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Wyoming Energy Authority – Hydrogen Pilot Program

Williams Southwest Wyoming Hydrogen Hub Final Report

EXECUTIVE SUMMARY

FINAL TECHNICAL REPORT

1. ABSTRACT

This report examines the feasibility of creating a hydrogen hub in the Southwest Wyoming area. The three topics researched were 1) the availability of water for the formation of hydrogen, 2) the effects of hydrogen on the metallurgy of pipeline material, and 3) the ability to blend hydrogen into the fuel gas stream of turbines and reciprocating engines.

The project team employed a variety of sources to perform this research including using the University of Wyoming for the water availability and processing, compressor vendors for the engine testing and analysis, and a third-party testing facility for the pipe materials testing. The results were generally positive with the identification of several water sources that could be used to create hydrogen and the verification that the engines could operate at hydrogen blends up to 20%. Some findings will require further research before hydrogen transportation can be actualized including the reconciliation of increased Nitrous Oxides (NOx) as a result of hydrogen blending in the fuel gas and the pipe material toughness reduction due to hydrogen propagation into the pipe metal.

2. INTRODUCTION[1]

In 2021, the University of Wyoming's School of Energy Resources (UWyo-SER) and Williams partnered to develop a proposal in response to a request for proposals from the Wyoming Energy Authority to develop pilot projects demonstrating green and blue hydrogen production and use. In 2022, the University of Wyoming and Williams were awarded a nearly $1million grant with Williams contributing another $200,000 to close the technical gaps to make these projects a reality. A quote from the original proposal encapsulates the purpose of this study, "The feasibility study proposed here will reduce the risk… [which currently prevents Williams or a similar company from producing hydrogen] by achieving two key goals: first, ensure the existing natural gas infrastructure is compatible or adaptable to transporting hydrogen; and second, better understand water resources and water upgrading options in Wyoming."

[1] The number system within this document aligns with the full Final Technical Report and may appear to be non sequential. This is intended to provide clarity when comparing the two documents.

3. OBJECTIVES

Recipient will conduct a feasibility study to evaluate the water access and compatibility as well as asset integrity in support of green hydrogen production and transport in the vicinity of Wamsutter and Opal, Wyoming. The proposed feasibility study will evaluate two key areas:

A. Analytical and physical integrity assessments on Recipient's existing transmission pipeline network to understand:

   1. the effects of hydrogen on the physical assets, including potential use of hydrogen as a compression fuel source,

   2. the extent and effects of hydrogen embrittlement on vintage pipelines with various production dates using substantially similar available samples on hand,

   3. the percentage of hydrogen that can be blended and safely transported through existing pipelines, and

4. any mitigations or preventive maintenance that can be conducted to minimize the effects of hydrogen embrittlement.

B. Determine the quantity and quality of water needed to produce the desired amount of green hydrogen, and how this water will be obtained, processed, and utilized considering availability from a variety of local and regional sources.

Williams worked with subawardees, vendors, and subcontractors to produce four studies, identified by task list, which together would inform a decision on how to generate, transport, blend, combust, or otherwise use hydrogen to reduce primary and secondary emissions from midstream pipeline operations. The results of those vendors' and subawardees' four studies are summarized below.

4. TECHNICAL SUMMARY BY TASK

Task 1 – Water Resources and Treatment Options

4.1.A Description: All methods of hydrogen generation require a hydrogen source. The most common sources are water (H_2O) and methane (CH_4). At present, demand for hydrogen is met by Auto-Thermal-Reforming (ATR) which is an improvement on Steam Methane Reforming (SMR). ATR and SMR still require water in addition to methane as a reagent for their hydrogen-generating chemical reaction. In electrolysis methods, water is the sole source of hydrogen. This means that regardless of the process used in a hydrogen plant, large volumes of water are necessary.

As this project focused on production of hydrogen by electrolysis, the water used as a reagent must be especially high purity. This would pose a challenge in any environment, but in arid Wyoming finding a water source was expected to be especially difficult. This study accordingly had to answer two questions: First, what water sources were legally available for consideration? Second, what would the cost be to treat that water source to the extreme level of purity needed for electrolysis?

4.1.D Task 1 Conclusion: Water is available in the Green River Basin through three paths. If a group is willing to invest significant time, and has a use which would pass NEPA, then Fontanelle Reservoir can be used to supply ultrapure water at very low cost. If a group is willing to invest more significantly and tolerate modest legal uncertainty, then produced water waste can be disposed through treatment and hydrogen generation. And lastly, if a group is willing to risk being among the first water rights cut, then it is possible to acquire a junior water right in the Green River Basin. Water is a deeply emotional issue in the arid west, and those intense feelings are reflected in the regulatory regime. It is possible to meet demands for hydrogen production, although not without risk and cost. Though the upper limit to the availability of water has not been identified, there is adequate water available for the production of industrial scale hydrogen.

4.2 Task 2 – Pipeline Material Review

4.2.A Description: Vintage pipelines have variable steel composition and quality because they have been constructed and replaced in many different construction campaigns over the years. Due partly to their age, vintage pipes suffer failures more often than newer pipes. This risk of failure is partially managed by transporting only dry methane with low impurities. Hydrogen blending is directly at odds with that risk management technique, and so a vintage pipeline's ability to tolerate an 80% natural gas and a 20% hydrogen blend needed to be studied. Engineering theory suggests that hydrogen has two mechanisms that lead to increased risk of pipe failures:

1. hydrogen may cause embrittlement of pipe walls which leads to fractures when the pipe is deformed during normal operation, and
2. hydrogen possesses the ability to penetrate small linear defects or material imperfections which can accelerate fatigue crack growth.

These two measured factors are used to help determine the probability of failure. If these two risks remain manageable, there is potential for simple hydrogen blending in existing vintage pipelines. The following is a list of some of the defect types that may be impacted by hydrogen introduction: stress corrosion cracking, hard spots, wrinkle bends, planar defects, cracks, dents, laminations, corrosion (uniform and localized). The Pipeline Research Council International (PRCI) is currently studying the anticipated impacts of hydrogen blending to each of these defect types as each will pose unique challenges.

4.2.C Findings:

In the fatigue crack growth (FCG) testing, no significant difference in behavior is noted between 1% H_2 and laboratory ambient air. Work performed by Sandia National Labs shows that all tested materials follow a similar curve regardless of the material being analyzed. Since Williams operates their pipelines on the lower end of the stress intensity factor, the difference in the hydrogen and air should be manageable. These test results further validate that the fatigue crack growth rate will have very little impact on the operation and maintenance of existing pipelines as long as the pipelines are operated with low cycles and the pipelines are free of existing defects.

For the toughness testing exercise, the initial plan was to assess the pipeline material samples at partial pressures that would equate to 1%, 5% and 10% hydrogen. However, after the original plans were laid out, Sandia National Labs produced data (https://www.osti.gov/biblio/1871634) that showed that 1% hydrogen produced fracture toughness reductions of -22% to -25%, similar to 10% and 100% hydrogen tests. While 10% and 100% toughness reductions were slightly larger than the 1% sample, the majority of the toughness reductions occurred between 0% and 1%.

Due to the availability of this new information, Williams decided to assess the material at 0.25%, 0.5% and 1.0% hydrogen concentrations to determine the lowest percentage of hydrogen that could be blended without appreciable toughness reductions. The test results show that at even 0.25% hydrogen concentrations, there is a significant negative impact (-24%) to the toughness of the pipe material. At this point, the lower limit of when hydrogen can be blended without significant impact to the material toughness is still unknown.

4.2.D Task 2 Conclusion: While hydrogen negatively affects both fatigue crack growth rate and toughness, fatigue crack growth will generally not be a major problem due to the relatively consistent pressures that Williams maintains in their pipelines. Reduced toughness is a concern at all but de minimis hydrogen blends. Moving forward, Williams will conduct an ECA to mitigate risk should a specific opportunity present itself to introduce hydrogen into our natural gas infrastructure. Through an ECA process, fatigue and toughness will be studied on a case-by-case basis using the same type of testing as SwRI performed for this effort. This will allow Williams to understand the impacts to the fatigue characteristics in a specific segment of our pipeline network. The ECA will also assist in the creation of specific risk profiles for the different defect types that exist in a specific segment of the pipeline network.

The testing data suggests that a hydrogen blend may be manageable in legacy pipes. However, the flowrate and/or pressure may need to be decreased, and/or alternatively baseline inspections and re-assessments may need to be more frequent.

4.3 Task 3 – Hydrogen Blending (Turbines)

4.3.A Description: In natural gas pipeline transportation, compression is performed by turbines which currently run on natural gas. To reduce the CO_2 emissions of these turbines there are three main options: their exhaust could be rerouted to the plant's separation equipment, a new dedicated CO_2 capture system could be attached to the exhaust, or their fuel could be switched to hydrogen (or a hydrogen blend). This study considered the last option of fuel switching because that option can eliminate CO_2 emissions entirely, whereas the others only approach total elimination (~95%) of CO_2 emissions.

4.3.C Findings: The study revealed the majority of older turbines would require an extensive overhaul to manage concentrations greater than 4% hydrogen. The two newest turbine models studied would be suitable for a 20% hydrogen blend with only minor changes. The hydrogen incompatibility frequently comes from: various valves, start systems, fuel gas filters, and the sensors which monitor the combustion to autotune the turbine's settings.

Turbine Model	Taurus 70	Centaur 50	Taurus 60	Mars 90	Centaur 40	Titan 130	Mars 100
Year unit was shipped	2001	2001	1992	1983	2006	2009	2009
Engine between 4% and 10% H_2	Overhaul	Overhaul	Overhaul	Overhaul	Overhaul	Suitable	Suitable
Engine between 10% and 20% H_2	Overhaul	Overhaul	Overhaul	Overhaul	Overhaul	Suitable	Suitable
Control system	Replace	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
HMI	Replace	Suitable	Suitable	Suitable	Replace	Replace	Replace
Package fuel system	Replace	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade
Start System	Replace	Replace	Replace	Suitable	Replace	Suitable	Suitable
Guide vane	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
Bleed valve	Replace	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
BAM	Replace	Replace	Suitable	Replace	Replace	Replace	Replace
Gas fuel off skid system	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade

Orange - Overhaul or Replace Minor Upgrade Required Suitable for blended fuel gas service

Figure 6. *Common turbine models and changes necessary for each to manage up to 20% hydrogen blend.*

4.3.D Task 3 Conclusion: Because turbine models vary and each unit has a unique repair and refurbishment history this analysis concludes that for any project considering utilizing a blended fuel gas, a Tier 2 Turbine study should be conducted by the turbine manufacturer. Turbines are able to burn blended fuel gas, but the cost to do so will vary.

4.4 Task 4 – Hydrogen Blending (Reciprocating)

4.4.A Description: In contrast to the overhaul analysis performed on the turbine engines, the reciprocating engine testing included field tests to validate that hydrogen could safely be blended into the fuel gas stream. To study engine response, the decision was made to study up to 30% hydrogen fuel blend. During the field test, we measured combustion stability and exhaust emissions. The test site was selected for its importance to pipeline flow, which resulted in the compressor running at full 100% load (torque) often.

4.4.D Task 4 Topic Specific Conclusions: The study determined that a hydrogen blend was beneficial to all tested metrics, except NOx emissions. This improvement increased with higher hydrogen concentrations, and preserved performance when the engine was throttled below 100% load. If compressor engines are converted to hydrogen, those which frequently operate at less than 100% load should be converted first.

The counterpoint to these across-the-board improvements was NOx emissions. If these increase too much they will exceed the allowable environmental limit. There are adjustments to reciprocating engines and bolt-on emissions control technologies which can reduce NOx. These may be worth further study as they could counteract the only discovered downside to blending hydrogen into a reciprocating engine's fuel.

This study also discovered that a means to introduce more oxygen to the system could be beneficial because engine performance increased at high hydrogen blends when the ambient air cooled 30°F degrees, leading to greater oxygen density.

6. DEVELOPMENT PLAN

The Williams Wyoming Hydrogen Hub has established a strong platform for our commercial and project development teams to expand into the hydrogen industry in the state of Wyoming. The data uncovered throughout the process of this study has provided additional clarity to Williams path forward to the establishment of a low-carbon hydrogen hub. The below development plan summary will more fully detail our view of the results of this study through the lens of a forward-looking business development opportunity. This summary will also address the challenges and tailwinds facing the development of a hydrogen hub in Wyoming, which will need to achieve all of the following:

A. Proximity to available water with acceptable quality (which this study has identified;)

B. Proximity to some localized demand in order to provide an anchor for hydrogen production (which this study has identified); and

C. The ability to drive down the production costs of hydrogen in order to make it an economic energy solution for consumers in Wyoming and neighboring regions (which this study has provided clarification to help focus our efforts).

6.1 Challenges to Green Hydrogen Production

Williams' original focus of producing hydrogen through electrolysis for transmission as a blended stream via existing natural gas pipelines may still be a viable path forward. However, there are hurdles to address prior to production of "green" hydrogen becoming economically viable. These must all be addressed before in-depth engineering, hydraulic studies, and operational risk assessments can be done to support the concept of blended pipeline transmission.

The most entrenched challenges to green hydrogen generation and midstream transportation in Wyoming, in order of importance to the success of a commercial project, are as follows:

6.1.A Energy Costs: Electrolytic hydrogen production is extremely energy intensive, and the largest variable expense to any green hydrogen project will be the electricity used to power the electrolyzer facility and balance of plant. Regulated market pricing for renewable power in the Wyoming market would lead to levelized costs of hydrogen which are not currently supported by regional market demand price points. There are opportunities for premium price demand in neighboring state markets, but even those states with imposed regulations for carbon abatements are unable to support the cost of green hydrogen generated in the Wyoming market at this time.

6.1.B Renewable Energy Availability: Understanding that market rate power was not price favorable to hydrogen production economics, Williams' initial approach to solving the power cost challenges was to partner to develop greenfield renewables in order to power the green hydrogen production facilities. Limiting factors were quickly apparent with this path forward, as forecasted development times in the region were anywhere from 7-10 years, with that power still required to be delivered to the existing grid and then delivered at regulated rates as above.

6.2 Expanding from "Green" to "Clean"

Blue hydrogen offers solutions for net carbon reductions via capturing CO_2 emissions of natural gas upstream from combustion and can work to reduce emissions in the state of Wyoming, as well as those of the ultimate demand point of the produced low carbon hydrogen. Additionally, due to feedstocks to this process being lower cost than renewable energy, the levelized cost of the produced hydrogen will be more in line with market demand.

6.2.A Carbon Capture and Sequestration: Carbon capture and sequestration (CCS) capabilities are a requirement in order to decarbonize existing natural gas feedstock hydrogen ("gray" hydrogen) production facilities by enabling the permanent capture and storage of associated carbon emissions from those processes. Williams has partnered with the University of Wyoming to submit for federal funding under the Department of Energy's CarbonSAFE program in order to develop a test well which would be used to determine the viability of that geology for use in carbon sequestration.

6.2.B Blue Hydrogen Developments: If carbon sequestration is proven viable in the Wamsutter area, the emissions from Williams Echo Springs gas plant may be enough to support the initial development of a sequestration hub. This would provide a platform to expand into blue hydrogen production. Williams would have natural gas supply, pipeline right-of-way, water availability, and most importantly, carbon sequestration capabilities all overlaid in a central location in Wyoming. The combination of these advantages would be the key to unlocking a low-carbon hydrogen hub in the region.

Assuming the challenges around carbon sequestration can be overcome, blue hydrogen offers lower cost approaches to a low-carbon hydrogen molecule produced in the region, which provides additional flexibility in the transportation of that production. By producing a lower cost, low-carbon intensity hydrogen in the Wamsutter region, Williams would have the ability to develop new pipelines for the purpose of purity hydrogen, rather than the original target of blending to existing gas transmission pipelines.

6.3 Path Forward

The hopeful outcome for those projects selected by the Wyoming Energy Authority under this grant phase was to "get something off the whiteboard and into the field." In that spirit, Williams is very excited that we have a number of projects that are set to move into development phases as a direct result from this funding which will spur incremental project origination in the region.

6.3.A Echo Springs CCS Project: As mentioned above, Williams is focused on developing capabilities for CCS in the Wamsutter region of Wyoming, and we are working to progress a full value chain project using the amine gas processing emissions from our Echo Springs gas plant to commercially backstop the development of a sequestration hub in the region.

Williams has partnered with the University of Wyoming to submit this project to the Department of Energy's CarbonSAFE Program under Phase II to demonstrate that the geology surrounding Echo Springs is viable and

safe for permanent geological carbon sequestration. Our current target (should the project be selected for award) would be to begin drilling a test well in the region in 1Q2024.

Should this project continue to see success, it will directly add value to cost effective hydrogen production in the region by enabling the production of blue hydrogen with the option for carbon capture and sequestration from the steam methane reformation or auto-thermal reformation process used to generate hydrogen from low-carbon intensity natural gas.

6.3.B Hydrogen as Fuel: This study has clearly demonstrated that the utilization of hydrogen for fuel in reciprocating and turbine compression is an excellent path to decarbonization of methane and CO_2 emissions. As such, we see the demand for locally produced, locally consumed hydrogen as fuel for multiple off takers in the gas gathering, processing, and transmission industry of Wyoming. We are currently working on projects which would produce hydrogen for onsite consumption at compressor facilities to reduce our own emissions, as well as to continue multiple demonstration platforms for the efficacy of hydrogen across our asset footprint.

6.3.C Water Availability for Hydrogen Production: Our strong partnership with the University of Wyoming has also led to Williams partnering with their School of Energy Resources in another application for DOE funding, specifically to research the efficiency of thermal desalination followed by high temperature hydrogen generation in Wyoming. This exciting study will utilize Williams' land and produced water in the Wamsutter region to perform a field demonstration of thermal desalination, which has the potential to provide additional options for water in the production of low-carbon hydrogen in the region. We believe this is an excellent next step to the water availability study completed in this project, as it will enable our teams to expand the regions where hydrogen production may be operationally viable.

In the two-year field demonstration project, the desalinated water will be utilized in steam methane reformation for hydrogen production, which will give Williams access to locally produced, small-scale hydrogen production for utilization in additional studies, including compression fuel and pipeline blending. If this platform proves effective, it also provides additional tailwinds to our efforts for carbon sequestration in the area, as the emissions from the hydrogen productions could be captured and permanently sequestered to further reduce the carbon intensity, especially if the SMR unit were upgraded to ATR.

6.3.D Continued Technical Research: Williams continues to engage with organizations that are actively pursuing research in creation, transportation, and storage of hydrogen and carbon dioxide. Williams is developing the guidance document for hydrogen infrastructure as part of the National Petroleum Council (NPC) while serving as a leader in the industry through organizations like INGAA, with our Executive Vice President of Corporate Strategic Development as Chairman of the Board. These organizations are designed to guide public policy and create documentation to guide the owner and operators of the US infrastructure in managing the hydrogen energy transition. Williams also holds the position of Chair of the Pipeline Research Council International – Emerging Fuels Institute (PRCI-EFI), an organization that is tasked with producing the innovative research required to safely manage the nascent hydrogen economy. The PRCI-EFI currently has 34 active projects researching pipeline integrity in the following areas:

- Measurement
- Inspection and Maintenance
- Network and Design Guidelines
- Safety

- Compression
- Underground Storage

The PRCI-EFI will be producing an initial technical guidance document for hydrogen management in Q1 2025 with subsequent modifications designed to reduce the conservative assumptions required as new refined information is developed. This document should allow further development of the hydrogen network more economically than current guidance allows.

7. ACKNOWLEDGEMENTS

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FINAL TECHNICAL REPORT

1. ABSTRACT

This report examines three potential hurdles in creating a hydrogen hub in the Southwest Wyoming area. The three topics researched were 1) the availability of water for the formation of hydrogen, 2) the effects of hydrogen on the metallurgy of pipeline material, and 3) the ability to blend hydrogen into the fuel gas stream of turbines and reciprocating engines.

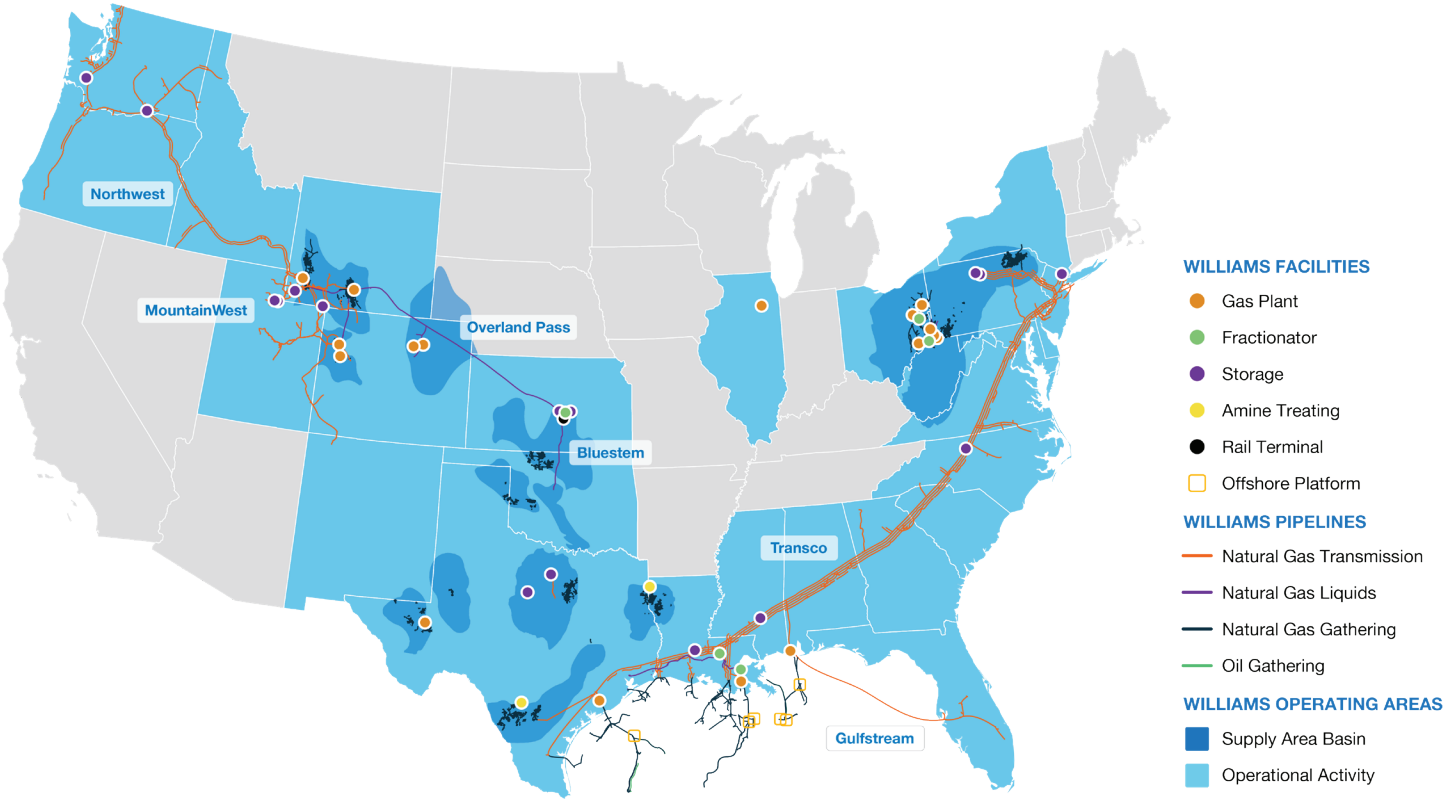
The project team employed a variety of sources to perform this research including using: the University of Wyoming for the water availability and processing, compressor vendors for the engine testing and analysis, and a third-party testing facility for the pipe materials testing. The results were generally positive with the identification of several water sources that could be used to create hydrogen and the verification that the engines could operate at hydrogen blends up to 20%. Some findings will require further research before hydrogen pipeline transportation can be realized including the reconciliation of increased Nitrous Oxides (NOx) as a result of hydrogen blending and the pipe material toughness reduction due to hydrogen propagation into the pipe metal.

Williams is continuing to perform research and develop projects to further progress the development of a hydrogen and carbon capture hub in the Southwest Wyoming area. We continue to believe that Wyoming is uniquely situated due to its location and geological formations to play a significant role in the energy production of the Western United States.

2. INTRODUCTION

As the world demands reliable, low-cost, and low-carbon energy, The Williams Companies, Inc. (Williams) (NYSE: WMB) will be there providing the best transport, storage, and delivery solutions to reliably fuel the clean energy economy and explore long-term innovations needed to transition to a sustainable energy future. Headquartered in Tulsa, Oklahoma, Williams is an industry-leading, publicly traded, Fortune 500 company with over 5,000 employees across the United States (U.S.).

With a focus on transporting natural gas, our operations span much of the value chain, including gathering, processing, interstate transportation, storage, wholesale marketing and trading of natural gas and natural gas liquids (NGL). With major positions in 14 top U.S. supply basins, Williams connects the best supplies with growing demand for clean energy. Williams owns and operates more than 33,000 miles of pipelines system-wide — including Transco, the nation's largest volume pipeline — and handles approximately one third of the natural gas in the U.S. Our assets span 25 states, encompassing the Gulf of Mexico, Rockies, Pacific Northwest, and Eastern Seaboard regions.



Due to Williams' broad footprint across the United States, we are in a unique position to provide clean and affordable energy to some of the largest markets in North America. One of the primary assets in Williams' portfolio is the Northwest Pipeline that provides natural gas from Utah, Colorado, and Wyoming to the markets in the Pacific Northwest. Williams has a strong presence in Wyoming which makes the state a natural partner as we supply the energy needs of our customers. As our customers' needs evolve into lower carbon energy demand, Williams and the State of Wyoming have the ability to meet these changing needs.

Williams early on recognized the transitioning landscape of energy demand and actively began making the changes to meet these future needs. Williams was the first North American midstream company to commit to actionable climate targets. As a result, we have reduced our company-wide Scope 1 and 2 GHG emissions by 43% since 2005, making considerable progress toward our 2030 goal of a 56% reduction. This progress puts us on a positive trajectory toward achieving net zero GHG emissions by 2050. Currently, we are strategically focused on reducing Scope 1 and 2 emissions, but we continue to have ongoing conversations with internal and external stakeholders regarding the role of Scope 3 emissions for midstream pipeline companies.

In 2021, the University of Wyoming's School of Energy Resources (UWyo-SER) and Williams partnered to develop a proposal in response to a request for proposals from the Wyoming Energy Authority to develop pilot projects demonstrating green and blue hydrogen production and use. In 2022, the University of Wyoming and Williams were granted a nearly $1 million grant with Williams contributing another $200,000 to close the technical gaps to make these projects a reality. A quote from the original proposal encapsulates the purpose of this study, "The feasibility study proposed here will reduce the risk… [which currently prevents Williams or a similar company from producing hydrogen] by achieving two key goals: first, ensure the existing natural gas infrastructure is compatible or adaptable to transporting hydrogen; and second, better understand water resources and water upgrading options in Wyoming."

As a result of this proposal the following Project Purpose and Description was developed in Exhibit A of the Funding Agreement.

3. OBJECTIVES

Recipient will conduct a feasibility study to evaluate the water access and compatibility as well as asset integrity in support of green hydrogen production and transport in the vicinity of Wamsutter and Opal, Wyoming. The proposed feasibility study will evaluate two key areas:

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Williams worked with subawardees, vendors, and subcontractors to produce four studies, identified by task list, which together would inform a decision on how to generate, transport, blend, combust, or otherwise use hydrogen to reduce primary and secondary emissions from midstream pipeline operations. The results of those vendors' and subawardees' four studies are summarized below.

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As this project focused on production of hydrogen by electrolysis, the water used as a reagent must be especially high purity. This would pose a challenge in any environment, but in arid Wyoming finding a water source was expected to be especially difficult. This study accordingly had to answer two questions: First, what water sources were legally available for consideration? Second, what would the cost be to treat that water source to the extreme level of purity needed for electrolysis?

4.1.B Activities: The legal analysis considered Wyoming law, consulted with the Wyoming State Engineer's Office (SEO), and tracked the annual regulation of selected water rights in the Greater Green River Basin.

The analysis of treatment costs collected water samples from oil and gas operations in the Greater Green River Basin, and historic water quality data from Fontenelle Reservoir. The chemistry revealed from these samples and data were then fed into UWyo-SER's Center of Excellence in Produced Water Management's (CEPWM) treatment train modeling program. This model produces a sequence of commercially available treatments that achieve a specified water quality output.

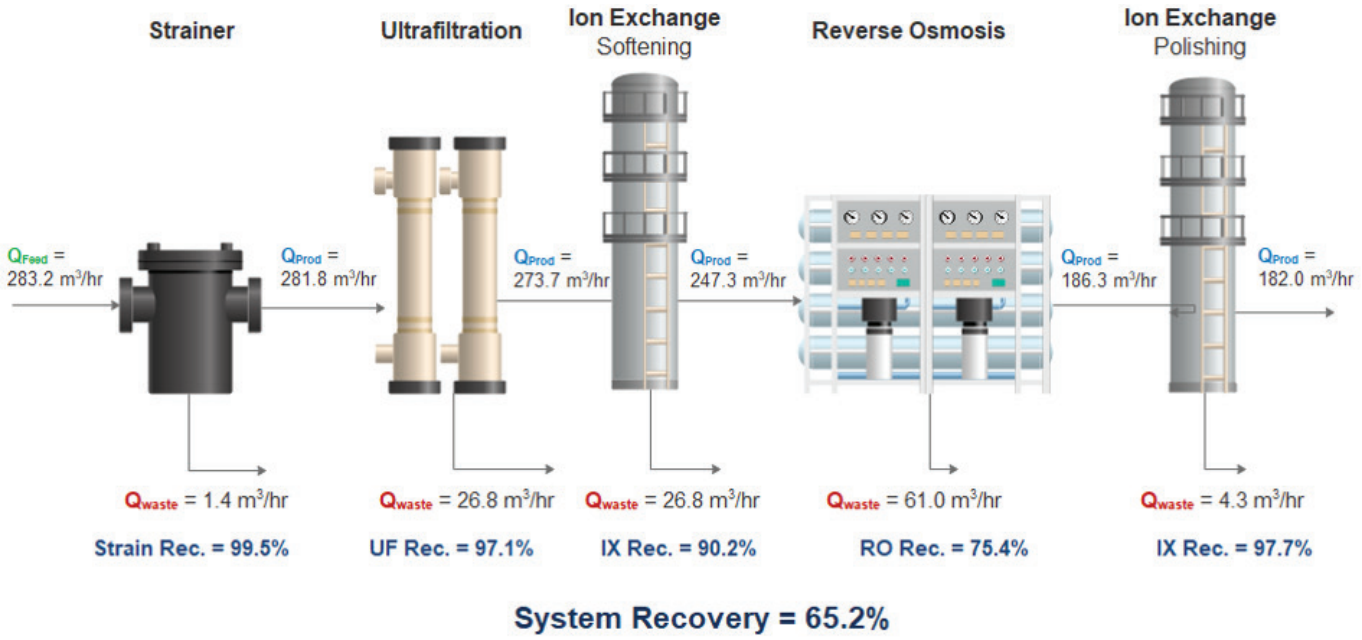

Figure 1. *The treatment train considered for producing ultrapure water from a water associated with Coal Bed Methane(CBM). The recovery of a system describes what fraction of the input water must be rejected in the course of purifying the remainder. Rejection of some water is necessary to remove the salt from the process.*

4.1.C Findings: The legal analysis[1] found that most water in Wyoming is subject to annual regulation, but there is little to no annual regulation of water in the Green River Basin. This means that a newly acquired water right (called a junior right) in the Green River Basin has a reasonable chance of being utilized for many years. Fontenelle Reservoir has significant water volumes held by the US Bureau of Reclamation, which have historically been contracted to industrial interests such as Jim Bridger Power Station at Point of Rocks, Wyoming. Access to that water would require Federal consent and a National Environmental Policy Act (NEPA) review.

The analysis concluded that as long as: 1) the water produced associated with oil and gas activities is necessary, reasonable, and proportional to the extracted oil and gas, and 2) that the produced water is normally removed from a site for disposal elsewhere, then the way that water is disposed is unaffected by water rights. Although no case in Wyoming has confirmed this, the choice of disposal can include treatment for beneficial use, such as hydrogen production, and the water is likely owned by the entity treating it. This prediction follows the same line of reasoning as spelled out in Texas water law (Texas Natural Resource Code §122.002) and led to choosing the sample collection sites indicated above.

The water treatment analysis found that the water in the traditional oil and gas field was moderately salty, a Coal Bed Methane (CBM) operation was slightly salty, and the water in Fontanelle Reservoir was fresh. The capital and operating costs to treat these waters were calculated with the assumptions specified in the full technical report. Treating an initially saltier water or treating to a higher purity increases costs. However, the details of a water's chemistry nuance this rule. The presence of (bi)carbonate requires the addition of acid to "burn" it off, and silica can irreversibly foul a system, either of these cases can cause these ions to have a disproportional effect on costs.

[1] The information provided in this document does not, and is not intended to, constitute legal advice. No person should act, or refrain from acting, on the basis of any information contained in this document without first seeking legal advice from their own legal counsel. Therefore, all liability with respect to actions taken or not taken based on the contents of this document are expressly disclaimed. Use of the information contained in this document does not create an attorney-client relationship between anyone, including but not limited to, the reader, the author, or any entities discussed herein. The views expressed in this document are those of the individual authors, within their individual capacities, and do not necessarily reflect the views of their respective employers.

4.1.D Task 1 Conclusion: Water is available in the Green River Basin through three paths. If a group is willing to invest significant time, and has a use which would pass NEPA, then Fontanelle Reservoir can be used to supply ultrapure water at very low cost. If a group is willing to invest more significantly and tolerate modest legal uncertainty, then produced water waste can be disposed through treatment and hydrogen generation. And lastly, if a group is willing to risk being among the first water rights cut, then it is possible to acquire a junior water right in the Green River Basin. Water is a deeply emotional issue in the arid west, and those intense feelings are reflected in the regulatory regime. It is possible to meet demands for hydrogen production, although not without risk and cost.

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1. hydrogen may cause embrittlement of pipe walls which leads to fractures when the pipe is deformed during normal operation, and

2. hydrogen possesses the ability to penetrate small linear defects or material imperfections which can accelerate fatigue crack growth.

These two measured factors are used to help determine the probability of failure. If these two risks remain manageable, there is potential for simple hydrogen blending in existing vintage pipelines. The following is a list of some of the defect types that may be affected by hydrogen introduction: Stress Corrosion Cracking, hard spots, wrinkle bends, planar defects, cracks, dents, laminations, corrosion (uniform and localized). The Pipeline Research Council International (PRCI) is currently studying the anticipated effects of hydrogen blending on each of these defect types as each will pose unique challenges.

4.2.B Activities: Testing was done on a segment of vintage X52 pipe with a 22-inch diameter and a 1/4 –inch wall thickness. This pipe is typical for western interstate pipelines. Two tests were conducted on this segment of pipe. The first test was a fracture toughness test and the second was a fatigue crack growth rate test. The variable changed in both tests was the blended gas that the pipe sample was exposed to. This included a control sample of plain laboratory air, and 4 hydrogen-nitrogen blends ranging from 0.1% to 20%. Testing in air was performed at ambient pressure whereas hydrogen tests were performed at 850 psi in an autoclave.

Fracture toughness testing followed ASTM standards. The instantaneous crack length was then measured. Following these tests each specimen was fatigued to failure to allow for more rigorous measurements of the pre-crack and final-crack profiles. This test measures pipe response in the presence of hydrogen to the fatigue caused by internal pressure fluctuations which are a normal part of daily pipeline operations.

Fatigue crack growth rate testing also followed ASTM standards. This test simulates the wear caused by passive exposure to hydrogen without an aggravating mechanical stress.

4.2.C Findings: In the fatigue crack growth (FCG) testing, no significant difference in behavior is noted between 1% H_2 and laboratory ambient air. Although testing in hydrogen was evaluated at 1 Hz, this frequency may be too aggressive at such high delta K (change in stress intensity factor K) and Kmax. Similar to toughness testing, the crack growth rates associated with these relatively high DKs may minimize hydrogen diffusion to the moving crack tip, thereby reducing the effects of hydrogen on the resulting FCG behavior. Analogous to the K-rate study for fracture toughness, a frequency scan to determine an appropriate FCG test frequency was not performed under this project. It is worth noting that testing at significantly lower DKs and/or lower test frequencies would result in excessive test durations (e.g., in excess of 6 months at 0.1 Hz). These results align with similar work performed at Sandia National Labs and will help Williams demonstrate, through Engineering Critical Assessments (ECA), that fatigue crack growth, even in hydrogen blended scenarios, will generally be manageable.

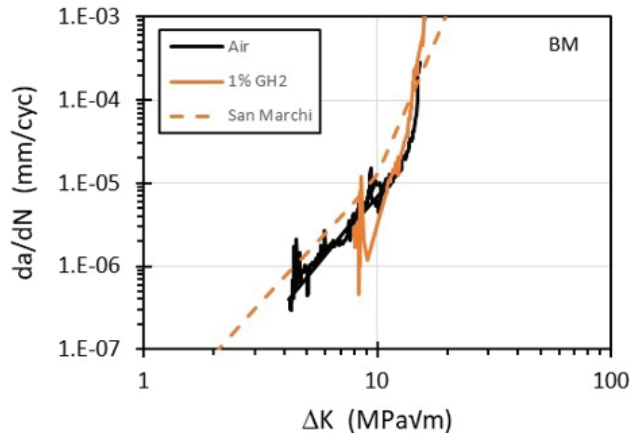


Figure 2. *No appreciable difference between air and 1% hydrogen on base metal.*

As can be seen in Figure 3, similar work performed by Sandia National Labs shows that all tested materials follow a similar curve regardless of the material being analyzed. Since Williams operates their pipelines on the lower end of the stress intensity factor, the difference in the hydrogen and air (lower dotted line) are negligible. These test results further validate that the fatigue crack growth rate will have very little effect on the operation and maintenance of existing pipelines as long as the pipelines are operated with low cycles and the pipelines are free of existing defects.

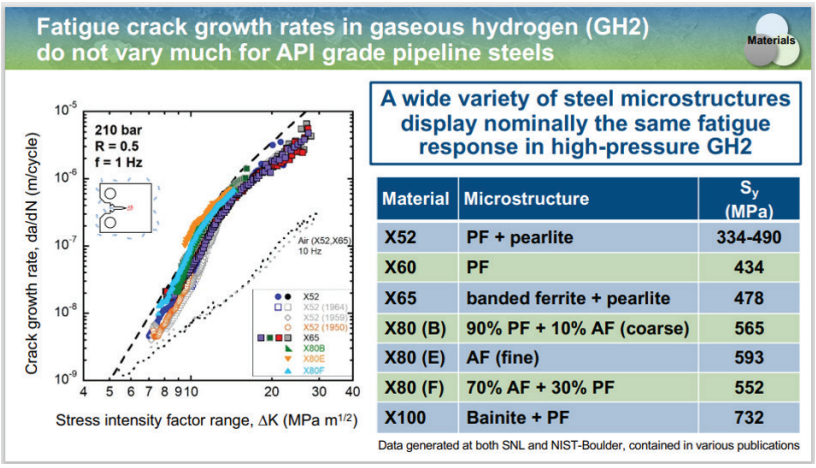


Figure 3. *Fatigue Crack Growth rates of various steels in Gaseous Hydrogen, reproduced from San Marchi and Ronevich 2022 (https://www.osti.gov/biblio/1871634).*

For the toughness testing exercise, the initial plan was to assess the pipeline material samples at partial pressures that would equate to 1%, 5% and 10% hydrogen. However, after the original plans were laid out, Sandia National Labs produced data (https://www.osti.gov/biblio/1871634) that showed that 1% hydrogen produced fracture toughness reductions of -22% to -25%, similar to 10% and 100% hydrogen tests. While 10% and 100% toughness reductions were slightly larger than the 1% sample, the majority of the toughness reductions occurred between 0% and 1%.

Due to the availability of this new information, Williams decided to assess the material at 0.25%, 0.5% and 1.0% hydrogen concentrations to determine the lowest percentage of hydrogen that could be blended without appreciable toughness reductions. The test results show that at even 0.25% hydrogen concentrations, there is a significant negative effect on the toughness of the pipe material. At this point, the lower limit of when hydrogen can be blended without significantly changing the material toughness is still unknown.

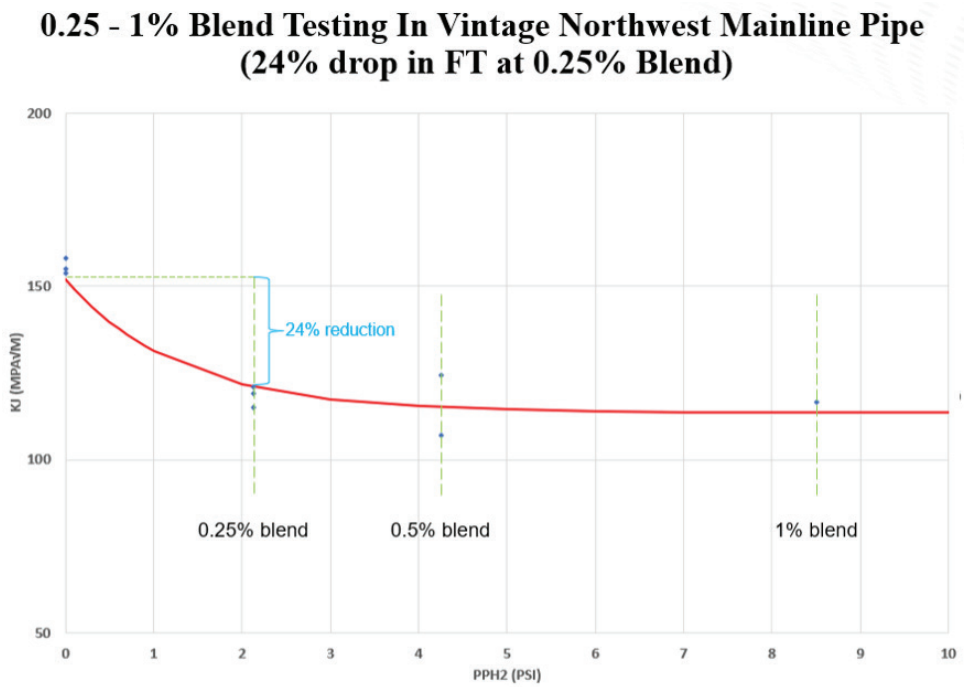


Figure 4. *Fracture Resistance vs. Hydrogen Partial Pressure*

The tests confirmed that hydrogen diffuses to the crack tip where its embrittling effect is especially detrimental. The study also showed that the toughness decreases with decreasing load rate resulting in a~24% reduction in toughness regardless of its concentration.

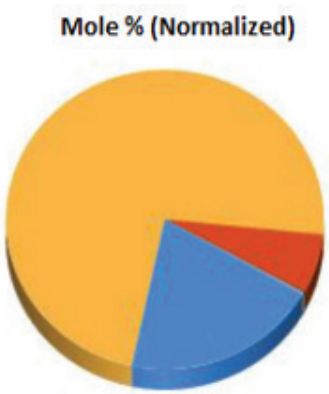
4.2.D Task 2 Conclusion: While hydrogen negatively affects both fatigue crack growth rate and toughness, fatigue crack growth will generally not be a major problem due to the relatively consistent pressures that Williams maintains in their pipelines. Reduced toughness is a concern at all but de minimis hydrogen blends. Moving forward, Williams will conduct an ECA to mitigate risk should a specific opportunity present itself to introduce hydrogen into our natural gas infrastructure. Through an ECA process, fatigue and toughness will be studied on a case-by-case basis using the same type of testing as SwRI performed for this effort. This will allow Williams to understand the changes to the fatigue characteristics in a specific segment of our pipeline network. The ECA will also assist in the creation of specific risk profiles for the different defect types that exist in a specific segment of the pipeline network. The testing data suggests that a hydrogen blend may be manageable in legacy pipes.

However, the flowrate and/or pressure may need to be decreased, and/or alternatively baseline inspections and re-assessments may need to be more frequent.

4.3 Task 3 – Hydrogen Blending (Turbines)

4.3.A Description: In natural gas pipeline transportation, initial compression is performed by turbines which currently run on natural gas. To reduce the CO_2 emissions of these turbines there are three main options: their exhaust could be rerouted to the plant's separation equipment, a new dedicated CO_2 capture system could be attached to the exhaust, or their fuel could be switched to hydrogen (or a hydrogen blend). This study considered the last option of fuel switching because that option can eliminate CO_2 emissions entirely, whereas the others only approach total elimination (~95%) of CO_2 emissions.

4.3.B Activities: The turbine study was conducted by looking at each of the subsystems within a turbine package and determining each subsystem would be able to function with hydrogen fuel (up to 20%). If the subsystem would not natively function, sometimes a simple change of a single sensor or software update would make it compatible. In other cases, the subsystem would need a full replacement or extensive changes at the level of a full overhaul. These minor or major changes were priced out and normalized as shown in Figure 6. This hydrogen suitability study identified the potential modifications required to operate with hydrogen-enriched natural gas in seven common turbine models, albeit with unique maintenance histories.



20% H_2 Composition

Component	% Mole	% Weight
Hydrogen(H2)	20.00	2.84
Methane(CH4)	73.30	82.90
Ethane(C2H6)	6.45	13.67
Propane(C3H8)	0.08	0.25
Nitrogen(N2)	0.17	0.34

Figure 5. *Pie chart showing the composition of an input fuel gas. The 20% hydrogen blend described here is by mole% not by mass.*

4.3.C Findings: The study revealed the majority of older turbines would require an extensive overhaul to manage concentrations greater than 4% hydrogen. The two newest turbine models studied would be suitable for a 20% hydrogen blend with only minor changes. The hydrogen incompatibility frequently comes from: valves, start systems, fuel gas filters, and the sensors which monitor the combustion to autotune the turbine's settings.

Turbine Model	Taurus 70	Centaur 50	Taurus 60	Mars 90	Centaur 40	Titan 130	Mars 100
Year unit was shipped	2001	2001	1992	1983	2006	2009	2009
Engine between 4% and 10% H2	Overhaul	Overhaul	Overhaul	Overhaul	Overhaul	Suitable	Suitable
Engine between 10% and 20% H2	Overhaul	Overhaul	Overhaul	Overhaul	Overhaul	Suitable	Suitable
Control system	Replace	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
HMI	Replace	Suitable	Suitable	Suitable	Replace	Replace	Replace
Package fuel system	Replace	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade
Start System	Replace	Replace	Replace	Suitable	Replace	Suitable	Suitable
Guide vane	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
Bleed valve	Replace	Suitable	Suitable	Suitable	Suitable	Suitable	Suitable
BAM	Replace	Replace	Suitable	Replace	Replace	Replace	Replace
Gas fuel off skid system	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade	Minor Upgrade

Orange - Overhaul or Replace Minor Upgrade Required Suitable for blended fuel gas service

Figure 6. *Common turbine models and changes necessary for each to manage up to 20% hydrogen blend.*

4.3.D Task 3 Conclusion: Because turbine models vary and each unit has a unique repair and refurbishment history this analysis concludes that for any project considering utilizing a blended fuel gas, a Tier 2 Turbine study should be conducted by the turbine manufacturer. Turbines are able to burn blended fuel gas, but the cost to do so will vary.

4.4 Task 4 – Hydrogen Blending (Reciprocating)

4.4.A Description: To meet climate commitments, Williams needs to reduce CO_2 emissions from the compressor stations that move natural gas along pipelines. One method of accomplishing this is to replace the pure natural gas in the fuel with a hydrogen blend. Engines converted to run on hydrogen face two risks: some pollutants may increase, and the engine combustion may become unstable. To study engine response, the decision was made to study up to 30% hydrogen fuel blend in a field test. During the field test, we measured combustion stability and exhaust emissions. The test site was selected for its importance to pipeline flow, which resulted in the compressor running at full 100% load (torque) often.

4.4.B Activities: A series of 38 tests were performed in which hydrogen blend %, ignition timing, and air/fuel ratio were independently varied and their effect on the compressor measured. In addition to these controlled experiments, a natural experiment occurred when the ambient temperature dropped by 30°F on the last day, which increased air density. The team performed 20 additional tests to take advantage of the new conditions. The field test used a blending skid to introduce hydrogen to an existing compressor station. Hydrogen was introduced as a blend with natural gas between 0-30% hydrogen concentrations. A pressure monitoring system was installed in each of the six cylinders to record a position versus pressure graph and the position of each cylinder. Pollutants

were measured by continuous emissions monitoring. Hydrogen was supplied via a tube trailer. Because emissions can change as the compressor throttles within its working range of 70%-100% load multiple tests were performed within that range.

4.4.C Findings: As hydrogen concentration increases in the fuel blend this leads to a decrease of all measured pollutants with the exception of NOx. The "no-hydrogen" results also show that emission rates were dependent upon load (torque). At full load, the compression engine burns cleaner than at 70%. Running at full load is especially beneficial for some emissions like CH_4 which pass a cylinder unburned at lower loads. Including hydrogen in the fuel can improve emissions while operating below full load, and the effect is greater the more hydrogen is present in the fuel.

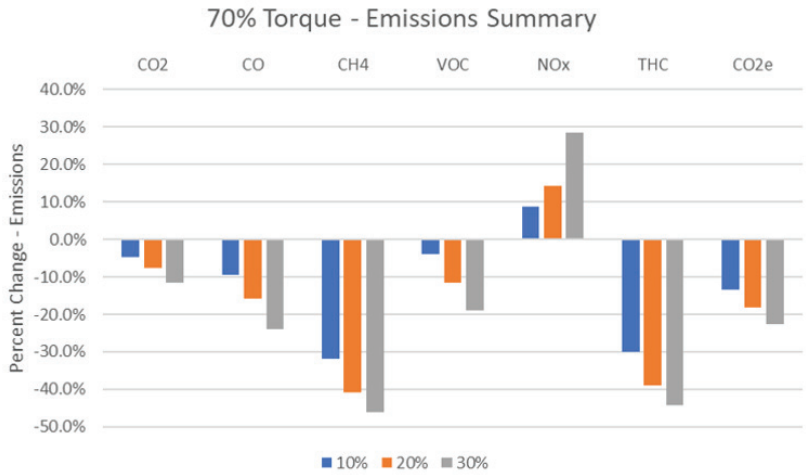


Figure 7. *Bar graph showing the percentage decrease/increase of pollutants*

The only exception to this improvement in emissions was NOx which increased with increasing hydrogen concentrations. The size of this increase was from 916 to 1140 parts per million volume dry (ppmvd) NOx within the exhaust emissions at 15% O_2. This NOx increase is probably a result of slightly higher combustion temperatures when burning hydrogen rather than methane.

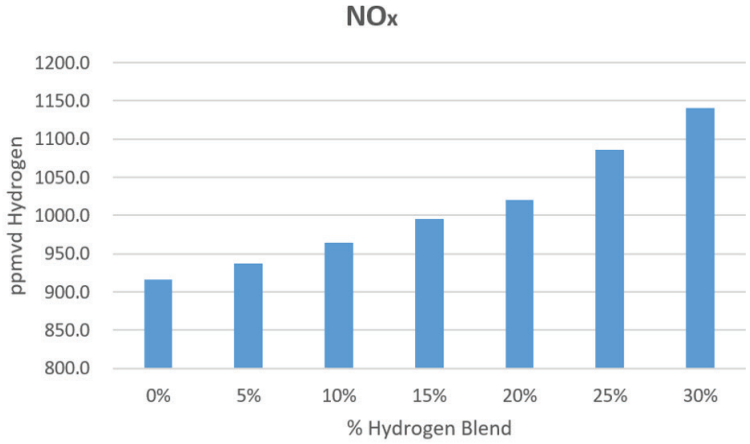


Figure 8. *Bar graph displaying the percentage increase of nitrogen oxide emissions as H_2 composition increases.*

Measurements from the cylinder pressure and crank angle monitoring system allowed study of hydrogen's effect on engine stability. The results show that higher hydrogen compositions lead to greater engine stability, especially at lower loads. Near 100% load hydrogen only marginally improves stability because the engine is optimized for full load.

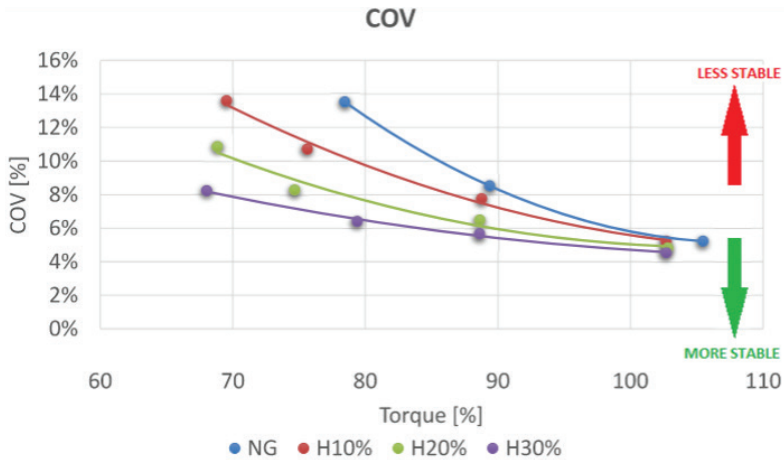


Figure 9. *Trendline chart displaying that an increased hydrogen blend percentage increases stability. The increased stability is typically most noticeable at lower torques, as stability tends to even out near 100% torque.*

4.4.D Task 4 Conclusions: The study determined that a hydrogen blend was beneficial to all tested metrics, except NOx emissions. This improvement increased with higher hydrogen concentrations, and preserved performance when the engine was throttled below 100% load. If compressor engines are converted to hydrogen, those which frequently operate at less than 100% load should be converted first.

The counterpoint to these across-the-board improvements was NOx emissions. If these emissions increase too much they will exceed the allowable environmental limit. There are adjustments to reciprocating engines and bolt-on emissions control technologies which can reduce NOx. These may be worth further study as they could counteract the only discovered downside to blending hydrogen into a reciprocating engine's fuel.

This study also discovered that a means to introduce more oxygen to the system could be beneficial because engine performance increased at high hydrogen blends when the ambient air cooled 30°F degrees, leading to greater oxygen density.

5. CONCLUSIONS AND RECOMMENDATIONS

This investigation focused on three specific topics. The first being water availability in Wyoming and the quality or purity of that water. Determining both the availability of water as well as the quality of that water would go a long way to support the establishment of a hydrogen generating plant. The second topic was to investigate the effect of hydrogen on material integrity of existing vintage pipelines. The final topic was to determine the effect on the combustion characteristics when utilizing a blended hydrogen and methane fuel gas in both reciprocating engines as well as turbine engines.

The water research confirmed that while surface water availability is limited in Wyoming, produced water associated with oil and gas activities appears to be readily available. The produced water examined does not require significant purification which makes it a potential source in a hydrogen application. The water volumes represented in this study are adequate to support the generation of hydrogen utilizing electrolysis or more conventionally, steam methane reformation (SMR). This study also revealed junior water rights in some areas and NEPA-gated reservoirs as alternatives if an actor were willing to accept the legal and regulatory risks associated with those.

The next aspect of the grant investigation was the materials testing of vintage pipe in a blended hydrogen atmosphere. The SwRI scope of work was developed to address low volume percentage blending (but at full transmission pressures) that might be representative of early hydrogen blending opportunities. The low volume percentage blending protocols also filled in data gaps past studies had left unanswered.

The materials selected for the SwRI testing were representative of a large percentage of vintage materials in Williams' system in Wyoming. The study focused on fatigue crack growth rates and fracture resistance. These two attributes are key variables in managing pipeline defects such as cracking, corrosion, dents and all other defects affected by material properties.

At high-level, the test results show that even a small amount of hydrogen will affect the toughness of the material. The fact that a small amount of hydrogen will affect the fracture resistance of pipeline materials means that vintage pipelines will need to be inspected for injurious defects prior to introduction of hydrogen. General mitigation and preventative maintenance recommendations cannot be made at this time. The effect on the specific kinds of pipe defects will warrant conducting an ECA on a project-by-project basis. This approach will allow for the specific attributes of the affected pipe to be evaluated and specific mitigation strategies to be explored and eventually executed.

PHMSA will expect pipeline operators to use this knowledge to safely operate systems with hydrogen blending. Higher operating and maintenance costs for assets where hydrogen is being blended should be expected.

The final aspect that we investigated was the effect on combustion systems when utilizing a blended hydrogen-methane fuel gas supply. The turbine units selected were evaluated in a desktop study by the turbine manufacturer. The study led to the conclusion that turbines in our fleet would in fact be able to utilize a blended fuel gas with minor modifications to the turbine packages. The modifications to the turbine packages would vary in cost. That cost variation would be a function of the age of the turbine itself and what updates to the turbine had already occurred over the life of the equipment.

Reciprocating combustion also proved capable of consuming hydrogen-methane blended fuel gas. The results achieved during the field study exceeded our expectations while utilizing 20% hydrogen by volume. Due to an encouraging performance of the reciprocating unit, the decision was made during the field testing to run the study up to a 30% hydrogen by volume blend. The engine performed well with a primary learning that for some reciprocating packages, a modification to install a turbocharger to increase the volume of oxygen may be necessary.

The only negative that we have identified in association with the combustion of hydrogen is that while CO_2 and all other studied emissions are improved utilizing a blended fuel gas, NOx emissions are degraded. This will require further decision making along with permit evaluation to determine whether hydrogen in a blended fuel gas capacity would equate to any net emissions improvement.

6. DEVELOPMENT PLAN

The Williams southwest Wyoming Hydrogen Hub has established a strong platform for our commercial and project development teams to expand into the hydrogen industry in the state of Wyoming. The data uncovered throughout the process of this study has provided additional clarity to Williams path forward to the establishment of a low-carbon hydrogen hub. The below development plan summary will more fully detail our view of the results of this study through the lens of a forward-looking business development opportunity. This summary will also address the challenges and tailwinds facing the development of a hydrogen hub in Wyoming, which will need to achieve all of the following:

A. Proximity to available water with acceptable quality (which this study has identified;)

B. Proximity to some localized demand in order to provide an anchor for hydrogen production (which this study has identified); and

C. The ability to drive down the production costs of hydrogen in order to make it an economic energy solution for consumers in Wyoming and neighboring regions (which this study has provided clarification to help focus our efforts).

The final metric above was identified as a result of this study, and Williams commercial efforts in this space have taken these learnings to contribute the following concepts which work to address how to achieve a lower hydrogen production cost, as discussed in the following sections. Williams' intention is to establish the operational and commercial capabilities to anchor a clean hydrogen economy by first driving down the levelized cost of hydrogen production. Once hydrogen solutions are able to be commercialized, then further steps can be taken to expand hydrogen to even lower emission production standards, including electrolytic. This staged approach is the most effective way to ensure that Wyoming remains at the forefront of the hydrogen production and transportation economy developing through the United States.

6.1 Challenges to Green Hydrogen Production

Williams' original focus of producing hydrogen through electrolysis for transmission as a blended stream via existing natural gas pipelines may still be a viable path forward. However, there are hurdles to address prior to production of green hydrogen becoming economically viable. These must all be addressed before in-depth engineering, hydraulic studies, and operational risk assessments can be done to support the concept of blended pipeline transmission.

The most entrenched challenges to green hydrogen generation and midstream transportation in Wyoming, in order of importance to the success of a commercial project, are as follows:

6.1.A Energy Costs: Electrolytic hydrogen production is extremely energy intensive, and the largest variable expense to any green hydrogen project will be the electricity used to power the electrolyzer facility and balance of plant. Regulated market pricing for renewable power in the Wyoming market would lead to levelized costs of hydrogen which are not currently supported by regional market demand price points. There are opportunities for premium price demand in neighboring state markets, but even those states with imposed regulations for carbon abatements are unable to support the cost of green hydrogen generated in the Wyoming market at this time.

6.1.B Renewable Energy Availability: Understanding that market rate power was not price favorable to hydrogen production economics, Williams' initial approach to solving the power cost challenges was to partner to develop brownfield or greenfield renewables in order to power the green hydrogen production facilities. Limiting factors were quickly apparent with this path forward, as forecasted development times in the region were anywhere from 7-10 years, with that power still required to be delivered to the existing grid and then delivered at regulated rates as above. This extended timeline would defer revenues associated with the hydrogen production to the extent that projects would become economic and demand for hydrogen would be exceedingly challenging to contract.

Additionally, in order to align with the findings of the water availability study, the best location for a production facility would be in the Wamsutter region. However, due to subprime capacity factors for solar and lengthy permitting requirements for wind in the region, the commercialization of renewable energy assets is a major

challenge by itself, even before the commercialization of a hydrogen production facility. Williams is continuing to research options for low carbon electricity in the area to power the different hydrogen options.

These two challenges are the guiding forces behind the position that blue hydrogen production should be the focus in the near term in order to drive down the levelized cost of hydrogen production, with the ultimate goal of expanding toward green hydrogen on a longer timeline as transportation is established, renewable energy becomes more abundant and price favorable, and electrolysis technology becomes less capital intensive.

6.2 Expanding from "Green" to "Clean"

These three challenges are the guiding forces behind the position that "blue" hydrogen production (that which is generated via steam methane reformation or autothermal reformation with carbon capture and sequestration) should be the focus in the near term in order to drive down the levelized cost of hydrogen production. Blue hydrogen offers solutions for net carbon reductions via capturing CO_2 emissions of natural gas upstream from combustion and can work to reduce emissions in the state of Wyoming, as well as those of the ultimate demand point of the produced low carbon hydrogen. Additionally, due to feedstocks for this process being lower cost than renewable energy, the levelized cost of the produced hydrogen will be more in line with market demand.

Once hydrogen transportation capabilities have been operationally established, renewable energy becomes more abundant and price favorable, and electrolysis technology becomes less capital intensive, then the longer-term shift to green hydrogen production will be economically viable in the State of Wyoming, albeit on a longer-term timeline.

In order for this expansion to the view of clean hydrogen production in the region, the following topics must first be deeply studied and understood:

6.2.A Carbon Capture and Sequestration: Carbon capture and sequestration (CCS) capabilities are a requirement in order to decarbonize existing natural gas feedstock hydrogen ("gray" hydrogen) production facilities by enabling the permanent capture and storage of associated carbon emissions from those processes. Williams has partnered with the University of Wyoming to submit for federal funding under the Department of Energy's CarbonSAFE program in order to develop a test well which would be used to determine the viability of that geology for use in carbon sequestration.

The combination of the University of Wyoming's excellent geology and research capabilities, paired with Williams' drive to execute commercial and decarbonization developments in the region, forge a natural synergistic relationship which is determined to unlock CCS in this region. Additionally, the Wyoming Energy Authority is working to support these efforts via their cost share matching for the University of Wyoming.

6.2.B Blue Hydrogen Developments: If carbon sequestration is proven viable in the Wamsutter area, the emissions from Williams Echo Springs gas plant may be enough to support the initial development of a sequestration hub. This would provide a platform to expand into blue hydrogen production. Williams would have natural gas supply, pipeline right-of-way, water availability, and most importantly, carbon sequestration capabilities all overlaid in a central location in Wyoming. The combination of these advantages would be the key to unlocking a low-carbon hydrogen hub in the region.

Assuming the challenges around carbon sequestration can be overcome, blue hydrogen offers lower cost approaches to a low-carbon hydrogen molecule produced in the region, which provides additional flexibility in the transportation of that production. By producing a lower cost, low-carbon intensity hydrogen in the Wamsutter

region, Williams would have the ability to develop new pipelines for the purpose of purity hydrogen, rather than the original target of blending to existing gas transmission pipelines.

6.3 Path Forward

The hopeful outcome for those projects selected by the Wyoming Energy Authority under this grant phase was to "get something off the whiteboard and into the field." In that spirit, Williams is very excited that we have a number of projects that are set to move into development phases as a direct result from this funding which will spur incremental project origination in the region.

6.3.A Echo Springs CCS Project: As mentioned above, Williams is focused on developing capabilities for CCS in the Wamsutter region of Wyoming, and we are working to progress a full value chain project using the amine gas processing emissions from our Echo Springs gas plant to commercially backstop the development of a sequestration hub in the region.

Williams has partnered with the University of Wyoming to submit this project to the Department of Energy's CarbonSAFE Program under Phase II to demonstrate that the geology surrounding Echo Springs is viable and safe for permanent geological carbon sequestration. Our current target (should the project be selected for award) would be to begin drilling a test well in the region in 1Q2024.

In its most successful form, this project will directly add value to cost effective hydrogen production in the region by enabling the production of blue hydrogen with the option for carbon capture and sequestration from the steam methane reformation or auto-thermal reformation process used to generate hydrogen from low-carbon intensity natural gas.

6.3.B Hydrogen as Fuel: This study has clearly demonstrated that the utilization of hydrogen for fuel in reciprocating and turbine compression is an excellent path to decarbonization of methane and CO_2 emissions. As such, we see the demand for locally produced, locally consumed hydrogen as fuel for multiple off takers in the gas gathering, processing, and transmission industry of Wyoming. We are currently working on projects which would produce hydrogen for onsite consumption at compressor facilities to reduce our own emissions, as well as to continue multiple demonstration platforms for the efficacy of hydrogen across our asset footprint.

6.3.C Water Availability for Hydrogen Production: Our strong partnership with the University of Wyoming has also led to Williams partnering with their School of Energy Resources in another application for DOE funding, specifically to research the efficiency of thermal desalination followed by high temperature hydrogen generation in Wyoming. This exciting study will utilize Williams' land and produced water in the Wamsutter region to perform a field demonstration of thermal desalination, which has the potential to provide additional options for water in the production of low-carbon hydrogen in the region. We believe this is an excellent next step to the water availability study completed in this project, as it will enable our teams to expand the regions where hydrogen production may be operationally viable.

In the two-year field demonstration project, the desalinated water will be utilized in steam methane reformation for hydrogen production, which will give Williams access to locally produced, small-scale hydrogen production for utilization in additional studies, including compression fuel and pipeline blending. If this platform proves effective, it also provides additional tailwinds to our efforts for carbon sequestration in the area, as the emissions from the hydrogen productions could be captured and permanently sequestered to further reduce the carbon intensity, especially if the SMR unit were upgraded to ATR.

6.3.D Continued Technical Research: Williams continues to engage with organizations that are actively pursuing research in creation, transportation, and storage of hydrogen and carbon dioxide. Williams is developing the guidance document for hydrogen infrastructure as part of the National Petroleum Council (NPC) while serving as a leader in the industry through organizations like INGAA, with our Executive Vice President of Corporate Strategic Development as Chairman of the Board. These organizations are designed to guide public policy and create documentation to guide the owner and operators of the US infrastructure in managing the hydrogen energy transition. Williams also holds the position of Chair of the Pipeline Research Council International – Emerging Fuels Institute (PRCI-EFI), an organization that is tasked with producing the innovative research required to safely manage the nascent hydrogen economy. The PRCI-EFI currently has 34 active projects researching pipeline integrity in the following areas:

- Measurement
- Inspection and Maintenance
- Network and Design Guidelines
- Safety
- Compression
- Underground Storage

The PRCI-EFI will be producing an initial technical guidance document for hydrogen management in Q1 2025 with subsequent modifications designed to reduce the conservative assumptions required as new refined information is developed. This document should allow further development of the hydrogen network more economically than current guidance allows.

7. ACKNOWLEDGEMENTS

University of Wyoming | School of Energy Resources

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Wyoming Energy Authority – Hydrogen Pilot Program

Williams Southwest Wyoming Hydrogen Hub Final Report

APPENDICES

Legacy Pipe Testing in Support of Hydrogen Service

Southwest Research Institute

Williams Southwest Wyoming Hydrogen Hub (W2H2) Project

University of Wyoming School of Energy Resources

Legacy Pipe Testing in Support of Hydrogen Service

FINAL REPORT

SwRI® Project No. 18.27456
Purchase Order No. WPO028162

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SOUTHWEST RESEARCH INSTITUTE®

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1 INTRODUCTION

Williams is studying the feasibility of blending hydrogen into its vintage pipeline network. Transporting high-pressure hydrogen introduces material compatibility concerns, as hydrogen can have potentially significant deleterious effects on the mechanical properties, and hence long-term performance, of pipeline steels and welds.

The objective of this project was to determine the toughness and fatigue crack growth (FCG) properties for a 22-in. diameter (0.25-in. wall) legacy X52 pipeline steel in a 60 psi partial pressure H_2, 1140 psi partial pressure N_2 (or methane) environment. Testing also included double submerged arc weld (DSAW) seam and girth welds as well as their associated heat affected zones (HAZ).

2 MATERIALS AND SPECIMENS

Williams provided Southwest Research Institute® (SwRI®) with pipe segments of a 22-in. diameter DSAW seam-welded (0.25-in. wall) X52 pipeline (see Figure 1). The pipe segments contained both an axial seam weld and a girth weld (not visible in Figure 1).

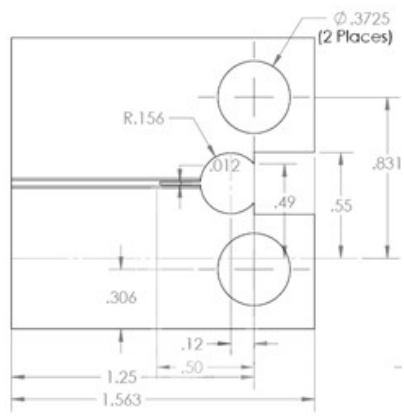
Figure 1. Williams legacy X52 pipe segment.

Given the relatively thin wall (0.25-in. WT), compact tension (CT) specimens were utilized for the toughness and FCG characterization (see Figure 2).

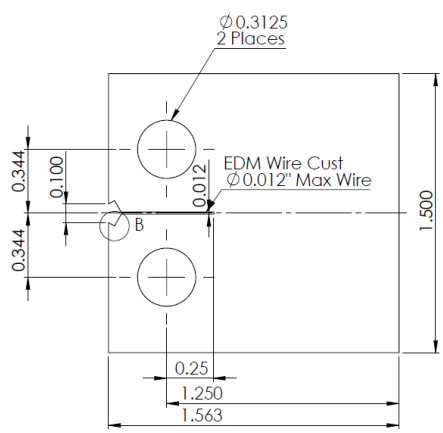
The CT specimen for fracture toughness was designed with a width, W, of 1.25 in., per ASTM E1820. The specimen design includes an integral knife edge for a clip gage to measure the load-line crack opening displacement. All fracture toughness specimens were fatigue pre-cracked targeting a crack length (a) with an a/W of 0.5 followed by 20% side-grooving (depth of side-groove was 10% of the specimen thickness on each side). The FCG specimens were designed with W = 1.25 in. per ASTM E647. An integral knife edge was included on the front face to allow for a clip gage to measure the front face compliance. All FCG specimens were pre-cracked to extend

a fatigue crack from the EDM notch by nominally 0.05 in. The resulting thickness of the toughness and FCG specimens was nominally 0.17 in., the maximum thickness achievable when excising a W = 1.25-in. CT specimen from the pipe wall.

Toughness and FCG specimens were excised in the C-L (circumferential-longitudinal) orientation for the base metal (BM), seam weld (SW), and seam HAZ (SH) as well as in the L-C orientation for the girth weld (GW) and girth HAZ (GH) corresponding to the principal loadings and crack growth directions of the pipe, as indicated in Figure 3. Weld and HAZ specimens were etched with a nitric solution to reveal the weld in order to properly locate the EDM notch along the weld centerline or HAZ. Each specimen was engraved with a unique specimen ID that indicated the pipe segment (2 or 3) and material (BM, SW, SH, GW, or GH).



(a) Fracture toughness specimen



(b) FCG specimens

Figure 2. CT specimen configurations for fracture toughness and FCG testing.

Figure 3. Williams legacy X52 pipe segment indicating specimen extraction orientations.

3 TEST METHODS

Characterization of the fracture toughness and FCG behavior was performed in lab air (baseline) and high-purity hydrogen blends of 0.1, 0.5, 1, and 20% (balance nitrogen). Testing in lab air was performed at ambient pressure and testing in hydrogen was performed at 850 psi (corresponding to 72% SMYS, specified minimum yield strength, of the legacy X52 pipe).

3.1 Fracture Toughness

Fracture toughness testing was performed in keeping with ASTM E1820 to determine the initiation toughness (J or K_J). All tests were performed on a servohydraulic test frame with clevis-style grips. A clip gage attached to the integral knife edges was used to measure the load-line crack opening displacement (COD). For tests in lab ambient air, the unloading compliance method was utilized to infer crack length from the specimen compliance from periodic partial unloads during the test. Testing was performed using a Fracture Technology Associates (FTA) controller designed explicitly for performing ASTM E1820 partial unload toughness testing. This FTA control automates the periodic unloading segments and accurately controls the test.

Toughness tests in blended gas were performed in autoclaves coupled to servohydraulic test frames with internal load cells. The test specimens were instrumented with a clip gage to measure load line opening displacement and direct current potential drop (DCPD) probes to measure the in-situ crack length. Once the specimen was installed in the autoclave, the system was sealed, leak-checked using high-pressure nitrogen gas, and then purged using SwRI standard operating

procedures. To ensure gas purity in the test autoclave, the autoclave was placed under vacuum, and a series of nitrogen gas and hydrogen gas purges were performed. These procedures have been verified with gas sampling to achieve less than 1 ppm O_2 and less than 5 ppm H_2O. Following the autoclave purging protocol, the autoclave was then pressurized with the high-purity hydrogen blend to the prescribed 850 psi pressure and maintained throughout the test with the aid of a pump. Fracture tests in hydrogen were performed under continuous rising-displacement (without any partial unloads). The instantaneous crack length was determined using DCPD as outlined in ASTM E1820 Annex 18.

Following testing, each specimen was fatigued to failure to allow for rigorous measurements of the pre-crack and final crack profiles needed to determine the initial and final crack lengths and for validity requirements. The lab air ambient tests were analyzed using FTA software, which has an integrated software package for post-test analysis to develop J-R curves, identify the cracking initiation toughness (J_Q), and determine if validity requirements were satisfied.

Tests in hydrogen were analyzed according to ASTM E1820 using Microsoft Excel and data from the clip gage, internal load cell, and DCPD signal. The DCPD signal was used to identify the initiation potential per Annex 18 and was then linearized with the initial and final measured crack lengths. The initiation toughness (J_Q) was identified from the R-curve construction per ASTM E1820.

3.2 Fatigue Crack Growth Rate

Fatigue crack growth testing was performed according to ASTM E647 to determine the FCG behavior. All tests were performed on a servohydraulic test frame with clevis-style grips. A clip gage attached to the integral knife edges was used to measure the front-face COD. Tests in blended hydrogen were performed in autoclaves coupled to servohydraulic test frames with internal load cells. Once the specimen was installed in the autoclave, the system was sealed, leak-checked using high-pressure nitrogen gas, and then purged using SwRI standard operating procedures. To ensure gas purity in the test autoclave, the autoclave was placed under vacuum, and a series of nitrogen gas and hydrogen gas purges were performed. These procedures have been verified with gas sampling to achieve less than 1 ppm O_2 and less than 5 ppm H_2O. Following the autoclave purging protocol, the autoclave was then pressurized with the high-purity hydrogen blend to the prescribed 850 psi pressure and maintained throughout the test with the aid of a pump.

FCG testing was controlled using an FTA controller designed explicitly for performing ASTM E647 FCG testing. Testing was performed in load control (using the internal load cell for the hydrogen testing) at a load ratio, R, defined as P_{min}/P_{max} of 0.8. Testing in lab air was performed at 10 Hz and testing in hydrogen was performed at 1 Hz.

FCG tests were analyzed using FTA software, which has an integrated software package for post-test analysis to develop the fatigue crack growth behavior (da/dN-ΔK). The instantaneous crack length was determined from the unloading compliance during fatigue cycling and post-test corrected with measurements of the initial and final crack lengths in keeping with ASTM E647.

4 TEST RESULTS

4.1 Fracture Toughness

Fracture toughness tests were performed in the C-L orientation for the BM, SW, and SH and in the L-C orientation for the GW and GH. Testing was performed in lab air ambient and in 0.1, 0.5, 1, and 20% hydrogen (balance N_2) at 850 psi (58.6 bar).

It should be noted that, owing to the minimal specimen thickness, no specimen met the crack front planarity validity requirements, thereby invalidating determination of a plane strain elastoplastic toughness, J_{Ic} or K_{JIc}. As such, results are reported as J_Q or K_{JQ} as defined in ASTM E1820, indicating that results are not strictly valid plane strain toughness measures. In some instances (as noted), out-of-plane growth due to a weld defect or secondary cracking along the fusion line further invalidated results. Results from these tests were excluded from subsequent analyses and interpretations.

During toughness testing in hydrogen, hydrogen diffuses to the crack tip due to the high triaxial (dilatation) stress state at the crack tip. As the local hydrogen concentration results in embrittlement, it is important that toughness tests performed in hydrogen are performed at loading rates (typically expressed in terms of the driving force K) that allow for sufficient diffusion of hydrogen (high rates will minimize hydrogen diffusion, resulting in nonconservative, over-estimates of the fracture toughness).

In order to determine the appropriate loading rate, a rate study was performed on toughness tests in 0.1% hydrogen. The results of the rate study for the BM are shown in Figure 4. As indicated, the toughness decreases with decreasing loading rate, approaching a lower-bound asymptote at K-rates below approximately 1 N $mm^{-3/2}$ s^{-1}. As indicated in Figure 5, little rate dependency was found in the welds.

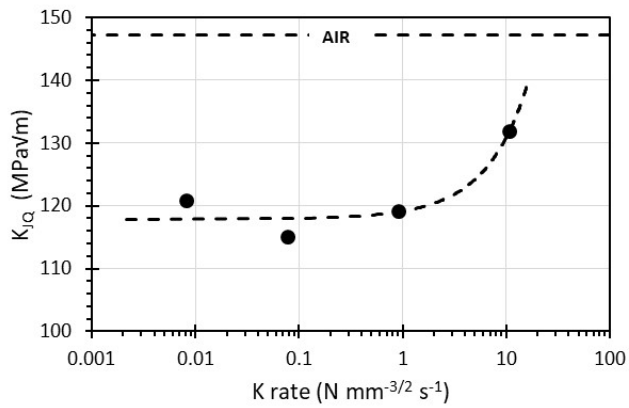


Figure 4. Base metal K-rate study in 0.1% H_2 at 850 psi.

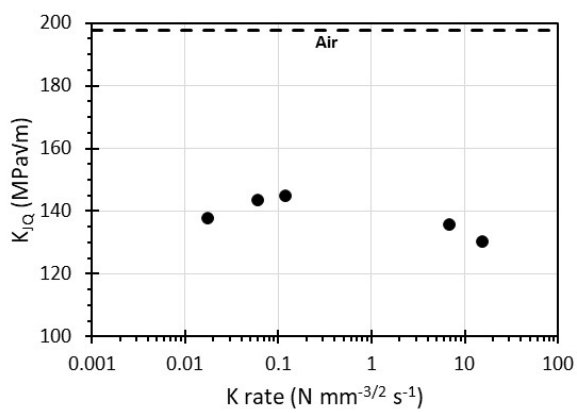
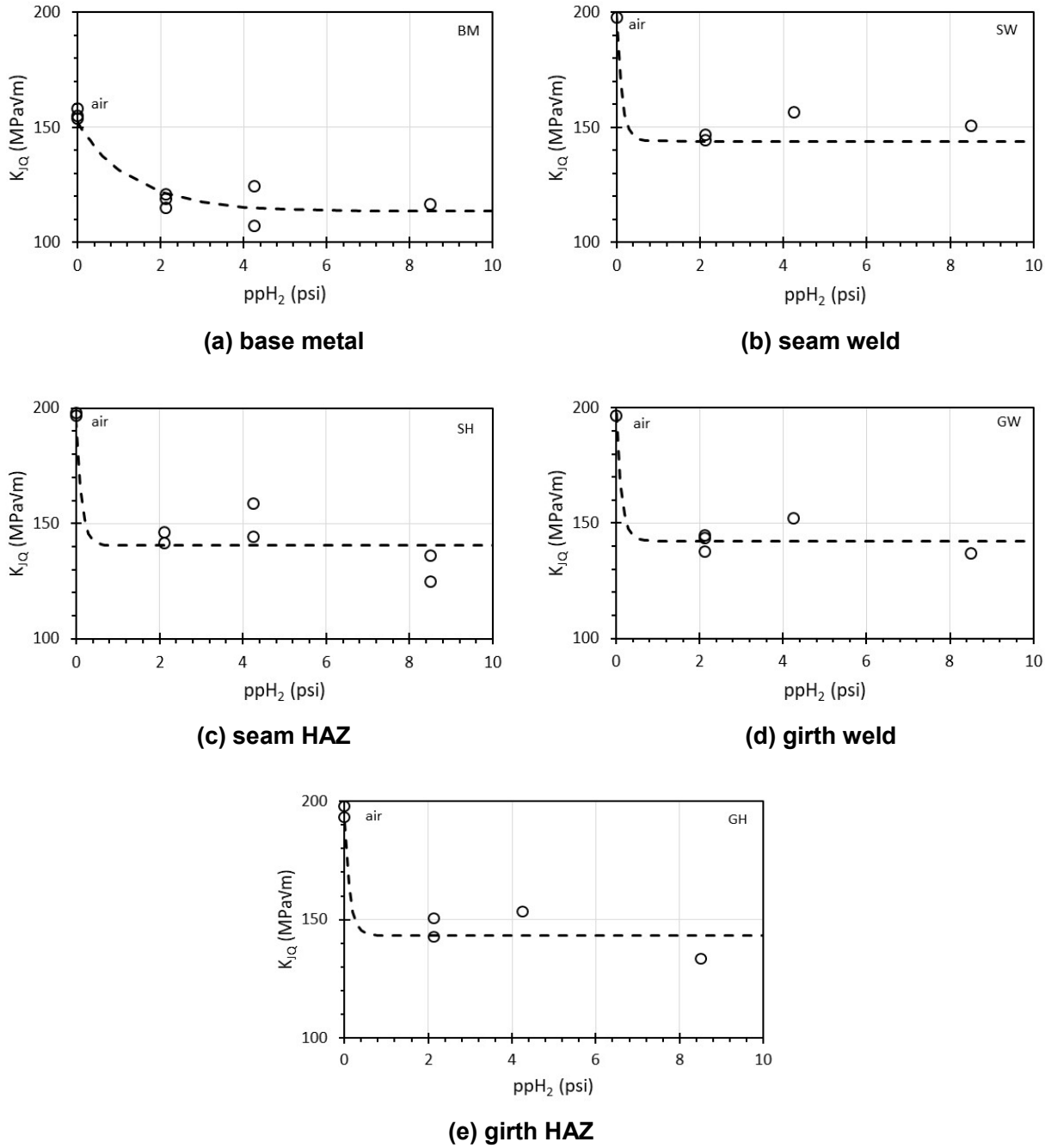


Figure 5. Girth weld K-rate study in 0.1% H_2 at 850 psi.

Based on the results of this K-rate study and in concert with Williams technical staff, a conservative target K-rate of 0.1 N mm$^{-3/2}$ s^{-1} was identified to be used for determining the fracture toughness. The results of the toughness testing are shown in Figure 6 as a function of hydrogen partial pressure (ppH_2). Tabulated results are provided in Appendix A. Each material exhibits nominally a 25% reduction in toughness irrespective of the hydrogen concentration.

The average BM toughness in hydrogen is 115 MPa√m (independent of hydrogen concentration) as compared to 155 MPa√m in lab ambient air. The toughness in hydrogen of the welds and HAZs average approximately 142 MPa√m (independent of hydrogen concentration) as compared to their average toughness of 198 MPa√m in lab ambient air.



(a) base metal

(b) seam weld

(c) seam HAZ

(d) girth weld

(e) girth HAZ

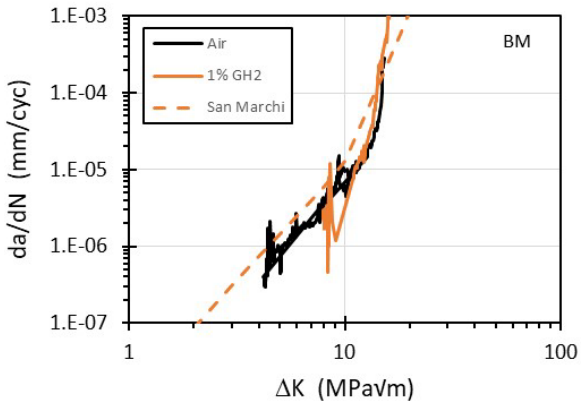
Figure 6. Fracture toughness in various partial pressures of hydrogen at 850 psi.

4.2 Fatigue Crack Growth Rate

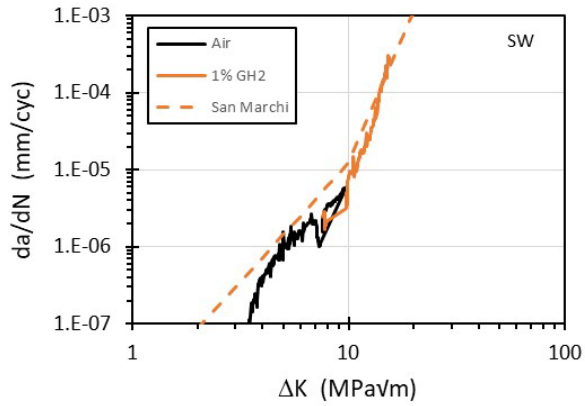
Fatigue crack growth tests were performed in the C-L orientation for the BM, SW, and SH and in the L-C orientation for the GW and GH. Testing was performed in lab air ambient and in 1% hydrogen (balance N_2) at 850 psi (58.6 bar). All testing was performed at R = 0.8 and 1 Hz in hydrogen.

The resulting FCG behavior is shown in Figure 7. The FCG behavior is consistent across all materials. Also shown is the ASME hydrogen design curve (dashed line) augmented for fugacity by San Marchi and Ronevich, which closely bounds the hydrogen FCG data.

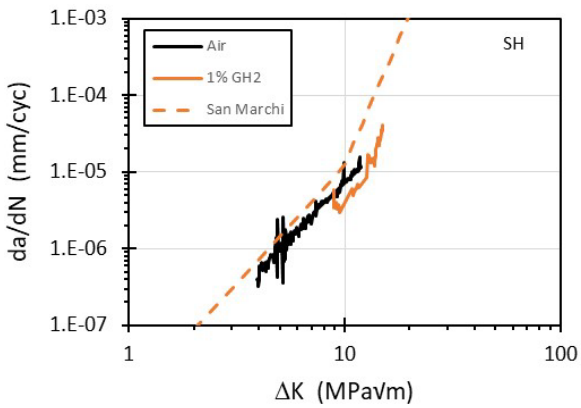
No significant difference in behavior is noted between 1% H_2 and lab ambient air. Although testing in hydrogen was tested at 1 Hz, this frequency may be too aggressive at such high ΔK and K_{max}. Similar to toughness testing, the crack growth rates associated with these relatively high ΔKs may minimize hydrogen diffusion to the moving crack tip, thereby reducing the effects of hydrogen on the resulting FCG behavior. Analogous to the K-rate study for fracture toughness, a frequency scan to determine an appropriate FCG test frequency was not performed under this project. It is worth noting that testing at significantly lower ΔKs and/or lower test frequencies would result in excessive test durations (e.g., in excess of 6 months at 0.1 Hz).



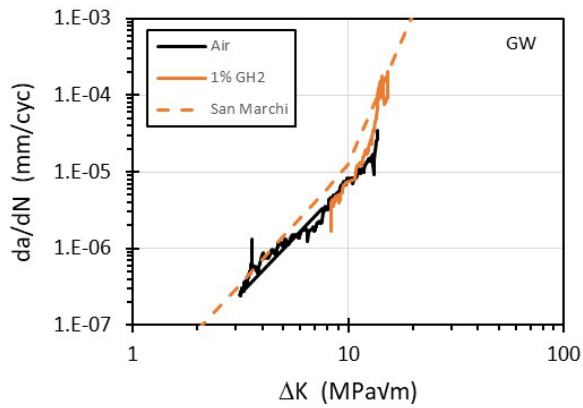
(a) base metal



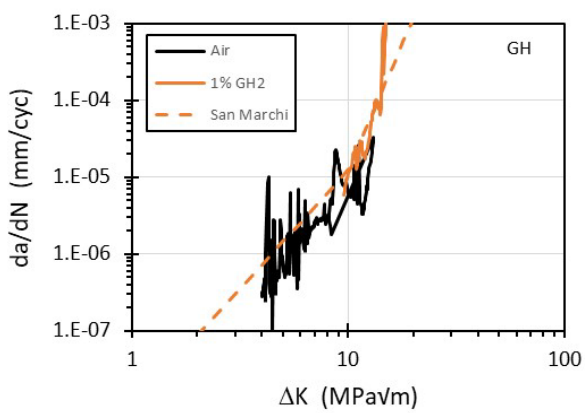
(b) seam weld



(c) seam HAZ



(d) girth weld



(e) girth HAZ

Figure 7. FCG behavior in 1% hydrogen at 850 psi.

5 REFERENCES

ASME B31.12-2019, "Hydrogen Piping and Pipelines," ASME Code for Pressure Piping, B31, American Society of Mechanical Engineers, New York, NY, Feb 2020.

ASTM E1820 (2022), "Standard Test Method for Measurement of Fracture Toughness" (West Conshohocken, PA: ASTM International).

ASTM E647 (2023), "Standard Test Method for Measurement of Fatigue Crack Growth Rates" (West Conshohocken, PA: ASTM International).

C. San Marchi and J. Ronevich, "Carbon Steels for Hydrogen Service," Study Group on Materials Testing and Qualification for Hydrogen Service, Las Vegas, NV, July 21, 2022 (based on Sandia report SAN2022-8369 PE).

APPENDIX

Fracture Toughness Data

Material	ID	H2 (%)	ppH2 (psi)	K_{JQ} (MPa√m)
Base Metal (BM)	BM-7	Lab air	0	158.26
	BM-8	Lab air	0	153.86
	BM-10	Lab air	0	154.96
	2-BM-3	0.25	2.125	119.06
	2-BM-4	0.25	2.125	115.10
	2-BM-5	0.25	2.125	120.83
	2-BM-9	0.5	4.25	107.10
	3-BM-21	0.5	4.25	124.29
	2-BM-11	1	8.5	116.60
	2-BM-1	20	170	112.04
	2-BM-6	20	170	108.36

Material	ID	H2 (%)	ppH2 (psi)	K_{JQ} (MPa√m)
Seam Weld (SW)	2-SW-9	Lab air	0	197.82
	2-SW-7	Lab air	0	201.12
	2-SW-1	0.25	2.125	146.67
	2-SW-2	0.25	2.125	144.28
	2-SW-10	0.5	4.25	156.48 (tunneling)
	2-SW-8	1	8.5	150.57
	2-SW-3	20	170	142.40
	2-SW-4	20	170	136.30

Material	ID	H2 (%)	ppH2 (psi)	K_{JQ} (MPa√m)
Seam HAZ (SH)	2-SH-10	Lab air	0	197.82
	2-SH-2	Lab air	0	196.72
	2-SH-1	0.25	2.125	141.58
	2-SH-3	0.25	2.125	146.41
	2-SH-6	0.5	4.25	158.69
	2-SH-7	0.5	4.25	144.28
	2-SH-8	1	8.5	136.16
	2-SH-9	1	8.5	124.76
	2-SH-4	20	170	137.71
	2-SH-5	20	170	130.81

Material	ID	H2 (%)	ppH2 (psi)	K_{JQ} (MPa√m)
Girth Weld (GW)	2-GW-6	Lab air	0	202.22
	2-GW-9	Lab air	0	196.72
	2-GW-4	0.25	2.125	143.34
	2-GW-7	0.25	2.125	137.57
	2-GW-8	0.25	2.125	144.82
	3-GW-20	0.5	170	152.23
	3-GW-21	0.5	4.25	weld defect
	2-GW-5	1	4.25	136.87
	3-GW-22	1	8.5	weld defect
	3-GW-19	20	8.5	135.30

Material	ID	H2 (%)	ppH2 (psi)	K_{JQ} (MPa√m)
Girth HAZ (GH)	2-GH-4	Lab air	0	197.82
	2-GH-6	Lab air	0	193.42
	2-GH-1	0.25	2.125	142.80
	2-GH-2	0.25	2.125	150.44
	2-GH-8	0.5	4.25	153.49
	2-GH-10	0.5	4.25	112.04 defect
	2-GH-7	1	8.5	93.84 defect
	2-GH-9	1	8.5	133.44
	2-GH-3	20	170	145.35
	2-GH-5	20	170	125.38

University of Wyoming | School of Energy Resources

WILLIAMS SOUTHWEST WYOMING HYDROGEN HUB (W2H2) PROJECT

University of Wyoming School of Energy Resources Final Report

2023

Produced by the School of Energy Resources:
Hydrogen Energy Research Center
Center for Economic Geology Research
Center of Excellence in Produced Water Management

WILLIAMS SOUTHWEST WYOMING HYDROGEN HUB (W2H2) PROJECT FINAL REPORT

This report was prepared by Charles Nye, Jonathan Brant, William Lawler, Jacob Schneider, Jada Garofalo, Matthew Johnson, and Dayana Zhappassova. In support of the "Williams southwest Wyoming Hydrogen Hub" (W2H2) project. The project was funded by the Wyoming Energy Authority. Williams, the University of Wyoming, and others investigated hydrogen generation, transport and consumption. Charles Nye of the Center for Economic Geology Research was responsible for performance of W2H2.

ABOUT THE HYDROGEN ENERGY RESEARCH CENTER

The Hydrogen Energy Research Center (H_2ERC) leads applied research to identify and quantify the relative competitive advantages of Wyoming in an emerging hydrogen economy, and collaborates with Wyoming stakeholders to support growth of a hydrogen industry focused on serving the state's existing energy customers and growing new markets.

University of Wyoming
School of Energy Resources
Hydrogen Energy Research Center

ABOUT THE CENTER FOR ECONOMIC GEOLOGY RESEARCH

The Center for Economic Geology Research (CEGR) investigates solutions to the challenges in Wyoming's fossil fuel and mineral industries. CEGR research projects explore opportunities to use Wyoming's distinctive geology and resources in order to develop those opportunities, diversify Wyoming's economy, and to maintain competitiveness in a low-carbon fossil energy future.

University of Wyoming
School of Energy Resources
Center for Economic Geology Research

ABOUT THE CENTER OF EXCELLENCE IN PRODUCED WATER MANAGEMENT

The Center of Excellence in Produced Water Management (CEPWM) provides innovative science and engineering research for application in the oil and gas industry for the purposes of reducing environmental impacts, improving industry process efficiencies, increasing profitability, and enhancing society benefits.

CENTER OF EXCELLENCE
IN PRODUCED WATER MANAGEMENT

BACKGROUND ON W2H2:

The overall project objective of W2H2 is to establish the southwest corner of Wyoming as a regional green hydrogen and/or synthetic natural gas production hub. In W2H2, Williams will partner with the University of Wyoming and others to address two key technical challenges: 1) what is the best way to transport hydrogen using existing infrastructure, and 2) what is the best way to provide water for the proposed electrolysis plant? The findings will help determine the feasibility, sizing, and location within Wyoming of follow-up projects.

A follow-up project resulting from this work would be expected to be in the 200-600MW range making it the largest of its type in North America. Local and state benefits of a follow-up to W2H2 will include the need for skilled labor and associated training to construct and operate all related facilities resulting from this study's conclusions. Additionally, such a follow-up project would elevate the University of Wyoming to become a leader in green hydrogen production technologies. At the national level, Wyoming would continue its position as an energy exporter and establish itself as a primary green hydrogen supplier in the United States. Ultimately, the Williams Wyoming Hydrogen Hub would accelerate the clean energy economy and connect with potential regional renewable energy opportunities.

FINAL REPORT 2023

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Background

Wyoming has a vested interest in the green energy transition. Wyoming has faced drought for most of the last two decades. This prolonged drought threatens the limited agriculture, tourism, and forestry which the state's mountain-desert historically could support. Wyoming is also a net energy exporter, powering the United State's electric grid directly through generation and indirectly through extracted fuels. This reliance on the energy industry means the state must either adapt to changes in industry or guide those changes to remain relevant and stable. And finally, because the green energy transition is accompanied by promises of environmental justice, Wyoming – which qualifies for aid because of jobs lost due to the decline of traditional fossil fuels – stands to gain from using this moment to diversify and retrain for new jobs. For these three reasons among others, Wyoming needs to be an active participant in the green energy transition.

Wyoming accordingly has championed new nuclear technologies, Carbon Capture and Storage (CCS), renewable wind, energy storage, and more recently, hydrogen. Hydrogen is a combustible gas like methane (natural gas) but burns without producing CO_2. Hydrogen therefore holds promise for replacing natural gas or other hydrocarbons like oil and coal in applications which need combustion. Little to no hydrogen is commercially produced from naturally-occuring deposits, which can occur in geologic traps just as oil and gas do. At present all human needs for hydrogen are met through on-site generation of the gas (principally at hydrocarbon refineries). This human-made hydrogen requires energy input and either comes from steam-methane reforming (SMR/ATR, called "grey" or "blue") or from electrolysis of water (called "green" or "yellow"). In both these cases the energy embodied in the resulting hydrogen is less than was used to form it (due to losses from waste heat and other by-product molecules). This net loss means that hydrogen produced by human actions is an energy storage medium, not a primary energy source. The value of hydrogen is that it can be stored (with some difficulty) to level out surges in supply and demand over the course of a day, or be moved from one place to another in hydrogen pipelines or in the tanks of a large vehicle (e.g. cargo ship, train, truck).

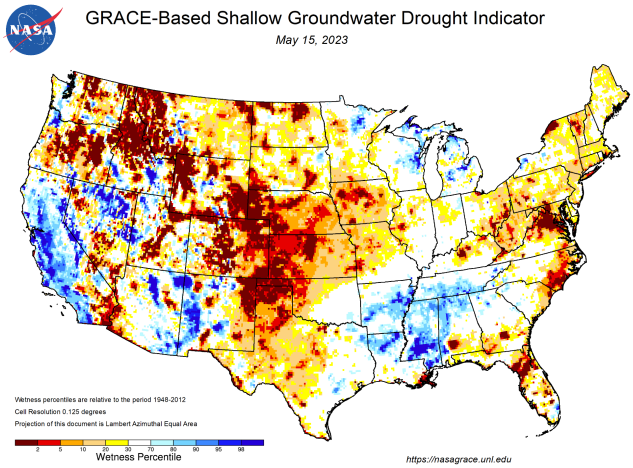
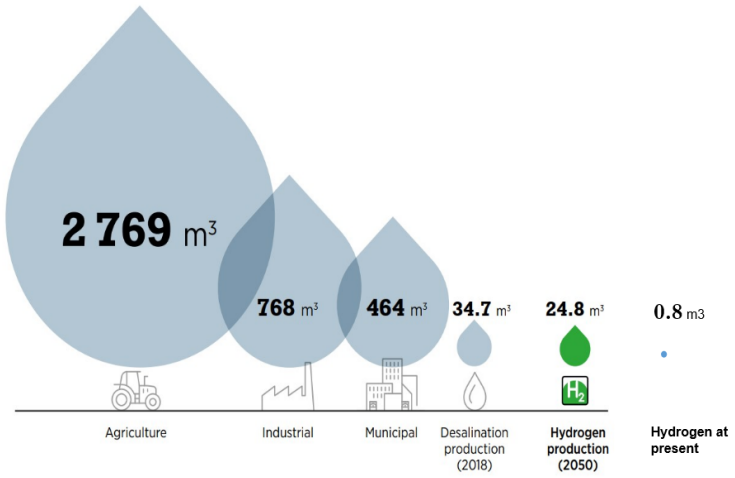


Figure 1: Map of the continental US showing much of the west – and the majority of Wyoming – is very dry. Although current models vary, with some showing a slight increase in wetness, this drought will on average become worse as earth's temperature rises.

Due to water scarcity, Wyoming is very concerned about maintaining access to water for agriculture, industry, and municipal use. This anxiety has been articulated by state government officials, including the Wyoming Governor, and may represent state policy. In early September 2022 Governor Gordon voiced support for hydrogen generation, but also said "We're not going to burn water for transportation" (CowboyStateDaily, 2022). This understanding that water is a scarce resource is widespread in Wyoming, and leads to criticism of new consumptive uses of water.

When compared to existing water use hydrogen is a literal drop in the bucket as shown on Figure 2, below. Even the most optimistic hydrogen generation predictions in 2050 barely rival the amount of water produced by desalination in 2018, showing just how small a burden hydrogen generation would be on existing water uses. A decimal-percent (<1%) improvement in agricultural efficiency would yield far more water than hydrogen generation could consume in the next 30 years. Nevertheless, the visceral feeling which drives people to oppose new consumptive water use is a real feeling even if the facts suggest a different target would be wiser. Therefore this project sought to use water which does not compete with existing uses.



To find water in southwest Wyoming's Greater Green River Basin (GGRB) with volumes and quality adequate for Electrolysis. This project studied water law first and followed-up on the two sources the law-review found: unallocated water in Fontenelle Reservoir, and produced waste-water from oil and gas development. This project showed that both sources are viable. Fontenelle requires greater work in permitting, NEPA, and contracting. Using produced water requires greater monetary expense. Armed with this knowledge Williams, and other companies like Williams, can design good projects in Wyoming.

The next sections describe the project's background, activities, and findings including the cost of treating the sampled waters, and assessment of where a hydrogen project should be situated geographically - both from the perspective of a Williams-like company with existing assets and from the perspective of a generic assetless company elsewhere in Wyoming.

UWyo Project Narrative

Following post-award negotiations with WEA, Williams, and UWyo, work began in early 2022. This work was organized to produce 5 milestone/deliverables, which are appended to this report. These 5 milestone/deliverables generally match the chronological sequence of activities in the project.

#	Title	Due Date
1	Wyoming Water Law Overview	3/24/22
2	Wyoming Water Availability in Study Area	3/24/22
3	Local Water Quality Assessment	9/23/22
4	Assessment of Wyoming Water Availability—Surface, Ground, & Produced	12/23/22
*	Extra: Preliminary GIS Site Selection Study	Voluntary
5	Determine Treatment Options and Costs	3/24/23

Table 1: The deliverables UWyo produced during this project. These align with "Task 3" in the WEA-Williams agreement, and have content specified in the UWyo-Williams Research Agreement. Because the project found that surface and groundwater were generally unavailable, our workload was smaller than expected, and to compensate we added a GIS study after discussion with Williams.

Summary of Legal assessment (Milestones 1 and 2)

In the first days of the project, UWyo's legal experts considered legal restrictions on water acquisition and water treatment in southwest Wyoming. These restrictions apply statewide, with limited nuance in the Platte River watershed's "green zones". In general, Wyoming's surface water resources are fully appropriated, although a junior water right in the Green River Basin could be enjoyed until someone downstream requests a "callout". Further information on callouts, and the risks associated with holding a junior right can be requested from Jeff Cowley, Administrator for Interstate Streams at WY State Engineer's Office (https://seo.wyo.gov/home/contact-us).

The legal assessment concluded that needs for non-consumptive use can easily be met under the current legal regime, but that consumptive use (such as hydrogen production, industrial cooling, agriculture, or reservoir evaporation) is fraught. Three options exist for using surface/ground water: 1) acquire a Fontenelle Reservoir contract for water, 2) establish a highly-vulnerable junior water right, or 3) use brine water produced in the course of enjoying mineral rights.

Ample water resources exist in Fontenelle Reservoir, but would likely trigger federal NEPA review and run afoul of the Wyoming governor's policy. In 2010, Fontenelle Reservoir had 78,450 acre-feet per year of water available for new contracting. The volume of water withdrawn from Fontenelle Reservoir by Jim Bridger Power Station totaled 28,560 acre-ft in 2006 (221,578,973 bbl/year). Jim Bridger Power Station's four units will convert to natural gas or retire before 2030, with the first two units doing so before 2024. Jim Bridger's water use will fall by 80%-100% as a result. Fontenelle reservoir is comparatively clean water averaging 220mg/l (ppm) TDS over the last 20 years. Clean water like this reduces costs from a few dollars per cubic meter to a few cents per cubic meter because treatment is simpler, but using Fontenelle water could fall afoul of current Wyoming Governor's policy to not "burn water for transportation". High Savery Reservoir is State of Wyoming owned, and much smaller, but is the closest analog near Echo Springs. Like Fontenelle, use of High Savery Reservoir is not straightforward. In sum, reservoir water is clean and plentiful, but legally and politically uncertain.

Junior water rights are traditionally considered worthless in the arid west. The Green River Basin, which feeds into Flaming Gorge Reservoir is unique because holders of water rights in this area rarely ask the State Engineer's Office (SEO) to perform a "callout". In a callout any water-rights-holder who suspects their right is being infringed may ask the SEO to confirm the caller's right is infringed. If the right is indeed infringed, then the SEO will consider all upstream holders of junior rights, and turn off those rights in sequence of seniority until the caller's water-right is no longer infringed. In areas like the Green River Basin, it is rare for a user to ask for a callout, and even rarer to have any significant junior right turned off. This historical norm is no guarantee of future norms, but if it did persist a junior water right of modest size could be enjoyed. In sum, the Green River Basin is one of the few places in Wyoming where a junior water right is not worthless, but a sword of Damocles hangs over this option.

The most promising option, which the W2H2 project focused on, is to make use of produced water which is viewed as a waste-product of mineral-right activity. Mineral rights include the right to perform other activities necessary to enjoyment of those minerals. In all oil and gas operations, and especially Coal Bed Methane (CBM), this means production of salty water entrained with the hydrocarbons. CBM operations produce a much higher percentage of water per unit of natural gas than conventional operations, and this water poses a burden to the CMB operator who must dispose of the brine. W2H2 considered treatment of this brine to generate clean water which could be used for hydrogen electrolysis. Some brine (carrying the salt-load which would have been in the now cleaned-up water) must still be disposed, but with a significantly reduced volume the disposal costs are much smaller. As shown in the following sections this route is the most certain to work, and imposes manageable costs to a hydrogen project.

The above legal concerns are described more fully in Milestone #1 and Milestone #2.

Summary of Local Water Quality (Milestone 3 and 4)

Produced water has the lowest social/legal/regulatory risk, as shown by the Legal Assessment. In the next step of the project the team quantified the technical possibility of sourcing large volumes of high-quality water from oil and gas development in the Greater Green River Basin. The identified locations would be sampled and analyzed. The water chemistry and volume would in turn inform the treatment designs.

Oil and gas are generated over large geographic areas in certain formations at modest depth, and then migrate along similar fracture/permeability pathways in the subsurface until they are trapped in impermeable subsurface structures. This is analogous to rain falling over a large area, flowing along streams and rivers, and coming to rest in various lakes - but inverted to be below the earth's surface. The result is different formations "pooling" oil and gas from different ages. In the Greater Green River Basin these form three groups: the Frontier formation on the Moxa Arch, the Lance formation on the Pinedale anticline, and the Almond-Mesaverde formation in the Washakie Basin.

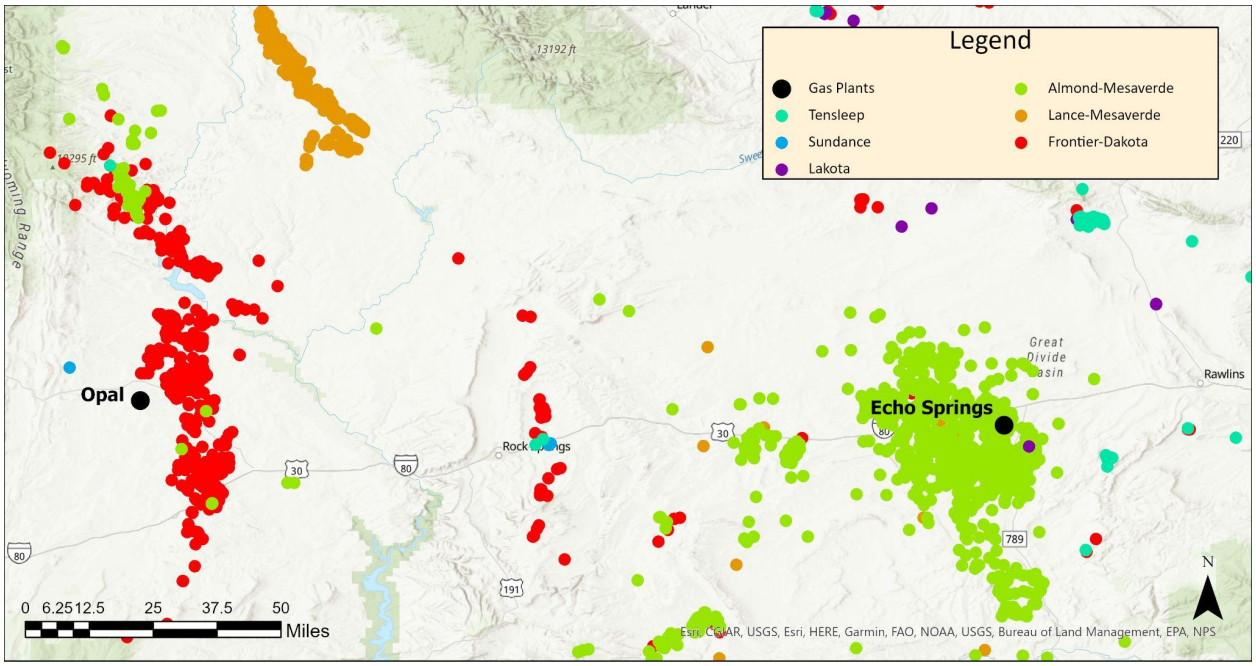


Figure 2: Map of producing formations in the Greater Green River Basin (GGRB) and William's two gas plants at Echo Springs and Opal. There are three main plays in the GGRB, shown here after reduction from the full WOGCC database, reproduced online here: https://www.arcgis.com/apps/mapviewer/index.html?webmap=5db650dc49e94ae1b8103b8244bc1c1b. The formation name used in the database is operator-reported and varies based on who is filling out the forms. Names on this map have been simplified and some names merged.

The three largest oil and gas plays, as identified on Figure 2, have some changes in chemistry across their area. Sharing the same formation is nevertheless a first-order proxy for sharing the

same chemistry. The team therefore considered three targets for sampling at this point in time, and especially the Moxa Arch near Opal, and the Washakie Basin (Wamsutter area) near Echo Springs because those would require minimal transport to an existing Williams-affiliated facility.

The next consideration was the volume of water produced at each of these locations. The details of how oil and gas moved through the subsurface lead each field to produce more or less water per unit of oil or gas – called the "water cut" in industry. The team plotted the water volumes produced in one year in the GGRB and performed calculations on WOGCC data to find the areas which produce the most water. The Moxa Arch produces relatively little water except in the far northern Tip-Top and Hogsback fields. The Pinedale anticline produces significant water due to recharge off the Wind River Range – called "water drive" in industry – but is neither controlled by Williams, nor near Williams-affiliated facilities. The Washakie basin has middleing water production and Williams' Echo Springs plant in its center. The greatest water production in the area is at Atlantic Rim, a CBM operation strictly outside the basin to the east. The greatest production controlled by a Williams affiliate is Chain Lakes, in the northern Washakie basin.

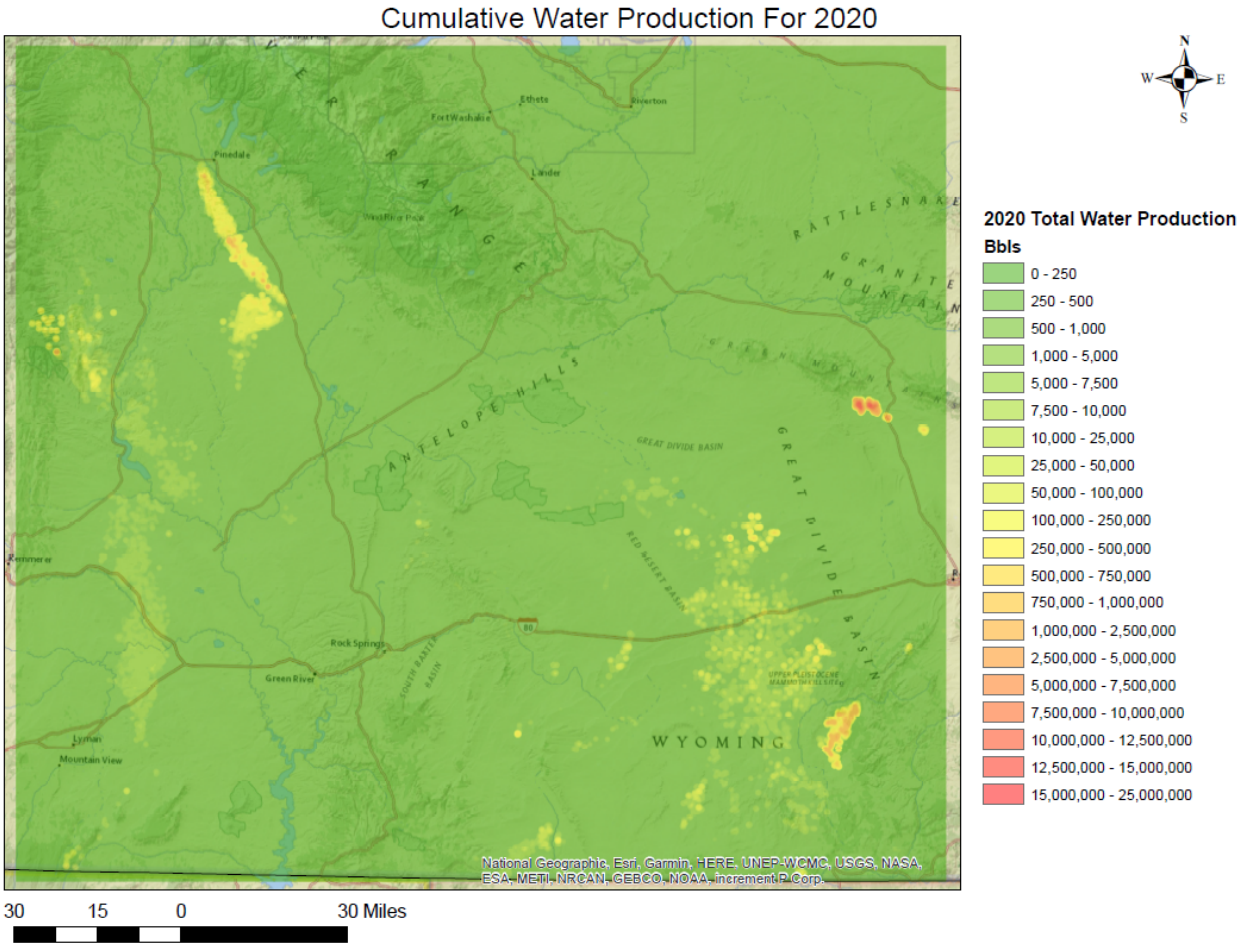


Figure 3: Map of water production in the Greater Green River Basin (GGRB). The volumes are in barrels per year, using data from 2020. These data are for individual wells, but because the well density in each field is roughly equal this gives an impression of field production.

In consultation with Williams the team down-selected three sites for sample collection: the Opal plant's onsite water, the Chain Lakes area north of Echo Springs, and the Atlantic Rim area east of Echo Springs. Fontenelle Reservoir was included as a fourth site to study because it represents an option for fresh water radically different from these produced water sources, and because USGS records the reservoir's chemistry in the National Water Information System at: https://nwis.waterdata.usgs.gov/usa/nwis/qwdata/?site_no=09211200 negating the need for sampling and analysis.

	Opal	Chain Lakes	Atlantic Rim
Number of Wells	550	437	368
Water (barrels)	108,787	2,021,059	28,235,824
Oil (barrels)	90,996	417,632	6,528
Gas (Mcf)	10,415,126	8,001,491	4,404,586

Figure 4: Map of southwest Wyoming, showing the three locations involved in this study, and a table of the water, oil, and gas volumes from those sites. The details of oil and gas sourcing and production affect the water to oil ratio in each location. The Atlantic Rim area produces large water volumes. Source: WOGCC 2020 data

Opal

Opal was known from the start to suffer from low water volumes, but some of the gathering stations might have summed the water from enough wells to become meaningful. There were also two tanks of industrial water generated from de-watering the natural gas. These four

samples (two tanks and two wells) were taken from the area near Williams' Opal facility (41.7729°, -110.3418°). These waters have more debris in them than the others due to contacting the inside of holding tanks for long periods of time.

Chain Lakes

Chain Lakes is a new area (roughly around 41.95°, -107.90°) just south of the eponymous chain lakes. These wells were constructed very recently and their produced water gathered to a pair of evaporation pits. The water used to assess treatment came from this gather station because water is evaporated there for disposal, and if a hydrogen plant were built this water could be redirected and disposed of in that way instead. Chain lakes is north of Echo Springs.

The analysis On Figure 5 shows that water from the Chain Lakes area is slightly saltier than originally expected but near the USDW threshold of 10,000mg/L total dissolved solids. These would-be-waste waters are gathered at the Chain Lakes gather station and present a clear front-runner for water quality and volume. Therefore UWyo also partially completed Milestone UWyo #5 part 1 at the same time by collecting a large-volume sample of the Chain Lakes gathering station water.

Atlantic Rim

Atlantic Rim is a long-operating Coal Bed Methane operation (41.40° -107.68°) east of Echo Springs. CBM requires production of the water in a coal seam to liberate the methane which adheres to coal under pressure. Producing the water causes formation pressure to drop. Because non-methane hydrocarbons are minimal, and those which are present tend to be gas-phase ethane, propane, and butane, this water is generally more pure and easier to treat than traditional oil and gas produced water.

Fontenelle Reservoir

Fontenelle Reservoir was sampled from just below the dam by USGS in June of 2012 (42.0211°, -110.0505°). Because the historical water quality has been similar to this analysis and because the reservoir is very large, this chemistry likely continues to reflect modern conditions in the reservoir. This water, though carrying a risk of triggering NEPA, is by far the cleanest and highest volume.

#	Name-Description	Lat	Long	TDS	Remarks or key challenge
WA-175	Chain Lakes I5 35-5H	41.9316	-107.8909	10560	~100ppm Silica - fouling risk
WA-176	CHAIN LAKES I5 33-3H	41.9277	-107.9150	10367	~100ppm Silica - fouling risk
WA-177	CHAIN LAKES I5 33-A2H	41.9272	-107.9248	9281	~100ppm Silica - fouling risk
WA-178	Gather-Pond	41.8831	-107.9097	9841	~100ppm Silica - fouling risk

WA-179	Gather-Pond	41.8831	-107.9097	10116	~100ppm Silica - fouling risk
OPAL-180	Produced Water Tanks	41.7778	-110.3404	8647	Limited volume
OPAL-181	Ken Tank	41.7751	-110.3387	5700	Limited volume
OPAL-182	Loading Rack Yard – south	41.7703	-110.3378	679.0	Limited volume
OPAL-183	Loading Rack Yard – north	41.7710	-110.3378	693.2	Limited volume
CBM-191	Gather Station: Catalina Beta	41.4023	-107.6563	3837	2000ppm Alkalinity - acid needed
CBM-192	17T 91R "11-22"	41.4311	-107.6361	2359	1300 ppm Alkalinity - acid needed
CBM-193	17T 91R "11-13i"	41.4467	-107.5959	1075	700 ppm Alkalinity
CBM-194	Sun Dog Gen Station	41.3704	-107.6563	3202	1800 Alkalinity - acid needed
CBM-195	Grace Point	41.2892	-107.6603	2224	1300 ppm Alkalinity - acid needed
FONT-218	Fontenelle Reservoir: USGS sample	42.0209	-110.0498	219.8	https://nwis.waterdata.usgs.gov/usa/nwis/qwdata/?site_no=09211200

Figure 5: Table of water samples location and high-level treatment challenges. TDS and all chemistry is given in ppm, meaning milligrams of analyte per liter of sample. Full chemistry is attached as an appendix to this report.

In summary, groups of water samples were taken from Opal, Echo Springs, and Carbon Creek Energy's Atlantic Rim. These oil and gas produced waters were analyzed for basic chemistry and other physical parameters which matter for Water Treatment. These analyses are summarized in Figure 5, and given in full in the attached appendix .

Summary of Local Water Treatment (Milestone 5)

The team had thus far been working on the assumption that the Hydrogen plant would have an arbitrary scale defined at the time of construction. No data nor discoveries before the study of the water treatment system (Milestone 5) required a known scale. However, economy of scale is a key factor in water treatment, so the team assumed a 600MW scale. 600MW is the electrical output of a larger boiler-turbine unit at a coal-fired powerstation, or two smaller powerstation boiler-turbine units. In terms of Hydrogen plants, 600MW is larger than hydrogen plants which currently exist, but smaller than some which are planned. Selection of this scale involved some consultation with Williams.
Setting scale in terms of the electrolyser input implies the scale of other needs. For example, the team estimated that at the 600MW size, a green electrolyser could produce 11,400kg of hydrogen per hour. With preliminary assumptions of how much water could be recovered from treatment, and how much was needed per kg of hydrogen the team quickly found the water requirement was on the order of millions of barrels of produced water per year. This scale of water needs makes Opal unable to satisfy water demand, so no treatment train was designed for it. Opal sample chemistry was still reported to provide a point of reference, because Opal sample chemistry was available before these water volume needs were known.

The initial estimate showed that the water volumes could be excessively large, and so the team adopted various assumptions which might save water. First among these assumptions was the use of an air-cooled electrolyser, which causes performance to be more dependent on ambient temperature than evaporative cooling systems. The benefit of air-cooling is that water requirements can be reduced to slightly above the chemical reaction minimum. For Green hydrogen by electrolysis this can be as low as 10kg pure water per 1kg hydrogen. To allow for substantial error in early-phase planning this volume was increased to 16kg of pure water per 1kg of hydrogen output. At the 600MW plant scale this equals about 10 million barrels of ultrapure water per year.

There is a complex relationship between price and % recovery. If one is willing to pay more one can recover a higher % of a given water. Likewise, if one is willing to recover only a small % of the total water flowing into a system, that recovery can be less expensive. The initial assumption for this work was a 33.3% recovery rate. In practice this rate would vary with the water being treated, but an initial assumption was important for deciding if a source could meet the volume requirements of the electrolysis system. This initial assumption implied that 30 million barrels of raw water would be needed per year. Estimates at this point presumed all water would need to be treated to ultrapure levels, but the true amount of water needed could be lower as non-reaction water could be lower quality. Even so, this eliminated Opal from further consideration due to inadequate volume. For Opal to be viable at least 90 more dedicated water wells, each as good as those currently in the laydown yard would be needed. That is a broadly infeasible task to accomplish economically.

With these initial assumptions three treatment trains were developed: Chain Lakes (North Echo Springs), Atlantic Rim (East Echo Springs), and Fontanelle Reservoir. The advantages or disadvantages of each are summarized below and described in full in the appendix.

North Echo Springs has favorable OPEX costs around $1.57/m3 or $1.28/m3 but this OPEX might increase by as much as $10/m3 if silica were to foul the membranes. Adding an anti-scaleant such as Sodium Phosphate would make this option the most expensive considered here. Recovery is expected to be better than originally assumed at 67.9%-69.0%. Boron is known to pass the proposed treatment train, but will not be a problem as boron is well tolerated by electrolysis systems.

East Echo Springs has less impressive OPEX costs around $6.11/m3 or $5.66/m3 but as there is no silica challenge this OPEX can be relied upon. The higher OPEX is a result of adding acid to “burn-off” alkalinity. Recovery is expected to be better than originally assumed at 65.2%-66.8%. As with North Echo Springs, boron is known to pass the system but should be well tolerated.

Fontanelle Reservoir has very low OPEX around $0.39/m3 or $0.09/m3 because the water is so clean. In a similar vein recovery reaches 81.7%-97.2% depending on ultrapure or potable standards. For the highest purity options removal of Calcium may be a minor challenge, but no other ions pose a risk to the system. The simplicity of this treatment train allows a very small amount of ions through. If that were a challenge a small ion-exchange system would achieve the full purity requested.

In sum, Fontanelle Reservoir is a clear choice if the project is willing to trigger NEPA and negotiate with the state of Wyoming. If those are prohibitive, the next best option is East Echo Springs, because although there may be a higher cost associated with this water, fouling is

a non-issue, and there are huge volumes of water available. A fairly standard polymeric UF membrane with a high pressure RO should be able to achieve 90% recovery without much trouble. Some antiscalants and acid may be needed to mitigate silica, CaF, and CaCO3, but this is routine in water treatment. To reach 1 ppm TDS, you would either need an IX resin system or EDI post treating the RO permeate. There would be a slight economic benefit to going with EDI but IX is simpler to operate.

Preliminary GIS Site Selection Study (Extra Milestone)

The GIS assessment portion of this project was done using ArcGIS Pro, ArcGIS Storymap, and used data publicly available from Esri's online database, the WOGCC, and the USGS. In conducting this review, the modeling tools used include Empirical Bayesian Kriging with cross validation analysis, Euclidean Distance, Inverse Distance Weighted, and a Suitability Modeler Analysis Tool. The GIS portion of this project had three steps: gathering geospatial data related to infrastructure and regulatory schema, creating an initial suitability model, then refining this model based on input from Williams and other stakeholders. These steps are detailed below as well as the results which are evaluated under five scenarios.

Data Gathering

The initial phase of this project sought to determine what infrastructure would be necessary to support both green and blue hydrogen production facilities and what other factors could be mapped that would control cost. Land ownership, total dissolved solids (TDS) content, and proximity to gas plants, suitable wind energy, electric transmission lines, pipelines, county roads, highways, oil and gas wells, water resources, protected wetlands, and Section 368 energy corridors were all considered.

First GIS Suitability model for Williams' area

After converting this information into raster layers an initial Suitability Model was created using the suitability modeler analysis tool in ArcGIS Pro. This model used weighted distance connected with various weightings that represented the level of importance for each layer in order to find the ten best 50 acre parcels of land that possess the right characteristics for a hydrogen production facility. This analysis concluded that the best site is located approximately five miles directly east of Echo Springs. The second best option was found to be on the southern Moxa Arch, 20 miles southeast of Opal. The third option identified is located 20 miles west of Echo Springs near Red Desert and the fourth option is 7 miles northwest of Opal in the foothills of the Wyoming Range. These results can be seen in the map below, or in the more detailed titled story map #1 in appendix B.

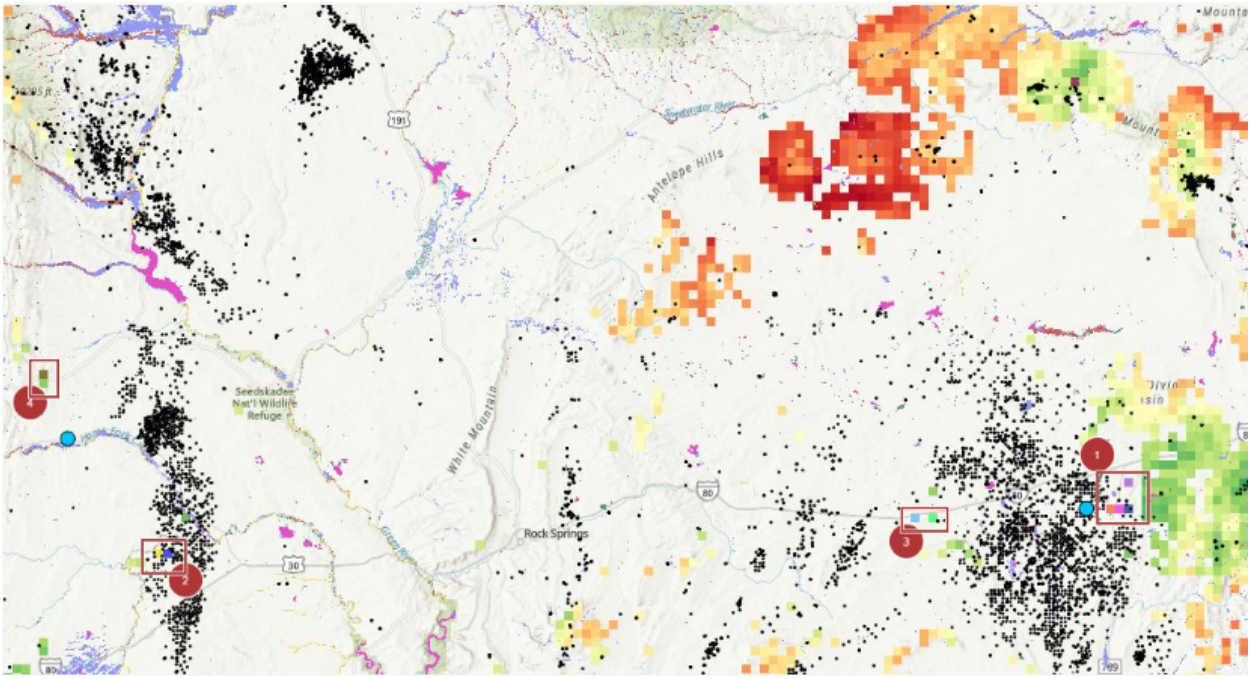


Figure 5: Initial suitability model created using initial assumptions and values for weights for each layer. The story map describing the process of creating this model can be found in Appendix A and online here: https://storymaps.arcgis.com/stories/170d8aea96244b4c817480726ba9223b

Refined GIS Suitability Model for Williams' area

Once the initial story map was presented to Williams, we consulted with Williams' new business ventures, lands, and GIS department to place more accurate weights on each of the different layers. By doing so, we were able to create a more accurate suitability model that better represented what Williams values as a midstream pipeline company. Even with these new weights, the same location east of Echo Springs still ranked the highest in the suitability model as can be seen in the red box in the map below. With this information, and all key pieces of infrastructure and regulatory information mapped, five scenarios were created with associated cost figures for each. More information on the specifics of this process can be found in story map #2 attached in appendix B.

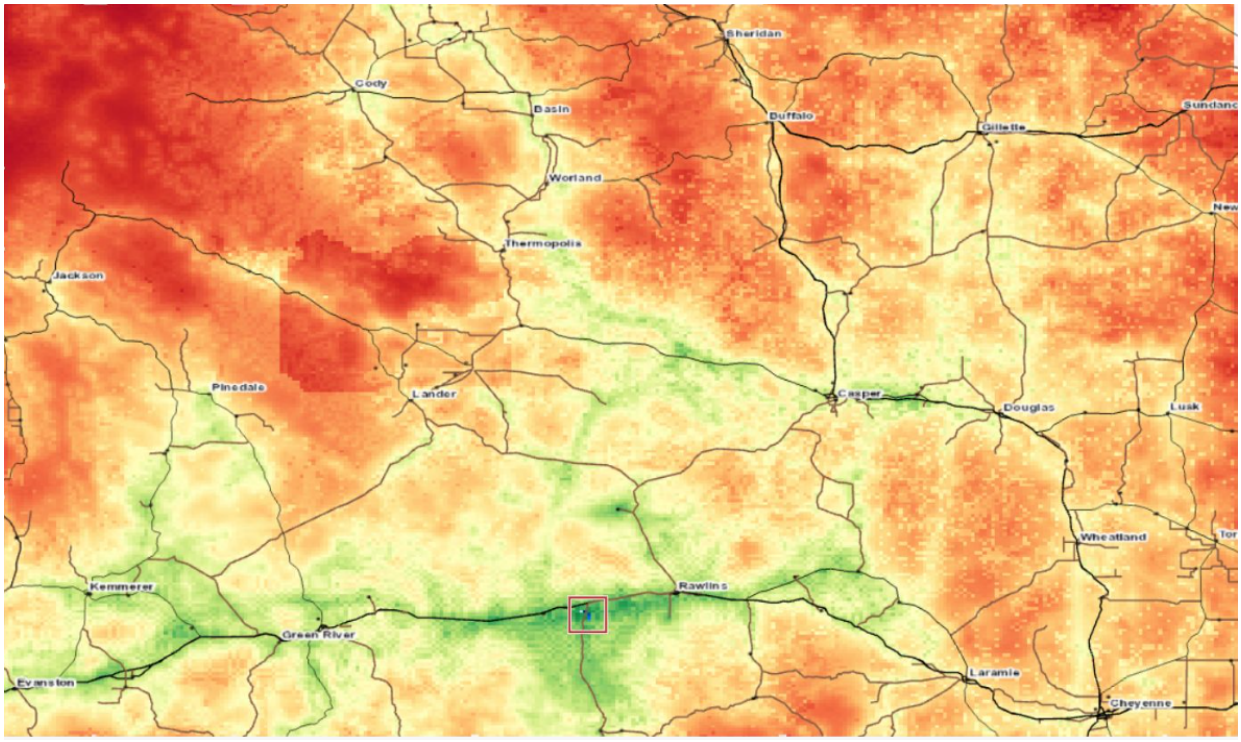


Figure 6: Final suitability model for the Williams case. This map is far more accurate and representative to the entire state of Wyoming for Williams. How this model was created and used to the cost estimates below is outlined in the following story map which is also attached in Appendix B: https://storymaps.arcgis.com/stories/9629ef4e2083447daf3d3b1115792466

Resulting Five Scenarios and Evaluation

In Scenarios A B C D E each situation follows a general set of assumptions:

Water treatment cost will be the same. The price of injecting the water per well will be the same. All water will be gathered from Atlantic Rim (or Fontenelle Reservoir, as explained below). The cost of easements, right of ways, permits, & any other form of land acquisition is not considered for any form of infrastructure except for the construction of the wind farm. The cost of conforming to certain environmental standards is not considered. Neither the Northwest Pipeline nor any other natural gas pipeline is considered to be a viable option for hydrogen transport in large volumes, and therefore because this prospective hydrogen plant is large, all pipelines must be built for their intended purpose, eg. H_2, CO_2, and water. All costs for human-hours and other planning considerations are included in these estimates. Further, these costs do not consider the cost of upkeep or maintenance for the aforementioned infrastructure nor the increase of price for natural gas over a 30 year time period. Thirty years was used as the multiplier for the natural gas figure as this is the average lifespan of a wind turbine without undergoing significant repairs. As a result, the costs in these scenarios are internally consistent but represent no more rigor than AACE level 5: Concept Screening.

Upon discovery that the legal, regulatory, and policy barriers to using water from Fontenelle Reservoir are not insurmountable for Williams, a fifth scenario was added at the very end of the project. Unlike the other scenarios which assume water from Atlantic Rim, this scenario "E" considers transport of water from Fontenelle. Each scenario is outlined below;

In Scenario A, all water is transported from Atlantic Rim to the High Point Compressor Station, where it is purified to appx. 300 TDS and the wastewater is reinjected in the nearby oil/gas field adjacent to Echo Springs. It is then converted into hydrogen via green hydrogen electrolysis using wind power from Miller Hill. The hydrogen is then transported to Echo Springs where it will be connected to a large diameter hydrogen pipeline. Scenario A considers this pipeline to be built jointly with other operators therefore, the cost of this pipeline is not considered for the final estimate.

In Scenario B, all water is transported in a large diameter pipe from Atlantic Rim to Echo Springs, where it is purified to appx. 300 TDS and the wastewater is reinjected in nearby wells. The water is then piped to Opal in a small diameter water pipeline. Once at Opal, using steam methane reforming, blue-hydrogen is made and transported to the nearest Sec. 368 energy corridor in a small diameter hydrogen pipeline and the excess CO_2 is injected using class 6 wells. Once again, the pipeline which would move hydrogen along this corridor is assumed to be jointly built.

In Scenario C, the water is treated directly on-site at Atlantic Rim and then the waste water is reinjected in these wells. It is then transported in a small diameter pipeline to the High Point Compressor station where it is turned into H2 using green hydrogen electrolysis utilizing wind energy from Miller Hill. Then the hydrogen is transported to Opal in a small diameter hydrogen pipeline where it would connect to a large diameter hydrogen pipeline that would be jointly built to connect to the rest of the western United States, probably on a parallel route to the existing Northwest Pipeline.

In Scenario D, the water is treated directly on site at Atlantic Rim and the waste water is also reinjected there. The now pure water is transported in a small diameter pipeline to Opal. Using the reasonable assumption that a wind farm could be built within 20 miles of an electric transmission line and connect to this transmission line with a new transformer station, power will be sent to Opal in this manner. Thus, green hydrogen electrolysis can be performed here. There is not suitable wind energy near Opal to operate a 600 MW facility in a practical manner without doing this, so electrical power must be brought into the site from far away.

In Scenario E, pure water is gathered from the Fontenelle Reservoir northeast of Opal and transported in a small diameter pipeline adjacent to a Williams owned pipeline to Opal. Here, steam methane reforming is conducted and hydrogen is produced and transported to a Section 368 energy corridor. The excess carbon produced is then sequestered nearby with a class VI well.

The cost of water is not considered for this scenario because the project has estimated it will be de-minimis.

Infastructure Type	Cost Factor	Distance & # A	Distance & # B	Distance & # C	Distance & # D	Distance & # E
Large diameter water pipeline	$2 mil/mile	25.4 miles	30.9 miles			
Small diameter water pipeline	$700,000/mile	5.3 miles	148.6 miles	25.4 miles	174.0 miles	29.5 miles
Large diameter hydrogen pipeline	$13.6 mil/mile					
Small diameter hydrogen pipeline	$6.8 mil/mile	5.3 miles	29.8 miles	148.6 miles		29.8 miles
Natural gas	$7.9/mcf		1,500,000 mcf * 30			1,500,000 mcf * 30
Transmission Line Cost	$2 mil/mile	33.56 miles		33.56 miles	20 miles	
Compressor Stations Cost	$15 million	3 compressors	9 compressors	5 compressors	9 compressors	2 compressors
Wind Turbines Cost	$5.8 million	182 turbines		182 turbines	182 turbines	
Substation Cost	$140 million				1 substation	
Total Cost For Class IV Well(s)	$19.5 million		$19.5 million			$19.5 million

Total Cost A	Total Cost B	Total Cost C	Total Cost D	Total Cost E
$1.258 B	$618.0 M	$2.227 B	$1.492 B	$317.8 M

Figure 7: Here, the numbers used for each cost estimate can be seen. The chart alludes that scenario E possesses the lowest infrastructure cost at $317.8 million dollars. This low-cost is achieved by using cleaner water with de minimis treatment costs, and avoiding construction of Wind Turbines.

Background

These estimates were generated using the average overall cost of projects with the same characteristics to the infrastructure needs for the scenarios above and reducing these costs into a per well, turbine, mile, etc. format. This was done using a form of dimensional analysis. The projects used to create these numbers include the H2PI Pipeline, Union Hills to Cave Creek Pipeline, TB Flats and Ekola Flats Wind Projects, Carbon Safe Phase II, and annual project estimates from the U.S. Energy Information Administration and the Federal Energy Regulatory Commision. While not directly used, the Illinois Basin Decatur Project and Petra Nova Project were used to provide further clarity when a range of estimates was given. By going through this process high level estimates were produced for each piece of critical infrastructure that would be necessary for both a green and blue hydrogen production facility.

Results for Southwest Wyoming

After using estimates in conjunction with ArcGIS Pro, Scenario E came out to be the most cost effective method for blue hydrogen production at $317.8 million. This scenario is significantly less expensive because: i. Its water source is close to the proposed plant location; ii. There are already many pipelines in the area; iii. Wind power is not used; iv. There are nearby oil and gas wells; and v. the hydrogen is being created close to its final destination eliminating the need for a long hydrogen pipeline. While using this method of cost estimation did yield this result, the legal challenges, from both the federal government and environmental groups, that would arise from using a large volume of water from a surface level drinking water source would most likely add a

significant amount of cost or halt the project entirely even with the consideration that a large amount of water allocation rights are still held by the state of Wyoming. For this reason, a thorough legal review would need to be conducted specifically for the Fontenelle case in order to determine its viability.

When looking at the viability of building an electrolysis plant for green hydrogen, the infrastructure for scenario A came had the lowest cost, $1.258 billion. This cost was lower than others because the pipeline connecting Echo Springs to Opal was replaced with a large diameter pipeline with other operators. If Williams wants to solely own all the infrastructure for this project, a water pipeline should be built from Atlantic Rim or another closer, suitable water source to Opal and the hydrogen should be produced there. If possible, the site at which the water is produced should also be the site where the water is purified and wastewater reinjected to further reduce cost. Another option that should be considered would be to build a wind farm then connect this windfarm to the grid in order to transport the power over large distances to the plant location. This may be impossible, as 600 MW is a substantial amount of power, but this option should be considered because it externalizes the cost of transporting electricity. In conclusion, there is not an exact answer as to the most economic way to produce green hydrogen using electrolysis in Wyoming but, the scenarios and suggestions herein stated can be used as a general guideline for planning a green hydrogen project.

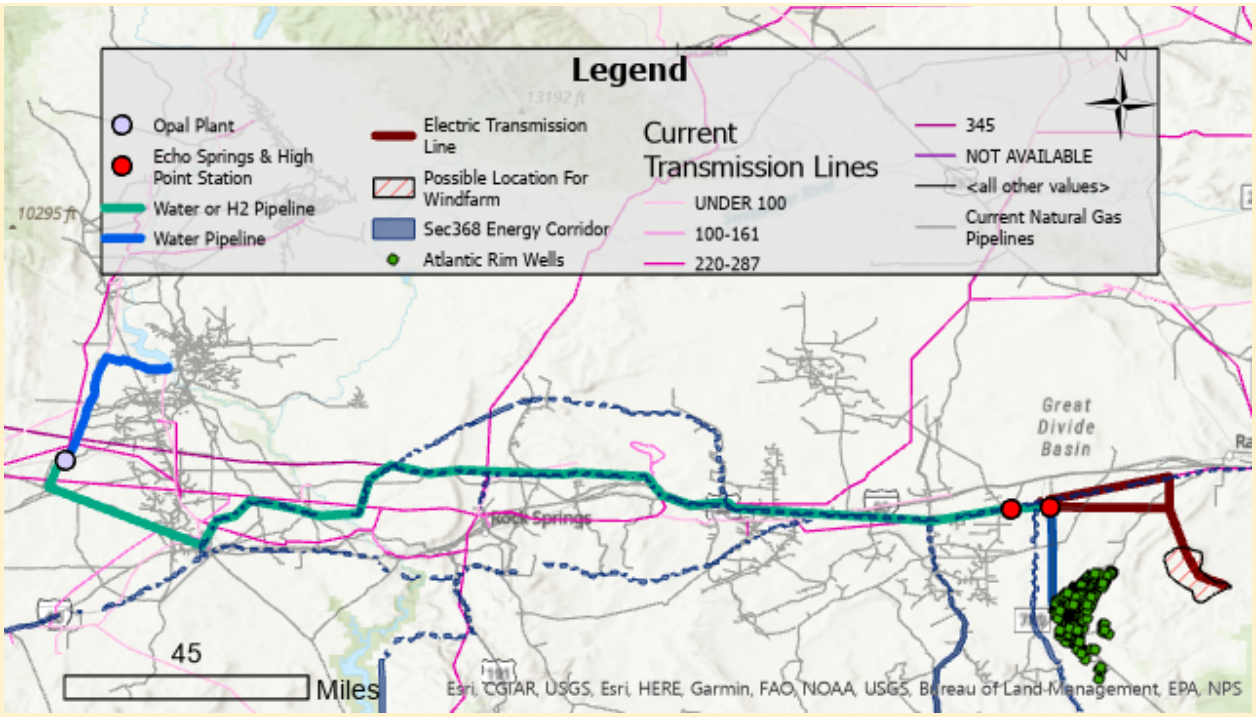


Figure 8: Map depicting proposed pipeline, transmission line, produced water gathering wells, and possible wind farm site. These routes were used to create the above mentioned scenarios.

Hydrogen production plants from literature

Cost estimates were made from levelized cost estimates of hydrogen found in publicly available literature. Each category of hydrogen production was investigated through multiple journals and then filtered for similarity compared to the proposed Williams project. The scientific articles were filtered by year, not including any articles older than one decade. They were also filtered by location only including countries with similar workers' wages or material costs. If a carbon capture system (CCS) was necessary, as it is in "blue" hydrogen production, estimates that did not include CCS were excluded. Lastly, estimates were filtered by production size to eliminate all production rates below 200 kg of hydrogen/hr. If the available data in the article met these four criteria it was then recorded and used in the average estimates. These cost estimates therefore represent a curated subset of reported costs.

Costs and adjustments

Three green hydrogen production methods and two blue hydrogen production methods were studied and calculated on a cost per kg of hydrogen produced basis. The findings showed that green hydrogen is the most expensive. Estimates for all green hydrogen production methods including proton exchange membrane electrolysis (PEM), alkaline electrolysis (AEL) and solid oxide electrolysis (SOE) were on average $5.52, $4.49, and $5.13 respectively. The cost estimates for the two forms of blue hydrogen production, steam methane reformation (SMR) and autothermal reformation (ATR), were relatively much less expensive on the same basis. SMR has an estimated cost of $2.73 per kg of hydrogen produced and ATR has the lowest estimated cost of $2.30 per kg of hydrogen produced. Although blue hydrogen is estimated to be the most cost efficient, both blue hydrogen production methods carry with them greenhouse gas concerns. These concerns can be negated, however, if a carbon capture system is implemented. All cost estimates were also adjusted for the current year (2023) using the consumer price index equation below.

$$CPIt = (Ct \div C0) * 100 \quad (1)$$

Where CPI_t is the consumer price index in the current period, C_t is the cost of the market basket in the current period, and C_0 is the cost of the market basket in the base period.

Hydrogen cost estimates

Currently the team has investigated three main types of hydrogen production for cost estimates. These include electrolysis, which has the three sub categories of "green" hydrogen: PEM, AEL and SOE. The other two main forms of hydrogen production are SMR and ATR, both of which produce"blue" hydrogen.

The cost estimates were made by reading publicly available data and journals of real world examples as well as estimates for novel ideas for plants that are similar to those being considered for the Williams project. Considerations when evaluating a source included scale, location, energy source, year the study was conducted, and presence of CCS for blue hydrogen. Whenever the study was from 2022 or older, the sources were then averaged by category and converted to U.S. dollars to adjust for inflation and escalation. Dollar values from 2023 were left unaltered. Using these costs per category of hydrogen production methods yielded the results detailed below.

Proton exchange membrane electrolysis

PEM can range widely on the amount of heat energy required depending on the operating temperature. It also only requires electricity as a power source, and water as a reactant. The PEM method has an average price ranging from $4.26 to $8.00 per kg of hydrogen produced. The average cost estimate for AEL electrolysis is $5.52 per kg of hydrogen.

Alkaline electrolysis

AEL requires a moderate amount of heat energy when compared to the other methods. It too only requires electricity as a power source, and water as a reactant. The AEL method has a similar average price ranging from $2.27 to $7.66 per kg of hydrogen produced. The average cost estimate for AEL electrolysis is $4.49 per kg of hydrogen.

Solid oxide electrolysis

SOE has the highest amount of heat energy required among the methods investigated. It only requires electricity as a power source, and water as a reactant. The SOE method has a similar average price ranging from $3.10 to $8.32 per kg of hydrogen produced. The average cost estimate for SOE electrolysis is $5.13 per kg of hydrogen.

Steam methane reformation

SMR has the third lowest heat energy requirement. It requires both electricity and methane as a power source, and it requires both water and methane as reactants. The SMR method has a much lower average price ranging from $2.57 to $3.00 per kg of hydrogen produced. The average cost estimate for SOE electrolysis is $2.73 per kg of hydrogen.

Autothermal Reformation

ATR has the second lowest heat energy requirement only behind PEM. It requires both electricity and methane as a power source, and it requires water, methane and oxygen as reactants. The ATR method has a similar average price ranging from $1.67 to $2.85 per kg of hydrogen produced. The average cost estimate for SOE electrolysis is $2.30 per kg of hydrogen.

Cost overview

The data below show that the two most cost-efficient forms of hydrogen production are SMR and ATR averaging $2.73 and $2.30, respectively. The most expensive method of hydrogen formation is electrolysis. All three categories of electrolysis cost nearly twice as much as blue hydrogen, averaging between $4.08 and $4.65. Estimates of SMR cost are fairly inexpensive and group the most tightly within $2.57 to $3.00. The estimated costs of SOE has the widest range from $3.10 to $8.32. The uncertain cost of electricity is the main source of ambiguity in all cost estimates. Electricity cost was typically location dependent and on average made up 50-65% of the total cost.

Method	Range	Average	N =
Electrolysis (PEM)	$4.26-8.00	$5.52	3
Electrolysis (AEL)	$2.27-7.66	$4.49	8
Electrolysis (SOE)	$3.10-8.32	$5.13	4
Steam Methane Reformation (SMR)	$2.57-3.00	$2.73	4
Autothermal Reformation (ATR)	$1.67-2.85	$2.30	6

Figure 9: A Table showing range of estimates used to calculate the average, and the average cost estimate per kg of hydrogen produced.

The graph below represents three types of green hydrogen production via electrolysis and two types of blue hydrogen via SMR and ATR. The most expensive form of hydrogen production under current estimates is PEM electrolysis at an estimated $5.52 followed closely by SOE and AEL electrolysis at $5.13 and $4.49 respectively. SMR is the second most cost-effective hydrogen production method at an estimated cost of $2.73 per kg of hydrogen. The most cost-effective form of hydrogen production is ATR with an estimated cost of $2.30 per kg of hydrogen.

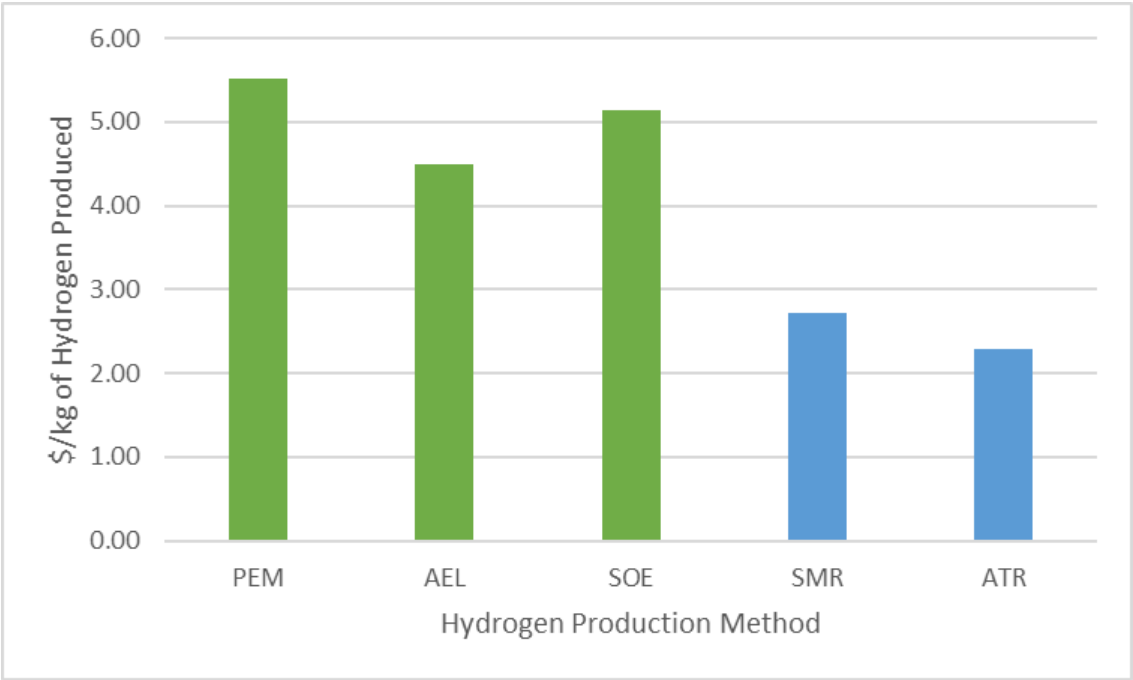


Figure 10: A graph showing the visual representation of the three forms of green hydrogen electrolysis costs versus the two forms of blue hydrogen cost in $/kg of hydrogen produced.

The scale of input requirements

Calculations were made estimating the water, methane, and oxygen requirements for electrolysis, SMR and ATR. All five methods (3 electrolysis, SMR and ATR) require water; however, methane is only a requirement in SMR and ATR, and oxygen is only required for ATR.

Electrolysis material demand

Electrolysis is a process that uses DC electricity to split a water molecule (H_2O) into hydrogen and oxygen. During this process, an electric current is sent through an electrolyte (the high-purity water), this electricity is consumed when the water splits, and it is stored in the molecular bonds of the hydrogen and oxygen produced. The reaction is not self-sustaining and requires continuous input of electricity. Below is the fully balanced equation for the electrolysis process.

$$2H_2O \rightarrow 2H_2 + O_2;\ \Delta H_{rxn} = 286 \text{ kJ/mol} \quad (2)$$

As seen above from the balanced equation, the only reactant necessary for this reaction to proceed is water. After the reaction, two H_2 and one O_2 molecule will be produced for every H_2O molecule reacted.

A material balance and water estimate were calculated for annual water needed in barrels (bbl) per year based on a 600 MW electrolysis facility that is capable of producing 11,430 kg of hydrogen per hour. Work by Hinkley et al., 2022 has shown that an average of approximately 2.5 weeks of downtime can be expected in a normal year of electrolysis operations, leaving the plant with 8340 operating hours yearly. Electrolysis of water requires an estimated 9.1-15.5 kg of water for every kilogram of hydrogen produced (Motazedi et al., 2021). Dr. Jonathan Brant of the University of Wyoming's Center for Excellence in Produced Water Management has calculated that the salt water produced during oil and gas operations near the study site can be purified to an ultra-pure standard at a recovery rate of nearly 67%.

Using the previous assumptions we estimated 13.8 million bbl of water would be required. This estimate assumed an additional 6.5 kg of water would be needed throughout the plant per kg of hydrogen produced.

Steam methane reformation material demand

Steam methane reformation is a process where heat is supplied to a system and methane reacts with steam under low pressure to produce hydrogen and carbon monoxide. Below is the fully balanced equation for an SMR process.

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2;\ \ \Delta H_{rxn} = 165 \text{ kJ/mol} \quad (3)$$

As seen above from the balanced equation there are only two reactants necessary for this reaction to proceed: water (H_2O) and methane (CH_4). The product will produce four H_2 molecules and one CO_2 for every two H_2O molecules and one CH_4 molecule.

Steam methane reformation water requirement

A material balance for water and methane was calculated for an annual basis of water in bbl/year and methane in tonne/year based on a facility that produces 11,300 kg of hydrogen per hour and operates 8340 hours per year. A conservative estimate using assumptions of 11 kg of water per kg of hydrogen produced (4.55kg for water to be reacted and 6.45 kg of water needed for other amenities in the facility) and Dr. Jonathan Brant's 67% recovery rate for ultra-pure water.

Using the previous assumptions, we estimated 9.8 million bbl of water would be required. This estimate assumed an additional 6.45 kg of water would be needed throughout the plant for per kg of hydrogen produced.

Steam methane reformation methane requirement

Two assumptions that were made for methane estimates were that 95% of power usage will come from methane and that the methane has a 80% thermal efficiency. Under these two assumptions 4.13 kg of methane per kg of hydrogen produced is required as a power source in addition to the 1.99 kg of methane used as reactant per kg of hydrogen produced. A total of 6.12 kg of methane will be required per kg of hydrogen produced via SMR.

Assuming 11,300 kg/hr of hydrogen produced for an estimated 8340 annual operating hours for an SMR plant, 289,000 tonnes of methane will be required. It is also important to note a novel electric SMR could replace the need for methane as a power source and decrease the need for methane strictly as a reactant to 94,000 tonnes per year, but at the price of vastly increased electricity consumption.

Autothermal reformation material demand

ATR is a process that is a combination of steam methane reformation and the combustion of methane. During the oxidation process steam is added. Then the heat from the oxidation process is used as energy for the steam reforming process. The fully balanced equation can be seen below.

$$4CH_4 + O_2 + 2H_2O \rightarrow 10H_2 + 4CO;\ \Delta H_{rxn} \approx 0 \text{ kJ/mol} \quad (4)$$

As seen above from the balanced equation there are three reactants required for this reaction to proceed: water, methane, and oxygen. The product will produce ten H_2 molecules and four CO molecules for every four CH_4 molecules, one O_2 molecule, and two H_2O molecules.

Autothermal reformation water requirement

A material balance for water, methane, and oxygen were conducted for an annual basis of water in bbl/year and methane and oxygen in tonne/year based on a facility that produces 11,400 kg of hydrogen per hour and operates 8030 hours per year.

Using the previous assumptions, we estimated 6.7 million bbl of water would be required. This estimate assumed an additional 6.0 kg of water would be needed throughout the plant for per kg of hydrogen produced.

Autothermal reformation methane requirement

Two assumptions that were made for methane requirement were that 93% of power usage will come from methane and that the methane has a 94% thermal efficiency. Under these two assumptions, 2.96 kg of methane per kg of hydrogen produced is required as a power source in addition to the 3.21 kg of methane used as reactant. A total of 6.17 kg of methane will be required per kg of hydrogen produced via ATR.

Assuming 11,400 kg/hr of hydrogen produced for an estimated 8030 operating hours for an ATR plant, 283,000 tonnes of methane will be required. Although no such study currently exists, it could be estimated that a novel electric autothermal reformation plant could decrease the need for methane to as little as 147,000 tonnes per year if all of it were used strictly as a reactant.

Autothermal reformation oxygen requirement

For ATR, pure oxygen is a required reactant. The only oxygen requirement will be for the reaction itself and no other additional oxygen was accounted for in the estimates. Using the previous assumption of 11,400 kg hydrogen produced per hour and 8030 operating hours per year, 73,000 tonnes of oxygen will be required per year to meet the demand.

Reactant requirement overview

The graph below represents three types of hydrogen production and their respective material requirements. Electrolysis has the highest water demand at 1.10 million tonnes/year, but it has no methane or oxygen requirement. SMR has the second highest water requirement at 778 thousand tonnes per year, and the highest methane requirement at 289 thousand tonnes/year. ATR has the lowest water requirement at 536,000 thousand tonnes per year, a methane requirement of 283 thousand tonnes/year, and an additional oxygen requirement of 72 thousand tonnes per year.

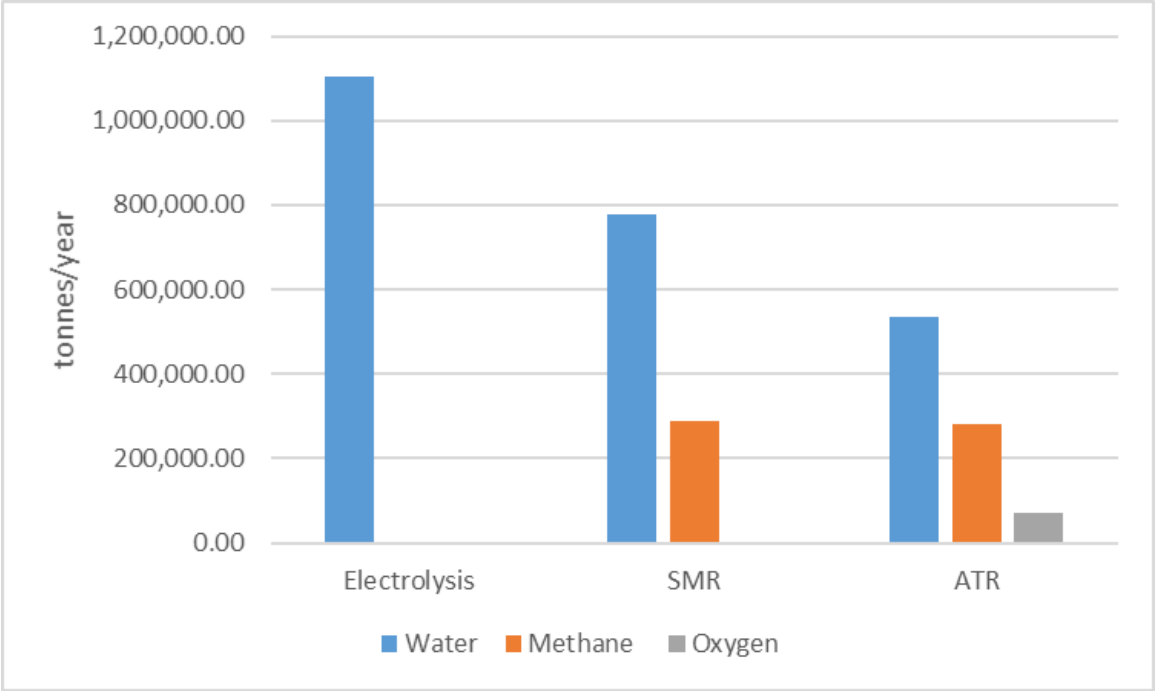


Figure 11: A graph showing the visual representation of reactant requirements for each method of hydrogen production.

Power requirement overview

The power requirement was calculated in the three main categories: electrolysis, SMR, and ATR. Electrolysis does not require methane and is purely reliant on electricity to power the system. Electrolysis requires nearly 191 MJ/kg of hydrogen produced. SMR requires both methane and electricity as power sources and it has the largest power requirement with a total of 271 MJ/kg of hydrogen produced. The largest power source for SMR is natural gas or methane accounting for 93% of the total power required and electricity makes up the other 7%. ATR has the lowest power requirement with a total of 163 MJ/kg of hydrogen produced. An estimated 92% of the power required is from methane and the other 8% is from electricity.

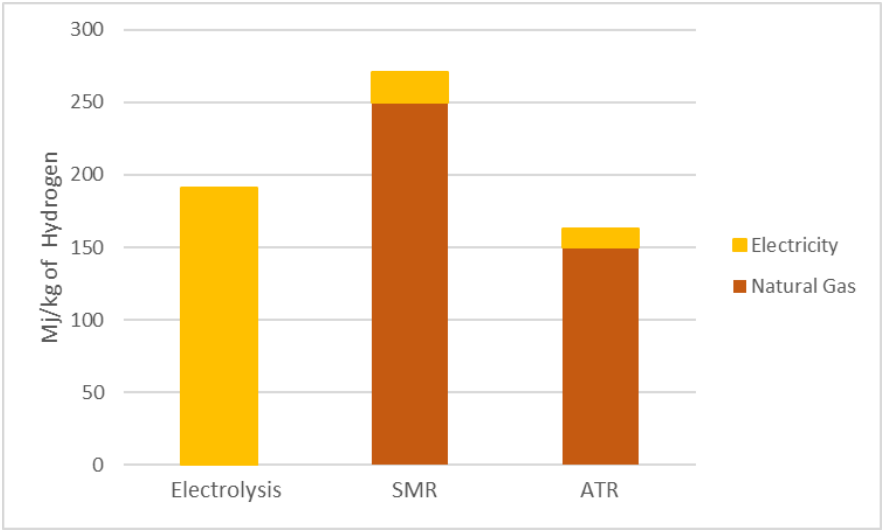


Figure 12: A graph showing the electricity and natural gas requirements to power each hydrogen production method.

Heat requirement overview

The heat requirement was calculated for PEM, high-temperature PEM electrolysis (HT-PEM), AEL, high-temperature AEL electrolysis (HT-AEL), SOE, SMR and ATR. HT-PEM and HT AEL are used independently in this section for its comparative value to the other hydrogen production methods discussed, whereas they were included under the PEM and AEL categories in previous sections. A wide range of temperature values can be used for each method, so a median temperature was used for each method from publicly available literature. PEM was calculated using an operating temperature of 90 ºC and found to require 2,400 kJ/kg of hydrogen produced. HT-PEM was calculated using an operating temperature of 180 ºC and found to require 24,400 kJ/kg of hydrogen produced. AEL was calculated using an operating temperature of 150 ºC and found to require 23,900 kJ/kg of hydrogen produced. HT-AEL was calculated using an operating temperature of 80 ºC and found to require 2,060 kJ/kg of hydrogen produced. SOE was calculated using an operating temperature of 750 ºC and found to require 34,600 kJ/kg of hydrogen produced. SMR was calculated using an operating temperature of 800 ºC and found to require 21,600 kJ/kg of hydrogen produced. ATR was calculated using an operating temperature of 900 ºC and found to require 15,700 kJ/kg of hydrogen produced. Although the operating temperatures range widely from 80 to 900 ºC the heat budget of all techniques except for PEM and AEL are similar due to the fact that the bulk of the energy is used to convert water to steam. The latent heat of vaporization is nearly 540 times that of the specific heat of water and nearly 1,140 times that of steam. PEM and AEL do not convert water into steam and therefore do not have a latent heat of vaporization energy requirement. The energy requirement for the latent heat of vaporization is even greater when compared to the specific heat of methane or oxygen gas.

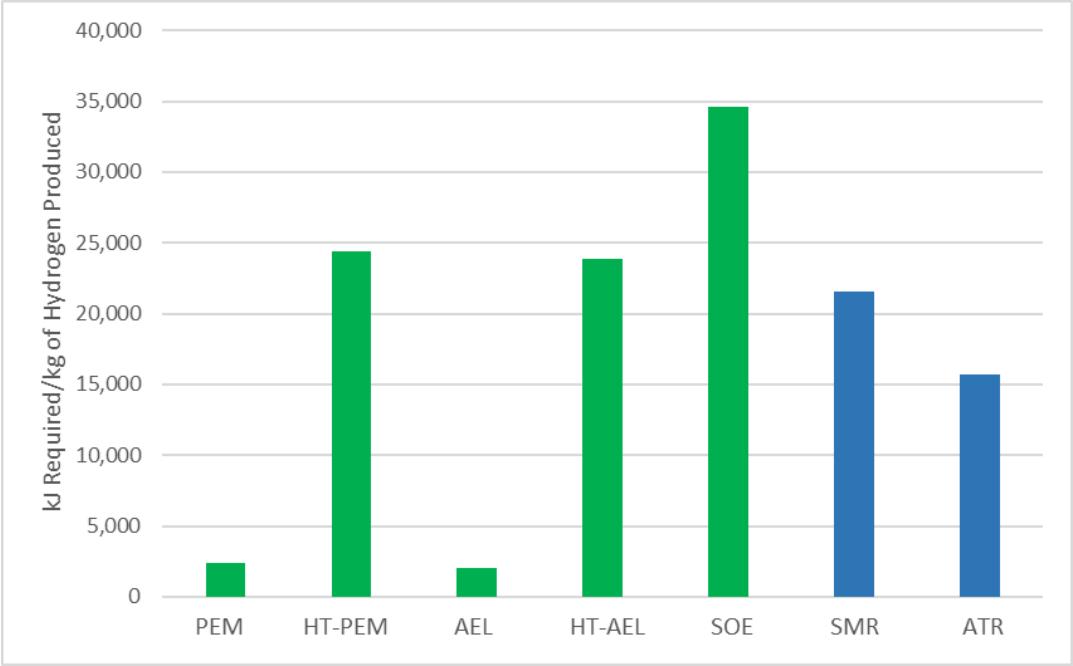


Figure 13: A graph showing the heat requirement for each hydrogen production method.

Comparing the three main hydrogen production methods ATR appears to be the best option for hydrogen production. It is the most cost-effective hydrogen production method with an average cost of $2.30 per kg of hydrogen produced. In terms of reactant demand ATR is once again the best option if the water available is limited and of concern, as it requires the lowest amount of water. Lastly ATR requires the least amount of heat and total energy per kg of hydrogen produced implying it may also be the most most energy efficient method of hydrogen production.

Statewide suitability map

Feedstocks for hydrogen generation always include water and electricity. If the hydrogen is produced by the SMR or ATR process with carbon-capture-and-storage then methane is also needed. The exact style of producing Hydrogen from these feedstocks affects their relative quantities needed. For this milestone, we have selected a weighting which combines both electrolysis and the ATR processes. The result approximates both of the most likely hydrogen production methods, but is a true representation of neither.

The GIS project used to make this map weights every location in the state (at variable scale) based on factors which make siting a hydrogen plant there more or less favorable. The top ten rated locations form four clusters around Wyoming, as shown on the figure below.

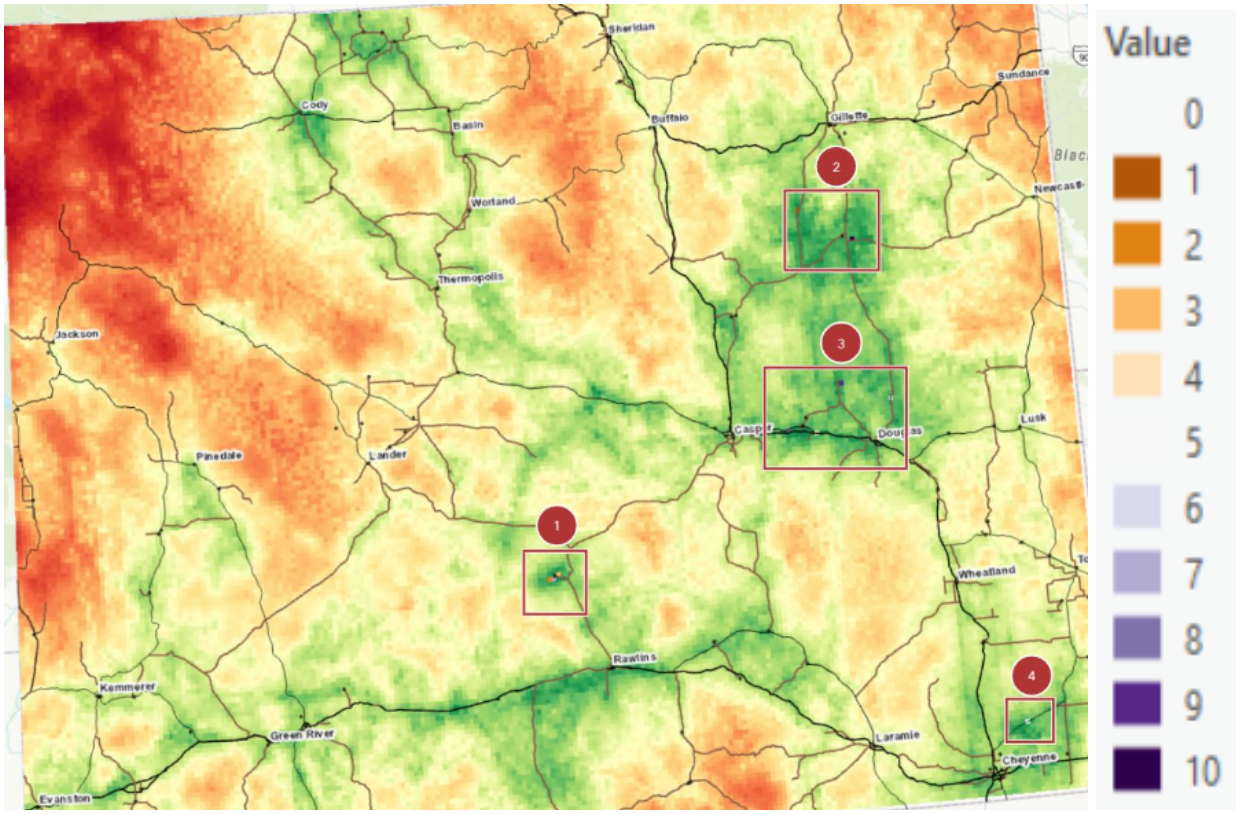
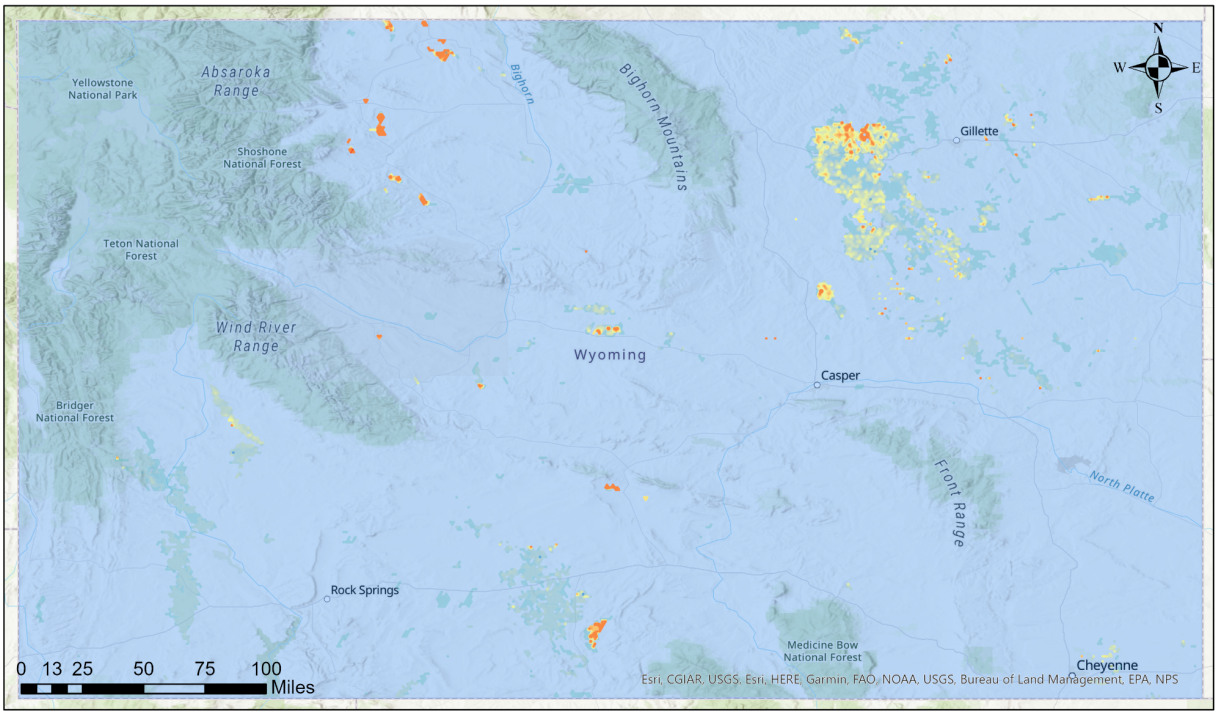


Figure 14: Final Suitability Model considering no Williams-specific infastructure. This model indicates that the best areas for hydrogen to be produced in Wyoming are in and near the Powder River Basin. The Bairoil area of the Greater Green River Basin and the Denver-Julesburg Basin also scored highly.

When considering the entire state and no Williams specific needs, the above suitability model was generated. Location #1, which is near Bairoil Wyoming, ranked the highest because of its access to water, windpower, proximity to a Section 368 Energy Corridor and all pieces of critical infrastructure for this project. Locations #2 and #3, which are located in between Gillette and Douglas, scored highly because the PRB has a plentiful supply of water and pipelines as well an abundance of wind power. Lastly, location #4 which is north of Cheyenne, scored highly for the same reasons as locations two and three. In terms of supporting infrastructure, wind power, and availability to water, these four locations possess the best conditions for a hydrogen production facility in Wyoming.

This map of hydrogen feedstock availability does not weight surface waters as a feedstock because use of those waters frequently triggers a NEPA review or cannot be realized due to over-allocation of water rights. This generalization notably does not hold in the Greater Green River Basin, where Fontanelle Reservoir has significant unallocated water-rights.



BBLS OF WATER PRODUCED PER WELL PER YEAR, 2020

00.0-100.0	10,000.0-14,000.0	50,000.0-60,000.0	1,300,000.0-1,500,000.0
100.0-1,000.0	14,000.0-20,000.0	60,000.0-72,000.0	1,500,000.0-2,000,000.0
1,000.0-2,000.0	20,000.0-26,000.0	72,000.0-84,000.0	NoData
2,000.0-4,000.0	26,000.0-32,000.0	84,000.0-98,000.0	
4,000.0-6,000.0	32,000.0-40,000.0	98,000.0-1,140,000.0	
6,000.0-10,000.0	40,000.0-50,000.0	1,140,000.0-1,300,000.0	

Statewide Water production, puts the scaling of gives some perspective on Figure 3's detail of the Green River Basin. Although Atlantic Rim is a significant producer, the Moxa Arch and Pinedale anticline do not appear as impressive when the whole state is considered.

Conclusions

Water is available in the Green River Basin through three paths. If a group is willing to invest significant time, and has a use which would pass NEPA, then Fontanelle Reservoir can be used to supply ultrapure water at very low cost. If a group is willing to invest more significantly and tolerate modest legal uncertainty, then produced water waste from Atlantic Rim can be disposed of through treatment and beneficial use in hydrogen generation. And lastly, if a group is willing to risk being among the first water rights cut, then it is possible to acquire a junior water right in the Green River Basin. Water is a deeply emotional issue in the arid west, and those intense feelings are reflected in the regulatory regime. It is possible to meet demands for hydrogen production, although not without risk and cost.

Future projects in Wyoming could study whether a particular kind of project is the most favorable everywhere, or if this is more a matter of matching with local conditions.

Contributions and Acknowledgements

Charles Nye drafted this manuscript. Jon Brant, Jacob Schneider, and William Lawler contributed sections on water treatment, GIS, and hydrogen generation respectively. Matthew Johnson provided figures and data analysis. Dayana Zhappassova adjusted costs to a common year and advised on economics. All authors reviewed the manuscript and compiled edits.

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Further reading

Killough, Kevin. 2022 "Gordon: Wamsutter, Wyoming Is Ground Zero For Hydrogen Power; Williams To Invest $300 Million" Cowboy State Daily, September 15, 2022. Accessed from: https://cowboystatedaily.com/2022/09/15/gordon-wamsutter-wyoming-is-ground-zero-for-hydrogen-power-williams-to-invest-300-million/

Texas Natural Resource Code §122.002. Title 3 "Oil And Gas". Subtitle D. "Regulation Of Specific Businesses And Occupations". Chapter 122. "Treatment And Recycling For Beneficial Use Of Fluid Oil And Gas Waste" Accessed from: https://statutes.capitol.texas.gov/Docs/NR/htm/NR.122.htm

Wyoming Water Law Overview

Jada F. Garofalo*

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INTRODUCTION

The waters of Wyoming flow within and across the states' borders; thus, the allocation of water rights is affected by both intrastate regulations (*e.g.*, state-based regulations) and interstate regulations (*e.g.*, federally-based regulations). Accordingly, there are a variety of legal tools and instruments that apply to the allocation of water rights and a variety of regulators.

This document provides an overview of the regulatory framework governing water rights and allocation in the state of Wyoming. It begins with a summary of each of the water regulating bodies, including their duties and scope. It then describes Wyoming's regulatory framework used for intrastate water allocation—the prior appropriation doctrine. An overview of the permitting system implemented by water regulators to administer water rights is discussed next. The paper closes with a discussion of methods to acquire water rights in Wyoming. Areas of interest to the Williams Wyoming Hydrogen Hub (hereinafter "W2H2") are highlighted, where relevant throughout the document. While the whole of this document provides context for the W2H2 project, the most relevant sections of this document to the project are Sections 4 and 5, which discuss different methods to acquire or modify water rights and what the take-aways are for the W2H2 project.

1. WATER REGULATION IN WYOMING

a. The State Engineer

The Wyoming Constitution established the State Engineer as the entity responsible for water administration and regulation in the state.[1] The State Engineer is appointed by the Governor and charged with supervision of the waters of the state and of the officers connected with its distribution.[2] The State Engineer serves for six-year terms or until a successor is appointed.[3]

The State Engineer's Office (hereinafter, "SEO") is comprised of the State Engineer, the Deputy State Engineer, the Board of Professional Engineers and Professional Land Surveyors,[4]

[1] Wyo. Const. Art. VIII, § 5.
[2] *Id*.
[3] *Id*.
[4] Wyoming was the first state to require engineer licensure in 1907. The Board of Professional Engineers and Professional Land Surveyors oversees and administers the licensing of professional engineers and land surveyors. *See* WYOMING BOARD OF PROFESSIONAL ENGINEERS AND PROFESSIONAL LAND SURVEYORS, https://engineersandsurveyors.wyo.gov/ (last visited Nov. 1, 2021).

the Water Well Contractors Licensing Board,[5] the Support Services Division,[6] the Interstate Stream Division, the Surface Water Division, the Groundwater Division, and the Board of Control Division.[7]

i. The Surface Water Division

The Surface Water Division of the SEO is responsible for reviewing permit applications and issuing permits for water uses that beneficially use surface waters of the state of Wyoming.[8] Permits are issued for the following uses:

- Diverting waters through ditches or pipelines;
- Storage in reservoirs;
- Enlargements to existing ditch or storage facilities;
- Instream flow purposes;
- Temporary industrial water hauls; and
- Weather modification.[9]

The Surface Water Division is also responsible for overseeing petitions for changing adjudicated water rights and approving temporary changes of use when water right owners sell rights to another user on a temporary basis.[10] Maintaining the safety and integrity of all dams in the state also falls under the Surface Water Division's purview.[11]

ii. The Groundwater Division

The Groundwater Division of the SEO processes and administers all groundwater permits in the state.[12] It also maintains a statewide observation-well network, conducts investigations on claims of well interference, inspects water rights for adjudication and prepares proofs of

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[5] In 2008, the Wyoming Legislature passed a law requiring licensure for all water well drilling contractors and pump installation contractors. The Water Well Contractors Licensing Board is responsible for overseeing and administering the licensing process. W.S. 33-42-103(f); WYOMING WATER WELL CONTRACTORS LICENSING BOARD, http://wwcb.state.wy.us/AboutUs.aspx (last visited Nov. 1, 2021).

[6] The Support Services Division performs various services, including but not limited to: computer resources management; records retention, management, and preservation; database management; maintenance of the water library, and mapping services. WYOMING STATE ENGINEER'S OFFICE, AGENCY DIVISIONS, https://seo.wyo.gov/agency-divisions (last visited Oct. 21, 2021).

[7] WYOMING STATE ENGINEER'S OFFICE, AGENCY DIVISIONS, https://seo.wyo.gov/agency-divisions (last visited Oct. 21, 2021).

[8] WYOMING STATE ENGINEER'S OFFICE, ABOUT THE SURFACE WATER DIVISION, https://seo.wyo.gov/surface-water (last visited Oct. 21, 2021).

[9] *Id*.

[10] *Id*.

[11] *Id*.

[12] WYOMING STATE ENGINEER'S OFFICE, ABOUT THE GROUND WATER DIVISION, https://seo.wyo.gov/ground-water (last visited Oct. 21, 2021).

adjudication for the Board of Control's consideration, reviews water supply reports in subdivisions, and serves as mediator in ground and surface water appropriation conflicts.[13]

iii. The Interstate Streams Division

The Interstate Streams Division is responsible for administering and overseeing all matters involving Wyoming's interstate streams and rivers on behalf of the State Engineer.[14] Its goal is to safeguard Wyoming's current and future water supply, by preserving the state's ability to use and develop its water allocations.[15] State rights to waters of interstate streams are determined by decrees of the Courts of the U.S., by interstate compacts (agreements between states that allocate the waters), and by treaties (agreements between the U.S. and other countries).[16]

The Interstate Stream Division of the SEO provides policy and technical support for water allocation, planning, and administration.[17] Wyoming's rights to waters in the Laramie River and the North Platte River were established by decree of the U.S. Supreme Court.[18] Wyoming's rights to waters in the Teton Creek and South Leigh Creek were settled by decree of the U.S. District Court for the District of Wyoming.[19] Wyoming's rights to waters in the Bear River; the Belle Fourche River; the Colorado River (via the Green River, Little Snake River, and Henry's Fork of the Green River); the Niobrara River; the Snake River; and the Yellowstone River (via Clark's Fork of the Yellowstone River, Big Horn River, Tongue River, and Powder River) were settled by interstate compact.[20] Finally, some of Wyoming's rights to water in the Green River, a major tributary of the Colorado River, are settled by an international treaty with Mexico.

The following interstate allocations are relevant to the W2H2 project and will likely affect availability of water within the study area:

- The Laramie River Decree;
- The North Platte River Decree;
- The Bear River Compact;
- The Colorado Compact of 1922 (and the Upper Colorado River Basin Compact of 1948); and

[13] *Id*.
[14] WYOMING STATE ENGINEER'S OFFICE, ABOUT INTERSTATE STREAMS, https://seo.wyo.gov/interstate-streams (last visited Oct. 21, 2021).
[15] *Id*.
[16] *Id*.
[17] *Id*.
[18] *Id*.
[19] *Id*.
[20] *Id*.

- The Mexican Water Treaty of 1944 (and the series of agreements that followed: Minute 319 and Minute 323).[21]

These interstate allocations will be examined in more detail in the next phase of this analysis, *Wyoming Water Availability in Study Area*.

b. The Board of Control

While the Board of Control (hereinafter, "BOC") is a division of the SEO, it also works in conjunction with the SEO to complete the permitting process administered by the SEO. The SEO and the BOC work together to administer the permitting system with the BOC responsible for conducting the adjudication process and evaluating final proofs of beneficial use.[22]

The Wyoming Constitution establishes the BOC as a "quasi-adjudicative body with sole jurisdiction over water adjudication, administration, and amendments."[23] Adjudication is the process by which the BOC conducts a field inspection of water use to ensure water is put to the beneficial use specified on the permit application previously submitted to the SEO.[24] The BOC also administers the process through which permit holders may change a previously adjudicated water right, such as changing the point of diversion, the type of use, the area of use, or abandoning a right.[25] The legislature awarded the BOC authority to develop rules and regulations to administer these processes.[26]

i. Water Divisions & Water Districts

The Wyoming legislature divided the state into four Water Divisions and provides for the appointment of Superintendents of each Division;[27] divisions are indicated on the map below.[28] The BOC is composed of the State Engineer, who serves as the BOC president, and the Superintendents of each of the four Water Divisions in the state.[29] The Superintendents of each Water Division regulate and control the storage and use of the water under the permits approved by the SEO, whether the rights have gone through the adjudication process administered by the BOC or not.[30] The Superintendents of each Division are appointed by the Governor and must be a

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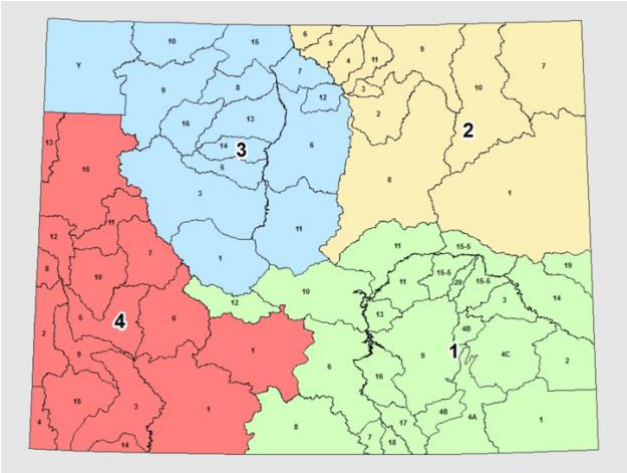
[21] WATER EDUCATION FOUNDATION, COLORADO RIVER WATER AND MEXICO, https://www.watereducation.org/aquapedia/mexico-and-colorado-river-water (last visited Oct. 21, 2021).
[22] WYOMING STATE ENGINEER'S OFFICE, PERMITTING/ ADJUDICATION/ CHANGES, https://seo.wyo.gov/permittingadjudicationchanges (last visited Oct. 21, 2021).
[23] Wyo. Admin. Code 037.0007.1 § 1(a)(b); Wyo. Const. Art. VIII, § 2.
[24] WYOMING STATE ENGINEER'S OFFICE, ABOUT THE BOARD OF CONTROL, https://seo.wyo.gov/agency-divisions/board-of-control (last visited Oct. 21, 2021).
[25] *Id*.
[26] W.S. § 41-4-211.
[27] Wyo. Const. Art. VIII, § 4.
[28] W.S. § 41-3-501; Wyo. Const. Art. VIII, § 4; Map taken from: WYOMING STATE ENGINEER'S OFFICE, BOARD OF CONTROL, https://sites.google.com/a/wyo.gov/seo/agency-divisions/board-of-control (last visited Oct. 21, 2021).
[29] Wyo. Const. Art. VIII, § 2; Wyo. Const. Art. VIII, § 5; W.S. § 41-4-201.
[30] W.S. § 41-3-503.

resident within the Water Division where appointed.[31] Each Division also has various hydrographers, inspectors, office support staff, and analysts depending on the specific need of that Division.[32]



Divisions 1 and 4 are relevant to the W2H2 study area. Water Division 1 consists of "all lands within [the] state, drained by the North Platte River, and the tributaries of the North Platte River and the South Platte River, Snake River, (a tributary of Green River) and its tributaries, and Running Water Creek and its tributaries."[33] Water Division 4 consists of "all lands within this state drained by the Green, Bear and Snake Rivers, and the tributaries thereof; except Snake River, (a tributary of Green River), and its tributaries."[34]

The Wyoming legislature also required that the BOC further divide the state into various water districts.[35] A Water Commissioner is appointed by the Governor for each water district.[36] Each water Division Superintendent has general control over the water District Commissioners within their division.[37] While the Division Superintendent is responsible for "executing the laws relative to the distribution of water in accordance with the rights of priority of appropriation,"[38] the Commissioner is responsible for dividing, regulating, and controlling the water of all streams, springs, lakes, ditches and reservoirs within their district in a manner that will "prevent the waste of water or its use in excess of the volume to which the appropriator is lawfully entitled."[39] Any person holding a "Wyoming water right may request that the source of supply for the . . . rights be

[31] W.S. § 41-3-502.
[32] WYOMING STATE ENGINEER'S OFFICE, AGENCY DIVISIONS, https://seo.wyo.gov/agency-divisions (last visited Oct. 21, 2021).
[33] W.S. § 41-3-501.
[34] W.S. § 41-3-501.
[35] W.S. § 41-3-601.
[36] W.S. § 41-3-602.
[37] W.S. § 41-3-503.
[38] W.S. § 41-3-503.
[39] W.S. §§ 41-3-603 through 41-3-608.

regulated by a water Commissioner" by providing the request to the Commissioner or Superintendent in writing.[40] This process is typically requested during periods of water shortage.

Regarding underground water, each Water Division in the state is required to have an Advisory Committee on Underground Water, consisting of three people appointed by the Governor.[41] The Underground Water Advisory Committee is responsible for assisting and advising the SEO and the BOC on policies that impact ground water in the state, providing solutions to Control Area Advisory Boards,[42] and provide information to ground water users within the Division about the regulation of ground water.[43] The SEO is authorized to determine areas and boundaries of Ground Water Districts overlying various aquifers and may established Subdistricts if parts of an aquifer require separate regulation from the rest or may establish different Districts for different aquifers that overlie each other in whole or in part.[44]

c. The Wyoming Water Development Program

The Wyoming Water Development Program (WWDP) was created in 1975 by statute to promote the optimal development of the state's combined resources.[45] The Wyoming Water Development Commission (WWDC) is responsible for developing, reviewing, and revising water and related land resources plans for the state of Wyoming."[46] The WWDC is comprised of ten individuals who are appointed by the Governor, with representation from the four water Divisions and the Wind River Reservation.[47]

The Wyoming State Water Plan is one output of the WWDC, funded by legislation starting in 1997.[48] The State Water Plan is comprised of the seven water basin plans, which quantify existing water uses and project future needs by water basin, groundwater reports, and environmental and recreation use reports.[49] The water basins are depicted in the map below.[50]

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[40] W.S. § 41-3-606. Any person injured by the action or inaction of the water Commissioner has the right to appeal to the Superintendent, who's decision may be appealed to the State Engineer. An appeal of the State Engineer's decision may be taken to the district court of the county where the controversy is situated. W.S. §41-3-603(b).
[41] W.S. § 41-3-908.
[42] These are defined and discussed in the Ground Water Section below.
[43] W.S. § 41-3-908.
[44] W.S. § 41-3-910.
[45] W.S. § 41-2-112; WYOMING WATER DEVELOPMENT OFFICE, HOME PAGE, https://wwdc.state.wy.us/ (last visited Oct. 21, 2021).
[46] W.S. § 41-2-107.
[47] WYOMING WATER DEVELOPMENT OFFICE, HOME PAGE, https://wwdc.state.wy.us/ (last visited Oct. 21, 2021).
[48] W.S. § 41-2-107; WYOMING STATE WATER PLAN, MISSION STATEMENT, https://waterplan.state.wy.us/about/mission.html (last visited Oct. 21, 2021).
[49] WYOMING STATE WATER PLAN, WYOMING RIVER BASIN PLANS, https://waterplan.state.wy.us/plan/plan.html (last visited Oct. 21, 2021).
[50] Map taken from: WYOMING STATE WATER PLAN, NEW AND INFORMATION, MISSION STATEMENT https://waterplan.state.wy.us/about/mission.html (last visited Oct. 21, 2021).

The WWDC is required to publish, disseminate, and recommend action based on the water resource plans; thus, the plans may heavily influence legislation and the acquisition of water rights by the state.[51] At the direction of the Governor, the WWDP is required to file any necessary permit applications in the name of the state to appropriate water, construct dams, acquire, or maintain the priority of any right essential to any project of the WWDP, but there is no power of eminent domain.[52] The Green River Basin Plan, the Platte River Basin Plan, and the Groundwater Reports will be examined in more detail in phase two of this analysis, *Wyoming Water Availability in Study Area*.

2. A Summary of Wyoming Water Law

a. The Prior Appropriation Doctrine

The Wyoming Constitution specifies that, "[t]he water of all natural streams, springs, lakes or other collections of still water, within the boundaries of the state, are hereby declared to be the property of the state."[53] The state defines a water right as the "right to *use* the water of the state, when such use has been acquired by the beneficial application of the water under the laws of the state . . ."[54] Notably, the right is one of *use*, not of ownership; "[w]ater always being the property of the state."[55]

Wyoming, like many other western states, follows the prior appropriation doctrine for both surface and ground water.[56] Under the prior appropriation doctrine, the first person to take water

[51] W.S. § 41-2-110; W.S. § 41-2-116.
[52] W.S. § 41-2-116.
[53] Wyo. Const. Art. VIII, § 1.
[54] *Id*.
[55] W.S. § 41-3-101 (emphasis added).
[56] W.S. § 41-3-101 et. seq. (emphasis added).

and put it to *beneficial use* has the right to continue to use that water and their right has seniority over any junior appropriator so long as the use does not *injure* any other appropriator.[57] Wyoming statutes specify that "beneficial use shall be the basis the measure and limit of the right to use water at all times."[58] A water right also attaches to the land or place of use for which appropriated, and is limited to the use for which appropriated and by public interest.[59]

The State Engineer's office defines and establishes the following categories of beneficial use:

- Irrigation, defined as water used for the irrigation of any lands for agricultural purposes not included in the definition of domestic use;
- Municipal, defined as the water used within a municipality (this does not include water used within non-municipal subdivisions, trailer parks, etc.);
- Industrial, defined as including oil field secondary recovery operations, industrial processing, mining and other industrial uses;
- Domestic, defined as household use and the watering of lawns and gardens for non-commercial family use, where the area irrigated is not larger than one acre;
- Stock, defined as the normal watering of livestock. Feedlot operations are not "stock use" but instead are classified as "miscellaneous";
- Miscellaneous, consisting of any other beneficial uses not previously described. For instance, trailer parks, campgrounds, temporary drilling or industrial use, automobile service stations, motels, and subdivision developments. On an application, the use must be described in detail.[60]

Wyoming codified the prior appropriation doctrine and the administration of water rights in Title 41 of Wyoming's Statutes, which now governs the allocation of surface and ground water.[61] According to the water code, some uses are preferred over others. Preferred uses for both surface and ground water include, with preference in the following order:

- Water used as drinking water for "man and beast";
- Water for municipal purposes;
- "[W]ater for the use of steam engines[,] . . general railway use, water for culinary, laundry, bathing, refrigerating . . . for steam and hot water heating plants, and steam power plants";
- Water for industrial purposes; and

[57] BARTON H. THOMPSON, JR. ET AL., LEGAL CONTROL OF WATER RESOURCES CASES AND MATERIALS 6 (West Publishing Co. 5th ed. 2013).
[58] Wyo. Admin. Code 037.0007.1 § 4; W.S. § 41-3-101.
[59] *Id*.
[60] Wyo. Admin. Code 037.0006.3 § 2.
[61] W.S. § 41-1-101 et seq.

- Water used for irrigation, which is superior to any water used for hydroelectric power.[62]

While any existing superior preferred use may condemn an inferior preferred use or a non-preferred use, the exception is that *industrial uses do not have power of condemnation over water for irrigation*.[63] Municipalities also have eminent domain power in addition to their power of condemnation over lower priority uses.[64] Type of use preferences typically become most relevant in times of shortage, where water is "under regulation" and is apportioned based on priority of the right.[65]

i. Water Measurements

Water is typically measured in terms of flows or total quantities. Water flows, measured in cubic feet per second (cfs), indicate how much water is flowing in a river or how much water is removed from a river over time.[66] For this reason, direct flow diversions and instream flow rights are measured in cfs.[67] Quantities of water are measured in acre-feet (af), or the amount of water it would take to cover one acre of land in one foot of water, or gallons per minute (gpm).[68] Quantities are typically used to indicate the rate by which water is removed, sometimes from a body of water, like a reservoir, and other times from groundwater sources, like aquifers, or wells.[69] Storage rights are measured in af and ground water rights are measured in gpm and af per calendar year.[70]

Water managers use conversions to translate water flows (cfs) into water quantities (mgd), and vice versa.[71] The following provides a summary of conversions and water quantities:

Conversions	*Cubic feet/ second = (cfs)* *Million gallons/ day = (mgd)* *Acre-feet (af)*	Quantities	
1 cubic foot/ second =		**1 cubic foot =**	7.4805 gallons
1.983 acre feet/ day		**1 acre foot =**	325,851 gallons
722.7 acre-feet/ year		**1 gallon =**	0.1337 cubic feet
448.8 gallons/ minute		**1 mill gallons =**	3.07 acre feet[72]
7.48 gallons/ second			

[62] W.S. § 41-3-102.
[63] W.S. § 41-3-102; Wyo. Admin. Code 037.0007.1 § 19(a).
[64] W.S. § 41-3-906.
[65] E-mail from Brian Pugsley, Superintendent Water Division 1, Wyoming State Engineer's Office, (Nov. 23, 2021 at 07:26 pm MST).
[66] THOMPSON, JR. ET AL., *supra* note 57.
[67] Wyo. Admin. Code 037.0007.1 § 4(c).
[68] THOMPSON, JR. ET AL., *supra* note 57.
[69] THOMPSON, JR. ET AL., *supra* note 57.
[70] Wyo. Admin. Code 037.0007.1 § 4(c).
[71] THOMPSON, JR. ET AL., *supra* note 57.
[72] Chart represents information found from: COLORADO RIVER DISTRICT, WATER MEASUREMENT, https://www.coloradoriverdistrict.org/water-measurement/ (last visited Oct. 21, 2021).

The prior appropriation doctrine, as codified by statute, guides the permitting process, now used for the administration of both surface and ground water rights in the state. Permits are issued for five primary uses of water:

- Direct diversions of natural streams, measured in cfs and for irrigation use limited to one cfs per 70 acres of land irrigated (except when surplus or excess flows are available);
- Storage of water in a reservoir, measured in af and only filled in order of priority;
- Secondary attachment of stored reservoir water to specific lands, measured in af and filled in order of priority;
- Instream flow uses, measured in cfs; and
- Ground water withdrawals, measured in gpm pumping rate and af per calendar year.[73]

ii. Surface Water

Surface water is defined as the "water derived from rains and melting snows that is diffused over surface of the ground . . ."[74] Direct diversions from natural streams, storage of water in a reservoir, secondary attachment of stored reservoir water to specific lands, and instream flows are surface water uses. The most applicable surface uses of water for the W2H2 are direct diversions from a natural stream and the right to build or use water stored in a reservoir, however. This is because instream flows are dedicated to the purpose of "providing a recreational pool or . . . to establish or maintain new or existing fisheries is a beneficial use of water subject to normal stream loss"[75] and "[n]o person other than the state of Wyoming shall own any instream flow water right."[76]

Direct diversions allow a permit holder to withdraw the permitted amount of water flow from a natural stream and put it to beneficial use in accordance with their permit. In times of water shortage, priority for direct diversions is influenced by the surplus and excess water provisions of the water statutes.[77] In 1945 and again in 1985, the Wyoming legislature passed statutes defining and governing surplus and excess water, respectively.[78] Under the surplus water provision, appropriators with water rights for irrigation use dating from on or before March 1, 1945 are entitled to up to double the use statutorily allowed for irrigable lands (normally one cfs per 70 acres, allowable up to two cfs per 70 acres) before any other user.[79] Under the excess water provision, appropriators with water rights for irrigation use dating from on or before March 1,

[73] Wyo. Admin. Code 037.0007.1 § 4(c).
[74] *State v. Hiber*, 48 Wyo. 172, 44 P.2d 1005 (1935).
[75] W.S. § 41-2-1001.
[76] W.S. § 41-3-1002.
[77] Pugsley, *supra* note 65.
[78] W.S. §§ 41-4-317 through 41-4-324; W.S. §§ 41-4-329 through 41-4-331.
[79] Pugsley, *supra* note 65.

1985 are entitled to double the irrigable use statutorily allowed for irrigable lands before any other user, after all pre 1945 rights are filled.[80]

These surplus and excess water provisions only apply: (1) to irrigable acreage and (2) during periods of shortage. In addition to surplus and excess water rights there are also supplemental water rights; like the other provisions these only apply to irrigable lands. Supplemental rights are defined as "a permit or certificate of appropriation for the diversion, from a stream, of water from a new source of supply for application to lands for which an appropriation of water from a primary source already exists."[81] Supplemental water rights work to ensure that an appropriator attains their allotted 1 cfs per 70 acres of irrigable land in times of shortage. In the instance that their primary right cannot meet the statutory amount for irrigation (1 cfs/ 70 acres), the supplemental supply right from a different source would kick in to make up any difference such that the appropriator would still get the 1 cfs per 70 acres.

Despite the fact that the excess, surplus, or supplemental provisions apply to only irrigable acreage, these rights can still influence other water rights, particularly during times of shortage and especially if they are senior to other uses. Water used for irrigation is not a highly ranked preferred use as compared to drinking water, municipal water, water for steam power, or water for industrial use. Thus, supplying senior irrigable water rights first during times of shortage could interfere with a preferred more junior water use. If that were to occur, a permit holder with a preferred water use would need to file condemnation of the lower ranking use through court action and argue that surplus and excess water provisions were interfering with, or injuring, their preferred use.[82] However, a "[p]referred use is only as good as its priority date[,] . . . [so in many cases] an earlier priority appropriation will still be allowed the water in times of shortage regulation" despite its lower preferred use ranking.[83]

Surface water may also be stored or diverted into a reservoir. Reservoirs can have multiple sources: surface, ground, or by-product water.[84] A permit to construct a reservoir allows construction of a reservoir for storage of water either along a natural stream or off-channel, so long as there is a way to transport off-channel water to the reservoir. Water rights to reservoir waters may be either tied to the land the reservoir sits on or tied to irrigable lands downstream and called "secondary water rights." In the first instance, a land owner may have built a reservoir on their property and because no secondary rights are attached to the reservoir, that person has rights to the stored water.[85] In the second instance, one may have a reservoir on part of their property but have

[80] Pugsley, *supra* note 65.
[81] W.S. § 41-3-133.
[82] Pugsley, *supra* note 65.
[83] *Id*.
[84] *Id*.; W.S. § 41-3-301.
[85] W.S. § 41-3-320.

no rights to that reservoir waters because land owners downstream own all of the secondary water rights in the reservoir. When reservoirs have secondary attached water rights the right to use water in the reservoir is attached to those irrigable lands and are permitted for the purpose of irrigation.[86] To use water stored in a reservoir, a party must acquire either the lands entitled to the secondary water rights or enter into an agreement with the parties in interest to secure the right and then proceed with acquiring a permit.[87]

There are a variety of water districts that can restrict the availability of water in a particular area. For instance, Water Conservancy Districts may be established to provide for the conservation of the water resources of the state of Wyoming and to facilitate the greatest beneficial use of water within the state.[88] Each Water Conservancy District has a Board of Directors with the power to take, sell, lease, encumber by appropriation, grant, purchase, bequest, or devise water, water works, water rights, and sources and any property, real or personal, necessary or convenient to provide for the use of such water within the district and to do and perform any and all things necessary or convenient to exercise its power.[89]

Watershed Improvement Districts may be formed as subdistricts of Conservation Districts to "provide for the prevention and control of erosion, floodwater and sediment damages, for agricultural uses, and the storage, conservation development, utilization and disposal of water, and thereby to preserve and protect land and water resources, and protect and promote the health, safety and general welfare of the people of [Wyoming]."[90] Any owner in fee of lands that constitute part of the district may file a petition requesting that their lands be excluded from the Water Conservancy District[91] or may petition the board of supervisors to have the land withdrawn from the watershed improvement district.[92]

"An Irrigation District is a court-established assessment district organized under Wyoming Statutes to deliver water to the lands within its boundaries that have water rights."[93] The SEO typically monitors the headgate of the larger diversion canal, and the Irrigation District is responsible for supplying numerous smaller ditches that deliver water to lands with irrigation water

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[86] W.S. § 41-3-302.
[87] W.S. § 41-3-301 et seq.
[88] W.S. § 41-3-701. After a court has declared the Water Conservancy District a corporation, a copy of the decree must be sent to the SEO, the county clerk recorder in each county where the lands of the Water Conservancy District reside, and with the Secretary of State. W.S. § 41-3-725.
[89] W.S. § 41-3-742.
[90] W.S. §§ 41-8-102–103.
[91] W.S. § 41-3-752.
[92] W.S. § 41-8-111.
[93] Caleb Carter, Kristi Hansen, Windy Kelley, Lucy Pauley, Ed. J. Thompson, *Wyoming Small Acreage Irrigation*, UNIVERSITY OF WYOMING EXTENSION, 6 http://www.uwyo.edu/barnbackyard/_files/documents/resources/irrigation/wysmallacreageirrigationguide.pdf

rights.[94] The WWDC maintains a database of Irrigation Districts in Wyoming.[95] The existence of Irrigation Districts may change the availability of water, depending on the extent of the water use by each district. The map below indicates the location of Irrigation Districts.[96] There are presently 157 active Irrigation Districts and Canal Companies in the WWDC database.[97]

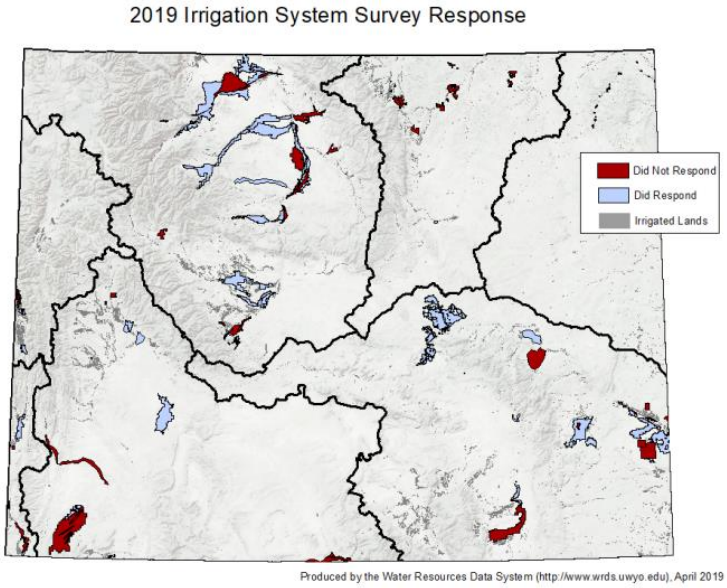

Fig. 1. Approximate location of Irrigation Districts and Canal Companies in the WWDC database. Entities in blue responded to the most recent survey (2019), entities in red did not.

iii. Ground & By-product Water

The Wyoming Statutes define underground water as "any water, including hot water and geothermal steam, under the surface of the land or the bed of any stream, lake, reservoir, or other body of surface water, including water that has been exposed to the surface by an excavation such as a pit."[98] When ground waters in different aquifers are "so interconnected as to constitute . . . one source of supply", or where ground waters and the waters of surface streams are "so interconnected as to constitute . . . one source of supply", the priorities of rights to use the interconnected waters are correlated and a single schedule of priorities will govern the entire common supply.[99]

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[94] *Id*.
[95] WYOMING WATER DEVELOPMENT OFFICE, STATE OF WYOMING 2019 IRRIGATION SYSTEM SURVEY REPORT, https://wwdc.state.wy.us/irrsys/2019/irrsys.html (last visited Oct. 21, 2021).
[96] *Id*.
[97] WYOMING WATER DEVELOPMENT OFFICE, THE WYOMING WATER DEVELOPMENT COMMISSION 2021, WYOMING IRRIGATION SYSTEMS REPORT, https://wwdc.state.wy.us/irrsys/2021/raterept.html (last visited Oct. 21, 2021).
[98] W.S. § 41-3-901(a)(ii).
[99] W.S. § 41-3-916.

"In the administration and enforcement of [Wyoming ground water law][100] and in the effectuation of the policy of the state to conserve its underground water resources, the [SEO] is authorized and empowered on advice and consent of the BOC."[101] The SEO governs the administration of ground water permits, sets regulations for spacing wells in critical areas, develops requirements for reports from well drillers, creates standards for well construction, and other items.[102] The BOC handles the adjudication process whereby the appropriation is evaluated on the ground for beneficial use in accordance with the terms of the permit.[103]

Ground water permits are issued for both ground water wells and for by-product water. By-product water is defined by statute as water that "has not been put to prior beneficial use, . . . is a by-product of some nonwater-related economic activity[,] and has been developed only as a result of such activity."[104] "By-product water includes, but is not limited to, water resulting from the operation of oil well separator systems or mining activities such as dewatering of mines."[105]

For the purposes of administration and control, by-product water is sometimes considered ground water and sometimes considered surface water; its classification will affect the type of permit pursued and priority of use. By-product water is considered "in the same class as groundwater" when it is "intercepted while it is readily identifiable and before it has commingled with the waters of any live stream, lake, reservoir or other surface watercourse, or part of any groundwater aquifer" and either the "developer of the water is the applicant [for permit], or an agreement is filed in the office of the state engineer wherein the developer of the water gives the applicant permission to use the water as proposed in the application."[106] Importantly "the agreement must be signed by the developer of the water" but the developer-grantor is permitted to reserve portions of the by-product water.[107] "[I]f so stipulated, the reservation can be superior in right and title to any use by the applicant-grantee."[108] In all other cases, an application to appropriate by-product water shall be governed by the laws pertaining to surface water, and by-product water shall be considered as part of the surface supply, subject to use by existing priority rights."[109]

Rights to ground water are subject to the same preferential uses specified for surface waters, and similarly, rights that are not preferred may be condemned and changed to a preferred

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[100] W.S. §§ 41-3-901–938.
[101] W.S. §§ 41-3-909.
[102] *Id*.
[103] Wyo. Admin. Code 037.0007.4 § 2; W.S. § 41-4-511; W.S.§ 41-4-513.
[104] W.S. § 41-3-903.
[105] *Id*.
[106] W.S. § 41-3-904.
[107] *Id*.
[108] *Id*.
[109] *Id*.

use.[110] However, appropriations of ground water for non-commercial stock or domestic household use with an area not exceeding one acre and flow not exceeding .056 cfs/ 25 gmp have a "preferred right over rights for all other uses, regardless of their dates of priority."[111] Additionally, ground water permits for irrigation are not limited to one cfs per 70 acres of water like surface water permits.[112]

The priority of ground water rights depends on the regulatory framework existing when water was first appropriated. The priority of ground water appropriated before April 1, 1947 is based on the date of well completion.[113] The priority of ground water appropriated between April 1, 1947 and March 1, 1958 is based on the date registration was filed with the State Engineer's Office.[114] The priority of ground water appropriated on or after March 1, 1958 is the date the application is filed with the State Engineer's Office.[115] The priority of ground water appropriated for non-commercial stock or domestic use prior to December 31, 1972 is the date of well completion, if properly registered with the SEO.[116] The priority of ground water appropriated for non-commercial stock or domestic use after December 31, 1972, is the date registration was filed in the State Engineer's Office.[117] Wells used for stock or domestic purposes completed prior to 1969 may not have a permit on file with the SEO because wells drilled for those purposes prior to 1969 were exempted from permitting requirements.[118]

Akin to surface water, certain districts may also be designated for underground water resources. The BOC may designate groundwater management districts called "Control Areas" at the recommendation of the SEO or on its own when any one of the following conditions exist:

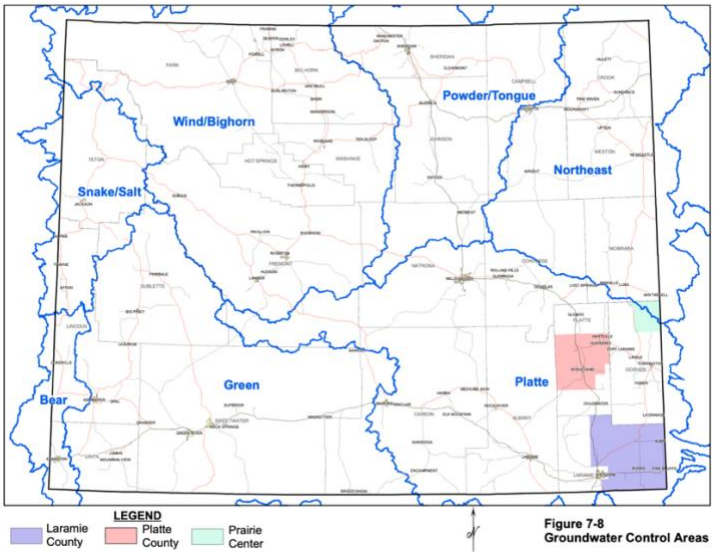
- The use of underground water is approaching a use equal to the current recharge rate;
- Ground water levels are declining or have declined excessively;
- Conflicts between users are occurring or are foreseeable;
- The waste of water is occurring or may occur; or
- Other conditions exist or may arise that require regulation for the protection of the public interest.[119]

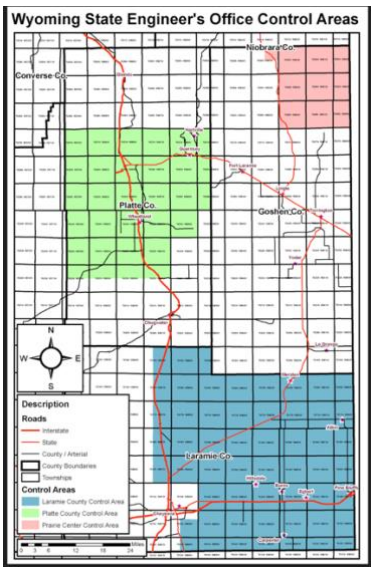
When any one of these conditions exist, the BOC will fix a time and place to consider the evidence at a hearing after which it will issue an order designating or not designating the area a control

[110] W.S. § 41-2-906.
[111] W.S. § 41-3-911.
[112] Carter et al., *supra* note 93, at 14.
[113] W.S. § 41-3-936.
[114] *Id*.
[115] *Id*.
[116] *Id*.
[117] *Id*.
[118] Carter et al., *supra* note 93, at 14.
[119] W.S. § 41-3-912.

area.[120] On the petition of five property owners within a Control Area or recommendation by the SEO, the BOC may consider re-designating geographic or stratigraphic boundaries of a Control Area using a similar notice, hearing, and order process.[121]

Most Control Areas are established in the southeastern part of Wyoming (see maps below) and where extant, they create an addition level of review.[122] Applications for new wells exceeding 25 gpm (exempting stock, domestic, and miscellaneous uses under 25 gpm) and petitions to change ground water use must go through a review process requiring public notice and formal recommendation from an elected Groundwater Control Area Advisory Board prior to approval.[123] Groundwater Control Area Advisory Boards advise and assist the SEO and BOC with managing groundwater within a Control Area.[124] The Groundwater Control Area Advisory Boards are five-member boards elected from property owners within the Control Area elected for four-year terms.[125]





The SEO has broad authority over the Control Area's administration. It may close the Control Area to any further appropriation of underground water and refuse to grant any

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[120] *Id*.

[121] *Id*.

[122] WYOMING STATE ENGINEER'S OFFICE, GROUNDWATER CONTROL AREAS AND ADVISORY BOARDS, https://seo.wyo.gov/ground-water/groundwater-control-areas-and-advisory-boards (last visited Oct. 21, 2021); State-wide Map taken from: WWC Engineering, Hinkley Consulting, Collins Planning Associates, Greenwood Mapping, Inc., States West Water Resources Corporation, *Wyoming Framework Water Plan Volume I*, at 23 (2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf; County-Level Map taken from: WYOMING STATE ENGINEER'S OFFICE, GROUNDWATER CONTROL AREAS AND ADVISORY BOARDS, https://seo.wyo.gov/ground-water/groundwater-control-areas-and-advisory-boards (last visited Oct. 21, 2021).

[123] WYOMING STATE ENGINEER'S OFFICE, GROUNDWATER CONTROL AREAS AND ADVISORY BOARDS, https://seo.wyo.gov/ground-water/groundwater-control-areas-and-advisory-boards (last visited Oct. 21, 2021).

[124] *Id*.

[125] W.S. § 41-3-913.

applications for a permit until evidence suggests there is unappropriated water available, determine the total permissible withdrawal amounts of underground water within the Control Area, order junior appropriators to cease or reduce withdrawals, impose a system of rotational use, institute well spacing requirements for new permits and wells, or initiate an agreement between appropriators within a Control Area.[126]

3. THE STATE ENGINEER'S PERMITTING SYSTEM

Wyoming's first state legislature enacted a comprehensive water code, "establish[ing] a filing procedure for securing water rights by permit from the State Engineer with final adjudication by the State Board of Control."[127] Before the State Board of Control and State Engineer were created, a number of water rights were confirmed by a court decrees.[128] The rest of historic water rights established prior to statehood were adjudicated by the State Board of Control after its creation under the category of "Claims to Water Filed under Territorial Law" and are referred to as "territorial appropriations."[129] Most existing water rights have been acquired through the permit and adjudication system.[130]

A permit to appropriate water from the SEO is an authorization to make use of the water as specified in the permit; however, the water right is established only once the water is applied to a beneficial use.[131] "A water right is publicly recognized and specifically defined when it is adjudicated by the BOC, and a certificate of appropriation is issued."[132] Typically, stock reservoirs, stock or domestic wells, test wells, and other temporary uses are not adjudicated by the BOC.[133] Once a water right has been adjudicated, it can only be changed or modified by the BOC.

a. Permit Application & Issuance by the SEO

Before an applicant may commence construction on any water development project, the applicant must first submit an application to the SEO, and the SEO must issue a permit for water use.[134] During this preliminary step, the SEO evaluates whether there is water available in the proposed source of supply, whether the proposed use conflicts with existing rights, or whether the

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[126] W.S. § 41-3-915.
[127] Wyo. Admin. Code 037.0007.1 § 4.
[128] *Id*.
[129] *Id*.
[130] *Id*.
[131] *Id*.
[132] *Id*.
[133] *Id*.
[134] W.S. § 41-4-501 et seq. The specific requirements for each application are specified in the SEO Regulations and Instructions found here: STATE ENGINEER'S OFFICE, REGULATIONS/ INSTRUCTIONS, https://seo.wyo.gov/regulationsinstructions (last visited Oct. 21, 2021).

proposed use would be detrimental to the public interest.[135] If any of those conditions exist, the SEO has a duty to reject the application and refuse to issue a permit and the applicant shall not take any steps toward completing the proposed work or may face penalties.[136] Sometimes the SEO may request additional information from the applicant.[137] If there is no issue with the proposed use, the SEO will endorse the application and authorize the applicant "to proceed with construction . . . , and to take all steps required to apply the water to a beneficial use, and to perfect the proposed appropriation."[138]

When the SEO endorses an application, the SEO will set a deadline for construction completion in the permit and it shall not exceed a period of five years after the date of approval of the application.[139] In some cases, the SEO may also set a deadline for application of beneficial use (*e.g.*, application for a ditch permit).[140] Should a permit holder fail to meet the deadlines specified by the permit, the SEO may cancel the permit.[141] Though, the SEO is required by statute to provide notice of expiration of time at least three months prior to expiration.[142] Upon a demonstration of good cause to the SEO, an applicant may extend the deadline(s) for construction or beneficial use.[143] The priority of an appropriation dates to the date on the initial permit application filed with the SEO.[144]

b. Adjudication by the BOC

After the SEO issues a permit[145] and the applicant completes work according to the terms of the permit the BOC may adjudicate the water rights upon proof of beneficial use.[146] Adjudication finalizes the priority date of the water right, the point of diversion, the place of use, the type of use, and the rate at which water may be diverted or pumped from the source.[147] The

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[135] W.S. §§ 41-4-503–504.
[136] *Id*.
[137] W.S. § 41-4-505.
[138] W.S. § 41-4-504.
[139] W.S. § 41-4-506.
[140] *Id*.
[141] *Id*.
[142] *Id*.
[143] *Id*.
[144] W.S. § 41-4-512.
[145] See *Green River Dev. Co. v. FMC Corp.*, 660 P.2d 339 (Wyo. 1983) (Defining a water permit:

> "Water permit" is authority to pursue water rights, and is conditional but unfulfilled promise on part of state to allow permittee to one day apply state's water in particular place and to specific beneficial use under conditions where rights of other appropriators will not be impaired, and application for and obtaining a water permit is necessary first step, mandatory, which has effect of temporarily reserving certain of state's waters in order that certificate of appropriation for water rights may be later acquired by petitioner.)

[146] W.S. § 42-4-104; STATE ENGINEER'S OFFICE, ADJUDICATE, https://seo.wyo.gov/home/adjudicate (last visited Oct. 21, 2021); WYOMING STATE ENGINEER'S OFFICE, PERMITTING/ ADJUDICATION/ CHANGES, https://seo.wyo.gov/permittingadjudicationchanges (last visited Oct. 21, 2021).
[147] STATE ENGINEER'S OFFICE, ADJUDICATE, https://seo.wyo.gov/home/adjudicate (last visited Oct. 21, 2021).

adjudication process involves submission of advertising, holding open for inspection, opportunity of contest, and allowance of proofs of appropriation of water.[148]

When an applicant files their Final Notice of Completion of Beneficial Use, a BOC Adjudication Officer forwards a proof form to the Water Division Superintendent in the Division where the water right is situated and a letter is sent to the applicant listing necessary actions to submit final proof of appropriation.[149]

The appropriator must submit a BOC proof form with the appropriate fees to the Superintendent.[150] The Superintendent, or a designated Hydrographer Commissioner, will then conduct an on the ground inspection, which ensures that the correct amount of water is put to beneficial use in accordance with the terms of the permit.[151] After inspection, the Superintendent or Hydrographer Commissioner will make any adjustments to reflect actual usage and will submit a written report to the BOC for its consideration.[152] The proof is advertised in a newspaper of general circulation within the area of the water use at least thirty days but not more than forty-five days before a regular meeting of the BOC and must include the time, date, and place where proofs will be available for inspection, which must occur at least 15 days before the regular BOC meeting.[153] The Superintendent must transmit the proof of appropriation and affidavits of advertisement to the BOC.[154] At the next regular meeting, the BOC will consider all proofs of appropriation from Division Superintendents.[155] If the proof is uncontested and otherwise in order, the BOC will accept the proof and approve the appropriation issuing the Certificate of Appropriation which is filed in the County Clerk's Office where the appropriation is located.[156] If the proof is contested, evidence must be provided to support the water right.[157]

The specific requirements of the adjudication process vary depending on whether the water right is a surface water right or a ground water right. The specific requirements for adjudication are set out in W.S. § 41-4-511 and W.S. § 41-3-935, with specific processes for surface and ground proofs contained in Chapter VI, Sections 1 and 2, respectively, of the Board of Control's Regulations.[158] Further requirements for adjudication may exist in Control Areas, as specified by W.S. § 41-3-914.

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[148] Wyo. Admin. Code 037.0007.4 § 1.
[149] Wyo. Admin. Code 037.0007.4 § 1.
[150] Wyo. Admin. Code 037.0007.4 § 1.
[151] Wyo. Admin. Code 037.0007.4 § 1; W.S. § 41-4-511.
[152] *Id*.
[153] Wyo. Admin. Code 037.0007.4 § 1.
[154] W.S. § 41-4-511.
[155] W.S. § 41-4-511.
[156] W.S. § 41-4-511; Wyo. Admin. Code 037.0007.4 § 1.
[157] Wyo. Admin. Code 037.0007.4 § 1.
[158] Wyo. Admin. Code 037.0007.4 § 1; Wyo. Admin. Code 037.0007.4 § 2; for the procedure for filing applications for the Application for the Appropriation of By-Product Water see Wyo. Admin. Code 037.004.2 § 6.

A water right is assigned a priority date corresponding to the date that the application is received by the SEO and the priority date does not change, even when the water right is not adjudicated for years.[159] After the SEO issues a permit and the applicant completes work according to the terms of the permit, the right is said to be "perfected."[160] Once a water right is perfected the BOC may adjudicate the right.[161] When a water right has been "adjudicated" the BOC has determined that water has been, and is being, put to beneficial use in accordance with the terms in the permit.[162] Alternatively, when a water right is labeled "unadjudicated," the BOC has not yet determined that water has been, and is being, put to beneficial use.[163]

Importantly, some older water rights, particularly ground water wells, were exempted from the permitting process until about 1947.[164] Other rights may not have finished the adjudication process after perfecting the water right. Thus, some rights may be perfected but unadjudicated and some rights may be unperfected and unadjudicated (because they were historically exempted from the permitting process). Regardless of this fact, water rights are said to be "valid" once they are put to beneficial use.[165]

c. The E-permit System

The SEO uses an e-permit system to facilitate the administration of water rights within Wyoming. The interactive online system allows applicants to submit water rights instruments online (*e.g.*, applications, requests, affidavits, consents, and petitions), search the SEO database of water rights, track and research instruments as they are processed, use GIS systems, and retrieve documents attached to water rights.[166] To use the website, a new user must register a new account but creating login credentials.[167]

4. Acquiring Water Rights

One may acquire a water right by virtue of purchasing land with water rights attached, by purchasing the right to use water from a current water right holder, or by establishing a new water right with the SEO.

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[159] Pugsley, *supra* note 65.
[160] W.S. W.S. § 41-4-511.
[161] W.S. § 42-4-104; State Engineer's Office, Adjudicate, https://seo.wyo.gov/home/adjudicate (last visited Oct. 21, 2021); Wyoming State Engineer's Office, Permitting/ Adjudication/ Changes, https://seo.wyo.gov/permittingadjudicationchanges (last visited Oct. 21, 2021).
[162] State Engineer's Office, Adjudicate, https://seo.wyo.gov/home/adjudicate (last visited Oct. 21, 2021);
[163] Pugsley, *supra* note 65.
[164] *Id*.
[165] *Id*.
[166] Wyoming State Engineer's Office, Surface Water Division, *Performing a Water Right Search in e-Permit*, at 3 (2018), https://drive.google.com/file/d/1XpZ6MPPDDvb3ASZujtE7l97qqbwbCOnR/view.
[167] *Id*.

Water rights may attach to the land they are applied to or to the purpose or object for which they are acquired.[168] However, because the right to use water may not always run with the land and because not all lands have water rights associated with them, it is important to understand how to acquire a water right independent of land ownership—whether an existing water right or a new water right. It is, therefore, also important to understand both how to modify, challenge, or expand a water right and how the priority date of the water right may or may not change when making modifications to a water right. This section discusses the relationship between water rights and land ownership, how to modify existing water rights, and how to acquire new water rights.

a. Water Rights Associated with Land Ownership

Generally speaking, "water rights attach to the land for irrigation, or to such other purposes or object for which acquired in accordance with the beneficial use made for which the right receives public recognition, under the law and the administration provided thereby."[169] Specifically, "[w]ater rights for the direct use of the natural unstored flow of any stream cannot be detached from the lands, place or purpose for which they are acquired, except" when an applicant can demonstrate to the BOC that a preferred use will be made, or an applicant needs to amend the permit due to a clerical error.[170]

Reservoir waters are unique. "Water may . . . be impounded in a reservoir by anyone who is neither the owner or in possession of any land . . . [and t]he owner of such reservoir may sell, lease, transfer, and use such water in such manner and upon such lands as the owner may desire . . . ."[171] For instance, "one man may divert and impound water . . . for the ultimate use of it by another. The only material difference between such case and diversion by direct flow from a stream [is that] . . . in the former case the water is not *required* to be attached to land, while in the latter case it is."[172] Whether reservoir water rights attach to the lands beneath or adjacent to the reservoir depends on how the reservoir is permitted. For reservoirs filed for stock watering, the water in the reservoir is permitted for in-place use so any person owning the lands covered by the reservoir are entitled to that water.[173] In contrast, if a reservoir is permitted for irrigation and there are no secondary water permits attached to that reservoir, the owner may use the water anywhere they can physically move the water for the purpose of irrigation.[174] Finally, if the reservoir is permitted

[168] W.S. § 41-3-101.
[169] W.S. § 41-3-101.
[170] W.S. §§ 41-3-101 – 103; W.S. § 41-4-514; see also *Scherck v. Nichols*, 55 Wyo. 4, 23 (Wyo. 1939) (stating this has been the law since adopted in 1909 ("Section 122-401, Rev. St. 1931, first enacted in 1909 and modified by Chapter 161, S.L. 1921, adopted the policy that a water right by direct flow from a stream shall be attached to land.")).
[171] *Scherck v. Nichols*, 55 Wyo. 4, 95 P.2d 74, 78–79 (1939).
[172] *Id*. (emphasis added).
[173] Pugsley, *supra* note 65.
[174] *Id*.

for irrigation and there are secondary permits attached to the reservoir, then only the lands the secondary rights are attached to may receive that water.[175]

Typically, all ground water rights attach to the land or to the point of use permitted for unless the water right is specifically reserved at the time the permit is issued.[176] When a ground water permit, or an interest therein, is transferred or assigned, that assignment must be recorded with the SEO.[177]

b. Modifying Already Existing Water Rights

Changing an existing water right typically requires modifying either the type of use, the place of use, the point of diversion (if a surface water right) or location of a well (if a ground water right), or the amount of use, but can also include acquiring a temporary right, or seeking abandonment.

To modify a direct diversion water right, a water user must demonstrate to the BOC that a preferred use will be made by the change in use.[178] Acquiring water stored in a reservoir may prove difficult, depending on the filing of the reservoir and whether there are secondary water rights attached. To modify a reservoir water right, the type of use and place of use would likely need to be modified. Specifically, for an acquired secondary water right in a reservoir, the petitioner must undertake at least two actions. First, the new entity must petition the BOC to separate, or detach, the irrigable lands from the water right (essentially this works as an abandonment of the secondary right to the water and ensures that the water in the reservoir is no longer attached to any lands). Second, the new entity must change the use of the right from irrigation to the desired use. To modify a ground water right, a petitioner follows the same process for acquiring a new groundwater right.[179] The petitioner must demonstrate that the proposed use will not be detrimental to the public interest, will not injure any other water user in the area, and that there are unappropriated waters in the proposed source.[180] Additionally, the petitioner should ensure that the proposed means of diversion or construction is adequate and that the location of the proposed well or other work does not conflict with any well spacing or well distribution regulation.[181]

i. Changing Type of Use & Place of Use

For both surface and ground water, "[w]hen an owner of a water right wishes to change a water right from its present use to another use, or from the place of use under the existing right to a new place of use," the appropriator must file a petition requesting permission to make the

[175] *Id*.
[176] Wyo. Admin. Code. 037.0004.2 § 14.
[177] *Id*.
[178] W.S. §§ 41-3-101 – 103; W.S. § 41-4-514.
[179] W.S.§ 41-3-932.
[180] W.S.§ 41-3-932.
[181] W.S.§ 41-3-932.

change.[182] The petition must include any relevant information about the existing use and the proposed change in use, or the existing place of use and the proposed place of use,[183] and an appropriator must demonstrate to the BOC that a preferred use will be made.[184]

The procedure required for a change of use includes public notice, possibly an advertised public hearing or hearings at the petitioner's expense,[185] an inspection, and a hearing in front of the Division Superintendent.[186] The Division Superintendent will provide a report to the BOC, and the BOC must issue an order approving or denying the change.[187] When making its determination, the change may be allowed if, after the change, the quantity of water transferred does not exceed the historic amount of: water diverted, rate of diversion, or consumptive use, and does not decrease the historic amount of return flow, or injury any other existing appropriator in any way.[188] Relevant facts that the BOC may consider include whether the change would cause economic loss to the community and the state if the historic use from which the right is transferred is discontinued; whether such economic loss will be offset by the new use; and whether other sources of water are available for the new use.[189] For ground water rights, a change in the location of an existing well or drilling an existing well deeper will likely be approved without losing priority, under certain conditions (*e.g.*, the new well is in the same aquifer and the same general vicinity as the old one).[190]

Importantly, modifying the type of use or place of use does not change the priority of the water right, but it may change both the amount of water the applicant is able to use and the preference of that water use compared to other uses drawn or diverted from the source. Because the law only allows for a change in the consumptive portion of the water right, the previous user's historic consumption, not withdrawal, amount will determine the new user's permitted amount of use.

ii. Changing Point of Diversion/ Location of Well

To change the point of diversion and/ or means of conveyance of a surface water right a person must file a petition with the BOC when the water has been adjudicated under a certificate of appropriation and with the SEO in all other cases.[191] The SEO may consider a petition to change

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[182] W.S. § 41-3-104.
[183] W.S. § 41-3-104.
[184] W.S. § 41-3-103. W.S. § 41-3-102 lists the preferred uses in the following order: (1) water used as drinking water for man and beast; (2) water for municipal purposes; (3) water for the use of steam engines, general railway use, culinary use, laundry, bathing, refrigerating, for steam and hot water heating plants, and for steam power plants; (3) water used for industrial processes; and (4) water used for irrigation.
[185] W.S. § 41-3-104.
[186] W.S. § 41-3-103.
[187] *Id*.
[188] W.S. § 41-3-104; Wyo. Admin. Code 037.0007.1 § 17.
[189] W.S. § 41-3-104.
[190] Carter et al., *supra* note 93, at 14.
[191] W.S. § 41-3-114.

the point of diversion or means of conveyance even when the water has not yet been put to beneficial use, provided that the change does not alter the original project concept and the diversion is from the same source of supply described in the original permit.[192] Importantly, no change in the point of diversion or means of conveyance will be granted if the change would cause injury to another appropriator.[193]

Petitions must be in affidavit form and include the name and address of the petitioner, proof of ownership of the appropriation, and maps, prepared under certificate of a registered land surveyor and showing the location of the stream and/or the ditch involved, the location of any intervening diversions, and if relevant, the location of the lands affected by the change.[194] For point of diversion changes, petitions must also include: the name and form of the diversion course from the stream, the stream from which water is appropriated, the date of priority, the amount of the proposed appropriation change, the permit number, the ownership of the appropriation, and the location of the present and the proposed new point of diversion by course and distance from a corner of the public land survey.[195] For changes that apply to irrigable acreage, petitions must include a description of the acreage irrigated in each legal subdivision, the reason for the proposed change, whether any other appropriator from the same source will be injured, and whether the consent of all owners of intervening diversions has been obtained.[196] For petitions changing the point of diversion *and* means of conveyance, in addition to the above information, a petition must include the name, permit number and date of priority of the conveyance, ditch, or facility to which it the diversion will be changed, and whether the petitioner is the sole owner of both facilities involved or has the consent of the other owners of both ditches or facilities.[197]

If the written consent of owners of appropriations that divert between the old and new points of diversion or the owners of the ditches or courses involved in the proposed change are not secured and attached to the petition, it must be referred to the Superintendent of the water division where the change is proposed when the right is adjudicated and the SEO when the right is unadjudicated.[198] Upon receiving the petition, a hearing is set, providing thirty day's notice of the hearing to the petitioner and any owners of appropriations or facilities that may be impacted by the change.[199]

For ground water rights that have been adjudicated or are unadjudicated but have been applied to beneficial use, "[a]n appropriator . . . may change the location of . . . [a] well to a point

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[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Id.*
[196] *Id.*
[197] *Id.*
[198] *Id.*
[199] *Id.*

within the same aquifer in the vicinity of the original location, without loss of priority, by securing approval of the [BOC]."[200] For stock water wells, which are not adjudicated but the water has been applied to beneficial use, an appropriator may change the location of the well by securing approval from the SEO.[201] A petition to change the location of a groundwater well cannot "increase the total amount of the appropriation water set forth in the original permit."[202] Additionally, the petition will not be granted if the rights of other appropriators are injured by the change.[203]

Changing the point of diversion, the means of conveyance, and the location of the well does not change the priority of the water right. This is because the statutes ensure there is no injury to other neighboring users.

iii. Enlargements

For surface water rights an enlargement can be filed for reservoirs and for means of conveyance. Because an enlargement creates a new priority date, other surface rights do not typically need enlargements and can instead file for a "new" right. For reservoirs, an enlargement is a "change in or addition to an existing dam or reservoir which raises or may raise the water storage elevation of the water impounded by the dam.[204] Ditches or pipelines may apply to enlarge a facility so that it can physically divert more water or add more points of use to the existing facility.[205]

For ground water, enlargements are additional permits that cover the same well or facility as the original permit but expand the water right under a later priority date.[206] An enlargement can be filed to increase yield or the volumetric quantity (yearly amount), to add types of use or places of use, or to increase the irrigable acreage.[207]

iv. Acquiring a Temporary Water Right

The SEO/ BOC will issue temporary water rights for two years at a time, but parties may re-file to continue the temporary right.[208] Temporary water rights may impact the security of supply because they are the first right to be shut off in the instance of shortage or injury to other appropriators.[209] For instance, if the owner of a permanent right of water cannot satisfy their right

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[200] W.S. § 41-3-917.
[201] *Id*.
[202] *Id*.
[203] *Id*.
[204] W.S. § 41-3-307.
[205] STATE ENGINEER'S OFFICE, APPLICATIONS, FORMS, AND INSTRUCTIONS, https://seo.wyo.gov/ground-water/applications-forms-and-instructions (last visited Oct. 21, 2021).
[206] STATE ENGINEER'S OFFICE, PROCEDURE FOR PREPARING AN APPLICATION FOR ENLARGEMENT, https://drive.google.com/file/d/1cUkKD5AjnD8wsLfgA6RwzsniMYYfbFt1/view (last visited Oct. 21, 2021).
[207] *Id*.
[208] W.S. § 41-3-110.
[209] *Id*.

in full due to the temporary user's diversion under the temporary right, the permanent water right holder has the "absolute right" to cause the temporary diversion to be shut off until the permanent right can be satisfied in full.[210] Any person may acquire a temporary water right, and it does not matter if the original right is adjudicated or unadjudicated.[211]

Conveying a water right to another entity for a temporary basis does not cause impairment, loss, or abandonment of the water right for the permanent water right holder—upon termination of the temporary use, the right automatically reinvests with the permanent water right holder for the uses they previously held.[212] To ensure the temporary water right becomes operative, an appropriator must file their application with the SEO including a copy of the conveyance or agreement for the temporary right and the SEO must ratify and approve the temporary right.[213] There is a fee of up to $100 when temporary water right applications are filed.[214] The historic consumptive use of the water right will serve as a limit to the available water for the temporary use.[215] Upon approval, the SEO will issue an order designating the place, method, and period of use.[216]

v. Water Exchanges

It is the policy of the state to encourage water exchanges, though the SEO may not grant an exchange if "the proposed exchange would adversely affect other appropriators, or . . . be too difficult to administer or would be adverse to the public interest."[217] A water exchange is permitted when an appropriator owning a valid water right of the state and either: the source of the appropriation is at times insufficient to fully satisfy such appropriation, better conservation and utilization of water can be accomplished, or the appropriator can develop appropriable water but cannot economically convey it to its point of use.[218] Water exchanges are permitted among any combination of surface, reservoir, or ground waters.[219] However, just like an ordinary water right, an exchange is subject to the requirements of beneficial use and equality of water exchanged, and the SEO may consider consumptive and transmission losses.[220] Petitions for water exchanges should be accompanied by maps, plans, relevant information, recording and filing fees, and the agreement (if one is made) between two appropriators.[221]

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[210] W.S. § 41-3-111.
[211] *Id*.
[212] W.S. § 41-3-110.
[213] *Id*.
[214] *Id*.
[215] *Id*.
[216] *Id*.
[217] W.S. § 41-3-106.
[218] *Id*.
[219] *Id*.
[220] *Id*.
[221] *Id*.

vi. Abandonment

When an appropriator of reservoir, surface, or ground water "fails, either intentionally or unintentionally, to use the water therefrom for the beneficial purposes for which it was appropriated, whether under an adjudicated or unadjudicated right, during any five . . . successive years, he is considered as having abandoned the water right and shall forfeit all water rights and privileges appurtenant thereto."[222]

An appropriator who has not diverted and beneficially used all of the storage water from a reservoir may apply to the BOC for a five-year extension by demonstrating reasonable cause exists for nonuse, despite due diligence toward the utilization of the appropriation.[223] Reasonable cause may include delay due to court or administrative proceeding, planning, developing, financing, or and construction time added, among other causes.[224] The BOC may grant an extension as it finds proper, and a prior grant of extension does not preclude another application for extension.[225]

An abandonment application can be brought by either a water use who might benefit from a declaration of abandonment of existing water rights or who might be injured by the reactivation of the water right or by the SEO.[226] If a water user brings the abandonment petition, the case must be presented to the BOC in writing and a "if the facts so justify" the matter may be referred to the Superintendent of the Water Division for a public hearing.[227] Those with standing to petition the BOC to declare abandonment of an existing water right include: any person with a valid adjudicated water right or a person holding a valid permit from the same source of supply and a right that is equal to or junior to the right for which abandonment is sought, or the holder of a valid water right entitled to surplus water from the same source of supply and the right sought to be abandoned has a priority date of March 1, 1945 or earlier.[228] An abandonment petition will not succeed on an irrigation water right if the reason for failure to put water to beneficial use is due to a water shortage or water regulation, or due to a problem with facilities used to divert the water.[229]

If the facts justify a public hearing, the Superintendent will notify the holders of the water rights sought to be abandoned and all interested parties of the time, place, and purpose of the hearing.[230] A transcript is made of the hearing and the evidence and the transcript is provided to the Superintendent, who transmits the record to the BOC.[231] The BOC will, at its next meeting,

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[222] W.S. § 41-3-401.
[223] W.S. § 41-3-401.
[224] *Id*.
[225] *Id*.
[226] *Id*.; W.S. § 41-3-402.
[227] W.S. § 41-3-401.
[228] *Id*.
[229] *Id*.
[230] *Id*.
[231] *Id*.

vote to declare the right in question abandoned, wholly or partially, or decline to declare the right abandoned.[232] An order is then drafted and entered to reflect the BOC's decision on the abandonment hearing.[233]

Roughly the same process is followed when the SEO initiates an abandonment proceeding, except that the state is designated as the contestant instead of another water right holder and the SEO may not participate as a voting member on the BOC's decision on the petition.[234] When the BOC determines a water right has been forfeited, it shall issue a certified copy of the declaration to each contestee within sixty days.[235] If after two years of the order by the BOC forfeiting the water right, any person can demonstrate to the satisfaction of the BOC by written petition, proof, or affidavit, that they had no actual notice of the forfeiture hearings and damages, the BOC may reopen the case to determine whether the right shall remain forfeited and or change priority.[236]

c. Acquiring New Water Rights

Specific procedures for surface water applications are contained in Wyo. Admin. Code 037.0006.1 §§ 1 – 3 (the SEO's rules and regulations). Generally speaking, to acquire a new surface water right, one must:

- Arrange for the services of a licensed professional engineer or land surveyor to survey the land and water and prepare required maps;
- File the application, maps, plans, and fees with the SEO;
- Wait for approval from the SEO for a permit, correcting any errors in submitted materials;
- Commence construction within time allowed on the permit and provide notice of commencing construction to the SEO *prior* to the expiration deadline for commencing construction on the permit;
- Complete construction within time allowed on the permit and provide notice of completion to the SEO *prior* to the expiration deadline for construction completion on the permit;
- Apply water to beneficial use as described on the permit and provide notice to the SEO of completion of application *prior* to the expiration deadline for beneficial use on the permit;
- Submit proof of appropriation of water to beneficial use, or proof of construction of reservoir to the Water Superintendent; and
- Receive and Record certificate of appropriation or certificate of construction by the BOC evidencing the adjudicated water right.[237]

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[232] *Id.*
[233] *Id.*
[234] W.S. § 41-3-402.
[235] *Id.*
[236] *Id.*
[237] Wyo. Admin. Code 037.0006.1 § 2.

Specific procedures for ground water applications are contained in Wyo. Admin. Code 037.0004.2 § 2 and 037.0004.2 § 10 (the SEO rules and regulations).[238] Generally speaking, to acquire a new ground water right, one must:

- Submit an application (specific details included in Wyo. Admin. Code 037.0004.3 § 2) to the SEO with the $2.00 filing fee for each well;
- Wait for approval from the SEO for a permit, correcting any errors in submitted materials;
- Once the application is approved by the SEO, the SEO issues a permit with a number, and a copy is returned to the applicant;
- Complete construction of well within time allowed on the permit and provide notice of completion to the SEO *prior* to the expiration deadline for construction completion on the permit;
- Submit written notification to the SEO of the dates: well is commenced; completed, with pump or valve; and beneficially used for the purposes specified in the permit, with information on water levels, a driller's log, and other pertinent data relating to the well;
- Submit Proof of Application and Beneficiation Use of Ground Water (Form U.W. 8), to SEO's office, including plats or maps certified by a licensed professional engineer or land surveyor with the Proof of Appropriation and Beneficial Use of Ground Water form (specific details included in Wyo. Admin. Code 037.0004.5 § 1 et seq.), which serves as the basis for adjudication of water right;
- Submit final proof to the BOC for consideration;
- Receive and Record certificate of appropriation issued by BOC evidencing the adjudicated water right.[239]

5. What this means for the Williams Wyoming Hydrogen Hub Project

Should Williams acquire an existing water right from another permit holder, unless the place of use and type of use remains the same, Williams will likely need to file a petition to change the type of use and place of use with the BOC, if the water right is adjudicated, or the SEO, if the water right is unadjudicated. If the land where the water is acquired is not owned by Williams, Williams may also need to enter into an agreement to use, access, or purchase the land in order to utilize or access the water. Modifying the type of use or place of use does not change the priority of the water right, but it may change both the amount of water the applicant is able to use and the preference of that water right over other uses drawn or diverted from the source. Because the law only allows for a change in the consumptive portion of the water right, the previous user's historic consumption, not withdrawal, amount will determine the new user's permitted amount of use.

[238] Wyo. Admin. Code 037.0004.2 § 10; Wyo. Admin. Code 037.0004.2 § 2.
[239] Wyo. Admin. Code 037.0004.2 § 10; Wyo. Admin. Code 037.0004.2 § 2.

Regarding ground and produced water, it will be informative to locate productive wells within the W2H2 study area and identify whether any of William's land or nearby locations would be suitable for groundwater wells or useful sources of produced water. It does not appear that the groundwater Control Areas in the southeastern portion of the state will impact the W2H2 project because they are not located on or near Williams' property.

Regarding surface water, acquiring a new direct diversion right is not recommended unless a senior water right (currently consuming most of its permitted water) can be acquired from another permit holder. Any new water right would have junior priority to all other existing water rights on that particular stream; thus, the new water right would be the first to lose water in the instance of a shortage.

Water rights held for irrigable acreage may have decent seniority due to the fact that many irrigable-acreage water rights were adjudicated in the 40s and 80s. Therefore, irrigable water rights may provide senior water rights, if they can be identified, acquired, and modified for a new use and place of use. Notably, water used for irrigation is statutorily limited at one to two cfs per 70 acres, so irrigable-acreage water rights will be limited by the historical consumptive amount and the water right's affiliated irrigable acreage.

Reservoir water may prove a valuable source of water, *if* these rights can be acquired from secondary permit holders with irrigable acreage or from those who hold the reservoir water rights for other purposes. Identifying current reservoir water permit holders may prove difficult. Without knowing the name of the permit holder or the legal land description of the lands the right is attached to, it will be nearly impossible to search for the right in the SEO's e-permit system.

Seeking an enlargement for an existing water right, whether ground or surface, is not recommended because an enlargement modifies the priority date as to the enlarged portion of the right. In practice, the effect of an enlargement is similar to that of acquiring a new water right– both are junior to every other water right in the area or on that stream or tributary. Similarly, acquiring a temporary water right is not encouraged because the right is not assured in times of shortage and while renewal can be pursued, it is not guaranteed.

Pursuing an abandonment petition for an existing water right could be useful, should someone with a senior surface water right from the same stream or tributary, or a ground water well from the same aquifer, not be using their appropriation. However, the abandonment procedures are fairly involved, so one should be fairly confident that the process would be fruitful prior to pursuing this course of action.

Wyoming Water Availability in Study Area

Jada F. Garofalo,[*] Matthew Johnson, Charles Nye, Jonathan Brant, & Arindam K. Das

PROJECT SUMMARY:

CERPA will identify promising areas for surface, ground, and produced water, based in part on legal availability of water, in part on Williams' willingness and ability to acquire surface water rights, in part on CEPWM's assessment of water quality, and in part on CEGR's assessment of production wells in the study area. Specifically, after providing an overview of surface water availability in each Division, CEGR will provide an ultra-high-level estimate of how much produced and by-product water exists in the Green River Basin as well as rough locations so CERPA can provide suggestions for how Williams could acquire that water. CEGR will provide CEPWM a very-rough estimate of that produced water's average chemistry and William's estimate of how pure input water for Siemens' Hydrolyzer needs to be, so CEPWM can estimate a very-rough percentage recovery-factor from a generic treatment option. Finally, CERPA, CEGR, and CEPWM will collectively summarize areas where water is available, in desirable quality, and (while adding huge caveats to make it clear this is an ultra-high-level estimate) recommend locations that might be suitable for Williams to acquire water from for its project.

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1) CLIMATE CONSTRAINTS ON WATER AVAILABILITY IN WYOMING

The 4th National Climate Assessment found that "[t]he quality and quantity of water available for use by people and ecosystems across the country are being affected by climate change, increasing risks and costs to agriculture, energy production, industry, recreation, and the environment."[1] When drought affects the water supply it is called hydrological drought, and it can lead to inadequate water, affecting streamflow, reservoirs and lakes, and groundwater.

In Wyoming specifically, the 21st century has been the warmest period on record.[2] The state has seen a net 1.4° F temperature increase since the beginning of the 20th century during all seasons, with warming most evident during winter.[3] Under both high and low emission projections, average annual temperatures are expected to exceed historic averages by mid-century.[4] As a result, the intensity of future drought in Wyoming is projected to increase, even if overall precipitation increases.[5]

With increasing average temperatures, more precipitation will fall as rain than snow, causing a decline in seasonal snowpack, which is fundamental to water supply in the western U.S.[6] Declining seasonal snowpack and changes to the seasonal snow cycle influences the timing and magnitude of groundwater recharge, vegetation dynamics, and stream discharge, which directly impacts water availability and can influence water quality.[7] Climate models indicate that over the last century, anthropogenic climate change has already caused a substantial decline in water resources across the western U.S., due to a reduction in snowpack ranging from 15% to 30%.[8] Seasonal snowpack is projected to continue to decline or even disappear across the western U.S. before the end of the twenty first century if emissions continue unabated.[9]

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[1] FOURTH NATIONAL CLIMATE ASSESSMENT, SUMMARY FINDINGS (2018), https://nca2018.globalchange.gov/.
[2] R. Frankson, K. Kunkel, L. Stevens, D. Easterling, and B. Stewart, WYOMING STATE CLIMATE SUMMARY, NOAA TECHNICAL REPORT NESDIS, (2017) at 4, https://statesummaries.ncics.org/chapter/wy/.
[3] *Id*.
[4] *Id*.
[5] *Id*.
[6] Siirila-Woodburn, et al., *A low-to-no snow future and its impacts on water resources in the western United States*, 2 NAT. REV. EARTH ENVIRON 800-819 (2021), https://doi.org/10.1038/s43017-021-00219-y; https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 69.
[7] Siirila-Woodburn, et al., *A low-to-no snow future and its impacts on water resources in the western United States*, 2 NAT. REV. EARTH ENVIRON 800-819 (2021), https://doi.org/10.1038/s43017-021-00219-y.
[8] *Id*.
[9] *Id*.

Wyoming is a major headwater state for four major river basins (Missouri-Mississippi, Green-Colorado, Snake-Columbia, and Great Salt Lake), at least three of which are already experiencing drought conditions.[10] Further climate-induced reductions in seasonal snowpack will have severe repercussions for water availability across much of the west.[11] Because much of the water infrastructure was designed and most water allocation was determined based on an assumed stationary climate and during one of the wettest periods in the past 4,000 years, there is also high confidence that climate-induced warming will continue to reduce river flows and groundwater recharge and challenge the ability to meet growing water demand for many water users.[12]

Compounding the issue of water shortage is the push to decarbonize. The effort to mitigate the effects of climate change and reduce emissions requires utilizing new technologies for electricity generation, but some low and zero carbon generation technologies need as much or more water than conventional forms of electricity generation and all types of generation are impacted by more severe and frequent extreme weather events.[13] Thus, climate mitigation efforts also impact and drive demand for water. Because reduced water availability (due to anthropogenic climate change) and increased future water demand (due to the energy transition and increased

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[10] NOAA, NATIONAL INTEGRATED DROUGHT INFORMATION SYSTEM, Drought.Gov, Missouri River Basin, https://www.drought.gov/drought-status-updates/drought-status-update-missouri-river-basin; NOAA, NATIONAL INTEGRATED DROUGHT INFORMATION SYSTEM, Drought.Gov, Colorado River Basin, https://www.drought.gov/watersheds/colorado; USGS, STATE NEWS RELEASE, GREAT SALT LAKE REACHES NEW HISTORIC LOW, https://www.usgs.gov/news/great-salt-lake-reaches-new-historic-low.

[11] R. Frankson, K. Kunkel, L. Stevens, D. Easterling, and B. Stewart, WYOMING STATE CLIMATE SUMMARY, NOAA TECHNICAL REPORT NESDIS, (2017) at 4, https://statesummaries.ncics.org/chapter/wy/.

[12] Siirila-Woodburn, et al., *A low-to-no snow future and its impacts on water resources in the western United States*, 2 NAT. REV. EARTH ENVIRON 800-819 (2021), https://doi.org/10.1038/s43017-021-00219-y.

[13] ENERGY, SUSTAINABILITY, AND SOCIETY (Feb. 1, 2018), https://energsustainsoc.biomedcentral.com/articles/10.1186/s13705-018-0146-3#:~:text=Conclusions,range%20of%2045%20to%2090%25 (explaining that coal-fired generation plants retrofitted with CCS technology can increase water consumption by 45-90%); WATER RESOURCE CONSIDERATIONS FOR THE HYDROGEN ECONOMY (Dec. 17, 2020), https://www.jdsupra.com/legalnews/water-resource-considerations-for-the-84603/ (explaining that hydrogen production may require as much as nine kilograms of high-purity water per kilogram of hydrogen); A. Lohrmann, *et al.*, *Global scenarios for significant water use reduction in thermal power plants based on cooling water demand estimation using satellite imagery*, NAT ENERGY 4, 1040–1048 (2019) https://doi.org/10.1038/s41560-019-0501-4; P. Ganguli, D. Kumar, & A. R. Ganguly, *US power production at risk from water stress in a changing climate*, SCI. REP. 7, 11983 (2017); *Water Energy Nexus* WEO-2016 Special Report (INTERNATIONAL ENERGY AGENCY, 2016) (stating:

> "Water and energy are closely related. Thermal electricity generation constituted of coal, gas, oil, biomass and nuclear power plants requires water for cooling purposes. Water is also used in numerous technological processes to harness, extract and produce energy. Meanwhile, water extraction, treatment and distribution consume energy. This dependency is often called the water-energy nexus and is increasingly highlighted by many scholars and policymakers as a sustainability concern for future planning and for water security.").

need in the industrial and domestic sectors) are expected,[14] it is important to ensure adequate water supply for energy projects prior to engaging in those projects. Project developers are simultaneously encouraged to identify legal and technological means to acquire water from alternative sources or novel legal approaches to ensure adequate supply for energy projects.

2) SUMMARY OF WYOMING WATER AVAILABILITY

Wyoming conducts a statewide comprehensive water planning process nearly every thirty years. The first was completed in 1973 and the most recent, the Wyoming Framework Water Plan (hereinafter, "Water Plan"), was completed in 2007.[15] The Water Plan provides data on water availability and projected use for various categories of water use, on a basin-by-basin basis, and for a thirty-year time horizon.[16] While some of this data is rather dated, it is informative and is used here where relevant. Individual Basin Plans are conducted more often and the Green River Basin Plan from 2010 is also used where relevant.[17]

Under existing water compacts and treaties, Wyoming's share of the surface water supply flowing out of the state in 2007 was approximately 3,313,500 acre-feet of water.[18] Thus, in addition to water rights that already exist, Wyoming should have approximately 3,313,500 acre-feet of surface water available for future use, so long as water supply remains fairly the same.[19] However, as noted above, surface water availability has declined since the early 2000s and is expected to continue to decline due to the recorded increase in average temperature.

Among surface water uses, the Water Plan estimates that most of the appropriated water in the state—approximately 2,500,000 acre-feet of surface water per year—was appropriated for

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[14] UNITED NATIONS WATER DEVELOPMENT REPORT (2019), https://www.unwater.org/publications/world-water-development-report-2019/#:~:text=Global%20water%20demand%20is%20expected,the%20industrial%20and%20domestic%20sectors; Nick Bradford, THE NATIONAL ENVIRONMENTAL EDUCATIONAL FOUNDATION, THE INCREASING DEMAND AND DECREASING SUPPLY OF WATER, https://www.neefusa.org/nature/water/increasing-demand-and-decreasing-supply-water.

[15] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf.

[16] *Id*.

[17] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html.

[18] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf (see pie graph at 6).

[19] *Id*. at 5.

agriculture purposes, largely due to the stock feeding needs of the state.[20] Consumptive irrigation surface water use was projected to grow to approximately 2,900,000 acre-feet per year by 2030.[21]

Municipal water uses are served by a public water system, which can be sourced from ground water, surface water, or a combination.[22] Domestic water uses are satisfied by individual wells and small water systems not supplied by a public water system.[23] Overall municipal and domestic water uses in the Water Plan comprised a relatively small category of use in Wyoming, totaling approximately 102,000 acre-feet per year in 2007 and projected to be approximately 112,600 acre-feet per year by 2030, including both ground and surface water supply.[24]

Recreational water uses include boating, fishing, swimming, skiing, golfing, waterfowl hunting, and other uses.[25] Recreational uses may or may not be consumptive, but sufficient water supply is needed to ensure the activities are possible because most of these activities generate large profits for the state.[26] Similar to recreational water uses, environmental water uses may not be consumptive but are necessary to ensure adequate habitat for fish, wildlife, and ecosystems.[27]Environmental water uses are called "instream flow" water rights and they are held by the state.[28] Future demand for recreational water uses is dependent and proportional to population and tourism growth in each basin, but some recreation activities could reach the limits of presently available capacities in some regions of the state by 2030.[29] Future demand for environmental water uses will be determined by existing and new federal and state level legislation addressing environmental issues.[30]

Evaporative losses from reservoirs, and natural streams and lakes are thought of as consumptive uses because the water is lost from the water system.[31] Losses, due to

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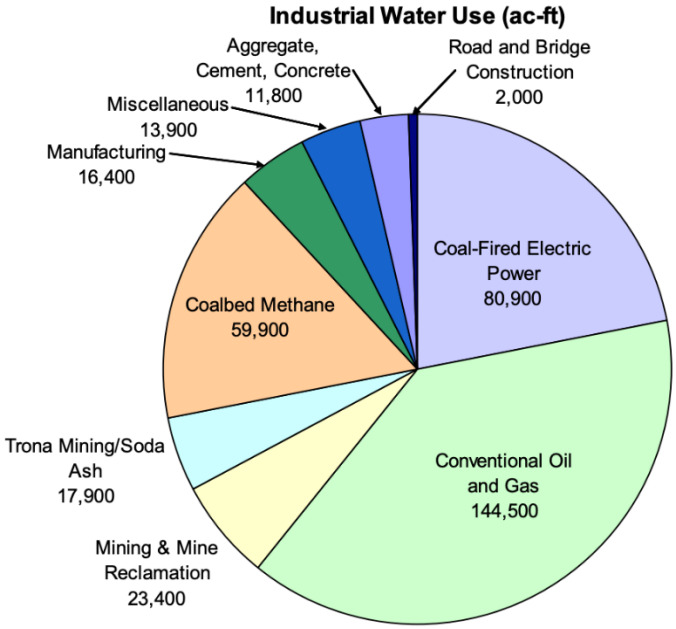
[20] *Id*.
[21] *Id*.
[22] *Id*.
[23] *Id*.
[24] *Id*.
[25] *Id*.
[26] *Id*.
[27] *Id*.
[28] *Id*.
[29] *Id*. at 13.
[30] *Id*. at 13.
[31] *Id*. at 5.

evapotranspiration,[32] which is accentuated by anthropogenic climate induced warming, are anticipated to increase greatly in years and decades to come.[33]

Industrial water uses include water used for electric power generation; conventional oil and gas production; trona mining and soda ash production; mining and reclamation; coalbed methane (CBM) production; manufacturing; aggregate, cement, and concrete; and road and bridge construction.[34] Water used for hydrogen production is likely to fall under the "industrial" water use category.[35] Total industrial surface water use amounted to approximately 371,000 acre-feet per year in 2007, 125,000 of which was surface water and 246,000 of which was ground water, with categories of use depicted on the image below.[36]



The Water Plan projects that overall industrial water use in Wyoming will decrease to approximately 331,000 acre-feet per year by 2030.[37] This projection seems to run counter to the nation-wide trend to transition sectors of the economy to electric power and simultaneously incentivize commercial deployment of low and zero carbon electricity generation technologies (the

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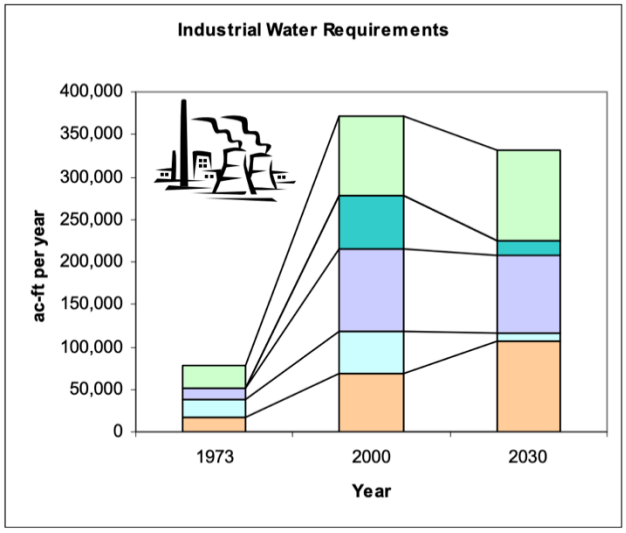
[32] *Id*. at 5.
[33] Siirila-Woodburn, et al., *A low-to-no snow future and its impacts on water resources in the western United States*, 2 NAT. REV. EARTH ENVIRON 800-819 (2021), https://doi.org/10.1038/s43017-021-00219-y.
[34] *Id*. at 5.
[35] Wyo. Admin. Code 037.0006.3 § 2.
[36] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf (image at 10).
[37] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf (see graph at 13).

"energy transition"), which can consume up to 90% more water than traditional electric generation technologies.[38] Depending on the course of policy and the success reaching commercialization of nascent electricity generating technologies, the energy transition could in fact increase industrial water use in Wyoming above the projected 331,000 acre-feet per year by 2030. This is especially the case if federal and state policy more fully incentivizes low carbon fossil-based electricity generation such as installing carbon capture equipment on existing coal-fired generation (*e.g.*, an enhanced Section 45 Q tax credit and Wyoming Statutes §§ 37-18-10--102), which is known to increase water consumption.[39] An increase in industrial surface water use could prove problematic for fully allocated water basins, especially because most of Wyoming's river basins are expected to continue to experience hydrologic drought due to climate-change induced increased average temperatures and reduced seasonal snowpack.[40]



Regarding ground water, the physical characteristics of an aquifer and the value of the intended use (whether the user can invest funding into accessing the groundwater) typically determine whether groundwater is available for a specific use.[41] In Wyoming, there are three main types of aquifers—alluvial, sandstone, and carbonate (limestone)—with alluvial aquifers generally

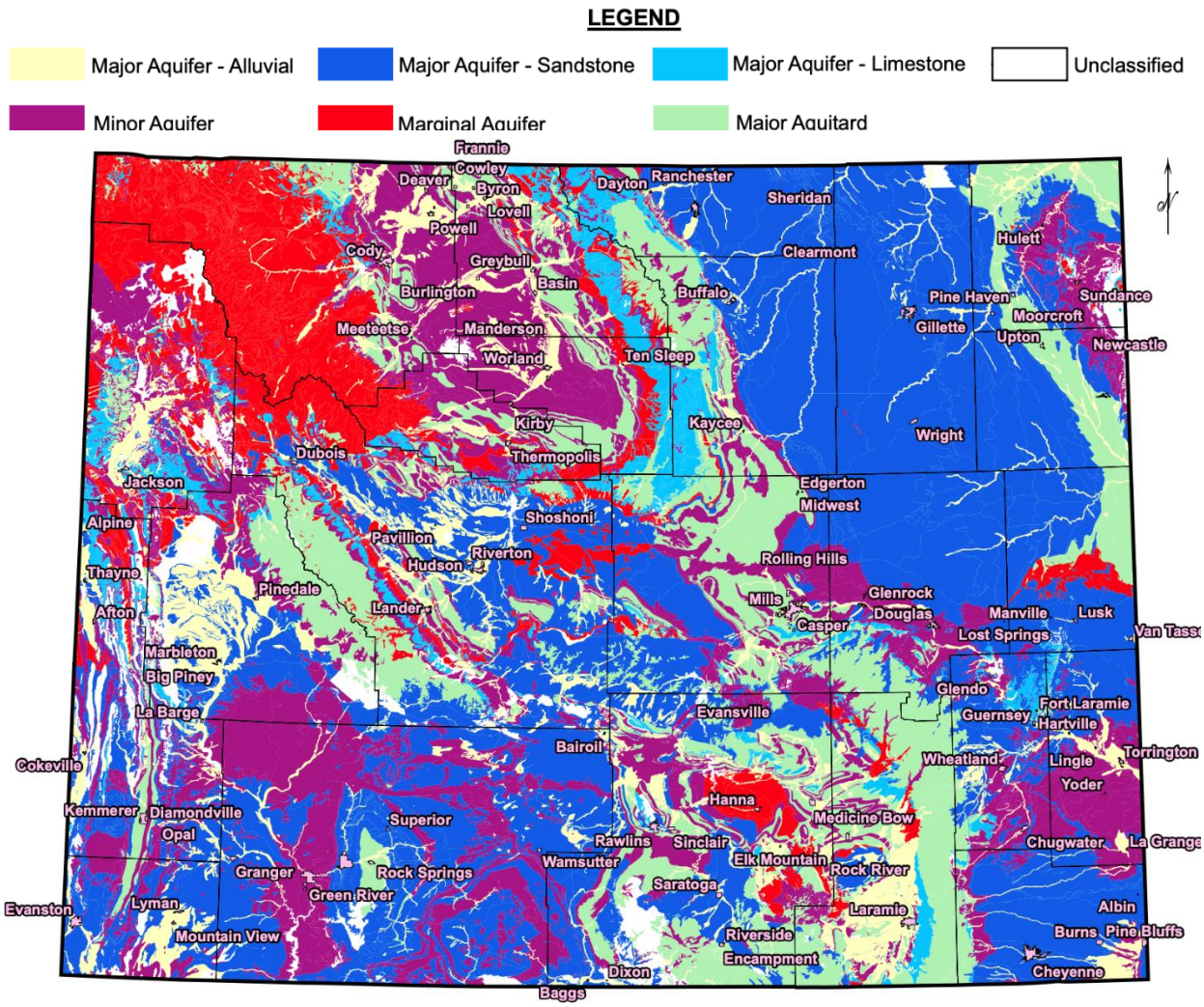
[38] See note 13.
[39] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf at 13.
[40] Siirila-Woodburn, et al., *A low-to-no snow future and its impacts on water resources in the western United States*, 2 NAT. REV. EARTH ENVIRON 800-819 (2021), https://doi.org/10.1038/s43017-021-00219-y.
[41] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf; WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.

producing yields of 500-1,000 gpm, sandstone aquifers generally having poor production, and carbonate aquifers with varying productivity based on fracturing and solution features.[42] The minor aquifers in Wyoming are typically thinner, less extensive, and/or less productive than the major aquifers, yielding 50 gpm or less.[43] The map below indicates where the major and minor aquifers are located throughout the state.[44]

WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf; WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.

[43] WYOMING WATER DEVELOPMENT COMMISSION, THE WYOMING FRAMEWORK WATER PLAN, EXECUTIVE SUMMARY (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/execsummary.pdf; WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.

[44] Map taken from: WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 95.



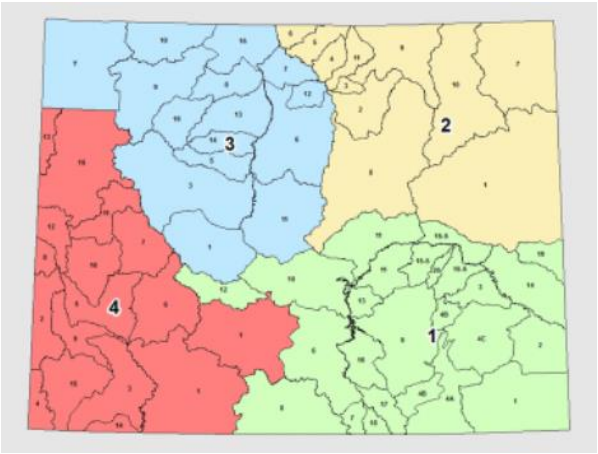
a. Division 1

i. <u>Surface Water Availability</u>

The Wyoming legislature divided the state into four Water Divisions[45] indicated on the maps below.[46]

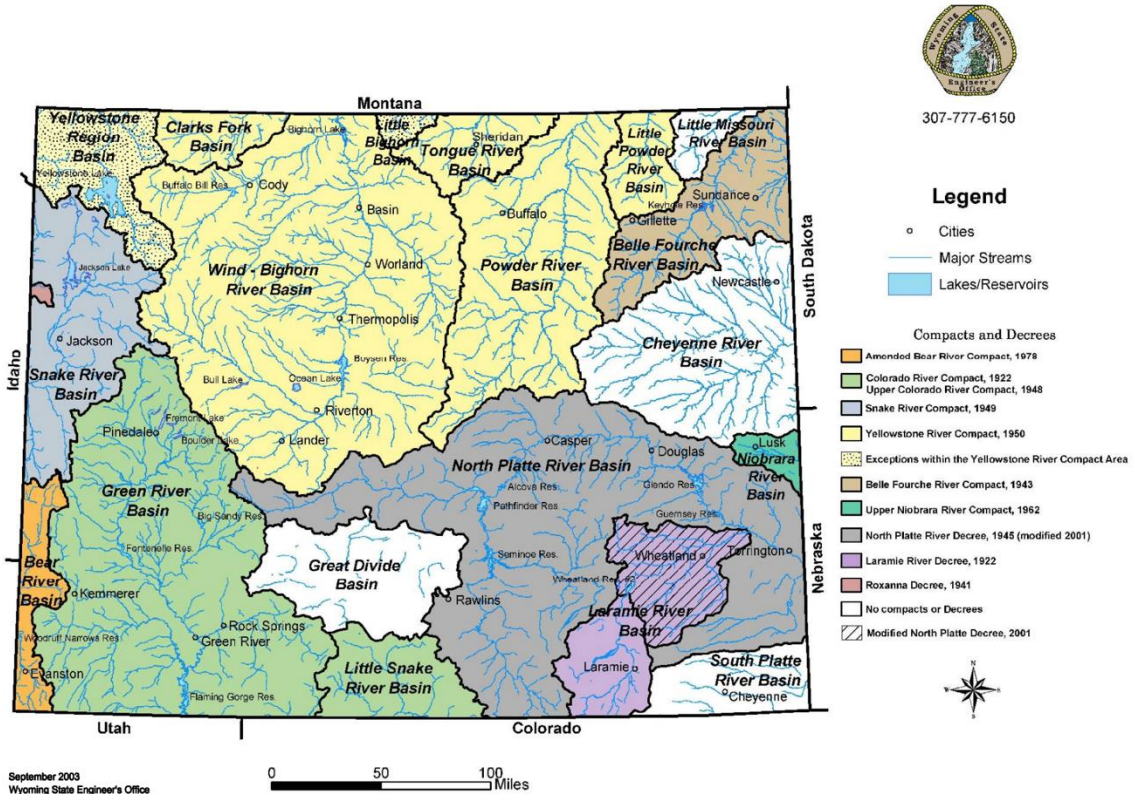
[45] Wyo. Const. Art. VIII, § 4.

[46] W.S. § 41-3-501; Wyo. Const. Art. VIII, § 4; Map of Divisions taken from: WYOMING STATE ENGINEER'S OFFICE, BOARD OF CONTROL, https://sites.google.com/a/wyo.gov/seo/agency-divisions/board-of-control (last visited Oct. 21, 2021); Map of Basins taken from: WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.



Water Division 1 consists of the North Platte River Basin, the South Platte River Basin, the Niobrara River Basin, and the Laramie River Basin. Surface water in Division 1 is allocated between states by the North Platte River Decree, the Laramie River Decree, and the Upper Niobrara River Compact.

Because the Laramie River Basin, the South Platte River Basin, and the Niobrara River Basin are much farther from the proposed location of the W2H2 production facility, it is not recommended that Williams pursue a surface water right in these water basins.



The Platte River Basin system is fully appropriated.[47] For this reason, a present-day water right is unlikely to be usable, especially considering the warming trends observed across the state. Therefore, Williams should not pursue a *new* surface water right within the Platte River Basin.

Williams may want to seek out *existing* senior water rights for purchase from a retiring coal-fired generator or oil and gas producer. Should existing coal plants begin to retire and their water rights become available, their water rights could prove useful to the W2H2 project. The Platte River Basin is one of the top industrial water users by Basin (both ground and surface water), using mostly surface water for coal-fired electric power generation and using mostly ground water for conventional oil and gas development and mining.[48] Laramie River Station is a coal-fired electric generation plant located in the Platte River Basin operated by Basin Electric Power Cooperative. It has a generating capacity of 1,670 MW and uses about 23,250 acre-feet of water annually.[49] While there are no public data available discussing when the facility will be retired, it may be worth reaching out to the owner to assess the likelihood of acquiring its water rights when the facility does retire.

An acquired existing water right, permitted for industrial use, will be limited by the historic consumptive use of that right and the type and place of use that was originally permitted. Thus, Williams may need to change the place of use, should a senior water right be acquired within the Platte River Basin in order to use the water at its W2H2 production facility. Williams may also need to consider methods to move and the cost to move acquired water to its W2H2 facility.

ii. <u>Ground & Produced Water Availability</u>

The Platte River Basin system is fully appropriated and there were reports of groundwater level declines and conflicts in the Basin as far back as 2007.[50] Wyoming has three Control Areas within the Platte River Basin, designated due to declining ground water levels, in Prairie Center, Platte County, and Laramie County.[51] For this reason, it is not recommended that Williams seek to attain any groundwater wells in Division 1. Even a currently producing well may be limited by

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[47] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.
[48] *Id*. (see table at 116).
[49] *Id*. at 115.
[50] *Id*.
[51] *Id*. at 201.

another neighboring water right and is likely to be constrained by declining water availability in years to come.

There has been a long-term trend of declining oil production in Wyoming, but historically, most of the oil refineries have been located in the Platte River basin.[52] Wyoming currently has five operating petroleum refineries that process up to 169,000 barrels of crude oil per day.[53] Water is typically produced as a byproduct of oil extraction; though, because actual water withdrawals are not monitored, the actual amount of water discharged by the industry is hard to determine.[54] Byproduct water from oil refineries may be a useful source of water, though it could be fairly low quality, requiring heavy treatment and it may not prove to be a long-term resource due to limited groundwater availability and declining oil production in the Basin.

b. Division 4

i. <u>Surface Water Availability</u>

Water Division 4 consists of the Green River Basin, the Great Divide Basin, the Bear River Basin, part of the Snake River Basin, and the Little Snake River Basin.[55] The W2H2 project has narrowed its focus to primarily the Green River Basin, which has various subbasins within it, depicted on the map below.[56]

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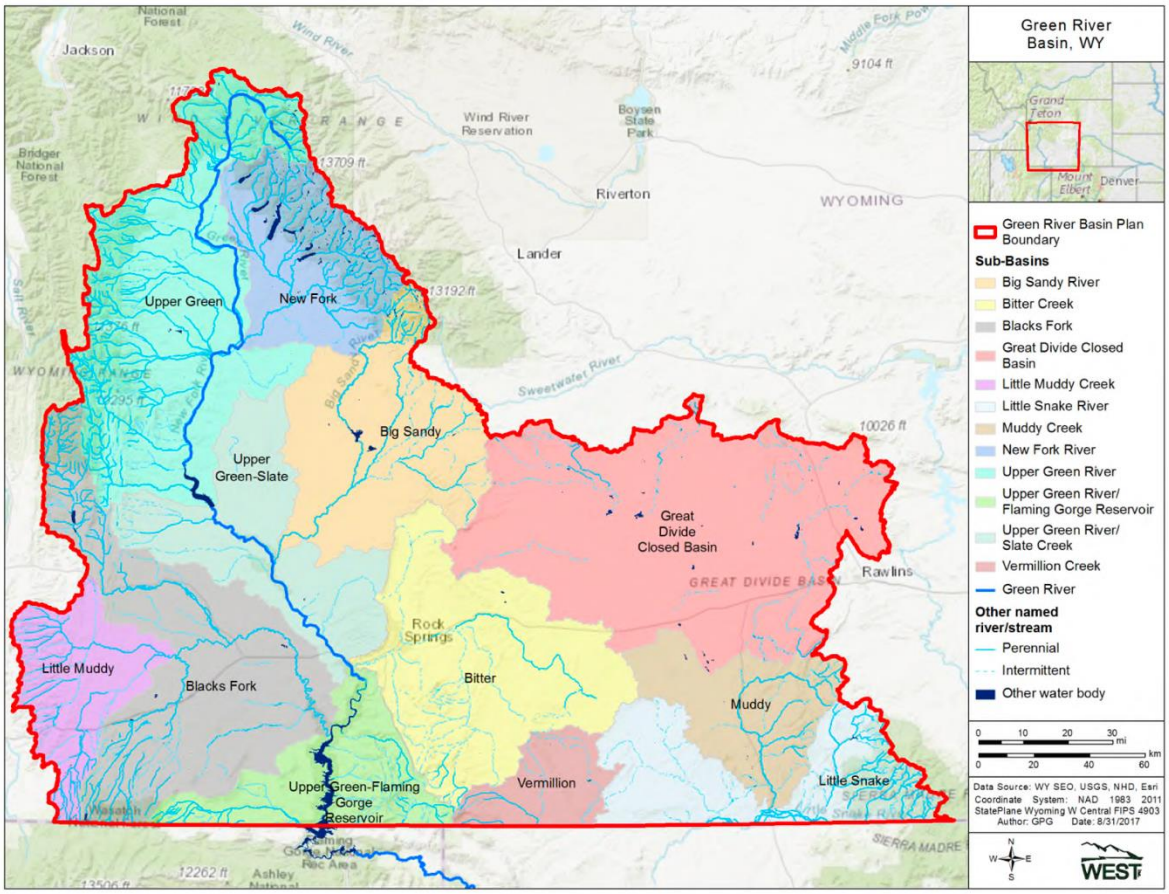
[52] *Id*. at 149-189.

[53] U.S. ENERGY INFORMATION ADMINISTRATION, WYOMING STATE PROFILE AND ENERGY ESTIMATES, https://www.eia.gov/state/analysis.php?sid=WY#:~:text=The%20state%20has%20five%20operating,Colorado%2C%20Montana%2C%20and%20Utah.

[54] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 149-189.

[55] *Id*.

[56] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 5.



"The Green River in Wyoming is the largest tributary to the Colorado River, which is one of the most regulated and managed rivers in the world."[57] Surface water within the Green River Basin is allocated between states by the Colorado River Compact and the Upper Colorado River Compact. Under the Colorado River Compact, negotiated in 1922, the Colorado River Basin is divided into the Upper and Lower Basin at Lee Ferry, Arizona.[58] It allocates 7.5 million acre-feet of water per year to each Basin, with an additional 1 million acre-feet to the Lower Basin for consumptive use.[59] In 1949, the Upper Basin states—Wyoming, Colorado, Utah, and New Mexico—negotiated and ratified the Upper Colorado River Compact.[60] Arizona was given fifty-thousand acre-feet per year because a portion of it falls within the Upper Basin, and the four other

[57] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 2.
[58] Colorado River Compact, 1923 Colo. Sess. Laws 648, COLO. REV. STAT. § 37-61-101 (Articles II, III(a) & III(b), and IV); Colo. Rev. Stat. §37-61-101, Article II(g) (2016) (defining the Lower Basin as the parts of Arizona, California, Nevada, New Mexico, and Utah from which waters naturally drain into the Colorado River System below Lee Ferry and as well as areas beneficially served within the states by water diverted below Lee Ferry).
[59] *Id.*
[60] Lawrence J. MacDonnell, *Colorado River Basin*, 5 WATERS AND WATER RIGHTS 5, 5–16 (2009).

states were given allocations in percentages: 14% to Wyoming, 51.75% to Colorado, 23% to Utah, and 11.25% to New Mexico.[61] Wyoming's allocation under these two Compacts is further administered by the SEO and under Wyoming water law (see *Wyoming Water Law Overview*).

Because the Colorado River and its tributaries are already over-appropriated, a problem that is compounded by increased climate-induced drought and growing water demands, Wyoming's ability to develop and consumptively use water within the Green River Basin is constrained by the two interstate compacts mentioned above.[62]

In 2007, the Green River Basin led in industrial use of surface water among Wyoming's water basins using an estimated 66,000 acre-feet of water.[63] Electric power generators, soda ash producers, and miscellaneous small industry users are the principal users of surface water in the Green River Basin.[64] Electric power generation comprised 68% of the total industrial water use in 2010.[65] The primary electric power generators using surface water are the Jim Bridger Power Plant and the Naughton Power plant, both owned by PacifiCorp.[66] The soda ash industry users of surface water include FMC Wyoming, General Chemical, OCI Wyoming, Solvay Minerals, Inc., and Church and Dwight.[67] The miscellaneous users of surface water in the Green River Basin include the Exxon Shute Creek Plant, which is a natural gas processing plant, and Simplot Phosphates, which produces chemical fertilizer.[68]

It is expected that any new water-intensive industrial development in the state of Wyoming through 2030 will fall under electric power generation or chemical products categories.[69] Future water needs for electric power generation are expected to be heavily influenced by regulation of the industry, which, in turn, is expected to be dependent on the policy response to the environmental concern over discharge of carbon to the atmosphere.[70] Despite the push to build out

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[61] *Id*.
[62] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 2.
[63] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 116.
[64] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 78-85.
[65] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117.
[66] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 78-85.
[67] *Id*.
[68] *Id*.
[69] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 169.
[70] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117.

renewable generation over the past few decades, it is also expected that some thermal generating capacity will be needed to ensure reliable and low-cost power in accordance with the growing base load demand associated with the movement to electrify multiple sectors.[71] While the most recent Water Plan estimates more natural gas and coal-fired generation will be built in Wyoming by 2030, many units are presently slated for retirement in the next few decades.[72] For instance, PacifiCorp plans to retire units at the two coal-fired plants within the Green River Basin—Jim Bridger and Naughton—from 2023 to 2037.[73] PacifiCorp, TerraPower, and the State of Wyoming announced plans in 2021 to site a Natrium small nuclear reactor demonstration project at the location of the retiring Naughton unit.[74] Because the Natrium plant will use liquid sodium as a cooling agent instead of water, it is unclear how much water the plant will need.[75] The discrepancy between projected growth in coal-fired and natural gas generation and actual coal-fired and natural gas generation could unpredictably impact water usage and availability in the Green River Basin.

Regardless of this uncertainty, the water used by the Jim Bridger and Naughton power plant may be a useful source of water for future industrial uses. PacifiCorp holds water rights in the Fontenelle Reservoir for the Jim Bridger plant during times of severe drought.[76] PacifiCorp also owns and operates Viva Naughton Reservoir, which is the primary source of water supply for the Naughton power plant.[77] The two plants depleted an estimated 40,000 acre-feet of water from 2005 to 2006.[78] However, the amounts used by each plant varies each year depending on fluctuations in generation load and weather.[79]

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[71] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117.

[72] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 160.

[73] PACIFICORP 2021 INTEGRATED RESOURCE PLAN, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf at 38.

[74] Catharine Clifford, *Bill Gates' TerraPower aims to build its first advanced nuclear reactor in a coal town in Wyoming*, CNBC (Nov. 17, 2021), https://www.cnbc.com/2021/11/17/bill-gates-terrapower-builds-its-first-nuclear-reactor-in-a-coal-town.html; PACIFICORP, *TerraPower, Wyoming Governor, and PacifiCorp announce efforts to advance nuclear technology in Wyoming* (June 2, 2021), https://www.pacificorp.com/about/newsroom/news-releases/pc-tp-announce-advanced-nuclear-technology-wyoming.html.

[75] https://www.cnbc.com/2021/11/17/bill-gates-terrapower-builds-its-first-nuclear-reactor-in-a-coal-town.html

[76] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 81.

[77] *Id.*

[78] *Id.*

[79] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 160.

Specifically, Fontenelle Reservoir could be a useful source of water for the W2H2 project if Williams can acquire an existing water right from a current user or contract with the state for some of the remaining storage for industrial development purposes. Wyoming holds a contractual right to perpetually market 125,000 acre-feet of water from Fontenelle Reservoir, which stores flows of the Green River and operates as a hydroelectric generating facility.[80]

In 1958, Congress authorized storage in Fontenelle Reservoir for future municipal and industrial development by the U.S. Bureau of Reclamation (USBR).[81] In 1959, the Wyoming legislature appropriated the funds and authorized the Natural Resource Board to contract with the USBR for storage in an amount not to exceed 60,000 acre-feet.[82] Again, in 1974, Wyoming contracted with the USBR to store and market an additional 60,000 acre-feet of Fontenelle Reservoir storage water for municipal and industrial purposes, with a provision allowing not more than 125,000 acre-feet per year.[83] Thus, Wyoming may market 125,000 acre-feet of the 345,397 acre-feet total capacity of Fontenelle Reservoir.[84] Though, the proposed sale must be reviewed pursuant to the National Environmental Policy Act (NEPA) and approved by the Wyoming Water Development Commission, which could be a lengthy process.[85]

As of 2010, Wyoming had allocated 46,550 acre-feet of water of its total 125,000 acre-feet allocation from Fontenelle Reservoir water and had an additional 78,450 acre-feet per year of Fontenelle Reservoir water available.[86] The Jim Bridger Power Plant receives roughly 35,000 acre-feet per year, FS Industries receives 10,000 acre-feet per year, Church and Dwight receive 1,250 acre-feet per year, and Exxon USA receives 300 acre-feet per year.[87] Each allocation is based on a water sales contract that requires a "readiness to serve fee," which reserves an amount of water specified in the contract that can be released when requested by the contractor.[88] Acquiring the water Jim Bridger currently uses from Fontenelle Reservoir and/ or acquiring a new contract to

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[80] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 43; GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 28-29.
[81] *Id.*
[82] *Id.*
[83] *Id.*
[84] *Id.*
[85] *Id.*
[86] *Id.*
[87] *Id.*
[88] *Id.*

use water from Fontenelle Reservoir could be a relatively reliable source of water for the W2H2 project, but because the contract must undergo a federal NEPA review, if this path is chosen it is it is suggested that Williams pursue this course with a sense of urgency.

ii. Ground & Produced Water Availability

1. Geographic Availability/ Modeling

While there is little information about the total groundwater budget in the Green River basin, the total industrial groundwater use in the Green River Basin was estimated to be roughly 1,954 acre-feet per year in 2010.[89] Within the Green River Basin, the industries that obtain their primary water supply from groundwater include coal mining, uranium mining, and the oil and gas industries.[90] Because these industries are not usually required to report actual water use on SEO permits and because groundwater use for these industries is typically intermittent or only for short durations, there is little information about industrial groundwater use.[91] As of 2010, the State Engineer's database indicated only 207 groundwater permits in the Green River Basin indicating industrial use on the permit.[92]

The Green River Basin has a total area of approximately 20,000 square miles.[93] There are large swaths of land—in roughly 925,000 acres of mountains and foothills—where the annual evapotranspiration is expected to exceed annual average rainfall, leading to the assumption that groundwater recharge in these regions is roughly zero.[94] There are also areas where there is surplus rainfall, or where the annual rainfall exceeds annual evapotranspiration.[95]The Green River Basin is estimated to yield somewhere between 50,000 and 100,000 acre-feet of groundwater per year.[96] However, many factors may impact future groundwater availability.[97] Future development of alluvial aquifers could have a direct impact on adjacent rivers and streams within the alluvial

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[89] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 85.
[90] *Id*.
[91] *Id*.
[92] *Id*.
[93] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 240.
[94] *Id*.
[95] *Id*.
[96] *Id*.
[97] *Id*.

system, for instance.[98] Additionally, the development of groundwater associated with coal-bed methane (CBM) extraction could impact groundwater availability.[99]

The process used in CBM development involves pumping water from coal seams to relieve pressure and allow gas to flow for capture at the surface.[100] Typically, the by-product water is not consumptively used, but is reinjected.[101] However, "CMB production is inherently in conflict with groundwater levels as it depends on substantial drawdown to release the methane gas from coal seams."[102] For this reason, CBM development cannot occur where water permeability is high; the industry locates itself in regions where groundwater sources are not abundant.[103] In 2007, water planners anticipated that groundwater levels following CBM exhaustion would remain 30 feet below original levels, however, this remains to be re-evaluated.[104] Though, water planners in 2010 also anticipated that the CBM industry would impact the groundwater resources in the Green River Basin for 50 years forward.[105] For instance, the Atlantic Rim coal-bed natural gas project was anticipated to produce over 500,000 acre-feet of groundwater over the life of the project based on a water to gas ration of 3 Bbls/ MCF.[106]

In sum, it may be potentially challenging to use CMB by-product water for the W2H2 project because Williams will need a consistent, ample, and relatively long-term supply of water.[107] Most CMB industrial facilities have design lives of 35-50 years or longer, but projections have shown that large amounts of CBM water may only be available for a relatively short period.[108] Additionally, the CBM industry is comprised of many companies.[109] While interest has been expressed in the past for use of CBM by-product water for power plant cooling, the life expectancy

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[98] *Id*.
[99] *Id*.
[100] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117-188; WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf.
[101] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117-188; https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 240.
[102] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 301.
[103] *Id*.
[104] *Id*.
[105] GREEN RIVER BASIN PLAN 2010, https://waterplan.state.wy.us/plan/green/2010/report.html at 117-188.
[106] *Id*.
[107] WYOMING WATER DEVELOPMENT COMMISSION, WYOMING WATER PLAN, VOLUME I (Oct. 2007), https://waterplan.state.wy.us/plan/statewide/Volume_I.pdf at 314-315.
[108] *Id*.
[109] *Id*. at 301.

of the water resource and the difficulty securing infrastructure to deliver the water from a multitude of suppliers may present hurtles to effectuating the use of the by-product water.[110]

2. Total O&G and CBM water volumes

The volume of oil and gas produced water in the Green River basin can be estimated from Wyoming production well data for the year of 2020 (the most recent year for which full data were available). Monthly production values of water, gas, and oil were summed up for cumulative year production along with percent of water from total fluids produced. The highest volume of produced water near the Echo Springs Plant was the coalbed methane wells (CBM) to the southeast, owned by Carbon Creek Energy LLC. The area was identified to be producing 28 million barrels of water and with a water cut of nearly 100%. The Echo Springs field produced in 2020 887,817 bbls with a water cut of 68%. Cumulative oil and gas production were 415,529 bbls and 19,207,186 Mcf respectively. Zyga (2007) estimates it requires 2.4 gallons of water to produce 1 kilogram of hydrogen which converts to 1 barrel of water equals 7.4 Mcf of hydrogen. This results in the CBM producing an estimated 209 million Mcf of possible green hydrogen. Other Top water producing formations were the Tensleep at 48 million barrels, Lance at 25 million barrels, Madison 24 million barrels and Lewis 3.6 million barrel.

3. Average water chemistry of O&G and CBM water

The Green River Basin is the headwaters for most of the water leaving Wyoming for Colorado which means most of the surface water is allocated as described above. This leaves groundwater, specifically produced waste brines from oil and gas development as the most likely source of water for a hydrogen hub in this part of Wyoming.

The Center for Economic Geology Research has previously worked with produced water in this basin which is easier to acquire, but contains significant salinity. The table below shows the concentration of major ions in CEGR's past samples from this area in mg/L. CEGR has further data on minor and trance components which is not shown here.

[110] *Id*. at 314-315.

Sample ID	Alkalinity as mg/L $CaCO_3$	Calcium (mg/L)	Chloride (mg/L)	Potassium (mg/L)	Sodium (mg/L)	Sulfate (mg/L)	Apparent salinity (mg/L)
WA-33	2,070	23	2,630	32	2,520	260	7,614
WA-34	2,460	8	1,760	25	2,170	243	6,726
WA-35	1,900	30	4,970	32	3,440	253	10,768
WA-36	954	70	6,440	35	4,180	184	12,026
WA-37	2,190	34	4,530	29	3,510	348	10,769
WA-38	1,410	23	4,280	59	3,220	995	10,137
WA-39	2,050	5	763	16	1,270	438	4,613
CBM (from 49-007-22322)	1,025	14	302	17.5	898	~3	2,260

The major ions in water samples which University of Wyoming collected from oil and gas wells near Echo Springs are all sodium-chloride to sodium-sulfate type. In addition to those ions shown here, University of Wyoming collected minor and trace elements, which are reflected in the total dissolved solids (TDS) shown as salinity in the last column. The final row of the table shows the chemistry of a CBM well which seems to represent the median chemistry in the Mesaverde formation's coal bed methane development. CBM water is generally cleaner than oil and gas produced water.

The cut-off for water protected under the Clean Water Act as an underground source of drinking water is 10,000 mg/L total dissolved solids. This means that most waters in this area are not protected as a USDW due to high salinity. The definition of a USDW also requires aesthetic standards, adequate flow-rate, and no aquifer exemptions (which were historically given for oil and gas development). When these additional standards are considered, even waters which pass the 10,000mg/L test do not qualify as a USDW due to failing one or more of these other areas.

For a summary of water quality standards in Wyoming, see pp. 30—31 of the state water plan: https://waterplan.state.wy.us/plan/green/2010/report.html

4. Estimates recovery factor from generic treatment

Based on the water samples reported in the table above, the CEPWM has developed a generic water treatment system that may be used for generating water that is suitable for use in an electrolysis system. For the sake of this discussion the product water from the proposed system will have a total dissolved solids (TDS) concentration of ≤ 1 mg/L. Further work will resolve specific treatment processes, chemical additives, and energy saving options, e.g., installation of energy recovery devices on high-pressure flow lines, based on more detailed water quality assessments. All of the identified waters are characterized as mildly brackish water sources with average TDS concentrations ≤ approximately 10,000 mg/L. Increases in TDS concentrations from a low of 2,200 mg/L to a high of 12,000 mg/L dictate the total dollar value that will have to be invested in the treatment system, in the form of CAPEX and OPEX expenditures, to achieve the product water TDS requirement. For example, as TDS increases so too does the pumping energy and chemical consumption to maintain a desired product water flowrate and/or feed water recovery (product flow / feed flow = recovery) ration. Recovery is an important consideration here as lower recovery values indicate larger volumes of wastewater that must subsequently be managed (lost revenue) and lower volumes of product water which may limit hydrolysis capacity. Therefore, achieving high feed water recovery values is important as it reduces the unit water energy value (kWh/m3) and maximizes the utilization of the targeted resource for hydrogen production. In this case the resource of interest is the raw water source. Wastewater flows from the treatment system will include the following (minimum): highly saline reject streams from membrane-based desalination, acidic/caustic flows from ion exchangers, and backwash flows (particulate solids, oils and greases) from membrane filtration processes. These flows, in addition to representing wasted economic and resource investment, must also be disposed of (additional cost). Likely disposal options will include discharge to surface impoundments for evaporation (land area intensive, low CAPEX/OPEX), reinjection into deep wells (permitting intensive, moderate CAPEX/OPEX), and discharge to a existing municipal sewer (geographically limited, permitting intensive, unknown incurred costs). Specific initial conclusions about the previously summarized water sources are as follows:

- The CBM water has a TDS concentration of 2,260 mg/L. Of this value the majority of the TDS is in the form of alkalinity (CO_3^{2-}, HCO_3^-). This composition

suggests that the starting TDS may be halved (approximately) using a relatively simple treatment process, like acidification, where the alkalinity is removed through the production of carbon dioxide (carbonate converted to carbon dioxide and off gassed). This process makes further desalination using reverse osmosis (RO) and/or ion exchange more efficient in terms of the recovery ration that may be achieved. Using this general treatment scheme an overall water recovery >95% may be achieved with relatively low CAPEX expenditures.

- All waters are relatively soft with calcium and magnesium concentrations <80 mg/L as ion. This indicates that chemical precipitation softening is not required to achieve high feedwater recoveries. Instead, nanofiltration (NF) or membrane softening is a more viable and economically viable treatment option. NF may be used as pretreatment and/or as treatment in between RO stages to remove minerals as their concentrations increase in the RO concentrate.
- RO will utilize a combination of brackish water and seawater water elements. By using a combination of membranes with different hydraulic and salt permeabilities we will maximize the energy efficiency of the process, while maintaining a high-quality product stream in terms of a low TDS concentration. Brackish water elements will be used as the lead elements (lower feed TDS, lower salt rejection efficiency, higher water permeability), while seawater elements will serve as the lag elements (higher feed TDS, higher salt rejection efficiency, lower water permeability). Treatment trains for waters outside of the CBM water can achieve water recoveries >90%. Ultimate values will depend on a full characterization of the intended waters and establishment of CAPEX and OPEX requirements by Williams.
- To achieve the targeted product water TDS concentration (~1 mg/L) we will explore two options: 1) permeate staging with the RO system, and 2) polishing of the RO permeate with ion exchange. Process economics will ultimately dictate the selection of the most appropriate process.

Sample ID	Date	Operator	Longitude	Latitude	Formation	pH	Cond mS/cm	°C	ORP mV	Est. TDS ppm	Alkalinity, Total as CaCO3	Bromide	Calcium
WA-175	04/26/22	CROWHEART ENERGY LLC	-107.89	41.93	Lewis	7.59		19.8			635	107	53
WA-176	04/26/22	CROWHEART ENERGY LLC	-107.92	41.93	Lewis	7.66		19.6			663	89.3	45
WA-177	04/26/22	CROWHEART ENERGY LLC	-107.92	41.93	MESAVERDE	7.83		19.4			767	77.8	38
WA-178	04/26/22	CROWHEART ENERGY LLC	-107.91	41.88	Lewis	7.67		19.5			796	96.2	45
WA-179	04/26/22	CROWHEART ENERGY LLC	-107.91	41.88	Lewis	7.71		19.7			799	95.5	45
OPAL-180	07/18/22	The Williams Companies	-110.34	41.78		5.4	0.01474	24.3	330	12.97	309	31.8	1170
OPAL-181	07/18/22	The Williams Companies	-110.34	41.78		9.77	0.09115	24.4	337	75.02	458	2	219
OPAL-182	07/18/22	The Williams Companies	-110.34	41.77		8.33	0.9019	29.2	332	612.5	281	ND	104
OPAL-183	07/18/22	The Williams Companies	-110.34	41.77		8.28	0.9077	25.2	86	625.1	295	ND	106
CBM-191	08/02/22	Carbon Creek	-107.66	41.40		8.51	5.45	30	52	4200	2020	2.5	12
CBM-192	08/02/22	Carbon Creek	-107.64	41.43		8.37	7.287	24.1	-31	5838	1390	0.6	13
CBM-193	08/02/22	Carbon Creek	-107.60	41.45		8.58	4.035	23.2	-74	2950	712	ND	8
CBM-194	08/02/22	Carbon Creek	-107.66	41.37		8.44	4.112	26.8	37	3088	1840	1.4	8
CBM-195	08/02/22	Carbon Creek	-107.66	41.29		8.53	2.13	25.8	129	2130	1360	0.3	6
FONT-218	06/14/12	USGS-WRD	-110.05	42.02	Surface River	8.1	0.297	14.7			117		38

Sample ID	Chloride	Fluoride	Magnesium	Ammonia as N	Potassium	Sodium	Sulfate	Barium	Boron	Iron	Lithium	Manganese	Strontium	Silica	Sum of TDS
WA-175	5900	ND	7	18	80	3890	22	5.44	17.3	17.9	2.3	0.32	15.2	95	10560.698
WA-176	5820	0.9	4	18	81	3780	19	6.05	19.5	4.7	2.7	0.07	14.7	138	10367.998
WA-177	5060	1	4	15	62	3460	ND	5.33	18.7	0.9	2.8	0.09	11.4	136	9281.498
WA-178	5370	1	5	17	66	3670	ND	5.52	18.2	3.4	2.8	0.21	12.8	110	9841.928
WA-179	5700	1	4	15	64	3620	ND	5.4	18.3	3.3	2.8	0.21	12.6	108	10116.698
OPAL-180	5030	ND	7	11.1	67	1850	17	5.29	5.1	131	2	4.61	25.8	14	8647.96
OPAL-181	2570	ND	98	16.9	54	1650	629	0.1	0.27	0.05	ND	0.002	6.57	7	5700.336
OPAL-182	22	0.4	27	ND	1	55	182	ND	0.09	0.29	ND	0.056	1.95	13.3	679.04
OPAL-183	21	0.4	28	ND	1	55	180	ND	0.09	ND	ND	0.014	2.09	14.4	693.208
CBM-191	528	2.4	5	2	16	1240	ND	1.6	1.9	0.34	ND	0.009	0.15	14	3837.749
CBM-192	192	3.5	8	1.68	13	731	ND	0.44	1.25	0.35	ND	0.03	0.07	12	2359.85
CBM-193	13	4.9	6	0.94	5	318	2	0.08	0.68	0.3	ND	0.014	0.04	10	1075.414
CBM-194	311	3.8	4	1.75	13	1010	2	0.6	1.69	0.18	ND	0.009	0.04	11	3202.429
CBM-195	144	4.7	3	1.31	8	691	ND	0.32	1.2	0.15	ND	0.004	0.05	12	2224.984
FONT-218	2.41	0.14	10.8	< 0.013	1.63	10.4	39.4							5.6	219.78

WATER TREATMENT QUALITY REPORT

JUNE 2023

Produced in support of the Williams Southwest Wyoming Hydrogen Hub (W2H2) Project

Prepared by:

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School of Energy Resources
Center for Economic Geology Research

CENTER OF EXCELLENCE
IN PRODUCED WATER MANAGEMENT

University of Wyoming
School of Energy Resources
Hydrogen Energy Research Center

WATER TREATMENT QUALITY REPORT

This report was prepared by Dr. Jonathan A. Brant of Department of Civil and Architectural Engineering and Center for Excellence in Produced Water Management in support of the "Williams Southwest Wyoming Hydrogen Hub" (W2H2) Project. W2H2 is funded by the Wyoming Energy Authority to answer questions about transport of hydrogen and production of hydrogen from water (either by electrolysis or steam methane reforming) in the Greater Green River Basin. Charles Nye of the Center for Economic Geology Research has responsibility for performance of W2H2.

ABOUT THE CENTER OF EXCELLENCE IN PRODUCED WATER MANAGEMENT

The Center of Excellence in Produced Water Management (CEPWM) provides innovative science and engineering research for application in the oil and gas industry for the purposes of reducing environmental impacts, improving industry process efficiencies, increasing profitability, and enhancing society benefits.

ABOUT THE CENTER FOR ECONOMIC GEOLOGY RESEARCH

The Center for Economic Geology Research (CEGR) investigates solutions to the challenges in Wyoming's fossil fuel and mineral industries. CEGR research projects explore opportunities to use Wyoming's distinctive geology and resources in order to develop those opportunities, diversify Wyoming's economy, and to maintain competitiveness in a low-carbon fossil energy future.

ABOUT THE HYDROGEN ENERGY RESEARCH CENTER

The Hydrogen Energy Research Center (H_2ERC) leads applied research to identify and quantify the relative competitive advantages of Wyoming in an emerging hydrogen economy, and collaborates with Wyoming stakeholders to support growth of a hydrogen industry focused on serving the state's existing energy customers and growing new markets.

BACKGROUND ON W2H2:

The overall project objective of W2H2 is to establish the southwest corner of Wyoming as a regional green hydrogen and/or synthetic natural gas production hub. In W2H2, Williams will partner with the University of Wyoming and others to address two key technical challenges: 1) what is the best way to transport hydrogen using existing infrastructure, and 2) what is the best way to provide water for the proposed electrolysis plant? The findings will help determine the feasibility, sizing, and location within Wyoming of follow-up projects.

A follow-up project resulting from this work would be expected to be in the 200-600MW range making it the largest of its type in North America. Local and state benefits of a follow-up to W2H2 will include the need for skilled labor and associated training to construct and operate all related facilities resulting from this study's conclusions. Additionally, such a follow-up project would elevate the University of Wyoming to become a leader in green hydrogen production technologies. At the national level, Wyoming would continue its position as an energy exporter and establish itself as a primary green hydrogen supplier in the United States. Ultimately, the Williams Wyoming Hydrogen Hub would accelerate the clean energy economy and connect with potential regional renewable energy opportunities.

BASIS OF DESIGN

The basis of design for the water treatment systems evaluated in this study for producing feed water for producing H_2 through electrolysis were as follows:

- **Finished Water Quality** = Two delivered water qualities were considered in the design simulations: ultrapure water (electrical resistivity = 18 MΩ•cm, TOC < 10 ppb) and drinking (potable) water quality (total dissolved solids ~ 500 mg/L, TOC < 10 ppm). The electrolysis process requires ultrapure water to protect the integrity of the anodes and cathodes, as well as maximizing the H_2 production efficiency. It should be noted that ultrapure water is an aggressive solvent that will require stainless steel transmission and storage components. This requirement suggests that the treatment system should be located in close proximity to the H_2 production facility to reduce the high costs associated with stainless steel components and to reduce a degradation in finished water quality during transmission. Drinking water quality water was also considered because some electrolysis vendors institute their own in-house treatment system to achieve the specified water quality for their system. The expectation is that a relatively "clean" water source would be required by the vendor and thus a drinking water standard was assumed.

- **Treatment Capacity** = the treatment system must achieve a production capacity of 182 m^3/hr (1.15 million gal/day). The assumed treatment capacity only considers the water being consumed by the electrolysis system and is sized for a 600 MW electrolyzer. Water consumption by the cooling system will depend on the type of cooling used. In fact, water consumption of the overall H_2 production system is largely determined by the type of cooling system employed. Two types of cooling systems may be employed: air cooling and evaporative cooling. Water consumption is lower for air cooled systems (30 to 40% lower); however, air cooled systems are more expensive than evaporative coolers and are only viable under specific site conditions.

- **Water Sources** = four different produced water (PW) generating sites, and one freshwater reservoir site were considered for this study. Water samples were collected from unique wells at each site and subjected to a range of applicable analyses to gather data required for treatment process selection and design.

- **Design Scope** = only the primary treatment systems required for achieving the target finish water quality were considered. Not considered were water/residuals transmission lines, impoundments required for storage of residual waste streams (concentrate/reject from membrane processes, precipitated solids, coagulated sludge), solids disposal via landfilling, support builds, and software control systems. Surface impoundments for waste flows can require substantial acreage and must be considered during future design phases. This will be an important consideration when identifying suitable sites for locating the treatment system.

OVERVIEW OF PRODUCED WATER (PW) SOURCES

Representative water quality values for the produced water (PW) sites considered in this study are summarized in **Tables 1** and **2**. Water quality analyses focused on those parameters pertinent to the design of treatment systems capable of achieving ultrapure water standards.

The PW from the Opal 180 and 181 storage tanks was characterized as very hard water due to high concentrations of calcium and magnesium. The PW from the Opal 180 tank is much harder (exceptionally hard water) than that from the Opal 181 tank. For both tanks the hardness primarily originates from calcium. Hardness is problematic as it contributes to scaling in treatment system components like heat exchangers, valving, and pining. Hardness is a concern for desalination systems, like reverse osmosis, as it limits the achievable feed water recovery and may lead to irreversible membrane fouling. Both PWs are mildly brackish (TDS<10,000 mg/L) and contain relatively high concentrations of organics (TOC~100 mg/L).

Table 1. Summary of water quality parameters for PW sources at the Opal site.

Parameter	**Units**	**Opal 180**	**Opal 181**
Total Suspended Solids (TSS)	mg/L	32	24
Total Dissolved Solids (TDS)	mg/L	8,674	5,707
Total Organic Carbon (TOC)	mg/L	100	95
Total Hardness (TH)	mg/L as $CaCO_3$	2,950	949
Cations			
Sodium	mg/L	1,850	1,650
Calcium	mg/L	1,170	219
Magnesium	mg/L	7	98
Barium	mg/L	5.2	0.1
Anions			
Chloride	mg/L	5,030	2,570
Sulfate	mg/L	17	629
Alkalinity	mg/L as $CaCO_3$	309	458

The PW from the North and East Echo Springs sites are respectively moderately hard and slightly hard (**Table 2**). On this basis alone, both Echo Springs sources appear more treatable than that from the Opal site. In all cases the hardness originates from the dissolution of minerals into the PW from their respective formations. Geological characterization of PW formations may prove useful in future efforts for identifying sources that may have lower mineral contents. The average (calculated for all wells at the respective sites) TDS concentration for the North Echo Springs site (10,033 mg/L) was much higher than the average value for the East Echo Springs site (2,540 mg/L). For the East Echo Springs wells the primary contributor to the TDS was alkalinity (bicarbonate). Conversely, for the North Echo Springs wells the TDS is primarily made up of chloride and alkalinity (lower concentration relative to the East Echo Spring wells). Such ion compositions are typical for coal bed methane (CBM) waters. Alkalinity is relatively easier to remove than other ions as it may be “burned” off using acid addition and/or through ion exchange. The North Echo Springs wells were all characterized by relatively high total silica concentrations (104 mg/L). There are two different forms of silica in water: dissolved and particulate. Particulate silica may be easily removed using filtration and is less a concern for fouling in membrane processes. Dissolved silica is much more problematic for membrane systems as it results in

irreversible fouling through the formation of hard cake structures. It therefore must be removed prior to the membrane process using ion exchange or some other suitable process. *The risks associated with silica fouling generally make silica containing waters non-viable for membrane treatment.*

Water from the Fontanelle Reservoir was considerably fresher (less saline) than the PWs from the Echo Springs sites. The Fontanelle water is very hard (TH>100 mg/L as $CaCO_3$); however, no other water quality values presented a concern in terms of water treatability.

Table 2. Summary of water quality parameters for PW sources at the Echo Springs and Fontanelle Reservoir sites. The reported values for North Echo are from WA-177 and those from East Echo are from CBM-191.

Parameter	Units	North Echo	East Echo	Fontanelle
Total Suspended Solids (TSS)	mg/L	165	12	n/a
Total Dissolved Solids (TDS)	mg/L	9,281	3,838	220
Total Organic Carbon (TOC)	mg/L	179	5	n/a
Total Hardness (TH)	mg/L as $CaCO_3$	111	50.5	139
Silicon				
Mean Total [1]	mg/L	104±18.7	12±1.4	5.62
Max Dissolved	mg/L	88±5.8	12±1.4	n/a
Minimum Dissolved	mg/L	16±13.1	0	n/a
Cations				
Sodium	mg/L	3,460	1,240	10.4
Calcium	mg/L	38	12	38
Magnesium	mg/L	4	5	10.8
Barium	mg/L	5.3	1.6	0
Anions				
Chloride	mg/L	5,060	528	2.41
Sulfate	mg/L	0	0	39.4
Alkalinity	mg/L as $CaCO_3$	767	2,020	117

[1] – The reported mean total is the mean of the total silicon concentration which is the summation of the particulate and dissolved forms of silicon.

Geochemical modeling done at the School of Energy Resources' (SER) Center for Economic Geology Research (CEGR) determined the maximum and minimum dissolved silica concentrations for the two PW sources. The PW from North Echo was characterized as having silica primarily in the dissolved form, while that from East Echo was most likely in the particulate form. Treatment scenarios will consider both maximum and minimum dissolved silica concentrations for both North and East Echo sites.

The organic content of the East Echo Springs wells was lower than those from the North Echo Springs wells, which were very high. This indicates that the East Echo PWs are “cleaner” than those from North Echo. The sources of these organics are likely a mixture of oils and greases that persist in the PW after the initial oil-water separators. Taken together the water quality data suggests that the PW from the East Echo site is more treatable, and would require less treatment, than that from the North Echo site.

It was determined through discussions with Williams that the water availability from the Opal 180 and 181 PW storage tanks is insufficient for meeting the required capacity of the treatment system (380,408 gal/day). Each storage tank produces approximately 12,000 gal/day for a combined capacity of 24,000 gal/day. This represents approximately 2% of the required daily water volume. Therefore, the Opal 180 and 181 tanks should not be considered as viable sources.

PW TREATMENT SCHEMES

The general treatment scheme for the East and North Echo Springs sites were similar despite differences in their compositions. The process components common to both sites included:

- **Membrane Filtration (Ultrafiltration)**: removal of particulate solids/turbidity, organics, oils and greases (emulsions).
- **Ion Exchange**: removal of hardness causing ions (calcium, magnesium, iron, barium) to mitigate membrane fouling.
- **Desalination (Reverse Osmosis)**: separation of dissolved solids (salts, trace metals).
- **Ion Exchange**: removal of trace amounts of sodium and chloride that passed through the RO membrane with protons (H+) and hydroxides (OH-) to produce ultrapure water free of ions.

North Echo Springs PW Treatment Systems

The PW treatment schemes for achieving ultrapure and potable water standards are given in **Figures 1** and **2**, respectively. Both systems incorporate ultrafiltration, ion exchange (IX), and reverse osmosis (RO). The ultrapure water production system also incorporates a second IX polishing process to remove those ions that pass through the RO membrane. Feed water recovery ratios for all processes are >90%, with the exception of the RO system (75%). The recovery for the RO process is set by the onset of mineral precipitation and silica fouling; however, this value may be optimized (higher or lower) during pilot trials where fouling over long periods will be observed.

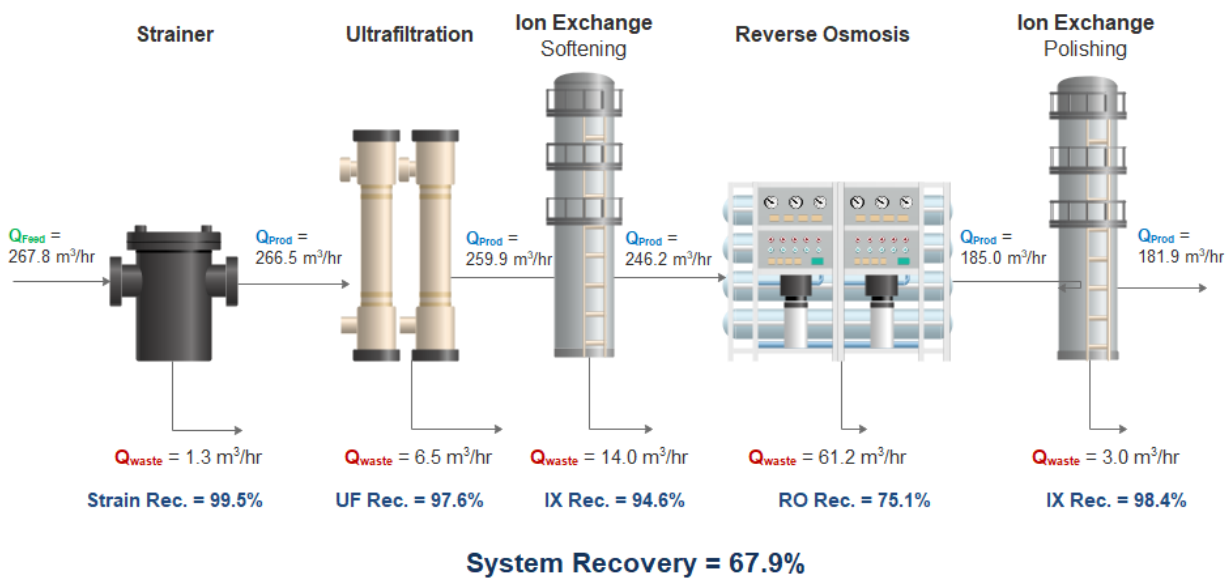


Figure 1. Process flow diagram for treating the North Echo Springs PW to a ultrapure water standard for total dissolved solids and total organic carbon concentrations (electrical resistivity = 18 MΩ•cm, TOC < 10 ppb).

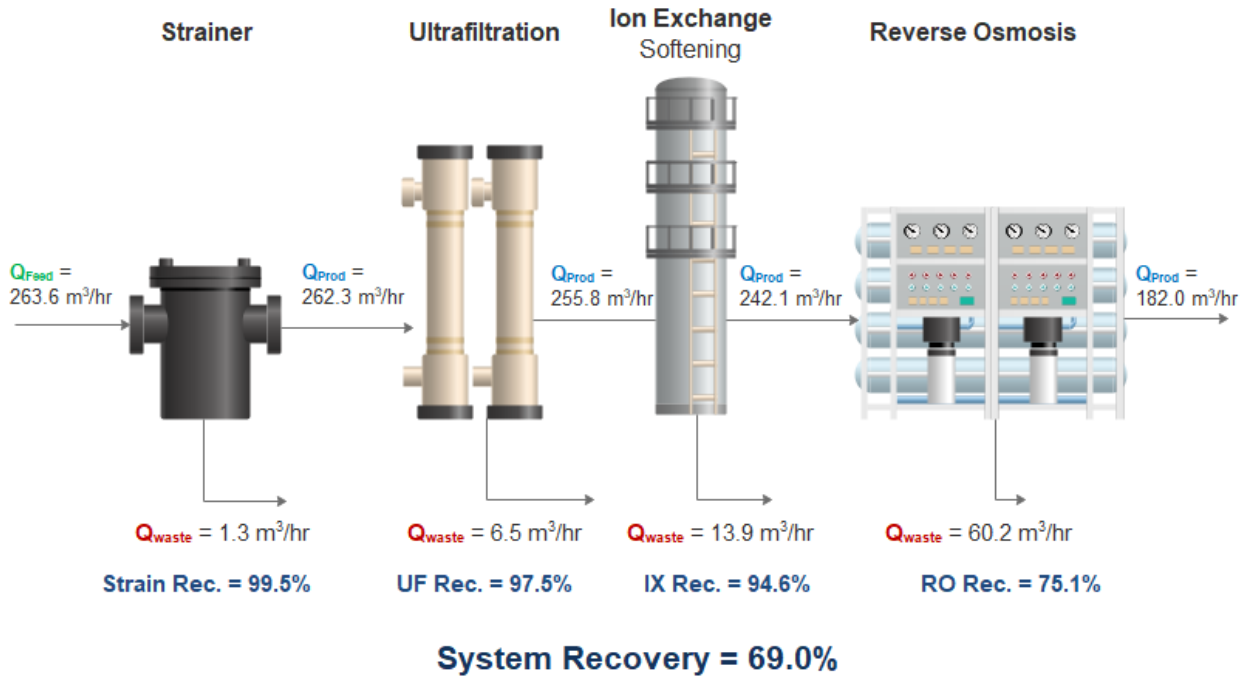


Figure 2. Process flow diagram for treating the North Echo Springs PW to a potable water standard for total dissolved solids (TDS ~500 mg/L).

The specifications and costs for treating PW from the North Echo Springs site under the two finished water quality standards are summarized in **Table 3**. Both projections consider the dissolved silica concentration in the PW to be 88 mg/L. Should the dissolved silica concentration

be lower, e.g., 16 mg/L, the same silica control strategy must be employed, which is the addition of an anti-scalant prior to the RO system. Therefore, the differentiator between the two systems is the type of RO membrane that must be employed (**Table 4**) and the ion exchange system at the tail of the system for polishing the RO permeate. The seawater RO membrane was required to achieve the ultrapure water standard, while the "looser" membrane was viable for the condition where more TDS was allowable in the permeate. Both systems utilized a sodium phosphate based antiscalant to control silica fouling of the RO membranes; however, the specific antiscalant formulation would have to be determined through detailed analysis of the PW and laboratory testing. A secondary, or complimentary approach, that was employed was increasing the RO feed water to pH 8.0. Silica is most highly soluble at this pH and thus less likely to form hard scale on the membrane surface. ***In both treatment scenarios, potable and ultrapure product water qualities, the silica is in a supersaturated state (saturation >250%) and thus represents a significant fouling risk.***

Table 3. Summary of system performance metrics for the North Echo Springs PW treatment system treating to ultrapure and potable water finished water standards.

Parameter	Units	Ultrapure Water	Potable Water
Specific Energy			
Ultrafiltration	kWh/m^3	0.06	0.06
IX Soft/Dealk	kWh/m^3	0.07	0.07
Reverse Osmosis	kWh/m^3	2.37	1.33
IX MB Polish	kWh/m^3	0.09	0.0
Operating Costs			
Ultrafiltration	$\$/m^3$	0.027	0.027
IX Soft/Dealk	$\$/m^3$	0.508	0.508
Reverse Osmosis	$\$/m^3$	0.660	0.566
IX MB Polish	$\$/m^3$	0.172	0
System Summary			
Specific Energy	kWh/m^3	2.68	1.51
Operating Cost	$\$/m^3$	1.57	1.28
Feed Flow Rate	m^3/hr	267.9	263.7
Daily Consumption	m^3/day (Mgal/day)	6429.6 (1.70)	6331.2 (1.67)

Table 4. Summary of RO membrane properties used for desalinating PW from the North and East Echo Springs sites under two different finished water standards.

Finished Water Standard	RO Membrane Designation	Property	Value
Ultrapure Water	SW30XHR-440	Active Area Salt Rejection Permeance	440 ft^2 99.8% 0.02 gal/day/ft^2/psi
Potable Water	BW30HRLE-440i	Active Area Salt Rejection Permeance	440 ft^2 99.3% 0.19 gal/day/ft^2/psi

The finished water properties for the two treatment scenarios for the North Echo Springs site are summarized in **Table 5**. The ultrapure water is a nearly completely demineralized water as indicated by the lack of ions present in the finished water. Boron (B) exists in the finished water for both treatment systems due to its relatively high permeability across RO membranes. The ion exchange process that is downstream of the RO membrane reduces this concentration in the ultrapure water scenario. Boron does not pose a challenge for electrolysis systems, though it is a concern for irrigation and drinking water applications. Further optimization of the treatment system design can further reduce the ionic composition of the finished waters.

Table 5. Summary of finished water quality values for the North Echo Springs site for the two different PW treatment scenarios.

Water Quality Measure	Units	Ultrapure Water	Potable Water
Gross Measures			
TDS	mg/L	15.4	327
pH	-	6.99	8.6
Cations			
Sodium	mg/L	0.03	118.7
Potassium	mg/L	0.00	2.54
Calcium	mg/L	0.00	0.0
Magnesium	mg/L	0.00	0.0
Anions			
Chloride	mg/L	0.00	170.1
Fluoride	mg/L	0.00	0.02
Boron	mg/L	2.70	9.65
Carbonate	mg/L	0.00	7.48
Neutrals			
SiO_2	mg/L	0.00	1.70

East Echo Springs PW Treatment Systems

The PW treatment schemes for achieving ultrapure and potable water standards are given in **Figures 3** and **4**, respectively. The treatment schemes for the East Echo Springs site are similar to those for the North Echo Springs site. The primary differentiator is the usage of large amounts of hydrochloric acid to remove the alkalinity prior to the UF membrane. This is required to control scaling of the UF membrane. Alkalinity could be removed using the IX process prior to the RO membrane; however, this scenario only shifts the costs to that process and did not reduce the overall OPEX costs for the treatment system. If possible other alternatives may be explored for reducing the alkalinity of the PW, which would have significant impacts on the treatment costs.

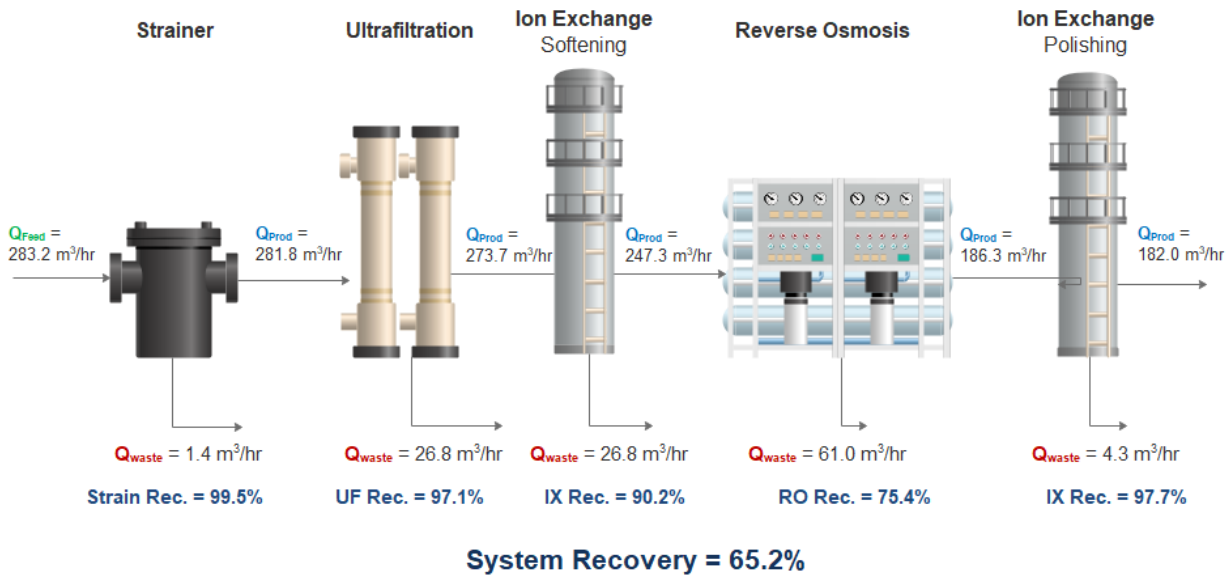


Figure 3. Process flow diagram for treating the East Echo Springs PW to a ultrapure water standard for total dissolved solids and total organic carbon concentrations (electrical resistivity = 18 MΩ•cm, TOC < 10 ppb).

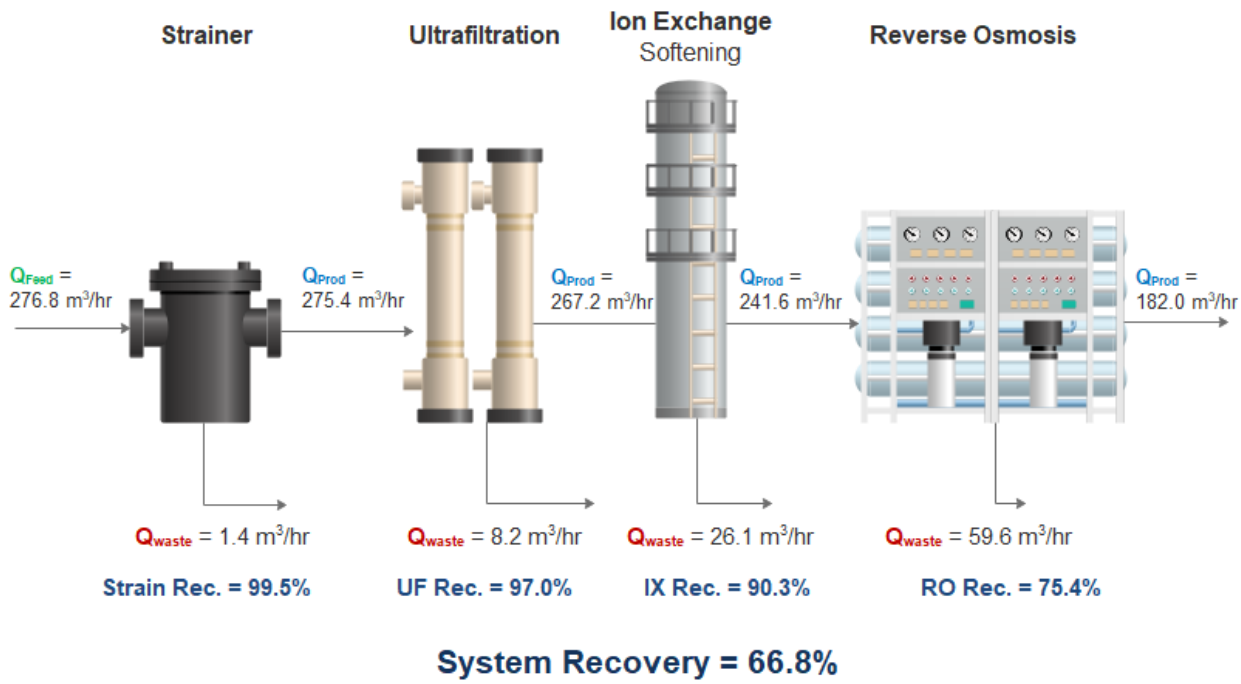


Figure 4. Process flow diagram for treating the East Echo Springs PW to a potable water standard for total dissolved solids (TDS ~500 mg/L).

Process and system performance statistics for the East Echo Springs PW treatment systems are summarized in **Table 6**. Like the North Echo Springs site, treating to the potable water standard was resulted in lower energy consumption and lower OPEX costs. This was due to less energy consumption by the RO process and the exclusion of the IX polishing process. In this design, we used a brackish water RO membrane (more permeable, lower salt rejection) in Stage 1 of the RO system and a tighter seawater RO membrane in the 2nd stage (**Table 4**). This approach was required in this case to achieve the target permeate TDS concentration of ≤500 mg/L.

Table 6. Summary of system performance metrics for the East Echo Springs PW treatment system treating to ultrapure and potable water finished water standards.

Parameter	Units	Ultrapure Water	Potable Water
Specific Energy			
Ultrafiltration	kWh/m^3	0.06	0.06
IX Soft/Dealk	kWh/m^3	0.12	0.13
Reverse Osmosis	kWh/m^3	2.81	2.00
IX MB Polish	kWh/m^3	0.10	0
Operating Costs			
Ultrafiltration	$\$/m^3$	2.101	2.103
IX Soft/Dealk	$\$/m^3$	1.114	1.114
Reverse Osmosis	$\$/m^3$	1.168	1.095
IX MB Polish	$\$/m^3$	0.243	0
System Summary			
Specific Energy	kWh/m^3	3.23	2.26
Operating Cost	$\$/m^3$	6.11	5.66
Feed Flow Rate	m^3/hr	283.2	276.8
Daily Consumption	m^3/day (Mgal/day)	6796.8 (1.80)	6643.2 (1.75)

The finished water qualities for the treated PW from the East Echo Springs site are summarized in **Table 7**. The water quality values for the finished waters are comparable to those achieved for the North Echo Springs site (**Table 5**).

Table 7. Summary of finished water quality values for the East Echo Springs site for the two different PW treatment scenarios.

Water Quality Measure	Units	Ultrapure Water	Potable Water
Gross Measures			
TDS	mg/L	1.68	489.2
pH	-	7.61	5.70
Cations			
Sodium	mg/L	0.02	185.8
Potassium	mg/L	0.00	2.54
Calcium	mg/L	0.00	0.01
Magnesium	mg/L	0.00	0.00
Anions			
Chloride	mg/L	0.00	276.0
Fluoride	mg/L	0.00	0.06
Boron	mg/L	0.29	1.12
Carbonate	mg/L	0.00	22.79
Neutrals			
SiO_2	mg/L	0.00	0.12

Fontanelle Reservoir PW Treatment System

The process flow diagrams for the two treatment scenarios for the Fontanelle Reservoir water are given in **Figures 5** and **6**. System performance statistics for both scenarios are summarized in **Table 8**. Finished water quality values for the two Fontanelle treatment scenarios are given in **Table 9**. Achieving potable water quality from the Fontanelle Reservoir source only required membrane filtration to remove particulates and any dissolved organics. Achieving ultrapure water standards required RO using high rejection RO membranes (**Table 4**). Ion exchange was not required in this case in light of the low salt concentration in the feed water, which resulted in low salt passage across the membrane. Thus, in this case the ion exchange process could be neglected.

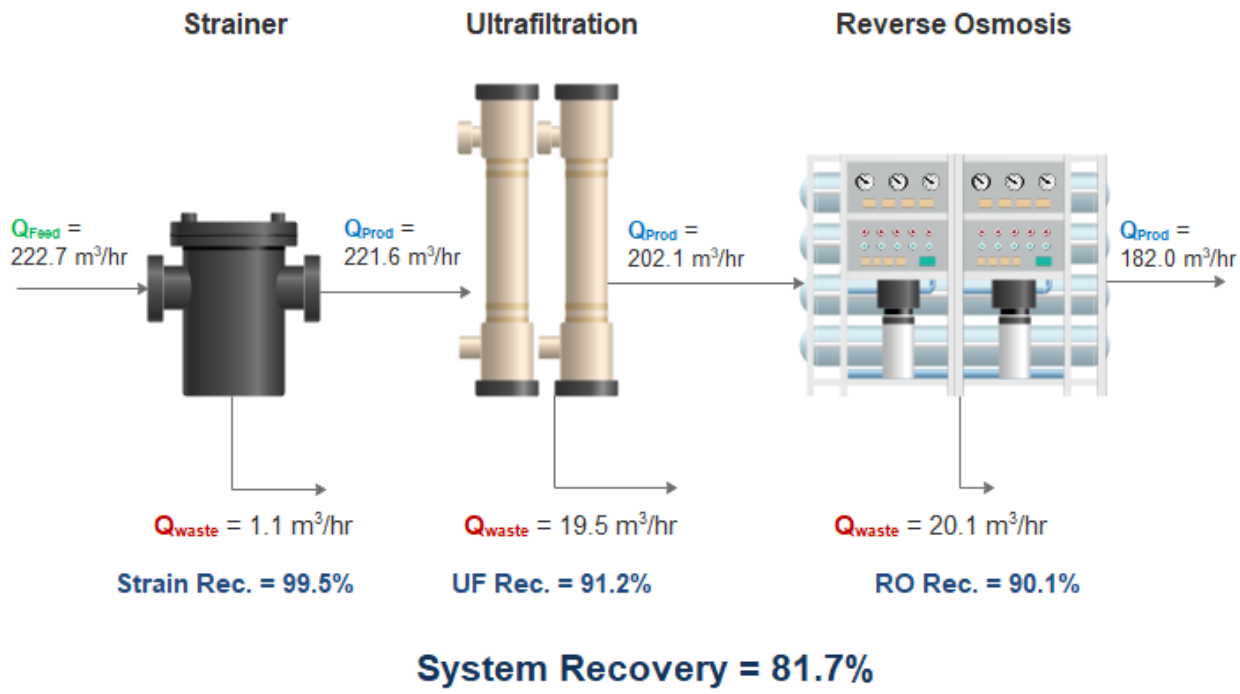


Figure 5. Process flow diagram for treating the Fontanelle Reservoir PW to a ultrapure water standard for total dissolved solids and total organic carbon concentrations (electrical resistivity = 18 MΩ•cm, TOC < 10 ppb).

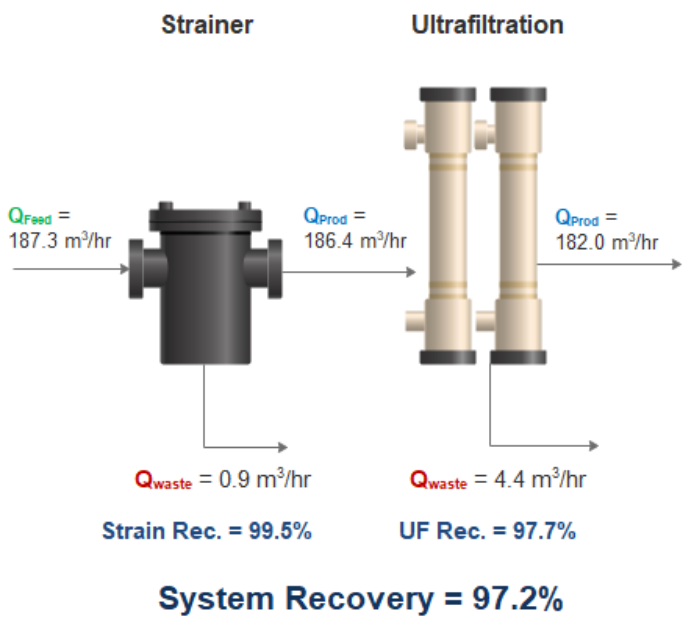


Figure 6. Process flow diagram for treating the Fontanelle Reservoir PW to a potable water standard for total dissolved solids (TDS ~500 mg/L).

Table 8. Summary of system performance metrics for the Fontanelle Reservoir treatment system treating to ultrapure and potable water finished water standards.

Parameter	Units	Ultrapure Water	Potable Water
Specific Energy			
Ultrafiltration	kWh/m^3	0.07	0.07
Reverse Osmosis	kWh/m^3	1.48	0
Operating Costs			
Ultrafiltration	$\$/m^3$	0.09	0.09
Reverse Osmosis	$\$/m^3$	0.286	0
System Summary			
Specific Energy	kWh/m^3	1.56	0.07
Operating Cost	$\$/m^3$	0.39	0.09
Feed Flow Rate	m^3/hr	222.7	187.3
Daily Consumption	m^3/day (Mgal/day)	5344 (1.4)	4495 (1.2)

Table 9. Summary of finished water quality values for the Fontanelle Reservoir site for the two different PW treatment scenarios.

Water Quality Measure	Units	Ultrapure Water	Potable Water
Gross Measures			
TDS	mg/L	2.47	220
pH	-	4.5	7.0
Cations			
Sodium	mg/L	0.07	10.4
Potassium	mg/L	0.01	1.63
Calcium	mg/L	0.08	38
Magnesium	mg/L	0.02	10.8
Anions			
Chloride	mg/L	0.27	2.4
Fluoride	mg/L	0.00	0.14
Boron	mg/L	0.00	0.0
Carbonate	mg/L	0.00	80
Neutrals			
SiO_2	mg/L	0.00	5.6

Comparative Summary.

Comparative statistics for North Echo, East Echo, and Fontanelle Reservoir treatment systems are given in **Table 10**. Treating the PW from the North Echo site is more economical from an OPEX standpoint relative to that for the East Echo site -- if silica fouling doesn't lead to continuous replacement of the membranes. This differential in OPEX costs results primarily from the greater chemical (acid) consumption required to remove the alkalinity in the East Echo Springs PW and the higher specific energy consumption of the overall treatment system. Treating the PW, for all sources, to potable water standards, in place of ultrapure water ones, reduces the OPEX costs for both sites by approximately 35%. CAPEX costs for the treatment systems are comparable for both sites, with that being lower for the potable water standard. The lower CAPEX costs result from removing the IX polishing process for the RO permeate, which is required to achieve ultrapure water quality. CAPEX costs are the same for both sites given the similarities in the process trains. Although treating PW from the North Echo site is more economically attractive, it is associated with a significantly higher risk than treating PW from the East Echo site. As noted earlier this is due to the relatively high dissolved silica concentrations in the North Echo Springs PW. The simulations done here accounted for silica by manipulating the pH of the RO feed water (pH~8) and through the addition of an antiscalant to the RO feed; however, even when such recommended strategies are used silica fouling can, and is likely to, occur. ***Such fouling, should it occur, can result in dramatically increased OPEX costs and even adjustments to the system design (incorporation of additional processes).*** It is therefore highly recommended that silica fouling using the North Echo Springs PW be evaluated in laboratory tests prior to final selection of the PW source. Because of their simplicity, the treatment systems for the Fontanelle reservoir water have considerably less CAPEX and OPEX costs relative to the Echo Springs waters.

Table 10. Summary system statistics for the PW treatment systems.

Parameter	North Echo Ultrapure Water	East Echo Ultrapure Water	Fontanelle Ultrapure Water	North Echo Potable Water	East Echo Potable Water	Fontanelle Potable Water
Specific Energy, kWh/m^3	2.68	3.23	1.56	1.51	2.26	0.07
CAPEX [1,2], $ OPEX, $/m^3	26M 1.57	26M 6.11	5M 0.39	21M 1.28	21M 5.66	1M 0.09
Risk	High	Moderate	Very Low	Low	Low	Very low
Primary Cost/Risk Driver in Design	IX Polishing of RO Permeate/ Silica	RO Desalination /Silica Fouling of RO	RO/None	Acid (HCl) Consumption for Scale Control/None	Acid (HCl) Consumption for Scale Control/None	UF/None

	Fouling of RO					

1 Capital expenditures (CAPEX) determined using the US Bureau of Reclamation's CAPEX cost estimating tool for brackish and seawater desalination systems. A contingency of 40% was assumed for the cost determination.

2 CAPEX costs do not consider land acquisition, water transmission lines offsite, waste disposal, and other infrastructure required for the treatment facility.

SUMMARY

Based on the PW treatment process simulations for the North Echo Springs, East Echo Springs, and Fontanelle Reservoir sites, we have drawn the following conclusions:

- PW from the North Echo Springs site is more economically treatable relative to the PW from the East Echo Springs site; however, the presence of dissolved silica is high risk and needs dedicated study during final sourcing of the PW for H_2 production.
- If PW is treated only to potable water standards, in terms of TDS, then the treatment costs are substantially reduced and would reduce system complexity. However, the electrolysis system vendor would then have to raise the water quality to ultrapure standards.
- The treatability of the PWs from the East and North Echo sites are largely determined by the presence of silica and high alkalinity concentrations. Identification of approaches for removing or mitigating these substances in the respective PWs would greatly improve the treatability of both waters and would have important consequences for selecting the optimum source for H_2 production.
- Sourcing water from the Fontanelle Reservoir presents the least expensive and simplest systems for achieving both ultrapure water and potable water finished water standards. However, this resource entails legal, regulatory, and political risks.

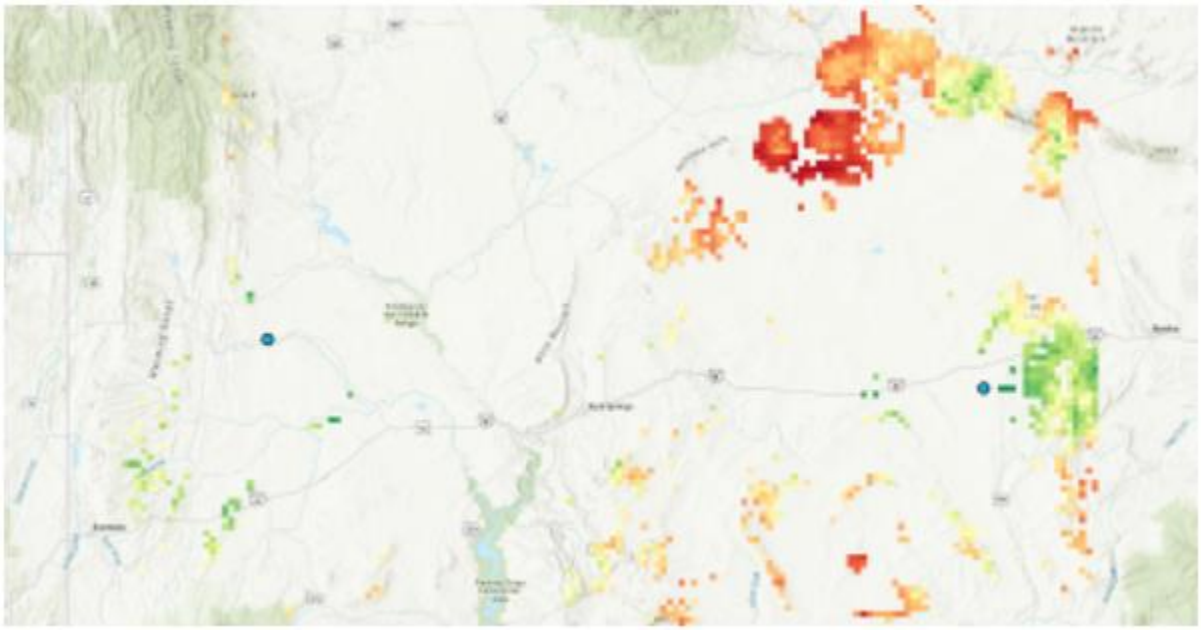
Appendix A: Initial Storymap

Electrolysis For Green/Blue Hydrogen Production In Wyoming

Where should an electrolysis plant near Opal or Echo Springs be placed?

Jacob Bradley Schneider December 9, 2022

Williams has expressed interest in finding good locations for an electrolyzer plant in south west Wyoming. UWYO is supporting this effort by performing geospatial analysis to identify areas containing all necessary infrastructure and resources as close as possible to Williams existing properties. I compiled roughly ten data bases and applied a weight which, in my judgment, seemed appropriate to each. The results near Echo Springs cluster to the east and the west suggesting that these locations are worth further study. The results near Opal are more scattered suggesting that more data and a better weighting are necessary before the ideal site at Opal comes into focus. The following represents the first attempt at this analysis and should be revised before being used.

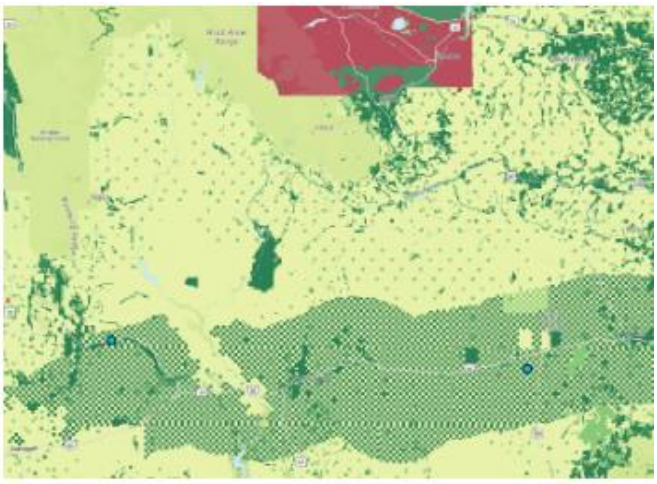


This report used data from ESRI's online database, the United States Geological Survey, the Wyoming Oil and Gas Conservation Commission, the Center for Economic Geologic Research, and the National Renewable Energy Laboratory. This map illustrates the unitless cost surface generated in this report.

The Geoprocessing tools I used for this map include Empirical Bayesian Kriging for the TDS map and Euclidean Distance for the distance from: oil and gas wells, Opal and Echo Springs, highways, county roads, transmission lines, and major pipelines. Also included are shapefiles for suitable wind farm locations, land ownership, and protected wetlands. All of these layers were converted into raster files with proper symbology and added to a suitability modeler

GeoAnalytics tool to predict the best location for this project. The layers were weighted as follows on a 1-10 unitless scale, 10 being the most important.

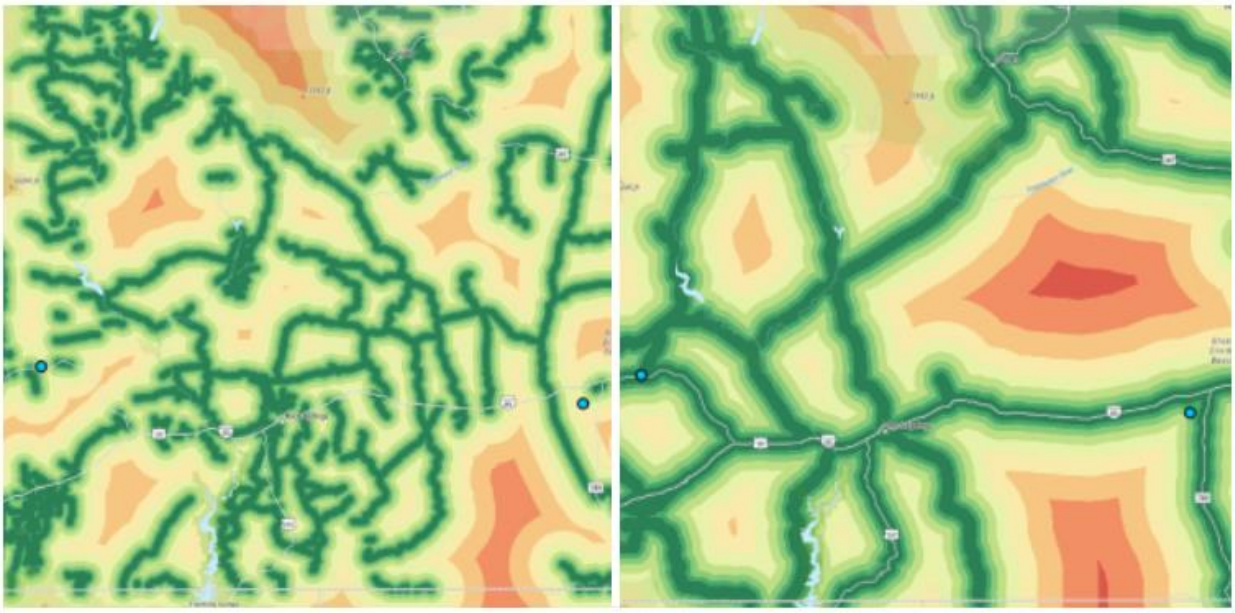
- Distance from gas plants: 10
- Suitability of wind turbines: 9
- Proximity to transmission lines: 8
- Proximity to major pipelines: 7
- TDS of produced water: 7
- Distance to oil & gas wells: 6
- Proximity to county roads: 5
- Proximity to highways: 4
- Land Ownership: 3



Land Ownership Map Rankings:

- Private land (dark green): 10
- State land (lighter green): 8
- Federal land (lightest green): 6
- Native American land (red): 2
- Private conservation land (red): 1

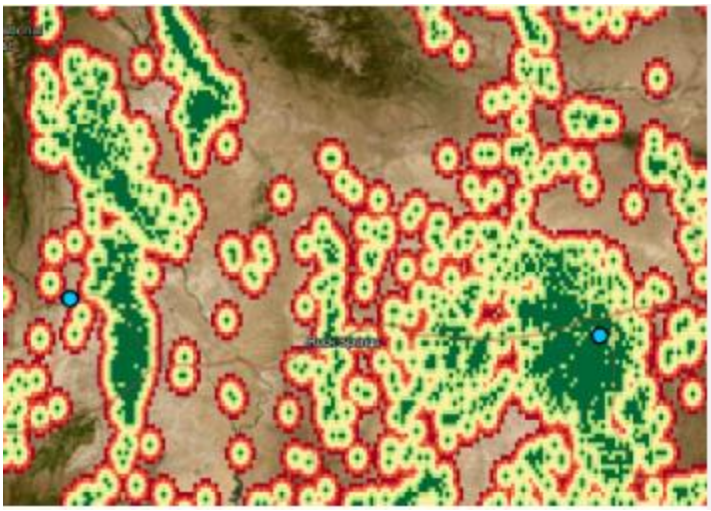
The map on the previous page depicts land ownership in Wyoming. This map is included in this study because developing energy projects is easier and more cost effective on certain types of land. The map includes the following information and is weighted from most favorable to least:

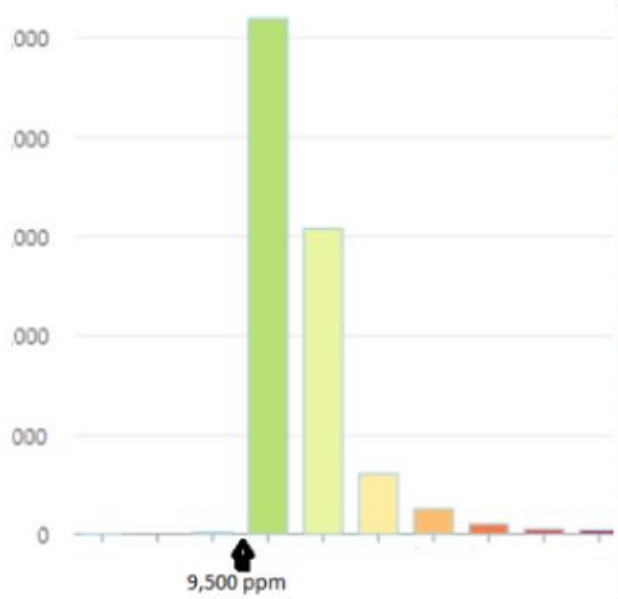


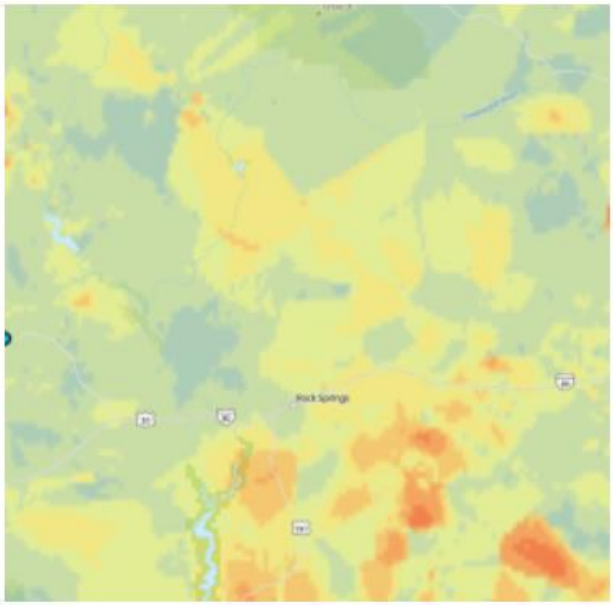
The proximity to county roads and highways is important because construction and operations will require road access. County roads are flexible, allowing for better development than

highways which have controlled access. To reflect this distinction proximity to a county road layer is weighted at 5 while proximity to a highway is weighted at 4.

The proximity to oil and gas wells is important for ease of development, water, and synergy with existing infrastructure. Areas with significant energy development will be less likely to receive pushback when permitting for a new energy project. A significant amount of water is needed for both green and blue hydrogen production, and this project will use treated oil and gas wastewater. Lastly, areas with significant energy production benefit from existing permits and access roads.

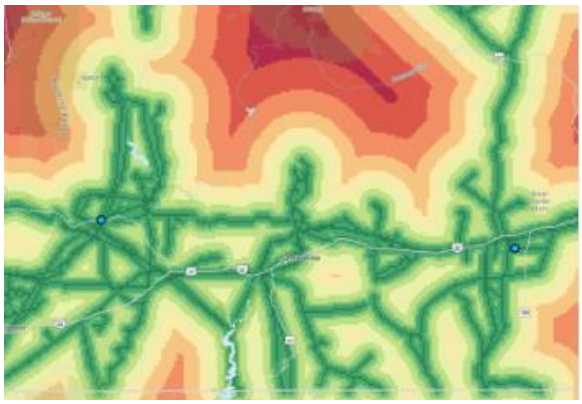




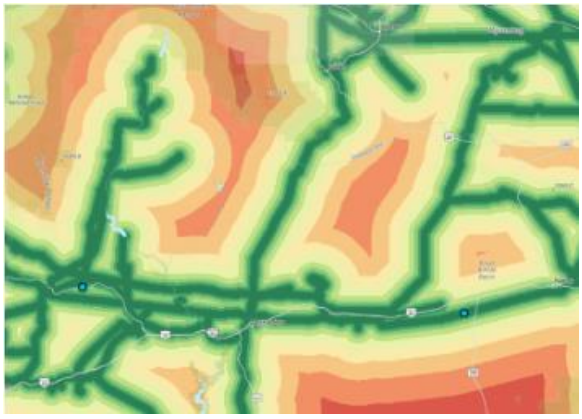


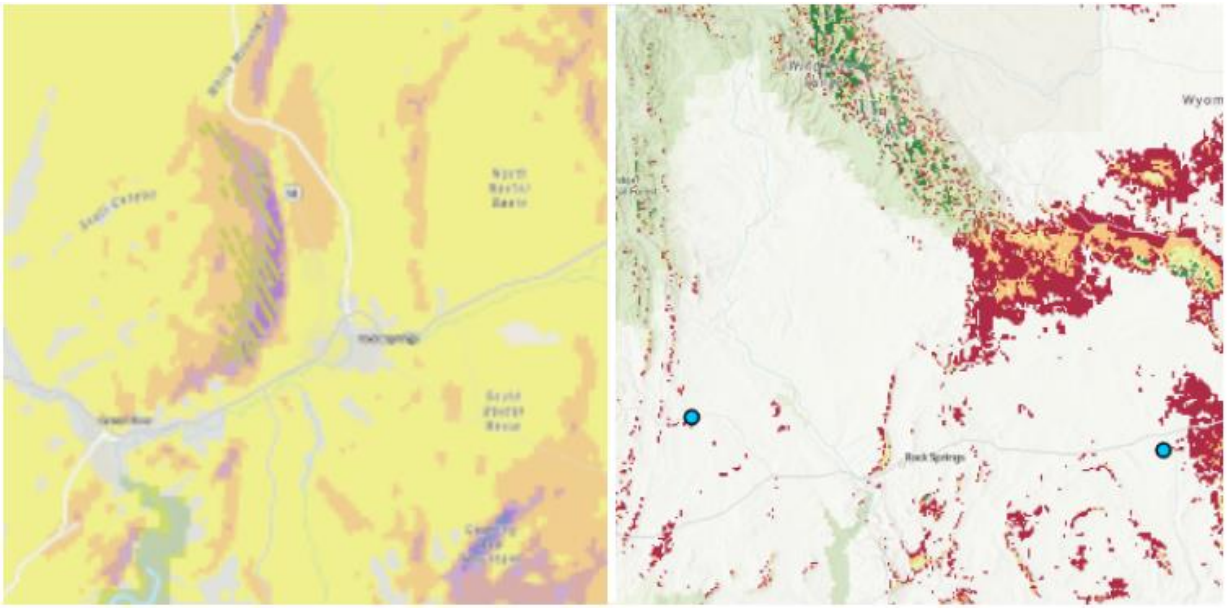
This map depicts the TDS of produced water from all oil and gas wells in Wyoming. The yellow, light green, and green areas are the areas that exhibit the most favorable TDS for a project of this kind ranging from 9,500 - 35,000 ppm respectively with light green containing the most suitable TDS as shown on the bar graph. This layer is important because the produced water must have a TDS above 10,000 ppm in order to be used for this project but the more dissolved solids present the higher the cost of development.

The proximity to major pipelines is critical for this project as permitting for hydrogen pipelines could prove costly and time consuming. By locating the electrolysis plant near these major pipelines this will ease the permitting burden while reducing cost and time. By locating the plant near existing pipelines this also presents the opportunity to connect with existing pipeline infrastructure either as a source of methane or a supplier of hydrogen.



Locating the electrolysis plant near electrical transmission lines is important to this project as there are not many high voltage transmission lines that traverse rural Wyoming compared to many other states. It is important that this plant be located near transmission lines to transport the power generated from this facility while also providing the facility with a reliable backup power source for when the wind is not blowing. Future work could refine this layer to show substations.

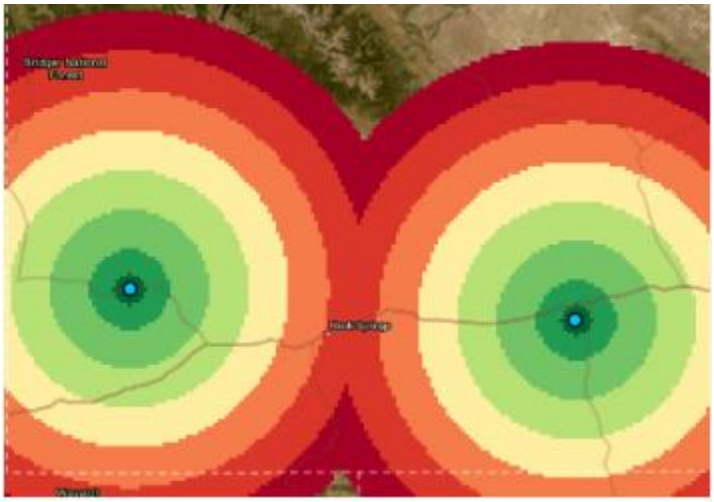




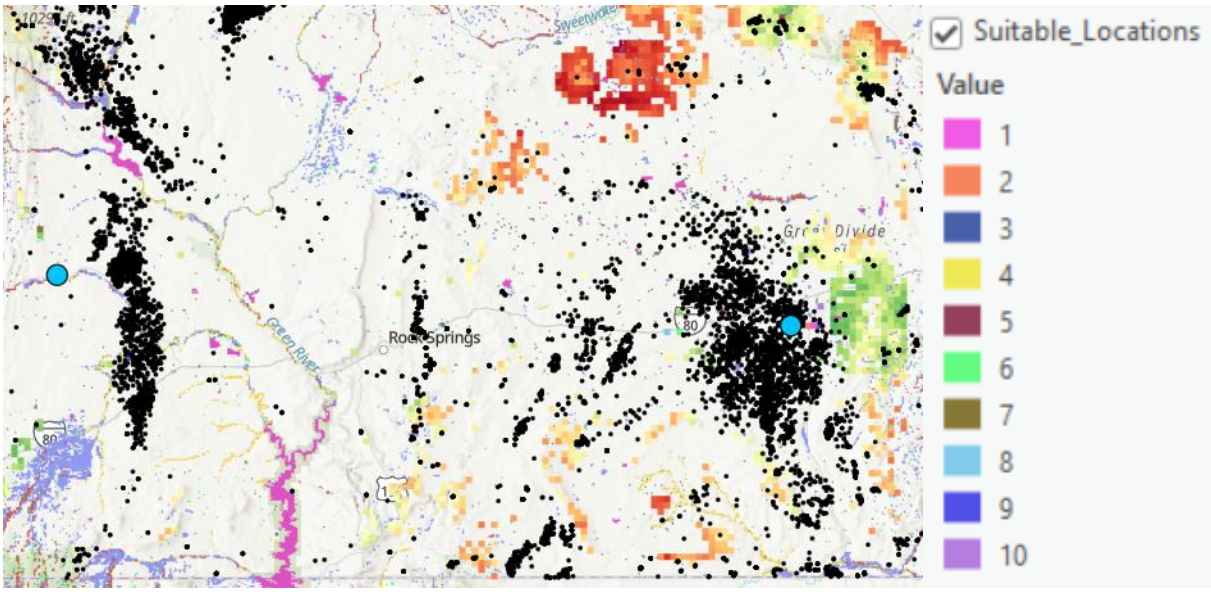
Williams has purchased land for wind or solar development. If the wind or solar development location is fixed it would simplify my analysis. Without knowing that location, this work used the assumption of following the availability of wind power maps from NREL. The dark purple area depicts the best areas for a wind farm while the yellow area depicts the worst areas for a wind farm. This map was transformed from to produce the image on the right. The image on the

left also shows a new wind farm development outside of rock springs that could look similar to one used for this project. During my research I noticed that all wind farms in Wyoming are in the highest wind zone. Additional data on Williams' plan could significantly affect this analysis.

Lastly, the distance from Echo Springs and Opal layer was included as the highest weighted feature for the following reasons. Having the electrolysis facility near a gas plant is crucial for a blue hydrogen project as that is where the supply of methane is derived from. While less important for green hydrogen production, as methane is not a key ingredient for this method of hydrogen production, it is still an important factor when considering centralizing major facilities and assets into one area.

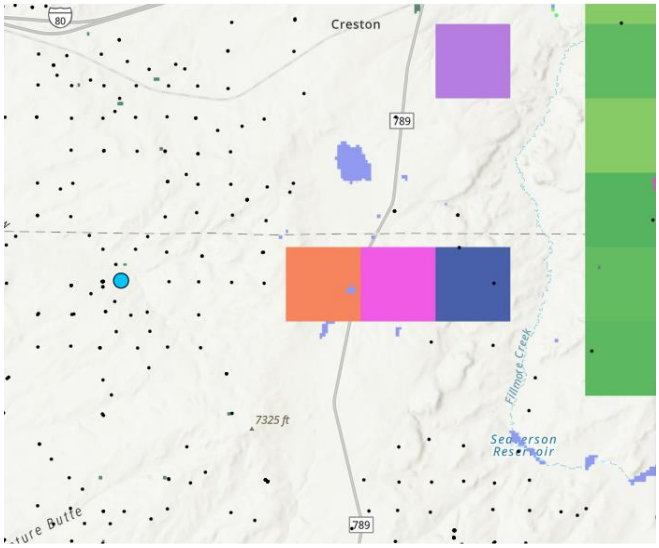


In addition to the above weighted map layers I have included two layers for informational purposes. The wells all have pop ups that when clicked on show information such as well depth, target formation, TDS, and API number. This information can be useful to get more exact data about the water quality and geology when looking at specific locations. The wetlands layer was not included in the suitability model because the presence of small protected areas that could easily be avoided was throwing off the model's results. This is why I included this layer as an overlay.

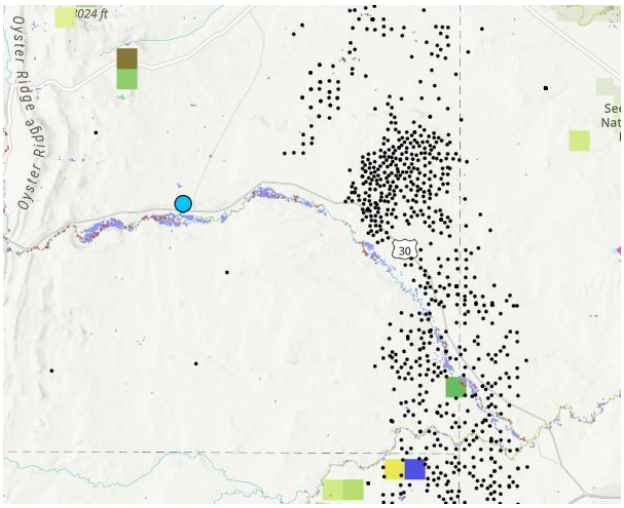


This map shows oil and gas wells and the protected wetlands layer overlaid on the suitability map. The suitability map shows the most suitable locations going from dark green to dark red respectively. The top ten most suitable 50 acre parcels of land have also been calculated by a suitability analysis based on the data inputted, the table above shows what colors represent what ranking.

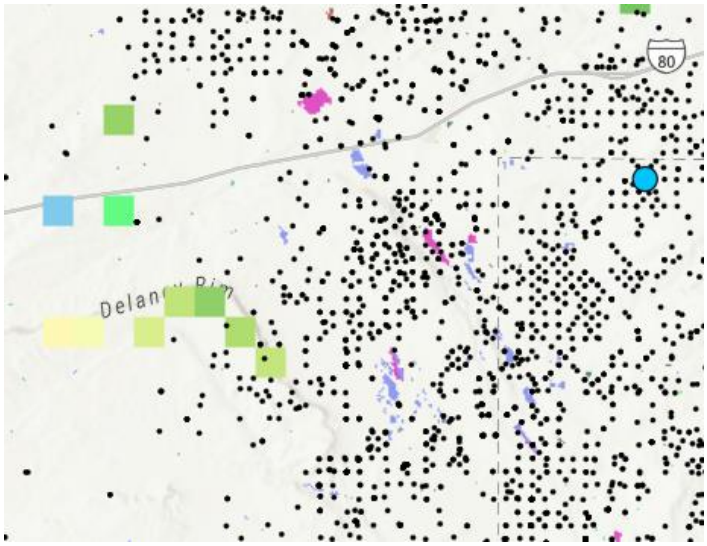
As can be seen here with the current weights on the data, these three 50 acre parcels of land scored the highest suitability score with the current weights. The only encumbrance that could burden this location is located within parcel 2 which contains a small area of protected wetland which would most likely easily be avoided. This location is very close to the Echo Springs plant, existing pipelines, transmission lines, a county road, a highway, oil and gas wells, and an area that shows promise for wind development. For all of the reasons stated above these four locations are ranked highly in this suitability analysis.



Near Opal are three 50 acre parcels of land that were ranked as the fourth, the seventh, and the ninth most suitable location for this project. While protected wetlands are not an issue for any of these areas the parcel ranked at number seven is not near a significant amount of oil and gas wells which would most likely cause a water supply issue. Another issue that could plague the fourth and ninth rated parcels is the distance from the Opal plant. This could prove especially cumbersome when considering blue hydrogen production.

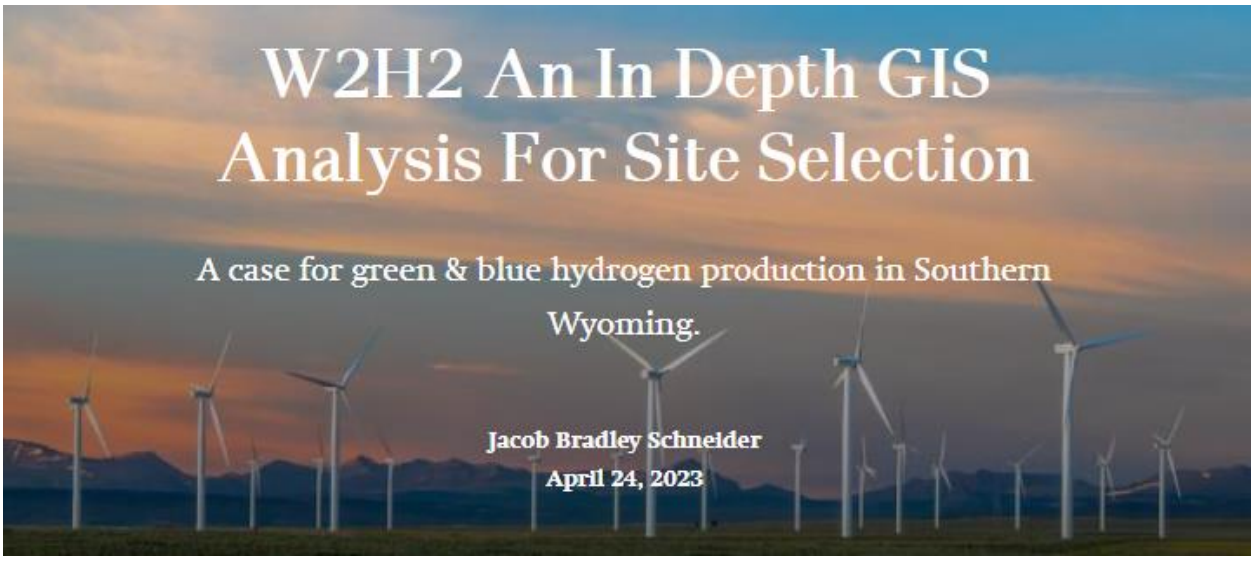


Two of the model's suggested top ten locations are near the Delaney Rim. This location is west of Echo Springs and has modest wind. It is on most major infrastructure arteries that run parallel to I-80. A spurious location like this is likely to change once price data is added. If arterial infrastructure factors as highly in the final model as they did in this work, a location like this could be worth choosing.

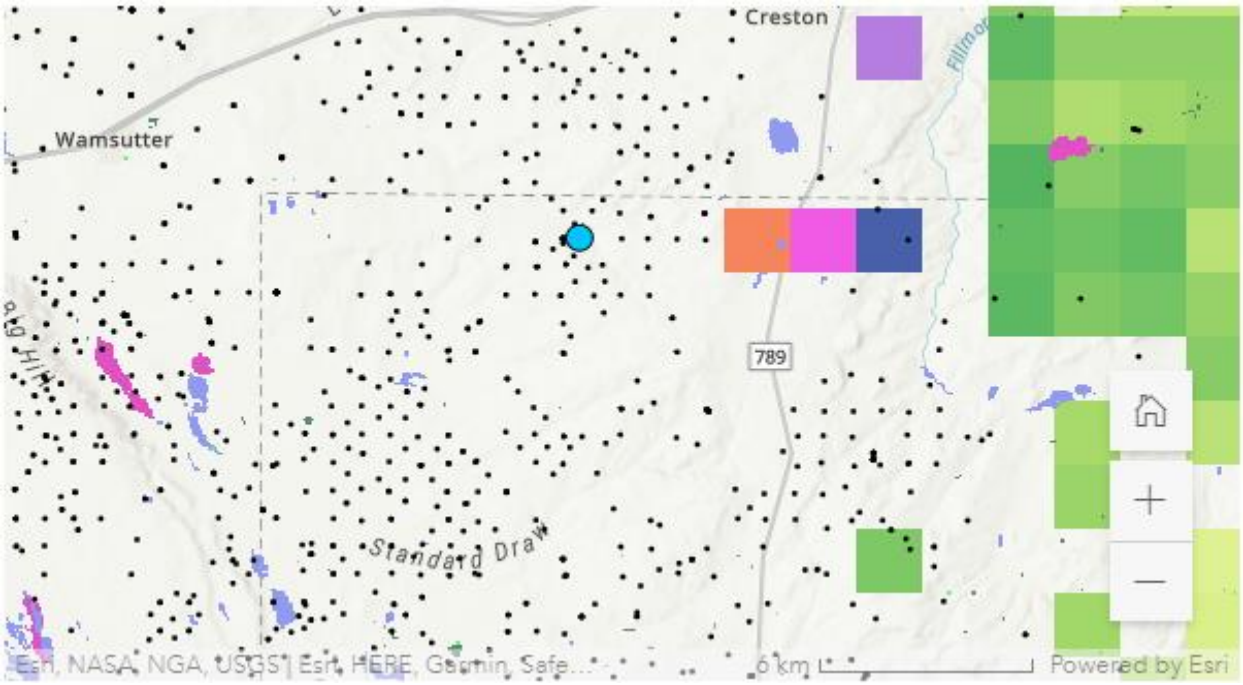


Overall, the conclusion of this analysis is that the 150 acre area directly east of Echo Springs exhibits the best characteristics for a produced water electrolysis plant for both green and blue hydrogen production near the Opal and Echo Springs gas plants in southern Wyoming. This is only a preliminary analysis. A better analysis will come from choosing weights based on dollar costs as well as from including more data. Future analysis will include real price figures connected to each data point as well as more data. Based on Williams' contribution of cost data, existing wind/solar land purchases, and existing Williams owned infrastructure a second version of this analysis can identify the best site for an electrolysis plant.

Appendix B: Final Storymap

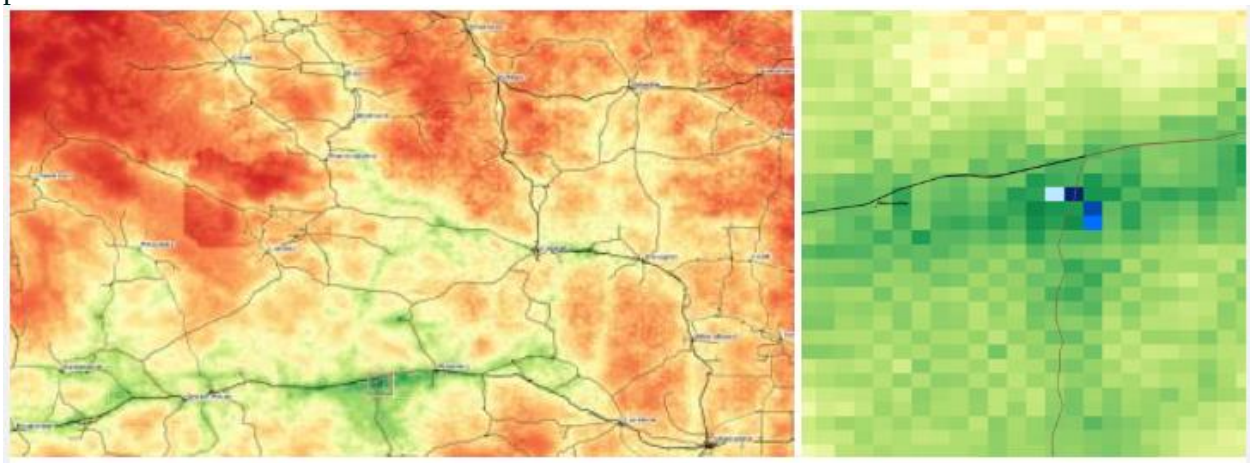


Background: In our previous analysis the suitability model calculated that these four fifty acre parcels ranked in the top ten for the most suitable location to build an electrolysis plant. After this initial model was made Williams personnel have made it clear that they would like to locate the facility next to a compressor station in order to use the excess heat produced from the compressor station to increase the efficiency of the electrolysis process. Furthermore, Williams has also expressed that their business development team is especially interested in locating the plant adjacent to the Opal plant. With this information along with further input from Williams GIS department and land team the original model was modified to more accurately portray real world weightings to help develop a lower level cost map.

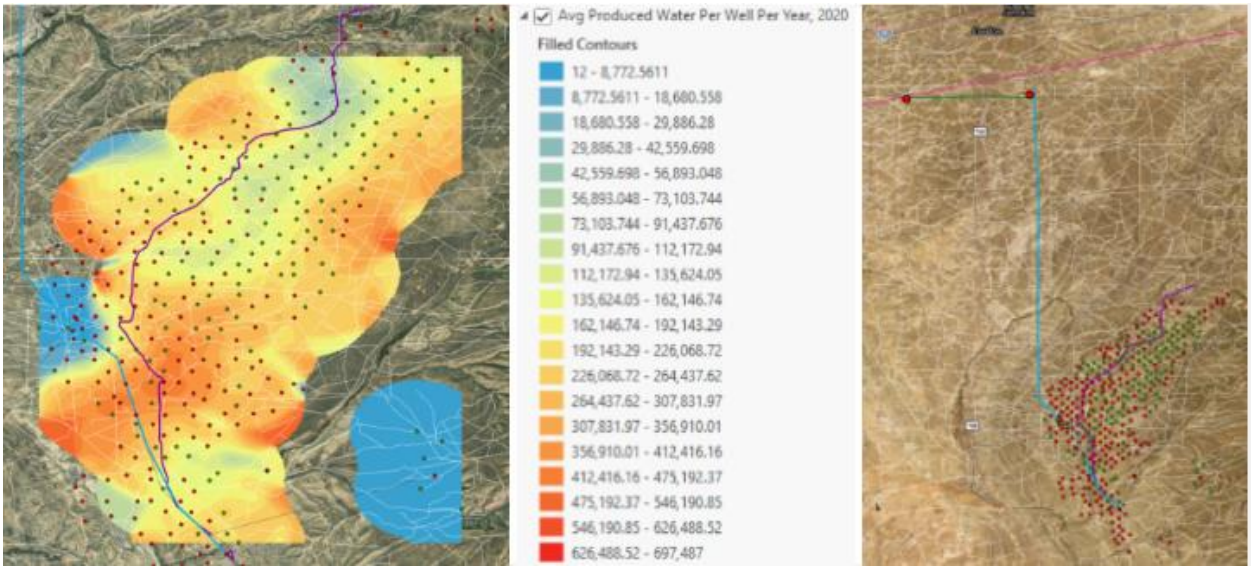


Using the new weightings provided by Williams as well as three new layers, proximity to

protected wetlands, proximity to Section 368 energy corridors, and proximity to a viable water resource a new model was created. This model predicted the top four best locations for this project to be located were approximately at the same location as the original model, the High Point Compressor Station. Thus, the High Point Compressor Station, which is located directly east of the Echo Springs Gas Plant in the blue blocks seen above and below, and Opal will be the two sights considered for this cost analysis. Since this location already scored so highly in the first model this will be the site that will be reviewed on an in depth basis for green hydrogen production.



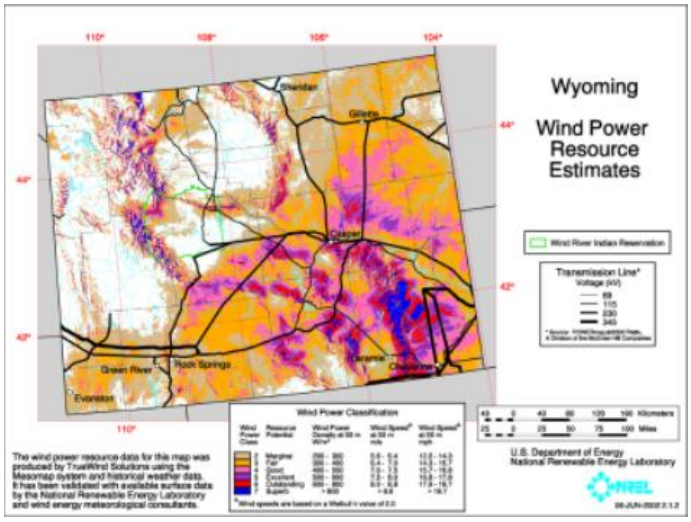
The foremost issue with hydrogen production in Wyoming is lack of water availability. Using produced water from oil and gas wells is most likely the best solution to this problem. Further, knowing that Williams is planning on constructing a 600MW electrolysis facility we can determine that this plant requires approximately a minimum of 30 million barrels of produced water per year to operate. The sand hills area produced approximately 28.5 million barrels of water from 143 active wells in the area in 2020. Well pads with active wells are depicted in green on the map and well pads with no active wells are depicted in red. 222 wells in the Sand Hills area were not active in 2020. Currently, the Sand Hills region is the only viable option for Williams to collect enough water from a produced water source for a 600 MW electrolyzer facility for both Echo Springs and Opal however, when the model was created other areas were considered. Practically speaking, the sand hills area is the most likely location to gather water for this project so this field is the only one that will be considered for this analysis.

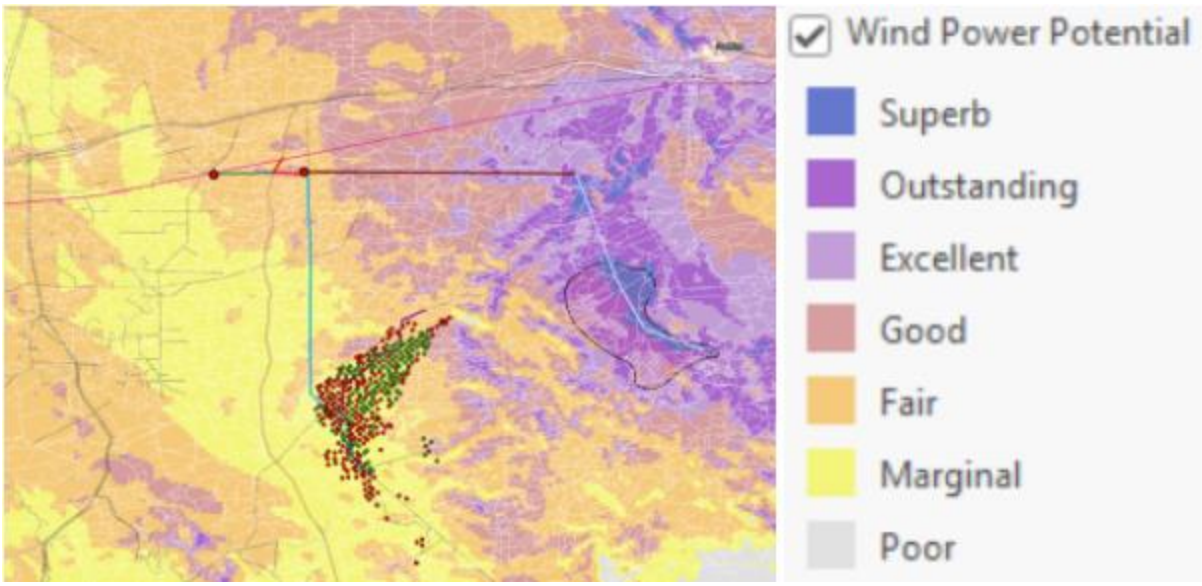


The above maps show that the southern end of the sand hills AOR produces significantly more water than the northern portion. These maps also show current pipelines and roads in the area. According to the BLM these areas with existing pipelines are seen as having "low impact" from an environmental standpoint. Since a pipeline is already in place along these routes, land owners and the BLM will also be more likely to permit another pipeline adjacent or within these existing easements. For this reason, I chose to follow these current pipeline routes for the produced water and hydrogen pipeline routes. The purple pipeline is owned by Escalara, the blue pipeline is owned by Western Transmission Corp, and the green pipeline is owned by Southern Star Central Gas. The white lines are existing roads.

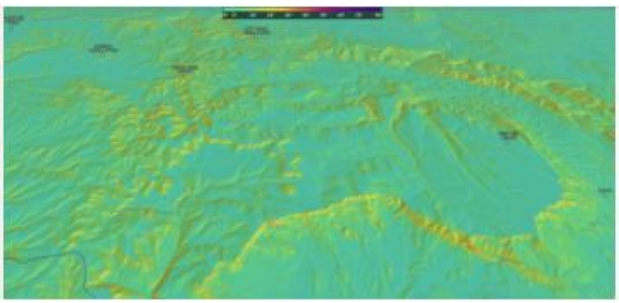
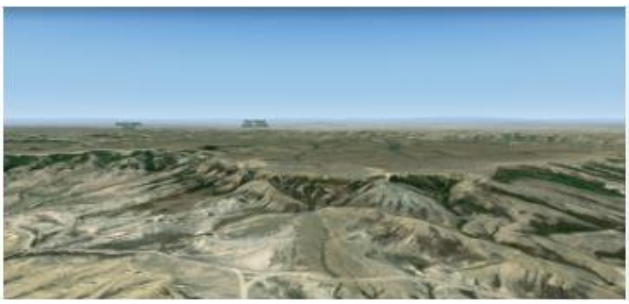
To further improve upon the above water production Bayesian Kriging model I created multiple models repeatedly testing them using cross validation until I attained the best result I could. The QQ plot illustrates that most values fall within close proximity to the reference line. Both the 90 and 95 percent interval scores were within one percent of their expected value. Furthermore, the root-mean-square standardized value was only 0.02147 off from a perfect model.

This map from NREL shows both wind power and transmission lines with their respective voltages. The area between Evanston and Laramie is where we will be focusing our study. The above map was formatted into an ArcGIS raster format and the AOR was shrunk to include areas close to the High Point Compressor Station. After doing so, an area 17.16 miles east of High Point was identified as a possible source of wind power. This source can be seen more clearly below.

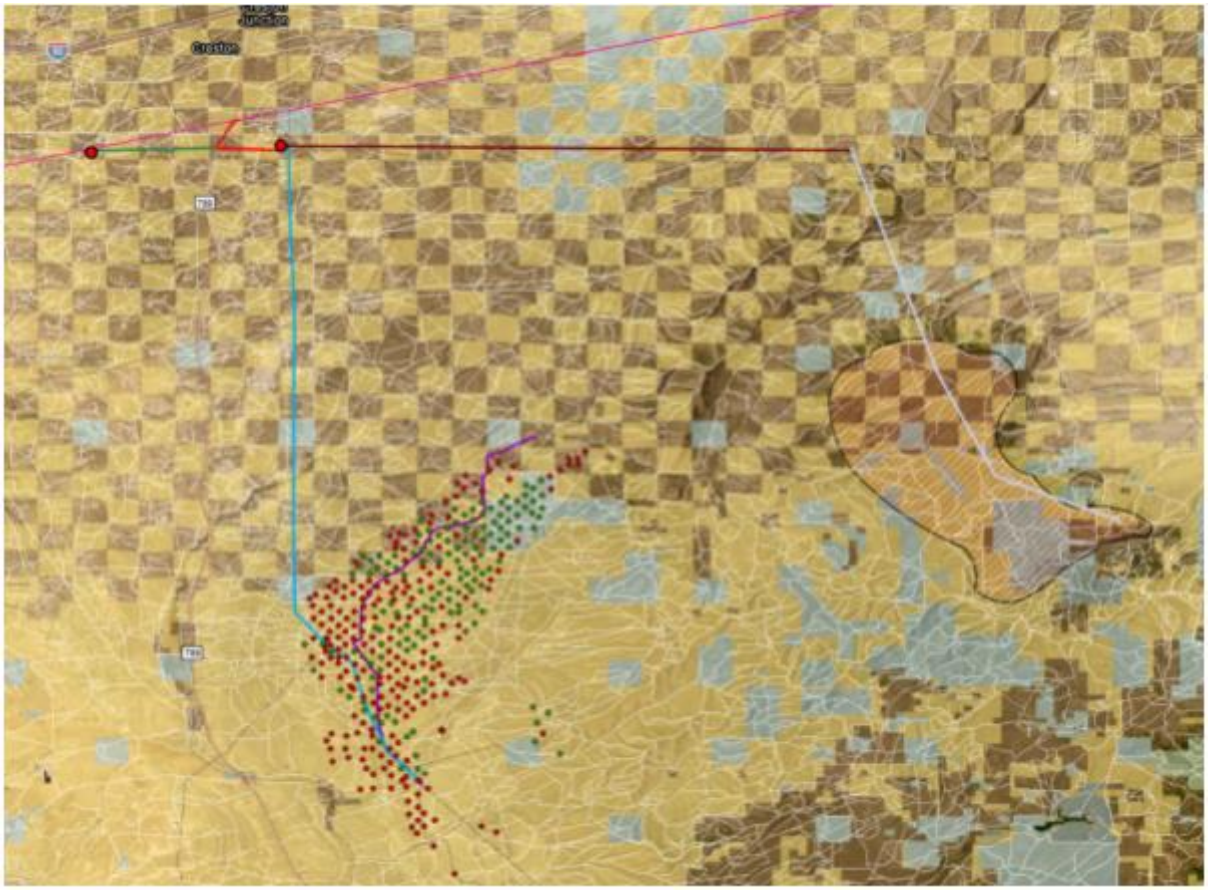




The above map illustrates areas with wind power ranked from superb to poor, going from dark purple to gray respectively. In the immediate area touching the light blue proposed transmission line there are two areas ranked as having superb wind power. The northern area consists of seven square miles and the southern area consists of fifteen square miles. In the immediate surroundings there are 111 square miles of land with outstanding wind power. Although this is a large area that shows much promise for wind development not all of the area can be used due to the rugged nature of this terrain, existing critical sage grouse habitat, and the presence of a nationally protected historic trail. The area depicted using a black outline with red lines crossing through it is a mostly flat plateau that also poses some critical habitat in a small portion of the AOR to the west but this area does possess the most favorable wind and terrain characteristics. The light blue line, 16.40 miles, the burgundy line, 17.16 miles, and the red line, 3.23 miles, all represent possible routes for transmission lines. The red line would be the connecting line from High Point Compressor Station to the 230 V PacifiCorp transformer substation.

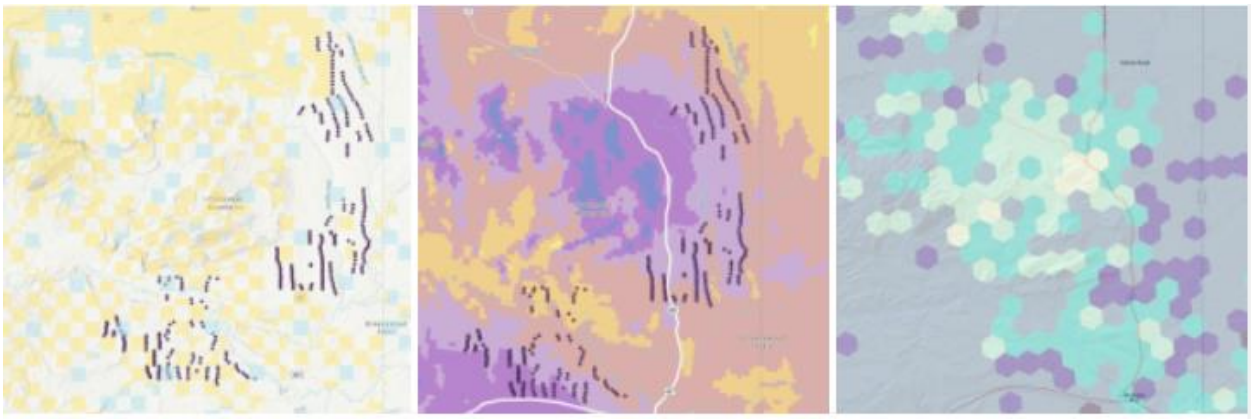



These two images show the plateau that was previously mentioned in the above map. The wind power is highest along the rim of this plateau but wind strength does remain consistently high along a majority of the plateau. To the north of Miller Hill, which is on the northern portion of the plateau, wind power also remains strong but the terrain becomes slightly more rugged with a series of small hills and valleys. For this reason, building on the plateau is favorable but building further to the north is certainly possible if needed. This plateau is approximately 44.3 square miles in size consisting of private land, federal land, and state land as can be seen below. For the purpose of naming this area, the plateau and area to the north will be referred to as Miller Hill as this is the only geographically prominent feature in the area.

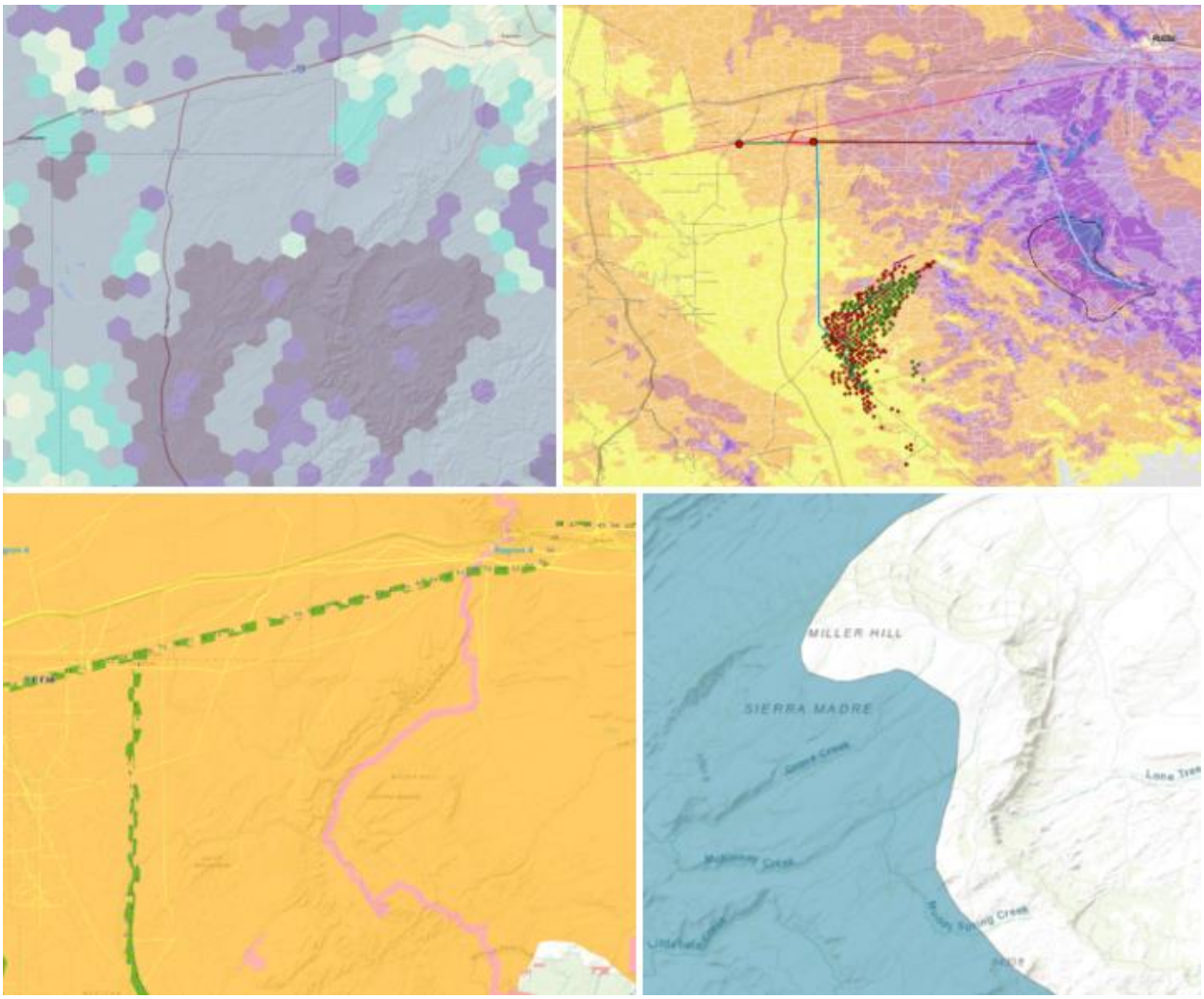


Here the blue sections depict state land, the yellow sections depict federal land, and the areas without any coloration depict private land. Without knowing where Williams has acquired land for the wind portion of this project it is hard to determine exactly where and how much this portion of the project will cost. Relying on the theory that developing energy projects on private

and state land is significantly cheaper and less timely that developing energy projects on federal land the AOR depicted by the area with slashing red lines does not have enough land to to house this project according to data from the TB Flats and Ekola Flats Projects. Accordingly, more private or state land further north of the AOR should be included or building on federal land should also be considered.



The TB Flats and Ekola Flats wind projects, completed in 2021, were used as references for sight selection. These projects bring 753.2 MW of energy each year. TB Flats alone produces 503 MW of electricity with 132 turbines on 44 square miles of land. When determining approximately how much land would be needed for this project, I considered the 600 MW capacity needed and multiplied it by 15% to have a comfortable margin of uncertainty. This puts the amount of energy that could be produced at max capacity at 690 MW. Using the same ratio of turbine to wind power produced from the TB Flats project the average amount of energy a wind turbine produces in this area with these kinds of turbines is 3.81 MW per turbine. Accordingly, this project would require 182 turbines on 61 square miles of land assuming similar conditions to the TB Flats project. Also, using the total cost of the TB Flats projects and dividing it by the amount of turbines present, one turbine cost $5.806 million. This value includes construction and administrative cost, permitting, regulatory, and land rights cost, as well as total cost of other wind farm supporting infrastructure such as access roads, electric gathering lines, and substation(s). Thus, I estimate that in order to build a 182 turbine wind farm in similar conditions the cost would be approximately $1.056 billion. However, there are three major differences between the TB Flats project and the project being reviewed. One, the wind power density for the TB Flats sight is indicatively less than at the sight currently being reviewed. Two, the TB Flats project was specifically sighted on only private and state lands. Three, the TB Flats project had to build at least one if not more new substations to connect to the grid. Another large concern in terms of cost and regulatory approval is the presence of crucial habitat. The blue map on the left shows BLM's crucial habitat assessment tool, going from light blue (6) to dark purple (1) as least to most important respectively. Most of the Ekola and TB Flats project was sighted on land ranked at 3 while some portions were sighted on areas ranked at 2 and 4.

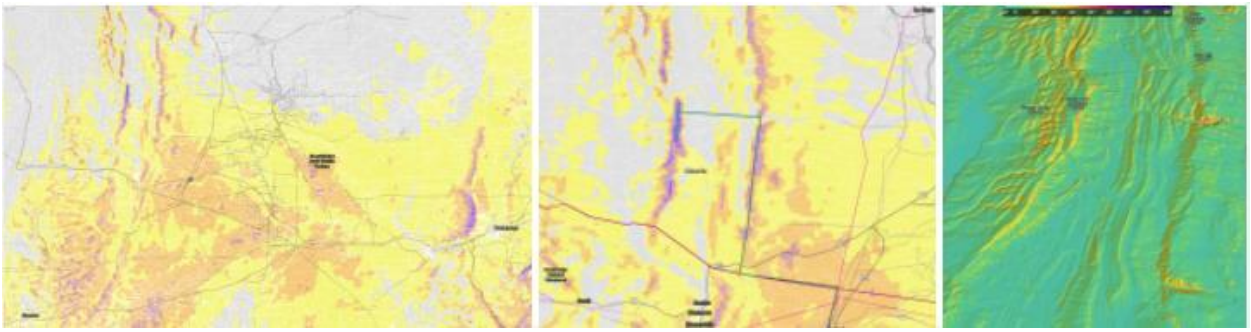


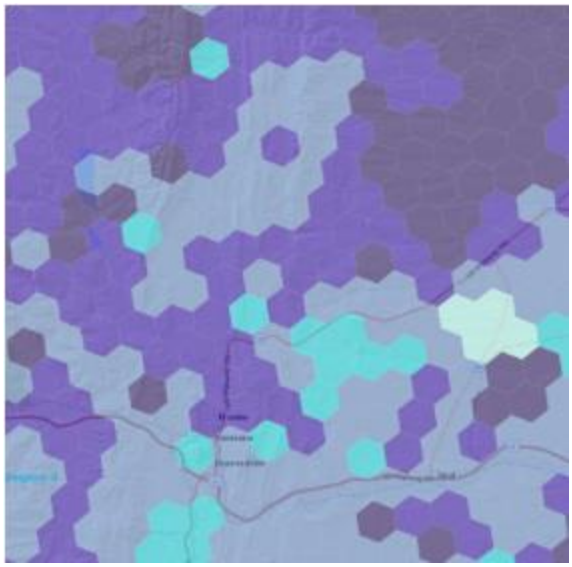
Here we can see that at least half of the area that I have chosen based on favorable wind conditions and terrain lies within a large area of level 1 critical habitat. This could pose problems for development in this area in terms of both cost and obtaining government approval. When using more project siting tools made by the BLM the map on the right shows us that the rim of the above mentioned plateau is excluded from critical sage grouse habitat. The map on the middle right shows that there are multiple routes for transmission lines that could be used that have a low environmental impact, (yellow and green lines). This map also shows the protected Continental Divide Trail which can be seen in red. While this site is not completely ideal it does possess enough of the right characteristics to be heavily considered. The other option here would be to sight the project further to the north in a slightly more rugged country and in slightly less favorable wind conditions. While this may mean more wind turbines must be built, this could be more worth while in the long run in order to avoid potential suits from environmental groups and less regulatory hurdles to jump through in the planning, development, and approval process.

Above, two possible pipeline routes have been selected that follow established Section 368 energy corridor routes. I choose to use these routes because according to the grid development office "Section 368 of the Energy Policy Act of 2005 (EPAct) directs the Secretaries of Agriculture, Commerce, Defense, Energy, and Interior to designate, under their respective authorities, corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on Federal lands in the 11 contiguous Western States (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming), to perform any required environmental reviews, and to incorporate the designated corridors into relevant agency land use and resource management plans or equivalent plans." -energy.gov. The uppermost pink route, (A), is 155.99 miles long and the lower route, (B), is 148.57 miles long. Their elevation profiles are below in respective order.

Elevation Profiles, Pink Route A (top), Light Blue Route B (bottom)

From the elevation profiles we can see that pipeline (A) has a considerable amount more elevation change and is slightly longer. However, Pipeline (B) has a greater maximum and average slope angle than pipeline (A). While Pipeline (A) is 7.19 miles longer it still has 1,340 feet less of elevation change and its maximum slope is 10.95% less than pipeline (B). Not considering other factors pipeline route (A) seems like the optimal route for both a hydrogen or water pipeline. In addition to these considerations, the water should also be filtered into a more pure form, appx. 300 TDS at or near Echo Springs plant or directly on sight at Atlantic Rim . This would decrease the amount of water that would need to be transported to 15 million barrels per year halving the diameter of the pipeline resulting in a significant decrease in pipeline and compressor station cost.





Transitioning to Opal, the two main factors that plague this case for green hydrogen production are far distance to a water resource and lack of wind power available near Opal. While the wind resource near Opal is scarce, especially considering the wind resource near Echo Springs, there are two potential locations that might work. These two areas are to the northwest of Opal. Both of these areas are relatively skinny and do not possess the best characteristics for a wind project, small target area and rugged terrain. Furthermore, a majority of the area that could be used for wind development lies in habitat listed as protection level 2 on the CHAT scale. All of these factors combined lead me to believe that Opal is not a good location for green hydrogen production. However, Opal is in a unique position in terms of blue hydrogen production.

For the Opal blue hydrogen case the assumption is still that all water will be gathered from the Sand Hills area if the water comes from a produced water source. Fontenelle Reservoir is also now being considered as another possible water source. With this assumption for the produced water case, it is my prediction that the best way to transport all the necessary resources to Opal for steam methane reforming with CCS would be to purify the produced water at Echo Springs or Atlantic Rim to appx 300 ppm TDS. Once the water is purified to this level it will be transported in a smaller diameter pipeline to Opal while the wastewater will be reinjected for water flooding or disposal purposes in wells near Echo Springs or Atlantic Rim. Once reforming has been completed the CO2 and excess water will then be transported from Opal to nearby sites for carbon sequestration and wastewater injection. For the Fontenelle case, the already pure water will be transported in a small diameter pipeline to Opal. Using previously described and used estimates, pipeline routes, and methodology as well as the assumption that Williams can buy methane for $7.9/mcf, four estimates were generated from the following scenarios. The assumptions and scenario descriptions for these estimates can be found above in the, Resulting Five Scenarios and Evaluation, Section.

Infastructure Type	Cost Factor	Distance & # A	Distance & # B	Distance & # C	Distance & # D	Distance & # E
Large diameter water pipeline	$2 mil/mile	25.4 miles	30.9 miles			
Small diameter water pipeline	$700,000/mile	5.3 miles	148.6 miles	25.4 miles	174.0 miles	29.5 miles
Large diameter hydrogen pipeline	$13.6 mil/mile					
Small diameter hydrogen pipeline	$6.8 mil/mile	5.3 miles	29.8 miles	148.6 miles		29.8 miles
Natural gas	$7.9/mcf		1,500,000 mcf * 30			1,500,000 mcf * 30
Transmission Line Cost	$2 mil/mile	33.56 miles		33.56 miles	20 miles	
Compressor Stations Cost	$15 million	3 compressors	9 compressors	5 compressors	9 compressors	2 compressors
Wind Turbines Cost	$5.8 million	182 turbines		182 turbines	182 turbines	
Substation Cost	$140 million				1 substation	
Total Cost For Class IV Well(s)	$19.5 million		$19.5 million			$19.5 million

Total Cost A	Total Cost B	Total Cost C	Total Cost D	Total Cost E
$1.258 B	$618.0 M	$2.227 B	$1.492 B	$317.8 M

Conclusion: The five scenarios here indicate that using steam methane reforming with carbon capture and storage at Opal seems to be the cheapest method to produce hydrogen under current conditions. This is of course without considering the cost of building each of these plants and all other assumptions listed above. In terms of green hydrogen production, Scenario A achieved the lowest cost at $1.258 billion for all the supporting infrastructure needed to build a 600 MW hydrogen production facility. Again, I assume that my estimates generated for building a 690 MW wind farm are to blame for this high estimate but it certainly seems that building a wind farm for a plant of this size will be one of the most expensive costs of this operation. Thus, if Williams is able to find a way to build a wind farm to power this facility for substantially cheaper than estimated, rather by using government funding or better technology, the economics of using electrolysis for hydrogen production begin to make more sense.