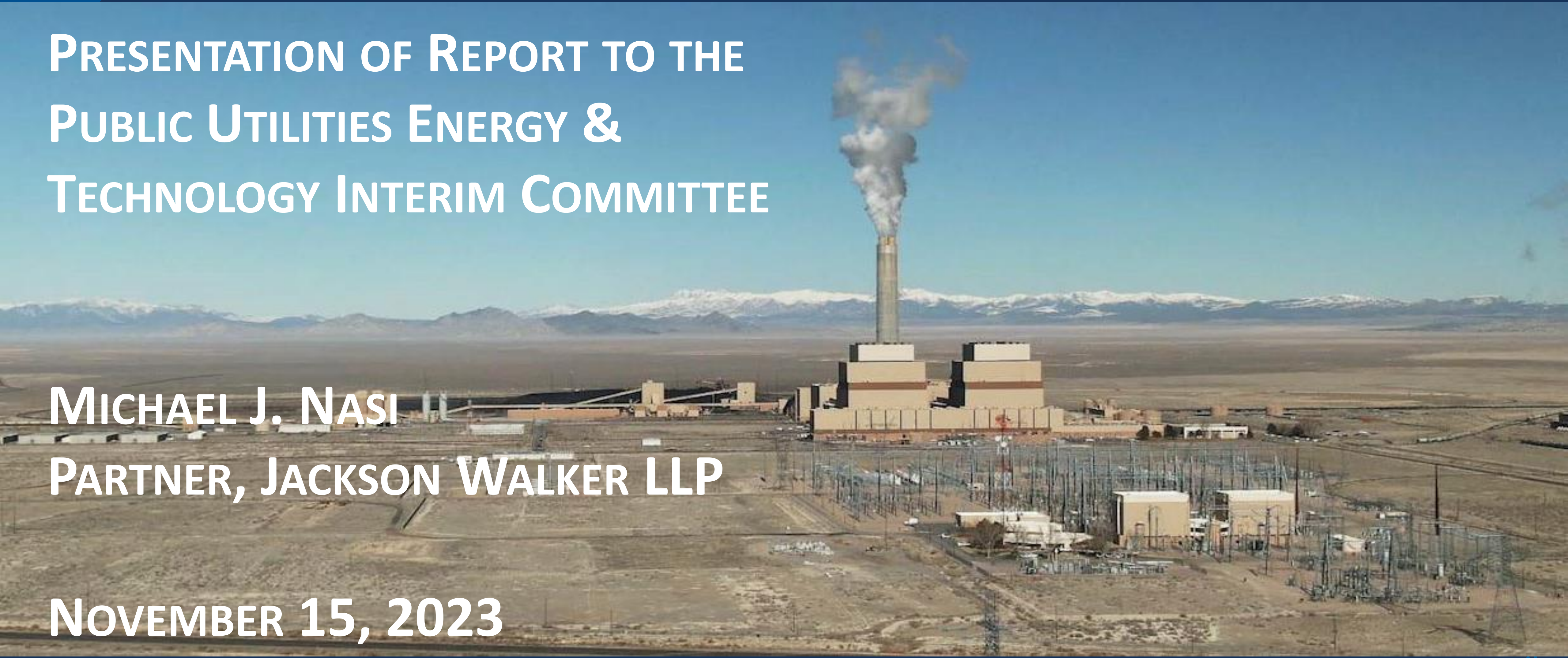
Final Report Implementing HB 425 Study: Feasibility of Intermountain Power Plant



Presentation of Report to the Public Utilities Energy & Technology Interim Committee

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Utah Code Sec. 11-13-319 (*established by HB 425*)

(1) *The Office of Energy Development shall conduct a study to:*

(a) *evaluate all environmental regulations and permits to be filed to continue operation of a project entity's existing coal-powered electrical generation facility;*

(b) *identify best available technology to implement additional environmental controls for continued operation of a project entity's existing coal-powered electrical generation facility;*

(c) *identify the transmission capacity of the project entity;*

(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;*

(e) *analyze the financial assets and liabilities of a project entity;*

(f) *identify the best interests of the local economies, local tax base, and the state in relation to a project entity;*

(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; and*

(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.*

Utah Code Sec. 11-13-319 (*established by HB 425*) (*continued*)

(2) *A project entity shall cooperate and provide timely assistance and information to the Office of Energy Development in the preparation of the study described in Subsection (1) . . .*

(4) *The report described in Subsection (3) shall include:*

(a) *the results of the study described in Subsection (1);*

(b) *recommendations for continued operation of a project entity's existing coal-powered electrical generation facility;*

(c) *environmental controls that need to be implemented for the continued operation of a project entity's existing coal-powered electrical generation facility;*

(d) *recommendations to increase local and state tax revenue through the continued operation of a project entity's existing coal-powered electrical generation facility; and*

(e) *recommendations for legislation to be introduced in the 2024 General Session to enable the continued operation of a project entity's existing coal-powered electrical generation facility.*

STUDY TEAM

JACKSON WALKER LLP	SUBCONTRACTORS
• Michael J. Nasi • Taylor Holcomb • Ben Rhem • Heath Armstrong • Alicia French • Lisa Kost • Donna Brown Willis	• Randy Eminger - *Eminger LLC* • Phillip Graeter - *Energy Ventures Analysis* • Connor Thompson, Charles McConnell, Dr. Ramanan Krishnamoorti - *University of Houston Center for Carbon Management in Energy (CCME)* • Dr. Brent Bennett - *Bennett Ventures, LP*

OUTLINE OF FINAL REPORT

TASK 1 (Regulatory Analysis) – KEY TAKEAWAYS

COAL COMBUSTION RESIDUALS (CCR) COMPLIANCE:

- It may be possible for IPA to extend the life of the boilers beyond July 2025.
- Under this scenario, the life of the boilers can be extended up to a time that will allow completion of closure of the surface impoundments by 10/17/28.
- Another potential option to extend the life of the coal-fired plant is for a third party entity 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.
- Under either option, the non-compliant surface impoundments must be closed no later than October 2028.

TASK 1 (Regulatory Analysis) – KEY TAKEAWAYS (*continued*)

AIR PERMITTING & REGULATORY COMPLIANCE:

- An air permitting strategy to enable the both the pursuit of the hydrogen project and continued use of the coal units beyond 2025.
- Assuming EPA's current slate of air rules survives judicial review, a strategy must be developed to ensure compliance through:
  - Deployment of NO_x-reducing technologies like Selective Catalytic Reduction (SCR) and/or to finance the purchase of allowances due to ozone transport rule/"good neighbor plan" requirements and, in part, regional haze rules.
  - Deployment of carbon control technology to meet EPA's new carbon regulations and, if power is still to be sold into the California market, to meet the California Energy Commission performance standard requirements.

TASK 2 (Technology Analysis) – KEY TAKEAWAYS (*continued*)

- 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 and potential non-carbon air quality regulations.
- As for future technology options targeting CO_2 emissions from the existing IPP coal units, 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.
- The sufficiency of existing water rights needs to be assessed to ensure sufficient quantity and category of use authorization for the simultaneous operation of both the hydrogen and coal power plants, as well as the hydrogen production and creation of salt domes for hydrogen storage.

TASK 2 (Technology Analysis) - 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

TASK 3 (Transmission Analysis) – 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 & Interest) – KEY TAKEAWAYS

- 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 & Liability Analysis) – 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) – KEY TAKEAWAYS

- The Legislature should consider subjecting IPA or any newly created governing entity of IPP to Utah Public Service Commission (UPSC) regulatory oversight and providing sufficient criteria and rulemaking authority to allow the UPSC to effectively regulate IPA.
- The Legislature might consider direct appointment of Project Entity Oversight Committee (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.

TASK 6 (Ownership Structure Analysis) – KEY TAKEAWAYS (*continued*)

- 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.
- 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, & Resilience) – 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.
- However, the onslaught of EPA rules targeting coal and gas fired power- will upend this situation by potentially accelerating the retirements of all of Utah's generating capacity.
- 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 new dispatchable power plants which makes existing assets critical.

TASK 7 (Energy Security, Reliability, & Resilience) – KEY TAKEAWAYS (*continued*)

- 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.
- 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.

RECOMMENDATION NO. 1

The 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 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.

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 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 Legislature should 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 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.

Utah Code Sec. 11-13-318 (*established by HB 425*)

. . .

(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.

QUESTIONS ?