section II.A.32 under the heading coal-fired boiler plant equipment shall remain in operation until such time as the new combustion turbines are installed and operational. The new combustion turbine plant will become operational only after a reasonable shakedown period, not to exceed 180 days. At*

[22] The retrofitting of the surface impoundment is a potential option if the new owner/operator does not convert the system to a dry handling system.

[23] Approval Order DAQE-AN103270029-22 (June 22, 2022).

> *that time the listed coal boiler plant equipment shall cease operations and be removed from service."*[24]

The IPA notified the Division of Air Quality that construction of the hydrogen/natural gas turbine project began on October 14, 2022, with operations expected to begin in December 2024.[25] Under the permit's current terms, and assuming that schedule does not change, the coal units would, therefore, be unauthorized from an air permitting perspective and shut down around Summer 2025.

Due to the manner in which IPA permitted the gas combustion turbine project, staff from the Division of Air Quality have preliminarily indicated that changing course to keep both coal units running could require treating the coal units as "new sources" required to undergo an entirely new and lengthy air permitting process. Under that scenario, the coal units may be treated as "new sources" subject to untenable, federally-driven new source performance standards. In the normal course of authorizing any significant project, discussions with air quality permitting staff are needed in order to stack hands on the right and best permitting approach. Thus, further discussions with staff would be required to determine if keeping the coal units running could instead be accomplished in a more tenable fashion through (a) unwinding the current permit and separately permitting the gas combustion turbine project as a standalone project, (b) modifying the current permit to both authorize the gas combustion turbine project and enable the coal units to continue running (perhaps by extending the 2025 retirement date), or (c) issuance by the Air Quality Board of a variance to the permit.[26] If the staff's final determination is that their statutory and regulatory authority compels treatment of the coal units as "new sources" subject to an entirely new and lengthy air permitting process and subject to untenable new source performance standards, it would be within the State of Utah's discretion to clarify the Division of Air Quality's statutory authority in order to permit continued operation of the coal units in the least burdensome manner. While the EPA may object to the permitting path chosen, Utah should be afforded deference both because Utah administers a federally-approved preconstruction permit program[27] and because the unpermitted part of the project, at least in option (a) above, would be seen as environmentally beneficial.

[24] Approval Order DAQE-AN103270029-22, Special Condition II.B.5.a (June 22, 2022).

[25] Letter from Intermountain Power Service Corporation to Utah Division of Air Quality (Nov. 7, 2022) ("On October 14, IPA commenced construction on its new natural gas fired electricity generating unit facility. This letter also serves as IPSC's notice under the Utah Administrative Code ("UAC") R307-401-18 that IPA has begun a continuous program construction for the IPP Renewal Project.").

[26] *See* Section 19-2-113 of the Air Conservation Act; *see also* Utah Admin. Code R307-102-4 ("Variance from these regulations may be granted by the Board as provided by law … unless prohibited by the Clean Air Act to permit operation of an air pollution source for the time period involved in installing or constructing air pollution control equipment in accordance with a compliance schedule negotiated by the director and approved by the Board … [or] to permit operation of an air pollution source where the control measures, because of their extent or cost, must be spread over a considerable period of time.").

[27] *See, e.g.*, 76 Fed. Reg. 41,712 (July 15, 2011) ("Utah has a federally-approved Prevention of Significant Deterioration (PSD) preconstruction permit program for new and modified sources impacting attainment areas in the State.").

<u>Key Takeaway</u>: If the hydrogen/natural gas turbines begin operating, an air permitting strategy must be developed and pursued in the near term to amend the air permit in order to keep the coal units running through 2025 and beyond.

a. Ozone Transport / "Good Neighbor" Rule

In Section 110 of the Clean Air Act, Congress requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary national ambient air quality standard.[28] The EPA conducted an analysis to identify states that are having trouble attaining the 2015 national ambient air quality standard for ozone and the contribution of ozone transport from upwind states to downwind air quality problems. Based on the modeling, EPA is requiring 23 upwind states, including Utah, to take steps to eliminate interstate transport of nitrogen oxide (NO_x) emissions allegedly contributing to downwind ozone issues.[29]

Federal requirements compelling Utah to reduce ozone-forming emissions became effective on August 4, 2023.[30] Generally speaking, Utah's fossil fuel-fired power plants will be required to participate in a federally-driven, allowance-based trading program. The EPA imposed these federal requirements after disapproving Utah's state-created plan to reduce these emissions.[31]

Because several aspects of EPA's Ozone Transport Rule arguably violate statutory requirements under the Clean Air Act and because Utah's alleged impacts on downwind receptors is so small (the State determined that its contributions to downwind states' air quality were not significant[32]), the State of Utah (along with several other states) sued, challenging EPA's disapproval. In response to Utah's legal challenge, the Tenth Circuit Court of Appeals has stayed EPA's disapproval of Utah's state-created plan,[33] and EPA has since announced that sources in Utah "are not required to comply with the Good Neighbor Plan at this time."[34]

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[28] *See* 42 U.S.C. § 7410(a)(2)(D).

[29] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023).

[30] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) ("This final rule is effective on August 4, 2023.").

[31] Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9,336 (Feb. 13, 2023).

[32] The State of Utah's Motion to Stay the Final Rule of the U.S. Environmental Protection Agency, No. 23-9509 at 7 (10th Cir. March 7, 2023) ("Ultimately, Utah concluded that contributions to downwind state air quality were not significant when considering all relevant data."). As context, Utah takes issue with EPA's decision because EPA asserted that combined upwind state emissions in the approval of Arizona's plan were "negligible" when they comprised 2 to 4 percent of ambient levels at relevant receptors, but that the combined upwind emissions in Utah's proposed SIP were "significant" because they comprise a "higher" 6 to 7 percent of ambient levels at relevant receptors. *Id*. at 19-20.

[33] Order, *Utah v. EPA*, No. 23-9509 (10th Cir. July 27, 2023).

[34] Memorandum from Joseph Goffman, EPA Deputy Assistant Administrator (Aug. 2, 2023) ("To comply with these additional orders, EPA will take action in the near future to extend the Interim Final Rule to stay the effectiveness of the Good Neighbor Plan's requirements for sources in Minnesota, Nevada, Oklahoma, and Utah while the orders partially staying the SIP Disapproval Action with respect to these states remain in place, and sources in these states

At this point, there is no clear indication that EPA will be able to overcome the legal hurdles set before them by the pending challenges. However, if EPA were to ultimately prevail in the litigation, resulting in the federal requirements taking effect in Utah, allowance-related impacts would begin in the near term, and substantial allowance-related impacts would begin in 2026. Specifically:

- The allowance budget EPA established for Utah in 2025, when IPA's coal units are projected to retire under the terms of the air permit, is 15,121 tons. In 2025, Unit 1 has been allocated 2,475 of those tons, and Unit 2 has been allocated 2,603 of those tons.

- Beginning in 2026, EPA will use a "dynamic budgeting" process to adjust allowance allocations on a year-by-year basis, and it is anticipated that the number of annual allowances will drop. Indeed, EPA's projected budget for the entire State of Utah in 2027 is 2,593 tons.[35] Utilizing EPA's Unit-Specific Good Neighbor Rule Emission Budget Calculation TSD, IPP's emission budget is projected to be 0 following 2025 due to the retirement expectation. Assuming the coal units remain running, and extrapolating and estimating from available EPA technical documents on projected allowances, we would expect IPA's budget to decline to less than 1,000 tons per year in 2027 and beyond. Without the installation of additional NO_x emission controls, the projected emission budget could limit the utilization of the IPP coal units to approximately 15% of their maximum capacity.

Assuming IPA's coal units are permitted to continue running through 2025 and beyond, EPA's projected budget for the entire State of Utah in 2027 is less than the number of allowances EPA allocated to Unit 2 alone in 2025. That indicates that installation of additional control technologies or allowance purchases would be necessary to keep the coal units running. Further to that point, for coal units like IPA's that currently do not have selective catalytic reduction ("SCR") installed, a "backstop" emissions limit based on application of SCR technology would take effect by 2030, with a 3-for-1 allowance surrender penalty for noncompliance.[36] Please refer to "Task 2" of this report for an assessment of technologies that may need to be deployed to comply with the Ozone Transport rule.

Key Takeaway: If an air permitting strategy is developed and successfully pursued to keep the coal units running through 2025 and beyond, and assuming EPA's ozone transport rule survives judicial review, a strategy must be developed to deploy NO_x-reducing technologies like SCR and/or to finance the purchase of allowances.

are not required to comply with the Good Neighbor Plan at this time."); *see also* 88 Fed. Reg. 67,102, 67,103 (Sep. 29, 2023) ("The effect of this action is that emissions sources in … Utah … will not be subject to the Good Neighbor Plan's requirements promulgated to address the States' good neighbor obligations with respect to the 2015 ozone NAAQS while the stay orders covering the States remain in place ….").

[35] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654, 36,663 (June 5, 2023).

[36] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654, 36,663-36,664 (June 5, 2023).

b. Regional Haze

The EPA adopted its Regional Haze Rule in 1999 in an effort to reduce haze at Class I federal areas, such as national parks and wilderness areas.

For the first implementation period, the Regional Haze Rule provides states with two compliance pathways depending on their locations. States can choose to perform individual point source Best Available Retrofit Technology ("BART") determinations for BART-eligible sources as well as evaluate other control strategies under or for states within the Transport Region. The IPP coal units were not subject to the first round of BART review as they did not meet the requirements for a BART-eligible source.

The EPA is currently considering Utah's Regional Haze State Implementation Plan ("SIP") for the Second Implementation Period, which covers the years 2018 through 2028. On July 6, 2022, the Utah Air Quality Board adopted the Regional Haze SIP for the Second Implementation Period.[37] The SIP establishes an enforceable closure date of no later than December 31, 2027 for IPP's coal-fired units.[38] Due to the planned retirement of the two IPP coal units, the UDEQ did not perform a four-factor analysis that is required to establish BART retrofit requirements for eligible point sources under the Regional Haze Rule. Therefore, no BART retrofits are currently required before the December 2027 closure date of the IPP coal units.

Utah's SIP submission for the Second Implementation Period has since been adopted into state law. Therefore, to allow for a continued operation of the IPP coal units beyond the December 2027 closure date as required by Utah's current Regional Haze SIP and state law, a revision to Utah's SIP will be required, including a four-factor analysis for the continued operation of the IPP coal units. Although the results of such an analysis are unknown at this time, it is reasonable to assume that the owner of the IPP coal units would likely be required to install emission control technologies that result in NO_x emission reduction to a similar degree as the installation of an SCR system. Additionally, an updated Regional Haze analysis including the IPP coal units has the potential to change the compliance requirements for other point sources in the state of Utah covered in the state Regional Haze SIP.

<u>Key Takeaway</u>: If an air permitting strategy is developed and successfully pursued to keep the coal units running through 2025 and beyond, and assuming the coal units are planned to remain operational beyond December 2027, the Utah Air Quality Board must revise the SIP accordingly and the coal units would likely be required to install additional control technologies. Of course, a shift in administration and the outcomes of pending or upcoming legal proceedings could mitigate the extent of additional controls, but it would be too speculative to assume that for the purposes of this report.

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[37] IPA's Annual Disclosure Report 2021-2022 at 44-45 (March 31, 2023), *available at* https://emma.msrb.org/P11658864-P11277630-P11705978.pdf.

[38] IPA's Annual Disclosure Report 2021-2022 at 45 (March 31, 2023), *available at* https://emma.msrb.org/P11658864-P11277630-P11705978.pdf; *see also* Memorandum from Chelsea Cancino to Air Quality Board (June 28, 2022) at 26 ("As such, UDAQ feels it is appropriate to retain the closure date of December 31, 2027, as outlined in section 8.D as well as the enforceable measures in IX.H.23."), *available at* https://documents.deq.utah.gov/air-quality/board/2022/DAQ-2022-008950.pdf#page=52.

c. EPA's Carbon Rule

In Section 111 of the Clean Air Act, Congress authorizes EPA to establish performance standards on both new and existing sources of certain air pollutants. On May 23, 2023, EPA proposed requirements under Section 111(d) to reduce greenhouse gas emissions from existing coal plants.[39] The stringency of the requirements is driven by retirement date, as follows:

- Coal units that commit to permanently cease operations prior to January 1, 2032, must comply by employing routine methods of operation and maintenance;
- Coal units that commit to permanently cease operations prior to January 1, 2035, and that commit to operate with an annual capacity factor limit of 20% must comply by employing routine methods of operation and maintenance;
- Coal units that commit to permanently cease operations prior to January 1, 2040, must comply by co-firing 40% natural gas by 2030; and
- Coal units that will operate past January 1, 2040, must comply by installing carbon capture and sequestration technology by 2030.[40]

Please refer to "Task 2" of this report for an assessment of technologies that may need to be deployed to comply with EPA's carbon rule.

Once finalized, EPA will face significant legal headwinds that will interfere with its imposition of this rule as proposed. Industry has already submitted public comments on the proposal, flagging that the proposal (a) is illegally based on imposition of undemonstrated technology (specifically, carbon capture and sequestration ("CCS") and hydrogen co-firing), (b) violates the recently articulated major questions doctrine because Congress has not clearly given EPA the authority to promulgate rules of this sort, (c) violates cooperative federalism principles, and (d) imperils the grid.

<u>Key Takeaway</u>: If an air permitting strategy is developed and successfully pursued to keep the coal units running through 2025 and beyond, and assuming EPA's final rule survives judicial review, an updated retirement date would need to be established and a compliance strategy pursued accordingly.

d. California's Carbon Rule

Once finalized, EPA's Carbon Rule will be challenged in court. Even if a court invalidates EPA's Carbon Rule, the majority of IPA's electricity is delivered into California, and so California's net-

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[39] 42 U.S.C. §7411(d).

[40] *See* New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 Fed. Reg. 33,240 (May 23, 2023); *see also* EPA Fact Sheet, Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule at 6-7.

zero laws impact continued operation of the coal units. Specifically, under Senate Bill 1368 ("SB 1368"), the California Energy Commission limits long-term investments in baseload generation by California utilities to power plants that meet a performance standard of 1,100 pounds of carbon dioxide per megawatt-hour. This is a low carbon standard, not a "no coal" standard, but it does not appear that IPP has ever given serious consideration to utilizing carbon control technologies (*e.g*., CCS) on the coal plants, and instead chose to focus exclusively on a conversion to gas as its method of compliance with the California standards. To that end, it is our understanding that the California Energy Commission in November 2016 approved replacing IPA's combined 1,800 MW coal units with SB 1368 performance standard-compliant natural gas combined cycle units (not necessarily hydrogen conversion), with commercial operation of the gas turbine facility expected by July 1, 2025.[41]

Please refer to "Task 2" of this report for an assessment of technologies that would need to be deployed for the coal units to remain open and comply with California's performance standard.

<u>Key Takeaway</u>: If an air permitting strategy is developed and successfully pursued to keep the coal units running through 2025 and beyond, and assuming power would continue to be sold into California, it is likely that: (a) some form of technology would have to be put in place that significantly reduces the carbon dioxide (CO_2) emissions associated with the operation of the IPP coal units (e.g., CCS) and (b) the California Energy Commission would have to entertain and approve new performance standard compliance filings from California purchasers of IPA power in order for a coal unit to remain in operation.

[41] *See, e.g*., Letter from City of Burbank to California Energy Commission, *EPS Compliance Filing for the IPP Repowering Project* (Oct. 8, 2018) ("A prior Compliance Filing package for the IPP Repowering Project was submitted to the CEC in November of 2016, which was approved by the CEC pursuant to Order No. 16-1019-3. In that order, the CEC approved replacing IPP's combined 1,800 MW coal generating units with SB 1368 Emission Performance Standard (EPS) compliant Natural Gas Combined Cycle (NGCC) units totaling 1,200 MW."); *see also* Memorandum from Drew Bohan, Executive Director, to California Energy Commission (Oct. 19, 2018) ("In that Order, the Energy Commission approved the procurement of energy from IPP's proposed 1,200 megawatt natural gas combined cycle (NGCC) facility. Since that time, participants in the IPP Project have re-evaluated their long-term power needs and have determined that new advanced class gas turbines with a reduced total output of 840 megawatt will allow additional capacity of renewable energy on the transmission lines associated with IPP. The Siting Division has informed Energy Assessments Division staff that the three proposed NGCC manufacturers presented in Burbank's compliance filing will meet the EPS, even if operated at their least efficient, highest greenhouse-gas-emitting load of 50 percent.").

TASK 2 – Technology Analysis

Excerpt from Contract No. 236352, Amendment 1

> *UCA 11-13-319.1(b) "identify best available technology to implement additional environmental controls for continued operation of a project entity's existing coal-powered electrical generation facility;"*
>
> *"Identify and analyze environmental control technologies and coal conversion technologies which are not currently in use at IPP. Analyze the most promising technologies with regards to overcoming potential regulatory constraints, reducing environmental impact generally, and/or in creating new product, revenue streams, and economic opportunities for coal conversion technologies which facilitate continued operation of the plant."*
>
> *"These technologies include but are not limited to: Selected catalytic reduction (SCR), carbon capture utilization and sequestration (CCUS), coal conversion to graphite with hydrogen byproduct, coal conversion to strategic minerals with hydrogen byproduct, anaerobic gasification of coal with hydrogen byproduct, other coal conversation technologies with energy byproducts which could fuel electricity generation at IPP."*

Analysis

The ordering of the technologies below is in no way meant to be a ranking of those technologies as potential solutions, i.e., the first option discussed has not been determined to be the preferred option at this time, nor have subsequently discussed options been determined to be less viable options. Rather, the order of discussion was selected as a logical progression by the authors.

In furtherance of completing the technology analysis, the IPP Study Team has met with several stakeholders, including the Utah Geologic Survey, researchers at Brigham Young University, and several companies who are interested in implementing their solutions to enable the continued operation of the existing coal-powered electrical generation facility. The IPP Study Team has also reviewed work done by the University of Utah and Utah State, as well as a wide range of source materials cited in the footnotes below.

Additionally, there is the need in subsequent studies and reports to firm up estimates of the range of potential capital and maintenance costs associated with maintaining the coal plants at IPP if they are to extend beyond the currently-contemplated retirement date. Based on conversations on September 11, 2023 with the plant's former manager and on October 11, 2023, with an IPSC representative, it appears that IPA has become less proactive on certain coal unit maintenance activities due to the retirement expectation. The 2024-25 preliminary maintenance budget of $29,769,000 is indicative of a declining maintenance focus, as it reflects a material reduction from the 2022-23 maintenance budget of $37,116,000. The IPSC representative stated that, were the coal units to run beyond 2025, the 2024-25 maintenance budget should be similar to the 2022-23 maintenance budget. As such, there is a backlog of deferred maintenance activities that may need to be addressed in the near-term to preserve the option of continuing to run the coal units beyond

2025, such as addressing boiler tubes in Units 1 and 2, upgrading coal conveyor belts, and replacing Unit 2's intermediate pressure turbine rotor. The IPSC representative estimated it could take 18 months to procure the parts necessary to fully re-tube Units 1 and 2 and that the total cost could be $300,000,000, that upgrading coal conveyor belts could cost $5,000,000, and that replacing Unit 2's intermediate pressure turbine rotor could cost $20,000,000.

The IPP Study Team cannot confirm the accuracy of these estimates or whether alternative, smaller-scale boiler tube repair/enhancement projects could suffice to ensure that Units 1 and 2 could live out several additional years of useful life without incurring the additional expenses of complete re-tubing.

1. Technical Assessment of NO_x Control Technologies

As described under Task 1, Regulatory Analysis, the IPP Study Team has concluded that continued operations of the existing IPP coal units would likely require the installation of SCR on any unit that is to remain operational to comply with the BART retrofit requirement under Utah's Regional Haze program and to meet the daily backstop emission rate included in the Environmental Protection Agency's ("EPA") Good Neighbor Plan ("GNP") and to allow additional operational freedom under the finalized emission budgets for the state of Utah and IPP specifically, should the EPA prevail in the legal challenges surrounding the GNP.

Currently, both coal units are equipped with low-NO_x burners and overfire air emission control systems. Over the last five years, the average NO_x emission rate for the two coal units was 0.25 lbs/MMBtu. However, when calculating and setting the state emission budgets for its GNP, the EPA assumed that all coal units in affected states that are currently not equipped with an SCR will be able to do so no later than May 1, 2027, the start of the 2027 ozone season. In its emission budget calculations, the EPA assumed that all coal units newly retrofitted with SCR control equipment can achieve an emission rate of 0.05 lbs/MMBtu, or an 80% reduction of IPP's current NO_x emission rate. Although EPA's GNP does not specifically require the SCR retrofit, the IPP coal units would be limited to a capacity factor of approximately 15% during the ozone season in order to stay within its emission budget.

In addition to the reduced allowance budget starting with a partial phase-in during the 2026 ozone season due to the assumed SCR retrofit and operation, the EPA's GNP also includes a daily backstop emission rate of 0.14 lbs NO_x/MMBtu that comes into effect with the 2030 ozone season. Any emissions above the daily backstop emission rate would need to be covered with allowances at a 3-to-1 ratio.

Furthermore, should IPA or any future owner of the IPP coal units decide to operate the units beyond the enforceable closure date of December 31, 2027, as required in Utah's latest Regional Haze State Implementation Plan ("SIP") and state law, an updated four-factor analysis of the IPP coal units as part of a required Utah Regional Haze SIP revision will likely conclude that the IPP will need to retrofit SCRs to ensure that Utah continues to meet EPA's reasonable progress definition.

According to IPA Staff, IPA previously assessed the potential SCR retrofit cost for the two IPP coal units. However, until IPA Staff provides the IPP Study Team with the IPP-specific SCR retrofit cost estimate, the following is a cost estimate for the SCR retrofit utilizing EPA's Retrofit Cost Analyzer ("RCA")[42]. EPA's RCA is an Excel-based tool that can be used to estimate the cost of building and operating pollution control such as SCR, Selective Non-Catalytic Reduction ("SNCR"), Wet Flugas Desulfurization ("FGD"), Dry FGD, Dry Sorbent Injection, Activated Carbon Injection and Particulate Matter, and was updated in 2023 by the engineering firm Sargent & Lundy. Utilizing the RCA and cross-checking the results against other real-world retrofit costs, the IPP Study Team estimates the SCR retrofit costs for one coal unit at approximately $250 - $300 million (~$275 - $333 per kW) or $475 - $525 million for both coal units (~$260 - $291 per kW). In 2016, IPSC commissioned high-level third-party estimates to retrofit the two IPP coal units with SCRs, with an estimated cost of SCR installation on both coal units of $280 to $340 million in 2016 dollars. When adjusting for inflation, the estimate using EPA's RCA appears reasonable and comparable to IPSC's original 2016 high-level cost estimate.

Key Takeaway: The installation of a new SCR system at one or both IPP coal units is likely required for the continued operation of the units to comply with EPA's GNP and the Utah Regional Haze plan. The SCR retrofit is by far the most costly environmental retrofit to allow the IPP coal units to continue operating while complying with all existing federal and state environmental regulations.

2. Technical Assessment of CCR Compliance Technologies

As described in Task 1, the IPP has two surface impoundments that are regulated under the 2015 Coal Combustion Residuals ("CCR") rule and its subsequent revisions and amendments. The Bottom Ash Basin was commissioned in 1986 and provides decant water to the Ash Water Recycle Basin for reuse in the ash water system and the sulfur dioxide removal system. The major waste sources contained within the Basin are bottom ash and boiler slag. The Bottom Ash Basin has an approximate size of 101 acres. The Waste Water Basin primarily receives flue gas emission control residuals as well as other process material, including process water separated for re-use, wash down, coal pile run-off, boiler blowdown, cooling tower blowdown, and regenerant rinsate.

The Bottom Ash Basin and the Waste Water Basin are considered unlined surface impoundments under the CCR rule as they do not meet the liner requirements laid out in the regulation. According to the rule, these units must cease receiving CCR and non-CCR waste streams by April 11, 2021, unless an extension request was filed and granted. On November 30, 2020, IPSC submitted its site-specific alternative deadline to initiate closure under the CCR rule's second option (permanent cessation of a coal boiler by a date certain). In the submittal, IPSC requested that both surface impoundments be allowed to continue to receive CCR and non-CCR waste streams after April 11, 2021, and complete closure no later than October 17, 2028.

The closure plan[43] for the Bottom Ash Basin includes dewatering of the impoundment, backfill with general fill to pre-consolidate the basin solids, assist in dewatering and to construct a sloping crown for the final cover system, construction of a high-density polyethylene ("HDPE") liner,

[42] https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

[43] https://ccr.ipsc.com/IPSC/CCRUnit/CCR1UnitTab?category=Closure%20%26%20Post-Closure%20care.

construction of an 18-inch general fill for liner protection, construction of a 6-inch vegetated layer of topsoil, and vegetation of the cover surfaces.

The closure plan[44] for the Waste Water Basin includes removal of standing water, construction of a divider berm to facilitate staged construction of the cover system over the CCR, placement of general fill, dewatering of the basin solids, construction of a sloping crown, placement of a low-density polyethylene liner to prevent surface water infiltration, capping with 18 inches of general fill to protect liner, and the construction of a 6-inch layer of topsoil. Although the existing bottom liner in the Waste Water Basin is an 80-mil thick HDPE geomembrane, it does not meet the liner definition of the CCR rule for continued operation.

According to the FY2022 financial disclosure, IPA estimates the total cost of compliance with the final CCR rule to be within the range of $55 to $70 million for all closure activities described above. Additionally, and not included in the current estimate, is an annual cost for long-term groundwater monitoring for 30 years post-closure as required by the CCR rule.

According to IPA Staff, the $55 to $70 million CCR compliance cost estimate is based on IPA's initial estimates of minimum compliance costs with the CCR Rule, including $45M in closure costs and approximately $10M in initial compliance and estimated groundwater remediation costs, totaling an estimated minimum compliance cost of $55 million, plus cost contingency and unknowns. Additionally, IPA evaluated a number of dry handling options from 2015 to 2017, with the minimum cost estimate in 2015 being $18 million, which did not account for the cost of building new landfill space.

As described in Task 1, to continue operating the IPP coal units beyond 2028, the Bottom Ash Basin and Waste Water Basin would need to be retrofitted to comply with the CCR rule for continued operation or will stop receiving CCR waste due to a conversion of the current bottom ash and FGD waste streams from wet to dry handling and disposal. Since the closure plan for the Bottom Ash Basin calls for the installation of a new HDPE liner, which will prevent further groundwater contamination due to the CCR waste, it is appropriate to assume that the new HDPE liner meets the liner requirement under the CCR rule and would allow continued operation of the CCR impoundment without any additional significant investment beyond what is already included in the $55 to $70 million closure cost estimate. Conversely, due to the groundwater contamination violations of the Waste Water Basin, the existing HDPE bottom liner of the impoundment is unlikely to meet the liner requirement of the CCR rule and would likely need to be replaced with a compliant HDPE liner if the impoundment were to be used for continued operation of the two IPP coal units. However, since the current closure plan of the WasteWater Basin does not call for the replacement of the existing HDPE bottom liner, the $55 to $70 million CCR compliance cost estimate likely underestimates the cost for continued operation of both surface impoundments. Additional information from IPA or its CCR subcontractor is needed to estimate the cost of replacing the existing HDPE bottom liner of the Waste Water Basin with a CCR rule-compliant HDPE liner.

Another option to comply with the CCR rule without changing the current closure plans for the Bottom Ash Basin and Waste Water Basin is to convert both CCR waste streams from wet handling

[44] https://ccr.ipsc.com/IPSC/CCRUnit/CCR2UnitTab?category=Closure%20%26%20Post-Closure%20care.

to dry handling and dispose of the dry CCR material in the existing CCR landfill. One of the most common retrofit technologies to convert the bottom ash handling from wet to dry is the installation of a mechanical drag system ("MDS"). The EPA included a cost methodology for the installation of a new MDS as part of its 2016 and 2020 Effluent Limitation Guidelines ("ELG") for steam-electric fossil fuel boilers rulemaking[45]. Using the cost estimates included in the rule docket, the IPP Study Team estimates the cost to install a new MDS at the IPP coal units at approximately $60 to $80 million with an ongoing operation and maintenance ("O&M") cost of about $1 to $2 million per year.

Also included in the EPA ELG rulemaking are cost estimates for the elimination of FGD wastewater. Using EPA's cost methodology to install a membrane filtration and encapsulation system for treating and drying the flue gas desulfurization residuals, the IPP Study Team estimates the cost to eliminate the FGD wastewater stream and allow the disposal of the dried FGD byproduct in the existing landfill at $50 to $70 million, with an ongoing annual O&M cost of $4 to $6 million. It is worth noting that converting both CCR waste streams from wet to dry handling significantly reduces the amount of water used by the IPP coal units.

Key Takeaway: To allow for continued coal combustion and CCR disposal at the IPP coal units beyond October 2028, the current CCR impoundments need to be retrofitted to comply with the CCR rule for continued operation or the CCR wastewater production needs to be eliminated by converting the existing systems to dry handling. Although retrofitting the existing impoundments for continued operation is likely to be a cheaper compliance option, the significant reduction of water consumed by IPP when converting from wet-to-dry CCR handling should not be discounted.

3. Technical Assessment of IPA's Current and Future Water Consumption Rates

In 1979, before the IPP coal units were constructed, IPA acquired water rights for four generating units averaging about 45,000 acre-feet annually at a cost significantly above its agricultural value. About 15,400 acre-feet are supplied from groundwater resources, while the remaining water is supplied via river surface water. The surface water resource can vary significantly from year to year. Any unused water is leased to local farmers for consumption in Utah's agricultural sector.

Since the original design of IPP was planned for four coal-fired generating units, IPP never exceeded its water rights since it started operating in the 1980s. According to IPA Staff, actual annual water consumption at IPP peaked at about 25,000 acre-feet but has fallen to about 12,500 to 15,000 acre-feet per year over the last few years due to the lower utilization of the IPP coal units.

In the future, IPA Staff estimates that the IPP Renewed project will consume about 6,500 acre-feet per year operating its heat recovery system and steam turbine. Additionally, water is required to produce the hydrogen planned for use in the IPP Renewed project. Upon startup, the electrolyzer is projected to consume about 300 acre-feet per year to supply enough hydrogen to the IPP Renewed gas turbines to achieve the targeted 30% hydrogen co-firing rate, increasing to about 2,700 acre-feet per year once the gas turbines operate on 100% hydrogen fuel. Lastly, an additional 7,000 to 8,000 acre-feet is needed during the first two years of the IPP Renewed project's

[45] https://www.epa.gov/eg/2020-steam-electric-reconsideration-rule.

operations to develop the long-term salt cavern storage for the produced hydrogen. These estimates will need to be refined and verified to ensure that sufficient water rights exist to supply both the existing IPP coal plants and the anticipated build-out of the Renewed project, especially once it is relying upon 100% water-based electrolyzer hydrogen production.

Noteworthy also is the current IPP Renewed construction plan, which includes changes and upgrades to the current water delivery system. According to IPA Staff, the entire river water supply infrastructure for the coal units is being transferred to the IPP Renewed gas turbines to support their operation. This includes the pumping structure and equipment at the D M A D reservoir, the pipeline to the plant, and the on-site reservoir. Because of the age of these systems, they are being upgraded, existing equipment is replaced during the construction of the new gas units, or they are considered capital projects that will be completed after the new generating units go online. Currently, contractors are running a new water pipeline to the onsite reservoir pump building. Additionally, IPA plans on relining the onsite reservoir in 2026 or 2027. During the relining project, there will not be adequate water to run the existing IPP coal units alongside the IPP Renewed combined cycle gas turbines and the hydrogen electrolyzer. It is anticipated that additional infrastructure would need to be installed to continue operations of the coal plants if their existing water supply systems, as upgraded per the description above, will be relied upon to operate the Renewed project and the IPP coal units continue to operate.

Key Takeaway: Based on information provided in this analysis, IPA owns a sufficient quantity of water rights to run the existing coal units, the IPP Renewed combined cycle gas turbines, and the hydrogen electrolyzer at sufficient levels over the year. However, current and future construction plans regarding the current and future water system supplying the surface water to the IPP site will likely need to be reevaluated and adjusted to allow for the continued operation of both the Renewed project and existing IPP coal units. Another issue worthy of more careful assessment moving forward is the sufficiency of the approved use category of existing water rights and whether they can be relied upon for certain aspects of the Renewed project not related to power plant operations that have been the prior basis of water use (e.g., use of water to supply hydrogen production and creation of salt domes for hydrogen storage).

4. Technical Assessment of Technologies Targeting CO_2 Emissions

In evaluating environmental control and coal conversion technologies, the IPP Study Team met with seven companies and one research team who expressed interest in implementing their technologies at IPP. One of these companies, offering a nuclear solution, expressed interest from 2015-2017, but has not expressed any recent interest in the plant. The solutions proposed more recently include carbon capture utilization and storage (“CCUS”), coal conversion to graphite with hydrogen byproduct along with coal conversion to strategic minerals with hydrogen byproduct, gasification of coal with CCUS, coal conversion to syngas, emissions reductions through fuel additives, and another company proposing an integrated hydrogen fuel center. After having had an opportunity to speak with the interested stakeholders, the IPP Study Team has identified at least three (3) viable options for continued operations of the existing coal unit(s) and at least two of those were submitted for consideration to IPA. The IPP Study Team’s evaluation of each proposed solution can be found below.

Each option, as described below, is evaluated through informational interviews, information provided by the proposing entity, and evaluated for its potential to (i) overcome regulatory constraints as outlined in "Task 1," (ii) reduce environmental impacts, and (iii) create new products, revenue streams, and economic opportunities.

5. Technological Options

a. Option A

i. Overview

Option A (the "coal to graphite option") would utilize existing infrastructure at IPP to convert coal to graphite, strategic minerals, and hydrogen byproduct. Coal conversion to graphite and hydrogen is technically feasible and is currently being further refined and developed by researchers across the country.[46] The company proposing the coal to graphite option has demonstrated commercial viability, albeit at a smaller scale than would be necessary for continued operations at IPP. However, the coal conversion process proposed for IPP is currently being adopted at a coal plant of a similar size to IPP in the state of West Virginia. The proposed process would enable coal to be used at the site, would utilize existing facilities, and create valuable byproducts in the form of graphite, valuable minerals, and hydrogen. The hydrogen produced would be used to generate electricity at the existing coal units after a retrofit to enable the burning of 100% hydrogen. The coal to graphite option was presented to IPA. The coal to graphite option would be available for one or both existing coal units at IPP.

ii. Economics

The cost for implementation of the coal to graphite technology has been assessed through information provided by the company. Estimates of costs are approximately $1 billion to convert both units. Because the actual electric generation component of the process would be fueled by hydrogen from converted coal, it is not anticipated that SCRs would need to be installed at the existing plant, and the coal to graphite option would be able to comply with the Regional Haze Rule without SCRs. The costs are anticipated to include a complete purchase and retrofit of both units.

In addition, the coal to graphite option would maintain or even increase jobs for upstream coal mining and transportation stakeholders. If both units were utilized for coal conversion, it is anticipated that the plant would require 2.1x more coal than is currently consumed at the plant, while utilizing a single unit would require 1.05x more coal than is currently consumed. While this does not directly impact the economic viability of the coal to graphite option outside of fuel costs, it does have upstream implications for providers of coal to IPP and the overall economy of the state.

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[46] Thapa et al., *Ab Initio Simulation of Amorphous Graphite*, PHYS. REV. LETT. Vol. 128, Iss. 23 (2022) *available at* *https://journals.aps.org/prl/abstract/10.1103/PhysRevLett.128.236402*, *see also* Masi et al., *Converting raw coal powder into polycrystalline nano-graphite by metal-assisted microwave treatment*, NANO-STRUCTURES & NANO-OBJECTS Vol. 25 (2021) *available at* https://www.sciencedirect.com/science/article/abs/pii/S2352507X20301281?via=ihub.

Beyond upstream benefits to coal mining and transportation firms, the coal to graphite option would involve the creation of valuable graphite and other products. The revenue from graphite would be expected to far exceed the revenue from power sales on an annual basis and could greatly increase tax revenues. Additionally, the CO_2, SO_x, and NO_x produced in the coal conversion stage of the process can be captured and either utilized to create additional products or in the case of CO_2 sold in offtake agreements to food processors and others in need of CO_2.

iii. Emissions

The coal to graphite option, as proposed to IPA, would nearly eliminate all CO_2, NO_x, and SO_x emissions at the plant *from the generation of electricity*. Because the plant would be converted to burn hydrogen and because of the burning conditions of that hydrogen, emissions from the plant would be materially reduced. Of critical importance, the hydrogen used for electricity generation in the coal to graphite option would not create any CO_2 emissions, and therefore the power would be marketable under both the California and EPA Carbon Rules discussed in “Task 1” and overcome that regulatory hurdle. However, the whole system is not entirely emissions free. While much of the carbon content of the coal burned would be utilized for the production of graphene/graphite, there are still CO_2 emissions that would need to be dealt with. The graphite/hydrogen production also produces NO_x and SO_x. Accordingly, the conversion process and production of hydrogen for the plant produces CO_2, NO_x, and SO_x and there may be additional regulatory hurdles faced in permitting the processing facility if the emissions are not dealt with.

To address this issue, the company proposing the coal to graphite solution claims that the emissions from the production of hydrogen and graphite can be captured through a cryogenic process, which will be used at the West Virginia site, and the gases can be used either to provide in offtake agreements (i.e. CO_2) or processed to create other valuable products depending on the project specific needs. Discussions with the proposing company indicate that such steps would and are being taken at existing project sites and therefore would be anticipated to be available at IPP. If successful, the company expects almost no greenhouse gases would be emitted through the entirety of the process.

iv. Risks

Potential risks associated with the coal to graphite option are technological, market based, and regulatory in nature. As mentioned herein, the technology has not yet been proven to be commercially viable at a scale comparable to what would be needed at IPP. However, the fact that the technology is being implemented at sufficient scale at another location is promising for the technology’s viability at IPP.

The economic risks for the coal to graphite option include variable capital costs for implementation, as IPP may have deferred maintenance costs, and the potential need for additional emission control technologies at the coal processing facility. While these costs are projected to be commercially reasonable by the proposing company based on the project in West Virginia, that plant is not yet complete and therefore cost estimates may be over or underestimating actual costs. Further, the success of the proposal is dependent on market factors, which include (i) the ability to continue to sell power from the existing units in addition to IPA’s hydrogen project on existing transmission lines and to existing customers and (ii) the market for graphite and valuable minerals.

The ability of the proposed coal to graphite option to be able to sell power into the existing market is discussed further in Tasks 3 and 7. However, as noted under Options B, there is significant interest from companies in locating high load facilities at or near the IPP site. This interest is likely to remain so long as a low carbon intensity solution is implemented at the site and the facilities keep running. In turn, this gives each option, including the coal to graphite option, the potential flexibility to sell power either to existing customers or new customers locating in Utah.

Additionally, the coal to graphite option is reliant on the ability to sell graphite and other valuable minerals into the marketplace. The existing market for the products is strong. For example, graphite is currently selling at $1,200-$1,800/ton with prices expected to trend slightly downward over the next 12 months. The coal to graphite option also faces permitting and environmental controls risks as discussed in more detail in this Task, as well as “Task 1” if emissions at the coal processing facilities are not captured and processed as discussed above. Further, there would remain a need for mitigation or elimination of risks from the existing CCR facilities either for IPA or if the CCR facilities were transferred, by the acquiring entity.

v. Unique Benefits

The coal to graphite option produces potable water in significant amounts, up to 8,300 acre-feet annually. This valuable resource could be available to the state or for use in the hydrogen production facilities at the IPP hydrogen project. Additionally, the technology produces valuable products like graphite at significant scale, which would be anticipated to bring significant economic benefits to the state. Based on information provided to the IPP Study Team, the coal to graphite option would also have the lowest emissions profile and could be implemented in the shortest amount of time.

b. Options B1 and B2

i. Overview

Options B1 (the “local load creation and CCUS option”) and B2 (the “standalone CCUS option”) would each utilize existing infrastructure at IPP to continue coal fired power generation. In either case, coal would continue to be utilized for power generation only. Both options would require that carbon capture technologies be installed at IPP to reduce CO_2 emissions. Carbon capture technologies vary and are quickly evolving. Despite this, the three primary methods of capture which might be commercially available today at IPP are amine separation, membrane separation, and cryogenic separation. The local load growth and CCUS option proposed using amine-based separation. CCUS retrofits at coal plants are technically and commercially feasible. There is currently one coal fired facility retrofit with CCUS technology in the United States. The Petra Nova project at the WA Parish plant in Texas cost about $600 million to retrofit one 680 MW unit of an existing coal facility. An additional $400 million covered up-front operating, administrative, and a portion of the CO_2 pipeline and enhanced oil recovery costs. Beyond coal, there are thirteen (13) additional projects that are operational throughout the United States, three (3) of which have been operational since the 1970s and 1980s.[47] Due in part to corporate and state decarbonization

[47] *US Carbon Capture Activity and Project Table*, Clean Air Task Force (2023), *available at* https://www.catf.us/ccsmapus/.

goals and in part to the recent passage of the Inflation Reduction Act in 2022, there has been a substantial increase in the number of projects being developed. There are currently 175 capture, transport, and/or storage projects in development across the United States, including eight (8) additional projects at coal plants.[48]

At IPP, the local load creation and CCUS option was proposed to IPA. To the IPP Study Team's knowledge, a standalone CCUS option has not been proposed to IPA but was identified by several parties who met with the IPP Study Team as a potential option to enable continued operations of IPP. The load creation and CCUS option has been assessed to be commercially viable by parties, but further information would need to be gathered to assess whether a standalone CCUS option is viable.

ii. Economics

One critical component of adopting a CCUS retrofit at IPP would be assessing whether the captured CO_2 should be utilized or stored, as most projects are typically either a CCU or CCS project. Before a project could proceed at IPP, studies would need to be undertaken to assess the economics and technical feasibility of storing and/or utilizing the CO_2. The most common form of utilization in place to date is enhanced oil recovery ("EOR"). For CO_2 from IPP to be utilized for EOR, any project would likely need to undertake the buildout of a pipeline approximately 130 miles, with a range of 105 to 180 miles, to reach many of the productive oil and gas fields in the state. Alternatively, the CO_2 could be utilized for the creation of other byproducts or permanent sequestration in areas more proximal to the IPP site.

As mentioned herein, the Petra Nova retrofit cost approximately $600 million to install carbon capture infrastructure at a 680 MW unit. With inflation and the larger unit size of the units at IPP, it is likely that retrofitting one unit might cost more than $1 billion. However, the costs are not necessarily linear and retrofitting both units may be significantly less than two times the cost of retrofitting one unit due to economies of scale. Recent studies on cost estimates for retrofitting 914 MW at the San Juan plant in New Mexico estimated that total costs for that project in 2022 would be approximately $1.5 billion, with a four-to-five-year project completion timeline. In addition to costs to capture, both the potential solutions face costs for storage and/or utilization of the captured CO_2. Several potential stakeholders proposed that CO_2 may be stored in salt caverns, which already exist and can be produced in the immediate vicinity of the IPP site. However, at the volumes produced by IPP today, the IPP Study Team has concerns about the long-term viability of storing CO_2 in salt caverns and the option would require further study.

Despite reservations about the long-term feasibility of storage at the salt caverns, the IPP Study Team, with the assistance of the Utah Geologic Survey, has identified four additional potential locations for storage. The first is in basalt formations in the immediate proximity of the IPP site. Storage in basalt has significant advantages when successful because the captured carbon tends to mineralize and solidify over short periods of time, reducing risks of recapture of tax benefits. For instance, studies have shown that CO2 injected in certain basalt formations can mineralize into carbonate solids over a period as short as several months to ten (10) years, whereas CO2 injected into a salt cavern or saline formation may remain a gas for thousands of years. Because tax credits

[48] *Id*.

for CO2 storage can be recaptured if there is later a release of the CO2 injected, options where CO2 converts from a gaseous or supercritical state into a solid state are increasingly becoming more attractive options. The basalt formations exist in the immediate vicinity of the site and would not require a large buildout of transport pipelines. However, storage in basalt is largely untested in the United States, despite its success at facilities in Iceland. The second is in a "more traditional" saline aquifer formation which may be a good storage option some 30-40 miles East to Northeast of the site. The third is in another saline aquifer 100-130 miles to the South. The final option is to transport the CO_2 for enhanced oil recovery as mentioned above. The fourth option would likely require the longest buildout of transport pipelines. Current cost estimates for pipelines capable of transporting the volumes of CO_2 needed from IPP range from $1.5 to $3 million/linear mile.

Importantly, these costs can be offset through one or more additional revenue streams beyond the revenue from the sale of power from the plants. All CCUS costs would be offset by the federal government's support of CCUS and available tax credits for successful CCUS operations. Today, tax credits are available at $60/metric ton for CO_2 captured and utilized and $85/metric ton for CO_2 captured and permanently stored. Additionally, for utilization options, there is an additional revenue stream for CO_2 sold for enhanced oil recovery and for additional products that could be produced if the CO_2 is not used for enhanced oil recovery. Outside enhanced oil recovery, CO_2 can also be used in the production of cement, food processing, synthetic fuels, chemicals, and agricultural and biofuels.

iii. Emissions

The two CCUS options would significantly reduce CO_2 emissions. Current plans for CCUS facilities around the county are typically being designed and constructed to capture 85-95% of CO_2 emissions. If successfully implemented at IPP, CO_2 emissions would be reduced to 105-330 lbs/MW of power produced. With this level of reduction, the power produced would be eligible to be sold under the California carbon rule and would comply with the EPA's proposed carbon rule as discussed in "Task 1". However, additional environmental control technologies would need to be implemented to address NO_x emissions.

iv. Risks

Potential risks associated with the two CCUS options are technological, market and public perception based, and regulatory in nature. As mentioned herein, while the technology has been proven at a handful of sites to be commercially viable at a scale comparable to what would be needed at IPP, CCUS is still not widely commercially demonstrated and there have been a number of commercial failures.

The economic risk profiles option B1 and B2 vary significantly regarding who would bear economic risk. The economic risk of the local load growth and CCUS option, as proposed to IPP, would be primarily held by the proposing corporations. However, a standalone CCUS option may require investment by IPA, the State, or other stakeholders. Despite the difference in who bears the risk, the two options share risks in the following: (i) implementation of the carbon capture technology, (ii) implementation of carbon utilization or storage, (iii) ensuring a customer base to purchase the power produced, and (iv) economic risks arising from regulatory requirements.

A standalone CCUS option also poses risks of maintaining a customer base with existing transmission infrastructure and the addition of the IPA hydrogen project. However, the local load growth and CCUS option has suggested that the power produced from the retrofitted existing coal facilities would be used locally. The companies proposing the local load growth option would locate and construct high load facilities at or near the IPP site and eventually use the entirety of the load locally. The local load growth and CCUS option would result in significant increases in jobs and tax revenues as discussed below.

Finally, both the local load growth and CCUS and the standalone CCUS options pose risks created by regulatory constraints. Both options would likely need to implement SCRs to reduce NO_x emissions, increasing costs to the overall retrofit. Additionally, it has been proposed under the local load growth option and is presumed to be true in the standalone CCUS option that the plants would need to convert to dry handling and a new CCR facility would need to be constructed. Finally, in each of these options, there is significant risk associated with the timeline and costs associated with permitting and constructing CO_2 transmission pipelines and storage sites. However, all these risks are manageable and are being addressed at sites across the United States and do not, per se, make the options unviable.

As is true for all feasible solutions, the success of the CCUS options is dependent on the ability to continue to sell power from the existing units in addition to IPA's hydrogen project on existing transmission lines and to existing customers. The ability of the standalone CCUS option to be able to sell power into the existing market is discussed further in Tasks 3 and 7. The ability of the local load growth and CCUS option to construct the necessary facilities needed to use the load locally is also a potential risk but also an opportunity. The clear opportunity is that there is significant interest from companies in locating high load facilities at or near the IPP site. This interest is likely to remain so long as a low carbon intensity solution is implemented at the site and the facilities keep running. In turn, this gives each option, including the CCUS options, the flexibility to sell power either to existing customers or new customers locating in Utah.

Both options include additional risk from the standpoint of public perception. While this is not likely to impact the capture itself, there are well documented cases across the country of public pushback against CO_2 pipelines and storage sites. Finally, the CCUS options also face permitting and environmental controls risks as discussed in more detail in this Task, as well as "Task 1." These risks include the need for mitigation or elimination of risks from the existing CCR facilities, construction and permitting of new CCR facilities, implementing SCR to address NO_x emissions, and permitting transportation and storage sites. Further, successful implementation of CCUS will require the managing entity to find feasible utilization or storage options. As discussed above, there are potential storage options and enhanced oil recovery options in Utah. However, for storage, there are site characterization studies that would need to be conducted at potential storage sites to further assess the technical feasibility. These studies can take multiple years to complete, and sites would need to be identified quickly to begin funding and completing those studies.

v. Unique Benefits

The local load growth and CCUS option would bring significant job growth and economic diversity to the area. The load would be utilized locally, in industries that are valuable to the state and the growth of the economy. Additionally, both CCUS options could spur the growth of new industrial sectors in the state, both from the capture, transport, and storage itself, but also from the utilization of the CO_2. CO_2 is being used in novel ways to help produce low carbon cement, in the beverage and food processing industries, and to create other valuable products. Finally, the CO_2, if used for enhanced oil recovery, could provide a boost to oil and gas operations in the state.

c. Option C

i. Overview

Option C (the "syngas option") would utilize all the existing infrastructure at IPP. In the syngas option, coal would be utilized to create syngas to be burned at the plant. While the company proposing the syngas option has not yet proposed their solution to IPA, the technology has been demonstrated commercially at smaller scale. To our knowledge, the technology has not been demonstrated at the scale needed for IPP. The technology is fuel agnostic and primarily produces syngas as a byproduct. The syngas is proposed to be used to generate electricity in the existing units with minimal modifications or retrofits needed.

ii. Economics

The costs for implementation of the syngas option were not made available and therefore cannot be assessed as a part of this analysis. However, importantly for this analysis, the technology would need to be phased in over a period of several years, which may cause implementation problems and economic risks associated with not meeting environmental compliance deadlines as discussed in Task 1. However, this does not per se exclude this option from consideration. There are unique benefits to the technology which warrant further investigation.

iii. Emissions

The syngas option is claimed to reduce CO_2 emissions by approximately 70%. The emissions reductions are due primarily to using approximately 70% less fuel for the same power output from syngas. Volatile metals and particulate emissions would be minimized and pulled out of the process as a valuable byproduct. It is unclear at this time if there would need to be additional environmental retrofits to address SO_x and NO_x emissions, but those emissions too would be significantly reduced in line with reduced fuel usage. At a 70% reduction, the power would be marketable under the California carbon rule and the power produced at the plant would have a CO_2 emissions intensity of about 700-733lbs/MW.

iv. Risks

Potential risks associated with the syngas option are like those faced by the prior options. As mentioned herein, the technology has not yet been proven to be commercially viable at a scale comparable to what would be needed at IPP. Like each previous option the ability of the proposed syngas option to be able to sell power into the existing market is a concern and is discussed further in Tasks 3 and 7. However, in each of the prior options, there is significant interest from companies in locating high load facilities at or near the IPP site. Again, there is significant potential that the syngas option could have the flexibility to sell power either to existing customers or new customers locating in Utah if the carbon emissions were deemed low enough by those interested parties to locate at IPP. The coal to syngas option also faces permitting and environmental controls risks as discussed in more detail in this Task, as well as Task 1. These risks include the potential need for SCRs for addressing NO_x emissions and the need for mitigation or elimination of risks from the existing CCR facilities. Further, because the proposing company does not plan to also include capture of emissions, the syngas option may entail further regulatory risk.

v. Unique Benefits

The syngas option does not require potable water to operate. Additionally, the technology is fuel source agnostic and is even capable of utilizing existing coal residuals and coal ash as a feedstock for the process. This has obvious implications for the existing CCR facilities and provides a potential option for assisting the current liable parties to close the facility and mitigate risks. Finally, the syngas and syngas process can be used for production of hydrogen, ammonia, fertilizer, aviation fuel, natural gas, and advanced materials, which like the coal to graphite option can be sold into the market to create significant additional revenue streams.

d. Other Options

Beyond the options discussed in depth above, the IPP Study Team also spoke with companies and researchers working on other technologies to retrofit and address emissions at IPP. These proposals include a company proposing a fuel additive to reduce emissions, a research team proposing gasification of coal with CCUS, a company proposing an integrated hydrogen hub at which they would produce synthetic fuels from the captured CO_2 emissions, and a company who had previously proposed installation of nuclear at the IPP site.

The fuel additive technology is currently not in use at any known coal facilities. However, the technology is worth mentioning because the company marketing the technology claims 5% increases in efficiency, 32-40% reductions in CO_2, and 40-70% reductions in NO_x depending on the systems in which the additive is implemented. Should any potential entity pursue running the existing plant beyond the current closing date, the technology may be available by that time to help mitigate emissions while other solutions are pursued.

The IPP Study Team also spoke with a researcher at Brigham Young University who is pursuing a coal gasification with CCUS option for implementation at existing coal plants or for use in building new facilities. The technology and process remain in the early stages of research and development and therefore are not currently commercially available. However, on a long-term basis, the technology is promising and may be viable in the future.

Another company that the IPP Study Team held discussions with proposed a plan spanning far beyond IPP. The plan included the development of hydrogen facilities across the state and an integrated hydrogen production and research hub. The company proposing the hydrogen solution would utilize captured CO_2 emissions to produce synthetic fuels. The IPP Study Team was unable to hold further discussions with all the necessary potential partners for the proposal, but cost estimates for a conversion given by the entity the IPP Study Team did speak with were approximately $900 million with a three-year timeline for construction.

Finally, the IPP Study Team also held discussions with a company that had previously proposed to IPA using the site for installation of small modular reactors (“SMRs”). The company utilizes a lithium fluoride thorium reactor and each unit installed would have a capacity of 250 MW. The company has not recently expressed interest in the IPP site, but a move to nuclear at the site is one potential option that may warrant further future discussion.

e. Conclusions

After meeting with several stakeholders, the IPP Study Team was able to evaluate a wide variety of technologies which might be used to maintain operations at the IPP site. While the IPP Study Team was able to identify three potential options for continuing operations based on the criteria listed herein, there certainly may be other options for continuing operations at IPP as the IPP Study Team was limited by data availability and time. Further, while the IPP Study Team has presented information herein about the perceived readiness of each technology, it is also helpful to compare the proposals on their ability to reduce emissions, which is a key component for marketing the power produced. The table below shows the associated emissions reductions of the technologies presented to the IPP Study Team based on statements and/or documents provided to the IPP Study Team.

Table 2.1: CO_2 emissions profiles of technologies in use, planned, or proposed at IPP

IPP today	2,058 lbs/MWh CO_2 (based on 2021 EIA data)
IPP Renewed	595 lbs/MWh CO_2 (based on 70% of plant average for natural gas combined cycle EIA)
Coal to graphite option	0.94 lbs/MWh CO_2 (based on company claims and data room and dependent on capture at coal conversion stage)
CCUS	103 lbs/MWh CO_2 (based on current emissions discounted for 95% capture design from San Juan Generating Station FEED)
Syngas Option	617.4 lbs/MWh CO_2 (based on unverified claim)
Fuel additive	1,399-1,233 lbs/MWh CO_2 (based on unverified claim)
Coal gasification with CCUS	103 lbs/MWh CO_2 (based on specifications at current rates with CCUS)
Hydrogen Hub Proposal	103 lbs/MWh CO_2 (based on unverified claim)
Nuclear Option	0.0 lbs/MWh CO_2

Key Takeaways:

Continued operations of the two existing IPP coal units will require significant financial investments to comply with existing state and federal environmental regulations. First, advanced emission control equipment (pre-, during, or post-combustion) is needed to reduce the NOx emissions from the existing coal units significantly. Installing state-of-the-art SCR equipment will likely equate to the greatest financial investment needed to continue operating the two coal units. Additional financial investment is needed to comply with EPA's Coal Combustion Residuals Rule or face imminent shutdown no later than October 2028. Notably, several companies that evaluated a possible purchase of the IPP coal units included these compliance costs in their evaluation and yet remained interested in the purchase.

As for future technology options targeting CO_2 emsission of the existing IPP coal units, there are at least three viable options that could be implemented. Of those options presented to the IPP Study Team, the coal to graphite and local load growth and CCUS options were presented to IPA. As presented to the IPP Study Team, each of these technologies may face regulatory hurdles as discussed in "Task 1," and the regulatory hurdles vary depending on the technology. Considering the technology readiness and emissions profile comparisons, the coal to graphite and CCUS options may be the best suited to continue operations at IPP and meet the criteria outlined for this study. On the longer time horizon, there are additional potential options as technologies and companies mature.

TASK 3 – Transmission Analysis

Excerpt from Contract No. 236352, Amendment 1

UCA 11-13-319.1(c): "identify the transmission capacity of the project entity;"

"Identify existing transmission capacity from IPP, and analyze potential needs for transmission upgrades if more electricity from the plant were sold into Utah (rather than Southern California) and other parts of the western grid."

Analysis

One of the critical components of the continued operation of the IPP coal units is transmitting the produced electricity to its end-users. The IPP Study Team investigated the current transmission and future assets to transport the produced electricity to a wide variety of end-use customers by interviewing various stakeholders involved in or intimately familiar with the IPP coal units. The IPP Study Team also referred to previous transmission studies done for and by the state of Utah and consulted other documents published by various stakeholders in the Western transmission grid, including California utilities like Los Angeles Department of Water and Power ("LA Department").

1. Current Transmission Line Connections at IPP

Located South of the two existing coal units is the IPP Alternate Current ("AC") switchyard. This switchyard is used to connect the two existing coal units with the Western electric power grid.

A total of four transmission lines connect at this switchyard to transport the electricity produced by the existing coal units to end-users located in Nevada, California and Utah. The four transmission lines are:

- 345 kV AC transmission line from IPP to the Mona, Utah substation connecting to Rocky Mountain Power; length: 50 miles; estimated capacity: 300 – 350 MW; Owner: IPA

- 230 kV AC transmission line from IPP to Gonder, NV substation connecting to NV Energy; length: 144 miles; estimated capacity: 50 MW; Owner: IPA

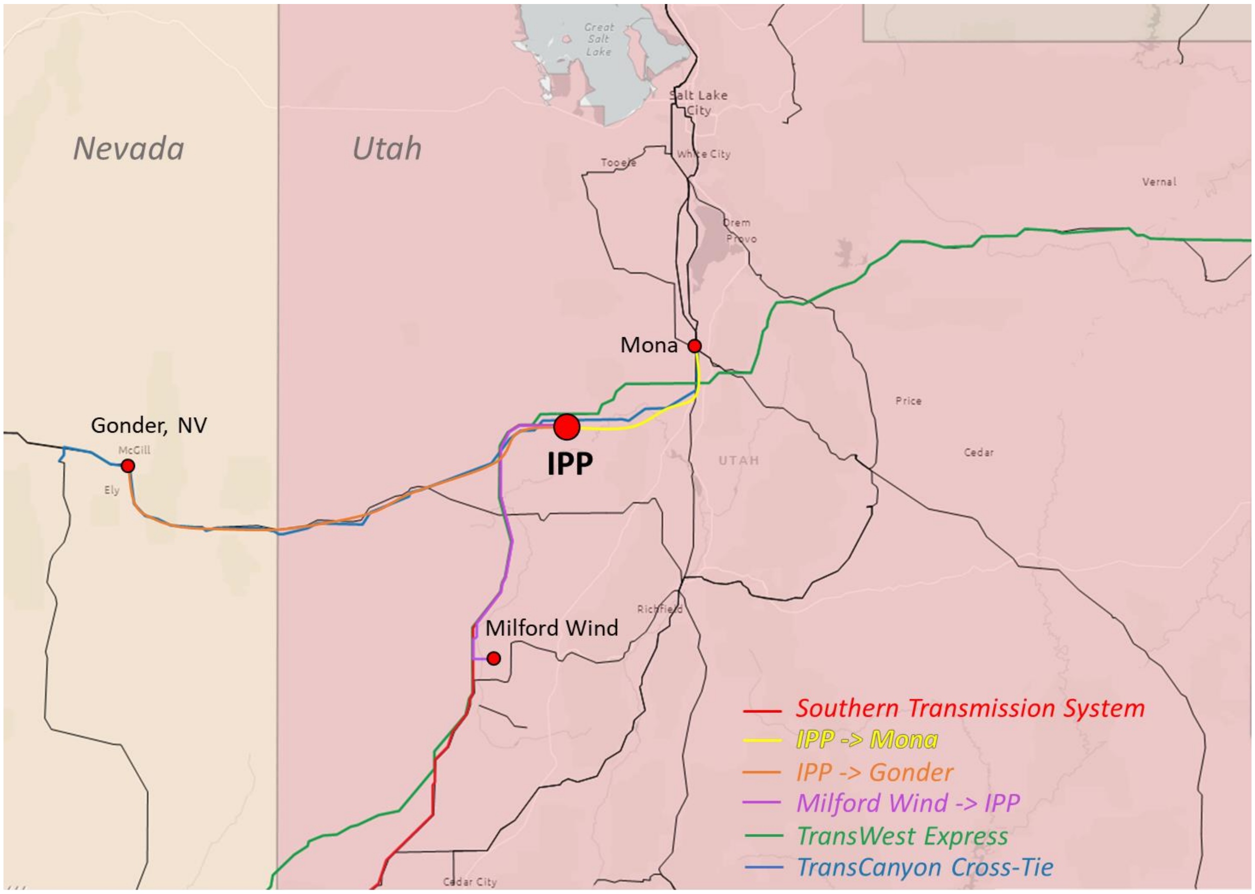
- 500 kV Direct Current ("DC") transmission line from IPP to Adelanto, California, connecting to CAISO and other California utilities; length: 490 miles; estimated capacity: 2,400 MW; Owner: IPA; Project Name: Southern Transmission System ("STS") or Path 27

- 345 kV AC transmission line from Milford Wind Farm to IPP: 80 miles; estimated capacity: 300 MW; Owner: First Wind

Besides the Milford-to-IPP AC line, which serves as the interconnection of the approximately 305 MW Milford Wind Corridor power project, all other transmission lines connecting at the IPP switchyard are owned by IPA.

The map below highlights the current and planned future transmission line projects located at or near the Intermountain Power site.

Figure 3.1: Overview of Transmission System at IPP



2. Future Transmission Projects Related to IPP Renewed

As part of the IPP Renewed project, significant upgrades and changes are in process at the existing IPP AC switchyard facility. The most important change will be the change-over of 345 kV intertie between the two coal-fired generators and the switchyard to the Combined Cycle Gas Turbines ("CCGT") generators. This will remove all power from the existing coal-fired generators and effectively disconnect them from the Western electric grid. The change-over is the last step in the construction process of the IPP Renewed project and will only be completed once the IPP Renewed project is fully operational and the coal units are no longer needed. As per IPA staff, no other major transmission projects are planned related to IPP Renewed that would directly impact the continued operation of the existing IPP coal units.

3. Future Transmission & Power Projects Located Affecting Transmission Capabilities at IPP

Besides the upgrades and changes made at the IPP switchyard itself as part of the IPP Renewed projects, other transmission and power projects located at or near the current IPP site will impact the transmission capabilities of the existing coal units at IPP. To support the electrolyzers that produce the hydrogen needed to power IPP Renewed, additional renewable energy power projects are planned to be located at or near the IPP site. For example, the 168 MW DC Notch Peak Solar project is planned to be located west of the current IPP site and will interconnect at the IPP switchyard.

In addition to co-located power projects at or near the IPP site, other transmission projects are planned to interconnect at the IPP switchyard. Most notably, the TransWestern Express ("TWE") transmission project includes a new DC-AC terminal due north of the current IPP site, where its 405-mile 600 kV DC line from South-Central Wyoming and its 330-mile 500 kV AC transmission line from southern Nevada will connect. The TWE includes a connection between the Utah terminal and the IPP switchyard to allow additional renewable interconnection to the TWE transmission system and renewable energy from planned Wyoming wind farms to be used in the ISPS and the electrolyzers of the IPP Renewed project. Construction of the TWE is expected to be completed by 2027.

Lastly, another transmission project aims to utilize the right-of-way established for the energy corridor north of IPP. TransCanyon's Cross-Tie transmission project is a 214-mile 500kV AC transmission line project aiming to connect the Clover substation in central Utah to the Thirty Mile substation in eastern Nevada by the end of 2026. Although current plans do not include a substation or interconnection point at the IPP switchyard, the possibility of an interconnection point at IPP in the future exists, according to TransCanyon's project-related documents.

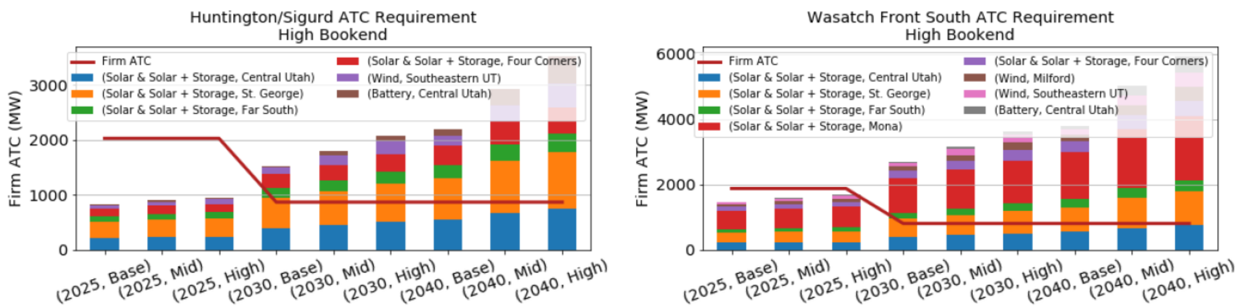
4. 2021 Utah Transmission Study

In 2019, Utah Senate Bill 3 allocated funds for an analysis of the Utah electric transmission grid. In 2021, Energy Strategies ("ES") released the report and analysis that were performed as a result of Senate Bill 3.[49]

The 2021 Transmission Study did not assume a continued operation of the IPP coal units. Conversely, ES modeled a projected buildout of wind, solar, and battery storage projects across the state of Utah and identified potential transmission bottlenecks where current transmission capabilities are insufficient to balance new generating resources with the notable load centers in the center of the state. In general, ES identified significant transmission constraints in the southern part of the state, where transmission lines connect electric generating resources located in Southern Utah with the Greater Salt Lake Metro Area. According to the analysis, these Southern "cutplanes" are projected to experience noticeable transmission congestion as early as 2025 of about 2,000 MW along the Wasatch Front South cutplane to over 5,000 MW by 2040 under some scenarios.

[49] https://energy.utah.gov/energy-information/utah-transmission-study/.

Figure 3.2: ATC Requirement vs. ATC Availability in Southern Utah by Scenario[50]



Therefore, irrespective of the faith of the existing IPP coal units, significant transmission upgrades are likely needed to allow for increased integration of electric generating resources located in Southern Utah to serve customers located in the Greater Salt Lake Metro Area and beyond.

5. Potential Future Transmission Constraints for IPP Coal Units

As part of the IPP Renewed project, IPA and the utilities plan for significant upgrades to the STS to accommodate the new combined cycle power plant as well as the planned renewable projects supplying electricity during peak electricity demand periods to the California and Utah utilities and to the electrolyzer to produce the hydrogen needed for the natural gas/hydrogen blend at the IPP Renewed project during off-peak hours. According to IPA's 2021-22 FY Disclosure document, in December 2022, IPA signed generator interconnection agreements with five renewable energy projects totaling 1,724 MW to interconnect at the IPP switchyard. An additional 285 MW solar and battery storage project is pending the execution of a generator interconnection agreement. Including the 840 MW IPP Renewed project, IPA estimates a total of 2,564 – 2,849 MW of generation capacity interconnected at the IPP switchyard in the future, consuming the vast majority of available transmission capacity existing today.

To enable the IPP coal units' continued access to the Western electric grid, significant transmission upgrades are likely needed to accommodate the IPP Renewed project and the renewable energy project that already signed generator interconnection agreements along with one or both existing IPP coal units.

First and foremost, the existing coal units will need to be reconnected to the IPP AC switchyard via a 345 kV intertie should the units resume operations after IPP Renewed starts operations and the initial change-over has already been completed. Additionally, the IPP AC switchyard will likely require additional upgrades to handle both coal units and IPP generators efficiently. A detailed cost analysis is needed to understand the financial requirements to either expand the existing AC switchyard to accommodate both the existing coal units and the IPP Renewed project or to construct an independent switchyard exclusively for operating the existing IPP coal units.

[50] https://energy.utah.gov/energy-information/utah-transmission-study/.

To increase the electricity flow to Utah utilities from the IPP site, a significant upgrade to the existing double-circuit 345 kV AC IPP-to-Mona transmission line is likely needed as the current transmission infrastructure is limited to about 300 – 350 MW of capacity. To allow for at least one of the two coal units to continue operating and provide additional low-cost electricity to Utah customers, at least one additional 345 kV double circuit line is likely needed. ES estimated the cost for an additional 345 kV double circuit line at between $2-2.5 million per mile or roughly $100 million to cover the 50 miles between IPP and the Mona substation in its 2021 Utah Transmission Study. Additionally, most of the transmission and planning rights serving Utah load centers belong to PacifiCorp's Rocky Mountain Power, with a small amount of transmission assets located in Eastern Utah owned by Deseret G&T cooperative. Any transmission expansion between IPP and the Mona substation serving the Greater Salt Lake Metro Area will need to get approval from Rocky Mountain Power.

Other possibilities include access to the TransWestern Express AC transmission line segment to southern Nevada or the installation of an interconnection point along TransCanyon's Cross-Tie transmission project. Additionally, co-locating any form of electricity end-user at or near IPP would minimize the need for additional transmission upgrades. For example, one company plans to utilize the existing IPP coal units as a dedicated power plant "behind the meter" for its potential data center project. Due to their around-the-clock runtime, data centers are in constant need of large amounts of electricity that the IPP coal units could provide. A behind-the-meter connection between the coal units and the data center project would likely negate any additional transmission upgrades. However, that would also remove the option for the current Utah utilities part of IPA to call on the energy produced by the coal units should the need arise.

Without any transmission upgrades, the future of the IPP coal units continues to be dependent on the "appetite" for coal-fired power in California, as the STS remains the primary transmission line from the IPP site. Besides possible physical capacity limits across the STS as additional renewable projects plan for interconnection and access to the STS in the future, contractual limitations will also likely persist. Notably, across the state of Utah, transmission rights are based on the "rated path" or "contract path" methodology. Under these methods, transmission is made available when there is available transmission capacity ("ATC") from the requested Point-of-Receipt ("POR") to the Point-of-Delivery ("POD"). In a contract path system, transmission service must be reserved and purchased from a specific POR to a specific POD to move power. Therefore, actual power flows can differ significantly from transmission contracts and reservations. In some cases, this parallel management of the physical versus the contractual grid can cause some amount of transmission capacity to go unused. To allow for the existing coal units to access existing transmission lines, new transmission contracts will need to be put into place on top of any physical transmission upgrades. Depending on the future ownership structure of the IPP coal units, these new contract negotiations can be more or less time-consuming.

Key Takeaways:

The transmission system surrounding IPP was designed to deliver most of the electricity generated to customers in California with limited transmission capability to customers in Utah. Should the future access to California customers via the Southern Transmission System (or other planned transmission projects) be limited to non-existent, major transmission upgrades connecting IPP with the primary Utah transmission grid operated by PacifiCorp are needed. Although costly and very time-consuming, previous transmission studies have identified these transmission upgrades are necessary to allow for greater integration of generating capacity (renewable and dispatchable) located in the South and East of the state into the main Utah transmission grid. Alternatively, transforming the IPP coal units into "behind-the-meter" generating resources would avoid the need for transmission upgrades, but also remove the units as possible electric reliability resources for Utah customers.

TASK 4 – Economic Development & Economic Interest Analysis

Excerpt from Contract No. 236352, Amendment 1

> *UCA 11-13-319.1 (d): "coordinate with state and local economic development agencies to evaluate economic opportunities for continued use of a project entity's existing coal-powered electrical generation facility;"*
>
> *UCA 11-13-319.1(f): "identify the best interests of the local economies, local tax base, and the state in relation to a project entity;"*
>
> *"Analyze economic development opportunities for continued operation of IPP in terms of retained jobs for plant employees, coal operators, transportation companies, service companies, etc. Analyze opportunities for new jobs related to coal conversion and coal to product technologies studied in Section 2b, and follow-on employment effects in the aforementioned sectors related to increased power generation and coal consumption."*
>
> *"Analyze economic development opportunities related to on-site consumption of electricity from IPP including data centers, manufacturing, crypto mining, etc."*
>
> *"Analyze current and future electricity market conditions which could affect the viability and value of IPP, including project supply and demand in the western interconnect, NERC reliability forecasts, IRPs from utility providers in the western interconnect, planned/forced retirement of baseload generation assets, growth in intermittent generation sources, increased use and demand for market purposes by utilities, etc."*
>
> *"Identify federal or state incentives available—or which could be created—for coal conversion technologies, minerals processing, or general economic development (EDTIF, opportunity zones, enterprise zones, etc.)."*
>
> *"Identify the economic impact to the state and local economies—including ongoing tax revenue from IPP and related industries—from the continued operation of IPP."*

Analysis

1. Utah Coal Market Analysis and IPP's Current and Future Coal Supply Options

Over the last decade, the Utah coal market has shrunk to about seven major coal mines which are operated by five different companies, three of which own and operate one mine each. Wolverine Fuels, formerly known as Bowie Resources, owns and operates the two largest coal mines located in Utah, Skyline and Sufco coal mines. Over the last five years, Wolverine Fuels accounted for over 50% of the coal produced in the state of Utah, as shown in the table below.

Figure 4.1: Annual Utah Coal Production by Coal Mine

Annual Utah coal production by mine *('000 tons)*

Company	Mine	2018	2019	2020	2021	2022	6M '23
ACNR	Lila Canyon	2,631	3,714	3,302	3,381	2,281	72
Alton Coal	Coal Hollow	488	240	569	434	354	67
Bronco	Emery	442	693	474	1,171	1,063	373
Gentry Mtn	Castle Valley	974	980	671	513	600	255
Wolverine	Dugout Canyon	550	416	-	-	-	-
Wolverine	Skyline	3,603	3,916	3,688	3,535	2,548	1,751
Wolverine	Sufco	4,904	4,374	4,459	3,310	3,877	1,098
Total Utah Production		**13,591**	**14,334**	**13,163**	**12,344**	**10,723**	**3,615**

Traditionally producing 13 to 15 million tons of coal per year, coal production in Utah had fallen to 12.3 million tons in 2021, when limited rail transport service limited coal offtake from the Utah coal operations to less than 11 million tons in 2022, after a mine fire at ACNR's Lila Canyon in September 2022 effectively closed most mining operations for the remainder of the year. Through six months in 2023, Lila Canyon's production is de minimis. ACNR hopes to return Lila Canyon to full production by Q1 2024.

Figure 4.2: Annual Utah Coal Shipments by End-Use Sector and Destination State

Utah Coal Shipments by Sector & Destination State *('000 tons)*

	2018	2019	2020	2021	2022
Power	**8,777**	**9,434**	**10,077**	**9,057**	**7,751**
Utah	8,663	8,860	9,800	8,654	7,363
Hunter	*3,888*	*3,357*	*4,918*	*3,376*	*2,559*
Huntington	*2,358*	*2,242*	*2,039*	*2,699*	*2,466*
IPP	*2,418*	*3,261*	*2,842*	*2,579*	*2,338*
Nevada	109	574	277	378	217
Other	5	-	-	24	171
Industrial	**2,163**	**1,880**	**1,545**	**1,603**	**1,366**
California	1,315	985	786	784	595
Utah	366	383	301	350	308
Nevada	219	261	271	204	206
Idaho	66	45	44	60	1
Other	198	206	142	206	255
Domestic Shipments	**10,940**	**11,314**	**11,622**	**10,661**	**9,117**
Exports	**2,940**	**2,732**	**1,316**	**2,298**	**1,624**
Total Utah Coal Shipments	**13,881**	**14,046**	**12,938**	**12,958**	**10,741**

Historically, about 70% of the coal produced in Utah coal mines is consumed within state borders, as shown in the table above. 70% of Utah coal is consumed in three Utah coal-fired power plants: PacifiCorp's Hunter and Huntington power plants and IPA's IPP. About 15% of Utah coal is consumed by industrial customers, primarily located in California, Nevada, and Utah. The remaining coal is exported via the ports in Stockton and Oakland, California, primarily to Japanese utility customers.

Since the beginning of commercial operations, the IPP coal units have consumed almost exclusively bituminous thermal coal mined in the state of Utah. The table below shows the coal deliveries to the IPP coal units for the last five and a half years by origin mine and owner.

Figure 4.3: Annual IPP Coal Deliveries by Coal Mine and Owner

(thousand tons)

Mine State	Mine	Owner	2018	2019	2020	2021	2022	1H 2023
Utah	Coal Hollow	Alton Coal	484.1	240.4	569.0	433.2	316.0	51.6
Utah	Emery	Bronco Coal	59.4	265.8	-	82.1	43.9	-
Utah	Gentry	Gentry Mountain	-	-	-	-	-	-
Utah	Lila Canyon	ACNR	-	765.0	-	-	-	-
Utah	Skyline	Wolverine Fuels	379.0	613.1	394.5	288.1	333.7	188.8
Utah	Sufco	Wolverine Fuels	1,495.5	1,319.5	1,577.5	1,350.8	1,240.3	457.3
		Utah Total	**2,417.9**	**3,203.9**	**2,541.1**	**2,154.3**	**1,933.8**	**697.7**
Colorado	West Elk	Arch	-	220.2	502.3	-	518.2	159.7
Wyoming	Black Thunder	Arch	-	-	-	-	-	175.3
		Total Deliveries	**2,417.9**	**3,424.1**	**3,043.4**	**2,154.3**	**2,452.0**	**1,032.7**
		Utah %	*100%*	*94%*	*83%*	*100%*	*79%*	*68%*

Wolverine Fuels is the primary provider of coal consumed at IPP, accounting for over two-thirds of the coal delivered to IPP since 2018. Overall, Utah coal accounted for more than 90% of the coal deliveries to IPP since 2018.

IPP is also one of the primary domestic customers of Wolverine Fuel's Skyline and Sufco mines, as well as the sole customer of Alton Coal's Coal Hollow mine. Coal from the Coal Hollow and Emery mines is delivered via truck, while all other coal is delivered via rail by Union Pacific using railcars owned by IPA.

Over the years, IPA has supplemented Utah coal supply with coal from Arch's West Elk mine, located in Colorado, primarily due to limited supply availability from Utah coal mines or significant cost savings between Colorado and Utah coal producers. In 2023, IPA purchased additional coal from Arch's Black Thunder coal mine located in the Powder River Basin ("PRB") in Wyoming due to the massive supply crunch in the Utah coal market caused by the Lila Canyon mine fire and subsequent temporary production suspension. However, Intermountain's plant design limits the amount of higher-moisture subbituminous coal from the PRB to about 20% of total coal input, therefore limiting the amount of out-of-state subbituminous coal IPA or the IPP coal units can purchase and consume. Additionally, the supply crunch currently affecting the Utah coal market will likely be over once Lila Canyon returns to normal mining operations in Q1 2024.

Additionally, the IPP Study Team analyzed responses from Utah coal mining companies to assess the adequacy of Utah coal supply for an extended operation of the IPP coal units. Based on the analysis, there exist adequate coal reserves at existing and possibly new coal mine developments within the state of Utah to support the operations of the IPP coal units for at least another 20 years.

Finally, it is worth noting that continued operations at IPP could possibly be job-saving for many coal miners across the state as Utah coal exports through California are likely in jeopardy starting in 2027 after the Richmond-Levin coal terminal in Oakland is forced to close. Due to draft limitations at the port of Stockton, Utah coal exports will likely cease if no other export opportunity materializes, putting over 15% of Utah coal deliveries at risk.

2. IPP's Current Employment and Economic Impact

Since its commercial operation started in 1986 and 1987, IPP has brought unique employment and economic benefits to the state of Utah and local Utah communities. Although almost all of the electricity produced by the two coal-fired generating units located at IPP was transported and ultimately consumed by end-users located in California, almost all of the economic (i.e., tax revenues) and employment benefits remained within the state of Utah.

The following table summarizes the direct coal mine employment associated with the operation of the IPP coal units. The table utilizes the average annual employment data reported by the mine owners to the U.S. Mine Safety and Health Administration ("MSHA") and Intermountain's share of coal deliveries from that mine.

Figure 4.4: Estimated Coal Mining Jobs Supported by IPP's Operation

Mine jobs due to IPP

Mine State	Mine	Owner	2018	2019	2020	2021	2022	1H 2023
Utah	Coal Hollow	Alton Coal	27.8	26.0	35.0	26.9	18.7	12.4
Utah	Emery	Bronco Coal	11.8	36.8	-	10.4	7.9	-
Utah	Castle Valley	Gentry Mountain	-	-	-	-	-	-
Utah	Lila Canyon	ACNR	-	53.8	-	-	-	-
Utah	Skyline	Wolverine Fuels	36.6	55.9	42.8	32.6	52.4	43.1
Utah	Sufco	Wolverine Fuels	127.2	129.4	145.4	151.4	111.6	156.6
		Utah Total	**203.4**	**301.9**	**223.2**	**221.4**	**190.6**	**212.2**
Colorado	West Elk	Arch	-	20.6	63.3	-	36.0	34.5
Wyoming	Black Thunder	Arch	-	-	-	-	-	5.9
		Total	**203.4**	**322.6**	**286.5**	**221.4**	**226.7**	**252.6**

Over the last five and a half years, IPP's coal units supported over 225 direct coal mining jobs in the state of Utah. However, coal mining activities also support other local jobs that are directly dependent on the coal mining operations, including contracted trucking services, coal mining equipment supply and maintenance companies, and also induce jobs in local communities as direct and indirect employees spend their income in local communities. In 2022, researchers at Utah State University tried to quantify the economic and employment impacts of Utah's energy and mining industries[51]. In 2019, Utah's coal mining industry included 1,763 direct, 1,093 indirect, and 1,039 induced jobs, accounting for $513, $142, and $94 million of the state's GDP during that year. Therefore, the approximately 300 direct coal mining jobs supported by IPP's operations in 2019

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[51] https://ugspub.nr.utah.gov/publications/misc_pubs/mp-176.pdf.

resulted in 186 indirect and 177 induced jobs and accounted for over $125 million of Utah's GDP in 2019.

Additionally, the direct, indirect, and induced coal mining jobs supported by IPP's coal units contribute substantially to the state and local tax base through payroll, sales, property, severance, and income taxes, among others. Again, utilizing the estimates for 2019 provided in the Utah State economic contributions study, the coal mining employment supported by IPP's operation contributed approximately $9.1 million to the state of Utah and local communities in 2019.

According to information provided by IPA, IPSC included about 340 direct employees in 2022, down about 140 employees since 2010 due to reduced operations of the plant over the years. Using the Utah state study multipliers for indirect and induced jobs in Utah's power generation industry, those 340 direct jobs at the IPP power plant resulted in 1,300 indirect and induced jobs. In total, over 1,600 direct, indirect, and induced jobs are supported by the operation of IPP's coal units, contributing over $410 million to the state's GDP in 2019. Additionally, IPP, through employment, production, and property taxes, among others, paid approximately $67 million in state and local taxes in 2019.

Furthermore, a 2022 presentation by IPSC staff stated that the $7.8 million paid in Millard County property taxes accounted for over one-quarter of all taxes collected in Millard County in 2020. In addition, since almost all employees of IPSC are Millard County residents, IPSC estimated that almost $40 million in gross payroll went to those Millard County residents in 2020. Although some of IPSC's employees will transition to operating the IPP Renewed project upon completion and retirement of the coal unit, further analysis is needed to estimate the impact to employment and local and state taxes due to the retirement of the two coal units in 2025.

3. IPP's Future Employment and Economic Contributions

As mentioned above, one of the greatest benefits of IPP is that almost all of the economic and employment benefits produced by the project benefit the state of Utah and its local communities. According to IPSC Staff, the current plant staff totaled about 320 employees. Due to lower workforce requirements to operate the IPP Renewed project, IPSC's workforce is projected to decline to just 120 employees. 120 of the staff not retained are at or near retirement age and are expected to retire, while at least 80 employees will be laid off permanently. As described earlier, these plant jobs are some of the highest-paying jobs in the area. Their loss will likely have noticeable downstream effects on the local economy.

Additionally, all of the natural gas projected to be consumed is produced out-of-state and transported to the plant via interstate pipeline. Since there are limited growth opportunities for Utah coal outside the state, any reduction in in-state coal demand will have a direct negative impact on direct, indirect, and induced coal mining employment and GDP and tax contributions. Since the IPP Renewed project shifts all of its supported fossil fuel production from in-state coal production to out-of-state natural gas production, all of the economic and employment benefits described above related to coal consumption at IPP will be lost once the coal units cease operations.

As described in Task 3 of this report, some additional renewable energy projects will likely be built in close vicinity to the IPP Renewed project to provide it with the electricity needed to power the hydrogen electrolyzer the project will rely on for future hydrogen supply. Although these renewable energy projects will provide tax revenue through property tax payments, their employment and economic contributions based on permanent employment will be minimal. Most jobs associated with new renewable energy projects are temporary construction jobs since permanent employment needs to operate and maintain the projects on an ongoing basis are minimal. For example, Energy Strategies' 2021 Transmission Study, described earlier in this report, estimated a 42:1 ratio between temporary and permanent jobs and a 15:1 tax revenue ratio associated with the transmission and renewable buildout.

Additionally, the plant equipment used to build the new renewable energy projects is likely manufactured out-of-state or even imported from foreign countries, which also fails to contribute to the Utah economy in a meaningful way. Further economic modeling and analysis are needed to quantify the net effect on employment and economic contributions due to the replacement of the coal-fired generating units through the IPP Renewed project.

However, many of the companies behind the technologies described in Task 2 that would allow for the continued operation of the existing coal-fired generating units would retain or even expand the current employment and economic contributions of these units. The company behind the coal-to-graphite-and-hydrogen project recently purchased a coal plant in West Virginia with similar characteristics as the current IPP coal units. The company estimates that its graphite production facilities as well as its expanded coal use, will create an additional 600 jobs at the power plant and graphite production site alone. The projected increase in coal consumption will also likely result in increased local coal production and, in turn, mining employment and economic growth. Since a similar project at IPP would operate almost exclusively on Utah coal, virtually all of the increased employment and economic growth would stay in the state of Utah.

Other proposals reviewed by the IPP Study Team include a combination of carbon capture at the coal plant and dedicated power supply from the coal plant to local data centers. The companies behind the project estimated an additional 202 local permanent jobs, $12.3 million in additional wages, $6.1 million in additional state and local taxes, as well as approximately $232 million in overall economic benefits. Since the proposal would maintain coal-fired operations at the plant, this project is unlikely to impact current in-state coal mining employment and economic contributions negatively.

<u>Key Takeaways</u>:

The economic benefits of the IPP coal units to the regional economy and the state as a whole cannot be overstated. IPP is the single largest employer and taxpayer in Millard County and accounts for a significant portion of direct, indirect, and induced jobs and tax revenue associated with coal production and transportation in the state of Utah. Replacing the coal units with the IPP Renewed project and associated renewable energy projects will lead to significant long-term job, economic, and tax revenue losses in Millard County and Utah's "Coal Country".

TASK 5 – Asset and Liability Analysis

Excerpt from Contract No. 236352, Amendment 1

> *UCA 11-13-319.1(e): "analyze the financial assets and liabilities of a project entity;"*
>
> *"Analyze the current assets and liabilities of IPP, including liabilities related to debt service, remediation of coal combustion residuals impoundments, and other closure liabilities."*

Analysis

As part of this report, the IPP Study Team is required to analyze and review *"the current assets and liabilities of IPP, including liabilities related to debt service, remediation of coal combustion residuals impoundments, and other closure liabilities."*

According to IPA's Fiscal Year ("FY") 2023 Annual Report posted on IPA's website[52], IPA's utility plant in-service assets at the end of FY2023 (ending June 30, 2023), were approximately $3.77 billion against $2.7 billion in accumulated depreciation, resulting in net utility plant assets in the value of $1.06 billion. However, it is worth noting that the stated net utility assets include assets put in place as part of the construction of IPP Renewed, the 840 MW combined cycle plant planned to replace the retiring coal assets. As part of the IPP Renewed project, some assets are being retained and will continue operating, including but not limited to all of the transmission lines owned and operated by IPA, IPA offices, and parts of the IPP switchyard. The table below includes a summary of the utility plant in-service assets for the last six years, their depreciation, the net utility assets, as well as the asset retirement obligation associated with retiring the two coal units in 2025.

Figure 5.1: Overview of IPA Assets & Liabilities Related to the IPP Coal Units

(in thousands)

	2018	2019	2020	2021	2022	2023
Utility Plant in service	$ 3,110,193	$ 3,091,197	$ 3,124,696	$ 3,180,813	$ 3,345,215	$ 3,771,742
less accumulated depreciation	$ (2,229,341)	$ (2,296,955)	$ (2,405,444)	$ (2,488,664)	$ (2,601,115)	$ (2,713,953)
Net Utility Plant Assets	$ 880,852	$ 794,242	$ 719,252	$ 692,149	$ 744,100	$ 1,057,789
Asset retirement obligations	$ 106,679	$ 124,107	$ 259,243	$ 273,242	$ 298,107	$ 307,050
Decommissioning Fund	$ -	$ -	$ -	$ -	$ 52,138	$ 80,543

According to IPA Staff, as of January 1, 2023, the net book value of the coal units was approximately $378,000,000, approximately $100,000,000 of which are non-depreciable assets. The remainder will be fully depreciated by June 30, 2025.

An asset retirement obligation ("ARO") is measured based on the best estimate of the current value of outlays expected to be incurred, including probability weighting of potential outcomes, with a

52 https://www.ipautah.com/financial-information/annual-reports-disclosure/.

deferred outflow of resources recognized at the amount of the corresponding liability upon initial measurement. IPA's AROs specified in the financial disclosure document are related to long-lived assets that will be decommissioned or reclaimed as part of the scheduled retirement of the two coal units at IPP.

On August 6, 2019, the IPA Board and IPP Coordinating Committee formally approved the Retirement Plan for the decommissioning and retirement of the existing coal units that are not to be used for the generation or transmission of power according to the renewed power contracts with the utilities. The renewal contracts created a contractual requirement to retire certain capital assets and dismantle existing utility assets previously unaccounted for, which resulted in a noticeable increase in AROs from 2019 to 2020. The continued increase in AROs since 2020 is primarily due to the rising cost of inflation. IPA began securing the AROs with the establishment of the Decommissioning Fund, which showed a value of $80.5 million at the end of FY2023. However, the latest financial disclosure also states that the Decommissioning Fund is yet to be established by supplemental resolution and is not subject to the pledge in favor of bondholders. At the current rate, the Decommissioning Fund is projected to include approximately $180 million or about $127 million short of the current ARO estimate.

According to IPA Staff, the $307 million ARO estimate includes the $55-70 million compliance cost estimate IPA is expected to incur to bring the two coal combustion residuals ("CCR") impoundments into compliance with EPA's 2015 CCR Rule and subsequent revisions after the retirement of the existing coal units. Additionally, IPA estimated its coal inventory asset at approximately $60.6 million at the end of FY2022, which is also accounted for in IPA's latest ARO estimate of $307 million at the end of FY2023.

Key Takeaways:

According to IPA Staff, there are no major financial liabilities (i.e., no outstanding debt service) beyond the current Asset Retirement Obligation of about $300 million associated with the closure of the existing IPP coal units. IPA plans to fund the ARO with funds collected in the newly established Decommissioning Fund from the current list of participating utilities based on the latest cost-sharing method. The ARO also includes current EPA CCR rule compliance estimates, including ongoing groundwater monitoring equipment and operations.

TASK 6 – Ownership Structure Analysis

Excerpt from Contract No. 236352, Amendment 1

> *UCA 11-13-319.1(g): "evaluate the viability of the continued operation of a project entity's existing coal-powered electrical generation facility: (i) under ownership of the state; or (ii) in a public private partnership;"*
>
> *"Evaluate the viability and favorability of different types of ownership structures for IPP if it were sold or otherwise separated from its current ownership entity, including direct state ownership, sale to a private operator, public private partnership with municipal power providers and/or rural co-ops, etc."*
>
> *UCA 11-13-319.1(h): "identify the steps necessary for the state to obtain first right of refusal for ownership of a project entity's existing coal-powered electrical generation facility.*
>
> *"Analyze steps needed—including legislation—to separate IPP from its current ownership entity either through a sale or via eminent domain."*

Analysis

Intermountain Power Plant Background

The IPA is a political subdivision of the State of Utah. It was organized on June 22, 1977, pursuant to the Interlocal Cooperation Act ("Act")[53] and under the IPA Organization Agreement.[54] The IPA Organization Agreement, as amended, is referred to herein as the "Agreement."

1. Interlocal Cooperation Act and IPA Governance

The Act authorizes local governmental units, such as municipalities, to make efficient use of their powers by cooperating with each other to provide facilities and/or services that will accommodate the needs and development of the local communities.[55] An interlocal entity like the IPA is formed under the Act when the governing bodies of two or more public agencies enter into an agreement to approve the creation of the interlocal entity.[56] The interlocal entity then becomes a political subdivision of the state, separate from the public agencies that created it, with powers and duties

[53] *See* Utah Code § 11-13-101 *et seq.*

[54] The Agreement is dated May 10, 1977, and was amended five times (with the First Amendment dated February 1, 1983, Second Amendment dated March 26, 1990, Third Amendment dated January 21, 2003, the Fourth Amendment dated November 26, 2013, and the Fifth Amendment dated May 23, 2018).

[55] Utah Code § 11-13-102.

[56] *See*, Utah Code § 11-13-203.

set out in the Act, including the power to provide the services contemplated in the agreement creating the entity.[57]

In accordance with the Act and under the Agreement, the IPA was created to "own, acquire, develop, finance, and/or operate… a facility to generate and deliver electricity to be known as the Intermountain Power Project" ("IPP" or "Project"), among other purposes.[58] The IPP is owned by IPA and operated by the IPSC. The IPP is located outside of Delta, Utah, and consists of two coal-fired power plants connected by a high-voltage, direct-current transmission line to the Southern California electrical market. It commenced commercial operations in 1986 and has been generating electrical power since that time.

As authorized by the Act, IPA's membership consists of 23 Utah members that own electric utilities ("Members").[59] IPA is governed by a seven-member Board of Directors elected by and from among the Members' representatives, for staggered four-year terms. Management of IPA is under the direction of its General Manager, who serves at the pleasure of the Board of Directors.

2. Purchaser Contracts

On August 24, 1978, Power Sales Contracts relating to the IPP were offered. These contracts are set to expire on June 15, 2027. The Power Sales Contracts irrevocably sold the entire capacity of the IPP to the Member Municipalities, six Utah cooperatives, Utah Power & Light Company, and six California municipalities ("Purchasers"). It is beyond the scope of this report to assess which of the many Purchasers might be willing to extend contracts for power from the existing units. Of course, the expressed concerns of some of the Purchasers will be discussed below because they are central considerations, but it should not be inferred from this discussion that there are none among the Purchasers that would welcome extensions beyond 2027.

The Purchasers are unconditionally obligated to pay all costs of operation, maintenance and debt service, whether or not the IPP or any part thereof is operating or operable, or its output is suspended, interrupted, interfered with, reduced, or terminated. There are 35 Purchasers holding different entitlements to the IPP, with the Los Angeles Department of Water and Power ("LA Department") being the largest Purchaser, holding approximately 48% of the entitlements to the project. Overall, Utah Purchasers hold approximately 21% of the entitlements to the IPP, and California Purchasers hold approximately 79% of the entitlements. Note, however, that certain Utah Purchasers have entered into an Excess Power Sales Agreement with the LA Department, Burbank, Glendale and Pasadena ("Excess Power Purchasers"), whereby capacity and energy available to such Utah Purchasers is sold to the Excess Power Purchasers unless and until the Utah Purchasers recall any such capacity and energy. As a result, approximately 98% of the total power has historically gone to California Purchasers.

[57] *See,* Utah Code §§ 11-13-203(1); 11-13-204(1)(a)(ii)(F)(III).

[58] *See* IPA Organization Agreement, Article I.

[59] The Members are located within the State of Utah and are: Beaver City, City of Bountiful, City of Enterprise, City of Ephraim, City of Fairview, Filmore City, Heber City, Town of Holden, City of Hurricane, Hyrum City, Kanosh, Kaysville City, Lehi City, Logan City, Town of Meadow, Monroe City, Morgan City, Mount Pleasant, Murray City, Town of Oak City, Parowan City, Price, and Spring City.

The Power Sales Contracts provide for, among other things, a Construction Management and Operating Agreement with the LA Department, whereby the LA Department is to serve as Project Manager and Operating Agent to construct, operate, and maintain the IPP in accordance with that agreement. The LA Department acts as the IPA's agent in fulfilling its duties as Project Manager and Operating Agent, subject to the provisions of the applicable legal documents and to the supervision and, as to certain matters, approval of the Coordinating Committee created under the Power Sales Contracts.

The Coordinating Committee consists of the Chairperson, who is a non-voting representative appointed by IPA, and representatives of the Purchasers or groups thereof. All actions taken by the Coordinating Committee require the affirmative vote of representatives of Purchasers having voting rights (which equal the Purchasers' entitlement shares) aggregating at least 80%. The LA Department, with over 48% of the voting rights, thus effectively has veto authority over the Coordinating Committee, as the Committee cannot take any action without the LA Department's approval. Moreover, even where Coordinating Committee oversight is required, when the California Purchasers are united, they may take action with only a small percentage of Utah Purchasers voting with them.

Among other functions, the Coordinating Committee provides liaison between IPA and the Purchasers with respect to construction and operation of the IPP; reviews, modifies and approves certain contracts; takes certain actions with respect to recommendations from the LA Department; and makes recommendations to IPA regarding financing. The Coordinating Committee also has the authority to review, modify, and approve procedures formulated by the LA Department with respect to the construction and operation of the IPP, budgets prepared by the LA Department, and all capital improvements proposed to be undertaken by IPA.

3. IPP Renewed

As a result of the environmental and other regulations imposed by California (and to some extent, the EPA) as discussed herein, and with the existing Power Purchase Agreements nearing expiration, IPA is working to transition the project. The new project has been dubbed "IPP Renewed," and aims to include installation of new natural gas-fueled electricity generating units capable of utilizing hydrogen for 840 megawatts net generation output; modernization of IPP's Southern Transmission System linking IPP to Southern California; and the development of hydrogen production and long-term storage capabilities. IPA also seeks to retire the existing coal-fueled units at the IPP site.

IPA and 30 of the Purchasers have in place Second Amendatory Power Sales Contracts, providing for the IPP's "Gas Repowering." IPA has offered the Purchasers renewal in their generation and associated transmission entitlements through the Renewal Power Sales Contracts. Such renewal contracts became effective on January 16, 2017 but will not govern until termination of the Power Sales Contracts. The contracts have a 50-year term and will terminate on June 16, 2077 (unless terminated sooner). A Renewal Contract Coordinating Committee has also been formed to provide liaison among IPA and the renewal Purchasers and functions similarly to the Coordinating Committee, with actions requiring the affirmative vote of representatives of Purchasers having voting rights aggregating at least 80%. Moreover, the LA Department is to continue to serve as Operating Agent and Project Manager and will continue to play a critical role in "IPP Renewed."

4. Utah Associated Municipal Power Systems

The IPP is also one of the Utah Associated Municipal Power Systems's ("UAMPS") projects. UAMPS is a full-service interlocal agency that provides comprehensive wholesale electric energy services, on a non-profit basis, to community-owned power systems throughout the Intermountain West. Such services include planning, financing, developing, acquiring, constructing, operating and maintaining varied projects and transmission for the benefit of members.

The UAMPS membership represents 50 members and includes IPA's 23 Members. UAMPS currently operates 16 separate projects that provide power supply, transmission, and other services to the members who participate in them, with the IPP being one such project. UAMPS acts as a scheduling agent for IPA's Members who have called-back capacity and energy from the IPP pursuant to Excess Power Sales Agreements.

5. State Oversight

The IPA is a political subdivision of the State of Utah and, as a result, is not subjected to the level of state regulatory scrutiny applied to an investor-owned utility ("IOU"). However, the impact of its decisions on the State of Utah are significant. As discussed below, there are certain state regulatory oversight measures, which IPA avoids due to its classification as a political subdivision of the State, that the Legislature should consider when evaluating the appropriate level of oversight for IPA in the future. As is discussed in detail below, there are several measures the Utah Legislature could employ to increase the level of IPA accountability, oversight, and transparency.

a. Utah Public Service Commission Oversight of IPA

IPA avoids the requirement in place for IOUs to submit to the Utah Public Service Commission ("UPSC"), a utility Integrated Resource Plan ("IRP"). An IRP is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy service needs at the lowest total cost to the utility and its customers in a manner consistent with the long-term public interest.[60] The process should result in the selection of resources based on the expected combination of costs, risk, and uncertainty.[61] Utah's IRP process involves an evaluation and acknowledgement by the UPSC as to whether the utility's IRP meets the principles stated in the IRP planning guidelines.[62] The IRP must address the following criteria:

- each utility is required to submit its IRP biennially;
- the IRP must be developed in consultation with the UPSC, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies,

[60] *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*. UPSC Docket No. 90-2035-01, Report and Order on Standards and Guidelines at 36 (Jun. 18, 1992) (hereinafter Order).

[61] *Id*.

[62] *Id*. at 40.

and interested parties with ample opportunity for public input and information exchange during the development of the IRP;

- the IRP must provide a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements;[63]

- the IRP must provide analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads;

- the IRP must evaluate all present and future resources, including future market opportunities, both demand-side and supply-side, on a consistent and comparable basis, including an assessment of all technically feasible and cost effective improvements in the efficient use of electricity, including load management and conservation, and generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources;[64]

- the IRP must provide an analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions;

- the IRP must assume a 20-year planning horizon;

- the IRP must provide an action plan outlining the specific resource decisions intended to implement the IRP in a manner consistent with the utility's strategic business plan. The action plan is required to span a four-year horizon and must describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan is also required to include a status report of the specific actions contained in the previous action plan;

- the IRP must provide a plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds;

- the IRP must provide an evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers in addition to a description of how social concerns might affect cost effectiveness estimates of resource options;

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[63] The forecasts must be made by jurisdiction and by general class and must differentiate energy and capacity requirements. The utility is required to include in its forecasts all on-system loads and those off-system loads which it has a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the IRP must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.

[64] Resource assessments should include the life expectancy of the resources, the recognition of whether the resource is replacing or adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource, and opportunities for customer participation.

- the IRP must provide an evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the utility's strategic business plan and the 20-year IRP, including identifying who should bear such risk, the ratepayer or the stockholder;

- the IRP must evaluate considerations permitting flexibility in the planning process so that the utility can take advantage of opportunities and can prevent the premature foreclosure of options;

- the IRP must provide an analysis of any anticipated "tradeoffs," including but not limited to conditions of service in terms of reliability and dispatchability compared to the acquisition of lowest cost resources;

- the IRP must provide a range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The IOU will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities; and

- the IRP must provide a narrative describing how current rate design is consistent with the utility's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.

Essentially, an IOU's IRP is required to include the demand and energy forecasts, the utility's options for meeting the requirements in an economic and reliable manner, assumptions and conclusions with respect to the IRP on cost and reliability, and a description of the external environmental and economic consequences of the IRP.[65] IPA is all but exempt from these IRP reporting requirements as a political subdivision of the state. After thorough review and analysis, the Legislature should consider imposing some of the resource selection and planning reporting requirements outlined above on IPA in order to ensure that the governance structure in place for IPA, or any modified version of that governance structure adopted by the Legislature in the future, is adequately substituting for the conventional reliability and resilience safeguards and ratepayer protections in place for IOUs. This type of IPA-specific reporting is best evaluated by the UPSC, the existing state agency with significant expertise in, and the primary responsibility of, ensuring the provision of safe, reliable, adequate, and reasonably priced utility service. In fact, the Utah Legislature has considered subjecting IPA to UPSC regulatory oversight in the past. During the 2022 General Session, it was contemplated that the UPSC, not the Project Entity Oversight Committee ("PEOC") discussed in further detail below, would be responsible for overseeing IPP operations and IPA decision making.[66]

The UPSC is composed of three full-time Commissioners appointed by the Governor, and those appointments are subject to Senate confirmation, providing a degree of legislative control and

[65] Utah Stat. Ann. § 54-17-102.

[66] H.B. 215, Utah Legislature, General Session, 2022 (Introduced Version).

accountability over the leadership of the UPSC. The Commissioners preside as a quasi-judicial body in formal hearings concerning utility regulation matters, such as applications for rate and service changes, and employ a support staff of technical and legal experts to assist the Commission. The UPSC routinely conducts evidentiary hearings and investigations of utility company operations and strives to protect efficient, reliable, reasonably-priced utility service for customers while maintaining the financial viability and integrity of utility companies. All of this is in addition to the traditional regulatory constructs and ratemaking principles applicable to IOUs that the UPSC routinely applies to utility operations which also provide a layer of ratepayer protection and utility accountability. For example, in determining whether an IOU action is prudent or a cost associated with providing service is prudently incurred, UPSC is required to ensure just and reasonable rates, focus on the reasonableness of any expense resulting from the action judged as of the time the action was taken, and determine whether a reasonable utility, knowing what the utility knew or should have known, at the time of action would have acted in the same manner.[67] This sort of prudence review and determination by UPSC is common in multiple states and ensures prudent and common sense decision making on the part of the utility.

Further, Utah electric utilities are required to conduct a solicitation prior to building any significant energy resource unless an exemption is obtained.[68] If an exemption is obtained, the utility is still required to obtain a decision approving the significant energy resource prior to constructing or entering a binding agreement to acquire the resource.[69] Finally, any IOU plans to acquire a significant resource must be included in the utility's IRP and an action plan must be filed by the utility.[70] A determination as to the prudence of any utility action to acquire a significant energy resource must be made by the UPSC in a future base rate proceeding and the UPSC is authorized to disallow recovery of the associated costs if the utility's decision-making is deemed to be imprudent.[71] These requirements are addressed primarily through the UPSC's regulatory decisions and substantive rules, making UPSC well situated to oversee the decision making of IPA and IPP operations and render judgement on the prudence of those decisions. Given IPA's decision-making regarding the retirement of IPP's combined 1,800 MW coal-fired generating units and their replacement through the acquisition and construction of EPA compliant natural gas combined cycle units totaling 1,200 MW at significant cost, UPSC could have evaluated those decisions and made a prudence determination prior to IPA moving forward with either decision.

If the Utah Legislature determines that it is appropriate to impose additional oversight on IPA or that it is necessary to separate IPP from IPA either through direct state ownership, the sale of IPP to a private utility operator, a public private partnership with municipal power providers or electric cooperatives, or through eminent domain, establishing IPA's or any newly created governing entity's accountability to UPSC would ensure the level of state oversight currently imposed on IOUs and the inevitable protections to Utah interests that result. As is discussed in detail above, IPA's reporting requirements to the UPSC would not be the same as an IOU's IRP reporting

[67] Utah Stat. Ann. § 54-4-4.

[68] Utah Stat. Ann. § 54-17-302.

[69] *Id*.

[70] Utah Stat. Ann. § 54-17-301.

[71] Utah Stat. Ann. § 54-17-303.

requirements; however, the Legislature could provide sufficient criteria and rulemaking authority to allow the UPSC to adopt the necessary rules to effectively regulate IPA.

b. Appointment of PEOC Members or Supervisory Board

During the 2022 legislative session, the Utah Legislature created PEOC to oversee the IPA.[72] PEOC is composed of nine members, including one member of the House of Representatives, one member of the Senate, one member appointed by the Governor, one member appointed by the Millard County Commission, one member appointed by the IPA board, one member appointed by the Millard County School District, one member appointed by the School and Institutional Trust Lands Board of Trustees, one member appointed by the Utah League of Cities and Towns, and one member appointed by the Millard County Department of Economic Development.[73] IPA is required, within a reasonable time of the information being available, to submit to PEOC all publicly available financial and operating information relating to IPA, including a copy of IPA's audited financial statements for each fiscal year; a list of IPA's financing sources, including outstanding and future planned bond issuances; a statement describing IPA's net charges to its power purchasers for each fiscal year, including a description of how those charges vary from IPA's previous fiscal year charges; and a statement describing IPA's annual power sales for the previous fiscal year broken down by entity, including the total amount of power sold.[74] PEOC is required to review the information submitted by IPA, make that information publically available, communicate any concerns to IPA, and compile and submit a corresponding report to the Public Utilities, Energy, and Technology Interim Committee ("Interim Committee") on or before October 30th of each year.[75] The Office of Energy Development is to ensure that PEOC is functioning as a sufficient liaison for the state, the Legislature, the local community, and IPA.[76]

The manner in which PEOC members are appointed directly impacts the effectiveness of its oversight of IPA. While the Senate and the House of Representatives each have one member appointed to the committee, the remaining appointees are an IPA board member, a member appointed by the governor, without confirmation by the Legislature, and members from the Millard County Commission, the Millard County School District, the School and Institutional Trust Lands Board of Trustees, the Utah League of Cities and Towns, and the Millard County Department of Economic Development. These local-level and discretionary appointments, while important in gaining local perspective on the impact of IPA decisions, also result in the potential for the appointment of individuals to PEOC that may be affiliated with current or former IPA board or coordinating committee membership. In order to ensure that PEOC is not subjected to undue influence, direct appointment of PEOC members by the Legislature, or at a minimum the Legislature's confirmation of those appointments, would ensure that the membership of the PEOC is fully vetted and can appropriately carry out its oversight duties.

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[72] H.B. 215, Utah Legislature, General Session, 2022 (Enrolled Version).

[73] Utah Stat. Ann. § 63C-25-201.

[74] *Id*.

[75] Utah Stat. Ann. § 63C-25-202.

[76] *Id*.

Alternatively, once the Legislature receives its initial report from PEOC on October 30, 2023, and as is discussed in further detail below, the Legislature could choose to create a separate supervisory board, either in addition to or in place of PEOC, to oversee the IPA board. If the Legislature elected to employ this option, there are several provisions it could include in the enabling legislation to provide for more effective oversight of the IPA Board. For instance, the supervisory board members could be appointed by the governor and formally vetted in public hearings and confirmed by the Legislature in order to ensure the supervisory board membership is not subject to undue influence and is focused on the best interests of Utah. Further, the decisions of the IPA board (initiated by the Coordinating Committee) could be subject to the supervisory board's approval and the supervisory board could also have the authority to dissolve the IPA's board under certain circumstances if the Legislature deems that measure to be warranted. Given the concerns surrounding the potentially disproportionate level of influence the LA Department has on the decisions of the Coordinating Committee and the Legislature's current lack of confirmation authority for appointments to PEOC, the creation of a supervisory board with the powers and duties described above would provide a level of oversight that could be uniquely beneficial.

c. IPA Accountability, Transparency, and Public Reporting

As was discussed in detail above, due to the significant amount of leverage the LA Department has within the Coordinating Committee, and the fact that the LA Department not only services as the operating agent of IPP but is also its single largest customer, ensuring transparency and accountability with regard to the Coordinating Committee and the IPA board's decision making and approval process is critical to effective state oversight.

The Legislature has recently recognized the importance of increased transparency and accountability in IPA Board actions and as a result passed S.B. 92 during the 2022 General Session to require IPA to comply with the Utah Open and Public Meetings Act.[77] Further, the IPA is prohibited from conducting closed meetings unless for specific purposes and only under certain conditions. However, the IPA Board is still permitted to hold closed meetings if a quorum of the IPA Board is present, the meeting is an open meeting for which notice has been properly provided, and at least two-thirds of the members of the IPA Board present at the open meeting vote to approve closing the meeting.[78] Additionally, in order to go to a closed session, the IPA Board has to be conducting an open meeting for the purposes of determining the value of an asset and developing a strategy related to the sale or use of that asset; discussing a business decision, the disclosure of which could cause commercial injury to, or confer a competitive advantage upon a potential or actual competitor of IPA; or conducting an open meeting for purposes of discussing a record, the disclosure of which could cause commercial injury to, or confer a competitive advantage upon a potential competitor of IPA. A two-thirds majority vote of the IPA Board members present, assuming a quorum exists, is required.[79]

While legitimate reasons likely exist as to why it would be necessary for the IPA Board to hold a closed session within an otherwise open meeting, it is also likely that the statutory criteria

[77] Utah Stat. Ann. § 11-13-316(5).

[78] Utah Stat. Ann. § 52-4-204.

[79] *Id*.

discussed above could justify a broader application of closed meetings than was intended to discuss a wide range of decisions. For example, the statue allows the IPA Board, by a two-thirds vote of its own members, to go to a closed session to discuss a business decision that could result in commercial injury if disclosed. The decisions of the Coordinating Committee, and the approval of those decisions by the IPA Board, presumably would often fall under this description, allowing the IPA Board to avoid the Open and Public Meetings Act requirements when convenient. In fact, in its report to the Interim Committee, the Office of the Legislative Auditor General ("OLAG") indicated that despite a request to the IPA Board, it was not allowed to attend IPA Board closed meetings in the course of its audit and that out of the five years of closed IPA Board meeting minutes, the IPA Board produced meeting minutes for only one closed meeting and informed the auditors that the remainder were deemed to be privileged and were withheld.[80] As a result, the conclusion of the OLAG was that "with little transparency, we could not document that the IPA Board had done anything, aside from negotiated contracts, to provide a check on the Coordinating Committee decisions and voting."[81] It is important to note that the open meeting requirements imposed on the IPA by S.B. 92 were not imposed on the Coordinating Committee, which is where the LA Department has the greatest ability to affect important decisions regarding IPP assets.

Ultimately, the Legislature must determine for itself the level of document production, accountability, and transparency it will require from a political subdivision of the state, including an interlocal entity like IPA. However, it would be reasonable for the Legislature to consider additional reporting and transparency requirements for IPA to ensure that out-of-state interests like the LA Department are not controlling the decision making of the IPA Board and determining the future of treatment of IPP electric generation assets. At a minimum, the Legislature should consider requiring IPA Coordinating Committee meetings to comply with the Open and Public Meetings Act to ensure a base level of transparency.

d. Direct Reporting Requirements to the Utah Legislature

Regardless of whether IPA is regulated by the UPSC, overseen by PEOC or a newly created supervisory board, or a combination of any or all of these options, the governance structure of IPA is presumably designed to supplement for the lack of regulatory oversight that is typically present for an IOU. However, despite being a political subdivision of the state, until recently the level of oversight imposed by the Legislature has been relatively low. While the IPA appears to have a significant lobbying presence at the Legislature, it has rarely been required to report to the Legislature directly with regard to its operational decisions compared to other interlocal entities.[82] Given the concerns with the existing governance structure of IPA and the level of influence the LA Department has in deciding the future treatment of IPP's assets through its controlling vote in the Coordinating Committee, it would be prudent for the Legislature to insist on a more direct approach to overseeing IPA. Consequently, in addition to the decisions the Legislature has before it with regard to the options to strengthen state oversight discussed previously, it seems reasonable

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[80] *A Performance Audit of the Intermountain Power Agency*, Report to the Utah Legislature, Office of the Legislative Auditor General at 24, Footnote 31 (Oct. 10, 2023).

[81] *Id*.

[82] *Id*. at 43 ("IPA rarely presented to legislative committees for accountability purposes; rather, its presentations to the Legislature appear to support bills that further the operations of the IPP, which is owned by IPA").

for the Legislature to require IPA to regularly report on its activities and decision making directly to the Legislature. If the will of the Utah Legislature is to ensure that out-of-state interests are not controlling decisions regarding Utah electric generation assets, there is no means to accomplish that goal than direct representative control, accountability, and reporting by IPA to the Legislature.

6. House Bill 425

In 2023, the Utah Legislature passed HB 425, entitled "Energy Security Amendments," apparently in part to forestall the early retirement of the IPP's coal-fired units. The bill was sponsored by Rep. Ken Ivory and co-sponsored by Republican Sen. Derrin Owens and signed into law by Governor Spencer Cox on March 14, 2023.

HB 425 enacted or amended various statutes, including Section 79-6-303 of the Utah Code, which provides the Utah Legislature's findings concerning the forced retirement of electrical generation facilities.[83] Such findings include that "the state has invested substantial resources in the development of affordable, dispatchable, and secure energy resources within the state," and that the early retirement of electrical generation facilities providing such energy resources "is a threat to the health, safety, and welfare of the state's citizens."[84] The Legislature broadly authorizes the Office of the Attorney General to "*take any action necessary* to defend the interest of the state with respect to electricity generation" where a forced retirement of an electrical generation facility is threatened, including that it may file an action in court or participate in administrative proceedings.[85]

HB 425 also enacted Section 11-13-319 of the Utah Code, which directs the Utah Office of Energy Development to conduct this Study regarding the continued operation of the IPP. The study is to include an evaluation of the viability of the IPP under ownership of the state, or in a public private partnership.[86] The Study is also to "identify the steps necessary for the state to obtain first right of refusal for ownership of a project entity's existing coal-powered electrical generation facility."[87] An analysis of the state ownership issue is provided below.

7. Potential Options for Continued Operation of IPP

As discussed above, the IPP is largely controlled by Purchasers from California, and particularly the LA Department. Moreover, the IPA's decisions regarding the IPP and its plans to prematurely retire the coal-fired units arose primarily from restrictions imposed by California and, to some

[83] In this context, "forced retirement" means "the closure of an electrical generation facility as a result of a federal regulation that either directly mandates the closure of an electrical generation facility or where the costs of compliance are so high as to effectively force the closure of an electrical generation facility." Utah Code Sec. 79-6-303(1)(c).

[84] *See* Utah Code Sec. 79-6-303.

[85] *See* Utah Code Sec. 79-6-303 (emphasis added).

[86] Utah Code Sec. 11-13-319(g).

[87] Utah Code Sec. 11-13-319(h).

extent, the EPA, without regard to Utah jobs, Utah's energy security, or any other of the State's interests.

The IPA is, however, a Utah political subdivision, and the impact of IPA's decisions on the State of Utah should be of paramount concern to the entity. As discussed below, there are options the Legislature might consider that could result in redirecting the IPA's focus toward the State of Utah, including restructuring the IPA's Board and/or imposing additional oversight over the Board. Such options may be appealing at first glance, as they would enable the State to provide better oversight over the IPA and ensure the IPA is more responsive to the State.

However, as discussed herein, restructuring and/or providing for additional oversight over the IPA Board may not be the optimal solution to the problem posed by the "early retirement of affordable, reliable, dispatchable, and secure energy" to the health, safety, and welfare of the State's citizens.[88] Rather, the more expedient method of combatting the planned early retirement of IPP's coal-fired units may be to sell or transfer such units to the state. Such a transfer could be accomplished legislatively by either:

- Enacting a statute granting the State a right of first refusal ("ROFR") with regard to the acquisition of IPP's coal-fired power plants; or

- Enacting a statute providing for the automatic transfer of IPA's coal-fired power plants to the State upon their decommissioning.

Either option may benefit from, or necessitate, the creation of a New State Entity that would own the coal-fired plants.

a. Creation of a separate state entity to own the IPP coal-fired plants

If the Legislature decided to pursue a transfer of the coal-fired units to the State, it should consider creation of a separate state-owned entity ("New State Entity") to own the units, as outlined below.

1. Legislation creating the New State Entity

The Utah Constitution provides the Legislature with broad authority to establish political subdivisions of the State and to grant powers to such political subdivisions.[89] In accordance with the Utah Constitution, the Legislature may create the New State Entity and provide it with various powers by statute.[90]

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[88] *See* Utah Code Sec. 79-6-303.

[89] *See* Utah Constitution, Article XI, Section 8 ("The Legislature may by statute provide for the establishment of political subdivisions of the State, or other governmental entities, in addition to counties, cities, towns, school districts, and special service districts, to provide services and facilities as provided by statute. Those other political subdivisions of the State or other governmental entities may exercise those powers and perform those functions that are provided by statute").

[90] *Id.*

Such powers the Legislature may consider vesting in the New State Entity include the powers to acquire, construct, operate, maintain, modify, and repair IPP's coal-fired power plants and any associated facilities; make and execute contracts; acquire property; borrow money; and issue bonds. Moreover, the New State Entity should also have the authority to enter into a public-private partnership for operation of the coal-fired power plants to ensure it has maximum flexibility in operating the coal-fired units. Broad language granting the New State Entity with all the powers, rights, privileges, and functions that may be conferred on political subdivisions may also be beneficial.

The Legislature may also enact legislation designed to ensure that the New State Entity remains focused on and responsive to the needs of the State. This may be accomplished by providing for a board to be composed of certain members nominated for appointment by the governor and approved by the Legislature (perhaps after being formally vetted in public hearings), among other provisions. In addition, it may be beneficial for the New State Entity to be subject to certain reporting requirements.

In considering these and other provisions to include in the New State Entity's enabling legislation, the Legislature may consider reviewing and potentially borrowing from the enabling legislation of various other entities, including the Lower Colorado River Authority ("LCRA") in Texas.[91]

2. Benefits of Creation of a New State Entity to Own Coal-Fired Plants

There are various potential benefits associated with creating a New State Entity to own IPP's coal-fired units. Perhaps most importantly, creating a separate entity to own such units would allow the IPP's coal-fired generation assets to be split away from IPA and placed under the control of a new Board composed of persons who are focused on promoting the State of Utah's interests. At the same time, the IPA would be permitted to continue operating separately, with the LA Department at the helm, and to pursue its plans for IPP Renewed. This arrangement may help to avoid costly litigation with the City of Los Angeles.

Moreover, given the fact that the New State Entity has *not* made filings under the EPA's coal combustion residuals ("CCR") Rule concerning IPP's coal-fired units, this arrangement potentially allows for the continued operation of the coal-fired units *despite* IPA's filings pursuant to CCR Rule to cease operation of such units, as discussed in more detail above, in Section 1 of Task 1.

3. Issues with Creation of a New State Entity to Own Coal-Fired Plants

There are certain downsides to creating the New State Entity to own IPP's coal-fired units. Notably, unlike IPA, the New State Entity will not own any water rights. The New State Entity would therefore need to work with IPA or another water rights holder to either buy or lease water rights needed for operation of IPP's coal units.

[91] The LCRA's enabling legislation is found at Texas Special District Local Laws Code §§ 8503.001 *et seq*. Another statute that may be considered by the Legislature is South Carolina Public Service Authority's (Santee Cooper) enabling act at S.C. Code § 58-31-10 et seq.

The New State Entity would also need a new connection to the grid and Purchasers for the coal-fired units' capacity. Moreover, the Legislature may need to declare a new service district.

In addition, the State does not currently operate a coal-fired power plant and may not have the infrastructure in place to do so. For this reason, the legislation should consider explicitly granting the New State Entity with the authority to enter into a public-private partnership to operate the facility, as discussed above.

b. Right of First Refusal

The first method by which the State may obtain ownership of IPP's coal-fired units is by enacting legislation granting the New State Entity with a ROFR to purchase such units, as outlined below. This option may be the most expedient method of working to prevent the early retirement of the coal-fired units, as it may allow the State to acquire ownership of the units and take steps to continue operation of the coal-fired units, while avoiding the constitutional takings questions raised by the automatic transfer option.

1. Legislation granting the New State Entity a ROFR

If the Legislature elected to pursue the ROFR option, the legislation should provide that the IPA must provide notice to the New State Entity a specified period of time prior to a "trigger event," which could be defined to include:

- An agreement to dispose of or sell either of IPP's coal-fired units; and/or

- The decommissioning of either of IPP's coal-fired units.

Upon the occurrence of the "trigger event," however the Legislature elects to define it, the legislation would provide the New State Entity with a ROFR to acquire the coal-fired units.

2. Benefits of ROFR

There are numerous benefits to enacting legislation granting a ROFR to the New State Entity, including that this option would allow IPP's coal-fired units to be split away from IPA's control and placed under the control of the New State Entity, with a Board focused on Utah's interests. At the same time, this option should avoid the constitutional takings issues that may arise if the Legislature elected to have the coal-fired units automatically transfer to the State.

Moreover, given that IPA is required to pay certain taxes, the State may be able to structure a deal that would relieve IPA of some of its tax liability in exchange for the property. This option may be raised with IPA, if the Legislature elects to pursue this option.

3. Issues with ROFR

The potential environmental liability involved in assuming ownership of the coal-fired units is a key factor that must be considered by the Legislature. As discussed in detail in Section 1 of Task 1, the CCR units at the IPP have contaminated the groundwater, necessitating additional investigations and remedial actions under both the regulations relating to the operation and management of CCR units and the facility's groundwater discharge permit. This work could be costly. Our understanding is that the LA Department has agreed to take on responsibility for this work, but the state would assume these liabilities upon acquisition of the coal-fired units, in addition to all other liabilities and costs to bring the coal-fired plants into compliance with environmental regulations if it sought to continue operating the units. Further, there is a risk that, prior to the "trigger event" defined in the legislation, the IPA could make an agreement with EPA or otherwise take actions that would hinder the State's ability to come into compliance with environmental regulations and/or operate the coal-fired plants.

Moreover, if future operations at IPP involve the combustion of coal and production of CCR, the New State Entity would have to take steps to bring the facility into compliance with the EPA's CCR Rule in order to proceed with operation of IPP. This could involve constructing a CCR surface impoundment that is compliant with the CCR rule, or alternatively, converting to dry handling.

It may also be challenging to define the State's payment obligation, where it exercises its right to purchase the plants after their decommissioning and there is no readily available price of the facilities. The current assessed tax valuation may be the best way to define the payment obligation under the circumstances. However, there is a risk that this determination could give rise to litigation.

There are various additional challenges stemming from the New State Entity's taking ownership of the coal-fired units, including that the New State Entity would not own water rights and would therefore have to either lease water rights from IPA or find an alternate source of water rights. In addition, the New State Entity would need a new connection to the grid and Purchasers for the coal-fired units' capacity. Moreover, the Legislature may need to declare a new service district.

c. Automatic Transfer of Coal-Fired Units to State

As an alternative to the ROFR, the State could enact legislation providing that upon the decommissioning of the coal-fired plants, such plants shall automatically transfer to the New State Entity. This potentially creates a constitutional takings issue, however, while also sharing most of the same challenges as the ROFR option. For that reason, it does not appear to be as attractive an option as the ROFR.

1. Benefits of the Automatic Transfer

Similar to the ROFR, the main benefit of the automatic transfer option is that it would allow the IPP's coal-fired generation assets to be split away from IPA and placed under the control of a separate entity that would be focused on Utah's interests.

If the State were to pursue this option, it would avoid the question of the required payment to IPA when the units are decommissioned. Of course, it avoids this question by having the assets transfer to the State without any payment at all.

2. Issues with the Automatic Transfer

The automatic transfer option has the same potential issues as the ROFR (except for the State's payment obligation), including with regard to the remediation and environmental liability issues. In addition, there is a potential constitutional takings issue. ***A comprehensive analysis of the takings issue is beyond the scope of this Report, but an overview is provided herein***.

The Utah Constitution provides: "Private property shall not be taken or damaged for public use without just compensation."[92] If legislation were enacted that provided for the automatic transfer to the State of the IPP's coal-fired assets, it would give rise to an argument that such a transfer constituted a takings in violation of the Constitution.

It is unclear whether such an argument would be successful, however, since the coal-fired units are owned by the IPA – a political subdivision of the State – rather than a private entity. An automatic transfer to the State nonetheless risks expensive litigation over whether the legislation constitutes a taking. Moreover, an automatic transfer does not appear to have significant advantages over the ROFR. For these reasons, if the State elects to pursue ownership of the coal-fired units, legislation providing for a ROFR appears to be the superior option.

d. Supervising and/or Directing the IPA Board

We also considered, as an alternative to creating a New State Entity to own the coal-fired units, enacting legislation to make the IPA Board more responsive to the State of Utah. This goal could be accomplished either by creating a separate supervisory board over the IPA's Board, or by restructuring the IPA Board.

Supervising and/or directing IPA's Board may not accomplish the State's goals as efficiently as creating a separate entity to own the coal-fired plants, however. Moreover, this option would risk drawing a lawsuit from Los Angeles and/or other Purchasers.

1. Create a supervisory board to oversee the IPA Board

i. Legislation creating a supervisory board

If the Legislature were to create a supervisory board to oversee the IPA Board, there are several provisions it could include in the legislation in an attempt to provide for more effective oversight of the IPA Board. For instance, the supervisory board members could be nominated for appointment by the governor and approved by the Legislature (perhaps after being formally vetted in public hearings), in order to ensure the supervisory board was focused on Utah's interests. In addition, IPA's decisions, or at least its major decisions, could be subject to the supervisory board's

[92] Utah Const. art. I, § 22.

approval. The supervisory board could also have the authority to dissolve the IPA's board under certain circumstances.

ii. Benefits of creation of a supervisory board

Creation of a supervisory board would be a legally feasible and relatively straightforward way to accomplish the goal of providing additional oversight over the IPA. Were the State to have appropriate oversight and veto authority over the IPA's actions, the State may be able to better work to ensure State interests are being served.

iii. Issues with creation of a supervisory board

The key issue with this potential solution is that any supervisory board created by statute would not own the IPP's coal-fired plants, but rather, would simply provide oversight over the IPA. The supervisory board's ability to delay retirement of the coal-fired units or to otherwise promote the State's goals would thus be limited.

Moreover, if the supervisory board were to attempt to thwart IPA's existing plans for IPP Renewed and/or direct IPA to continue to operate the coal-fired plants, there may be *significant* pushback from the LA Department and/or others, and costly litigation may be likely. Pushback from UAMPS and/or the Municipal Members, which serve on the IPA Board, may also occur.

In addition, as addressed above in Section 1 of Task 1, due to IPA's filings pursuant to the CCR Rule, the life of IPP as a coal unit would be limited. The units could potentially be allowed to continue operating beyond their current tentative closure date of July 1, 2025, until a date that ensures the closure of the two CCR impoundments by October 17, 2028. Absent a change in ownership, however, it would be challenging, if possible, for the units to be operated beyond that point.

2. Restructure the IPA Board

i. Legislation restructuring the IPA Board

As an alternative to, or in conjunction with, establishing a supervisory board, the Legislature could enact legislation restructuring the IPA Board. This could be accomplished in a number of ways, including by dissolving the existing IPA Board, or by providing procedures for dissolution of all or a portion of the Board. In addition, the legislation could provide for all or a certain number of Board Members to be nominated for appointment by the governor and approved by the Legislature (perhaps after being formally vetted in public hearings).

ii. Benefits of restructuring the IPA Board

Restructuring the IPA Board could result in a new IPA Board composed of members focused on protecting the State's interests. As the IPA would continue to own the coal-fired plants and all of IPA's water rights, this could theoretically be beneficial.

iii. Issues with restructuring the IPA Board

Restructuring the IPA Board would have similar risks outlined above with regard to creating a supervisory board, including that there may be significant pushback and/or legal battles with the LA Department or others if the new Board attempted to thwart IPP Renewed or use resources dedicated to IPP Renewed to continue operating the coal-fired plants. There may also be pushback from UAMPS and/or the Municipal Members, which serve on the IPA Board. From a regulatory standpoint, the new Board would stand in IPA's shoes with respect to CCR rule filings, thus exposing the state to potential enforcement actions by EPA, and also citizen suits, if the IPA were to operate the coal-fired units inconsistent with the CCR rule filings.

Key Takeaways:

The Legislature should consider subjecting IPA or any newly created governing entity of IPP to UPSC regulatory oversight and providing sufficient criteria and rulemaking authority to allow the UPSC to adopt the necessary rules to effectively regulate IPA.

The Legislature might consider direct appointment of PEOC members, or at a minimum the Legislature's confirmation of those appointments to ensure more direct interaction during the coming critical few years of project development at the IPP site. Alternatively, the Legislature could consider creating a separate supervisory board, either in addition to or in place of PEOC, to oversee the IPA Board. At minimum, it would be prudent for the Legislature to require IPA to regularly report on its activities and decision making directly to the Legislature.

The Legislature should consider imposing additional reporting and transparency requirements for IPA. At a minimum, the Legislature should consider requiring IPA Coordinating Committee meetings to comply with the Open and Public Meetings Act to ensure a base level of transparency.

A hybrid approach involving aspects of each of the above-referenced options could also be adopted. For example, the Legislature could defer the most significant regulatory oversight steps and condition that deferral on IPA meeting certain milestones (e.g., cooperating with state efforts to extend the life of the IPP coal units, either under IPA oversight or via the transfer of assets from IPA to the above-referenced newly-created state entity so that it can pursue public-private partnerships to pursue alternative technologies at the site that would extend the life of the IPP coal plants, preserving jobs there and along the coal supply chain).

TASK 7 – Energy Security, Reliability, and Resilience for the Southwestern States Analysis

Excerpt from Contract No. 236352, Amendment 1

> i. *"Overview of the thermal capacity shortfall currently projected in the Southwestern US*
>
> ii. *Possible impact of joining the SPP-west regional transmission organization*
>
> iii. *Legal analysis of reliable electricity's role in the constitutional laws supporting the 'state's authority to protect the public welfare of its citizens"*

Analysis

1. Overview of the Thermal Capacity Shortfall Currently Projected in the Southwestern U.S.

The retirement of the coal units at the IPP will not be a large driver on degraded reliability and resource adequacy across the Utah electric grid because it currently provides the majority of its power to California, with only 378 MW to municipal and coop entities in Utah. Nevertheless, the permanent loss of the IPP coal units strips the state of Utah of a dispatchable asset that could prove essential in the future amid a frightening backdrop of retirements of reliable coal and gas generation across the Mountain West. This section will outline the effect of those retirements on resource adequacy of the region and assess the risk of further retirements due to federal regulations.

A starting point for the future resource adequacy situation for Utah can be built from data compiled by the Energy Information Administration ("EIA"), which publishes a monthly catalog of the planned retirements and additions of electric generators throughout the country[93]. Further refinements to that data can be made using PacifiCorp's 2023 Integrated Resource Plan ("IRP")[94] since PacifiCorp serves roughly 75% of Utah's customers[95] and owns a large portion of generation in the state. Figure 7.1 outlines the planned generation retirements and additions for all of Utah through 2030.

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[93] U.S. Energy Information Administration, "Preliminary Monthly Electric Generator Inventory, August 2023," retrieved October 23, 2023 from https://www.eia.gov/electricity/data/eia860m/.

[94] PacifiCorp, "2023 Integrated Resource Plan, Volume I (Amended Final)," May 31, 2023, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I_Final_5-31-23.pdf.

[95] Energy Strategies, "Utah Transmission Study: A Study of the Options and Benefits to Unlocking Utah's Resource Potential", January 21, 2021, p. 4, https://energy.utah.gov/wp-content/uploads/2021-Utah-Transmission-Study-Technical-Report-FINAL-210121.pdf.

Figure 7.1: Installed Capacity of Planned Generation Retirements and Additions in the State of Utah to 2030

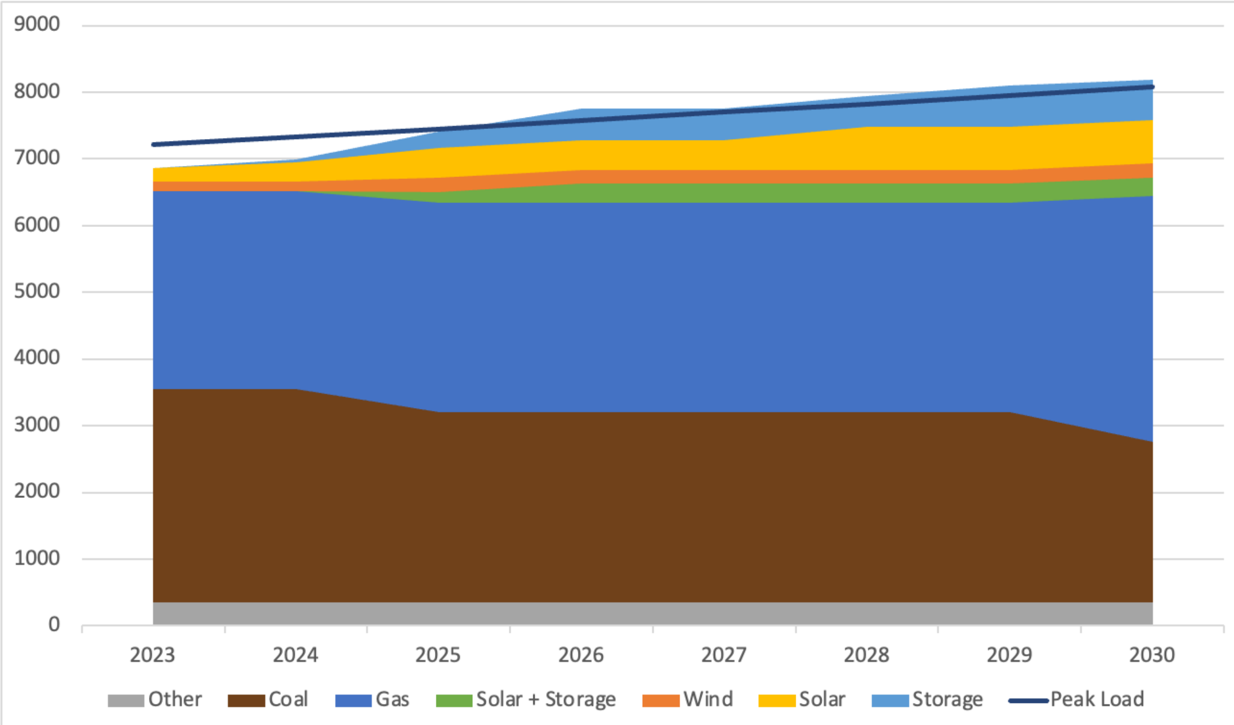
	2023	2024	2025	2026	2027	2028	2029	2030	2030 Total
Coal	3550		-378					-500	2672
Natural Gas (CC)	2174		180						2354
Natural Gas (CT)	1133							606	1739
Petroleum	29								29
Geothermal	84								84
Hydro	265								265
Biomass	14								14
Wind	390		220						610
Solar	1629	628	1217			1508			4982
Storage	1	58	272	300			200		831
Solar + Storage			200	150					350

Note: Units are in MW. Retirements and planned additions derived from U.S. Energy Information Administration, "Preliminary Monthly Electric Generator Inventory, August 2023," retrieved October 23, 2023 from https://www.eia.gov/electricity/data/eia860m/; further additions of wind, solar, and storage derived from PacifiCorp, "2023 Integrated Resource Plan, Volume II (Amended Final)," May 31, 2023, p. 183, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_II_Final_5-31-23.pdf.

The most important question is how this resource mix will contribute to meeting peak demand in Utah. While thermal power plants usually operate with greater than 90% availability during the highest net peak load hours, wind and solar contribute far less during those periods. PacifiCorp's 2021 IRP shows average wind and solar capacity contributions of 34% and 13%[96], respectively, across their service area during summer net peak hours (specific values are not given in the 2023 IRP). Solar plus 4-hour energy storage is given an average capacity contribution of 80%, and standalone 4-hour storage is given 74%.

[96] PacifiCorp, "2021 Integrated Resource Plan Volume II (Amended Final)," September, 2021, p. 220, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf.

Figure 7.2: Projected Firm Capacity and Peak Demand for the State of Utah Under the Generation Scenario in Figure 7.1



Note: Units are in MW.

Applying a generous assumption that these marginal capacity contribution values hold somewhat firm as wind and solar penetration increases,[97] and assuming a 90% availability rate for thermal units, plus a contribution of 176 MW (21% of the expected installed capacity) from IPP Renewed against a loss of 378 MW from IPP, the expected summer output of power plants in Utah is expected to grow from 6,869 MW in 2023 to 8,141 MW in 2030. Assuming peak demand growth of 12% for Utah from 2023 to 2030, per the rate of growth in the 2023 PacifiCorp IRP,[98] demand will increase from 7,211 MW to 8,086 MW. While the near-term resource adequacy situation for Utah appears to be stable, it is important to note that PacifiCorp is planning to retire its two coal facilities in Utah, Hunter and Huntington, between 2031 and 2032.[99] An additional 368 MW of PacifiCorp's gas-fired facilities in Utah are planned to retire in 2032. PacifiCorp is also reducing

[97] It is important to note that PacfiCorp does not have a long history of operating energy storage, so their assumed capacity contributions from energy storage are somewhat speculative and appear to be based on contributions across short periods of summer peak load. Also, as noted in PacifiCorp's 2021 IRP (see p. 220), "In general, wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases," so the marginal values quoted here will likely decline as wind and solar penetrations increase.

[98] PacifiCorp, "2023 Integrated Resource Plan Volume II (Amended Final)," May 31, 2023, p. 3, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_II_Final_5-31-23.pdf.

[99] PacifiCorp, 2023 IRP Volume 1, p. 148.

its coal capacity in Wyoming over the course of this decade. Therefore, the additions coming into place are needed to offset these expected retirements.

The situation does not look quite as rosy after accounting for the possibility that the retirements of Hunter and Huntington, as well as the Bonanza unit owned by Deseret Electric Cooperative, could be pushed up into this decade by several federal regulations being promulgated and litigated right now. For example, the EPA's Ozone Transport Rule ("OTR") will require Utah to reduce its NO_x emissions from power plants by 74% by 2030,[100] a requirement which by itself could force the retirement of every coal power plant in Utah in the next 5 to 7 years.

The EPA's denial of state implementation plans for ozone emissions in Utah and several other states was stayed by the Tenth Circuit Court of Appeals in July,[101] which puts the OTR's emissions budgets on hold for now. However, the proposed rule serves as an illustration of the knife-edge utilities across the Mountain West are walking in order to retire their coal plants over the next 15 years and how quickly the EPA can upend their plans with a single rule. Also, while the OTR and other rules affecting coal power plants would not force the premature retirement of any gas power plants in Utah, the new emissions budgets could compromise the ability of utilities to build new gas and mixed gas/hydrogen power plants.

Setting aside any potential premature retirements of gas generation, let's consider the impact of these early coal retirements and how much additional wind, solar, and energy storage would be needed to bring Utah back to the 2023 level of firm capacity relative to peak demand. Figure 7.3 provides a simple example of how this transition might occur, in terms of installed capacity, and Figure 7.4 shows the evolution of the firm resource mix relative to peak summer demand. This scenario, which is purely illustrative and not optimized in any fashion, assumes the retirements of coal units occur from 2028 to 2030 and the additions occur steadily from 2026 to 2030.

The OTR alone would reduce the total firm capacity to meet summer demand in Utah by 33%, from 8,641 MW to 5,786 MW and require at least an additional 2,000 MW of solar, 500 of wind, and 2,000 MW of energy storage (mostly paired with solar) to get back to the 2023 level of firm capacity relative to peak demand, much less the extra cushion shown in Figure 7.1. The resource mix during summer peak demand hours would shift from 47% coal and 43% gas in 2023 to 0% coal and 49% gas in 2030, with wind, solar, and storage comprising 47% in 2030. This new resource mix is not too far from what PacifiCorp is already planning for the next decade, but the OTR compresses the timeline for accomplishing the transition by half and will certainly increase the cost of the transition substantially.

[100] U.S. Environmental Protection Agency, "Good Neighbor Plan for 2015 Ozone NAAQS: Power Plant Ozone Season Emissions Reductions in 2027 Relative to 2021 Under the Final Good Neighbor Plan," October 18, 2023, https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#maps.

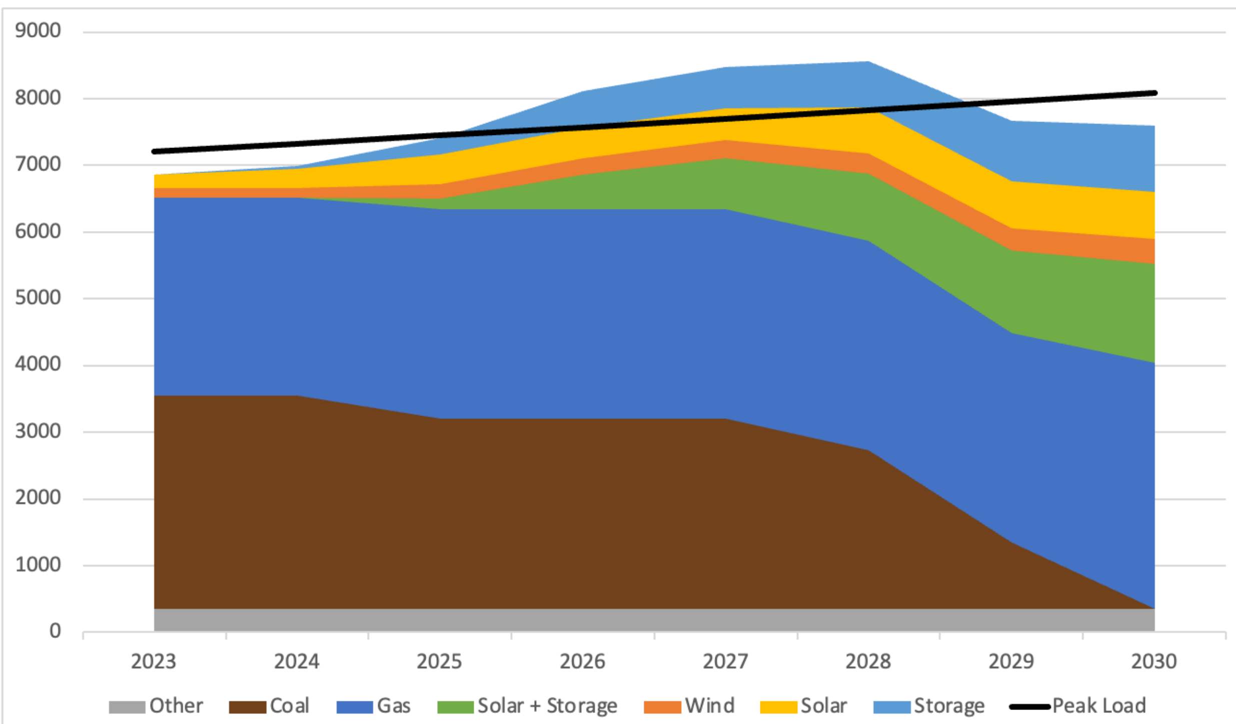
[101] Order at 4, *Utah v. EPA*, No. 23-9509 (10th Cir. July 27, 2023).

Figure 7.3: Installed Capacity of Generation Retirements and Additions in the State of Utah to 2030 Under the Ozone Transport Rule

	2023	2024	2025	2026	2027	2028	2029	2030	2030 Total
Coal	3550		-378			-525	-1548	-1099	0
Natural Gas (CC)	2174		180						2354
Natural Gas (CT)	1133							606	1739
Petroleum	29								29
Geothermal	84								84
Hydro	265								265
Biomass	14								14
Wind	390		220	100	100	100	100	100	1110
Solar	1629	628	1217	100	100	1608	100	100	5482
Storage	1	58	272	400	100	100	300	100	1331
Solar + Storage			200	450	300	300	300	300	1850

Note: Units in MW. The 378 MW loss of coal and 180 MW addition of gas are the Utah accredited portions of IPP and IPP Renewed, respectively.

Figure 7.4: Projected Firm Capacity and Peak Demand for the State of Utah Under the Generation Scenario in Figure 7.3



Note: Units are in MW.

The OTR is only one of many EPA rules that could impact Utah. Recently proposed limits on carbon dioxide emissions from new and existing power plants[102] would require gas and coal power plants to install carbon capture by 2035 or convert to utilizing 96% hydrogen by 2038. This rule would likely force the retirement of significant amounts of gas generation in Utah by the middle of the next decade and could even threaten the operation of IPP Renewed if it was unable to run economically with more than 30% hydrogen.

Zooming out to consider potential retirement and replacement scenarios throughout the Mountain West is a more complex undertaking given the complexity of the various utility systems and ownership structures of power plants, as well as how they help meet the system demand in Utah. An assessment of the expected capacity declines throughout the region, the planned replacement resource mixes, and the effects of these changes on resource adequacy and consumer prices in Utah is outside the scope of this study but may be possible to perform in a future study. However, to put the scale of the challenge in context, let's compare the planned thermal power plant retirements by 2030 under PacifiCorp's preferred portfolio in its 2023 IRP and the expected retirements under the OTR.

Figure 7.5: Thermal Generation Retirements in the PacifiCorp Portfolio Under the 2023 IRP Baseline Scenario and Under the Proposed Ozone Transport Rule

	2022 Capacity	2030 Baseline Retirements	% of total	2030 OTR Retirements	% of Total
Coal	5,246	737	14%	2,804	53%
Natural Gas	3,137	0	0	0	0
Total	8,383	737	9%	2,804	33%

Note: Units are in MW. Data derived from PacifiCorp, "2023 Integrated Resource Plan, Volume I (Amended Final)," May 31, 2023, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I_Final_5-31-23.pdf.

Again, the main effect of the EPA rules is to speed up the pace of retirements to the point that it may be physically impossible to bring on replacement capacity in sufficient time to avoid shortfalls. PacifiCorp is timing the retirements of Hunter and Huntington in 2031 and 2032 to fit between the retirements of other coal facilities in Wyoming and Colorado. The OTR requirement for those two facilities to install equipment to reduce NO_x emissions would render their continued operation uneconomic given how close they are to their planned retirement dates and would likely force a premature retirement before the 2030 compliance deadline. The amount of wind, solar, and energy storage needed to reliably replace the 2,804 MW of retiring coal generation would likely exceed 5,000 MW, with most of that replacement power needing to come from more expensive solar and storage facilities.

The bottom line is that forthcoming EPA rules represent an existential threat to the reliability of the electric grid in Utah and in the surrounding region, and the State of Utah should do everything it can to challenge those rules. The State of Utah should also seriously consider inserting itself into

[102] U.S. Environmental Protection Agency, "Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants", August 3, 2023, https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

the role of preventing retirements of in-state assets when capital improvements or alternative projects like those described at length throughout this report might insulate key dispatchable coal assets from EPA rule-driven retirement.

Even if coal retirements are avoided in the near term due to successful legal challenges and if IPP and PacifiCorp assets are allowed to be retired as currently scheduled, the State of Utah has reason to worry and intervene given that the replacement mix of wind, solar, energy storage, and gas is much more volatile than coal. PacifiCorp basically concedes these risks in its 2023 IRP,[103] as it expects to meet over 40% of its peak demand and reserve requirements with wind, solar, and energy storage by 2030, with 14% coming from storage alone.[104]

The experience of Texas shows that the output of even a large and geographically diverse wind and solar fleet will vary by more than 20% of its installed capacity during net peak load hours, compared to about 5% variance in the output of a large thermal fleet.[105] That 4 to 5 times increase in volatility must be accounted for with more stringent reliability standards on wind and solar generation, often called firming requirements, to ensure the same level of reliability that Utahans have become accustomed to.

PacifiCorp does not provide an analysis of net load in its 2023 IRP, although it appears to be careful to ensure that its modeling is driven by the need to meet net load at every hour.[106] Experience from other states with high wind and solar penetration, such as Texas and California, show that net load is highest immediately after the sun sets and that adding wind and solar to meet peak load will not necessarily reduce peak net load. The region served by the Electric Reliability Council of Texas, which covers about 90% of Texas' population, set a new record for peak net load on September 6, 2023, surpassing a previous record from 2019 despite the addition of 10 GW of wind and 15 GW of solar in the intervening 4 years.[107] The region essentially exhausted its supply of over 3 GW of energy storage in about 30 minutes and narrowly avoided rolling outages. This experience shows that it is imperative for expectations for wind and solar availability to be set around the highest net load hours instead of the highest peak load hours.

Winter resource adequacy is also of greater concern, as increasing electrification of heating and transportation drive strong winter demand growth across the country. The experience of Texas during the February 2021 winter storm shows that gas supply is more interruptible and more interdependent on the electric grid than coal supply, and that reduced resiliency must be mitigated with clear standards for weatherization and firm fuel supply.

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[103] PacifiCorp, 2023 IRP Volume 1, p. 147.

[104] PacifiCorp, 2023 IRP Volume 1, p. 322.

[105] B. Bennett, "Improving the ERCOT Grid Through a Reliability Requirement for Variable Generation," Texas Public Policy Foundation, October 2021, p. 6, https://lifepowered.org/wp-content/uploads/2021/10/LP-ImprovingReliabilityofERCOTGrid-10-18-21-BrentBennett-FINAL.pdf.

[106] PacifiCorp, 2023 IRP Volume 1, p. 147.

[107] B. Bennett, "Tight Grid Conditions This Summer Highlight the Investment Problem Plaguing the Texas Grid," The Cannon Online, September 8, 2023, https://thecannononline.com/tight-grid-conditions-this-summer-highlight-the-investment-problem-plaguing-the-texas-grid/.

Despite the looming resource adequacy problems throughout the Mountain West, the economics of continuing to operate IPP and other coal plants in the region without selling excess power to the coastal states is challenging. Electricity demand in Utah has grown 11% over the past decade[108] and in-state generation has remained flat over that time,[109] but the state is still producing 19% more electricity than it consumes. As noted above, entities such as PacifiCorp have considered options for purchasing IPP, and IPA concluded that the lack of customers for its power outside of its existing customers is the greatest obstacle to the continued operation of the IPP coal units.[110]

While it is not part of this study to consider specific scenarios under which outages could occur across the region, power plants across the West are retiring faster than the net peak loads of coastal states, particularly California, are declining. Therefore, California is likely going to continue to demand power, at increasingly higher prices, from a decreasing number of dispatchable power plants that are still available to serve it. This situation may impact the ability of other power plants in the region to serve Utah, and this is why Utah should consider the costs and benefits of partnering with more reliable electric markets outside the coastal states. With that said, the subject of the following section is an assessment of the impact of Utah joining the emerging Southwest Power Pool ("SPP")-west Regional Transmission Organization ("RTO").

Key Takeaways:

Absent federal regulatory impacts, Utah is currently in a stable situation regarding its resource adequacy, with capacity additions outpacing load growth through 2030. Planned retirements and additions in Utah show the state will increase its firm capacity from 6,869 MW in 2023 to 8,141 MW while its expected summer peak demand will increase from 7,211 MW in 2023 to 8,086 MW in 2030.

However, the onslaught of EPA rules targeting coal fired power- such as the Ozone Transport Rule, numerous efforts to limit particulate emissions, and proposed limits on carbon emissions - will upend this situation by potentially accelerating the retirements of all of Utah's coal capacity into this decade. Utah should support litigation against these rules, but even if such litigation is successful, the continued threat of federal action is increasing the risk and uncertainty of building and operating dispatchable power plants.

Even in the absence of additional federal regulations, the situation becomes more complex after 2030. The 2023 PacficCorp IRP projects the retirement of only 14% of the coal capacity in its portfolio by 2030, but the remainder of its coal will retire before 2040, including Hunter and Huntington in Utah in 2031 and 2032. The Ozone Transport Rule alone could force another 39% of its coal to retire before 2030 and require the construction of replacement power facilities to occur much faster than currently being planned.

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[108] U.S. Energy Information Administration, "Electricity Data Browser: Retail sales of electricity, Utah, annual," retrieved October 20, 2023 from https://www.eia.gov/electricity/data/browser/.

[109] EIA, "Electricity Data Browser: Net generation for all fuels (utility-scale), annual, Utah."

[110] Intermountain Power Agency, "IPP Renewed Update," March 2021, p. 4, https://www.ipautah.com/wp-content/uploads/2021/03/IPP-Renewed-Update-March-2021.pdf.

These retiring coal units across the Mountain West will be replaced by a mix of wind, solar, energy storage, and gas. As shown by states such as Texas, this more volatile resource mix necessitates more robust reliability standards, including separate winter and summer requirements, firm requirements for wind and solar, and firm fuel standards for gas.

2. Possible Impact of Joining the SPP-West Regional Transmission Organization

Historically, exporting electricity to the population centers on the West Coast had twofold benefits. First, it allowed Utah to profit from its coal and gas resources by providing a much larger market for those resources than would be available locally. Second, the economies of scale created by building larger power plants operating as efficient baseload units provided local communities with lower cost electricity than if they existed in isolation. Utah currently enjoys the third lowest residential electricity prices in the country.[111]

However, that situation is now changing as the coastal markets strive toward their zero-emissions goals and build up significant amounts of variable resources closer to home. Exporting states such as Utah and Wyoming must now contend with the challenging economics and operating conditions of exporting electricity primarily to serve peak loads and using more expensive combinations of peaking gas, wind, and solar instead of coal. This pushes local communities more toward an "island" situation, with a shrinking supply of 24/7 baseload generation from exporting power plants to support the local system. This is happening with the areas currently served by IPP and will happen with other areas as coal plants across the region retire.

As noted in the prior section, Utah is still producing 19% more electricity than it consumes. That means there is not enough local demand now or in the near future to support the continued operation of a power plant as large as IPP without additional in-state load growth or more out-of-state customers. Therefore, one of the questions to be addressed in this study is the impact of connecting Utah generation to more eastern markets, primarily through the proposed SPP-west project that would connect parts of the Mountain West to the Great Plains states currently being served by the SPP. This section will summarize those possibilities and put some context around how realistic they are.

Before doing that, it is important to note the findings of a 2021 transmission study performed by Energy Strategies for the Utah Office of Energy Development.[112] The primary limitation of that study was that it centered around PacifiCorp's 2019 IRP and how to enable the development of the significant solar and storage resources in southern Utah contemplated in that IRP. The base scenario used for the study increases solar and storage capacity by 4,040 MW by 2040 and increases gas capacity by only 720 MW.[113] The scope of the study did not include the potential early retirement of coal facilities in Utah and their effect on reliability throughout the state, nor did

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[111] U.S. Energy Information Administration, "Rankings: Average Retail Price of Electricity to Residential Sector, June 2023 (cents/kWh)," retrieved October 20, 2023 from https://www.eia.gov/state/rankings/?sid=UT#series/31.

[112] Energy Strategies, "Utah Transmission Study: A Study of the Options and Benefits to Unlocking Utah's Resource Potential", January 21, 2021, https://energy.utah.gov/wp-content/uploads/2021-Utah-Transmission-Study-Technical-Report-FINAL-210121.pdf.

[113] Energy Strategies, p. 23.

it consider the addition of interstate transmission to facilitate the import or export of additional electricity with neighboring states to provide reliability and market benefits for Utahans. As a result, the study identified additional north-south transmission upgrades as a primary need, whereas interstate connections will more likely span east and west.

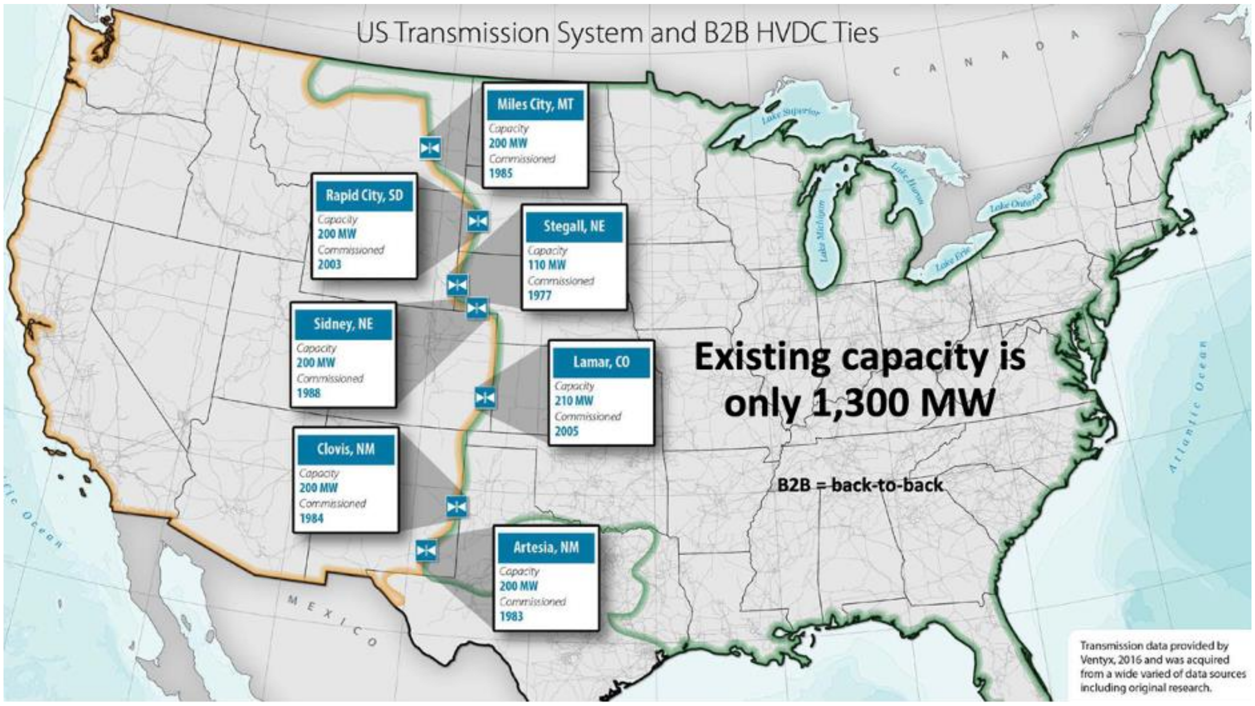
SPP recently announced the first phase of its westward expansion,[114] with several utilities across the northern Rockies, including Deseret in Utah, becoming full participants in the RTO by 2026. SPP expects additional utilities to seek membership and begin to integrate in 2027. The investments being made to facilitate this transition theoretically enable most of Utah to connect with SPP and trade electricity within that market. However, the ability of Utah to further connect with SPP and access that market will depend upon relieving the existing transmission constraints within the Mountain West.

Currently, 4 DC transmission lines connect SPP with the entities that are set to join the RTO, and the expansion of SPP into the Mountain West depends upon full use of those ties, instead of only using them during scarcity conditions, as has been the case up until now. The total capacity of those ties is about 700 MW (see the top 4 connections in Figure 7.6),[115] and they are already used for reliability purposes today. Therefore, there should be no expectation of significant reliability benefits for Utah utilities from joining SPP until those ties are upgraded or new connections are added. Additionally, as noted in the Energy Strategies study, the existing transmission from Utah to the east is primarily geared toward importing power from Wyoming and not toward bilateral trading of power or toward importing power from areas beyond Wyoming.

[114] Southwest Power Pool, "SPP RTO will expand with commitments from western utilities," September 14, 2023, https://www.spp.org/news-list/spp-rto-will-expand-with-commitments-from-western-utilities/.

[115] G. Brinkman, J. Novacheck, A. Bloom, and J. McCalley, "Interconnections Seam Study: Overview", National Renewable Energy Laboratory, October, 2020, p. 15, https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf.

Figure 7.6: Existing DC Connections Between the Eastern and Western Interconnects



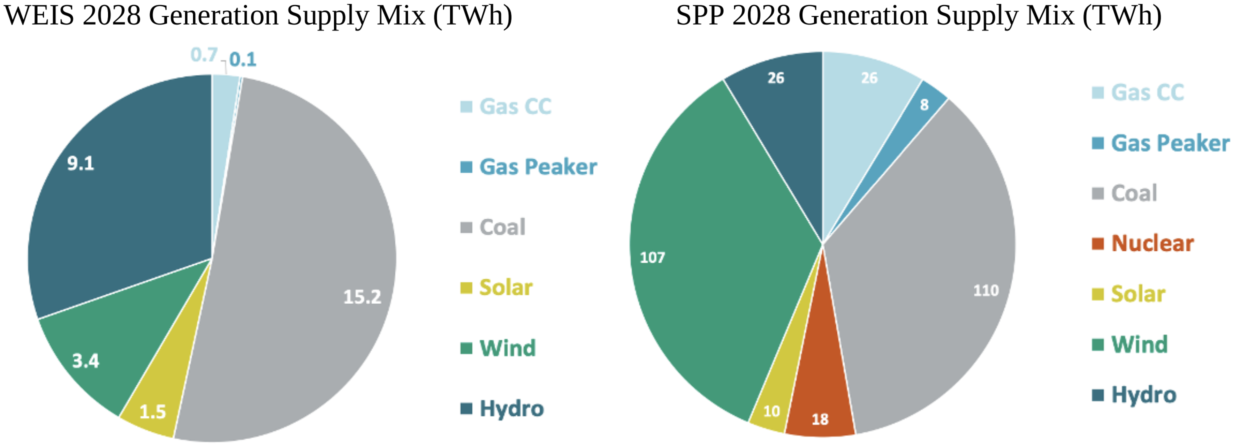
Note: Figure from G. Brinkman, J. Novacheck, A. Bloom, and J. McCalley, "Interconnections Seam Study: Overview", National Renewable Energy Laboratory, October, 2020, p. 15, https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf.

The main benefits of tying SPP and the Mountain West right now are related not to reliability but to the ability to trade electricity more efficiently across the region. A 2021 study conducted by the Brattle Group estimated nearly $50 million in annual savings from a union of SPP and the entities currently in the Western Energy Imbalance Service ("WEIS") market.[116] However, a large portion of those savings would accrue from selling excess wind from SPP into western markets, which brings problems of a similar nature to the problems with linking to coastal states. In 2022, 37.5% of the electricity in SPP came from wind[117], and the region is facing reliability concerns due to increasing wind and solar penetration. The forecast supply mix in SPP is decidedly more wind-heavy than the forecast mix of WEIS participants, which may not bode well for future reliability if WEIS participants choose to become more connected with SPP.

[116] The Brattle Group, "Western Energy Imbalance Service and SPP Western RTO Participation Benefits", December 2, 2020, p. iii, https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf.

[117] Southwest Power Pool, "Southwest Power Pool Annual Report, 2022" n.d., p. 5, https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.

Figure 7.7: Forecast Generation Supply Mixes for the WEIS and SPP Footprints



Note: Figure from The Brattle Group, "Western Energy Imbalance Service and SPP Western RTO Participation Benefits", December 2, 2020, p. 20, https://spp.org/documents/63517/weis%20and%20spp%20west%20rto%20benefits%20study.pdf.

In fact, SPP staff has explicitly stated that the current pace of retirements, as planned by utilities for their own reasons even before considering EPA impacts, will result in SPP's margin for retirements reaching zero by October 2024.[118] Recently, the leader of the REAL Team, Texas Public Utility Commissioner Will McAdams, and his fellow Texas commissioners made an unprecedented unanimous decision[119] to deem imprudent the premature retirement of a coal unit in the SPP part of the State of Texas, following an earlier unanimous decision to reject a wind, solar, and battery new-build[120] that was proposed to replace that retiring unit.

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118 SPP REAL Committee Meeting Materials, Agenda Item 5a (Resource Retention) at slide 4. (Jun. 19, 2023), https://spp.org/Documents/69503/REAL%20Meeting%2006_19_2023%20v3.zip

119 See Comments of Commissioner McAdams on "Item 10, Docket No. 53931; SOAH Docket No. 473-23-03499 - Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs, PUCT Open Meeting, September, 28, 2023, https://adminmonitor.com/tx/puct/open_meeting/20230928/. ("… the lack of depth in the 2020 analysis, especially when you are retiring a plant 22 years early, simply did not sit well with me. And then to not go back and reexamine the analysis in the wake of Winter Storm Uri is in my view both imprudent and some could say unconscionable. It tells me that SWEPCO knew what outcome they wanted to achieve and may have nudged the analysis parameters to match that.")

120 See "Commissioner McAdams Memorandum" at p. 1, *Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Acquisition of Generation Facilities*, PUCT Docket No. 53625, May 24, 2023, https://interchange.puc.texas.gov/Documents/53625_326_1297545.PDF. ("I believe that SWEPCO did not establish a need for the proposed generation facilities under PURA § 37.056(c)(2). Rather than pursuing less expensive, common sense remedial steps, SWEPCO has chosen to retire the Pirkey plant a full twenty-two years before the end of its useful service life…SWEPCO has made similar retirement decisions with its Dolet Hills and Welsch plants. These retirements have created a false appearance of a need for generation, and SWEPCO has not pursued far less expensive alternatives to keep dispatchable generation online.")

Figure 7.8: Operational Outlook

Note: Image taken from SPP REAL Committee Meeting Materials, Agenda Item 5a (Resource Retention) at slide 4. (Jun. 19, 2023), https://spp.org/Documents/69503/REAL%20Meeting%2006_19_2023%20v3.zip.

The positive side is that, like Utah, many members of SPP are taking proactive steps to improve reliability. SPP has created a Resource Adequacy and Energy Leadership ("REAL") Team to recommend policies to SPP leadership to improve resource adequacy throughout the region.[121] Some of the proposed items already passed up to the SPP board for consideration include a new winter reliability standard and improved reliability metrics. The pace of retirements of dispatchable power plants in SPP is more measured than the breakneck speed at which the coastal states are moving, and there are no states within SPP that have net-zero targets.

The stronger reliability posture of SPP constituents lends credence to the hope that SPP can provide a balancing market that will remove some of the "island" effects that will enable Utah consumers to enjoy the benefits of a larger market while avoiding the volatility and reliability problems caused by excessive wind and solar penetration. However, while parts of eastern Utah are already preparing to integrate with SPP, greater integration of the areas west of the Wasatch Front served by Rocky Mountain Power will likely stretch into the next decade if it happens at all. That integration will likely require significant transmission upgrades, and each step toward that integration will require careful consideration of costs and benefits. In the meantime, Utah will have to take proactive steps to ensure it has enough reliable generation across its existing markets to serve its customers.

[121] Southwest Power Pool, "Resource Adequacy and Energy Leadership Team: Organizational Group Scope Statement", January 2023, https://spp.org/documents/68934/real_scope_statement_v5.pdf.

<u>Key Takeaways</u>:

The 2021 Energy Strategies study of transmission needs in Utah primarily considered the need for additional transmission to fulfill PacifiCorp's 2019 IRP, which includes heavy solar and storage builds in Southern Utah. The study did not consider the costs and benefits of interstate linkages between Utah and neighboring markets, including the ongoing SPP-west expansion.

Linking with SPP would likely bring tens of millions of dollars in reduced power costs for Utahans when compared to operating independently, but it would come with a risk of greater exposure to the large amount of wind generation in SPP. Nearly 40% of SPP's total generation came from wind in 2022. Due to the small size of the DC ties between the west and SPP (~700 MW) the reliability benefits of linking with SPP, absent additional transmission upgrades, is limited.

The main positive of reducing reliance on coastal states and linking with SPP is the better policy alignment of SPP states with Utah. SPP states, and therefore the RTO as a whole, do not have net-zero goals and place a greater emphasis on reliability and low power costs than do the coastal states.

3. Legal Analysis of Reliable Electricity's Role in the Constitutional Laws Supporting the State's Authority to Protect the Public Welfare of its Citizens

While opining about the legal flaws in EPA's prior "Clean Power Plan" carbon regulation, Justice Gorsuch pointed out in the *West Virginia v. EPA* case a fundamental legal tenet that is central to many of the legal questions governing the State of Utah's options for addressing the IPP situation. In a pertinent part, he noted:

> *". . . the major questions doctrine and the federalism canon often travel together. When an agency claims the power to regulate vast swaths of American life, it not only risks intruding on Congress's power, it risks intruding on powers reserved to States. . . CPP unquestionably has an impact on federalism, as the regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States."*[122]

This admonishment is not just a shot across the bow of EPA about its coercive approach to state interactions on carbon regulation, it cites an important legal precedent making clear that electric utility regulation is at the heart of the state's police powers.[123]

A state's police powers over electric generation regulation is not only a basis for fending off federal overreach - it is a central police power obligation owed by each state to its citizens. With this robust power (and obligation) in mind, the State of Utah is, therefore, at a precipice - will it exert its police powers to protect Utah citizens from potential grid reliability and affordability risks? If so, how far is it willing to go and what creative public-private partnerships might be forged to avert the grid impacts the State fears? Also, is there a way for the State to tend to its police power

[122] *West Virginia v. EPA*, 142 S. Ct. at 2622 (Gorsuch, J., concurring).

[123] See *Arkansas Elec. Cooperative Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U. S. 375, 377 (1983).

obligations and still allow out-of-state ownership interests to leverage their assets and achieve their goals? An exhaustive analysis of these contrasting questions is beyond the scope and budget of this project but should be top-of-mind as the State moves forward with its evaluation of options and legislative response to the facts on the ground and analysis contained herein.

CONCLUSION AND RECOMMENDATIONS

Conclusions of individual authors within the IPP Study Team are provided at the end of several of the Task discussions above and will not be repeated here. Instead, the focus of this section will be to address key fundamental take-aways from the IPP Study Team's findings and how that translates into our recommendations to the Utah Legislature for further policy development relating to IPP. In the end, there may be regret about the situation that IPA has created for the State of Utah ("State"), but this report documents technical opportunities and restructuring recommendations that provide great promise for the IPP coal units if the State's leadership is prepared to take bold steps to right the ship.

While the Task 1 and 6 discussions (and the Legislative Audit) document some of the regrettable history that explains how the current dilemma came to be, the directive by the Legislature for this project is to focus on what can be made of the situation now, not what could have been. Having said that, lessons can be learned from the past that will greatly inform the State's path forward with respect to IPP. Most notably, the assumptions that appear to have been made about self-governance which rationalized insulating IPA from typical regulatory oversight of electric utility operations proved to be flawed and the dominant role of out-of-state interests led to decisions that might have been very different if IPA were obliged to keep the State more meaningfully informed or, preferably, more directly involved in future plans for the site.

As noted above in Task 6, it is not too late for the State to restore proper governance of IPA as they proceed with the Renewed Project while concurrently creating a structural framework for the State to preserve optionality for the IPP coal plants. Importantly, the governance recommendations set out at the end of the Task 6 discussions were developed by the IPP Study Team independent of the Legislative Audit that has been developed on a parallel path. Although neither team communicated with the other, several of the governance recommendations provided by both are in close alignment. This is telling given the lack of cross-pollination between the two groups and the consistent theme of the recommendations.

In addition to the threshold recommendations about governance and the structuring of a new entity to pursue IPP opportunities, the IPP Study Team recommends that the Legislature take steps to ensure that actions on the ground and in the permitting of the Renewed Project do not contravene the apparent intent of HB 425 (to preserve optionality for the continued operation of the IPP coal units.

To recap, HB 425 enacted Utah Code Section 11-13-318 which states in critical part as follows:

> (4) A project entity may not intentionally prevent the functionality of the project entity's existing coal-powered electrical generation facility.
>
> (5) Notwithstanding the requirements in Subsections (2) through (4), a project entity may take any action necessary to transition to a new electrical generation facility powered by natural gas, hydrogen, or a combination of natural gas and hydrogen, including any action that has been approved by a permitting authority.

As discussed in more detail in the Air Permitting discussion in Task 1, Regulatory Assessment, IPA's air permitting approach to the Renewed Project (which was initiated before the passage of HB 425) hard-wired retirement of the IPP coal units into its air permit authorization of the Renewed Project so that it could streamline the permitting process by assuming emission reductions arising from the permanent retirement of the IPP coal units. Because this approach was taken, unless the Renewed Project is re-permitted or other alternative permit strategies are developed, this approach will expose the IPP coal units to almost insurmountable re-permitting requirements and New Source Performance Standards. The analysis in Task 1 describes the path for changing course on this permitting strategy before it is too late so that the IPP coal units are not sacrificed to make the Renewed Project easier but, instead, both projects are permitted in such a way as to allow both the existing and new facilities to coexist.

In addition to the need to resolve IPA's current permitting strategy, the discussion in Task 2 flags two critical technical hurdles to continue operation of the coal plants that are of IPA's own doing and, therefore, capable of being resolved. Both the ongoing failure to budget the same level of maintenance that would be budgeted if the IPP coal units were going to continue operation (discussed at the beginning of Task 2) and IPA's future plans for shared facilities (e.g., water supply and treatment) (discussed later in Task 2) could foreseeably impair efforts to continue the operation of the IPP coal units. The IPP Study Team believes, based on the extensive research and interviews we conducted, that both of these issues, like the permitting issue, can be resolved with leadership from the Utah Legislature and cooperation by IPP. This dovetails with the organization recommendations that would lead to the parallel existence of an IPA with better governance and oversight, on the one hand, and a new governmental entity to house the IPP coal units for future project development, on the other hand.

This leaves the important policy issue of how to harmonize IPA's approach to permitting, maintenance, and shared facilities with the above-referenced sections of HB 425 designed to preserve the IPP coal units while allowing IPA to pursue alternative projects. The IPP Study Team believes that the Utah Legislature needs to clarify IPA's duties and responsibilities with regard to the IPP coal units, either through new legislation or other appropriate action given the intent of HB 425 to avoid legal and technical impediments to the continued operation of the IPP coal units.

The bottom-line goal of the recommendations embodied in this report is to assist the State of Utah with the development of two compatible paths forward for both the Renewed Project and the continued use of the IPP coal units. The IPP Study Team is honored to have been selected to conduct this critically important study. Our team stands ready to provide further advice and counsel, as the Legislature sees fit, regarding innovative legal and technical strategies to preserve the ability to continue operation of the IPP coal units while simultaneously improving the governance and transparency of IPA to integrate more stakeholder input and account for the Utah Legislature's desire to prevent the creation (or continuation of) hurdles that stand in the way of the continued viability of the IPP coal units.

For ease of reference, the key recommendations of the IPP Study team are set out below:

RECOMMENDATION NO. 1

The Utah Legislature should change existing laws to improve legislative and executive branch oversight of IPA. At minimum, the legislature should empower the Utah Public Service Commission to adopt the necessary rules to effectively regulate IPA. Alternatively, the Legislature could consider creating a separate supervisory board, either in addition to or in place of the existing Project Entity Oversight Committee ("PEOC"), to oversee the IPA Board. Members of any new or replacement supervisory board should be appointed by and required to regularly report to the legislature.

RECOMMENDATION NO. 2

The Utah Legislature should create a "New State Entity" (as that phrase is discussed in Section 6 of the Final Report) to allow the IPP's coal-fired generation assets to be split away from IPA and placed under the control of a new board composed of persons who are focused on promoting the State of Utah's interests. At the same time, the New State Entity should be granted the authority to enter into public-private partnerships to operate the facility and the authority, direction, and resources to retain/secure sufficient water rights for continued operation of the IPP coal-fired units and retain/secure grid interconnections to serve new power purchasers.

RECOMMENDATION NO. 3

The Utah Legislature should enact a statute providing for the automatic transfer of IPA's coal-fired power plants to the New State Entity upon their decommissioning. Alternatively, the Legislature could enact a statute granting the State a right of first refusal ("ROFR") with regard to the acquisition of the IPP coal-fired power plants so long as IPA's governance is enhanced, better transparency is in place, and UPSC regulatory oversight is established to ensure that IPA participates in good faith in the process.

RECOMMENDATION NO. 4

The Utah Legislature should enact a statute to direct the Utah Division of Air Quality (and provide for any necessary changes to that Division's statutory authority) to change the air permit authorization for the Renewed Project so that is not dependent on the closure of the IPP coal-fired units and that both the Renewed Project and the IPP coal-fired units may coexist without creating new regulatory barriers for the continued operation of the IPP coal-fired units.

RECOMMENDATION NO. 5

Because of the potential confusion arising from the tension between Sections (4) and (5) of Utah Code Section 11-13-318 (established by HB 425 during the 2023 Utah Legislative Session), the Utah Legislature should either amend that Section or establish a new section to clarify that IPA's ability to pursue the Renewed Project is conditioned upon IPA doing so in a way that does not create any legal, technical, or economic impediments to the continued operation of the IPP coal-fired units.

APPENDIX ONE

IPP Study Team, Outreach to IPP Stakeholders, Educational Sessions, Research and Reporting

Utah Study Team, Outreach to IPP Stakeholders, Educational Sessions, Research and Reporting

Date	Entity	Discussion
July 27, 2023	UOED	Outline study procedure, expectations, timelines
Aug 3, 2023	UGS	In-depth overview of carbon storage capabilities
Aug 10, 2023	Bi-weekly call with UOED	Report on progress and division of labor
Aug 10, 2023	Bill sponsors	Clarification and better understanding of HB 425
Aug. 17, 2023	IPA	Briefing of the regulatory and contractual obligations
Aug. 17, 2023	City of Bountiful	Understanding from an IPA member viewpoint
Aug. 18, 2023	UAMPS	Gain a broader prospective on the impact of IPP shutdown on municipal customers in Utah
Aug. 22, 2023	Enchant Energy – CCS	Briefing from carbon capture company and its offer to IPA for the IPP coal units
Aug. 24, 2023	Fibernet – Data Centers	Discussion with Fibernet about their offer to locate in Delta and purchase IPP coal units
Aug. 24, 2023	Omnis Technology	Overview of the coal to produces (graphene) and Hydrogen technology. Offer made to IPA to purchase coal-units
Aug. 24, 2023	UOED - Bi-weekly report	Brief UOED as to the progress and developments of the study
Aug. 25, 2023	BluRock Technology	Plasma Arc carbon capture technology briefing
Aug. 29, 2025	BYU Energy Center	Research underway on various DOE funded projects to lower emissions for coal-fueled power
Aug. 30, 2023	Deseret Coop. G&T	Gain an understanding of impact of IPP closure on the rural electric cooperatives in Utah
Aug. 31, 2023	IPP Study Team	Extensive meeting on report progress, issues to be addressed, timeline being met
Sept. 7, 2023	UOED	Bi-weekly update, further directions from UOED

Sept. 7, 2023	Enchant Energy - CCS	Follow-up meeting to clarify questions the IPP Study Team still had for Enchant
Sept. 7, 2023	UDEQ	Briefing from UDEQ as to the plant closing as a prerequisite for additional time to comply with regulations
Sept. 7, 2023	Fibernet – data center	Follow-up meeting to better understand economics of Fibernet proposal to purchase IPP
Sept. 8, 2023	IPA	Meeting to discuss several environmental and structural issues not covered in the first meeting
Sept. 11, 2023	Utah Legislative Council	State oversight governance and CCR issues
Sept. 12, 2023	Omnis Technologies	Follow-up questions on Pleasant Coal Plant purchased in West Virginia
Sept 12, 2023	IPP Study Team	Extensive discussion on progress and direction of the Report
Sept 21, 2023	UOED	Bi-weekly update to UOED and discussion on next steps
Sept. 26, 2023	IPP Study Team	Internal discussion, debriefing by subcontractors, strategy for Final Study completion
Sept. 29, 2023	Fibernet follow-up call	Better define the data center initiative and answer additional questions
Sept. 29, 2023	Omnis follow-up call	Conversation concerning differences and similarities between West Virginia project and Utah proposal
Oct 1, 2023	IPSC meeting	Detailed conversation on IPP operational characteristics and equipment needed for IPP Renew
Oct 5, 2023	Utah OED	Bi-weekly study progress and update report to OED
Oct. 10, 2023	IPSC follow-up meeting	Additional questions for IPSC and IPP operations
Oct. 11, 2023	Element One Technology	Discuss coal to hydrogen concept and implications for IPP
Oct. 11, 2023	Wolverine Resources	Gather understanding of force majeure and coal supply problems. Current deliveries and expectations of future deliveries

Oct 13, 2023	Rocky Mountain Power	Interest in IPP coal units, existing coal plants in Utah
Oct. 16, 2023	IPP Study Team	Meet with EVA on coal supply issues
Oct. 16, 2023	Element One	Follow-up call with coal to hydrogen technology
Oct. 18, 2023	IPP Study Team	Reports on various sections of the study. Areas that need more attention. Additional data needed.
Oct. 19, 2023	UOED	Bi-weekly reporting to UOED. Additional instructions for completing final version of the study.