FINAL

TRANSITION TO HYDROGEN FUELED COMBUSTION TURBINES FEASIBILITY STUDY

BLACK & VEATCH PROJECT NO. 193946

PREPARED FOR

PASSAIC VALLEY SEWERAGE COMMISSION

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BLACK & VEATCH

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1.0 Project Overview

Passaic Valley Sewerage Commission (PVSC) is interested in transitioning to a renewable fuel for one of four scenarios for its backup combustion turbine generators (CTGs) at the Standby Power Generation Facility (SPGF) in Newark, New Jersey. Scenario 1 assumes the SPGF would operate from on-site produced and stored green hydrogen for two weeks of two turbine operation firing on 100% hydrogen. Scenario 2 assumes the SPGF would operate from on-site produced and stored green hydrogen for three turbines firing on 100% hydrogen for an 8-hour monthly maintenance cycle. Scenario 3 would utilize delivered liquid hydrogen to cofiring 100% hydrogen in three turbines during the 8-hour monthly maintenance cycle. Scenario 3 is the only scenario where hydrogen is not produced on-site and is delivered from a local green hydrogen producer. Finally, scenario 4 assumes SPGF would operate from on-site produced and stored green hydrogen for three turbines firing on 5% hydrogen for an 8-hour monthly maintenance cycle. In Scenarios 1, 2, and 4, the hydrogen production facility would be located on the available site adjacent to the SPGF site.

PVSC engaged Black & Veatch to investigate a preliminary conceptual engineering design for a renewable hydrogen production and hydrogen cofiring at the backup power generation facility. The deliverables in this report include a conceptual engineering package for the scenarios consisting of: design basis document (Appendix A), conceptual block flow diagram (Appendix B), Class 5 Capital Cost estimate and basis (Section 4.0), O&M cost estimate (Section 5.0), process description (Section 3.0), plant layout drawings (Appendix C), electrical one line diagrams (Appendix D), level 1 EPC schedules (Appendix E), and economic modeling (Section 6.0).

2.0 Technology Overview

2.1 Photovoltaic

Photovoltaic (PV) cells take advantage of the photovoltaic effect, which generates an electric potential when exposed to sunlight. Typically, the cells are made from silicon or some thin film. The electric potential creates a DC current that can be used in applications such as electrolysis. If an AC current is required, an inverter is used to transform the DC current into AC current. Installed PV cells can track the sun, leading to an increased power production at an increased cost.

2.2 Electrolysis

Electrolysis is the process of splitting water into hydrogen and oxygen using electricity in an electrochemical cell. Electrolyzers come in a variety of capacities and chemistries, but the fundamental concept remains the same. Electrolyzers, like fuel cells, have electrodes (anodes and cathodes) separated by an electrolyte. The combination of electrodes and electrolyte vary by the type of chemical reactions taking place. Unlike steam methane reforming for hydrogen production, electrolyzers are considered “green” sources of hydrogen when the electricity consumed is provided by a renewable energy resource. Instead of using carbon as an energy carrier, electrolysis-derived hydrogen uses the splitting and combining of water.

Electrolyzer stacks are typically packaged together in skids or modules to meet a certain rating. Electrolyzers offer more operational flexibility for on-site hydrogen generation compared to carbon sourced steam methane reforming because of their shorter start-up and shut-down times. Additionally, electrolyzer units can typically turn down to 10%. These features allow electrolyzer units to better track with a variable hydrogen demand or to operate during non-peak hours to run on lower cost electricity, although the cost competitiveness of the technology is highly dependent on utility pricing.

The electrolyzer will emit an oxygen byproduct that is vented to a safe location. No additional air or solid effluents during normal operation are expected from the hydrogen production system.

2.2.1 Proton Exchange Membrane

Also known as Polymer Electrolyte Membrane electrolyzers, PEM electrolyzers exchange a proton in the electrolyte between the electrodes. In a PEM electrolyzer, water is split into oxygen and hydrogen, with the protons (H^+) traveling from the anode to the cathode and exiting out the cathode side of the stack. Oxygen, in turn, exits out of the anode side of the stack. Catalysts help lower the activation energy required for the splitting of water. Recent research and development (R&D) initiatives have optimized the catalytic activity of the cell while minimizing the amount of expensive electrocatalysts, thereby lowering costs. Figure 2-1 shows a schematic representation of a PEM electrolyzer.

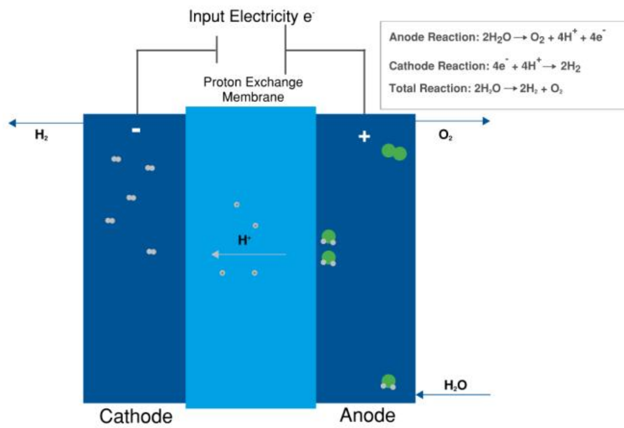

Figure 2-1 Diagram of a PEM Electrolyzer

2.2.2 Alkaline Water Electrolysis

AWE fundamentally functions using similar mechanisms to PEM electrolyzers; however, the ion transported in the electrolyte is hydroxide (OH^-) and travels from the cathode to the anode. The hydrogen then exits out the cathode side of the stack and the oxygen exits out of the anode side of the stack. Since AWEs have a lower current density, they also require a larger footprint compared to PEMs. However, this technology is considered more mature for large-scale hydrogen production given long production history. Figure 2-2 shows a schematic of an AWE system.

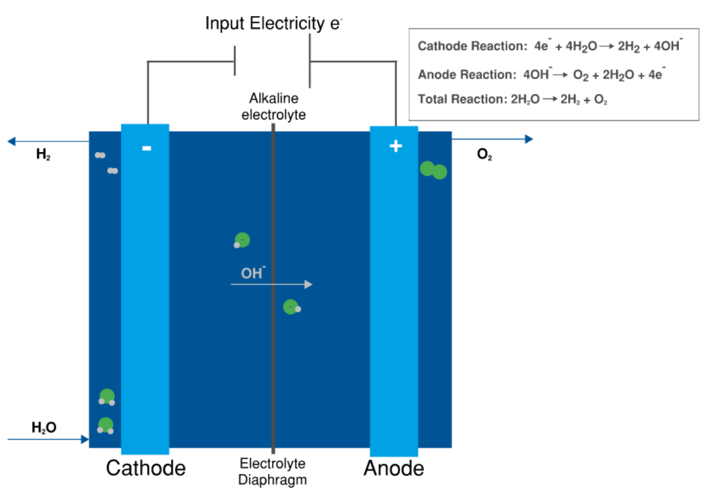

Figure 2-2 Diagram of an AWE Electrolyzer

2.2.3 Solid Oxide Electrolysis

SOE stacks have high conversion efficiencies relative to PEM and AWE, primarily because they operate at higher temperatures (i.e., 600 to 850°C) where thermodynamics and reaction kinetics are favored. Additionally, SOEs can be used for the direct electrochemical conversion of steam, carbon dioxide (CO_2), or both into hydrogen, carbon monoxide, and/or synthesis gas. SOEs consist of two porous electrodes surrounding a dense ceramic electrolyte capable of conducting oxide ions (O^{2-}). Typically, between 30 to 100 SOE cells are combined in series and assembled into stacks to achieve the desired hydrogen production rate. In addition to the efficiency benefits, SOE technology is also characterized by low-cost materials of construction compared with PEM electrolyzers, particularly in their use of non-noble metal electrocatalysts. Many SOEs in development are also thought to show greater promise than incumbent electrolysis technologies for reversible operation. Cell performance of SOEs has increased by more than a factor of 2.5 over the past 15 years. In addition, degradation rate has decreased by a factor of 100 and is currently below 0.5 percent per 1,000 hours of operation[1]. Figure 2-3 shows a diagram for a SOE cell.

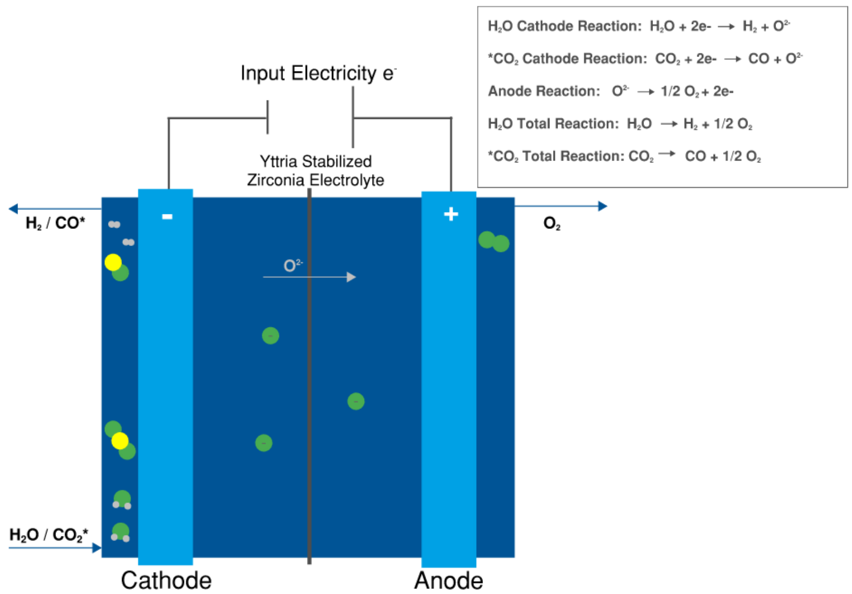

Figure 2-3 Diagram of a SOE Electrolyzer

2.2.4 Anion Exchange Membrane

The AEM electrolyzer is an emerging technology that offers construction and operational advantages from both PEM and AWE types. Similar to PEM, AEM electrolyzers utilize a membrane electrolyte, but instead of transporting a proton across the electrolyte, an OH- ion transports across, similar to AWE. However, AEM use an alkaline environment similar to AWE chemistry. AEMs also utilize less expensive electrocatalysts and can have a higher operating pressure. Current R&D into the technology is looking to scale to larger capacities to compete with PEM and AWE. Additional research is needed to reduce the rapid degradation of the materials and increase durability. Due to the low reactivity from the non-noble metal electrocatalysts, additional catalyst loading is required, thereby resulting in lower efficiencies relative to PEM. Hydrogen evolution reactions also tend to be slower in alkaline environments. AEM is still at early stages of R&D and will therefore require additional diligence relative to the aforementioned challenges. However, AEM technology shows significant promise as a lower-cost solution that takes advantage of desired properties from both PEM and AWE electrolyzer types.[2] Figure 2-4 shows a diagram for an AEM cell.

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[1] Hauch, A., et al. "Recent Advances in Solid Oxide Cell Technology for Electrolysis." Science, vol. 370, no. 6513, 2020, doi:10.1126/science.aba6118.

[2] Miller, H., Bouzek, K, Hnat, J (2020). Green hydrogen from anion exchange membrane water electrolysis: a review of recent developments in critical materials and operating conditions.

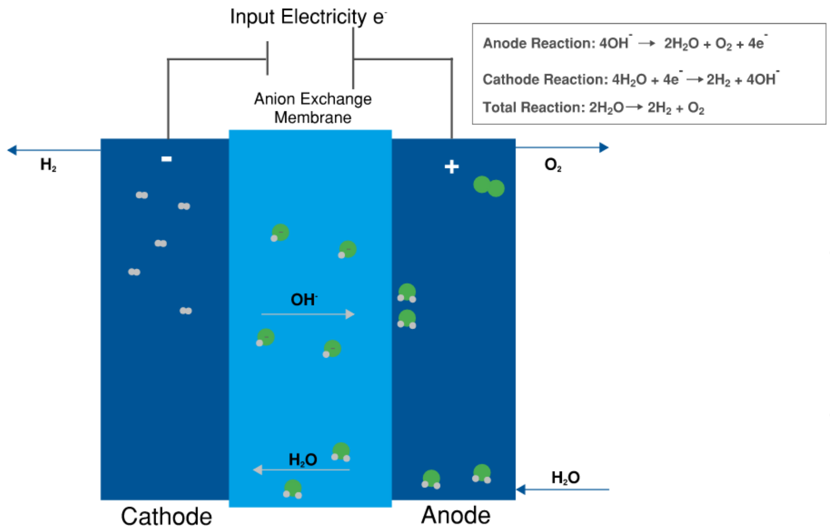


Figure 2-4 Diagram of an AEM Electrolyzer

2.2.5 Performance Comparison by Electrolysis Technology

For hydrogen production with intermittent renewables applications, PEM electrolysis has some key advantages over AWE and SOE; namely, the lower operating temperatures, non-corrosive electrolyte, smaller footprint, and dynamic response times. For energy storage applications that take advantage of varying renewable loads, PEM would be the recommended technology. As the technology of choice for many proposed projects, PEM electrolyzers are also more likely to experience production efficiency increase and cost decline as part of the learning curve. AWE is a more mature technology; however, its application is best used for steady state operation with very high-capacity factors due to its high operating temperature. And while SOE shows technological promise, it is not yet commercially available. AEM shows promise for its lower capital cost, higher current density and similar operating characteristics to PEM, however its decreased durability and increased degradation are still a subject of R&D. Table 2-1 compares the difference in performance between the four technologies.

Table 2-1 Comparison of Electrolysis Technologies

	PEM	AWE	SOE	AEM
Technology Maturity	Commercially available	Mature, commercially available	In development, not commercially available	In development, not commercially available
Technology Scale [3]	Small to Large Scale (100 kW to 1+ GW)	Small to Large Scale (1 MW to 1+ GW)	Small Scale (<1 MW)	Small Scale (<200 kW)
Technology Description	Solid polymer used to conduct the ions rather than a liquid electrolyte. Polymer is highly conductive for positively charged ions and resistive to negatively charged ions.[4]	Positively charged anode and negatively charged cathode immersed in liquid electrolyte.[4]	Electrolyzes water as steam. Two porous electrodes on either side of a dense ceramic electrolyte capable of conducting oxide ions.	Solid polymer electrolyte that is highly conductive for negatively charged ions and resistive to positively charged ions.[5]
Electrode Materials [6]	▪ Anode: platinum, platinum alloys, PGM oxides ▪ Cathode: platinum, PGMs	▪ Anode: nickel, porous carbon ▪ Cathode: nickel, porous carbon	▪ Anode: strontium-doped lanthanum manganite ▪ Cathode: nickel/yttric stabilized zirconia	▪ Anode: iron, nickel and cobalt oxides ▪ Cathode: nickel and nickel alloys
Operating Temperatures [7]	140°F to 194°F	Less than 212°F	1,300°F to 1,400°F	122°F to 140°F
High-Level Equipment Capital Expenses (CAPEX) [8]	$700-$1,000/kW	$600-$900/kW	N/A	N/A
Advantages	▪ Smaller footprint from higher allowed current density, 0.5-2.0 A/cm2. ▪ Faster dynamic response (5-15%/s), high turndown capabilities (10%). ▪ Higher membrane mechanical strength for greater operation pressure, decreasing downstream compression cost.	▪ Lower CAPEX and operating expenses (OPEX), when compared with PEM. ▪ Older, most established technology.[4] ▪ Current density typically 0.5 A/cm2 or less	▪ High conversion efficiency. ▪ Electrolysis current density of ~0.3-2.0 A/cm2 at 1.29 V (for splitting steam), compared to PEM electrolysis current density of ~0.5 A/cm2 at 1.47 V (for splitting water). ▪ Abundant raw materials for cell components.	▪ Smaller footprint ▪ Electrolysis current density of 0.2-1.0 A/cm^2 ▪ Lower CAPEX compared with PEM/AWE ▪ Higher pressure operation ▪ Higher purity product gas (99.99%)[5]

[3] Ranges are approximate and dependent on vendor.
[4] Wang, Xiaoting. Bloomberg Finance LP, 2019, Hydrogen: The Economics of Production from Renewables.
[5] Pozio A, Bozza F, Nigliaccio G, Platter M, Monteleone G. Development perspectives on low-temperature electrolysis. ENEA 2021, 1, 66-72.
[6] Electrode materials not exclusively mentioned above but commonly used each chemistry.
[7] Hydrogen production: Electrolysis. Energy.gov. Retrieved September 30, 2022, from https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis#:~:text=Solid%20oxide%20electrolyzers%20must%20operate,less%20than%20100%C2%B0C).
[8] CAPEX numbers are approximate, only for electrolysis equipment and dependent on vendor, scope and operation.

	PEM	AWE	SOE	AEM
	▪ Higher purity product gas (99.99 %).[9] ▪ Cost reductions likely given expected market demand and resulting production.			
Disadvantages	▪ Higher CAPEX and OPEX, when compared with AWE. [4] ▪ Expensive platinum electrocatalyst. ▪ Newer technology compared to AWE.	▪ Larger footprint (electrolyzer scope approximately 2-3x PEM), less suitable for space constrained facilities. [4] ▪ Lower gas purity, relative to PEM (>99.5%).[9] ▪ Requires bulk chemical storage of hazardous, corrosive electrolyte. ▪ Slower ramp times on order of 10%/min, slightly higher turndown at approximately 15%-40% load	▪ New emerging technology. ▪ Small stack capacities (<10kW). ▪ May require available waste heat source to be economically viable.	▪ New emerging technology. ▪ Lower current density compared to PEM ▪ Decreased durability ▪ Increased degradation rates[5]
Degradation Rates	▪ 11 µV/cell/h degradation.[10] ▪ Performance degradation 0.5% to 2.5% per year.[11] ▪ Performance degradation <10% operating for 5,000 hours under variable temperature conditions. ▪ Global Efficiency >49%.	▪ <3 µV/h degradation.[3] ▪ Performance degradation 0.25% to 1.5% per year. [3]	▪ Performance degradation <0.5% per 1,000 hours. [3]	▪ Unknown
Normalized Degradation [12]	1.5% per year	0.9% per year	4.2% per year	Unknown

[9] Schmidt, O., et al. "Future Cost and Performance of Water Electrolysis: An Expert Elicitation Study." International Journal of Hydrogen Energy, vol. 42, no. 52, Dec. 2017, pp. 30470–30492., doi:10.1016/j.ijhydene.2017.10.045.

[10] Carmo, Marcelo, et al. "A Comprehensive Review on PEM Water Electrolysis." International Journal of Hydrogen Energy, vol. 38, no. 12, 22 Apr. 2013, pp. 4901–4934., doi:10.1016/j.ijhydene.2013.01.151.

[11] Felgenhauer, Markus, and Thomas Hamacher. "State-of-the-Art of Commercial Electrolyzers and on-Site Hydrogen Generation for Logistic Vehicles in South Carolina." International Journal of Hydrogen Energy, vol. 40, no. 5, 2015, pp. 2084–2090., doi:10.1016/j.ijhydene.2014.12.043.

[12] Estimated based on 95 percent annual capacity factor (8,322 hours per year) and assuming moderate operating conditions (i.e., stable temperature/loading and minimal cycling). No specific formula for degradation exists and is based on a complex set of factors that have been discussed and modeled in the literature.

	PEM	AWE	SOE	AEM
Life Expectancy[6]	20+ Years – While PEM is a commercially-available technology, many PEM electrolyzers have not yet reached the end of their operational life, so this figure is being further refined from actual performance.	20+ Years	N/A	Unknown
Stack Replacement Schedule	20,000 – 60,000 hours[9]	60,000 – 90,000 hours [9]	<10,000 hours[9]	<10,000 hours [13]
Stack Hydrogen Yield Rate [9, 14, 15]	54 – 71% 47 – 61 kWh/kg	51 – 71% 47 – 61 kWh/kg	<94% >36 kWh/kg	58 – 62% 53 – 58 kWh/kg
Expected Cost Trajectory	28%-69% decrease by 2030	32%-42% decrease by 2030	Not enough information currently to estimate reductions	Not enough information currently to estimate reductions

[13] Faid A, Sunde S. Anion Exchange Membrane Water Electrolysis from Catalyst Design to the Membrane Electrode Assembly. Energy Technology, vol. 10, no. 9, 2022, 2200506.
[14] Efficiency calculated based on lower heating value of hydrogen.
[15] High SOE efficiency is based on utilization of high energy waste heat.

2.3 Hydrogen Fired CTGs and Emissions Impacts

Compared to natural gas, hydrogen is more energy dense on a gravimetric basis but less dense on a volumetric basis. Increased volumetric flow of the blended fuel will need to be delivered to the energy conversion system to achieve the same heat input as the reference natural gas, assuming no increase in fuel pressure. Piping velocities and pressure losses will increase as a result. Faster flame speeds, higher combustion temperatures, higher flammability range, and lower auto-ignition energy all need to be considered in the design of a hydrogen-fired power generation application.

2.3.1 Scaling Considerations

Scaling of a hydrogen blended thermal power plant from lower blending percentages to higher blending percentages tends to be a stepwise function of retrofitting. For lower blends of hydrogen less than 5 percent by volume there is not typically much retrofitting required. However, as hydrogen blending increases, balance of plant systems need to be analyzed (in particular the fuel gas supply system). The scale up from 5 percent to 100 percent hydrogen by volume will be very specific to the vendor, technology, and asset vintage. Typically, most of the balance of plant that is impacted by hydrogen will be upstream of the hydrogen combustion in the gas turbine (i.e., fuel gas system, fuel gas compression, fuel gas heating, turbine enclosure, etc.).

2.3.2 Hydrogen Embrittlement and Attack

Gaseous hydrogen exists in a diatomic state, however when exposed to materials like carbon steels with high strength, it can disassociate and move into the material in its atomic form. These single hydrogen atoms can, over time, embrittle the material and cause accelerated cracking. High strength carbon steels are especially prone to embrittlement compared to stainless steel. Higher pressures, higher temperatures, and frequent cycling can increase the rate of hydrogen embrittlement. ASME B31.12 provides guidance on hydrogen pipeline designs based on pipe pressures and temperatures. Hydrogen embrittlement is typically the primary concern and design consideration when retrofitting gas systems. Hydrogen attack is an additional concern at temperatures above 392°F. Hydrogen attack results when the atomic hydrogen atoms chemically react with the carbon in the steel, creating methane and leading to the formation of fissures in the steel. This is typically the reason why fuel gas systems downstream of fuel gas heaters (FGH) need to be swapped out with 316L SS when exposed to high hydrogen blends at or above 30 percent by volume.[16] Thus, the SPGF facility will require piping changeout downstream of the hydrogen injection point.

2.3.3 Greenhouse Gas Emission Impacts

The primary driver for using hydrogen as an energy carrier is to reduce carbon footprint. However, CO2 emissions are not directly proportional to the increase in volumetric hydrogen in the fuel. Since CO2 emissions are measured on a mass basis, the mass of carbon displaced by hydrogen needs to be considered. The correlation between blended hydrogen by volume and reduced CO2 by mass can be calculated. Based on 20 percent by volume hydrogen blended into the fuel supply, a CO2 reduction of approximately 7 percent is expected. This assumes a generalized CO2 emissions of 117 (lbCO_2)/MMBtu natural gas. Figure 2-5 shows the CO2 reduction versus hydrogen percent volume in the fuel.

[16] Hydrogen piping materials and design considerations are covered in detail in ASME B31.12. In addition, ongoing research on hydrogen mixtures within existing and new natural gas systems is ongoing. Material use cannot be generalized and needs to be evaluating on a case by case basis.

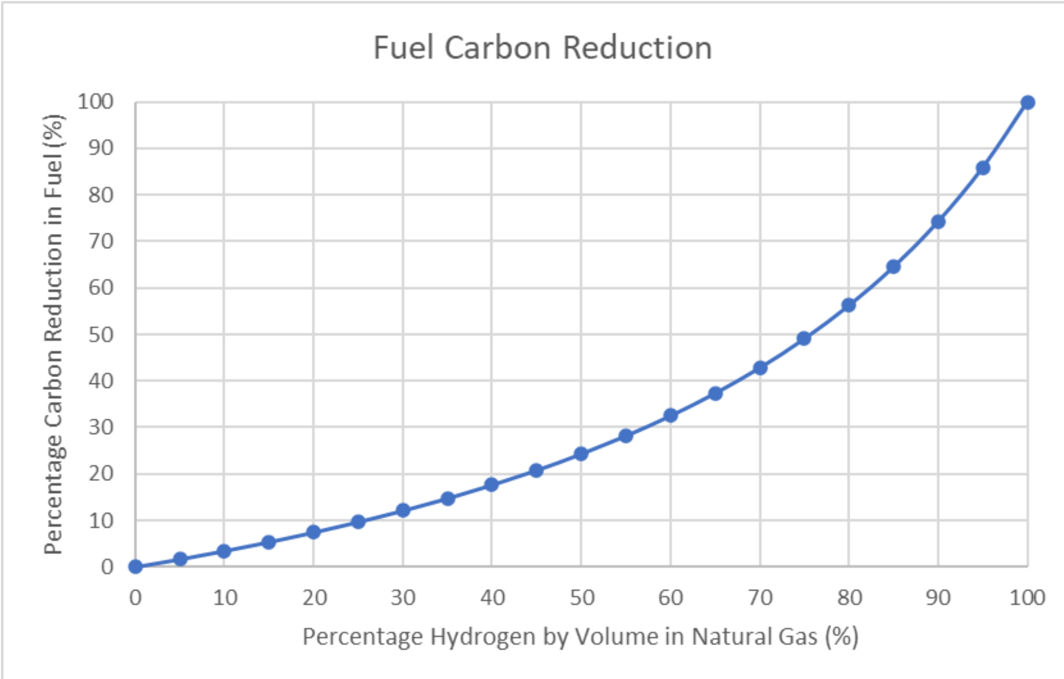


Figure 2-5 Fuel Carbon Reduction

The reason for the non-linear relationship found between percent H2 by volume blended and percent emission reduction encountered is because of the relative heat input from the fuel constituents, especially because natural gas and hydrogen provide very different energy densities. The difference between mass and volumetric energy density of H2 found in the blended fuel affects the heat input to the combustion turbine and correlates to the reduction in emissions.

2.3.4 NOx Emissions Impact

While hydrogen reduces the production of CO2 by displacing natural gas, it also can produce higher thermal nitrogen oxides (NOx) emissions due to the higher combustion flame temperature. Hydrogen has a higher adiabatic flame temperature relative to methane and other hydrocarbons. However, the fuel to air mixture within the combustor can be controlled to maintain temperatures and minimize thermal NOx production. In addition, for some diffusion flame combustors, diluent injection of water, steam, or nitrogen can be used to temper the flame temperature, especially in “rich” combustion sections. Design and control changes to mitigate temperature increases should be considered. Thermal NOx can be mitigated by de-rating the asset to keep the air to fuel ratio sufficiently high such to minimize high temperatures in the combustion process and emissions controls can potentially be expanded, within reason. Energy conversion system OEMs are working on new designs that will allow for higher hydrogen percentages while minimizing NOx production and de-rating by changing the combustion dynamics in the combustion system, staging combustion, or varying controls.

2.4 Hydrogen Safety

Black & Veatch is an executive member of the Center for Hydrogen Safety (CHS), a conglomerate of industry partners involved in the hydrogen space that work together to share safety knowledge, experiences, and resources with the public. CHS has a variety of resources, education, and courses available on their website. The following safety information comes from interactions Black & Veatch has had with CHS, including a course on Introduction to Hydrogen Safety for First Responders.[17]

2.4.1 Hydrogen Properties

Hydrogen is a colorless, odorless, and non-toxic gas. It is fourteen times lighter than air, thus it tends to rise and dissipate quickly. An important consideration when designing any hydrogen system is to ensure not to enclose the space without proper ventilation to prevent the formation of a flammable mixture. Due to hydrogen's very low density, it will rapidly dissipate into air as long as it is properly vented, or storage is outdoors. Its autoignition temperature is 1,085°F, flame temperature is 4,010°F and flammability range is between 4 and 75 percent by volume in air (with the greatest flammability at 29 percent). Energy content of one kg of hydrogen is approximately equal to one gallon of gasoline. 100% hydrogen flames burn with a pale blue flame and are not visible in daylight. A 100% hydrogen fire also gives off almost no radiant heat and no smoke.

2.4.2 Hydrogen Production via Electrolysis

Similar safety risks apply to electrolysis safety as to other hydrogen equipment and processes. The main risks include loss of hydrogen containment, unintended exposure to electrical/mechanical systems and hydrogen and oxygen stream mixing.

Loss of containment could result in hydrogen explosion or exposure to corrosive electrolyte (in alkaline systems). The loss of containment can occur because of a mix of hydrogen and oxygen streams resulting in explosion, over pressurization of the equipment or equipment freezing (depending on product hydrogen temperatures). In order to prevent loss of hydrogen containment, electrolyzer enclosures should be equipped with hydrogen monitoring equipment at the highest point of the building and have plenty of ventilation to prevent any hydrogen build-up. Similar to most process equipment, exposure to hot equipment, rotating equipment, and electrical hazards are possible. Adequate original equipment manufacturer (OEM) training and Lock Out Tag Out (LOTO) procedures should be followed before interacting with the equipment. ISO 22734 provides more detailed guidelines on electrolysis safety requirements and considerations.

The mixing of hydrogen and oxygen streams also presents a risk for explosion due to hydrogen's large range of flammability. In addition, oxygen stacks should be kept an adequate distance away from air intakes and combustibles to prevent ignition; NFPA 2 Section 13.2 provides guidance on distances. In the electrolyzer during normal operation, some oxygen is able to diffuse across the membrane, resulting in oxygen in the hydrogen stream. However, this is normal and is removed in the deoxygenation step of the processing. Measurement equipment downstream of the stack monitor the oxygen level, keeping the volumetric percentage below one percent. Note, flammability of oxygen in a hydrogen stream is six percent oxygen by volume. Oxygen cross over can occur more frequently at lower operating loads.

2.4.3 Emergency Response

Because hydrogen is colorless, odorless, tasteless, and burns invisibly in the daylight with little to no radiant heat, first responders need to listen for high pressure gas leaks, use portable hydrogen detectors, and utilize infrared imaging technology (if possible) to help detect leakages. If an accident has occurred and vented gaseous hydrogen is ignited, the safest option would be to isolate the source of hydrogen (if possible) and let it burn out rather than extinguishing it. If first responders respond to a tube trailer that is venting an ignited hydrogen gas, care should be taken to understand the type of cylinders on board.

[17] Center for Hydrogen Safety. AIChE. (2022, June 24). Retrieved December 11, 2023, from https://www.aiche.org/chs

3.0 Conceptual Design Basis and Process Description

Conceptual engineering design to transition the Standby Power Generation Facility from natural gas to green hydrogen was developed for each of the following scenarios. Since the SPGF is designed to operate under emergency conditions and is also permitted to operate under monthly maintenance cycles, these conditions are the basis for each scenario.

- Scenario 1: Two of the three CTGs utilizing 100% on-site generated and stored green hydrogen for a two-week duration.
- Scenario 2: Each of the three CTG utilizing 100% on-site generated and stored green hydrogen during the 8-hour monthly maintenance cycle.
- Scenario 3: Each of the three CTG utilizing 100% delivered green hydrogen during the 8-hour monthly maintenance cycle.
- Scenario 4: Each of the three CTG utilizing a 5% hydrogen and 95% natural gas blend during the monthly maintenance cycle, utilizing up to a 5 MW renewable energy system. PVSC has prior determined that a 5 MW solar field is technically feasible to be implemented within the Newar Bay WWTP proper.

Based on the project requirements for the scenarios, the CTGs, electrolysis system, hydrogen storage and compression, and the solar field were conceptually designed and sized to produce the required hydrogen storage. After determining the hydrogen storage capacity, the next steps involved sizing the electrolysis system and required solar capacity. This was followed by designing the balance of plant (BOP), which included the conceptual design of the cooling system necessary to support the hydrogen production system. Once the electrolysis system and BOP system were designed and sized, the total electrical and water requirement for each plant could be estimated. Using the total electrical requirement, modeling was used to vary the size of the solar system to find the minimum required capacities to meet the hydrogen production requirement.

All site design bases were determined using PVSC provided project requirements, all applicable codes & standards, and Black & Veatch design engineering experience.

3.1 Hydrogen Production Sizing Model

As part of the pre-feasibility study, Black & Veatch performed high-level modeling to size the systems within the hydrogen production facility including the electrolysis, hydrogen compression, hydrogen storage, and balance of plant equipment. This included sizing a solar photovoltaic (PV) field capable of supporting hydrogen production and fully refilling the hydrogen storage tanks within the required timeframes – 90 days for Scenarios 1 and monthly for scenarios 2 and 4. These timeframes were based on average daily hydrogen production rates of 11.2 million tons per day (MTPD) for Scenario 1, 1.8 MTPD for Scenario 2, and 0.4 MTPD for Scenario 4. The hydrogen storage refill duration was identified as the primary design driver, as green hydrogen generation (or delivery) is solely intended to support combustion turbine generator (CTG) operations.

Based on the hydrogen storage requirement, the respective refill times, and a capacity factor that matched the solar field, the electrolysis system and supporting BOP systems were sized to meet the hydrogen production requirement. Using the total electrical and water requirements of the project, Black & Veatch calculated the plant yield rate of 57.4 kWh/kgH_2, 58.2 kWh/kgH_2, and 53.5 kWh/kg$H_2$for Scenarios 1, 2 and 4, respectively. Both scenarios use the same model of electrolyzer and are assumed to have the same electrolyzer full load yield rates of 52.3 kWh/kgH_2.

The solar resource assessment assumed the use of single-axis tracking photovoltaic arrays, selected based on the site's latitude, and located within the same general region as the hydrogen production facility. Accordingly, the hydrogen production site—adjacent to the generation facility—served as the reference point for developing the 8760-hour solar dataset. A solar capacity factor was calculated for each hour of the year to estimate the available power for hydrogen production. For the larger-scale Scenarios 1 and 2, it is assumed that the solar field and hydrogen production facility will not be co-located, but rather interconnected via the electrical grid, enabling flexible power delivery. In these cases, PVSC is expected to utilize a power purchase agreement (PPA) to secure renewable electricity from the solar field. In contrast, for Scenario 4, the solar and hydrogen production systems are assumed to be co-located on-site. Across all scenarios, hydrogen production occurs whenever the available solar power exceeds the electrolyzer's minimum turndown threshold, evaluated on an hourly basis.

In Scenario 1, the objective is to store sufficient hydrogen to operate the CTGs for up to 960 hours annually. A 90-day storage refill period was assumed to be adequate to support this operational profile. In Scenario 2, hydrogen is intended for monthly 8-hour CTG maintenance runs, and the initial refill period was set at 30 days, but was subsequently reduced to 18 days based on modeling results to ensure full replenishment each month. Similarly, in Scenario 4, which involves 5% hydrogen cofiring during the same monthly maintenance operations, the refill time was also reduced from 30 to 18 days to maintain monthly availability. It is important to note that these scenarios may be subject to change pending the results of future hydrogen production optimization studies. Once hydrogen storage reaches its maximum capacity—1,011 metric tons for Scenario 1, 36.1 metric tons for Scenario 2, and 8.1 metric tons for Scenario 4—the electrolyzers will be shut down, and any excess solar power generated can be redirected to the grid.

The electrolyzer is assumed to have a minimum turndown of 40 percent and the solar field has an average capacity factor of 20.3 percent. These and additional modeling assumptions are listed below in Table 3-1.

Table 3-1 Modeling Assumptions

PARAMETER	SCENARIO 1	SCENARIO 2	SCENARIO 4
Solar Capacity Factor	20.3%	20.3%	20.3%
Electrolysis Yield Rate at Full Load (kWh/kg H_2)	52.3	52.3	52.3
Plant Yield Rate (kWh/kg H_2)	57.4	58.2	53.5
Electrolyzer Minimum Turndown	40%	40%	40%
Electrolyzer Capacity Rating Per Unit/Total (MW)	17.5/105	17.5/17.5	8.7/8.7
Electrolyzer Quantity	6	1	1 x 50%
Average Hydrogen Production (kg/hr)	468	84	19
Peak Hydrogen Production (kg/hr)	1,757	314	71
Hourly Hydrogen Usage (kg/hr)	3,009	4,513	90
Hydrogen Storage (metric tons)	1,010.9	36.1	8.1

With these assumptions and logic in place, the selected capacity of the solar field and hydrogen storage refill time is assumed to be an efficient combination of sufficient hydrogen production while maintaining a limited footprint. This leads to an electrolysis capacity factor of 26.6 percent for both scenarios.

3.2 Hydrogen Production Conceptual Design

The following sections discuss the process design for the facilities and scenarios. Additional details are included in the design basis documents.

3.2.1 Overview

The hydrogen production facility will include hydrogen production via electrolysis. The hydrogen production will be driven by the solar production in an off-site solar field delivering electricity via grid connection for scenarios 1 & 2 and in at a co-location solar site for scenario 4.

The hydrogen production site is assumed to use a hydrogen production profile that is aligned with the solar production. As such, hydrogen production will vary with the solar power generation which is further detailed in Table 3-2.

Table 3-2 Design Basis Hydrogen Capacity

PARAMETER	SCENARIO 1	SCENARIO 2	SCENARIO 4
Hourly Hydrogen Usage (kg/hr)	3,009	4,513	90
Average Hydrogen Production (kg/hr)	468	84	19
Peak Hydrogen Production (kg/hr)	1,757	314	71
Hydrogen Production	PEM Electrolysis	PEM Electrolysis	PEM Electrolysis

3.2.2 PV Solar field

The PV solar field was sized to 132.5 MW, 24.0 MW, and 5.0 MW for Scenarios 1, 2 and 4, respectively, using the logic in Section 3.1. The solar field will be the primary power for the hydrogen production and BOP via grid connection. Black & Veatch's solar team developed an 8760-model using a 1-acre parcel in the vicinity of the SPGF as a representative location of the solar field assuming that the actual solar field will be located in the same region as the hydrogen production facility. An average solar capacity factor of 20.3 percent was determined from historical data of the area. The 8760-model considers a single-axis tracking solar field due to the site location's proximity to the equator (near 40 degrees latitude).

Once the solar field produces power that is greater than the 40 percent turndown required for the electrolysis plant and the hydrogen storage has capacity, then hydrogen will be produced. Due to the dependence of the solar field on weather conditions, the division of energy flow from the solar field will vary day to day. For example, in a scenario when the solar field is producing less than the power required to run the electrolysis process, the electrolysis could be able to pull consistent power from the grid based on an assumed future PPA. A summary of solar field and requirements is shown in Table 3-3.

Table 3-3 Solar field

PARAMETER	SCENARIO 1	SCENARIO 2	SCENARIO 4
Solar field Size (MW)	132.5	24.0	5.0
Solar field Footprint (Acres)	500	90	20
Solar Modules (#)[1]	230,292	41,661	8,633
Solar Racks (#)[2]	2,559	463	96
Note 1: Each solar module is rated at 575 W. Note 2: Each solar rack contains 90 solar modules.			

3.2.3 Electrolysis

Based on the advantages listed in Section 2.2.1 and Table 2-1, specifically the operational flexibility of the technology, the hydrogen production system will use PEM electrolysis. Electrolysis capacity was selected to meet the hydrogen storage demand. A summary of electrolysis capacity and requirements is shown in Table 3-4.

Table 3-4 Electrolysis Capacity

PARAMETER	SCENARIO 1	SCENARIO 2	SCNENRIO 4
Average Hydrogen Production (kg/hr)	468	84	19
Peak Hydrogen Production (kg/hr)	1,757	314	71
Electrolysis Technology	PEM	PEM	PEM
Installed Capacity per Electrolyzer/total (MW)	17.5/105	17.5/17.5	8.7/8.7
Estimated Plant Yield Rate (kWh/kg)	57.4	58.2	53.5
Hydrogen Storage (metric tons)	1,010.9	36.1	8.1

3.2.4 Water Supply

It is assumed the water supply will be available on-site and will be utility supplied. The process water will be supplied to the demineralized water treatment process. Table 3-5 shows a summary of the water supply flows.

Table 3-5 Water Supply Flows

WATER USAGE (GPM)	SCENARIO 1	SCENARIO 2	SCENARIO 4
Raw Water Intake	101.1	18.0	4.1
Process/Demin Water Flow	77.3	13.8	3.1

Demineralized water will be required for the electrolysis process. This system will consist of reverse osmosis to remove the majority of dissolved solids followed by an electro-deionization or ion exchange system to polish the water to the final water quality requirements. The wastewater stream of concentrated dissolved solids will be discharged to the wastewater handling. Transfer pumps will be installed to supply water to the hydrogen production part of the facility. PEM electrolyzers require high purity demineralized water to maintain operational integrity and to avoid accelerated degradation of stack components. Demineralized water quality requirements vary between electrolyzer manufacturers; however, ASTM specification D1193 is frequently referenced in OEM specifications in the industry. Type II water is commonly specified as a minimum demineralized water quality and Type I is commonly specified as a preferred demineralized water quality. Water usage rates are shown in Table 3-6 and ASTM D1193 water quality specifications are shown in Table 3-7. This study assumes all water treatment will occur within the electrolyzer vendor scope.

Table 3-6 Water Usage and Discharge Rates

WATER USAGE AND DISCHARGE (GPM)	SCENARIO 1	SCENARIO 2	SCENARIO 4
Process/Demin Water Flow	77.3	13.8	3.1
Wastewater Flow	23.8	4.2	1.2

Table 3-7 ASTM D1193 Water Quality Standards

PARAMETER	ASTM TYPE I	ASTM TYPE II
Resistivity (MΩ-cm)	>18	>1
Conductivity (µS/cm)	<.056	<1
pH at 25°C	N/A	N/A
Total Organic Carbon (ppb or µg/L)	<50	<50
Sodium (ppb or µg/L)	<1	<5
Chloride (ppb or µg/L)	<1	<5
Silica (ppb or µg/L)	<3	<3

3.2.5 Cooling Systems

To conserve water, an air-cooled heat exchanger (ACHE) will be used as the source of cooling water for electrolysis and BOP equipment. The total process cooling load handled by the ACHE is specified in Table 3-8.

Table 3-8 Cooling System Requirements

PARAMETER	SCENARIO 1	SCENARIO 2	SCENARIO 4
Cooling Duty (MMBtu/hr)	86.2	14.4	7.2
Cooling Water Flow (gpm)	10,798	1,928	435

3.2.6 Instrument Air

An instrument air system is provided for air operated valves and equipment, including air compressors, dryers, and receivers.

3.2.7 Nitrogen

Nitrogen bottles will be provided for purging equipment and panels to maintain a safe environment and for system maintenance.

3.2.8 Wastewater Handling

Wastewater will be collected in a wastewater sump and be discharged to sewer. The quantity and quality of the wastewater will be determined based on the water quality of the available raw water.

3.3 Hydrogen Fired CTGs Conceptual Design

The following sections discuss the process design for the 100% hydrogen cofiring at CTGs. Additional details are included in the design basis documents.

3.3.1 Overview

The SPGF will utilize three Siemens' SGT-600 gas turbines. The energy production will be produced by combusting hydrogen in a 2+1x0 (2 operating units) for Scenario 1 and 3x0 (3 operating units) for Scenarios 2, 3 and 4.

The CTGs are designed to function as backup power supply, therefore, requiring two weeks of hydrogen storage for Scenario 1 and at least 8-hour hydrogen storage for the monthly maintenance cycle in Scenarios 2 and 4. Hydrogen consumption will vary pending the demand, below in Table 3-9 is the power production from the hydrogen fired CTGs.

Table 3-9 SGT-600 Hydrogen Firing Summary Table

PARAMETER	SCENARIO 1	SCENARIO 2	SCNEARIO 3	SCENARIO 4
Turbine Cycle Arrangement	2+1x0	3x0	3x0	3x0
Hydrogen Blend	100%	100%	100%	5%
Hourly Hydrogen Usage (kg/hr)	3,009	4,513	4,513	90
Turbine Heat Rate (BTU/kWh)	11,400	11,400	11,400	10,862
Plant Net Output (Per Turbine/Plant Total, MW)	15/30	15/45	15/45	19.3/57.9

3.3.2 Performance & Emissions

Utilizing hydrogen cofiring data from Siemens Energy, Black & Veatch has been able to estimate the plant performance of the CTGs at 100% hydrogen.

As mentioned on page 2-9, while hydrogen reduces the production of CO2 by displacing natural gas, it also can produce higher thermal nitrogen oxides (NOx) emissions due to the higher combustion flame temperature. As the hydrogen blend increases, the turbines are partially derated to maintain lower flame temperatures and also maintain lower NOx emissions.

Table 3-10 summarize key performance parameters for each configuration.

Table 3-10 SGT-600 Performance

PARAMETER	SCENARIO 1	SCENARIO 2	SCNEARIO 3	SCENARIO 4
Estimated Turbine Output (kW)	30,000	45,000	45,000	57,873
CTG Heat Rate (LHV, Btu/kWh)	11,400	11,400	11,400	10,862
CTG Heat Input (LHV, MMBTU/hr)	342	513	513	629
CO_2 Produced (kg/hr)	0	0	0	33,361
$C0_2$ Avoided (kg/hr)	27,225	40,837	40,837	1,184

3.3.3 Hydrogen Combustion Turbine Scope

Based on consultation with Siemens, SGT-600 turbines can currently operate up to 5% hydrogen by volume without requiring retrofit and can be upgraded to support a 75% hydrogen blend with available technology. Siemens has also outlined a development roadmap targeting to the commercial capability for 100 percent hydrogen combustion by 2030, pending turbine and supporting system modifications. To enable 75% and above hydrogen cofiring, Siemens has identified necessary upgrades to the fuel gas delivery system, including key components that must be evaluated and potentially replaced. The estimated cost for these upgrades is approximately $8MM per turbine. It is further assumed that the scope of work for 100% hydrogen capability will be similar in nature, with estimated costs around $11MM per turbine.

- Fuel Blending and Controls

    - Combustion Chamber Upgrades
    - Hydrogen Adapted Burners
    - Ignition System
    - Gas Fuel System Upgrades – Piping, Instruments, and Valves
    - Remote Connection
    - Adjustment to Operations to limit NOx
    - Maintenance of Fuel Temperatures
    - Gas Thermal Conductivity Detector
- Safety and Controls
    - Flashback Sensors
    - Flashback Out System
    - Combustion Pulsation Protection
    - Enclosure Gas Detection
    - Inert (N2) Purge System
    - Enclosure Fire Detection and Suppression System
    - Hazardous Zone and Enclosure Updates

3.4 Electrical/Control Conceptual Design

3.4.1 Electrical Equipment

Electricity for hydrogen production will come from the off-site solar field and supplied via a grid connection for scenarios 1 and 2. Scenario 4 assumes that the solar would be co-located with the hydrogen production facility. The transformers and power distribution center that have multiple switchgears and motor control centers, as well as other electrical equipment and cabling will feed the plant loads. Note that the utilization voltage for the hydrogen facility may vary depending on the manufacturer selected. It was assumed the power for the fuel compression would continue to be fed through the combustion turbines auxiliary transformers. A summary of the total electrical requirements is included in Table 3-11.

Table 3-11 Estimated Electrical Requirements

ELECTRICAL REQUIREMENT (MW)	SCENARIO 1	SCENARIO 2	SCENARIO 4
Electrolysis	89.5	16.2	3.2
Balance of Plant	11.4	2.0	0.6
Total	100.9	18.3	3.8

3.4.2 System Controls

The control system for the electrolysis will be supplied by the vendor. The specifics of the electrolysis control system will be dependent upon the selected supplier, but should have at least two modes of operation, including Command

Following mode and Load Following mode. Command Following mode is used when the load is fluctuating according to available power, such as a renewable source of electricity. Load Following mode is when hydrogen production is controlled based on process pressure. BOP system controls will be controlled by a programmable logic controller. All control systems will be included within an architecture that can allow remote start/stop control and monitoring of the facility using the existing plant distributed control system (DCS). The details of the control system will be developed during detailed design.

3.5 Civil/Structural Conceptual Design

The plant civil and structural design will be in accordance with the required codes, including seismic considerations. It is recommended that a subsurface investigation be conducted prior to the start of detail design to define the critical geotechnical characteristics of the site and the parameters to be used in the final design of the foundation systems. The existing site will likely need to be graded to a plant storm water drainage system to direct surface runoff away from equipment and structures by appropriate grading and sloping and collected in a storm water system. Roadways will allow for access to the hydrogen generation area and the bulk hydrogen storage area. There will be fencing along the perimeter. The specific civil and structural work required will depend on site location, which has not been determined at this stage of the project.

3.6 Hydrogen Delivery

In Scenario 3, where liquid hydrogen is delivered monthly to the power generation facility to support the 8 hour maintenance cycles, it is assumed that the liquid hydrogen will be vaporized using ambient vaporizers and fed directly to the gas turbines. With careful coordination of deliveries, this approach would require minimal on-site hydrogen storage, thereby reducing both capital costs and space requirements. Table 3-12 shows the liquid hydrogen required for each month of maintenance.

Table 3-12 Estimated Monthly Liquid Hydrogen Requirement

LIQUID HYDROGEN REQUIREMENT	SCENARIO 4
Number of Turbines Operating	3
Hourly Hydrogen Requirement (kg/hr)	4,513
Total Hydrogen Requirement (kg)	36,100
Total Hydrogen Requirement (gal)	127,300
Liquid H_2 per Tanker (gal)	15,400
Number of Tankers	8.3

3.7 Project Schedule

Black & Veatch developed Level 1 project schedules for Scenarios 1 and 2. Each project schedule includes nominal durations for upfront conceptual design and specification development work, permitting, and all major EPC activities, through checkouts, startup, commissioning, and testing. For both schedules, the critical path runs through procurement of long lead equipment such as electrolyzers and electrical equipment. A preliminary estimate for the completion of schedule 1 and scenario 2 is about 62 months and 36 months, respectively. Based on the project schedules of scenarios 1 and 2, a preliminary estimate for the completion of scenario 4 is about 26 to 30 months.

4.0 Capital Cost Estimate Basis and Scope

Black & Veatch (BV) has developed a Class 5 (+/- 50%) capital cost estimate as defined by AACE for transitioning future Combustion Turbine Generators from natural gas to Green Hydrogen at the request of PVSC (Owner). The existing brownfield site at which this project is to be located is PVSC's Newark Bay Wastewater Treatment Plant (WWTP) in Newark, New Jersey, USA. The estimate includes four scenarios:

1. 42 MTPD (105 MW) of hydrogen using PEM Electrolysis via six Siemens Elyzer P300 units
   - Includes H2 storage via gaseous H2 tube storage
2. 8 MTPD (18 MW) of hydrogen using PEM Electrolysis via one Siemens Elyzer P300 unit
   - Includes H2 storage via gaseous H2 tube storage
3. Delivered liquid hydrogen on site and vaporizing to meet required demand
   - Includes minimal gaseous H2 storage and LH2 pulled directly from tankers.
4. 4 MTPD (9 MW) of hydrogen using PEM Electrolysis via one 50% Siemens Elyzer P300 unit
   - Includes H2 storage via gaseous H2 tube storage

Scope for these scenarios is shown in Table 4-2.

Table 4-1 Capital Cost Estimate Scope

SCOPE	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Electrolysis	X	X		X
Hydrogen Compression	X	X	X	X
Gas Hydrogen Storage	X	X	X	X
Fuel Gas Blending	X	X	X	X
Raw Water	X	X		X
Demineralized Water	X	X		X
Cooling Water	X	X		X
Potable Water	X	X		X
Fire Water	X	X		X
Wastewater	X	X		X
Instrument Air/Plant Air	X	X		X
Nitrogen	X	X	X	X
Balance of Plant / Site General	X	X	X	X
Electrolyzer Building	X	X		X
Electrical and Control	X	X	X	X
Vaporization			X	
Truck Unloading Hookup			X	

4.1 Estimate Execution Methods

For scenarios 1, 2 and 3, the estimate was developed utilizing provided scope documents from BV engineering. Utilizing the provided information, the estimate was developed through equipment modelling and capacity-factored estimating techniques based on either BV historical data or recent similar process units with either actual costs or higher-grade estimates. The construction execution philosophy is assumed to be direct hire at the identified site location. The location is assumed to be a primarily union workforce. These assumptions are the basis for the labor within the Total Installed Costs (TIC) build-up. Based on the timing of evaluation for Scenario 4, the cost estimate was estimated using the factoring method of scenario 2.

This Basis of Estimate explains the key components of the estimate. All allowances, assumptions, clarifications, and exclusions that were made in the development of the estimate are listed within this document.

4.2 Basis Documentation

- Preliminary Equipment List
- Electrical Scope Estimate
- Solar Team Estimate
- Siemens Indicative Proposal

4.3 Estimate Development

The plant estimates were developed via a mix of a direct capacity factoring and equipment modelling using details in the equipment list where enough information was available. The results were then compiled and a final cost was decided.

The approaches taken are outlined in more detail below.

4.3.1 Estimate Factoring Method

For the direct capacity factoring method, similar scope projects were identified and utilizing a six-tenths factoring method served as the basis for the cost estimate. The electrolysis capacities from Section 1.1 served as the basis for the formula. The pricing derived from the capacity factor was adjusted to current-day pricing.

A six-tenths factoring method works utilizing known projects and capacities per the below formula:

- Known Cost x ((Unknown Capacity / Known Capacity) ^0.6) = Unknown Cost

The resulting cost was calculated based on US Gulf Coast (USGC). The estimate was then adjusted to the Newark, NJ project location and execution strategy by applying specific productivities and labor rates for union work at a congested brownfield site.

4.3.2 Equipment Modeled Method

For the equipment modelled method, the development of the estimate was completed using Aspen's Capital Cost Estimator™ (ACCE) estimating software version 14.2 and its modeling capabilities to the fullest extent available. ACCE is a commercially available program that BV has calibrated and customized to fit its historical project cost and quantity information. For all scenarios where new major mechanical equipment is being constructed and ACCE

Equipment models are available, the following methodology has been used for the development of the estimate. Where other ACCE models are available, they have been used as noted.

Equipment model estimating is a technique that takes each piece of process equipment and generates bulk quantities and prices to determine the direct field labor and bulk material costs associated with the complete installation of the equipment. Based on the equipment data sheet design specifications and the general design conditions of the project, an equipment model is generated to include the equipment item, plus the applicable bulk materials associated with that specific equipment type, i.e. foundations, piping, controls, power, etc.

The resulting cost as calculated is based on US Gulf Coast (USGC). The estimate has been adjusted to the Newark, NJ project location and execution strategy by applying specific productivities and labor rates for union work at a congested brownfield site.

4.4 Estimate Basis, Assumptions and Qualifications

- All costs are expressed in USD
- All costs are on a Q1 2025 basis. No forward escalation is included
- The estimate is based solely on the documents in section 1.3 and BV historical information
- The estimate includes for all engineering and procurement through detailed design
- The estimate includes for all construction equipment, backfill, dewatering piping, and construction roads
- No adjustments have been made for extreme productivity impacts or higher than local average labor costs
- The construction schedule and productivity assume normal weather conditions for the site location. No allowance has been made for dramatic weather events
- The estimate assumes a clear site upon which the scope can be constructed
- All construction work is considered to be executed as direct-hire
- The construction execution scenario is based on a stick-built execution philosophy
- The estimate includes costs for freight to the project site
- Contingency is included in the Total Installed Cost
- Profit and G&A is included in the Total Installed Cost
- The estimate does not include any work associated with removal of contaminated materials or hazardous waste that may be encountered
- No consideration has been made for Turnaround work
- No allowance has been included for all risk subcontractor liability insurance
- No consideration is made for the impact of COVID-19 or ongoing global conflicts

4.5 Exclusions & Owner’s Costs

The following items are excluded or fall within the Owner’s cost responsibility. These items include but are not limited to:

- Business management systems
- Catalyst and chemicals (initial inventory and operating) and loading
- Consultants
- Contaminated & hazardous material handling and/or disposal
- Geotech Report
- Insurances (marine cargo, all-risk etc.)
- Lab Equipment
- Land cost
- Licensor fees
- Lubricants (initial inventory and operating)
- Machine shop equipment
- Maintenance equipment and tools
- Operations Shared Costs
- Owner’s auditing/inspection/witness testing
- Owner’s contingency
- Owner’s escalation
- Owner staff and expenses
- Permanent office and laboratory equipment
- Permanent office furniture
- Permanent warehouse and warehouse equipment
- Permits (building/environmental)
- Plant operations/maintenance vehicles (ambulances, fire, switch engine, etc.)
- Plant security
- Process Simulator
- PV Solar System
- Taxes and duties
- Topo Map
- Training for Operations and Maintenance
- Underground exploration

4.6 Capital Cost Estimates

Table 4-2 shows the summary of the capital cost estimates completed.

Table 4-2 Capital Cost Estimate

TIC (MMUSD)	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Hydrogen Turbine Upgrades	33	33	33	-
Solar Field	69	9	-	2
Electrolysis	213	43	-	21
Hydrogen Storage	1189	47	1	11
Hydrogen Compression	61	53	38	21
Electrical and Control	7	6	3	2
BOP	107	44	14	17
Total	1,679	235	90	74

5.0 Operation and Maintenance Cost Estimate

The operation and maintenance (O&M) cost estimates are broken out into fixed O&M costs (e.g., labor, corporate, etc.) and variable O&M costs (e.g., water, unplanned maintenance, etc.). The basis of the estimate for fixed and variable O&M costs are primarily derived from original equipment manufacturer (OEM) input, publicly-available literature, and Black & Veatch experience. The basis for the variable O&M costs are based on an the hydrogen production site operating on an annual basis.

5.1 Fixed Operation and Maintenance Costs

The major maintenance associated with the electrolyzers is stack replacement. For the PEM electrolyzers, the stack replacement is estimated to be every 7 to 10 years at a cost of 20 percent of the initial capital cost of the electrolyzer. Fixed O&M costs for the electrolyzer plant primarily include labor, fees/corporate management [i.e., General and Administrative (G&A)], and planned maintenance actions (e.g., consumables, filter replacements, inspections, leak checks, etc.). A breakdown and basis for annual fixed O&M costs for the different scenarios are provided in Table 5-1.

Table 5-1 Fixed O&M Costs

COST (USD/YEAR)	BASIS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Labor	▪ Labor: Maintenance Technicians (Mechanical, Electrical, Instrument & Controls) and Delivery Driver (if applicable) ▪ Salaries are based on Bureau of Labor Statistics for California. ▪ Overtime: 25% of unburdened maintenance labor cost. ▪ Burden: 40% of total salary.	$398 K	$398 K	$238 K	$238 K
General and Administrative (G&A)	▪ 20% of total salary with burden.	$80 K	$80 K	$48 K	$48 K
Planned Maintenance	▪ Electrolyzer Stack Replacement: - 20% of electrolyzer equipment cost. Assumes stacks are replaced once during a 20-year plant life (year 10), averaged over 20 year plant life for annual cost. ▪ Structure Maintenance ▪ BOP Equipment: - 2% of total installed cost (TIC). Excludes electrolyzer planned maintenance and electrolyzer stack replacement. ▪ Contract Services: - 20% of labor, G&A, and planned maintenance. Excludes electrolyzer.	$37,420 K	$5,146 K	$2,194 K	$1,541 K
Total		**$37,898 K**	**$5,624 K**	**$2,480 K**	**$1,827 K**

5.2 Variable Operation and Maintenance Costs

The primary non-electricity variable O&M costs for the electrolyzer plant are unplanned maintenance and consumables such as nitrogen, water supply, water treatment, and wastewater disposal. Electricity has not been directly included in variable O&M costs due to the significant electrical energy consumption by the electrolyzer and product plant and is estimated separately at a flat rate within the economic analysis. A breakdown and basis for annual variable O&M costs is provided in Table 5-2.

Table 5-2 Non-Electricity Variable O&M Costs

COST	BASIS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Unplanned Maintenance	▪ 0.5% of TIC.	$8,395 K	$1,175 K	$445 K	$370 K
Water Supply, Water Treatment, Wastewater Disposal and Nitrogen	▪ Raw water, demineralized water, and wastewater disposal based on information received from TID and publicly available information. ▪ Delivered nitrogen from industrial gas supplier.	$426 K	$633 K	$2 K	$14 K
Total		**$8,821 K**	**$1,808 K**	**$447 K**	**$384 K**

6.0 Economic Analysis

For the scenario selected for evaluation, Black & Veatch developed an estimate of the LCOH using a macro-enabled, Excel-based economic model. To estimate these costs, Black & Veatch employed am economic model, which provides a preliminary estimate of the LCOH, in terms of USD/kg, levelized over the life of the project. The economic model considers capital cost, financing parameters, O&M costs, and technical considerations (e.g., capacity, electrolyzer/plant efficiency, etc.) associated with the hydrogen production site and scenario. Black & Veatch also ran sensitivity analyses to understand how variations in different aspects of the project impacts the LCOH.

6.1 Financial Model Assumptions

Financial assumptions affect the results of the economic model. A set of financial assumptions were developed for the LCOH model, which are defined in Table 6-1.

Table 6-1 Economic Model Financial Assumptions

FINANCIAL ASSUMPTION	VALUE
Inflation/Escalation	3.0%
Debt Percentage	100%
Debt Rate	3.0%
Debt Term	20 years
Economic Life	20 years
Depreciation Term	NA
Depreciation Basis	NA
Composite Tax Rate	NA
After Tax Cost of Equity, IRR	15%
Discount Rate	3.0%
Electricity Cost	$120.1/MWh
Oxygen Product Value	$0/kg
Tax Incentives	NA
Liquid Hydrogen Delivery Price	$15/kg

Black & Veatch developed a number of technical assumptions as part of the economic model to properly depict the scenarios selected for evaluation. A summary of the LCOH technical assumptions for economic modeling are shown in Table 6-2 and Table 6-3.

Table 6-2 Economic Model Technical Assumptions

TECHNICAL ASSUMPTION	VALUE
Electrolyzer Stack Life	10 years
Electrolyzer Replacement Timeline	Stack Life x $\frac{(Economic\ Life - Stack\ Life)}{Stack\ Life}$
Plant Capacity Degradation	0.5%

Table 6-3 Site Specific Economic Model Technical Assumptions

TECHNICAL ASSUMPTION	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Capacity Factor	4.9%	1.1%	1.1%	1.1%
Hydrogen Usage Rate (kg/hr)	3,009	4,513	4,513	90
Electrolyzer Energy Efficiency (kWh/kg)	50.9	51.7	NA	45.7
Site Energy Efficiency (kWh/kg)	57.4	58.2	NA	53.5

6.2 Economic Modeling Results

Using the financial and technical assumptions in the previous sections, the estimates for LCOH were calculated for each scenario. The results of the economic modeling are shown in Table 6-4.

Table 6-4 Base Scenario Economic Modeling Results

RESULTS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Capital Costs ($)	$1,679 MM	$235 MM	$89 MM	$74 MM
Fixed O&M Costs ($/kg-H2)	$29.16	$12.98	$5.72	$211.46
Variable O&M Costs ($/kg-H2)	$6.79	$4.17	$16.03	$44.44
Hydrogen Price Year 1 ($/kg-H2)	$110.48	$48.45	$33.61	$750.07
Levelized Cost of Hydrogen ($/kg-H2)	$144.19	$63.23	$43.87	$978.96

6.3 Sensitivity Analysis Results

Black & Veatch ran a number of sensitivity analyses to understand how variations in different aspects of the project impacts the LCOH. The following sensitivities were investigated as part of this study:

- Capital Cost ±50 percent.
- O&M Cost ±50 percent.
- Labor Cost ±50 percent.
- Electricity Pricing ±50 percent.
- Water Pricing ±50 percent.
- Capacity Factor ±10 percent.
- Third Party Solar Power

- Liquid Hydrogen Delivery Price ±50 percent.

For all analyses, the values for variables that were not being examined remained the same as the base scenario. Sensitives were analyzed as applicable to each scenario. Electrolyzer stack replacement costs were included in the O&M sensitivity analysis. The sensitivity analysis results, shown as impacts to LCOH in percentage (+/-), are summarized in Table 6-5, with detailed figure of LCOH impacts included below. Tornado chart that highlight the sensitivities for the modeled scenario are included in Figure 6-1, Figure 6-2, and Figure 6-3.

Based on these analyses, it can be seen that the LCOH is the highest for Scenario 1 and Scenario 4 due to the large amount of hydrogen storage required for Scenario 1 and the low hydrogen usage for scenario 4. Scenario 3 has the lowest capital cost and lowest LCOH. Based on the sensitivity, the LCOH values are highly sensitive to capital costs, which is expected given the amount of capital investment required. The LCOH values are moderately sensitive to O&M costs, which is expected given much of the O&M costs are estimated based on capital investment. The LCOH values are moderately sensitive to capacity factor, which is expected given the amount of capital investment required and reduction in capacity factor reduces the total hydrogen produced. The LCOH is less sensitive to labor rates and water costs given the relatively low costs relative to the rest of the related costs. For scenarios 1, 2, and 4 using a third party solar power provider shows a slight increase or decrease in LCOH but is relatively similar to owning the solar field instead. Finally, the liquid delivery scenario is very sensitive to the hydrogen delivery price as this fuel price is a large portion of the overall LCOH.

Table 6-5 Sensitivity Analysis Economic Modeling Results

SENSITIVITY	LCOH
Scenario 1	$144.19/kg
Scenario 1: +50% Capital Costs	$215.78/kg (+49.6%)
Scenario 1: -50% Capital Costs	$72.60/kg (-49.6%)
Scenario 1: +50% O&M Costs	$167.65/kg (+16.3%)
Scenario 1: -50% O&M Costs	$120.73/kg (-16.3%)
Scenario 1: +50% Labor Costs	$144.48/kg (+0.2%)
Scenario 1: -50% Labor Costs	$143.90/kg (-0.2%)
Scenario 1: +50% Water Pricing	$144.24/kg (+0.0%)
Scenario 1: -50% Water Pricing	$144.14/kg (0.0%)
Scenario 1: -10% Capacity Factor	$160.21/kg (+11.1%)
Scenario 1: +10% Capacity Factor	$131.08/kg (-9.1%)
Scenario 1: Third Party Solar Power	$145.79/kg (+1.1%)
Scenario 2	$63.23/kg
Scenario 2: +50% Capital Costs	$93.02/kg (+47.1%)
Scenario 2: -50% Capital Costs	$33.45/kg (-47.1%)
Scenario 2: +50% O&M Costs	$74.43/kg (+17.7%)
Scenario 2: -50% O&M Costs	$52.04/kg (-17.7%)
Scenario 2: +50% Labor Costs	$64.10/kg (+1.4%)
Scenario 2: -50% Labor Costs	$62.37/kg (-1.4%)
Scenario 2: +50% Water Pricing	$63.45/kg (+0.3%)
Scenario 2: -50% Water Pricing	$63.02/kg (-0.3%)
Scenario 2: -10% Capacity Factor	$70.26/kg (+11.1%)
Scenario 2: +10% Capacity Factor	$57.49/kg (-9.1%)
Scenario 2: Third Party Solar Power	$68.59/kg (+8.5%)

SENSITIVITY	LCOH
Scenario 3	$42.83/kg
Scenario 3: +50% Capital Costs	$54.45/kg (+27.1%)
Scenario 3: -50% Capital Costs	$31.21/kg (-27.1%)
Scenario 3: +50% O&M Costs	$56.51/kg (+31.9%)
Scenario 3: -50% O&M Costs	$29.15/kg (-31.9%)
Scenario 3: +50% Labor Costs	$42.83/kg (+0.0%)
Scenario 3: -50% Labor Costs	$42.83/kg (+0.0%)
Scenario 3: +50% Water Pricing	$42.83/kg (+0.0%)
Scenario 3: -50% Water Pricing	$42.83/kg (+0.0%)
Scenario 3: -10% Capacity Factor	$45.41/kg (+6.0%)
Scenario 3: +10% Capacity Factor	$40.72/kg (-4.9%)
Scenario 3: +50% Fuel Price	$52.62/kg (+22.9%)
Scenario 3: -50% Fuel Price	$33.04/kg (-22.9%)
Scenario 4	$978.96/kg (+0.0%)
Scenario 4: +50% Capital Costs	$1441.33/kg (+47.2%)
Scenario 4: -50% Capital Costs	$516.60/kg (-47.2%)
Scenario 4: +50% O&M Costs	$1145.96/kg (+17.1%)
Scenario 4: -50% O&M Costs	$811.97/kg (-17.1%)
Scenario 4: +50% Labor Costs	$1004.79/kg (+2.6%)
Scenario 4: -50% Labor Costs	$952.98/kg (-2.7%)
Scenario 4: +50% Water Pricing	$979.27/kg (+0.0%)
Scenario 4: -50% Water Pricing	$978.81/kg (0.0%)
Scenario 4: -10% Capacity Factor	$1087.74/kg (+11.1%)
Scenario 4: +10% Capacity Factor	$889.97/kg (-9.1%)
Scenario 4: Third Party Solar Power	$959.85/kg (-2.0%)

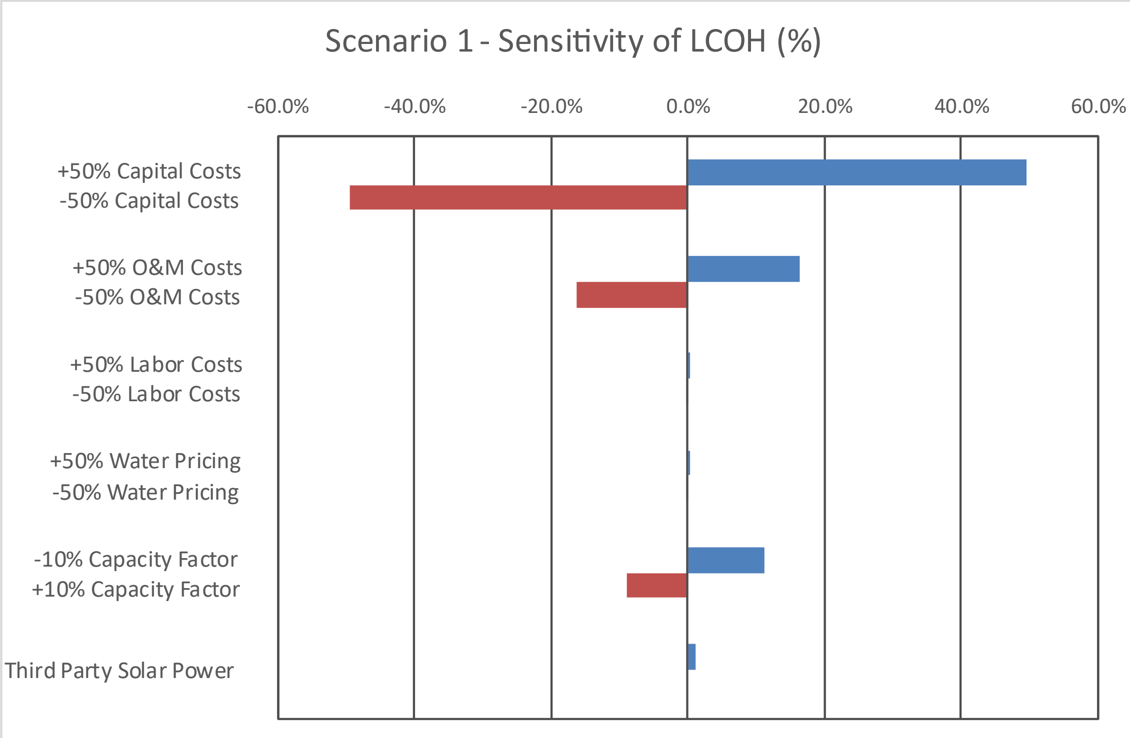


Figure 6-1 Sensitivities of LCOH Model Scenario 1

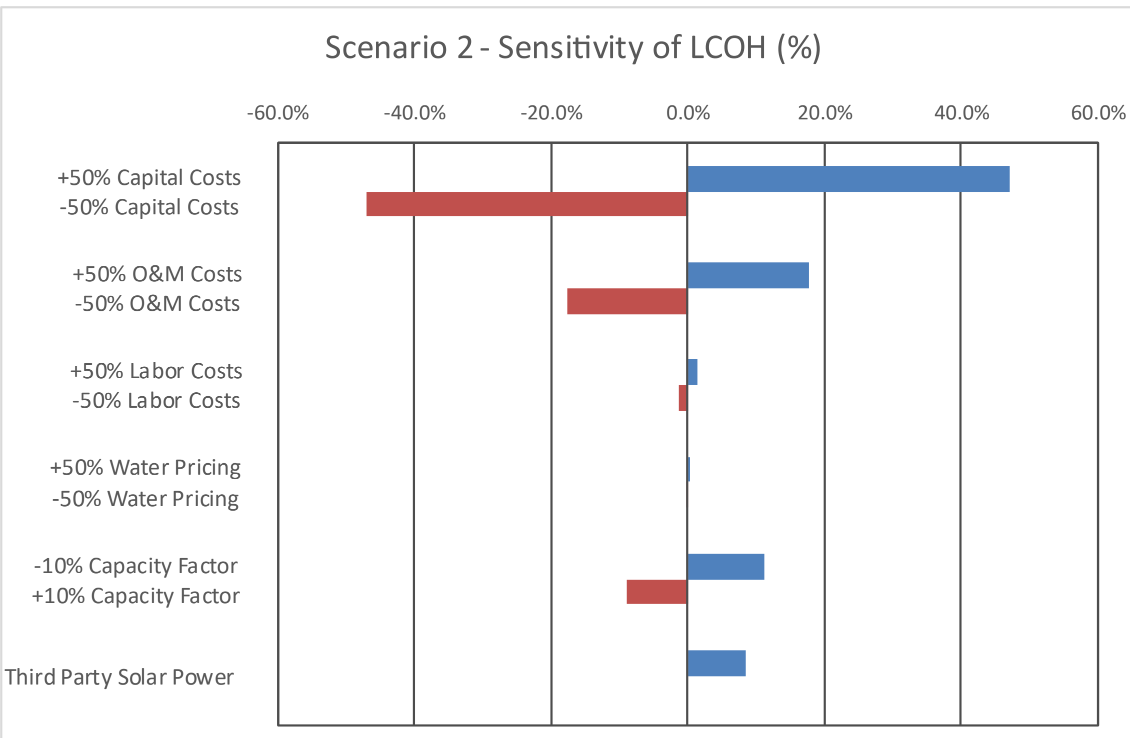


Figure 6-2 Sensitivities of LCOH Model Scenario 2

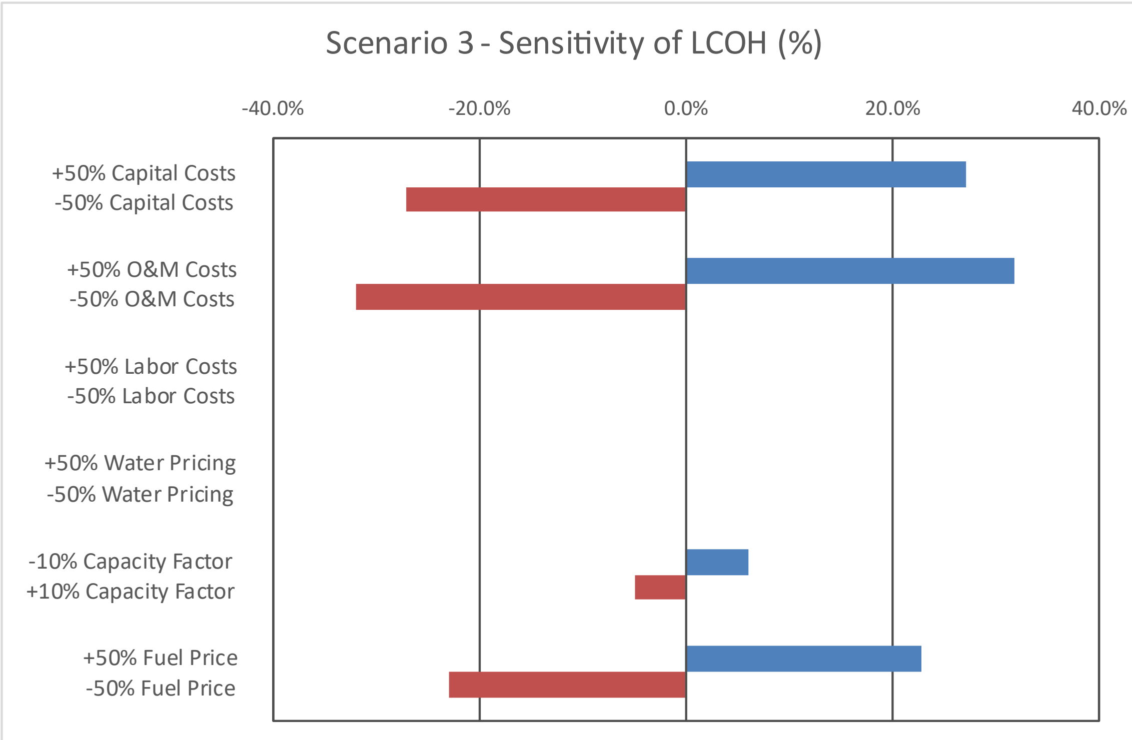


Figure 6-3 Sensitivities of LCOH Model Scenario 3

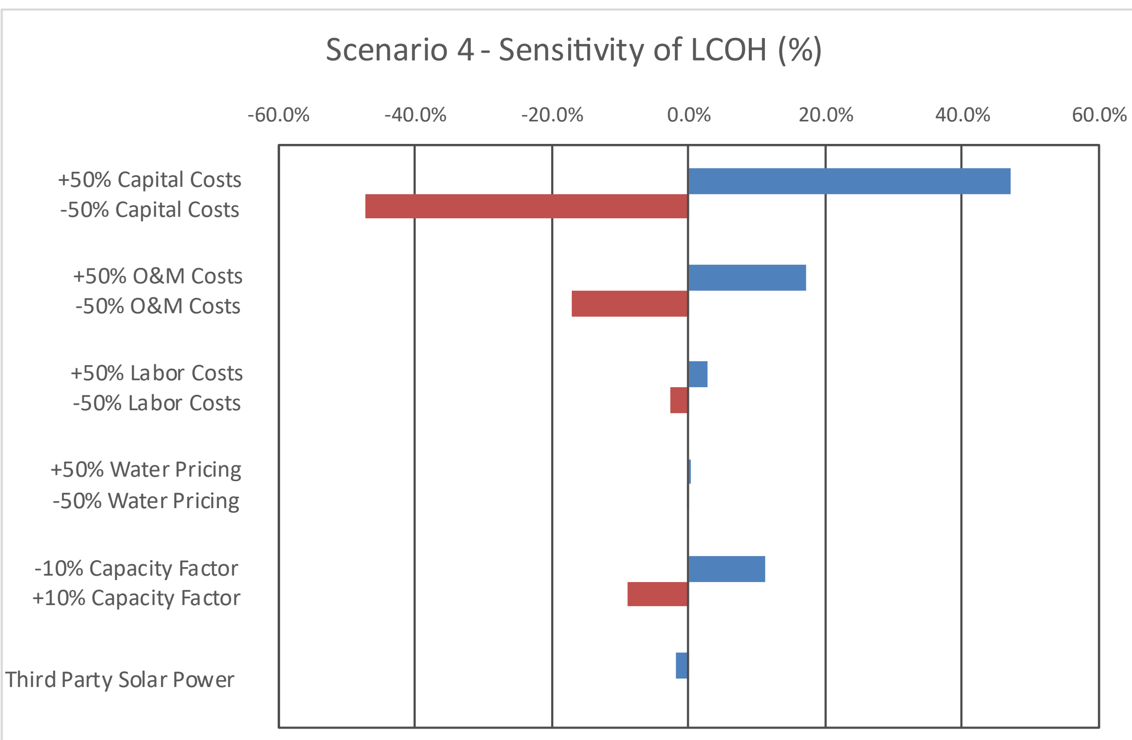


Figure 6-4 Sensitivities of LCOH Model Scenario 4

7.0 Conclusions

Black & Veatch developed a preliminary conceptual engineering design for four scenarios of 100% green hydrogen production, green hydrogen delivery, and 5% green hydrogen production and cofiring. Key findings as to which scenario is feasible are as follows:

- Scenario 1 - 100% green hydrogen cofiring over a 14-day period
  - To meet the operational requirements of Scenario 1—100% hydrogen cofiring over a 14-day period—the electrolysis system must generate up to 1,757 kg/hour of hydrogen, necessitating 1,011 metric tons of on-site hydrogen storage. Accommodating this storage capacity would require approximately 7 acres of land for the storage alone. To support the required hydrogen production, a 132.5 MW photovoltaic (PV) solar field spanning 500 acres would be needed.
  - While the combustion turbines (CTGs) would need to be upgraded for 100% hydrogen cofiring, current technology only supports upgrades to enable 75% hydrogen cofiring. Full 100% hydrogen combustion capability is not expected to be commercially available before 2030 and would require a second major retrofit of the CTGs.
  - Given the substantial space requirements, site constraints within PVSC's Newark Bay WWTP property, and the fact that only 75% hydrogen cofiring is technically achievable in the near term, at present, Scenario 1 is not considered a viable option.

- Scenario 2 - 100% green hydrogen cofiring during an 8-hour monthly event
  - To meet the operational requirements of Scenario 2—100% hydrogen cofiring during an 8-hour monthly event—the electrolysis system must produce up to 314 kg/hour of hydrogen, requiring 36.1 metric tons of hydrogen storage. This storage capacity would occupy approximately 83,000 square feet for the hydrogen production and storage. Supporting this level of hydrogen production would necessitate a 24 MW photovoltaic (PV) solar field, spanning 90 acres.
  - However, due to site constraints, the limited availability of land within PVSC's Newark Bay WWTP boundary, and the fact that only 75% hydrogen cofiring is currently achievable with extensive CTG modifications, at present, Scenario 2 is not considered a viable option.

- Scenario 3 - 100% green hydrogen cofiring via green hydrogen delivery during an 8-hour monthly event
  - Scenario 3 evaluates the delivery of locally produced green hydrogen in lieu of on-site generation. This scenario assumes 100% hydrogen cofiring during an 8-hour monthly operation, mirroring the CTG hydrogen consumption profile of Scenario 2. To minimize vehicular traffic impacts, delivery was limited to what is necessary to support monthly operations. Approximately nine cryogenic liquid hydrogen tanker deliveries would be required per maintenance cycle to fuel all three CTGs for one 8-hour event. Each tanker would transport approximately 15,400 gallons of liquid hydrogen, which would be vaporized and cofired as gaseous hydrogen.
  - Scenario 3 is attractive due to significantly reduced space requirements, as it eliminates the need for on-site renewable energy generation, electrolysis and most of the storage infrastructure. However, it is currently expected to be challenging due to due to the very limited commercial availability of green hydrogen suppliers and the fact that only 75% hydrogen cofiring is achievable with substantial CTG modifications. Therefore, Scenario 3 is not currently considered viable. Once local green hydrogen delivery becomes more accessible, it can be integrated into the facility's infrastructure.

- Scenario 4 - 5% green hydrogen cofiring during an 8-hour monthly event derived from 5 MW of solar power
    - Scenario 4 leverages the planned 5 MW solar photovoltaic (PV) installation at PVSC's Newark Bay WWTP. This solar capacity would enable the on-site electrolysis system to produce up to 71 kg/hour of green hydrogen. The scenario also includes hydrogen storage capacity of 8.1 metric tons, requiring approximately 40,000 square feet of space, to support hydrogen generation, compression, storage and delivery to the combustion turbines (CTGs).
    - Scenario 4 assumes 5% hydrogen cofiring, a level that is compatible with current CTG models without the need for burner modifications. Under this configuration, each CTG could operate for 8 hours during monthly maintenance cycles using the stored hydrogen and still have about 80 hours of hydrogen for each turbine operating at 5% hydrogen for emergency scenarios each month.
    - Scenario 4 is considered technically and logistically feasible, as it utilizes planned solar infrastructure, avoids major CTG modifications, and requires significantly less equipment than the other scenarios. Furthermore, Scenario 4 offers scalability, allowing hydrogen production capacity to increase incrementally in tandem with the availability of additional renewable energy resources.
- Combustion Turbine Hydrogen Modifications
    - Siemens has communicated that the SGT-600s are able to cofire up to 5% hydrogen without major modification to the turbines. Siemens' Hydrogen firing roadmap for their gas turbine product line identifies the SGT-600 model to be commercially available for 100% hydrogen firing by year 2030. Above 5% hydrogen cofiring will require significant turbine upgrades to support the higher hydrogen blends. Siemens provided indicative pricing for cofiring 75% hydrogen blend of which Black & Veatch has estimated the cost associated with a 100% hydrogen upgrade from there.
    - Due to the SPGF's role in emergency operations and the current lack of unlimited green hydrogen supply, it is essential that the combustion gas turbines maintain the capability to utilize natural gas as a reliable backup fuel source.

Due to the preliminary nature of this early design stage, several elements have not yet been fully addressed or incorporated. Throughout the study, Black & Veatch has identified and documented a range of considerations and opportunities for further optimization, which should be evaluated during the development of the final design and implementation plan.

- A detailed analysis of NFPA 2 would need to be performed that coordinates with safety distances which would be confirmed once equipment selection is finalized.
- Implementation would need coordination and review by Authorities Having Jurisdiction.
- Some redundancy for balance of plant equipment, e.g., pumps, was included in the design. However, to keep capital costs low, not all critical equipment included redundancy. Future studies should investigate which equipment should include spares for better resiliency.
- Assumptions were made for access/maintenance requirements based on Black & Veatch's experience. A detailed layout would be refined and optimized as design progresses.
- Based on the results of this feasibility study, the next step would be to down select to a specific scenario of hydrogen usage and production or delivery and then perform a detailed engineering or Front-End Engineering Design study to further development.

8.0 Recommendation

Based on the analysis presented in Section 7 – Conclusions, Scenario 4 is the only option that PVSC can confidently implement by the required initiation milestone. GR2 EJ Specifical Conditions Reference 10 of the Air Pollution Control Operating Permit Significant Modification requires that the transition of the CTGs from natural gas to green hydrogen or another technically feasible renewable energy source be initiated within 120 days of commissioning the SPGF.

Expansion beyond 5% hydrogen cofiring or the implementation of larger-scale on-site green hydrogen production will require additional time and is dependent on several critical factors: securing adequate funding, advancement of third-party green hydrogen delivery infrastructure, availability of additional renewable energy resources, and the overall financial viability of such investments.

8.1 Preliminary Schedule for Scenario 4 (5% Green Hydrogen Cofiring for Monthly Testing – 5 MW of solar power)

DESCRIPTION	ESTIMATED COMPLETION DATE
5 MW of On-Site Solar Power Generation	December 30, 2026
SPGF Notice to Proceed (Contract No. B040)	July 30, 2025
Receipt of Proposals for Engineering Services *Initiate Transition per GR2 EJ Special Condition	January 22, 2026
SPGF Commissioned (Contract No. B040)	July 30, 2027
120 Days from Commissioning	April 1, 2027
5% Green Hydrogen Cofiring System Project	
Design Notice to Proceed	March 5, 2026
Design Complete	March 5, 2027
Receive all AHJ Approvals	June 7, 2027
Commence Construction (NTP)	September 7, 2027
Substantial Completion	March 7, 2030

.

Appendix A. Design Basis Document

Design Basis Document

GENERAL INFORMATION

Client's Name: PVSC
Facility Location: Newark Bay Wastewater Treatment Plant (WWTP)
Unit Type(s): SC Backup Facility with GH2 via Solar Photovoltaic (PV) Cells and Electrolysis

Units

Variables and engineering units to be used for this project are shown in Table 1.

Table 1 Variables and Engineering Units

Variable	Engineering Units
Temperature	°F
Pressure	
Near Atmosphere	psig
Above Atmosphere	psig
Below Atmosphere (Vacuum)	psia
Level	
Process	ft or inches
Storage tanks	ft or inches
Flow	
Gas Volume	SCFM
Gas Mass	lb/hr, or kg/hr, or tonne/day
Liquid Volume, Process flows	gpm
Liquid Volume, Utility flows	gpm
Liquid Mass	lb/hr
Solid Mass	lb/hr
Electrical	
Voltage	V, or kV
Energy	kWh
Real power	W, kW, or MW
Apparent power	VA
Motor power output	hp
Frequency	Hz
Distance	ft, inches
Velocity	ft/s, ft/min
Length	ft
Thermal Conductivity	BTU/(hr ft °F)
Gross Heating Value	BTU/lb
Net Heating Value	BTU/lb
Density	lb/ft^3
Weight	lb, tons
Soil Bearing Pressure	psf

Variable	Engineering Units
Heat/Thermal Duty	MMBTU/hr
Sound Pressure Level	dBA

Design Codes and Standards

The design and specification of work will be in accordance with applicable state and federal laws and regulations, and local codes and ordinances. The codes and industry standards used for design, fabrication, and construction are listed below and will be the editions in effect, including all addenda. Other recognized standards may also be used as design, fabrication, and construction guidelines when not in conflict with the listed standards. Applicable codes shall be finalized during detailed design:

- American Concrete Institute (ACI).
- American Institute of Steel Construction (AISC).
- American Iron and Steel Institute (AISI).
- American National Standards Institute (ANSI).
- American Petroleum Institute (API).
- American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE).
- American Society of Mechanical Engineers (ASME).
- American Society for Testing and Materials (ASTM).
- American Water Works Association (AWWA).
- American Welding Society (AWS).
- New Jersey Uniform Construction Code.
- Cooling Tower Institute (CTI).
- Compressed Gas Association (CGA).
- Concrete Reinforcing Steel Institute (CRSI).
- Environmental Protection Agency 40 CFR Part 60 and 40 CFR Part 75 (EPA).
- Illuminating Engineering Society (IES).
- Institute of Electrical and Electronics Engineers (IEEE).
- International Organization for Standardization (ISO).
- International Society of Automation (ISA).
- Insulated Cable Engineers Association (ICEA).
- National Electrical Code (NEC).
- National Fire Protection Association (NFPA).
- National Institute of Standards and Technology (NIST).
- Occupational Safety and Health Administration (OSHA).

SITE INFORMATION

Site Conditions

Site-specific design criteria are shown in Table 2. The site location is Newark Bay wastewater treatment plant (WWTP) in Newark, NJ.

Table 2 Site-Specific Design Criteria

Parameter	Specification (Note 1)
Design Barometric Pressure	14.69 psia
Elevation	7 ft
Design Winter Ambient Temperature	20.3°F (Note 2)
Design Summer Ambient Temperature (dry bulb)	91.1°F (Note 3)
Design Summer Ambient Temperature (wet bulb)	72.8°F (Note 3)
Note 1: Non-site specific location of Newark, NJ, USA ASHRAE 2021 Data Note 2: 99.0% Heating Dry Bulb (DB) Note 3: 1.0% Cooling DB and Mean Coincident Wet Bulb (MCWB) to the DB.	

Raw Water and Demineralized Water Supply

The site is assumed to have water access supplied by the utility, before heading to an on-site demineralized water treatment process. Demineralized water will be required for the electrolysis process. The demineralized water will be produced via a reverse osmosis system and a downstream demineralizer. The required amount of demineralized water is shown in Table 9. The required amount of raw water is shown in Table 14, assuming 76.5 percent water recovery rate.

Wastewater Disposal

Plant wastewater includes compressor condensate, wastewater from the electrolyzer drains, and water treatment reject from the water treatment system. An evaluation of the wastewater quality, the plant's wastewater discharge permits, and the wastewater collection and handling approach will be completed during detailed engineering design to determine the strategy for wastewater disposal from the Hydrogen Production Facility. The current basis of design is that all wastewater will be pumped to wastewater sump. The amount of wastewater produced is indicated in Table 15.

Noise Limitations

The near-field noise emissions for each equipment component furnished shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 ft above floor/ground level and any personnel platform during normal operation. The equipment envelope is defined as the perimeter line that completely encompasses the equipment package at a distance of 3-ft horizontally from the equipment face.

Where the drive motors, variable frequency drives (VFDs), or mechanical drives for the equipment are also furnished, the total combined near-field sound pressure level of the motor, VFD, or mechanical drive and the driven equipment measured as a single component, operating at design load, shall not exceed a spatially-averaged, free-field, A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope. During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 110 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

UTILITY REQUIREMENTS – HYDROGEN PRODUCTION WITH ELECTROLYSIS AND SOLAR PHOTOVOLTAIC (PV) CELLS

The design basis will include two scenarios of hydrogen production and storage; the first (Scenario 1) assuming the SPGF will run two combustion turbines for two weeks on 100% hydrogen and the second scenario (Scenario 2), PVSC will fire 100% hydrogen with three turbines during its 8-hour monthly maintenance cycle. The two scenarios will have different requirements and therefore be discussed separately when applicable.

Utilities required for the traditional PV cells with proton-exchange membrane (PEM) electrolysis facility to operate are outlined in this section. Instrument air shall be sourced from an instrument air package and sized for the maximum expected instantaneous flow. Example instrument air system requirements are outlined in Table 3. The purpose of instrument air is to actuate valves and equipment.

Table 3 Instrument Air System Requirements

Parameter	Specification
Dew Point	-40°F at line pressure
Quality	Free of oil
Dryer	Heatless Regeneration
Maximum Operating Pressure	130 psig
Operating Temperature	140°F
Particle Size	< 1 micron
Minimum Operating Pressure	80 psig
Receiver Storage	5 minutes from normal pressure to minimum operating pressure

Nitrogen shall be sourced from a delivered nitrogen supply or onsite generation system. Example nitrogen system requirements are outlined in Table 4. The purpose of nitrogen is to provide dilution flow or inerting flow for hydrogen equipment and instrument panels prior to maintenance or shutdown.

Table 4 Nitrogen System Requirements

Parameter	Specification
Quality	> 99.98 % N2
Maximum Operating Pressure	250 psig
Operating Temperature	Ambient
Minimum Operating Pressure	145 psig

The cooling system will be provided by dry cooling consisting of air-cooled heat exchangers (ACHE). Preliminary cooling system requirements for are shown in Table 5.

Table 5 Cooling System Requirements

Parameter	Scenario 1	Scenario 2
Total Process Cooling Duty	86.2 MMBTU/h	14.4 MMBTU/hr
Cooling Water Flow Rate	10,798 gpm	1,928 gpm

Assuming that the solar generation will not be located next to the hydrogen production facility, electric power will be provided for hydrogen production facility per the requirements outlined in Table 6. Excess electricity generated from the solar farm could be distributed to the grid.

Table 6 Electrical Requirements

Utility	Utility Supply Information
Scenario 1: Solar Electrical Power Supply	For the basis of the study, it is assumed a varying power supply will be derived from the 132.5 MW solar farm.
Scenario 2: Solar Electrical Power Supply	For the basis of the study, it is assumed a varying power supply will be derived from the 24.0 MW solar farm.

PROCESS DESIGN BASIS – HYDROGEN FIRED CTGS WITH SOLAR PHOTOVOLTAIC (PV) CELLS WITH ELECTROLYSIS

Solar Requirements

Power will be supplied by the solar farm to the hydrogen production facility via grid connection and PPA. Expected solar requirements are outlined in Table 7 based on the solar profile used in the modeling effort. This solar profile has an average capacity factor of 20.3 percent using single-axis tracking modules due to the latitude of the project site. The representative profile was determined using the location of the Newark Bay WWTP.

Table 7 Solar Requirements

Parameter	Scenario 1	Scenario 2
Solar Capacity	132.5 MW	24.0 MW
Solar Module Rating	575 W	575 W
Solar Modules	230,292	41,661
Solar Racks[1]	2,559	463
Land Required	~500 acres	~90 acres
Note 1: Each rack is assumed to have 90 modules.		

Electricity Requirement Estimates

A summary of the plant electricity requirement at peak production is provided in Table 8. The solar farm has been sized by considering all plant loads, including any BOP.

Table 8 Plant Energy Requirement Estimates

Parameter	Scenario 1	Scenario 2
Electrolyzer	89,475 kW	16,210 kW
Water Supply	3.1 kW	1.0 kW
Cooling System	7,988 kW	1,429 kW
Water Treatment	4.6 kW	1.2 kW

Electrolysis Inputs

Expected sizing and requirements for electrolysis are outlined in Table 9 based on the maximum hydrogen production per hour. Electrolysis was sized with an assume capacity factor equal to the solar capacity factor to allow for hourly matching.

Table 9 Electrolysis Feedstocks

Parameter	Scenario 1	Scenario 2
Demineralized Water	77.3 gpm	13.8 gpm
Beginning of Life Operating Load[1]	100.9 MW	18.2 MW
Estimated Plant Yield Rate	57.4 kWh/kg	58.2 kWh/kg
Electrolyzer Availability	100%	100%
Note 1: BOL load includes all BOP and is for current plant operating philosophy and does not indicate the maximum value if PVSC was to select a different operating philosophy.		

Electrolysis Outputs

Expected products for electrolysis are provided in Table 10. These values assume the electrolyzer will provide sufficient hydrogen for each scenario's requirements.

Table 10 Electrolysis Products

Parameter	Scenario 1	Scenario 2
Average Hourly Hydrogen Production	468 kg/hr	84 kg/hr
Max Hourly Hydrogen Production	1,757 kg/hr	314 kg/hr
Average Hourly Oxygen Production	3,744 kg/hr	672 kg/hr
Max Hourly Oxygen Production	14,056 kg/hr	2,512 kg/hr
Wastewater	23.8 gpm (Note 1)	4.2 gpm (Note 1)
Note 1: Wastewater generation is from demineralized water production and based on 22.2% water treatment rejection from process water.		

Hydrogen Compressors

Expected requirements for the hydrogen storage compressor are outlined in Table 13. The overall storage method for fueling is a direct storage method.

Table 11 Hydrogen Storage Compressor

Parameter	Scenario 1	Scenario 2
Hydrogen Inlet Pressure	Near Ambient	Near Ambient
Hydrogen Outlet Pressure	4,000 psig	4,000 psig
Compressor Power	4,550 hp	813 hp
Compressor Capacity	1 x 100%	1 x 100%
Mass Flow	1,757 kg/hr	314 kg/hr
Compression Stages	7 Stages	7 Stages
Compressor Ratio	2.13	2.13

Expected requirements for the hydrogen fuel compressor are outlined in Table 13. The fuel compressor would replace the existing fuel compressor and use turbine auxiliary power.

Table 12 Hydrogen Fuel Compressor

Parameter	Scenario 1	Scenario 2
Hydrogen Inlet Pressure	Near Ambient	Near Ambient
Hydrogen Outlet Pressure	355 psig	355 psig
Compressor Power	4,550 hp	6,825 hp
Compressor Capacity	1 x 100%	1 x 100%
Mass Flow	3,009 kg/hr	4,513 kg/hr
Compression Stages	4 Stages	4 Stages
Compressor Ratio	2.13	2.13

Hydrogen Storage

Expected requirements for hydrogen storage are outlined in Table 13. The overall storage method for fueling is a direct storage method with hydrogen storage tubes and with inlet and outlet compression, as needed.

Table 13 Hydrogen Storage

Parameter	Scenario 1	Scenario 2
Storage Duration	14 days of 2 GT Operation	8 hours of 3 GT Operation
Average Complete Storage Refill Time	90 days	18 days*
Total Storage Mass	1,010,925 kg	36,139 kg
Storage Tubes Quantity	19,861	710
Storage Tube Dimension	11.5 ft diameter x 38 ft long	11.5 ft diameter x 38 ft long
Tube Storage Pressure	4,000 psig (275 bar)	4,000 psig (275 bar)
*Reduced from 30 days to ensure monthly fill		

Raw Water Consumption

Expected raw water demand is outlined in Table 14.

Table 14 Raw Water Consumption

Parameter	Scenario 1	Scenario 2
Raw Water to Water Treatment	101.1 gpm	18.0 gpm

Wastewater Generation

Expected wastewater generation is outlined in Table 15.

Table 15 Wastewater Generation

Parameter	Scenario 1	Scenario 2
Process Water	77.3 gpm	13.8 gpm
Water Treatment Rejection Rate	23.5%	23.5%
Wastewater from Water Treatment	23.8 gpm	4.2 gpm
Wastewater from Hydrogen Purification	5.2 gpm	0.9 gpm
Total Wastewater	29.0 gpm	5.1 gpm

Combustion Turbine Power Generation

Expected combustion turbine power generation is outlined in Table 16 after turbines have been retrofitted for 100% hydrogen cofiring. This is based on turbine output and performance that has been provided by OEM's up to 75% hydrogen and projected to 100% hydrogen cofiring. Turbine outputs are reduced at higher hydrogen blends to maintain lower flame temperatures and Nox emissions levels.

Table 16 Combustion Turbine Power Generation

Parameter	Scenario 1	Scenario 2
Turbine Arrangement	2+1x0	3x0
Maximum Daily Hydrogen Usage	3,009 kg/hr	4,513 kg/hr
Heat Input (LHV)	342 MMBTU/hr	513 MMBTU/hr
Turbine Heat Rate (LHV)	11,400 (BTU/kWh)	11,400 (BTU/kWh)
Plant Net Output (Per Turbine/Plant Total, MW)	15/30	15/45

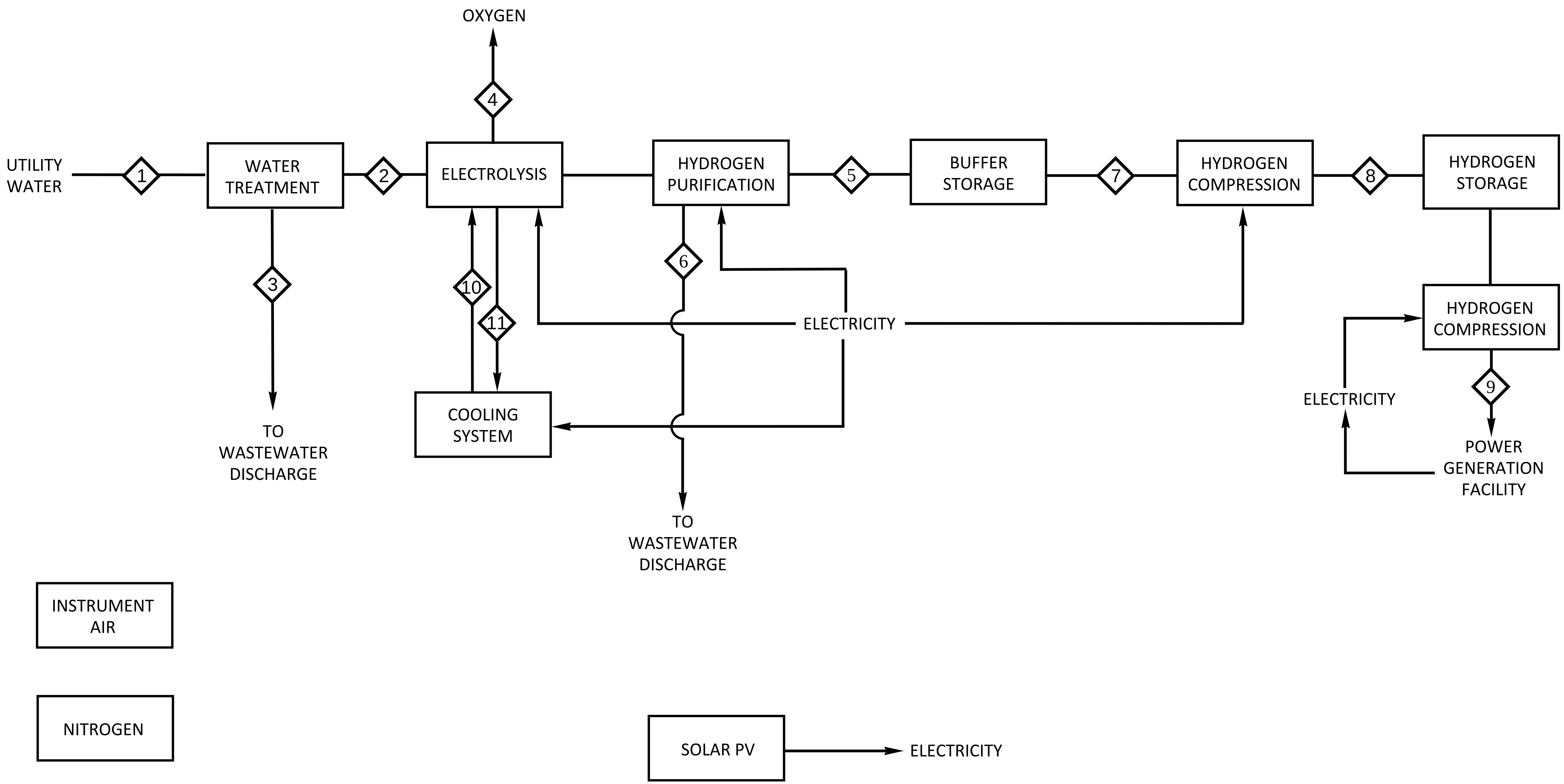
Sparing Philosophy

The equipment sparing philosophy is provided in Table 17. An installed spare is installed in the system but only used when the primary component fails.

Table 17 Equipment Sparing Philosophy

Equipment Type	Scenario 1	Scenario 2
Continuous Duty and Critical Service Pumps	Installed Spare(s)	Installed Spare(s)
Hydrogen Compressors	Not Spared	Not Spared
Heat Exchangers	Not Spared	Not Spared
Electrolyzers	Not Spared	Not Spared

Appendix B. Block Flow Diagrams



OXYGEN
4
UTILITY WATER
1
WATER TREATMENT
2
ELECTROLYSIS
HYDROGEN PURIFICATION
5
BUFFER STORAGE
7
HYDROGEN COMPRESSION
8
HYDROGEN STORAGE
3
10
11
6
ELECTRICITY
HYDROGEN COMPRESSION
9
ELECTRICITY
TO WASTEWATER DISCHARGE
COOLING SYSTEM
POWER GENERATION FACILITY
TO WASTEWATER DISCHARGE
INSTRUMENT AIR
NITROGEN
SOLAR PV
ELECTRICITY

Scenario 1: Heat & Mass Balance

Stream Name				Raw Water from Municipal System	Demin Water to Electrolyzer	Wastewater from Water Treatment	Oxygen from Electrolyzer	Hydrogen from Electrolyzer	Wastewater from Purification	Hydrogen Gas from Buffer Storage	Hydrogen Gas from Compression	Hydrogen Gas from Storage	Cooled Water to Electrolyzer	Cooled Water From Electrolyzer
Stream Number		Mol Wt	Units	1	2	3	4	5	6	7	8	9	10	11
	Vapor Fraction (Mole)			0.0	0.0	0.0	1.0	1.0	0.0	1.0	1.0	1.0	0.0	0.0
	Temperature		°F	70.0	70.0	70.0	70.0	70.0	70.0	70.0	261.0	268.0	106.2	121.2
	Pressure		psia	64.7	43.7	14.7	14.7	16.2	14.7	16.2	4,014.7	354.7	101.7	99.7
	Pressure		bara	20.5	19.0	17.0	17.0	17.1	17.0	17.1	292.8	40.5	7.0	22.9
	Mass Flow		lb/h	50,602.9	38,706.7	11,896.1	32,269.0	6,437.8	2,586.0	3,873.3	3,873.3	3,873.3	5,406,811.7	5,406,811.7
	Volume Flow (actual)		ft3/h	810.6	620.0	190.6	381,557.5	36,579.6	41.4	22,278.1	22,278.1	22,278.1	86,609.0	86,609.0
	Molecular Weight		lb/lbmol	18.0	18.0	18.0	30.7	3.1	18.0	3.1	3.1	3.1	18.0	18.0
Liquid Properties	Mass Flow		lb/h	50,602.9	38,706.7	11,896.1			2,586.0				5,406,811.7	5,406,811.7
	Mass Flow		STPD	607.2	464.5	142.8			31.0				64,881.7	64,881.7
	Volume Flow (standard)		USGPM	101.1	77.3	23.8			5.2				10,798.0	10,798.0
	Density		lb/ft3	62.4	62.4	62.4			62.4				62.4	62.4
	Viscosity		cP	1.5	1.5	1.5			1.3				0.5	0.5
	Thermal. Cond.		BTU/h-ft-°F	0.3	0.3	0.3			0.3				0.4	0.4
	Surface Tension		dyne/cm	75.4	75.4	75.4			74.3				75.4	75.4
	Mass Heat Capacity		BTU/lb-°F	1.0	1.0	1.0			1.0				1.0	1.0
	Molecular Weight		lb/lbmol	18.0	18.0	18.0			18.0				18.0	18.0
Vapor Properties	Mass Flow		lb/h				32,269.0	6,437.8		3,873.3	3,873.3	3,873.3		
	Mass Flow		MTPD				351.3	70.1		42.2	42.2	42.2		
	Volume Flow (standard)		MMSCFD				9.4	17.8		17.8	17.8	17.8		
	Density		lb/ft3				0.1	0.2		0.2	0.2	0.2		
	Viscosity		cP				0.0	0.0		0.0	0.0	0.0		
	Compressibility						1.0	1.0		1.0	1.0	1.0		
	Thermal. Cond.		BTU/h-ft-°F				0.0	0.1		0.1	0.1	0.1		
	Mass Heat Capacity		BTU/lb-°F				0.2	3.4		3.4	3.4	3.4		
	Molecular Weight		lb/lbmol				30.7	3.1		3.1	3.1	3.1		
Compositions	Water (H_2O)	18.02	lbmol/h	2,808.9	2,148.5	660.3	94.1	132.8	143.5	79.9	79.9	79.9	300,120.0	300,120.0
	Hydrogen (H_2)	2.02	lbmol/h	0.0	0.0	0.0	2.7	1,921.3	0.0	1,155.9	1,155.9	1,155.9	0.0	0.0
	Oxygen (O_2)	32.00	lbmol/h	0.0	0.0	0.0	955.3	5.4	0.0	3.2	3.2	3.2	0.0	0.0
	Nitrogen (N_2)	14.00	lbmol/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Ammonia (NH_3)	17.03	lbmol/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Molar Flow			lbmol/h	2,808.9	2,148.5	660.3	1,052.1	2,059.5	143.5	1,239.1	1,239.1	1,239.1	300,120.0	300,120.0

NOTES:

1. Water recovery rate of 76% assumed, to be confirmed in future design phases.
2. Values are representative of final build out.
3. Capacity factor of 26.6% assumed to match hydrogen production with rate of consumption.

Scenario 2: Heat & Mass Balance

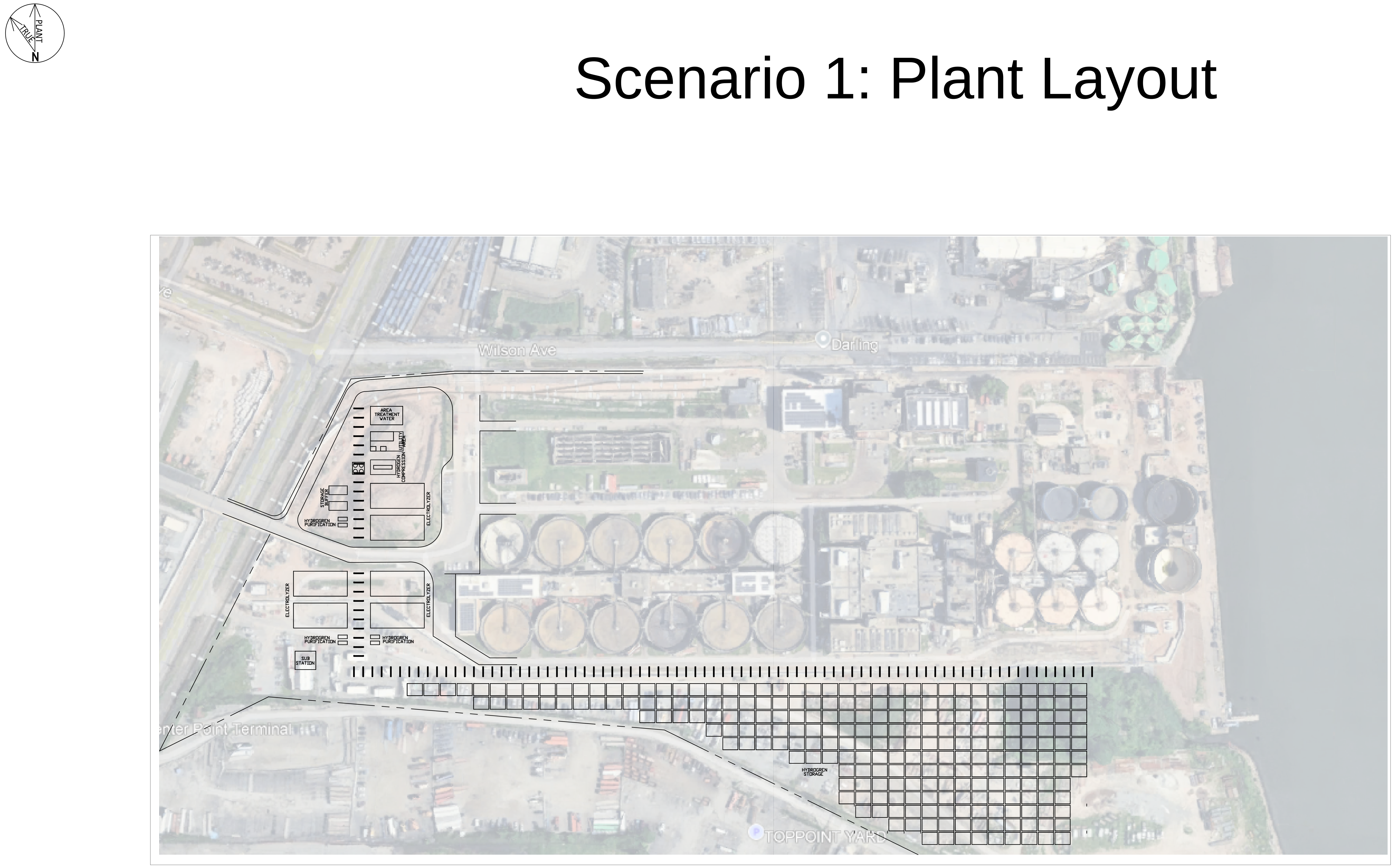
Stream Name				Raw Water from Municipal System	Demin Water to Electrolyzer	Wastewater from Water Treatment	Oxygen from Electrolyzer	Hydrogen from Electrolyzer	Wastewater from Purification	Hydrogen Gas from Buffer Storage	Hydrogen Gas from Compression	Hydrogen Gas from Storage	Cooled Water to Electrolyzer	Cooled Water From Electrolyzer
Stream Number		Mol Wt	Units	1	2	3	4	5	6	7	8	9	10	11
	Vapor Fraction (Mole)			0.0	0.0	0.0	1.0	1.0	0.0	1.0	1.0	1.0	0.0	0.0
	Temperature		°F	70.0	70.0	70.0	70.0	70.0	70.0	70.0	261.0	268.0	106.1	111.1
	Pressure		psia	64.7	43.7	14.7	14.7	16.2	14.7	16.2	4,014.7	354.7	97.9	99.7
	Pressure		bara	20.5	19.0	17.0	17.0	17.1	17.0	17.1	292.8	40.5	6.7	22.9
	Mass Flow		lb/h	9,082.2	6,947.1	2,135.1	5,791.6	1,155.4	464.1	695.2	695.2	695.2	965,394.8	965,394.8
	Volume Flow (actual)		ft3/h	145.5	111.3	34.2	68,481.8	6,565.3	7.4	3,998.5	3,998.5	3,998.5	15,464.2	15,464.2
	Molecular Weight		lb/lbmol	18.0	18.0	18.0	30.7	3.1	18.0	3.1	3.1	3.1	18.0	18.0
Liquid Properties	Mass Flow		lb/h	9,082.2	6,947.1	2,135.1			464.1				965,394.8	965,394.8
	Mass Flow		STPD	109.0	83.4	25.6			5.6				11,584.7	11,584.7
	Volume Flow (standard)		USGPM	18.1	13.9	4.3			0.9				1,928.0	1,928.0
	Density		lb/ft3	62.4	62.4	62.4			62.4				62.4	62.4
	Viscosity		cP	1.5	1.5	1.5			1.3				0.5	0.5
	Thermal. Cond.		BTU/h-ft-°F	0.3	0.3	0.3			0.3				0.4	0.4
	Surface Tension		dyne/cm	75.4	75.4	75.4			74.3				75.4	75.4
	Mass Heat Capacity		BTU/lb-°F	1.0	1.0	1.0			1.0				1.0	1.0
	Molecular Weight		lb/lbmol	18.0	18.0	18.0			18.0				18.0	18.0
Vapor Properties	Mass Flow		lb/h				5,791.6	1,155.4		695.2	695.2	695.2		
	Mass Flow		MTPD				63.0	12.6		7.6	7.6	7.6		
	Volume Flow (standard)		MMSCFD				1.7	3.2		3.2	3.2	3.2		
	Density		lb/ft3				0.1	0.2		0.2	0.2	0.2		
	Viscosity		cP				0.0	0.0		0.0	0.0	0.0		
	Compressibility						1.0	1.0		1.0	1.0	1.0		
	Thermal. Cond.		BTU/h-ft-°F				0.0	0.1		0.1	0.1	0.1		
	Mass Heat Capacity		BTU/lb-°F				0.2	3.4		3.4	3.4	3.4		
	Molecular Weight		lb/lbmol				30.7	3.1		3.1	3.1	3.1		
Compositions	Water (H_2O)	18.02	lbmol/h	504.1	385.6	118.5	16.9	23.8	25.8	14.3	14.3	14.3	53,586.9	53,586.9
	Hydrogen (H_2)	2.02	lbmol/h	0.0	0.0	0.0	0.5	344.8	0.0	207.5	207.5	207.5	0.0	0.0
	Oxygen (O_2)	32.00	lbmol/h	0.0	0.0	0.0	171.5	1.0	0.0	0.6	0.6	0.6	0.0	0.0
	Nitrogen (N_2)	14.00	lbmol/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Ammonia (NH_3)	17.03	lbmol/h	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Molar Flow			lbmol/h	504.1	385.6	118.5	188.8	369.6	25.8	222.4	222.4	222.4	53,586.9	53,586.9

NOTES:

1. Water recovery rate of 76% assumed, to be confirmed in future design phases.
2. Values are representative of final build out.
3. Capacity factor of 26.6% assumed to match hydrogen production with solar production.

Appendix C. Plant Layout Drawings

Scenario 1: Plant Layout



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DATE ________ REG. No. ________

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	05/27/2025	ISSUED FOR IN–HOUSE REVIEW	VPM	VPM	VPM		

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11401 Lamar Avenue
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JOB No. XXXXXX
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B&V REV.

PASSAIC VALLEY SEWERAGE COMMISSION
Facilities Inventory and
Condition Assessment Analysis

NEWARK BASE
WASTEWATER TREATMENT PLANT
COMBINED CYCLE
PLOT PLAN

OWNER	PLANT(S)	SCALE 1/128" = 1'
DRAWN VPM	CHK/APP VPM	SHT. 1 OF 1
JOB NO.	DRAWING NUMBER XXXXX	REV A

000-XXXX-0000 JKD - 10/31/2020

Scenario 2: Plant Layout

PASSAIC VALLEY SEWERAGE COMMISSION
Facilities Inventory and
Condition Assessment Analysis

NEWARK BASE
WASTEWATER TREATMENT PLANT
COMBINED CYCLE
PLOT PLAN

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SIGNED ____________

DATE ________ REG. No. ________

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A	06/10/2025	ISSUED FOR IN-HOUSE REVIEW	VPM	VPM	VPM		

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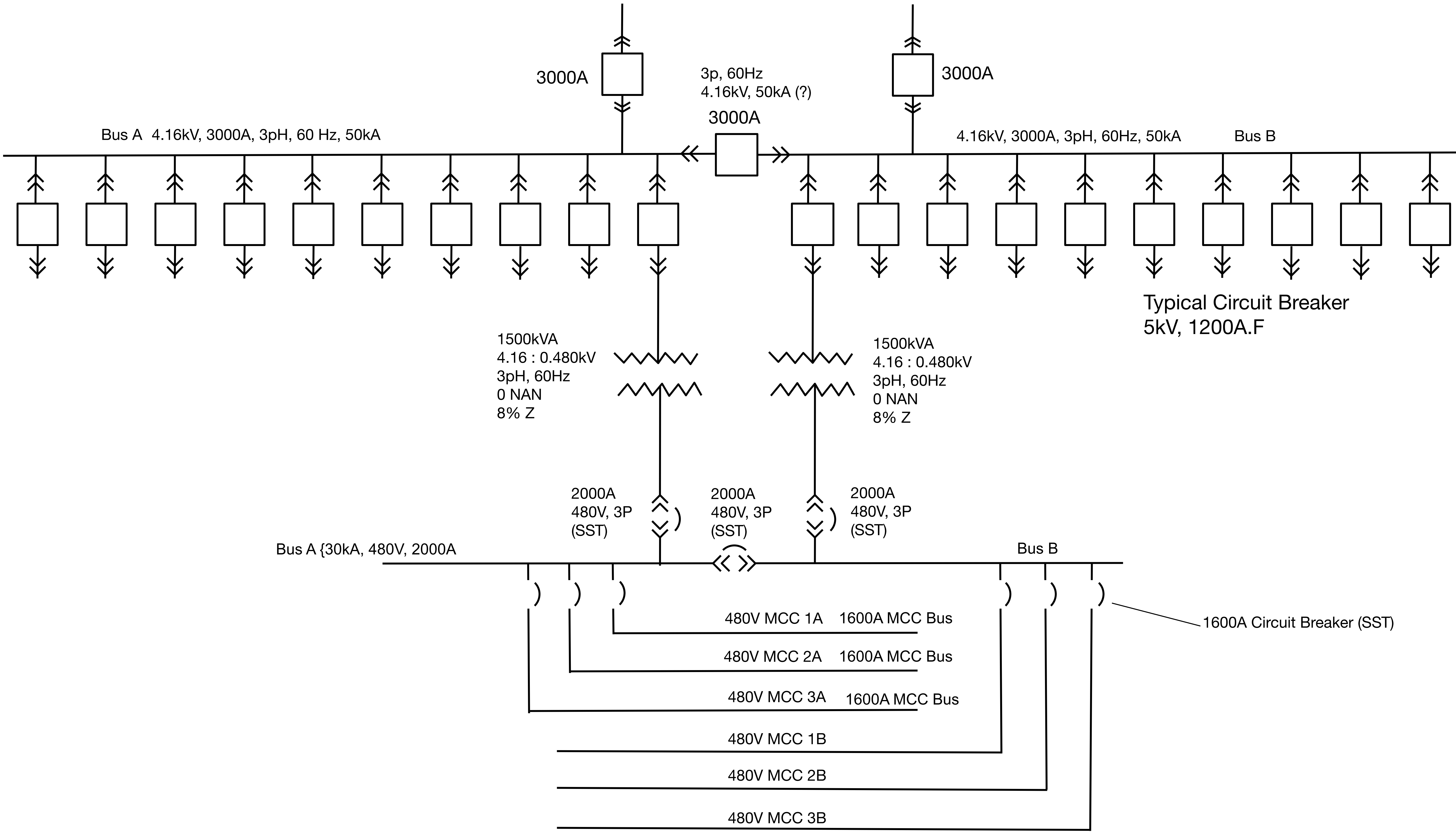
DRAWN VPM	CHK/APP VPM	SHT. 1 OF 1

JOB NO. | DRAWING NUMBER XXXXX | REV A

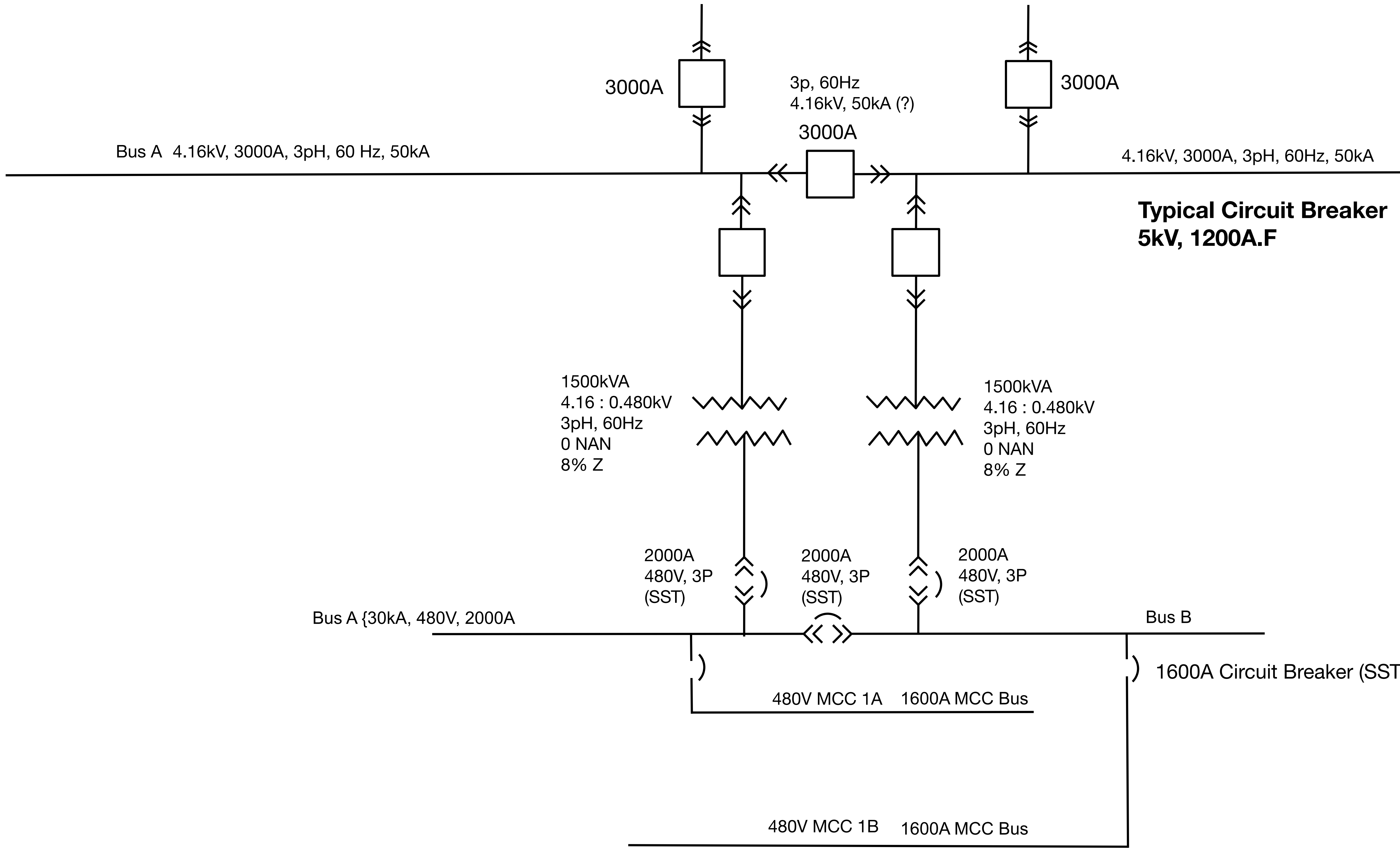
000-XXXX-0000 JKD - 10/31/2020

Appendix D. Electrical One Line Diagrams

Scenario 1: Single Line Digram



Scenario 2: Single Line Digram



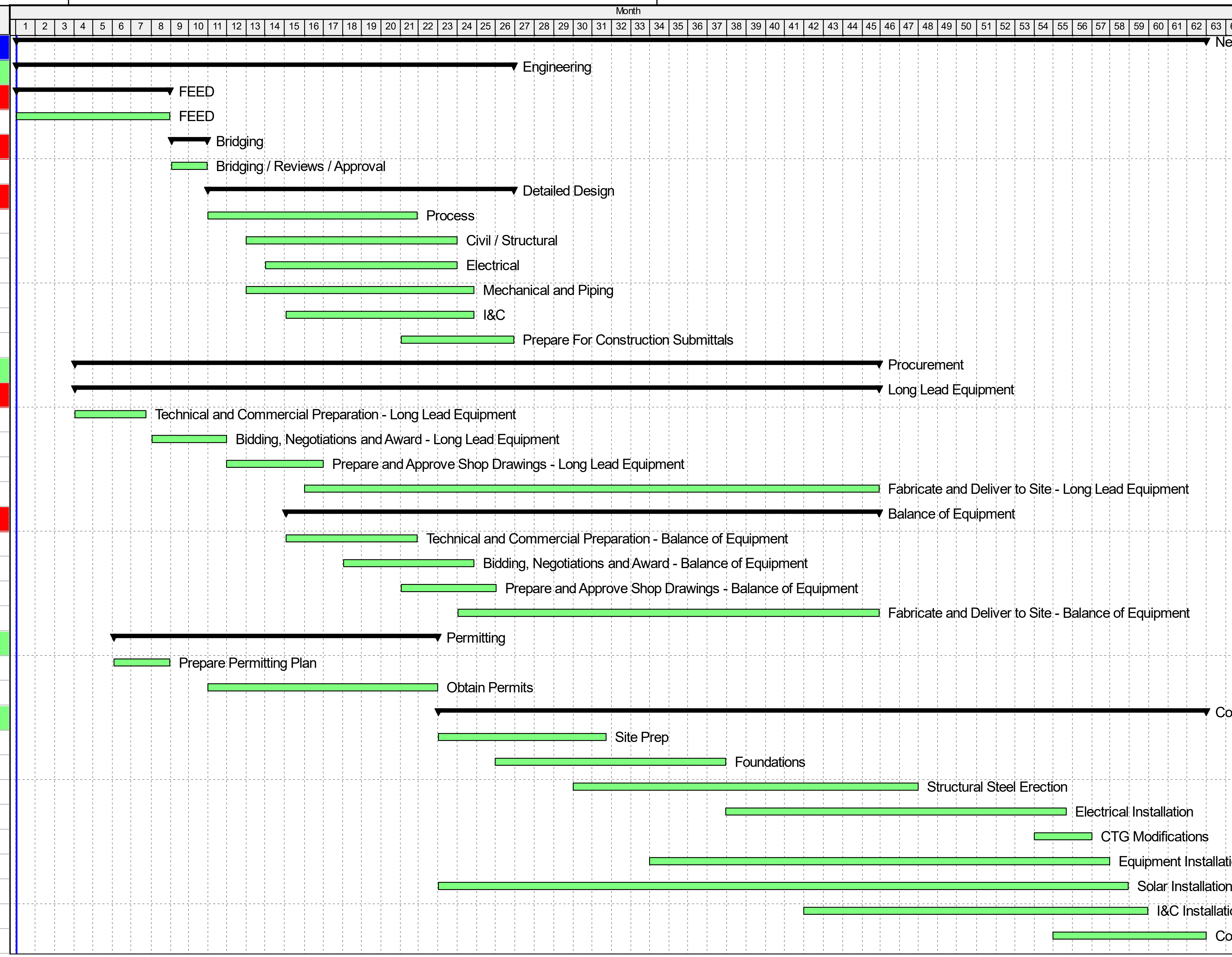
Appendix E. Level 1 EPC Schedules

Project: Newark Bay WWTP Green H2 Cofiring - Scenario 1
Layout Name: JGS - PVSC SPGF SC1 L1

PVSC Newark Bay WWTP SPGF H2 Cofiring Project
Scenario 1 (14 Day Runtime @ 100% H2)

Run Date:11-Jun-25

Activity Name
Newark Bay WWTP Green H2 Cofiring - Scenario 1
Engineering
FEED
FEED
Bridging
Bridging / Reviews / Approval
Detailed Design
Process
Civil / Structural
Electrical
Mechanical and Piping
I&C
Prepare For Construction Submittals
Procurement
Long Lead Equipment
Technical and Commercial Preparation - Long Lead Equipment
Bidding, Negotiations and Award - Long Lead Equipment
Prepare and Approve Shop Drawings - Long Lead Equipment
Fabricate and Deliver to Site - Long Lead Equipment
Balance of Equipment
Technical and Commercial Preparation - Balance of Equipment
Bidding, Negotiations and Award - Balance of Equipment
Prepare and Approve Shop Drawings - Balance of Equipment
Fabricate and Deliver to Site - Balance of Equipment
Permitting
Prepare Permitting Plan
Obtain Permits
Construction
Site Prep
Foundations
Structural Steel Erection
Electrical Installation
CTG Modifications
Equipment Installation
Solar Installation
I&C Installation
Commissioning and Startup



Remaining Work
Milestone
Summary

Level 1 EPC by WBS

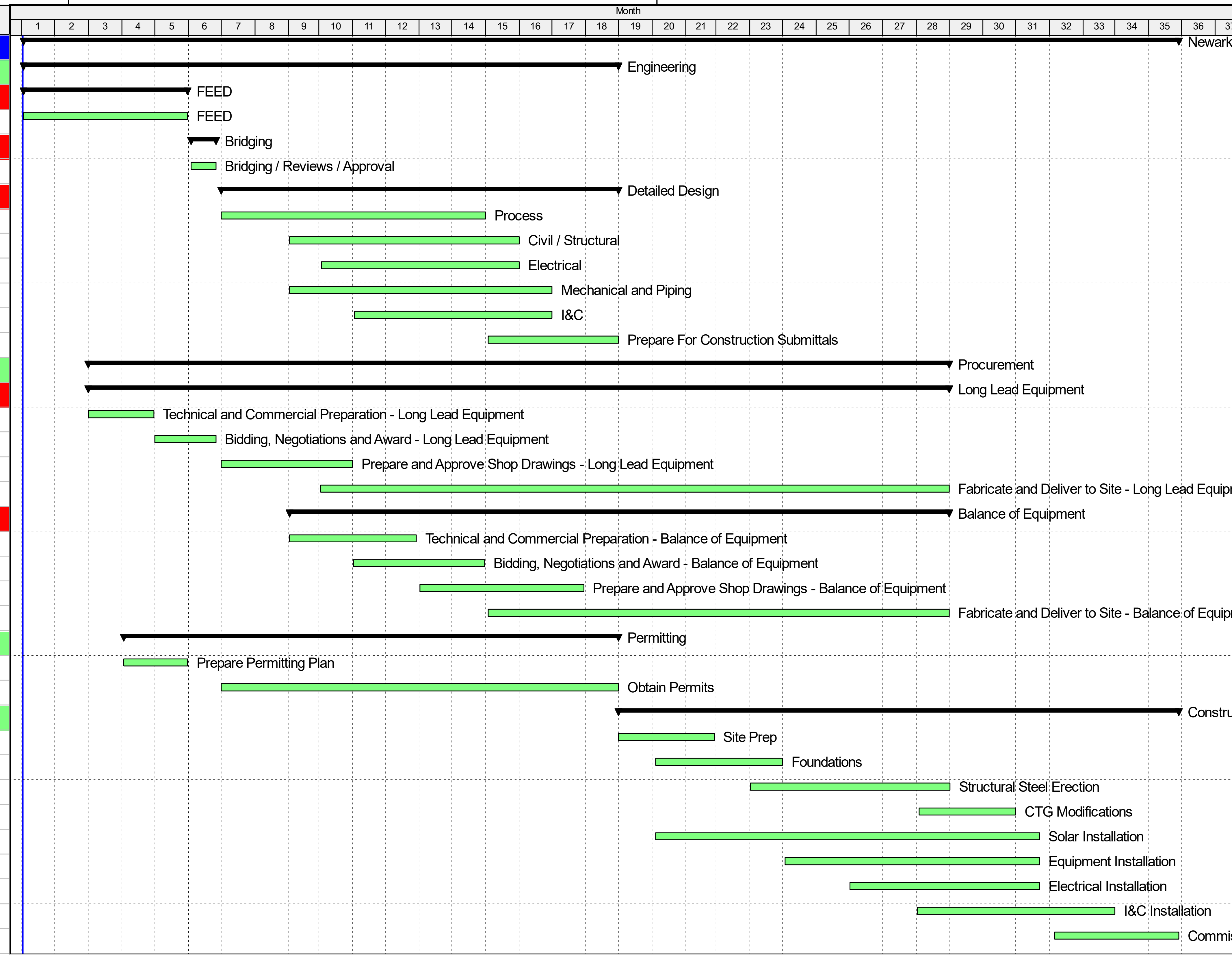
Date	Revision	Checked	Approved
11-Jun-25	R0 - For Submission	JGS	

Project: Newark Bay WWTP Green H2 Cofiring - Scenario 2
Layout Name: JGS - PVSC SPGF SC2 L1

PVSC Newark Bay WWTP SPGF H2 Cofiring Project
Scenario 2 (8 Hr Monthly Runtime @ 100% H2)

Run Date:11-Jun-25

Activity Name
Newark Bay WWTP Green H2 Cofiring - Scenario 2
Engineering
FEED
FEED
Bridging
Bridging / Reviews / Approval
Detailed Design
Process
Civil / Structural
Electrical
Mechanical and Piping
I&C
Prepare For Construction Submittals
Procurement
Long Lead Equipment
Technical and Commercial Preparation - Long Lead Equipment
Bidding, Negotiations and Award - Long Lead Equipment
Prepare and Approve Shop Drawings - Long Lead Equipment
Fabricate and Deliver to Site - Long Lead Equipment
Balance of Equipment
Technical and Commercial Preparation - Balance of Equipment
Bidding, Negotiations and Award - Balance of Equipment
Prepare and Approve Shop Drawings - Balance of Equipment
Fabricate and Deliver to Site - Balance of Equipment
Permitting
Prepare Permitting Plan
Obtain Permits
Construction
Site Prep
Foundations
Structural Steel Erection
CTG Modifications
Solar Installation
Equipment Installation
Electrical Installation
I&C Installation
Commissioning and Startup



Remaining Work
Milestone
Summary

Level 1 EPC by WBS

Date	Revision	Checked	Approved
11-Jun-25	R0 - For Submission	JGS	