Hydrogen for Heat: Utilizing Hydrogen for Long-Term Energy Storage in Northern Climates

by
Gertrude Villaverde

A THESIS

submitted to

Oregon State University

Honors College

in partial fulfillment of
the requirements for the
degree of

Honors Baccalaureate of Science in Energy Systems Engineering
(Honors Associate)

Presented January 18, 2019
Commencement June 2019

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Gertrude Villaverde for the degree of Honors Baccalaureate of Science in Energy Systems Engineering presented on January 18, 2019. Title: Hydrogen for Heat: Utilizing Hydrogen for Long-Term Energy Storage in Northern Climates.

Abstract approved:____

Chris Hagen

A long-term energy storage technology is necessary to utilize Oregon's curtailed renewable energy, an issue the state faces, even with a low percentage of renewable energy in the energy mix. This report proposes a system design that details how hydrogen power-to-gas technology can be used in conjunction with the existing natural gas infrastructure to store energy from intermittent renewable sources during peak generation. The system uses excess electricity and Proton On-Site's M100 electrolyzer to split water into oxygen and hydrogen gases, the latter of which can be directly injected into the natural gas pipeline and stored in underground reservoirs until months of higher energy demand. From the 304 curtailment hours in 2017, 2,850 kg of hydrogen could have been produced, which could have resulted in a hydrogen and natural gas admixture of 75 ppm hydrogen in NW Natural's depleted natural gas reservoirs. There are no significant environmental concerns with a system this size. Hydrogen blends up to 35% are compatible with current natural gas appliances and blends up to 8.7% are within energy content limits set by the Oregon Public Utility Commission. This system is not economically feasible without offering a premium price per therm to residential customers to fund the project.

Key Words: energy, hydrogen, power-to-gas, renewable, storage

Corresponding e-mail address: villaveg@oregonstate.edu

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Honors Baccalaureate of Science in Energy Systems Engineering project of Gertrude Villaverde presented on January 18, 2019.

APPROVED:

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Chris Hagen, Mentor, representing MIME

____

Rebecca Webb, Committee Member, representing MIME

____

Zac Taie, Committee Member, representing the OSU Energy Systems Laboratory

____

Toni Doolen, Dean, Oregon State University Honors College

I understand that my project will become part of the permanent collection of Oregon State University, Honors College. My signature below authorizes release of my project to any reader upon request.

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Gertrude Villaverde, Author

This paper was written as part of the OSU-Cascades team's submission to the Department of Energy's Hydrogen Education Foundation 2018 Student Design Contest. The team members and their contributions to this paper are as follows:

Gertrude Villaverde, Project Lead:

- Executive Summary
- Introduction
- System Design
- Siting
- Economic Analysis
- Conclusion

Jennifer Speaks, Co-author:

- Environmental Analysis
- Safety Analysis & Codes and Standards
- Policy & Regulatory Analysis
- 1-Pager for Policy Makers

Zac Taie, Technical Advisor and Co-author:

- Introduction
  - Technical advising and editing

Zoe Lavrich, Lead Editor:

  - Editing

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2 EXECUTIVE SUMMARY

Oregon's Renewable Portfolio Standard (RPS) requires that by the year 2040, at least 50% of the electricity consumed in the state be generated from renewable sources. This high level of renewable generation poses a challenge for grid management as curtailment has already been an issue with today's relatively low level of renewable generation (6% in 2016). New renewable power plants are expected to come online to meet the RPS which is expected to exacerbate curtailment issues. In Oregon, curtailment occurs in the spring when hydro-electric generation is plentiful due to snowmelt. However, Oregon's peak energy demand is seasons later in the winter, when heating loads are high. A long-term energy storage technology is necessary to utilize the curtailed energy.

NW Natural supported this work to investigate how power-to-gas technology could alleviate Oregon's curtailment issues. The technology is executed by an electrolyzer, which uses electricity to split water into oxygen and hydrogen gases, the latter of which can be stored stably in large quantities for long durations.

The proposed system design uses the Proton On-Site M100 electrolyzer module to produce hydrogen gas from renewably-generated electricity, in lieu of curtailment. The module package includes a compressor, which will pressurize the hydrogen for injection into NW Natural's natural gas pipeline. Hydrogen production in the spring will coincide with the months that the state's largest natural gas utility, NW Natural, increases inventory in the Mist Site, an underground natural gas storage facility. The blended natural gas will flow into storage until it is needed seasons later. Our analysis found that from the 304 hours of curtailment in 2017, 2,850 kg of hydrogen could have been produced, resulting in a concentration by vol. of 75 ppm hydrogen in a 453,100,000 m^3 reservoir filled with natural gas at standard temperature and pressure.

Herein, we worked with NW Natural to identify four possible sites for the project and created a decision matrix to rate each. The most suitable site, per our criteria, is Miller Station in Clatskanie, OR.

Our environmental analysis of the system shows there is no significant negative impact on the environment. Hydrogen sulfide is a toxic by-product of sulfate-reducing bacteria, but its occurrence is minimal at low hydrogen concentrations. Using only curtailment hours, the indirect greenhouse gas effect of hydrogen that is leaked at a rate of 4.5% is equivalent to the effect of 0.74385 metric tons of CO_2. However, the carbon dioxide reduction from burning this much hydrogen instead of fossil natural gas is 39 metric tons. Oregon does not currently offer incentives for carbon dioxide emission reduction, but following California's structure results in a carbon reduction incentive of $41.42 per metric ton of carbon dioxide.

An economic analysis of the system shows that to meet NW Natural's rate of return for this project, the price for the hydrogen produced would need to be $121.81/kg. This would result in a payback period of 9.75 years. A projected model for the year 2027, which accounts for a decrease in equipment costs, an increase in carbon credit, and an increase in utilization to year-round, could set the price of hydrogen as low as $2.83/kg.

All the equipment in the design meets code and safety standards set by various regulating organizations. Hydrogen embrittlement could be an issue if the pipeline does not meet the standards set by AMSE B31.12. However, NW Natural's upgraded pipelines fall within standards that indicate it should not be affected by low concentrations of hydrogen. Explosion risk is not increased when blending natural gas with up to 10% hydrogen. The low concentration of hydrogen in the natural gas should not change leak detection procedures.

There are currently no policies or standards that specifically address hydrogen-blended natural gas. However, using the Wobbe Index, concentrations of up to 35% by volume of hydrogen would have no effect on current natural gas appliances. Up to 8.7% by volume of hydrogen gas is allowed according to the energy content limits set by the Oregon Public Utility Commission.

We recommend that a hydrogen power-to-gas system be placed at Miller Station in Clatskanie, OR to facilitate a large-scale long-term energy storage solution for Oregon. To make the project economically possible, we propose that enrollment in a premium price per therm program should be offered to customers. We also recommend NW Natural install hydrogen sulfide monitoring and treatment equipment at their Mist Site, and that further investigation on hydrogen embrittlement be done by the research community.

3 INTRODUCTION

Regulatory bodies around the world, encouraged by public opinion, are trending toward mandating the use of carbon-free energy within their districts. This trend, which is clear on the west coast of the US, is driven by concerns regarding climate change and global warming. The State of Oregon, for example, has set a Renewable Portfolio Standard (RPS) that requires at least 50% of the electricity consumed in the state be generated from renewable sources by the year 2040. Even more strict, the city of Portland (the largest metro area in Oregon and home to 640,000 people) has committed to using 100% renewable *energy* by 2050 [1],[2]. These constraints show the importance that the state, and its citizens, place on moving away from carbon-emitting energy sources.

Currently, 6% of the electricity generated within Oregon's borders is derived from renewable sources, defined federally as "solar, wind, biomass, landfill gas, ocean (including tidal, wave, current, and thermal), geothermal, municipal solid waste, and *new* hydroelectric" [3],[4],[5]. *Old* hydroelectric facilities (those built before 1995) account for over 60% of Oregon's electricity generation, and as such are not considered renewable [1]. Therefore, in order to meet the RPS regulations, utility-led renewable energy projects are under construction around the state.

Integrating renewable energy sources that often exhibit inherently variable output has been difficult since Oregon's largest energy generators (hydro facilities) are seasonally variable themselves. Snowmelt during spring causes rivers in the state to run high, which increases hydroelectric production. However, spring in Oregon is relatively temperate and does not require a large heating or air-conditioning load. This combination of low power demand and high production leads to production-demand mismatch and electrical generation curtailment. Even at the current low level of 6% renewable penetration, curtailment has been an issue for the state.

In 2017, the Bonneville Power Administration (BPA) curtailed 139,000 MWh of renewable energy between the months of March and July, Figure 1. This represents enough energy to power 155,000 homes for one month [7]. An increase in renewable generation of up to 50% (RPS requirement) is expected to exacerbate curtailment issues significantly.

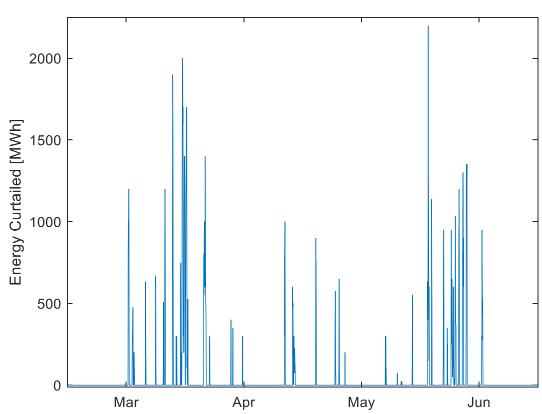

Figure 1. Energy curtailed by BPA in 2017 [6].

Winters in Oregon, contrary to the spring, require large heating loads (natural gas usage is eight times higher in the winter than summer) and see relatively low levels of hydroelectric generation. This production-demand mismatch is usually made up for by using natural gas (NG) for heating. However, fossil-derived natural gas will not be an acceptable energy source for the city of Portland under the new regulations. This presents a problem for the future scenario in which the renewable generation fleet cannot supply enough power to heat homes in Portland. To mitigate this, Oregon needs a long-term energy storage solution to shift available renewable energy from the spring to the colder winter months.

Several energy storage technologies are available, including compressed air energy storage, pumped hydro, power-to-gas hydrogen and power-to-gas methane. Figure 2 shows a comparison of different storage methods and their capabilities. In California, solar energy that exceeds the power demand during the day is stored in batteries to use later in the evening when the sun goes down and residential electricity demand is highest. Batteries are great for short-term utility shifts, but are not practical for utility shifts longer than a few hours due to their self-discharging rates [9]. Although batteries could satisfy the short-term intraday storage needs for Oregon, and other northern climates, this solution is not practical for long-term storage for seasonal shifting needed in the region [10].

A technology that shows promise for long-term energy storage is power-to-gas, which converts renewably-generated electricity into chemical energy that is stable and can be stored for long durations. Power-to-gas technology uses electricity to split water molecules into hydrogen gas and oxygen gas, after which, the hydrogen gas can be stored for later use [11]. Pumped hydro is the only other energy storage technology that is capable of storing large amounts of energy for long durations. However, it requires large amounts of water and land, resources that are themselves hard to come by. This is not feasible in Oregon.

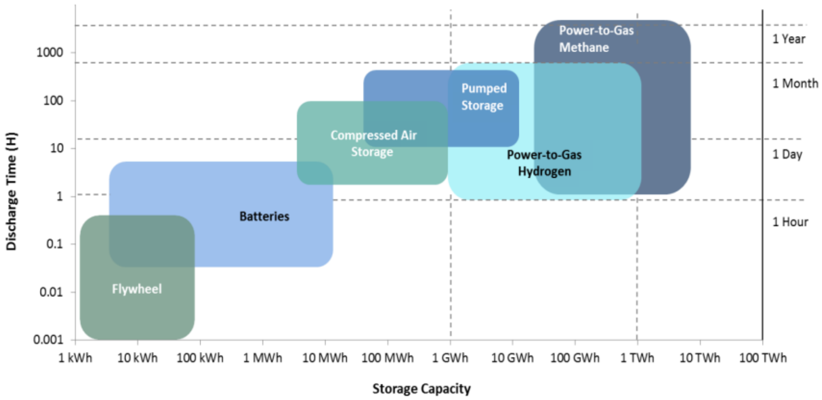

Figure 2. Storage technologies and their power/energy characteristics [8].

This report will document the design of a power-to-gas system used to seasonally shift energy from times of high renewable generation and low demand (spring in Oregon) to times of high heating load and low generation (winter in Oregon). This case study is suitable for northern climates and provides a contrast to the California battery-driven daily shifting model.

4 System Design

This section details the design efforts undertaken by the team, including: preliminary research, system selection, components of the selected design, and system operation and maintenance.

4.1 Preliminary Research and System Selection

The first step of our design process was gathering information on power-to-gas technology and familiarizing ourselves with hydrogen production via electrolysis. A literature review revealed that several European nations are currently injecting hydrogen, produced through electrolysis, into their natural gas networks [12],[13]. These projects are utilizing hydrogen at up to 10% in their natural gas systems, indicating that hydrogen injection for long-term energy storage is feasible [12]. The Netherlands is currently investigating the feasibility of storing hydrogen-enriched natural gas underground [12]. However, to the best of our knowledge, no one has stored hydrogen-enriched natural gas underground for long-term energy storage.

With this information, we spoke to NW Natural and discussed their distribution network system. We learned about their system's components and constraints, and how power-to-gas technology might fit in with their current operations. It was determined that a pilot-scale project (~ 0.5 $MW_{electric}$) would be beneficial for multiple reasons: 1) to prove out the technology on their grid and identify any issues for grid-level adoption, 2) to allow policy-makers and regional energy developers to get "hands-on" proof of the technology to spur support.

With a size in mind, the next step was to research commercially-available electrolyzers. An electrolyzer is a device that performs electrolysis, which is the process of splitting water molecules into hydrogen and oxygen gas using electricity. There are three electrolysis technologies available: alkaline, proton exchange membrane (PEM), and solid oxide [14]. Of the three, alkaline electrolysis and PEM electrolysis are commercially available. Although alkaline electrolysis is less expensive and has higher nominal efficiency (70% compared to 63% of PEM electrolysis), the quick ramp-up time of PEM electrolyzers makes them more suitable for responding to fluctuations in stochastic renewable energy generation, which is what an electrolyzer operating in the Pacific Northwest would likely respond to [15].

After conducting a national technology survey, three commercially available electrolyzers were identified: the ITM Power HGas1000, the Proton On-Site M Series, and the Hydrogenics HySTAT60. Effort was made to establish contact with each of these companies. Proton On-Site was the most responsive, and their M100 satisfied the pilot-scale project's size requirement of 0.55 MW. It also has a quick ramp-up rate (<5 min from off state and <10 sec from minimum to full load). The HGas1000 runs at almost double that electrical consumption rate and the next smallest unit from ITM Power only consumes ~360 kW. The Hydrogenics HySTAT60 is the largest unit that Hydrogenics offers and only consumes ~300 kW. For these reasons, we decided to select the Proton On-Site M100.

4.2 System Overview and O&M

The three main components of the system are the electrolyzer module, the compressor, and the underground natural gas storage facility. The electrolyzer module, which houses the electrolyzer stacks, will consume water and renewably-generated electricity to produce hydrogen gas. The hydrogen will move into a compressor and then be injected into the natural gas pipeline. The natural gas will flow toward the underground natural gas storage facility and will be injected at the reservoir wellheads. There, the hydrogen-enriched natural gas will stay for months until winter, when heating loads are higher. When demand for natural gas increases in the colder months, NW Natural will withdraw the stored gas and place it on its feeder pipelines, delivering hydrogen-blended natural gas to consumers in large cities like Portland, seen in Figure 3.

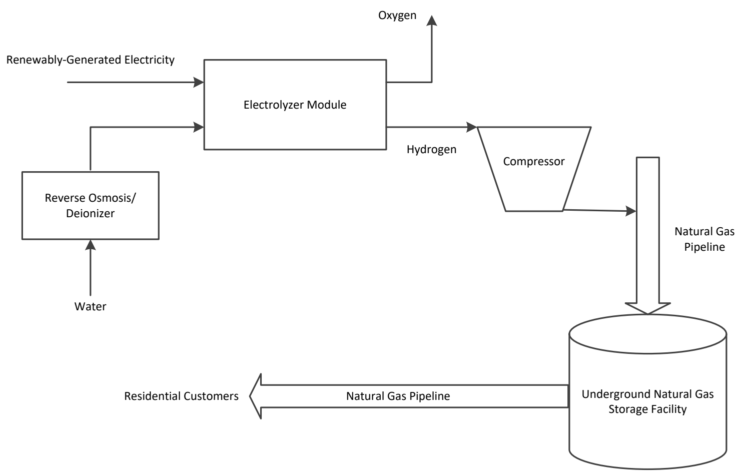

Figure 3. System overview.

4.3 Electrolyzer Module

Electricity enters the M100 electrolyzer module through the motor control center, which distributes power to all electronic components. Water undergoes a reverse osmosis/deionizing process in the site facility before entering the module at the O_2 & Cooling Management skid. It is stored in the water tank above the H_2 Production skid and pumped through the system for cooling. During hydrogen production, the water enters the electrolyzer cell stacks in the H_2 Production skid and is split into oxygen and hydrogen. The oxygen is diverted back to the O_2 & Cooling Management skid and vented out of the container. The hydrogen moves to the H_2 Gas Management skid where it is separated from the water that leaves the cell stacks with it, and where flow, temperature, and pressure are managed. For additional purification, the hydrogen moves through the H_2 Dryer before exiting the electrolyzer module. Having a minimal amount of water vapor is important in injecting hydrogen into the natural gas pipeline. With the presence of water, ice-like natural gas hydrates can form, creating blockages in the natural gas grid [16]. The hydrogen produced leaves the module at 3000 kPa, and will travel to the compressor in tubing that adheres to ASME B31.12 [17],[18].

Table 1. M100 electrolyzer module specifications [21],[17].

Electrolyte	Proton Exchange Membrane
Hydrogen Production	225 kg/24h
Delivery Pressure	3000 kPa
Hydrogen Purity	> 99.9% Water Vapor < 500 ppm, N2 < 2 ppm, O2 < 1 ppm, All others undetectable
Hydrogen Purity with Optional High Purity Dryer	ISO 14687-1:1999 Type 1 Grade C / ISO 14687-2:2012 Type 1 grade D > 99.9995% Water Vapor < 2 ppm, N2 < 2 ppm, O2 < 1 ppm, All others undetectable
Power Consumption at Cell Stacks	0.51 MW
Power Consumption at System	0.55 MW
Power Consumed per Volume of Mass H2 as Produced	59 kWh/kg
Electrical Specification	Typical Installation: 10 kV and 20 kV, 3-phase + neutral, 50 Hz/60 Hz
Start-Up Time (from Off State)	<5 min
Turndown Range	10 to 100% (Input Power Mode); 0 to 100% (H2 Demand Mode)
Ramp-Up Time (Minimum to Full Load)	<10 sec
Ramp Rate (% of Full-Scale)	≥ 15% per sec (Power Input Mode)
Water Consumption Rate	93 L/h
Maximum Inlet Flowrate	187 L/h
Water Temperature	5°C to 40°C
Input Water Quality	ISO 3696 Grade 2 Deionized Water required, < 1 micro Siemen/cm (> 1 MegOhm-cm) ISO 3696 Grade 1 Deionized Water recommended, < 0.1 micro Siemen/cm (> 10 MegOhm-cm)
Mass of Water Circulation Skid	5163 kg
Mass of H_2 Gas Management Skid	909 kg
Mass of Power Conversion Assembly	6500 kg
Mass of motor control center (MCC)	909 kg
Mass of Controls	300 kg
Dimensions of Water Circulation Skid (W x D x H)	7197 mm x 820 mm x 2563 mm
Dimensions of H_2 Gas Management Skid (W x D x H)	3317 mm x 575 mm x 2083 mm
Dimensions of Power Conversion Assembly (W x D x H)	6200 mm x 1200 mm x 2850 mm
Dimensions of MCC (W x D x H)	2032 mm x 549 mm x 2210 mm
Dimensions of Controls (W x D x H)	1550 mm x 382 mm x 2190 mm
Storage/Transport Temperature	5 °C to 60 °C
Ambient Temperature Range	10 °C to 40 °C

The electrolyzer package from Proton On-Site includes a reverse osmosis/deionizing (RODI) unit to supply the lab-grade water the system needs [17]. The RODI unit occupies a footprint space approximately 1.2 m x 2.4 m [19]. Assuming the RODI unit is 25% efficient, it requires 372 L/h of water input when the electrolyzer is running at full power. Excluding the RODI unit and the compressor, the entire electrolyzer module is housed in a 12.2 m x 2.4 m container to be placed outdoors [20]. Additional specifications of the electrolyzer module can be found on Table 1.

Figure 4 highlights some of the key features of the M100. The heat exchanger and the water circulation pump work together to regulate the temperature of the system. The cell stack is the actual electrolyzer that will produce hydrogen gas. The hydrogen and oxygen phase separators limit the water that is delivered with the hydrogen and oxygen from the cell stack. The hydrogen gas management system controls the quality of the hydrogen as it leaves the module. The combustible gas detector monitors hydrogen gas levels in the module container and alerts operators if there is a leak.

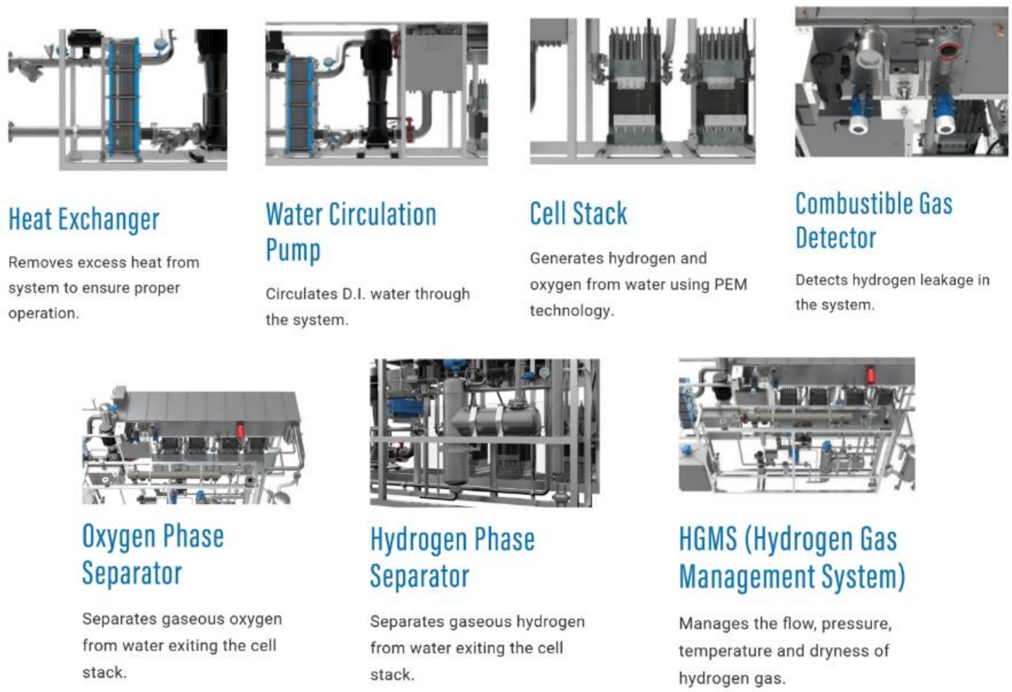

Figure 4. Key features of the M100 [17].

4.3.1 Electrolyzer O&M

The operation of the M100 is designed to be fully automated with remote monitoring and control [17]. The controls unit is included in the package, located inside the container, and will be monitored by the same staff that monitors the selected NW Natural site. Yearly maintenance is required and maintenance kits for the electrolyzer and RODI unit are available for purchase. Purchasing a kit of spare parts is recommended every two years. An annual preventative maintenance service is also recommended, which includes parts, labor, and is performed by a Proton On-Site trained and certified field service engineer [22].

4.4 Compressor

The M100 is capable of electrochemical compression of up to 3000 kPa, greatly reducing the additional compression power required for pipeline injection. If additional compression is needed, Proton On-Site offers a hydrogen-rated compressor to compliment the electrolyzer module. A hydrogen compressor for a system this size is expected to be slightly smaller than 2.57 m x 3.47 m, which is the footprint of a compressor sized for the M400 model. Its input requirement is 480 VAC, 3-phase. It's assumed to have enough power to compress hydrogen from 3000 kPa to 3620 kPa, to inject into a 3450 kPa NG pipeline. To estimate the compressor's power consumption, we calculated the specific work (w) required for isentropic compression, assuming steady-state operation, hydrogen is an ideal gas, and that changes in kinetic and potential energy can be neglected. We chose isentropic compression to give the most conservative estimate. This calculation is a relationship between the ratio of specific heats of hydrogen ($k = c_p/c_v$), gas constant of hydrogen (R), inlet temperature of the hydrogen (T), inlet pressure (P_1), and exit pressure (P_2).

$$w = \frac{kRT}{k-1}\left[\frac{P_2}{P_1}^{k-1/k} - 1\right]$$

Using hydrogen's ratio of specific heats k = 1.4 (from the Engineering Equation Solver [23]), R = 4.124 $kJ/(kg * K)$, P_1 = 3000 kPa, P_2 = 3620 kPa, and assuming the initial temperature of hydrogen to be T = 20 ºC, the work required to compress the hydrogen is 233.3 kJ/kg [24]. Using the M100's production rate of 9.375 kg/h, the compression would require a power consumption of 0.6076 kW during operation [17].

The compressor will connect to the NW Natural pipeline network using tubing that meets ASME B31.12 standards. For injection, a check valve will be utilized to allow higher-pressure hydrogen to enter the lower-pressure pipeline but prevent natural gas from back flowing from the pipeline into the compressor.

4.4.1 Compressor O&M

Since the compressor is included in the package from Proton On-Site, it is assumed the compressor is controlled by the same control unit inside the electrolyzer module, making it fully-automated and remotely monitored and controlled as well. We also assume maintenance will be included in the annual maintenance program.

4.5 UNDERGROUND NATURAL GAS STORAGE FACILITY

The underground storage facility for this project is the Mist Site in Mist, OR, which is controlled by NW Natural. The Mist Site has several depleted natural gas reservoirs with a working capacity of 453,100,000 m^3 [25]. Figure 5 shows the wind and solar power plants in Oregon and the location of the Mist Site, which is 60 miles northwest of Portland. Currently, the reservoirs are used as intermediate energy storage facilities for the state. Oregon's natural gas consumption increases by 8-fold from the summer to the winter, and the interstate pipeline would not be able to support this capacity. To mitigate this, NW Natural buys natural gas in the spring and summer months and stores it in the depleted reservoirs. This gas is then pulled out during the winter and is used for heating. Figure 6 shows that these months of gas acquisition coincide with BPA's months of curtailment in 2017. This indicates that there is capacity to store the generated hydrogen.

4.5.1 Underground Natural Gas Storage Facility O&M

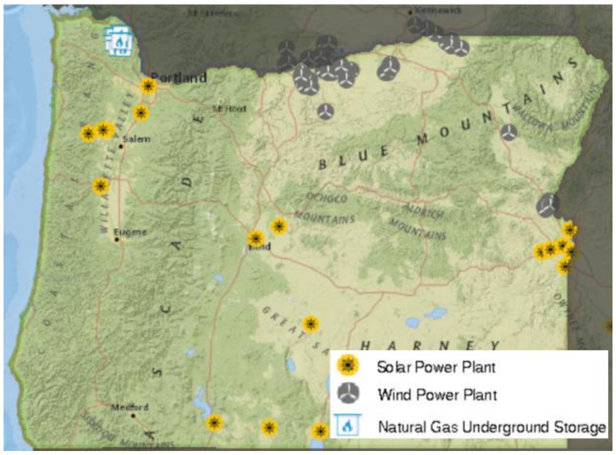

Figure 5. Natural gas underground storage, solar power plants, and wind power plants in Oregon. Adapted from [25],[4].

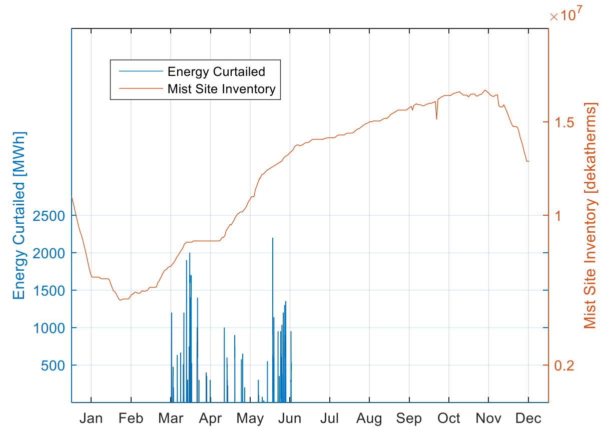

Figure 6. BPA curtailment and Mist Site inventory coincidence in 2017 [25],[6],[26].

Operation and maintenance of the Mist Site will not be altered by the production and addition of hydrogen from a system of this size, and NW Natural can continue with their usual procedures.

4.6 Hypothetical Hydrogen Production from 2017 Curtailment

The smallest amount of energy BPA's oversupply management protocol (OMP) requested for any hour of curtailment in 2017 was 1 MWh. With the system sized at 0.55 MW, it could run at full power for every hour of curtailment. This system, along with its compressor, would be able to use 0.12% of the total curtailment. Figure 7 shows a range of potential system sizes and the percent of curtailment they would have been able to use in 2017. While this is a low percentage of the curtailment, this demonstration size system is primarily intended as a proof of concept. If successful, a larger system will be necessary to utilize the large amount of curtailment expected.

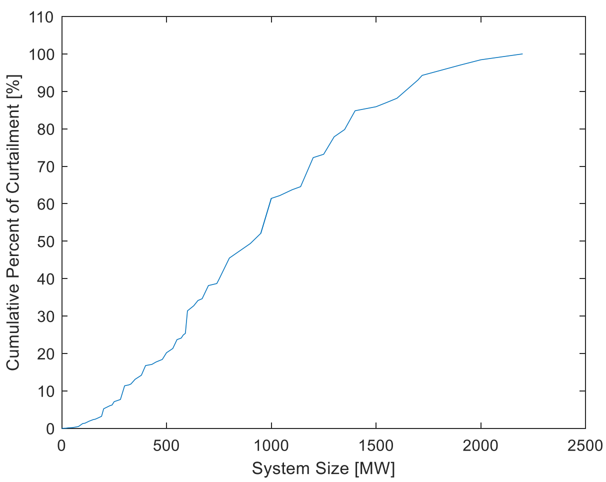

Figure 7. Cumulative percent of curtailment usable by system size.

If all 304 hours of curtailment were utilized, the M100 would produce 2,850 kg annually. Assuming the underground storage facility was filled with NG at 20 °C and 101.325 kPa, this addition of hydrogen would result in a volume percentage of 75 ppm.

5 Siting

This section details the siting requirements for the project and their weighting. The proposed sites are listed, information for each location is summarized, and site preparation costs are explained. A decision matrix used to determine the final site is found at the end of this section.

5.1 REQUIREMENTS

After discussion with NW Natural and Proton On-Site, six key criteria were identified. The general requirements for the project site are: 1) access to electricity, 2) access to water, 3) ample indoor space available for the water filtration system and compression unit, 4) ability to transport the generated hydrogen to the depleted reservoirs for storage, 5) minimal preparation costs, and 6) public access so that policy makers and energy developers can get a "hands-on" appreciation of the system. These will be briefly discussed in turn.

5.1.1 Electricity Requirement

The site needs to be able to provide enough power for the electrolyzer and the compressor simultaneously at each unit's required voltage. The M100's power requirements are 0.55 MW with a voltage between 10 kV and 20 kV, 3-phase power, at 50 Hz/60 Hz [17]. The compressor will require 3-phase 480 VAC, and the power requirement will depend on the compression needed for injection at the different potential sites [19].

5.1.2 Water Requirement

The electrolyzer module requires highly filtered water for operation (ISO 3696 Grade 1 or Grade 2). This water is provided via a reverse osmosis deionization (RODI) module sold as part of the M100 package. The electrolyzer consumes 93 L/h of filtered water from the RODI unit during operation [17]. Assuming the RODI is 25% efficient, it will require 372 L/h from the project site during operation.

5.1.3 Space Requirement

The site needs to have enough space for the container that houses the electrolyzer unit, compressor, and additional well, if needed. The M100 is housed in a container with a 12.2 m x 2.4 m footprint [17]. The compressor will occupy a little less than 2.57 m x 3.47 m [19]. If a well is needed on the site, a pump system sized at about 1 m x 1 m will suffice [27]. If there isn't enough space on the existing chosen site, NW Natural may need to purchase land adjacent to the site.

5.1.4 Ability to Transport Hydrogen to Mist

The project site must be in a location where the natural gas in the pipeline is flowing toward the Mist Site for storage during these months. The ability to store the produced hydrogen in the Mist reservoirs is a key component of the energy storage plan.

5.1.5 Minimizing Preparation Costs

Minimizing site preparation cost is important for any project, and we have included it in the siting requirements. Since different sites have their own preparation requirements, and costs could vary widely, this site requirement ranks the sites based on the cost of preparing the sites for the project.

5.1.6 Convenient Access

The site needs to be within a reasonable drive from NW Natural's headquarters in downtown Portland to allow for public access, so visitors can see the technology in action and have the opportunity to learn more about hydrogen power-to-gas and energy storage. This can help in adopting hydrogen power-to-gas as part of the solution to move toward renewable energy for the future. Since mileage between each of the sites to the headquarters involves different driving scenarios, like driving through cities in traffic and winding through mountain roads, drive time is considered a better measure than actual mileage for this site requirement. The team chose a reasonable drive time to be less than an hour and a half from NW Natural's headquarters.

5.2 REQUIREMENT WEIGHTING

Each site was evaluated on a scale from 0 to 5, with four choices, 5 being the best choice for the requirement and 0 meaning the requirement cannot be fulfilled. One hundred points were distributed between the requirements according to how important they were to site the project. Access to electricity, access to water, and having enough space for the system were all weighted at 20 points each. If any of these three requirements are missing, hydrogen production would not be possible. Requiring that the NG will flow toward the Mist Site has a weighting of 15 points. Although it is an important part of the system design, it was weighted less than the previous requirements because hydrogen production can commence to make use of curtailed energy regardless of which way the natural gas is flowing. However, if the hydrogen-enriched natural gas does not flow toward the Mist Site, it cannot be seasonally stored, which is the intended application of the system. Minimizing site preparation cost was also given 15 points. Lastly, public accessibility was given a weighting of 10 points. The system's success does not depend on how accessible the project site is from NW Natural's headquarters, but it is an important aspect of this project and is included in the siting requirements. After many conversations with the local utilities at each proposed site, information was gathered about each location. Table 2 summarizes this information.

5.3 Proposed Sites

After conversation with NW Natural, four possible project sites were identified in their network: Molalla Gate in Canby, OR; Deer Island Gate in Rainier, OR; Miller Station in Clatskanie, OR; and an undeveloped site in Newberg, OR. Aerial shots of each location, from Google Maps, can be seen in Figure 8 through Figure 11.

Figure 8. Satellite view of Molalla Gate.

Figure 9. Satellite view of Deer Island Gate.

Figure 10. Satellite view of Newberg Site.

Figure 11. Satellite view of Miller Station.

5.4 Explanation of Site Preparation Costs

5.4.1 Cost for Well Installation

Of the four sites, only Miller Station has water service, which is provided by well #95426. Molalla Gate and the Newberg Site are in areas where water access is obtained by drilling and installing a well pump system. Wells #99824 and #112591 from Gingerich Farms, and well #99820 from Highland Meadows Nursery near the Molalla site, average a well depth of 98.1 m. A local drilling contractor in the area concluded that a well depth of only 42.7 m would be required for a system requiring much less water throughput than the neighboring farmlands do, and this depth was used to determine the cost per length of drilling service [28]. Although the contractor provided us with the depth information, we were unable to obtain a quote. Wells #60734, #87153, and #118265 in the residential area near the Newberg site average a well depth of 43.6 m. We also could not obtain a quote from local drilling contractors in the Newberg area. The Deer Island site is not near a well to compare water table depth with, but we assume the depth required is the same as the Newberg site for calculating the cost of a well installation. For the cost of the drilling service, we took a high estimate of $50/0.3 m and added in the cost of a mid-range pump system of $11,750 [29]. The cost for installing a well on site is $18,750 for Molalla Gate, $18,900 for both the Newberg site and Deer Island Gate, and $0 for Miller Station.

Table 2. Information gathered for siting.

	Proposed Site			
Requirement	Molalla Gate	Deer Island Gate	Newberg Site	Miller Station
10 kV or 20 kV, capacity increase of 0.62 MW	Since this site is outside of the city limits, Portland General Electric is the power service provider [30]. PGE confirmed power service to the site, but would not provide the details of the service available [31]. The closest transmission line is ~5 km away [4].	Columbia River People's Utility District provides power service within the city limits of Rainier, OR. Although this site is outside of the city limits, one of the provider's lines runs along the highway on which it is located. 12.47 kV service is available, and to meet the capacity needed, lines from two feeders a few miles away need to be tied together and brought to the area. This upgrade would need a few dozen new poles to bring the line over. A system impact study, over the course of a few months, would need to be done to determine if the required power service could be provided by the existing scheme. If possible, the cost of bringing power to the site could decrease significantly [32]. The closest transmission line is ~8 km away [4].	Portland General Electric services the area this site is in. There is currently no power service at the site [31]. The closest transmission line is ~6.5 km away [4].	West Oregon Electric Co-op provides power service to this site. Upgrades are needed to meet the requirements of the electrolyzer module [33]. The closest transmission line is ~9.5 km away [4].
>372 L/h water availability	Since this site is outside of the city limits, a water well needs to be installed on the site [30]. Neighboring farms have high-yielding wells, much higher than needed for this project [34]–[36]. A well installation will yield enough water for the electrolyzer.	Since this site is outside of the city limits, a water well needs to be installed on the site [37]. Expected yield in the area is unknown.	Since this site is outside of the city limits, a water well needs to be installed on the site. Wells in the area have enough yield to satisfy the requirement [38]–[40].	There is a well on site, well ID #95426. According to the most recent well log, it yields 6800 L/h [41]. This is more than enough to satisfy the requirement.

40'x8' footprint, plus space for additional components is available	Space is limited due to area classification zones, but a satellite view of the site shows there may be room for an electrolyzer unit [19],[42]. It would be difficult to find space within the site for a compressor and a well. Expansion of the site may be difficult since it is surrounded on three sides by farmland and is bordered by a road on its fourth side.	Space is very limited within the existing fence due to recent improvements that include a new odorant tank and pig launchers [19]. There does not seem to be any space available for the container, compressor, and well [43]. The Columbia Land Trust owns the surrounding land, and it may be difficult to buy land for this project since their work is primarily land preservation.	There is enough space on site for all components [44]. However, NW Natural does not own the land, and it is unclear if they still own the natural gas line on the property [19].	Space is limited inside the station due to recent and planned improvement projects, but land outside the perimeter may be available from one of the land owners adjacent to the station [19],[45].
Pipeline flows toward Mist, OR in the spring	Molalla Gate is a primary receipt/delivery point for Mist storage [11]. Storage in the Mist facilities occurs in the spring and summer months, so flow through this site will go toward the underground reservoirs in Mist, OR [19].	Deer Island Gate is a primary receipt/delivery point for Mist storage [11]. Storage in the Mist facilities occurs in the spring and summer months, so flow through this site will go toward the underground reservoirs in Mist, OR [19].	The Newberg site is at the end of a 4970 kPa pipeline that feeds a 2070 kPa system that distributes gas to serve Newberg, OR [19]. This flow is away from the direction of the Mist reservoirs, and further investigation is needed to conclude whether the hydrogen produced at this site can be delivered to Mist [19].	Miller Station is the station adjacent to the Mist storage facilities. Natural gas that is injected or withdrawn from the reservoirs can pass through this station [19].
Within 1.5 h drive from NW Natural headquarters	1 h 10 min Drive	55 min Drive	1 h 5 min Drive	1 h 25 min Drive
Preparation Costs	$592,230	$933,630	$763,005	$1,086,981

5.4.2 Cost for Power Service

Portland General Electric (PGE) provides power service to the area that Molalla Gate and the Newberg site are in. PGE confirmed that Molalla Gate has power service, but we were unable to obtain details about the voltage and capacity for the site from PGE. We were also unable to obtain an estimate on installing power service to the Newberg site from PGE. West Oregon Electric Co-Op currently provides power service to the Miller Station. We were able to speak with an engineer who explained a possible solution to obtaining the required power service, and who also insisted that an engineering study on their system would be required to analyze the solution's feasibility. We were unable to obtain a quote for this service upgrade to the station. Columbia River People's Utility District controls the power line that runs along the highway right in front of the Deer Island Gate. They were able to confirm that the site currently does not have power service but installing 3-phase service with 12.47 kV is possible. The field engineer we spoke with suggested a system impact study would need to be done over months to determine if their current system can provide the capacity needed. Without that study, he provided a rough estimate of $910,000 for a solution to provide the capacity needed by tying lines from two feeders 8 km away and bringing in powerlines, requiring a few dozen new powerline poles, to the site. Since this is the only estimate we obtained, we used $113,750/km, along with each site's approximate distance from the nearest transmission line, to estimate the cost of providing the required power service to each of the sites. The approximate distances to the nearest transmission line are 5 km for Molalla Gate, 8 km for Deer Island Gate, 6.5 km for the Newberg site, and 9.5 km for Miller Station [4]. Using these distances, the estimated cost of access to electricity is $568,750 for Molalla Gate, $910,000 for Deer Island Gate, $739,375 for the Newberg site, and $1,080,625 for Miller Station.

5.4.3 Cost for Compressor Building

Since the compressor provided by Proton On-Site is sized for each module in the M Series, it would be the same regardless of where the system is located. It would require a compressor building of the same size at each site, and therefore incur the same cost. Using the compressor power consumption estimation stated previously in section 4.4 and an estimate of $2,295.80/kW cost for compressor buildings, and taking the highest value among the sites, we estimate a cost of $4,730 for a building to house a compressor [46].

5.4.4 Cost of Land

If there is not enough footprint space for the electrolyzer module, compressor, and well, acquiring a quarter-acre of land would be enough for the system and additional components. Based on the average land value of Oregon in 2015, this would add an additional cost of $1,625.75 for undeveloped land acquisition [47].

5.5 SITING RESULTS

The results from the decision matrix in Table 3 show that Miller Station will be the most suitable site for the project.

Table 3. Decision matrix for siting.

Customer Requirements/General Requirements	Engineering Requirement	Scale	Weight	Proposed Site			
				Molalla	**Deer Island**	**Newberg**	**Miller**
Access to electricity for electrolyzer	**10 kV or 20 kV, greater than 0.55 MW + compressor consumption rate**	5 - Power lines available, voltage and capacity met	**20**	**3**	**1**	**1**	**3**
		3 - Power lines available, upgrades or transformer needed to satisfy requirement					
		1 - No power transmission, need to install lines					
		0 - Voltage and capacity cannot be met					
Access to water	**>372 L/hr of water**	5 - Water meets quantity and quality requirements	**20**	**1**	**1**	**1**	**5**
		3 - Water access is available, but upgrades are needed to satisfy requirement					
		1 - No water access, needs new infrastructure					
		0 - Cannot make water accessible, need tank and driver					
Space for the system is available	**40'x8' footprint, and space for additional components is available**	5 - There is enough space	**20**	**1**	**1**	**5**	**3**
		3 - There is not enough space on site, but it is likely land can be acquired					
		1 - There is not enough space on site, but it may be difficult to acquire land					
		0 - There is not enough space on site, and land cannot be acquired					
Can store hydrogen in reservoirs from site	**Pipeline flows toward Mist**	5 - Pipeline flows toward Mist in the spring, or toward Mist most of the time	**15**	**5**	**5**	**0**	**5**
		3 - Pipeline flows both ways, but evenly or unpredictably					
		1 - Pipeline flows both ways, but mostly away from Mist					
		0 - Pipeline only flows away from Mist					
Accessible from NW Natural Headquarters	**Within 1 hour and 30 minutes drive from NW Natural headquarters in Portland, OR**	5 - Within a half hour drive from NW Natural headquarters	**10**	**1**	**3**	**1**	**1**
		3 - 0.5-1 hour drive from NW Natural headquarters					
		1 - 1-1.5 hour drive from NW Natural headquarters					
		0 - Over 1.5 hour drive from NW Natural headquarters					
Minimize Preparation Costs	**Rank sites in order of preparation costs**	5 - Incurs least amount of preparation costs	**15**	**3**	**5**	**1**	**0**
		3 - Incurs second to least amount of preparation costs					
		1 - Incurs second to most amount of preparation costs					
		0 - Incurs most amount of preparation					
			Totals:	**230**	**240**	**165**	**305**

6 ENVIRONMENTAL ANALYSIS

2017 was the second warmest year on record with global temperatures at 0.9 ˚C above the 1951-1980 mean [48]. This is partly due to carbon dioxide (CO_2), a heat-trapping greenhouse gas whose current level of 407.62 ppm, as of December 16th 2017, is at the highest concentration levels in 650,000 years [49]. Much of this rise can be attributed to human factors such as the burning of hydrocarbons to produce electricity and heat.

Environmental concerns are regulated federally by the Environmental Protection Agency (EPA). Oregon also has several specific regulatory agencies, namely the Oregon Department of Environmental Quality (DEQ), Oregon Department of Fish and Wildlife (ODFW), and the Oregon Health Authority (OHA) [50]. Consideration was given to the standards upheld by these agencies when examining the environmental effect of the proposed system.

Our proposed design will eliminate some of these CO_2 emissions by replacing a portion of the hydrocarbons in natural gas with clean-burning hydrogen. That is not to say there will not be any negative environmental impacts, though the benefits far outweigh the costs. Other concerns include water usage, the potential for a hydrogen sulfide by-product, and indirect greenhouse gas effects.

6.1 WATER USAGE

Water is a vital component to the continuation of life on earth and so may be treated as a precious resource, the allocation of which is limited. To analyze the impact of adding a new water consuming process to the current Clatskanie water grid we looked at the amount of water the electrolyzer will use, the source of that water, historical water restrictions, and affected wildlife.

The system uses 372 liters of water per hour at maximum production [52]. Running during the 304 curtailed electricity hours reported in 2017 uses 113,088 liters of water per year. To put this into perspective, we used the concept of virtual water, which looks at the entire life cycle of a product and the amount of water necessary to create, process, and distribute it [54],[55],[55]. A plain cheeseburger requires 2,714 liters of water to produce [56]. Therefore, it can be said that the electrolyzer uses roughly 42 cheeseburgers worth of water every year.

Miller Station receives water via a well, which may have an indirect effect on the city of Clatskanie's water supply, particularly during drought conditions. Wells can disrupt groundwater flows and introduce contaminants into adjacent water supplies [57]. Since the well is already in place, it is assumed to be in compliance with the clean water act, ensuring the risk of contamination to be minimal [58]. The location is not in an area typically associated with drought, though historically, there have been drought conditions as recently as 2002 [59]. Monitoring water use during times of scarcity is recommended.

Because the well may disrupt groundwater flows, we considered the ODFW list of endangered and threatened wildlife which contains several species that may be affected by water use in the area [60]. The Coho salmon is considered endangered in Oregon and has a critical habitat area that includes West Creek and Roaring Creek, where the city of Clatskanie harvests drinking water [61],[62]. Other endangered species migrate through the adjacent Columbia River gorge and may be affected by excessive water use.

The low water use of the electrolyzer is expected to have a minimal environmental impact on current water resources. During droughts it may be necessary to minimize, or stall, use of the equipment in favor of conservation. The impact on fish and wildlife should be monitored, though adverse effects are not expected. Excessive water use may influence water levels in the city of Clatskanie's reservoirs, though this effect will be minimal.

6.2 HYDROGEN SULFIDE

Hydrogen sulfide is a toxic and corrosive compound. It can form when hydrogen is stored in depleted mines, due to the presence of sulfate-reducing bacteria, as covered in section 8.5 [63]. The environmental impact is mainly attributed to health concerns due to this toxicity.

Health concerns arise because "[h]ydrogen sulfide is both an irritant and a chemical asphyxiant with effects on both oxygen utilization and the central nervous system" [64]. Exposure can include symptoms ranging from mild irritation of eyes, lungs, and throat, to coma and death. Symptoms may appear at concentrations as little as 2 ppm and instant death will occur at 1000-2000 ppm [65].

The United Nations global warming potential (GWP) index, a list of pollutants recognized for their effect on climate change, does not list hydrogen sulfide as a contributor to global warming. It does appear on the EPA's original list of pollutants, but was later redacted and moved under accidental release provisions [66],[67]. This provision is handled by the Chemical Emergency Preparedness and Prevention Office (CEPPO) and requires an emergency plan for the accidental release of hydrogen sulfide [68]. This plan is already in place as it is required for all currently operating natural gas mines.

Many states have additional regulations regarding the amount of hydrogen sulfide that can be found in the ambient air. Restricted concentrations are extremely low, largely related to the strong odor, described as rotten eggs. California, for example, restricts hydrogen sulfide to 30 ppb [69]. The Oregon DEQ does presently have this restriction, though it is working with the OHA to update the existing 24-hour toxic screening levels to include hydrogen sulfide at 98,000 ng/m^3 (68.7 ppb) [70],[71].

At low hydrogen concentrations, our design is not expected to raise hydrogen sulfide levels. However, the scalability of the project may be affected so it is imperative that the system be monitored, and daily quality checks performed to ensure safe levels are maintained.

6.3 INDIRECT GREENHOUSE GAS EFFECT

Hydrogen is not included on the EPA's list of toxic or priority pollutants, suggesting it is not classified directly as a pollutant [72]. Studies would argue that hydrogen may have a secondary, indirect effect on climate change. This is mainly due to the interaction of hydrogen with hydroxyl radicals (OH) in the Earth's atmosphere to produce water vapor, inhibiting the natural process of decomposing greenhouse gases [73],[74]. While this may counteract potential CO_2 reductions, it is an unofficial environmental impact and will not affect the potential carbon tax reduction.

The Global Warming Potential (GWP) is an EPA standard to compare the impact of various substances on climate change. Specifically, "it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2)" [75]. The GWP of carbon dioxide is 1 by definition, while the GWP of methane is 28 [76]. The estimated indirect value of hydrogen is assigned a GWP value of 5.8 for a 100-year period, associated only to the amount leaked into the atmosphere [73].

Hydrogen will leak through materials at a higher rate than natural gas due to its smaller size. Studies have found that at concentrations of 10% hydrogen leaked three times faster than methane through steel with the age of the pipe having no effect [77]. Other studies minimize this loss for low concentrations [78].

The average leak rate of natural gas in the United States is estimated at 1.5% of production [79]. Using this statistic as a reference, the leak rate of hydrogen is estimated to be 4.5% of the hydrogen produced. This statistic is somewhat skewed due to the use of cast iron piping, which has a much higher leak rate than the steel piping used by NW Natural. We expect the actual leak rate to be lower but will use this as a conservative baseline.

Multiplying the GWP by the amount of gas leaked yields the equivalent amount of CO_2 emissions [80]. The system is expected to create 2,850 kg of hydrogen using only 2017 curtailed hours. With an expected leak rate of 4.5%, this will amount to 128.25 kg of hydrogen leaked annually [79]. At a GWP of 5.8, this equates to an equivalent 0.744 metric tons of CO_2 each year. The maximum annual yield of the electrolyzer is 82,125 kg of hydrogen. This is a CO_2 equivalent of 3.7 metric tons.

The average CO_2 emissions per capita in the United States is 16.5 metric tons [80]. Our system is only 22.5% of the typical American's annual carbon footprint, if operated at maximum capacity all year. It is also negligible (<0.5%) when compared to the amount of carbon dioxide being reduced from the atmosphere as a portion of the natural gas is replaced by hydrogen.

6.4 Carbon Dioxide Reduction

Gaseous hydrogen is a clean energy carrier that can have zero to near-zero harmful emissions when burned [82],[83]. As a portion of the natural gas is replaced by hydrogen, the amount of CO_2 produced from the burning process will be reduced.

Table 4. NW Natural's gas composition % by vol. [84].

Substance	*Molecular Formula*	*% of Mixture*
Methane	CH_4	93.59
Ethane	C_2H_6	3.75
Propane	C_3H_8	0.92
Isobutane	C_4H_{10}	0.11
Butane	C_4H_{10}	0.15
Isopentane	C_5H_{12}	0.02
Pentane	C_5H_{12}	0.02
Hexanes	C_6H_{14}+	0.01
Carbon Dioxide	$C0_2$	0.25

To determine how much CO_2 is emitted by natural gas during combustion, we used the average chemical gas composition from the NW natural website as shown in Table 4. T-butyl mercaptan, methyl ethyl sulfide, and hydrogen sulfide were omitted due to negligible contributions to CO_2 emissions. Also excluded are nitrogen and oxygen, which do not combust to form CO_2.

As each compound is burned, it combines with oxygen in the air, forming CO_2 and H_2O. The chemical balance equation for each process reveals that the molar amount of CO_2 produced from the combustion of each hydrocarbon is directly proportional to the molar amount of carbon contained in each hydrocarbon fuel. For example, the process for propane indicates that:

$$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$$

Propane's three carbon atoms form three CO_2 molecules. This is true for every compound in this analysis. The amount of CO_2 formed per cubic meter of natural gas is then determined by using the equation:

$$Total\ CO_2 = \Sigma(Density * Volume\ Percent\ \div Molecular\ Weight * CO_2\ Conversion\ Rate\ )$$

The resulting values for each compound are shown in Table 5. When referring to CO_2 reduction, a value in terms of mass is more common. Multiplying the total result of 4.5E-2 kmol/m^3 by the molecular weight of CO_2 gives a total mass of 1.97 kg CO_2 formed per m^3 of natural gas burned.

Table 5. Calculation of total CO_2 formed per cubic meter of natural gas.

Compound	*Density* (kg/m³)*	*HHV*	*Percent by Volume*	*Molecular Weight (kg/kmol)*	*CO_2 Conversion Rate*	*CO_2 Formed (kmol/m³)*
Methane	0.6786	55530	0.9359	16.0425	1	3.959E-2
Ethane	1.28	51900	0.0375	30.069	2	3.193E-3
Propane	1.895	50330	0.0092	44.0956	3	1.186E-3
Isobutane	2.528	49080	0.0011	58.1222	4	1.914E-4
Butane	2.528	49150	0.0015	58.1222	4	2.610E-4
Isopentane	2.99	48570	0.0002	72.1488	5	4.144E-5
Pentane	2.99	48632	0.0002	72.1488	5	4.144E-5
Other Hexanes	3.582	48310	0.0001	86.1754	6	2.494E-5
Carbon Dioxide	1.868		.0025	44.0095	1	1.061E-4
Total:						4.463E-2

**Thermodynamic properties retrieved from EES database at standard conditions (1 atm of pressure and 20˚C)*

We used the higher heating value (HHV) of each gas to determine how much natural gas the hydrogen would replace. HHVs are used to characterize the energy content of fuels and measures the "amount of heat released during the combustion of one gram of fuel to produce CO_2 and H_2O" [84].

The HHV of hydrogen is 141 MJ/kg [85]. For the HHV of natural gas, we used a calculated heating value of 39 MJ/m^3, which can be found in section 9.3. Dividing by the density of our mixture yields a final HHV of 37,511 kJ/kg for the natural gas.

The typical efficiency of home furnaces is 80% in standard DOE certified appliances [86]. This requires that an efficiency be applied to account for heat loss during capture.

$$Total\ CO_2\left(\frac{kg}{kJ}\right) = CO_2\ formed\ \div (HHV * Efficiency)$$

The result of this calculation was then multiplied by the HHV of hydrogen to determine the amount of CO_2 emissions reduced per kilogram of hydrogen added. The results are shown in Table 6, alongside comparative calculations for coal to simulate heating with electricity produced from coal-fired plants. The calculations for coal used the same process as for natural gas, with bituminous coal having 137 carbons and anthracite coal having 240 carbons.

Table 6. Carbon dioxide reduction per kilogram of hydrogen produced [87].

Substance	*CO_2 Formed*	*HHV (kJ/kg)*	*Efficiency*	*HHV w/ efficiency*	*Total CO_2 (kg/kJ)*	*CO_2 Reduction (kg_{CO2}/ kg_{h2})*
Natural Gas	2.92 (kg/m^3)	37511.83	0.80	30009.46	9.74E-05	13.815
Bituminous Coal	3.12 (kg_{CO2}/kg_{coal})	38000	0.30	11400	27.4E-05	38.812
Anthracite Coal	3.43 (kg_{CO2}/kg_{coal})	38000	0.30	11400	30.0E-05	42.632

While the inclusion of coal is not relevant to the proposed system, it does put the potential carbon footprint reduction into perspective. If all electric furnaces currently running on coal-generated electricity were converted to hydrogen-natural gas blended furnaces, there is a potential reduction of nearly 43 times the CO_2 emissions per kilogram of hydrogen produced.

For our system, using only 2017 curtailed hours, 2,850 kg of hydrogen will be produced each year. This leads to a CO_2 reduction of 39,372 kg, or 39 metric tons (43 US tons), annually. If operated at full capacity all year, there is a potential for 82,125 kg of hydrogen. This equates to 763 metric tons (841 US tons) of CO_2 emissions eliminated each year.

6.4.1 CO_2 Reduction Incentive

In 2007, the Oregon legislature passed House Bill 3543, which outlines greenhouse gas emission reductions to be met by a series of targeted goals. Reduction goals are set by the Oregon Global Warming Commission (OGWP) and plan to reduce CO_2 emissions to 10% below 1990 levels by 2020 and 75% by 2050 [88]. Oregon does not expect to meet goals set for 2020 [89],[90].

One method being proposed to motivate CO_2 reductions is a "carbon cap-and-trade". Senate bill 557 is currently in the review stage and outlines a new plan, including new emission reduction goals and a penalty system aimed at forcing industries to lower emissions. The bill will change reduction goals to 20% by 2025, 45% by 2035, and 75% by 2050 [91],[92].

Carbon cap-and-trade works via an allowance system where each allowance is equal to one metric ton of CO_2, or equivalent GHG. The allowances are allocated to electric utility and natural gas companies each year, with additional allowances available for purchase. The amount allocated each year will reduce over time, while the price will rise. This creates a "cap" on the amount of GHG's emitted each year while the penalty makes it more economical for companies to remain in compliance by buying allowances [91].

No official pricing structure for the allowance system has been set, so we looked at California's cap and trade pricing structure as a model. California currently has three price tiers for administrative allowances, set at $50.69, $57.04, and $63.37 per metric ton with a trade market minimum price floor of $13.57 and a historical high of $22.45 [93]. This yields an average price of $41.42 per metric ton in 2017. These prices increase annually by 5%, plus inflation [94].

Assuming Oregon follows this trend and inflation remains steady at the current rate of 2.2%, the expected price per allowance shown Figure 12 is a reasonable forecast.

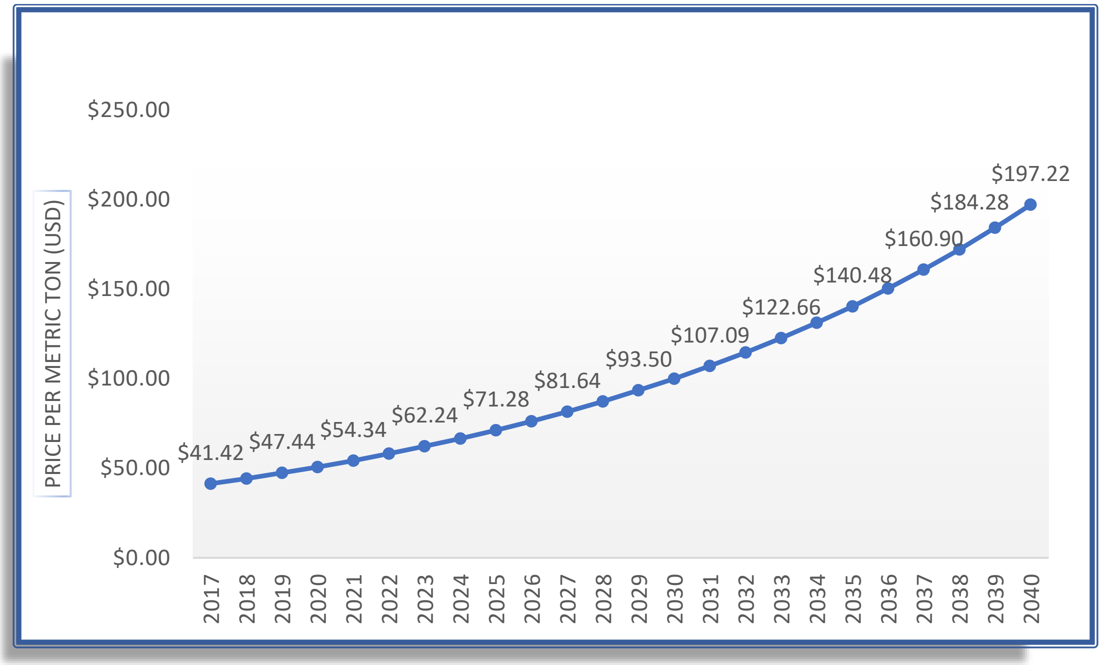

Figure 12. Expected allowance price per metric ton of carbon dioxide.

This forecast may be affected by the inclusion of Portland, which accounts for 15.6% of the population of Oregon [95]. Portland is the first U.S. city to create a climate action plan with the goal of 40% CO_2 reduction by 2030 and 80% reduction by 2050 [96]. Both the city and county have been pushing to adopt carbon pricing and have stated that even "[i]f the state does not adopt a carbon price, the City will consider local adoption of a carbon pricing mechanism" [97]. This could lead to a higher pricing structure and increases the likelihood of CO_2 emissions costs becoming reality.

7 Economic Analysis

This section examines the economic viability of the system by using a net present value model, a sensitivity analysis, payback period, and proposes a premium price per therm for hydrogen-enriched natural gas.

7.1 Net Present Value Model

The net present value model considers the present worth of costs and present worth of benefits associated with a project. The annual costs and benefits from each year of the project, usually lasting the duration of the service life of the equipment for which a capital expense is included, are discounted to today's dollar value, or present worth.

$$Net\ Present\ Value = Present\ Worth\ of\ Benefits - Present\ Worth\ of\ Costs$$

The net present value shows a relationship between the rate of return and the discount rate. An NPV greater than zero shows the project will yield a rate of return greater than the discount rate used in the calculation. This indicates that a project would exceed the required return and would be a good investment. An NPV less than zero shows the project would not meet the required rate of return. When NPV is equal to zero, the rate of return and the discount rate are equal, and the required rate of return is met exactly. Since NW Natural adheres to a rate of return limited by the Oregon Public Utility Commission, the desired outcome for the NPV model, using their set rate of return as the discount rate, is a value of $0.

For this system design, the elements that make up the net present value include capital expenses, operation and maintenance (O&M), revenue, and salvage value. As shown in Figure 13, the initial capital expense and the annual O&M expenses make up the costs associated with the project, and the annual revenue and salvage value at the end of the project's life make up the benefits.

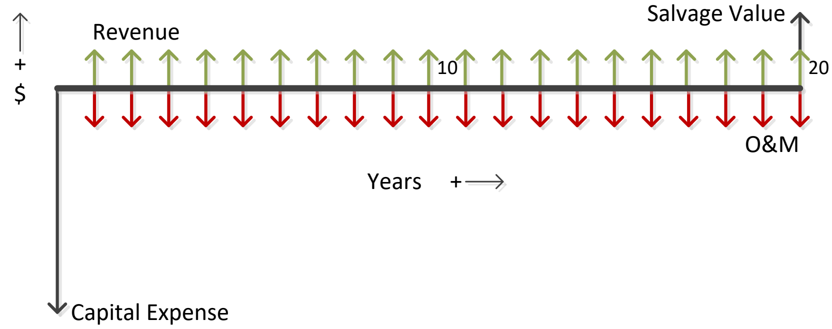

Figure 13. Cash flow diagram for NPV model.

The capital expenses are expenses paid for in today's dollars and include costs of the components, installation costs, and site preparation costs. Since these costs are incurred at year zero of the project, they do not need to be discounted as they are measured in today's dollars.

The major components that have an initial cost in this project are the electrolyzer module and the compression unit. The natural gas grid and the storage facility are already in place, and any costs associated with their construction are sunk costs and cannot be considered for present and future value calculations.

The installation costs include that of the compressor and the electrolyzer module, the latter divided into four parts: container installation, transformer outdoor upgrade, installation supervision, and operator training.

Site preparation costs are also divided into costs associated with the electrolyzer module and the compressor. The preparation costs for the electrolyzer module include expenses to bring water and power to the site and land acquisition for the system, if needed. The preparation cost for the compressor includes a building to house the compressor in.

Operation and maintenance costs for the electrolyzer are an annual expenditure, except the cost of spare parts, which occur every two years. To obtain the present value of the O&M costs, all the O&M costs need to be in their annual form, added together, and multiplied by the factor that determines present worth based on annuity. The O&M costs are electricity, water, spares, annual maintenance kit, reverse osmosis/deionizer (RODI) maintenance kit, cost of an operator to apply maintenance kits, and an annual preventative maintenance performed by a technician. The cost of electricity includes the electrical consumption of both the electrolyzer unit and the compression unit.

$$Present\ Worth\ of\ O\&M = Annual\ O\&M * \left(\frac{P}{A}, \%, N\right)$$

$$\left(\frac{P}{A}, \%, N\right) = \frac{(1+i)^N - 1}{i(1+i)^N}, where\ i = rate\ of\ return\ and\ N = total\ years\ of\ annuity$$

The biennial spares need to be taken to their present value, then transformed into their annual equivalent before adding in with the rest of the O&M costs.

$$Annual\ Equivalent\ of\ Spares = Present\ Worth\ of\ Spares * \left(\frac{A}{P}, \%, N\right)$$

$$\left(\frac{A}{P}, \%, N\right) = \frac{i(1+i)^N}{(1+i)^N - 1}, where\ i = rate\ of\ return\ and\ N = total\ years\ of\ annual\ cost$$

$$Present\ Worth\ of\ Spares = Cost\ of\ Spares * [\left(\frac{P}{F}, \%, 2\right) + \left(\frac{P}{F}, \%, 4\right) + \left(\frac{P}{F}, \%, 6\right) + \left(\frac{P}{F}, \%, 8\right) + \left(\frac{P}{F}, \%, 10\right) + \left(\frac{P}{F}, \%, 12\right) + \left(\frac{P}{F}, \%, 14\right) + \left(\frac{P}{F}, \%, 16\right) + \left(\frac{P}{F}, \%, 18\right)]$$

$$\left(\frac{P}{F}, \%, N\right) = (1+i)^{-N}, where\ i = rate\ of\ return\ and\ N = each\ year\ spares\ are\ bought$$

The revenue is calculated annually, and is dependent on the amount of hydrogen produced, and its selling price. The annual revenue also needs to be multiplied by the same factor as above that transforms the annuity into a present value. We also factor in the carbon offset of the hydrogen produced. This concept and calculation is discussed in section 6.4.1. We get the price of hydrogen by taking its energy content, multiplying it by the ratio of energy units to one US therm, and multiplying that by NW Natural's rate of price per therm of natural gas.

$$Present\ Worth\ of\ Revenue = Revenue * \left(\frac{P}{A}, \%, N\right)$$

$$Revenue = Price\ of\ Hydrogen * Total\ Hydrogen\ Produced + Total\ Hydrogen\ Produced * Carbon\ Offset$$

Salvage value is a single future value that needs to be discounted back to present value for the net present value model.

$$Present\ Worth\ of\ Salvage\ Value = Future\ Salvage\ Value * \left(\frac{P}{F}, \%, N\right)$$

$$\left(\frac{P}{F}, \%, N\right) = (1+i)^{-N}, where\ i = rate\ of\ return\ and\ N = service\ life$$

7.1.1 Explanation of Calculated Values Used

This project will be owned and operated by NW Natural, whose rate of return is controlled by the Oregon Public Utility Commission (OPUC) [98]. NW Natural provided us with this rate, which comes from a capital structure of 50% equity and 50% long-term debt, and it is the discount rate used in the model [11]. The rate consumers pay for natural gas is also controlled by the OPUC, and the rate per therm used in the calculation comes from NW Natural's rate schedule for residential customers [99],[100].

There are a few preparation costs accounted for in the calculation. NW Natural has a well on the chosen Miller Station site and does not need to install a new source of water for the system; the water preparation cost is $0. The preparation of power service is a cost associated with upgrading the current power service to supply the electrolyzer system. This cost is based upon the estimate given for the Deer Island Gate in Rainier, OR and incremented as a cost per kilometer to the nearest transmission lines. The preparation of footprint includes the cost of purchasing a quarter-acre piece of land adjacent to the Miller Station and the construction of a building for a hydrogen-rated compressor. These preparation costs are discussed in detail in section 5.4. Values used in the NPV model are summarized in Table 7.

Table 7. Values used in NPV calculation.

	Value	Source
Fixed Costs		
Electrolyzer	Confidential	[20]
Compressor	Confidential	[20]
Installation of Compressor	Confidential	[20]
Container Install	Confidential	[20]
Transformer Outdoor Upgrade	Confidential	[20]
Installation Supervision	Confidential	[20]
Operator Training	Confidential	[20]
Preparation of Water	$0	[41]
Preparation of Power	$1,080,625	Calculated, [32]
Preparation of Footprint	$3,180	Calculated, [46], [47]
Operation Costs		
Cost of Spares	Confidential	[20]
Electricity Rate	$0.1258/kWh	Calculated, [101][102]
Carbon Offset	$0.38/kg H_2	Calculated, see section 0
Water Rate	$0.001453/L	[103]
Annual Maintenance Kit	Confidential	[20]
RODI Maintenance Kit	Confidential	[20]
Annual Preventative Maintenance	Confidential	[20]
Operator	$7,600	Calculated, [19]
Price per therm	$0.8385	[100]
Parameters		
Consumption Rate of Electrolyzer	0.55 MW	[17]
Consumption Rate of Compressor	1 kW	Calculated, see section 4.4
Water Consumption Rate	372 L/h	[17]
Running Time	304 hours	[6]
Hydrogen Production Rate	225 kg/24h	[17]
Energy Content of Hydrogen	142,081.38 kJ/kg	[104]
Volumetric Energy Density of Hydrogen	12079 kJ/m^3	[104]
Volumetric Energy Density 0.0075% H_2	39057.91 kJ/m^3	Calculated, see section 9.3
Volumetric Energy Density 0.1082% H_2	39030.74 kJ/m^3	Calculated, see section 9.3
Energy Content to therms	105,505 kJ/therm	[83]
Rate of Return	8.1%	[11]

The calculated operation costs are the electricity rate, operator cost, and consumption rate of the compressor. The HEF's Hydrogen Design Contest Rules page provides a base electricity rate to use in our calculations, and a premium of $0.02 was added to ensure renewably-generated electricity from West Oregon Electric Co-op is used to power the system. Proton On-Site asserts the operation and maintenance cost is expected to be 1.5% of the capital cost of the electrolyzer module. Since current operation and maintenance costs exceed that percentage, we assumed it to be 2.5% instead, taking the difference between current costs and 2.5% of the capital cost to be the operator cost. The calculation for the compressor consumption can be found in the Siting section.

There are two calculated revenues: the carbon offset of hydrogen and the value of hydrogen according to natural gas's price per heating value. More detail, including the calculation of the carbon offset, can be found in section 6.4.1.

The unit was assumed to have no salvage value at the end of its service life.

7.2 Results of NPV Calculation

Four cases were studied to determine NPV. Case 1 and case 2 use the curtailment hours of 2017 as the only operating hours while case 3 and case 4 run continuously for six months, from the beginning of February to the end of July. The electricity cost for case 1 and case 2 are assumed to be $0/kWh. In BPA's Oversupply Management Protocol, its procedure to request curtailment, several actions are taken first to avoid the need to displace non-hydro generation. The first of the listed actions includes selling power at zero cost [105]. Case 1 and case 2 take advantage of this free electricity while simultaneously providing grid stability and storing clean, carbon-free energy. Case 3 and case 4 also assume the energy used during 2017's curtailed hours cost $0/kWh, and the rest of the electricity is paid for at $0.1258/kWh. Case 1 and case 3 are calculated with the price of hydrogen set at the price of natural gas for an equivalent amount of energy. If we sold the hydrogen at this price, the price of delivered natural gas would not increase for consumers. The hydrogen is valued at $1.129/kg for case 1 and 3 using the following calculation:

$$Hydrogen\ Value \left[\frac{\$}{kg}\right] = \frac{Energy\ Content\ of\ 1\ kg\ Hydrogen\ {}^{kJ}/_{kg}}{kJ\ to\ Therm\ Conversion\ Factor} * NG\ Price\ per\ Therm$$

Using this value, the NPV stays negative for case 1 and case 3. When hydrogen energy is valued at the same price as natural gas, the rate of return for the project is lower than NW Natural's desired rate. To allow the NPV to reach a value of approximately $0, the price of hydrogen was increased for case 2 and case 4, as seen in Table 8. Keeping the NPV approximately $0 ensures NW Natural does not exceed its allotted rate of return. When the price for hydrogen was increased, NW Natural's rate of return was achieved, but the price per therm of the blended gas goes up as well.

Table 8. NPV calculation results.

Case	*Hours Running [h]*	*Electricity Rate [$/kWh]*	*H_2 Price [$/kg]*	*NPV [$]*
1	304	0	1.129	-3,351,785
2	304	0	121.81	0
3	4,380	0.1258	1.129	-3,086,644
4	4,380	0.1258	8.84	0

7.3 Sensitivity Analysis

Analyzing the economic viability of this project using the curtailment hours of 2017 provides a base case from which we can evaluate how the economics are affected by changing factors. The sensitivity analysis is more relevant in investigating the future economics of the proposed system. Figure 14 shows the NPV's sensitivity to increasing and decreasing inputs by +/- 15%. Each line follows the change in the NPV as the input that represents that line is altered individually. The case used for the sensitivity analysis is case 2, and all values, other than the input being tested for sensitivity, are kept the same in the calculation. The most dramatic changes in NPV occur when the running time and the capital expenses are altered. In the future, if running time can be increased and capital expenses decreased, an NPV of $0 can be achieved with hydrogen selling at a lower price.

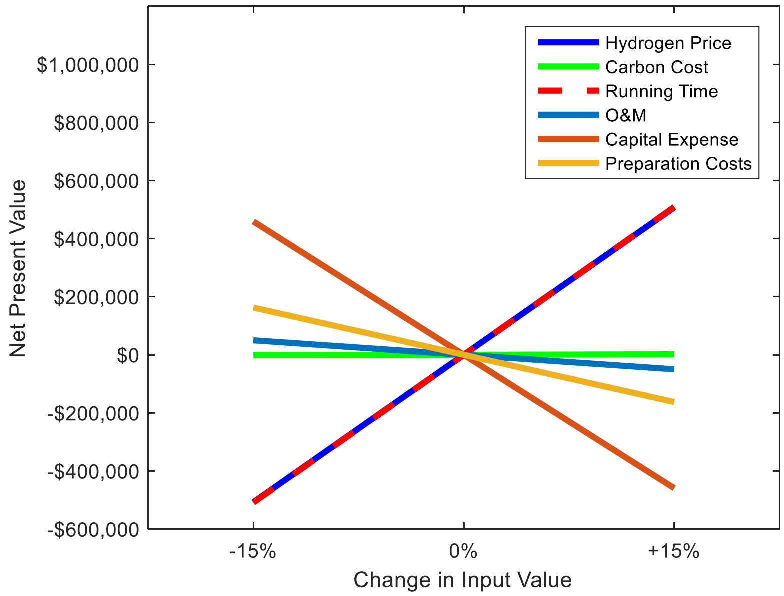

Figure 14. Sensitivity analysis of the Net Present Value.

7.4 Payback Period

The simple payback period for this project is the capital expense divided by the expected revenue. The payback period for case 2 and case 4 are approximately the same, as seen in Table 9. The capital expenses are the same, and although the O&M and the revenue are different, the price of hydrogen is adjusted to keep the rate of return the same between the two cases.

Table 9. Payback period for case 2 and case 4.

Case	*Payback Period*
2	9.75 years
4	9.75 years

7.5 Premium Price per Therm

Many energy providers fund their renewable energy projects by offering a premium add-on for customers interested in supporting them. NW Natural currently offers a carbon off-setting program, called “Smart Energy”, in which customers may enroll. This program funds projects that prevent greenhouse gas emissions, and NW Natural does not profit from any contribution made toward them. Two premium options are available: the Average Option charges residential customers $5.50/month, and the Climate Neutral Option charges just over 10 cents for every therm of gas used [106]. Since the value of hydrogen is one of the few factors of the NPV model that we can control, we can adjust the hydrogen price per kilogram to get the NPV to equal $0. The price of hydrogen will apply toward the energy content it contributes to a therm of hydrogen-enriched natural gas. The rest of the therm that is supplied by natural gas will cost customers the normally scheduled rate. Once this new price per therm of blended natural gas is determined, the current rate for natural gas will be subtracted to determine the premium add-on customers may subscribe to. To calculate the premium price per therm, we assume the hydrogen and natural gas are at 20 °C and 101.325 kPa.

Using the volumetric energy density of the hydrogen-enriched natural gas (at a specific percentage), we can determine how many cubic meters of gas is needed to supply a therm of energy.

$$\frac{Energy\ Content\ of\ a\ Therm}{Volumetric\ Energy\ Density\ of\ Blended\ Gas} = Volume\ of\ Blended\ Gas$$

The volume of hydrogen is obtained by multiplying the volume of the blended gas by the percent by volume admixture. The mass of hydrogen is found from multiplying volume and density. This mass and the price of hydrogen needed to achieve an NPV of $0 will determine the cost of the hydrogen portion of a therm.

$$Cost\ of\ Hydrogen\ Portion\ of\ a\ Therm = Mass\ of\ Hydrogen * Price\ of\ Hydrogen$$

Using the energy content of a therm and the amount of energy hydrogen contributes toward a therm, we can find the portion of the energy that natural gas contributes.

$$Energy\ from\ Hydrogen = Mass\ of\ Hydrogen * Energy\ Content\ of\ Hydrogen$$

$$\frac{Energy\ Content\ of\ a\ Therm - Energy\ from\ Hydrogen}{Energy\ Content\ of\ a\ Therm} = Natural\ Gas\ Portion$$

Pricing this portion at the normally scheduled rate and adding it to the cost of the hydrogen portion of a therm will get us the new price per therm with the premium included.

$$\begin{aligned} &Price\ of\ Blended\ Therm \\ &\qquad = Natural\ Gas\ Portion * Price\ per\ Therm \\ &\qquad + Cost\ of\ Hydrogen\ Portion\ of\ a\ Therm \end{aligned}$$

The premium add-on can be found by subtracting the base rate from the new price per therm.
An NPV of $0 is achievable with case 2 and case 4, and their resulting premium price is found in Table 10.

Table 10. Premium add-on calculation results.

Case	*Percent Hydrogen*	*Price of Hydrogen Needed to Achieve NPV = $0*	*Premium*
2	0.0075%	~$121.81/kg	$0.20/therm
4	0.1082%	~$8.84/kg	$0.18/therm

7.6 PROJECTION

The commercially-available electrolyzer is a fairly new technology and, like other technologies that lack maturity and availability, is expensive and may seem uneconomical. The real value may not be realized for some years when multiple factors converge in the technology's favor. One of these factors is the capital cost associated with a power-to-gas system. If the price for electrolyzer modules follows the same trend as that for solar panels, we may see a price decrease of approximately 4.4% each year [107]. Another factor that may change in the favor of power-to-gas via electrolyzer is an increasing carbon credit. If NW Natural can save money by decarbonizing the gas they provide, the price of hydrogen would decrease in response, and a premium may not be needed. Lastly, utilization of power-to-gas technology could increase in the future. With Oregon's movement toward a 50% renewable portfolio standard by 2040, more solar and wind power plants are expected to connect to the electrical grid. An increase in variable energy generation could mean more unpredictable activity and oversupply for the power balancing authority. The quick response time of an electrolyzer could prove useful in consuming extra electricity, whose generation would otherwise be curtailed. It may even serve as the primary grid-balancing technology and be kept running throughout the year. To illustrate the effect that these combined factors have on a hydrogen power-to-gas system, we created a projected NPV model for the year 2027, and the results are shown on Table 11.

The projected NPV model assumes NW Natural's rate of return is the same as it is today, the cost of electricity is $0/kWh, and a cost for power-to-gas hydrogen can be found by making the NPV = $0. The capital equipment costs are discounted 4.4% each year until 2027 for the calculation, and the carbon credit is increased to $0.76/kg of hydrogen. To model the increase in utilization, we assumed the electrolyzer is running at full power throughout the year. Even with the changing factors, the price of hydrogen will still be more expensive than natural gas in 2027. However, it is a lot less expensive than the price hydrogen would have to sell for today. This decreasing trend indicates that the price for hydrogen may eventually be the same, or less than, the price we pay for natural gas.

Table 11. 2027 projected NPV of system.

Hydrogen Admixture	*Running Hours*	*Price of Hydrogen*	*Premium*
0.2164%	8760	~$2.83/kg	$0.08/therm

7.7 Discussion of Economic Results

In case 2, where the only operational hours are those from curtailment, the price of the energy from hydrogen is 100x the price of the same amount of energy from natural gas. Although this project is economically infeasible, it can be made possible by offering a premium price per therm. New technologies in their early stages of maturity are expensive, but outside of the economics, this project has value in the positive externalities that result from its implementation. This project would prove out the technology and offer insight to using it on a larger scale in the future, inform policy-makers on emerging technologies that may influence their decision making, regarding a renewable future, and educate the public on power-to-gas technology and how energy providers like NW Natural are making progress toward the renewable future they want to see. Consumers are willing to pay a premium price for energy to support renewable projects already, and a project like this would follow a similar funding structure to programs like NW Natural's "Smart Energy". Realizing the energy climate is changing, we created a sensitivity analysis to see how this project would look in the future. We expect the technology to decrease in price and the utilization to increase, and the model with these changes shows the price of hydrogen decreases, approaching the price we are currently paying for natural gas.

8 Safety Analysis & Codes and Standards

As with any good design, safety is a top priority. Codes and standards are meant to limit risks through a set of rules and guidelines. This system design meets or exceeds all relevant safety codes and standards as set by various regulating agencies.

NW Natural is an interstate natural gas distributor providing service to Oregon and Washington. This classification puts their operations under federal jurisdiction, which is regulated by the Federal Energy Regulatory Commission (FERC), in collaboration with the U.S. Department of Transportation (DOT) [108]. This is monitored and enforced by DOT's Pipeline and Hazardous Material Safety Administration (PHMSA) with consideration to the Oregon Public Utility Commission (OPUC) [109].

Many of the safety codes come directly from the National Fire Protection Association (NFPA), which seeks to minimize fire risks as they pertain to equipment, distribution pipelines, and storage of hydrogen.

Most of these codes are already being met by the existing equipment and safety standards in place for the natural gas distribution currently in operation. This report focuses on where these codes differ.

To meet these codes, some organizations have devised standards for the transportation, storage, and use of hydrogen and natural gas. Namely, the American Society of Mechanical Engineers (ASME) and the American Petroleum Institute (API) [110],[111],[112]. Standards that specifically address a hydrogen-natural gas blend do not currently exist, an issue addressed in section 10.

8.1 EQUIPMENT

The system design includes an electrolyzer, a compressor, and piping that is subject to NFPA codes as gaseous hydrogen is a flammable substance [113]. The NFPA currently has codes that cover materials, maintenance, and storage of hydrogen related equipment [114].

The electrolyzer involves the handling of hydrogen, ventilation of oxygen, and piping to transport the produced hydrogen to an injection site. According to Proton On-Site, the electrolyzer has been built to meet, "all international safety standards", which suggests NFPA codes have been met by the manufacturer in terms of materials used and built-in safety features [115].

We opted for an outdoor container to house the electrolyzer, which will have built-in ventilation, remote monitoring, and protection from freezing temperatures and other potentially damaging elemental conditions. The purchase of additional land is recommended, to allow for placement away from potential ignition sources, combustible materials, air conditioners, and compressors. This is to meet NFPA 2 codes [114].

The electrolyzer will be connected to the natural gas pipeline via a steel pipe. To prevent embrittlement-related issues, it will be built to ASME B31.12 standards for "Hydrogen Piping and Pipelines" by using a low tensile strength steel rated for hydrogen transport. This will prevent hydrogen-related fatigue cracking.

Oxygen created through the electrolysis process will be removed from the system via ventilation equipment on the top of the electrolyzer compartment. Oxygen itself is not flammable, however it may act as an accelerant, causing fires to burn hotter and spread faster. Concentrations above 23.5% are considered oxygen rich, with an increased risk of fire ignition and are restricted by NFPA code 2.13 [114][116]. Oxygen monitoring systems will be installed, though this risk is minimized by an outdoor ventilation system.

Regular maintenance is included in Proton On-Site's care package. This will include preventative care and replacement of parts should issues arise [115]. Should an alarm be activated, the issue will be addressed immediately by certified technicians. This will ensure code compliance and satisfy safety concerns as it pertains to the hydrogen generation equipment.

8.2 PIPELINE INTEGRITY

Blending hydrogen into the existing natural gas pipeline brings up the issue of hydrogen embrittlement, a process in which hydrogen permeates metal, causing a loss of ductility and making the material more brittle and prone to fracture [117],[118]. Hydrogen embrittlement is theorized to be caused by smaller hydrogen atoms penetrating microcracks in materials, causing deformation on a molecular scale [119]. This can lead to an increase in fatigue related stress cracking of the pipes.

Hydrogen enriched natural gas, at low blends, is treated similarly to compressed natural gas (CNG) in terms of fire safety regulations, with a few exceptions. Pipeline material restrictions, such as the disallowance of cast iron piping, limit what materials are safe for hydrogen transport. According to NFPA code 2 7.1.15.1, all hydrogen piping must meet the standards set by ASME B31.12 as well as relevant International Fuel Gas Codes (IFGC) [114]. The fuel gas codes require all piping materials to be 300 series steel or other approved materials [120].

NW Natural has an updated pipeline infrastructure using only, "polyethylene pipes and cathodically protected and coated steel pipes" [121]. Polyethylene has a tendency to absorb hydrogen without the same embrittlement problems as steel and so for our purposes, only the effect on steel will be considered [76],[122]. NW Natural's steel is rated to meet all minimum federal safety standards and does not exceed pipe grade X52 [123]. This is a low tensile strength steel which is less susceptible to embrittlement-related cracking and fatigue [124],[125],[126],[127].

For natural gas fueled vehicles, a study was done on the effect of hydrogen compressed natural gas (HCNG) on steel fuel tanks. They found that for steels with a tensile strength below 950 MPa, all hydrogen blends were considered compatible [128]. According to API standards for seamless line pipe, the maximum tensile strength of X52 grade steel will be 760 MPa [129]. This suggests the effects of embrittlement may be minimal, but a full review and additional testing is highly recommended.

The DOT Code of Federal Regulations §192.475 allows for a potentially corrosive gas to be transported if its effects are thoroughly investigated and steps are taken to minimize risks [130]. This is in contrast with the OPUC which completely disallows the addition of impurities that may cause corrosion in natural gas piping [131]. Whether the addition of hydrogen causes excessive corrosion, due to embrittlement, will need to be evaluated to ensure compliance.

Studies have been done on the feasibility of hydrogen transportation through the existing natural gas infrastructure. This includes five projects operating in Europe which have successfully integrated hydrogen into the natural gas grid [12]. Studies have also shown varying conclusions about the increased corrosion risk associated with hydrogen embrittlement [132],[126]. The grade of steel piping used by NW Natural is expected to minimize hydrogen embrittlement related risks.

8.3 EXPLOSION RISK

The risk of explosion can be broken into three categories: the likelihood of an ignition event, the severity of the explosion, and the frequency of explosion. The likelihood of an explosion refers to how likely the gas is to ignite, should a leak or rupture occur. The severity of the explosion looks at the intensity of the blast in terms of temperature, blast radius, and the potential for damage. The frequency of the explosion refers to whether the addition of hydrogen will increase the likelihood of an explosion.

The likelihood of an ignition event is dependent upon the auto-ignition temperature of the involved gases. Hydrogen has an ignition temperature of 500 ˚C while methane (natural gas) has an ignition temperature of 580 ˚C [134]. This may increase the probability of ignition should a leak in the pipeline occur. However, studies estimate that at concentrations of hydrogen below 10%, the increase in ignition probability is only marginally greater than with natural gas alone [77],[135],[136],[137]. This suggests the increase in the likelihood of an ignition event is negligible for this project.

Explosion severity is dependent multiple factors and will vary based on the surrounding conditions. Hydrogen has a greater flame speed and will burn more intensely than methane, though it will not burn for as long [138],[139]. Hydrogen is also lighter and will dissipate quicker than methane in the open air. In the event of an explosion we would expect a more severe explosion in terms of pressure and heat release if in a confined space, though likely no change would be apparent should the event occur in a ventilated area.

Most explosions occur due to rupture, usually caused by accidental puncture of the pipeline. There is nothing to suggest that the addition of hydrogen to the gas blend will increase the likelihood of a rupture-induced explosion. However, hydrogen amplifies cracking by embrittlement in compromised pipes, possibly leading to an increase in leaks. If these leaks are left untreated, it may increase the likelihood of an explosion, though preventative measures will minimize this risk.

At low concentrations, we expect the effects of hydrogen to be minimal to the risk of explosion for all three categories. NW Natural already has plans in place to prevent accidental ruptures, including a free service to have utility lines marked to avoid potential accidents [140]. This should be sufficient and a large change in explosion risks is not expected.

8.4 UNDERGROUND STORAGE

The underground storage of natural gas is a federally-regulated process monitored by the DOT [130]. NW Natural has been operating the proposed storage site in Mist, OR since 1981 and have received site certification from the Energy Facility Siting Council, proving compliance with all relevant codes and regulations [140]. An additional amendment may be required if the change to gas composition is considered substantial as well as to allow the electrolyzer to be placed at Miller Station.

An assessment of the cap rock at the mine to ensure an adequate seal against leakage would be beneficial. Hydrogen loss due to leakage either through the cap rock, or at the injection site is possible, though generally, when a site is determined to be adequate for natural gas storage it is assumed that leakage will be minimal [12]. Chemical reactions may also lead to hydrogen loss, particularly involving sulfate-reducing bacteria.

8.5 HYDROGEN SULFIDE

Due to the presence of sulfate-reducing bacteria in hydrocarbon reservoirs, the injection of hydrogen into natural gas mines may increase levels of hydrogen sulfide [62]. The toxicity of hydrogen sulfide, as covered in section 0, makes it a particularly dangerous health and safety concern. It can also cause damage to the pipeline with its corrosivity and preventative care is necessary.

Hydrogen sulfide is regulated on both the federal and state level, with OPUC code 860-023-0025 having the most conservative restriction of, “no more than 0.25 of one grain of hydrogen sulfide in each 100 cubic feet” (4 ppm) [131]. It is vital that any excess hydrogen sulfide is removed to ensure pipeline integrity.

Hydrogen sulfide is a naturally-occurring compound in gas mines and methods for its removal are available. This is referred to as “gas sweetening” and is most commonly done with an amine treatment where the sulfur is absorbed, often for further treatment and resale [141],[142]. NW Natural does not currently have this equipment in place at the Miller Site.

Beyond pipeline concerns, hydrogen sulfide may cause complications when it comes to underground storage. It can settle in porous materials, effectively cutting off sections of the mine and possibly leading to ground destabilization [143]. There are too many variables to quantify what percentage of hydrogen and operating conditions will minimize this risk [77]. A full soil analysis is necessary to determine whether sulfur, a key element in the hydrogen sulfide production process, is present in the mine.

For the single system proposed here, the low hydrogen blend will likely be insufficient to cause any major concern [12]. In terms of scalability, preventative measures can be made to limit the amount of hydrogen sulfide produced. Some studies show the effect can be minimized at low pressures and temperatures [144],[124]. One study suggests an expected increase of only 0.5 ppm if temperatures are kept below 130 ˚C [145]. Further research and testing is required if the project is to be scaled to higher hydrogen concentrations.

8.6 LEAK DETECTION

DOT code §192.706 requires that a leakage survey be performed annually [130]. Some equipment can be recalibrated to detect hydrogen, and some will be unaffected by the hydrogen blend. Flame ionization detection (FID) devices are typically used for pipeline inspections and cannot detect hydrogen. It is generally considered acceptable for hydrogen concentrations below 5% as the majority of the leaked gas will be hydrocarbons that are detectable by FIDs [77]. For this system design, this is not expected to be an issue, but for higher concentrations, semiconductor technologies are better suited for hydrogen detection [77].

8.7 EFFECT ON OTHER INDUSTRIES

8.7.1 Natural Gas Vehicles

Natural gas vehicles are gaining in popularity with an estimated 150,000 operating in the US and 15.2 million worldwide [146]. Hydrogen blended natural gas can cause issues with fuels tanks which may be made of materials unable to withstand hydrogen embrittlement related cracking. Some studies indicate this concern may be limited and depends on the class of fuel tank being examined [128].

NFPA 52 "Vehicular Natural Gas Fuel Systems Code" restricts hydrogen content to 2% by volume for use by CNG vehicles [114]. This could require additional equipment to eliminate the excess, or require additional natural gas to be blended in, for which NW Natural may be liable. However, it may be safe to implement higher hydrogen concentrations were these codes to change.

Hydrogen-blended compressed natural gas (HCNG) fuel is being investigated as a potential solution to some of the pitfalls of natural gas vehicles. The improved laminar flame speed of hydrogen provides an improvement to combustion properties, increased engine efficiency, and decreased CO_2 emissions [147],[148],[149],[150]. While high concentrations of hydrogen require engine modification, lower concentrations "from 0% to 20% by volume may be run without engine retuning" [151].

For this project to be implemented with higher hydrogen concentrations, some changes to the existing natural gas vehicles will need to be made. The current certification of fuel tanks will need to be re-examined to consider the effect of higher hydrogen concentrations on embrittlement. Otherwise, fueling stations will need to be supplied with unblended natural gas.

8.7.2 Gas Turbine Power Plants

Natural gas power plants use turbines with specific ratings for allowable hydrogen content; as low as 0.5% hydrogen by volume [77]. Combustion instabilities and higher combustion temperatures make hydrogen-rich natural gas blends unsuitable for turbine technologies not specifically designed for hydrogen blends [152],[153],[134]. For our design, the hydrogen concentration is too low to cause issues, however it does affect the scalability of the project.

It may be possible to modify existing turbines to be compatible with higher hydrogen blends. The River Road Generating plant in Vancouver, Washington uses a GE 7FA combustion turbine not rated to support hydrogen but modification equipment does exist for this model to allow for higher hydrogen blends, up to 5% by volume [154],[77],[155].

It is highly recommended that a full review of the current equipment being used in natural gas power plants in NW Natural's service area be conducted to ensure they can support a higher hydrogen concentration should the project expand.

8.8 FAILURE MODE

A failure mode effects analysis (FMEA) is a, "step-by-step approach for identifying all possible failures in a design" [156]. It is used to analyze the ways in which a design might fail and the consequence to that failure. For our purposes, a focus was made on the hydrogen-producing equipment and how the inclusion of hydrogen to the natural gas blend may create additional problems for the existing natural gas distribution network, as shown in Table 12.

Table 12. Failure mode effects analysis of the system.

Process	Failure	Effect	L	P	Cause	F	Control	D	Action
Electrolysis	Oxygen leak	Elevated Oxygen levels	1	1	Equipment failure	2	Alarm, ventilation	10	Automatic shut-off of electrolyzer. Evacuate immediate area until dissipated. Inspection and repair
		Fire	8	9	Equipment failure and presence of ignition source	1	Alarm, ventilation, fire suppress- ion	10	Immediate evacuation, notify fire department, emergency shutdown of all equipment on-site
	Hydrogen leak	Hydrogen detected	7	1	Equipment failure, crack or rupture	1	Alarm, outside placement	10	Automatic shut-off of equipment, emergency shut-off of adjacent equipment, evacuate area, inspection and repair
		Explosion	10	10	Presence of ignition source	1	Separate container with on-board safety equipment	10	Immediate evacuation and emergency shutdown of all station equipment. Emergency shut down of pipeline.
Pipeline	Cracking pipe	Leaking	4	1	Embrittlement	4	Quality steel, leak detection equipment	8	Shut down section of pipeline, remove and replace cracking pipe, inspect adjacent pipes. Same policy as for natural gas, may increase frequency
	Rupture	Outdoor/ Indoor / Leak/ Explosion	9	9	Embrittlement, corrosion, human error, Puncture	1	Leak detection equipment, routine inspection, public education	8	Same Policy as for natural gas
Mine Storage	Hydrogen Sulfide	Corrosion, toxicity	6	7	Microbes	2		9	Monitoring equipment, tested daily, flush affected pipeline with steam

L = Severity of effect on life whether by injury or loss of life
P = Severity of effect on property
F = Likelihood of failure
D = Likelihood of prevention methods to avert failure

9 POLICY & REGULATORY ANALYSIS

Natural gas is primarily used by residential customers in furnaces for heating purposes. This requires company policy to ensure end-user safety and quality is maintained and to ensure that customers receive a consistent quality of natural gas that is compatible with their appliances.

Pricing, end-use appliance compatibility, and gas quality are regulated in Oregon by the OPUC. Pricing structure regulation has historical significance meant to protect consumers and maintain the integrity of natural gas supplies. The compatibility of appliances can be determined through Wobbe Index calculations while gas quality is a company-set energy content range. These three factors will determine the amount of hydrogen that can be blended in to the existing natural gas infrastructure.

9.1 REGULATION

In Oregon, the OPUC is the main regulating agency responsible for setting distribution standards between natural gas suppliers and end-users. Gas companies are required to regularly report on the heating value and properties of the natural gas being delivered to customers.

The natural gas policy act of 1978 regulates the sale and distribution of natural gas [157]. No changes may be made to the pricing or gas quality without commission approval and public notification. Meant to protect consumers from monopolies and eventually leading to gas shortages, the natural gas act sets price ceilings and regulates how natural gas prices are determined [158].

The natural gas composition is required by OPUC 860-023-0045, Service Standards, to be maintained so that, “the established heating value, the chemical composition, and specific gravity shall be such as to attain satisfactory combustion in the customer’s appliances”, as well as that, “[w]hen supplemental or substitute gas is distributed by a utility, the gas quality shall be such that the usage performance will be satisfactory, regardless of the heating value of the gas” [159]. This suggests that there are two components to examine when determining whether a new gas blend will meet current policies: one that looks at compatibility of the appliances and one that looks at performance according to the amount of heat generated.

9.2 WOBBE INDEX

The Wobbe Index is used to determine whether an alternative fuel is interchangeable with the current fuel-gas blend for end-user appliances [160]. A gas composition with a similar Wobbe Index number ($\pm$ 4%) is considered to be a compatible replacement [161].
For our gas composition, we used the percentage of each compound found in NW Naturals mixture and applied the following equation:

$$Wobbe\ Index = HHV * \sqrt{Specific\ Gravity}$$

The calculation for each compound in NW Natural’s mixture is shown in Table 13. HHV’s are at standard conditions, 20 ˚C and 1 atm of pressure [163].

Table 13. Wobbe Index calculation of NW Natural's gas mixture.

Compound:	*HHV (kJ/m³)*	*Specific Gravity*	*Wobbe Index (kJ/m³)*	*% of mixture by volume*	*Wobbe Index for % (kJ/m³)*
Methane	37682.66	0.5537	50641.232	0.9359	47395.130
Ethane	66432	1.0378	65210.945	0.0375	2445.410
Propane	95375.35	1.5219	77311.319	0.0092	711.264
Isobutane	124074.24	2.01	87515.221	0.0011	96.267
Butane	124251.2	2.0061	87725.187	0.0015	131.588
Isopentane	145224.3	2.48	92217.523	0.0002	18.444
Pentane	145409.68	2.487	92205.203	0.0002	18.441
Other Hexanes	173046.42	2.973	100361.043	0.0001	10.036
Total					50826.579

For a Wobbe Index of 50,827 kJ/m³ a plus or minus 4% interchangeability range yields compatibility from 48,794 kJ/m³ to 52,860 kJ/m³. Hydrogen, by the same calculation, has a Wobbe Index of 45,036 kJ/m³. We used the following formula to determine the percentage of hydrogen blended into NW Natural's current natural gas blend that would remain within this range.

$$New\ Wobbe\ Index = (\%\ H_2\ added) * (H_2\ Wobbe\ \#) + \left(1 - (\%\ H_2\ added)\right) * (NG\ Wobbe\ \#)$$

By this method, a 35% hydrogen blend, having a Wobbe Index of 48,800 kJ/m³, is the highest concentration allowed. This hydrogen concentration is far greater than the concentration levels in this project, and compatibility issues are not expected.

It should be noted that the Wobbe Index is best examined using a historical average, rather than a snapshot of the current gas composition. This number is a general guideline to get an idea of what percentage of hydrogen may be allowed now. The number will need to be reevaluated as the gas composition fluctuates.

9.3 GAS QUALITY STANDARDS

The energy content of a gas blend determines how much of the gas must combust to produce a desired effect. In this case, how much hydrogen can we blend into natural gas without noticeably changing the heating quality.

NW Natural policy states that "[t]he quality of Natural Gas or Biomethane procured and delivered by the Company or by Customers under Schedule T shall conform to standard purity requirements of the Commission; shall have an energy content between 985 and 1115 Btu per standard cubic foot; and shall permit satisfactory operation of appliances" [163]. The purity requirements were examined in detail in section 8.5 of this report. The satisfactory operation of appliances was covered with the Wobbe Index interchangeability.

Table 14. Energy content of natural gas.

Compound	*Energy Content (kJ/m^3)*	*% of mixture by volume*	*Energy Content for % (kJ/m^3)*
Methane	37706.01	0.9359	35289.05
Ethane	66432.62	0.0375	2491.22
Propane	95271.01	0.0092	876.49
Isobutane	124966.35	0.0011	137.46
Butane	125525.23	0.0015	188.29
Isopentane	149072.86	0.0002	29.81
Pentane	149370.93	0.0002	29.87
Other Hexanes	177199.60	0.0001	17.72
Total			39059.93

The energy content is a standard policy set by the company and is used to calculate how much to change the customer pricing structure based on the quality of the delivered product. It is possible to change this value, but it is easier to stay within this range as any changes would require commission approval and a regulation process.

The energy content of NW Natural's gas composition is 39,060 kJ/m^3. This was calculated by multiplying the energy of each compound with the percentage of that compound found in NW Natural's mixture, as shown in Table 14.

Hydrogen has a much smaller energy content of 12,079 kJ/m^3 [164]. To stay within the current company policy for energy content, we applied the following formula to find the energy content for hydrogen blended natural gas:

$$HBNG\ energy\ content = (\%H_2)(H_2 energy\ content) + (1 - \%H_2)(NG\ energy\ content)$$

At 8.7% hydrogen concentration, the energy content of the natural gas and hydrogen blend will be 36,713 kJ/m^3. This will require no altering of the current billing policy while providing end-users with the same quality of gas to which they are accustomed.

We do not expect to reach this concentration with the current project. In terms of scalability, the energy content is set by NW Natural and may be changed as necessary. At this point, other factors limit the amount of hydrogen that can be blended into the current natural gas admixture, such as the effect on natural gas vehicles and power plants. What these calculations prove is that a higher hydrogen concentration in the blend is possible should other limiting factors be eliminated or adjusted.

10 1-PAGER FOR POLICY MAKERS

Project Overview

Our design seeks to lower CO_2 emissions associated with natural gas, while providing a storage solution for excess energy from renewable sources during peak generation. This provides a viable mean for increasing our renewable energy portfolio while providing a positive impact on climate change.

The design works by utilizing excess energy to generate hydrogen via electrolysis. The produced hydrogen will be injected directly into the natural gas infrastructure where it will be stored in depleted hydrocarbon mines for seasonal use.

Background

- Electrolyzers use electricity to separate water molecules into hydrogen and oxygen gas. The oxygen is released into the air, leaving hydrogen which is a clean energy carrier that produces nearly zero harmful emissions when burned.
- Oregon is working to reduce harmful CO_2 emissions to 10% below 1990 levels by 2020 and 75% below 1990 levels by 2050. Oregon is already behind on meeting these goals and a need for alternative CO_2 eliminating pathways is needed.
- During the spring of 2017, 139,000 MWh of renewable energy was curtailed. That is clean, renewable energy wasted due to load restrictions of the power grid. This amount does not include the energy sold to other states and is expected to continue increasing.
- Oregon plans to increase the amount of energy produced from renewable sources to 50% by 2040. This will further increase the amount of clean energy being curtailed in months where hydro-power and solar-power overperform.

Research Findings

Our research finds that a hydrogen-enriched natural gas blend is both possible and beneficial, reducing CO_2 emissions by 9.29 metric tons for every metric ton of hydrogen blended into natural gas. In 2017, the pilot-sized system could have used 0.12% of Oregon's curtailed energy to produce 2,850 kg of hydrogen. This would have displaced 39.37 metric tons of CO_2.

Using the Wobbe Index, we found a concentration of up to 35% hydrogen would have no effect on current natural gas appliances. Hydrogen concentrations of up to 8.7% will remain within energy content limits set by the Oregon Public Utility Commission.

The biggest inhibiting factors to hydrogen-blended natural gas are:

- Lack of incentives for the reduction of CO_2, a known contributor to climate change.
- Natural gas fueled vehicles are restricted to 2% hydrogen by volume due to fuel tank classifications.
- Natural gas power plants may be restricted to as little as 0.5% hydrogen by volume.
- Hydrogen permeates materials causing deformation and fatigue cracking, otherwise known as hydrogen embrittlement.

Policy Recommendations

- Incentives to improve the economic viability of green expenditures, such as carbon cap-and-trade programs.
- A re-evaluation of current ratings for natural gas vehicles and power plants to determine if higher hydrogen concentrations may be allowed.
- A standard to specifically address hydrogen-blended natural gas to ensure pipeline integrity and limit hydrogen embrittlement related issues.
- A recognition of power-to-gas as a viable energy storage resource in policymaking and renewable energy policy development.

11 CONCLUSION

Even with low renewable energy penetration in Oregon, there is already an issue with the curtailment of renewably-generated electricity. To meet the increasing Renewable Portfolio Standard, growth in the number of renewable power plants is expected in the state. Without large-scale long-term energy storage solutions, the amount of curtailment could worsen as the number of renewable power plants increases.

A storage solution for Oregon has been presented: use power-to-gas technology to produce hydrogen gas for seasonal storage. The proposed system uses an electrolyzer to take advantage of excess renewable energy and produce hydrogen gas, which can then be blended with natural gas using the existing natural gas infrastructure owned by NW Natural. The spring months of curtailment coincide with the months that NW Natural increases its inventory in its Mist Site, an underground natural gas storage facility, and the blended gas will flow into the reservoirs for seasonal storage. In the winter, when heating loads are higher, the gas will be withdrawn and distributed to customers per NW Natural's normal operations.

Out of four possible sites, Miller Station in Clatskanie, OR is the most suitable location for the project, based on siting criteria established from communications with NW Natural and Proton On-Site. There are no significant negative environmental impacts of the system, and carbon dioxide emission is reduced by using the hydrogen produced as a fuel in place of fossil natural gas.

Although the project is currently economically infeasible, it can be made possible by offering a premium price to consumers who wish to support renewable projects. The real value of the project is in the positive externalities that arise from its implementation: proving out technology that could help usher Oregon into the renewable future it envisions, educating policy makers on new technology that needs to be considered in decision-making to comply with renewable energy standards, and educating the public on power-to-gas technology and how renewable energy fits into their lives.

Codes and safety standards for the design are met, and the system does not increase safety risks associated with the natural gas system it will join. There are currently no policies or standards that specifically address hydrogen-blended natural gas. However, hydrogen admixture up to certain percentages can still comply with the Wobbe Index and energy content limits for natural gas set by the Oregon Public Utility Commission.

Implementation of the proposed system is recommended to take advantage of the renewable energy curtailment Oregon currently faces, and to explore the scalability of the system to mitigate the increased amount of curtailment likely to be seen in the future.

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