A PUBLIC AGENCY
NCPA
NORTHERN CALIFORNIA POWER AGENCY

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# Notice – Call of Special PPC Meeting

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**Date:** March 26, 2021

**To:** NCPA Lodi Energy Center Project Participant Committee

**From:** Basil Wong, Chairman

**Subject:** **March 31, 2021 LEC PPC Special Meeting Notice & Agenda**

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PLEASE TAKE NOTICE that pursuant to Government Code section 54956, a special meeting of the Northern California Power Agency Lodi Energy Center Project Participant Committee is hereby called for **Wednesday, March 31, 2021 at 10:00 am** to discuss those matters listed in the attached Agenda. The meeting will be held at the Northern California Power Agency, 12745 N. Thornton Road, Lodi, California.

Basil Wong, Chairman

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Lodi, CA 95242

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# LEC PPC Agenda

**Date:** March 26, 2021

**Subject:** **March 31, 2021 Lodi Energy Center Project Participant Committee Meeting**

**Location:** **12745 N. Thornton Road, Lodi, CA and/or Posted Teleconference Locations**

**Time:** **10:00 am**

*****This meeting is being held in accordance with the Brown Act as currently in effect under the State Emergency Services Act, Governor Newsom's Emergency Declaration related to COVID-19, and Governor Newsom's Executive Order N-29-20 issued on March 17, 2020 that allows attendance by LEC PPC Members, staff, and the public to participate and conduct the meeting by teleconference.**

**In compliance with the Executive Department, State of California, Executive Order N-29-20, and the Brown Act, you may participate in the meeting via teleconference by:**
https://www.gotomeet.me/GenServicesAdmin
**Dial: 1-872-240-3412**
**Access Code: 439-093-085**

*Persons requiring accommodations in accordance with the Americans with Disabilities Act in order to attend or participate in this meeting are requested to contact the NCPA Secretary at 916.781.3636 in advance of the meeting to arrange for such accommodations.*

*The Lodi Energy Center Project Participant Committee may take action on any of the items listed on this Agenda regardless of whether the matter appears on the Consent Calendar or is described as an action item, a report, or an information item. If this Agenda is supplemented by staff reports, they are available to the public upon request. Pursuant to California Government Code Section 54957.5, the following is the location at which the public can view Agendas and other public writings: NCPA, 651 Commerce Drive, Roseville, CA or www.ncpa.com*

1. **Review Safety Procedures**

2. **Call Meeting to Order and Roll Call**

**PUBLIC FORUM**

Any member of the public who desires to address the Lodi Energy Center Project Participant Committee on any item considered by the Lodi Energy Center Project Participant Committee at this meeting, before or during the Committee's consideration of that item, shall so advise the Chair and shall thereupon be given an opportunity to do so. Any member of the public who desires to address the Lodi Energy Center Project Participant Committee on any item within the jurisdiction of the Lodi Energy Center Project Participant Committee and not listed on the Agenda may do so at this time.

**INFORMATIONAL/ DISCUSSION ITEMS**

3. **BV Hydrogen Feasibility Study** – Staff will provide an informational-only presentation regarding the recently completed Hydrogen Feasibility Study.

**ADJOURNMENT**

Next Regular Meeting: Monday, April 12, 2021 at 10:00 am

*Persons requiring accommodations in accordance with the Americans with Disabilities Act in order to attend or participate in this meeting are requested to contact the NCPA Secretary at 916.781.3636 in advance of the meeting to arrange for such accommodations.*

**FINAL**

# LODI HYDROGEN FEASIBILITY STUDY

**B&V PROJECT NO. 406377**
**B&V FILE NO. 40.1600**



**PREPARED FOR**

Northern California Power Agency

19 FEBRUARY 2021

**Reviewed by:**

________________________________ ____________
**Signature** **Date**

Jonathan Cristiani, Engineering Manager
**Printed Name**

**Professional Engineer:**

________________________________ ____________
**Signature** **Date**

Craig Hums, P.E.
**Printed Name**

M38483
**License No.**


**Approved by:**

________________________________ ____________
**Signature** **Date**

Chris Koller, Project Manager
**Printed Name**

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# Executive Summary

Black & Veatch conducted a high-level technical and economic evaluation for a hydrogen production and storage facility to be co-located at the Lodi Energy Center (LEC). The capacity of the hydrogen production was determined based on an assumed 45 percent hydrogen by volume blending of hydrogen with natural gas basis for a Siemens F-class combustion turbine used in LEC's 1x1 combined cycle. This results in a 155 megawatt (MW) electrolyzer. The storage capacity is based on two scenarios: an eight-hour, short-term storage for daily "shifting" and a ten-day, twelve-hour per day, long-term storage scenario. Sources for the evaluation in the study include the following:

- Black & Veatch in house experience.
- Budgetary quotes and input from Original Equipment Manufacturers (OEMs).
- Technical and financial input from LEC and NCPA.
- Data from the United States (US) Energy Information Administration (EIA).
- Publicly-available data on hydrogen markets.

For the storage evaluation, Black & Veatch investigated the feasibility of the following scenarios:

- Short-term compressed hydrogen storage: 8 hours of stored production at approximately 26.1 tons.
- Long-term liquefied hydrogen storage: 10 days of stored production based on operating 12 hours per day at approximately 392 tons.

For hydrogen production, Black & Veatch reviewed budgetary quotations and technical performance information for numerous electrolysis technologies/vendors. Based on the cases studied, capital cost estimates were developed and indicate that the compressed storage cases would require a $254 to $335 million dollar investment while the liquefaction cases would require a $674 to $754 million dollar investment. Additionally, operations and maintenance (O&M) costs were estimated for both the production and storage subsystems. Fixed O&M costs were estimated to be approximately $0.32 per kilogram (kg) for the compressed storage case and $0.93/kg for the liquefied storage case. Non-electricity variable O&M costs were estimated to be $0.13/kg for all cases.

Black & Veatch used an integrated market assessment approach to determine projected wholesale electricity prices, which are used to project the cost to power the electrolysis process and produce hydrogen throughout the life of the project. A two-step economic model was developed to first determine the levelized cost of hydrogen (LCOH) using the capital/O&M costs and electricity prices. The second step of the model determines the Levelized Cost of Energy (LCOE) for LEC while co-firing natural gas with hydrogen. The results of the model indicate LCOH values as follows:

- Between $5.24/kg ($46.06/MMBTU) and $6.04/kg ($53.12/MMBTU) for compressed storage cases.
- Between $6.94/kg ($61.00/MMBTU) and $7.39/kg ($64.96/MMBTU) for liquefied storage cases.

The resultant LCOE was found to be as follows:

- Between $108.45/MWh and $112.27/MWh for compressed storage cases.
- Between $151.97/MWh and $155.48/MWh for liquefied storage cases.

A sensitivity analysis conducted indicated that levelized costs were most sensitive to capital costs, O&M costs, electricity prices, debt rate, and co-product oxygen sales. It was found that levelized costs were least sensitive to inflation and electrolyzer stack life. Black & Veatch provided a set of assumptions related to a scenario whereby a third-party developer would own/operate the hydrogen plant, but this scenario was not studied to a sufficient extent to show a significant benefit to NCPA. Additional economic modeling may be warranted to explore additional third-party ownership scenarios. It was also determined that revenue sharing of renewable energy credits (RECs) could have a significant, positive impact on LCOE.

Based on the findings of the base case economic modeling and subsequent sensitivity analysis, Black & Veatch developed five scenarios to investigate combinations of decreased capital costs, co-product oxygen sales, and REC revenue sharing. The goal of the scenario building exercise was to determine if the LCOE associated with hydrogen co-firing could achieve parity with the LCOE associated with natural gas only operations. This was achieved in all five of the modeled scenarios with reductions in capital costs of 25 to 50 percent, pricing of oxygen between $0.20 to $0.37/kg, and REC revenue sharing between 50 and 97 percent. Thus, it was concluded that a successful hydrogen energy storage and co-firing project could be potentially developed to achieve cost parity with current operations at LEC.

# 1.0 Introduction

NCPA is a nonprofit consortium of utilities in northern California with an over 50-year commitment to environmental stewardship. Their power generation portfolio includes geothermal, hydropower, and natural gas-fired power plants with about half of the portfolio being emission free. This study focuses on reducing emissions at the Lodi Energy Center (LEC) through hydrogen generation and storage. LEC is a fast start 300 megawatt (MW) combined cycle power plant used to provide power during periods of increased electrical grid demand.

The operational intent of the new hydrogen production and storage facility is to utilize grid over-generation associated with renewable energy resources to produce “green” hydrogen via electrolysis, store the hydrogen, and later blend it with natural gas to be used as fuel within the LEC gas turbine. Hydrogen is considered a clean fuel when produced via electrolysis and has high gravimetric energy density but low energy density by volume. Based on preliminary analysis by NCPA and input from the turbine original equipment manufacturer (OEM), it is believed that LEC can co-fire up to 45 percent by volume of hydrogen with natural gas with OEM-approved modifications to the existing equipment.

NCPA requested that Black & Veatch investigate the feasibility of installing a hydrogen production and storage facility that would provide green hydrogen to LEC. The purpose of this study is to explore different concepts for such a hydrogen energy storage system, perform some initial conceptual engineering to develop initial capital and operations and maintenance (O&M) cost estimates, and provide insight into the key economic drivers of the project.

## 1.1 Background

The primary technologies considered for the LEC hydrogen production and storage facility include proton exchange membrane (PEM) electrolysis, alkaline water electrolysis (AWE), compressed storage, and liquefied storage. The report also outlines the various auxiliary systems associated with each of these technologies including a fin-fan cooling system, hydrogen compressors with inter-stage coolers, vessels/tanks for compressed or liquefied storage, a demineralized water system, and electrical handling equipment. The following sections briefly introduce each of the technologies.

### 1.1.1 Renewable Energy Generation and Over-generation

As greater amounts of renewable energy sources are interconnected to the electrical grid, the frequency and magnitude of power over-generation events are increasing. Solar and wind are examples of generation sources with daily production cycling, whereas hydropower is an example of a generation source with seasonal fluctuations. Seasonal and daily fluctuations in power demand are also present but rarely perfectly mirrored by the generation sources.

When over-generation occurs, generation must be curtailed typically starting with the most carbon intensive generation sources. The cost of power also decreases during these times. The concept of the proposed hydrogen production and storage facility is to take advantage of the reduced electricity rates during an over-generation event and use it to produce hydrogen via electrolysis, which is an energy-intensive process. The hydrogen can then be burned as fuel for conversion back to electricity once the over-generation event has passed and the cost of electricity increases.

### 1.1.2 Electrolyzers

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. For this study, two types of electrolyzers are examined: PEM and AWE.

#### Proton Exchange Membrane Electrolyzers

As the name suggests, PEM electrolyzers exchange a proton through the electrolyte between the electrodes. In a PEM electrolyzer, water is split into oxygen and hydrogen, with the hydrogen ions 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 the cost. Figure 1-1 shows a schematic representation of a PEM electrolyzer.

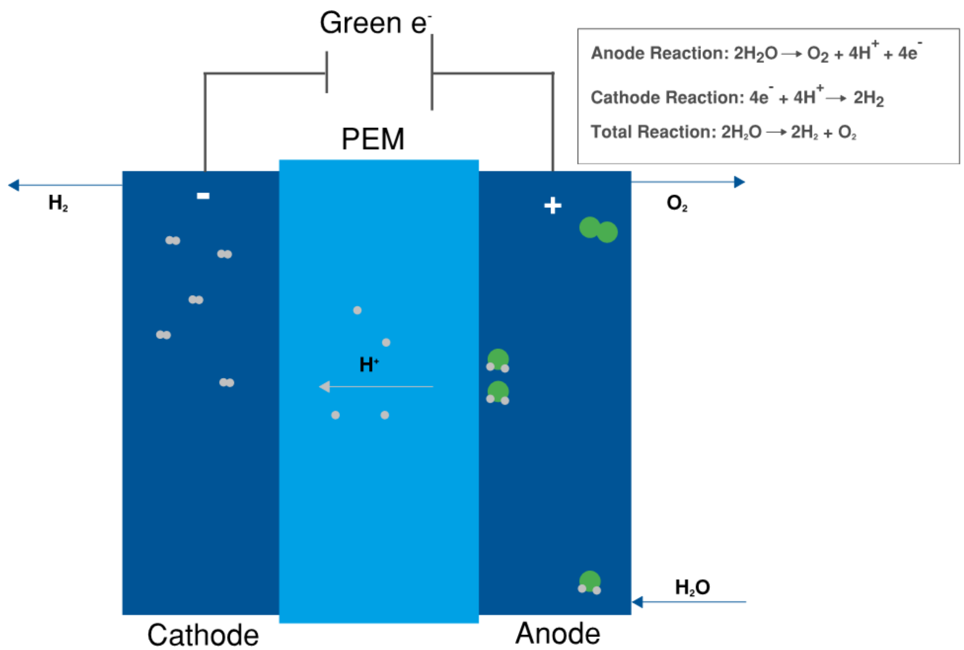


**Figure 1-1 Diagram of a PEM Electrolyzer**

#### Alkaline Water Electrolysis

Alkaline water electrolyzers fundamentally function similarly to PEM electrolyzers; however, the ion transported in the electrolyte is $OH^-$ 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, the technology is considered more mature for large-scale hydrogen production. Figure 1-2 shows a schematic of an AWE system.

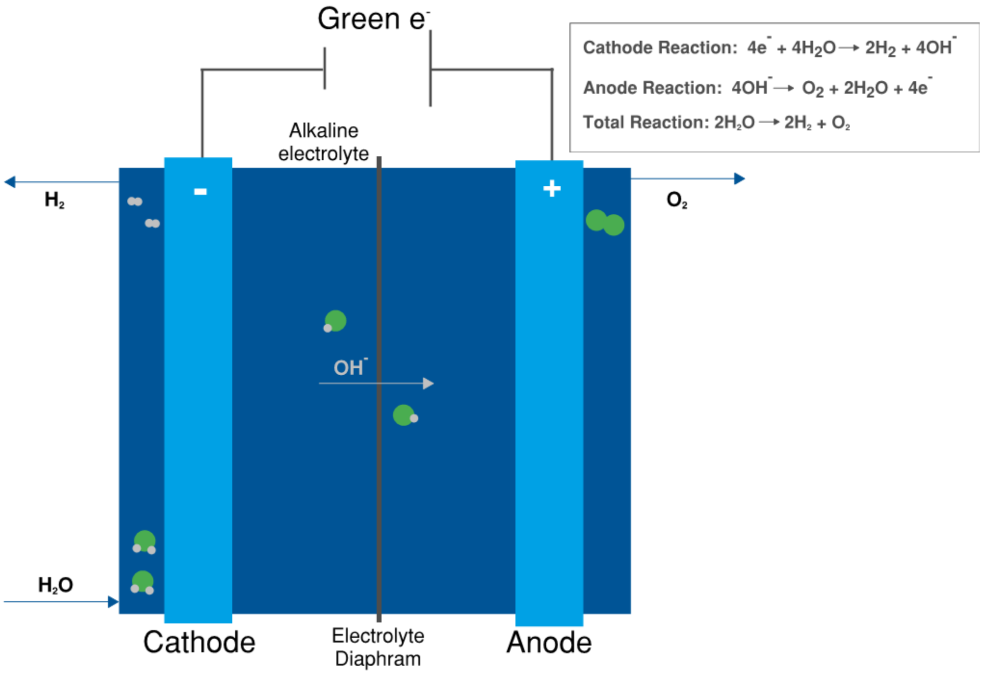


**Figure 1-2 Diagram of an AWE Electrolyzer**

### 1.1.3 Hydrogen Storage Options

Since green hydrogen production typically occurs either during renewable over-generation events or via direct interconnection with renewable energy resources, there is a need to store the hydrogen for later use when those renewable energy resources are no longer available. Since hydrogen is the lightest element, it can be challenging to store large quantities. Methane is about eight times denser than hydrogen at standard conditions, so the pressures and temperatures required to store hydrogen in an economical manner are more extreme than that of natural gas. The storage options outlined in the following subsections are considered the most promising with respect to current market conditions.

#### Compressed Hydrogen Storage

Compressed hydrogen storage is the most common method of storage for today's industrial hydrogen consumers. Depending on the amount of hydrogen being stored, pressures can range from 2,000 to 10,000 psig with the high end of this range more suitable for small cylinders used in the transportation sector rather than large bulk tanks for industrial users. Depending on the pressure and storage volume, many smaller vessel may be more economical than one large bulk tank. Hydrogen also presents an issue with leakages. Some compressed storage applications may require special materials to line the inside of the vessel to prevent leakage.

Generally, compressed hydrogen storage is more economical for short, cyclical storage requirements. An area with over-generation events during the day and hydrogen consumption at night might be a good example. However, the cycling of the hydrogen cylinders would need to be considered as well, depending on the capacity factor of the hydrogen facility and consumption profile of the hydrogen.

## Liquefied Hydrogen Storage

Hydrogen liquefaction is more energy intensive than compressed storage. However, depending on the amount of hydrogen storage needed, it can be an attractive option. Consider the density of liquefied hydrogen compared to compressed hydrogen: liquefied hydrogen density is approximately 4.42 $\frac{\mathrm{lbm}}{\mathrm{ft}^3}$ while compressed hydrogen density ranges from 0.16 to 3.12 $\frac{\mathrm{lbm}}{\mathrm{ft}^3}$, depending on the pressure. The storage volumes for liquefied hydrogen would be much smaller than the storage volumes for compressed for the same amount of mass. However, liquefied hydrogen requires more complicated auxiliary equipment.

To liquefy hydrogen, extremely cold temperatures (i.e. -423°F) need to be maintained. This is only about 37°F above absolute zero. A vapor-compression cycle with liquid nitrogen as a refrigerant is required to achieve such temperatures. Boil-off compressors are also required to re-liquefy the hydrogen that will boil off while being stored. However, depending on the scale of storage required, liquefaction can still be more economical than compressed storage, particularly at large scales.

An additional consideration with the liquefaction equipment is the thermal cycling and ramp time. Cycling from ambient to the extremely low temperature thermally stresses the equipment. The equipment associated with liquefaction is designed for only so many thermal cycles over its lifetime and frequent cycling will significantly reduce the useable life of the equipment. Ideally, the liquefaction equipment is run continuously to minimize thermal cycles and maximize the life of the equipment. Additionally, the startup/shutdown times associated with the liquefaction train are estimated to be in the 4 to 8 hour range. Liquefaction is best suited for continuous operation or seasonal operation at a minimum. Daily cycling of the liquefaction equipment is not considered feasible; however, designing a system for very low turndown may offer some additional operating flexibility.

## Geophysical Hydrogen Storage

Another method to store hydrogen takes advantage of existing geological formations. Geological formations such as salt caverns, rock caverns, and depleted gas fields present an opportunity to store large volumes of hydrogen in existing features. Conceptually, hydrogen is compressed and stored in an existing geological formation and then withdrawn for later use. The details of this concept are extremely site specific.

Salt caverns present the most suitable geological storage feature followed by rock caverns and then depleted gas fields as the least suitable of the three. Since hydrogen is the lightest gas, it has the fastest molecular velocity compared to any other gas at the same conditions. Depending on the geological feature, upgrades such as a liner may need to be added to prevent leakage. Another consideration associated with geological storage is contamination. Depending on the geological formation, other compounds may be present such as methane or water. Additional clean up equipment may be required depending on the geographic location and the hydrogen user quality requirements.

Geophysical storage presents an attractive method to store large quantities of hydrogen for seasonal variations but is highly dependent on the location. Upgrades to the geological formation or additional clean up equipment may drive the effective cost above that of traditional compressed storage or liquid storage.

### Consideration of a Nearby Reservoir

LEC provided Black & Veatch with a brief overview of a nearby geophysical reservoir by a third party. The report claims to have approximately 13 billion standard cubic feet (scf) of capacity available in the old gas reservoir with approximately 1 billion scf of free native gas still available. It notes the change in pressure from initial measurements did not change substantially between 1985 to 2014. This suggest a strong water drive, meaning sufficient water has entered the field to maintain the pressure.

The report discusses concern about the impact the water drive might have to the pressure of the reservoir if enough gas is injected into the well. Investment in pushing back the water drive would need to be implemented to not exceed the maximum pressure. There is also concern that the porosity of the field would likely lead to notable losses in hydrogen. Combustible mixture potential would also need to be investigated in more detail to check the impact of hydrogen introduction. However, the author also notes that the potential containment of hydrogen within the underground structures looks favorable.

Black & Veatch cannot comment on the feasibility of hydrogen storage in the specific reservoir discussed beyond what is available in the report. Due to the expensive cost of hydrogen production, the risk of significant losses while being stored and the corruption of the hydrogen purity, it does not appear to be the best path forward for storage. As the results show in the economic analysis section of the report, electricity costs are one of the biggest drivers of the price of hydrogen energy. If a large portion of hydrogen is lost, the cost of electricity to make up the hydrogen could outweigh the cost of more conventional forms of storage like compressed and liquefied hydrogen. Further analysis would need to be done to understand the potential use of the reservoir for hydrogen storage. A detailed geological investigation would need to be conducted, including a characterization of the subsurface features (i.e. boundaries of storage zone and characteristics of the caprock) and demonstration of water displacement capabilities. Additionally, an exploration of the seismic characteristics of the site and impacts on surface/wellhead would also be required.

### Pipeline Hydrogen Storage

Pipelines are the most cost efficient way to transport large quantities of hydrogen over long distances. There are currently approximately 1,600 miles of hydrogen pipelines installed in the US, primarily in the Gulf Coast region, which are predominantly owned/operated by major industrial gas companies. Hydrogen pipelines are considered mature technologies and can typically cost approximately up to 10 percent more than a traditional natural gas transmission pipeline. For dry hydrogen service, the use of carbon steel is perfectly acceptable for the typical temperatures/pressures associated most electrolysis projects. In instances where corrosive contaminants or condensate are present, a stainless steel pipeline material would be selected instead, which can drive costs even higher.

One attractive option is to blend hydrogen in the existing US natural gas pipeline network, which includes over 400,000 miles of infrastructure. It is estimated that at typical pressures and diameters associated with natural gas pipelines, approximately 21 tons of hydrogen could be stored per linear mile. Hydrogen is generally thought to be limited to 5 to 10 percent blending throughout most of the US, primarily due to safety and pipeline integrity concerns. While greater percentages may be possible if natural gas pipelines and supporting infrastructure are converted for use with hydrogen, these costs and the required modifications are the subject of significant R&D.

### 1.1.4 Co-firing Hydrogen and Environmental Impacts

#### Greenhouse Gas Emission Impacts

When hydrogen is blended with natural gas, the characteristics of the fuel are changed. 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 combustion turbine to achieve the same heat input as the reference natural gas. Piping velocities and pressure losses will increase as a result. There are also additional considerations for the gas turbine combustor nozzles with the higher velocities. Gas turbine OEMs should be consulted on these issues.

The primary driver for using hydrogen as an energy carrier is to reduce carbon footprint. However, carbon dioxide ($CO_2$) emissions are not proportionally decreased by increase in volumetric hydrogen in the fuel. Due to the fact that carbon emissions are measured on a mass basis, consideration for the mass of carbon displaced by hydrogen needs to be considered. The correlation between blended hydrogen by volume and reduced $CO_2$ by mass can be calculated. Based on 45 percent by volume hydrogen blended into LEC's fuel supply, a $CO_2$ reduction of 20.4 percent is expected. This results in approximately 51,081 tons of $CO_2$ reduction each year. This assumes a generalized 117 $\frac{\text{lbsCO}_2}{\text{MMbtu}}$ natural gas and a 25 percent capacity factor for the electrolyzer. Figure 1-3 shows the $CO_2$ reduction vs hydrogen percent volume in the fuel.

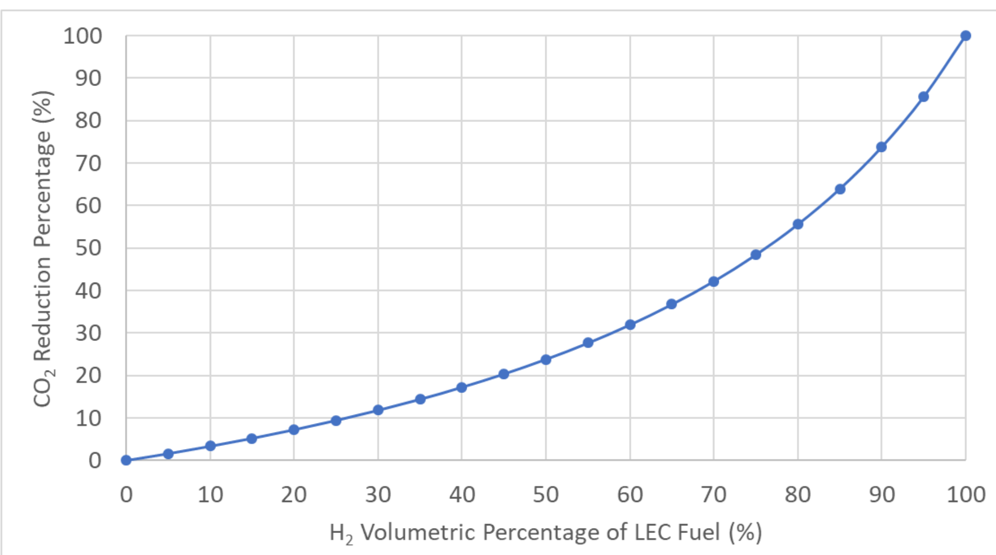


**Figure 1-3 $CO_2$ Reduction vs. $H_2$ Percent Volume**

By determining the tons of $CO_2$ reduced as a result of hydrogen use, California's cap-and-trade program could potentially be used to further incentivize the use of hydrogen. Currently the average ton of $CO_2$ costs approximately $16.84, which results in approximately $860,000 a year in carbon allowance credits, based on the aforementioned 45 percent blending of hydrogen at LEC. Additionally, there will be some natural gas displaced by the introduction of hydrogen, which means less fuel purchased from the pipeline, thereby further incentivizing the use of hydrogen. However, since this is covered in the price of natural gas, it is not modeled as a potential source of revenue for the LEC project for the purpose of the economic analysis.

Based on a review of historical carbon allowance credit pricing since late 2014, Black & Veatch estimates that prices have grown by only a 0.02 percent compound annual growth rate. It is believed that the reason for this is due to several key market trends:

- Gas and electric utilities are meeting their carbon emission reduction obligations primarily through the installation of renewable energy resources and energy efficiency measures.
- Allocations provided by the California Air Resources Board are in excess of needs, particularly in light of the fact that many utilities are returning allowances to their ratepayers in the form of rate reductions.
- The installation of renewable energy resources is resulting in decreased capacity factors for gas-fired power generation resources.

Black & Veatch expects that these observed trends will continue to drive the market dynamics for carbon allowance credit pricing into the future, even with the advent of more aggressive caps on carbon emissions.

### Criteria Air Pollutants

Hydrogen has a higher flame temperature than that of natural gas. Blending hydrogen into the fuel will result in the combustion turbine burning at a higher temperature. This higher temperature correlates directly to a higher production of nitrogen oxide ($NO_x$) emissions. Steam can be injected into the combustion turbine to reduce burner temperature and prevent increased $NO_x$ emissions but at a cost to efficiency. Increased ammonia feed to the selective catalytic reduction (SCR) unit may be required to keep $NO_x$ emissions within the limits of the LEC air permit.

Siemens has indicated that the F class turbine at LEC will be capable to use fuel with up to 45 percent hydrogen by volume. The predicted impact to performance for a 45 percent by volume hydrogen fuel are further discussed quantitatively in Section 2.4.

## 1.2 Objectives

The objective of this study is to present a high-level sizing and economic evaluation of a green hydrogen production and storage facility to be blended into the fuel supply for LEC. The capacity of the hydrogen production is based on blending 45 percent hydrogen by volume with the maximum monthly pipeline fuel consumption at LEC. Different electrolyzer technologies were assessed for hydrogen production. The storage capacity is based on two scenarios: an eight-hour short-term storage with daily cyclical operation and a ten-day, twelve-hour per day, long-term storage scenario.

General assumptions used for the capital cost and O&M costs that are incorporated into the economic modeling estimates are found in Section 4.0. Black & Veatch is presenting the economic evaluation in the form of levelized costs for each operating scenario. The objective is to allow NCPA to better understand which hydrogen production and storage scenario would be most economical for LEC's future operations. Although not studied as part of the current project, it is expected that opportunities for higher electrolysis equipment utilization, such as the sale/local dispensing of hydrogen for use as a transportation fuel and revenues associated with the California Low Carbon Fuel Standard (LCFS) credits as well as other emerging high-value end use applications, will further enhance project economics. It is currently estimated that hydrogen from electrolysis using renewable energy resources could monetize LCFS credits for as much as $4.00 per kilogram.

## 1.3 Approach

Black & Veatch analyzed the historical fuel consumption at LEC. Using the historical monthly maximum fuel consumption, Black & Veatch then determined the hydrogen production capacity that corresponds to a 45 percent by volume hydrogen blend. With a production capacity defined, Black & Veatch solicited budgetary quotations from numerous electrolyzer vendors.

Black & Veatch analyzed the existing demineralized water treatment facility at LEC and determined that there is sufficient installed capacity to supply the electrolyzer. Black & Veatch also considered the effluent from the White Slough Water Pollution Control Facility to confirm that enough makeup water to the plant is available. We then worked with NCPA to define the desired storage scenarios. It was determined that a short-term scenario to account for daily cycling and a long-term scenario to account for longer-term cycling would be analyzed.

Black & Veatch prepared a design basis, abbreviated equipment list, and simplified site arrangement associated with each case investigated. Using this high-level engineering design documentation, capital and O&M cost estimates were compiled using reference installations scaled to capacity, literature data, vendor quotes, and comparison to a liquefied natural gas (LNG) facility (for the liquid storage case). Black & Veatch also researched the cost of electricity considering the daily and seasonal fluctuations, which were incorporated into the economic model. Black & Veatch estimated the frequency and cost of large maintenance activities using input from the vendors and available literature.

With capital and O&M costs estimated, Black & Veatch calculated the levelized costs for both the hydrogen as well as for the resultant electricity from LEC. We then performed a sensitivity analysis on selected factors to determine the impact on the levelized cost of hydrogen (LCOH) and levelized cost of energy (LCOE). Within the sensitivity analysis, Black & Veatch considered potential secondary sources of revenue, including renewable energy credits (RECs) and sales of oxygen byproduct.

# 2.0 Basis of Design

Black & Veatch has prepared a comprehensive design basis document that can be referenced in Appendix B. Key portions of the design basis, including commentary, are included in this section.

## 2.1 Electrolyzer Sizing

To determine the approximate hydrogen production and storage facility sizing, Black & Veatch analyzed LEC's fuel consumption, combustion turbine hydrogen capability, and natural gas composition. The fuel consumption was determined using US Energy Information Administration (EIA) data from 2012 through 2019. Based on the highest fuel consumption in a month, an average fuel consumption was determined for LEC. The natural gas constituents were determined by obtaining recent data from the local pipeline. The reference natural gas composition is shown in Table 2-1 while the blended fuel composition is displayed in Table 2-2.

**Table 2-1 LEC Reference Fuel Gas Composition**

| N2 | CO2 | Methane | H2 | Ethane | Propane | I-Butane | N-Butane | I-Pentane | N-Pentane | C6+ |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.40 | 0.74 | 94.35 | 0.00 | 3.37 | 0.15 | 0.010 | 0.02 | 0.01 | 0.01 | 0.01 |

**Table 2-2 LEC 45 Percent Hydrogen Blended Fuel Gas Composition**

| N2 | CO2 | Methane | H2 | Ethane | Propane | I-Butane | N-Butane | I-Pentane | N-Pentane | C6+ |
|---|---|---|---|---|---|---|---|---|---|---|
| 0.22 | 0.41 | 51.89 | 45.00 | 2.27 | 0.17 | 0.02 | 0.02 | 0.02 | 0.01 | 0.01 |

Using this information, the electrolyzer was sized such that the hydrogen production would equal the consumption of the combined cycle at base load. That is, if the electrolyzer runs at full load for eight hours a day, during over-generation events, the plant could then use the stored hydrogen for eight hours with the 45 percent hydrogen blended natural gas. Black & Veatch used this initial hydrogen production analysis to determine the required capacity of the electrolyzer. Using commercially-available modeling software, the electricity consumption, demineralized water consumption, heat rejection requirements, oxygen production, and hydrogen production were estimated. These inputs and outputs were then used to develop the design basis, which was subsequently used to solicit budgetary information from OEMs.

### 2.1.1 Electrolyzer Performance

To better understand electrolyzer capabilities, Black & Veatch engaged numerous electrolyzer vendors for a budgetary estimate of performance and costs for the LEC project. Table 2-3 outlines the performance for the electrolyzers.

**Table 2-3 Electrolyzer Performance**

| Parameter | Values |
|---|---|
| Hydrogen production | 6,547 lb/hr |

| Parameter | Values |
|---|---|
| AC system power consumption at nominal H2 production | 155 to 165 MW |
| Hydrogen delivery pressure before compression | 15 to 19 psia |
| Hydrogen purity at module outlet | >99.8% |
| Hydrogen contaminants | Water and/or Oxygen |
| Load range | 0-100% |

## 2.2 Hydrogen Storage Sizing

For the hydrogen storage scenarios, Black & Veatch investigated two alternatives: short-term compressed vapor storage and long-term liquefied storage. Based on preliminary analysis, Black & Veatch determined that compressed vapor storage was most promising for the short-term case while liquefied storage was most promising for the long-term case. The footprint, number of tanks, and capital costs of compressed storage becomes excessive when a large capacity of stored hydrogen is required. Alternatively, the liquefaction equipment and liquid storage tanks may be inappropriate for frequent cycling applications, even though the overall footprint might be smaller than the equivalent compressed storage system. However, the liquefaction of hydrogen requires complex equipment, has additional safety/startup challenges, and has a higher specific energy cost per unit mass of hydrogen stored, thus is better suited for long storage durations. Similar to LNG applications (such as for long distance transportation and peak shaving applications), hydrogen liquefaction is most appropriate for periods of operation of months rather than weeks or days. Due to the fact that hydrogen liquefaction processes effectively involve two LNG-type trains in series, there are additional challenges associated with refrigerant selection and process turndown. Additionally, heavy cycling of liquefaction equipment would not be economical, as the thermal wear and tear would severely limit the life of the equipment.

### 2.2.1 Short-Term Storage

The short-term storage alternative considers a daily cycling scenario where over-generation creates hydrogen during the day for eight hours, and the plant consumes that hydrogen at night. This scenario takes advantage of the so-called “duck curve” in California, where hydrogen is produced when excess renewable electricity is available and associated electricity prices are cheaper then subsequently using that stored energy at night. Using this basis, a simple calculation of baseload electrolyzer production times eight hours in the day equates to approximately 26 tons of hydrogen storage.

### 2.2.2 Long-Term Storage

The long-term storage alternative considers ten days with twelve hours per day of hydrogen production. This scenario similarly would produce hydrogen during the over-generation as well. However, it assumes the existing LEC plant may not be able to run for an extended period and therefore would require larger quantities of storage capacity. Given this option, when the plant does use the hydrogen, it would be able to run for 120 hours on a 45 percent by volume hydrogen fuel blend. In this scenario, the capacity of the liquefied storage would be approximately 392 tons.

## 2.3 Ancillary Equipment Sizing and Process Overview

### 2.3.1 Ancillary Electrolyzer Equipment

For the hydrogen production and storage system, additional electrical equipment is required to step down the grid voltage for medium- and low-voltage consumers. The electrolyzers require low voltage, high amperage power, while the rotational equipment (e.g. compressors) require medium voltage power. The largest power consumer is the electrolyzer; however, ancillary systems such as the fin-fan cooler, compressors, pumps, and/or liquefaction equipment also require power. Typical electrical loads associated with Heating Ventilation and Air Conditioning systems and lighting in buildings is also required.

### 2.3.2 Compressed Storage Equipment

To compress and store hydrogen for later use, a combination of compressors, heat exchangers, tanks, and balance of plant piping is required. Depending on the final storage pressure, there may be several inter-cooled compressor stages. The balance of capital and O&M costs would need to be optimized to determine the best means of compression. Lower pressure storage would require less power consumption to achieve the storage pressures, but at a cost of greater quantities of tanks and a larger footprint to hold the same mass of hydrogen. Higher pressure storage would require more power consumption to achieve the storage pressures, but at the benefit of fewer tanks and reduced footprint.

For budgetary purposes, Black & Veatch selected a storage pressure of 2,600 psia. This pressure takes advantage of the readily available stationary tube trailer style of tanks. Storage at higher pressures on this scale would require a customized solution because as pressure and tank size increase, the required tank wall thickness increases as well. There may be potential for cost optimization when a more detailed analysis is conducted for the LEC project.

### 2.3.3 Liquefaction and Liquefied Storage Equipment

Liquefaction and liquefied storage of hydrogen offers a more energy dense solution compared to compressed hydrogen storage. However, the capital and O&M costs of producing and storing liquid hydrogen is much higher. The quantity of hydrogen stored is the biggest driver for compressed storage compared to liquefied storage. The larger the quantity of hydrogen being stored; the more economical liquefaction becomes relative to compressed storage on a mass basis.

Current methods for liquefying hydrogen use a vapor-compression cycle. This process requires various equipment including trains of intercooled compressors, brazed aluminum heat exchangers, parallel closed loop nitrogen refrigerant cycles, and boil off compressors. As mentioned, the equipment required to liquefy hydrogen is analogous to placing two LNG trains in series, thus the process of liquefying hydrogen is quite energy intensive. There is also concern about cycling the equipment too often since the operating temperatures are very low. This would contribute to significant thermal degradation over time if the system is cycled too frequently.

Because of concerns with thermal cycling and startup/shutdown ramp times, the liquefaction equipment will need to run continuously. This operational requirement does not align well with producing hydrogen during an over-generation event during the day and then shutting down the electrolyzer at night. The turndown of a single hydrogen liquefaction train is estimated as only 50 percent. In order to provide the required operational flexibility, Black & Veatch estimates that four hydrogen liquefaction trains will be required to match the turndown capability of the electrolyzer.

The operational profile would be to run the electrolyzer and all four liquefaction trains at their minimum capacity at night when the cost of electricity is high and then ramp up production during the day as over-generation occurs. Ramping up and down the liquefaction trains so frequently will incur efficiency losses but at least provides the operational flexibility to keep running. Seasonal over-generation from a source such as hydropower that is not limited to daytime hours is best suited to necessitate a liquefied hydrogen storage facility.

## 2.4 Lodi Energy Center Performance Impact

The impact for combined cycle power plants in relation to hydrogen blending with natural gas is still the subject of significant R&D by combustion turbine OEMs due to the fact that the hydrogen energy storage industry is still an emerging commercial field. The general understanding is that for hydrogen blending above 5 percent by volume with natural gas, retrofitting existing combined cycle and simple cycle power plants will likely be required. At higher blending percentages, hydrogen begins to introduce challenges that need to be considered, including differing flame speeds, rate of change in Wobbe index, and increased NOx production. Combustion turbine OEMs have been working diligently to develop premixers and combustors that mitigate the flame speed and flashback issues associated with hydrogen co-firing. Additionally, OEMs have been applying significant focus to scaling up advanced fuel gas systems and modifying controls and instrumentation systems to enable higher hydrogen co-firing and mitigate risks associated with Wobbe index rate of change issues and their impacts on power output and NOx production. The primary consideration with respect to NOx production, though, is the higher temperatures associated with hydrogen combustion. For LEC, with a blending percentage of 45 volumetric percent of hydrogen in natural gas, Black & Veatch estimates an increase in NOx production of approximately 30 percent. However, this risk is expected to be mitigated via the installation of ultra-low NOx burners at LEC.

NOx production is a function of firing temperature and exposure of nitrogen to high firing temperatures. Since the adiabatic flame temperature of hydrogen is approximately 4,000°F whereas methane is 3,565°F, there will be an increase in firing temperature as hydrogen is introduced. The best way to control the NOx leaving the exhaust of the gas turbine is by decreasing the firing temperature. However, decreasing the firing temperature also directly impacts the output and heat rate of the gas turbine. NOx production can also be managed through staged combustion in the combustor. However, this is specific to each combustor and unique to different OEMs. At a certain point of hydrogen introduction, the flame temperature might be so hot that steam or water injection into the combustor would be required. This could result in increased maintenance costs over time, as well as a potential derating of the turbine performance. A detailed analysis by the LEC combustion turbine OEM would need to be conducted to fully understand any retrofit costs and operational impacts.

Another consideration for plant impact involves piping design upstream of the gas turbine combustor. As hydrogen is introduced into the fuel, the density of the mixed gas decreases relative to the reference fuel. Specifically for LEC, the fuel gas heating value goes from approximately 1,006.3 BTU/scf to 694

BTU/scf (both based on higher heating value). Due to hydrogen's very low volumetric density, the heating value on a volumetric basis is much lower. This means for a given fuel pressure, the volumetric flow of fuel will have to increase proportionally to meet the same heat input. The higher velocities resulting from the increase in volumetric flow could have an impact on fuel gas piping and gas turbine fuel nozzles. A detailed analysis would be required to understand any additional retrofitting requirements, including piping material selection (carbon vs. stainless steel depending on moisture content), line sizing, and fuel mixing system design. Currently, no retrofitting to the combined cycle plant is considered in the capital costs.

# 3.0 Project Development Considerations

## 3.1 Environmental/Permitting Considerations

The California Energy Commission (CEC) authorized NCPA to construct and operate LEC in April 2010. The CEC Siting Regulations require that any changes to the design, operation, or performance of a licensed project, including related facilities, are approved by CEC prior to implementation. Therefore, an amendment to LEC's current license will be required to construct and operate the hydrogen production and storage facility, and prior to using hydrogen in the LEC fuel stream.

The CEC has sole permitting authority regarding the siting of LEC related facilities, superseding the City of Lodi's building and zoning permitting authority. CEC's review will encompass all state, local, and regional agency requirements applicable to the project. The construction and operation of the hydrogen production and storage facility will likely require other federal, state, and local permits and approvals; or modifications to the existing permits. A preliminary list of the expected federal, state, and local permits and approvals that would likely need to be addressed by NCPA is included in Appendix C. Black & Veatch has identified the considerations outlined in the following subsections associated with the proposed project.

### 3.1.1 Waters of the United States Permit Considerations

The US Army Corps of Engineers (USACE) has determined that the unnamed agricultural drainage ditch located immediately south of the proposed project site is a jurisdictional water of the US. The project will need to be sited to avoid temporary and permanent impacts to the agricultural drainage ditch.

### 3.1.2 Special-Status Species Permit Considerations

Numerous special-status species were identified during previous studies conducted for the LEC certification process as having the potential to be present within the proposed project site. The agricultural drainage ditch located immediately south of the proposed project site supports vegetation and is considered to be potential habitat for the federal- and/or state-protected giant garter snake, western pond turtle, northwestern pond turtle, and the California black rail. The giant garter snake, a federal- and state-listed threatened species, also has the potential to occur upland within the proposed project area during its winter dormancy period. Additionally, any impact to the agricultural drainage ditch may destroy or adversely impact federally designated critical habitat for the delta smelt.

The San Joaquin Council of Governments' Multi-Species Habitat Conservation & Open Space Plan requires a 200-ft setback from giant garter snake habitat (i.e. agricultural drainage ditch). A variance was granted for LEC, reducing the required setback to 30 ft with additional mitigation being provided, which was included as a condition of CEC's authorization. Off-site mitigation, such as compensation, may be required in addition to observing the 30-ft setback to ensure that the loss of giant garter snake upland habitat is mitigated to a less than significant level.

### 3.1.3 Land Use Permit Considerations

The construction of the hydrogen production and storage facility at the proposed location may result in the conversion of farmland of local importance to a non-agricultural use, which is considered a significant land use impact under the California Environmental Quality Act (CEQA). Compensation may be required for the loss of farmland to mitigate the loss to a less than significant level.

### 3.1.4 Air Permit Considerations

LEC recently decided to install a new combustion turbine that can combust a mixture of natural gas and hydrogen. LEC provided the draft Authority to Construct (ATC) permit issued by the San Joaquin Valley Air Pollution Control District (SJVAPCD) that, once finalized, will authorize the installation of a new combustion turbine. Black & Veatch notes that the draft ATC only allows the combustion turbine to fire California Public Utilities Commission-regulated natural gas. Another ATC will be required for the combustion turbine to install a hydrogen production system and use hydrogen as a fuel in the combustion turbine with natural gas. Black & Veatch expects that additional analysis would need to be performed for the change in emissions, particularly with respect to NOx (as noted in Section 2.4) and ammonia ($NH_3$) due to potentially higher $NH_3$ injection in the SCR system.

The draft ATC permit contains NOx and $NH_3$ emission limits for the combustion turbine during normal operation and startup, shutdown, and malfunction events. The various emission limits contained in the draft ATC cover hourly, daily, and quarterly time periods. Black & Veatch notes that the current Best Available Control Technology emission rates at the stack for the combustion turbines are 2.0 ppmvd at 15 percent $O_2$ for NOx (1-hr rolling average) and 10 ppmvd at 15 percent $O_2$ for $NH_3$ (24-hr rolling average). The emission rates contained in the ATC will not change with the introduction of hydrogen as a fuel used in the combustion turbine. As mentioned previously, the installation of ultra-low NOx burners at LEC is expected to lower NOx emissions using 100 percent natural gas, thus the increased NOx emissions associated with hydrogen blending up to 45 volume percent should still be below the permitted threshold.

### 3.1.5 Surrounding Community Considerations

The public will have the opportunity to voice concerns regarding the proposed hydrogen processing facility during CEC's review of the proposed amendment to LEC's license. Public involvement is a key component of the CEC licensing process. The public and surrounding landowners will be notified of proposed project upon CEC's receipt of the license amendment petition, and of any workshops, hearings or other meetings. Throughout the review process the public will have the opportunity to comment on the project and pertinent CEC assessments and determinations. Members of the public can participate in the proceedings informally by attending meetings, workshops, and hearings and provide comments on issues of interest or concern. The CEC will take into consideration any comments that are received, but the comments are not considered to be formal evidence and not sufficient to support a CEC decision. Additionally, a person or a group of people can petition the CEC to become an intervenor in the proceedings, which allows them to testify and present evidence during the proceedings.

The project is not anticipated to have any significant adverse impacts on surrounding properties and communities; or alter existing land use patterns in the area. The proposed site is to be located adjacent to the existing LEC power plant; approximately 6 miles west of the City of Lodi center and 2 miles north of the City of Stockton. The project is to be located on land designated as Public/Quasi-Public by the City of Lodi General Plan, and zoned Public and Community Facilities under the City's Zoning Ordinance. The surrounding land use is predominately agricultural and industrial.

The proposed site is located in a California Disadvantaged Communities area. This site is an area that is in the 91 to 95 percentile meaning they have a high burden of pollution, environmental degradation, and adverse health effects while in a low socioeconomic area. However, there are no sensitive receptors, such as residential areas, schools, day-care centers, hospitals or nursing homes located within 1 mile of the proposed site. Three residences are located approximately 0.85 miles north of the site, and a housing development is located about 2 miles south of the site along W 8 Mile Road.

As discussed in Section 3.1.4, an ATC application will be required to co-fire hydrogen in the combustion turbine. This application will be separate from the CEC process, and have a separate public review opportunity after the SJVAPCD completes their review of the application and issuance of a draft ATC permit. Members of the public can comment on the draft ATC permit and typically the SJVAPCD will address any public comments by either rejecting them or incorporating them into the draft ATC permit.

The LEC is located within a degraded airshed that is non-attainment for the 8-hour Ozone, $PM_{2.5}$, and $PM_{10}$ national and state ambient air quality standards. However, co-firing hydrogen with natural gas will not change the permitted emission limits for these pollutants contained in the LEC's air operating permit.

### 3.1.6 Other Regulatory Considerations

Hydrogen is a flammable gas that is considered highly hazardous and is regulated by two federal rules and a state rule when hydrogen is stored in quantities greater than 10,000 lbs. The following provides a description of the applicability of these rules.

#### EPA Risk Management Plan

The Risk Management Plan (RMP) is a requirement of the US Environmental Protection Agency (EPA) rule at 40 CFR 68. Hydrogen is listed as a regulated flammable gas and subject to EPA's RMP rule if it is stored or used in a process in quantities greater than 10,000 lbs. The RMP deals with the prevention of accidental release of hazardous chemicals to the atmosphere. This rule is primarily concerned with the offsite effects of chemical release or leaks that may occur at a facility. Any facility within California would be subject to EPA's program level 3 requirements.

However, there is an exemption from EPA's RMP rule for facilities that use all the regulated chemical as a fuel at the facility or is held for sale as a fuel at a retail facility. A retail facility is defined as a stationary source at which more than half of the income is obtained from direct sales of the hydrogen to end users. The key here is that the hydrogen would need to be sold as a fuel exclusively and end users could not use it as a chemical feedstock. This exemption would need to be explored in greater detail by LEC to examine if the facility could qualify for this exemption if they decide to sell some of the hydrogen produced to the transportation sector.

Even if the hydrogen production and storage system is exempt from RMP requirements, there is the General Duty Clause that still will apply. Principally, the General Duty Clause requires that the facility meet industry standards to prevent accidental releases and undertakes measures designed to minimize the likelihood of an accidental release. Thus, the liability would be on the facility if an accident happened with the hydrogen process.

Black & Veatch also notes that some of our clients have decided to voluntarily follow the RMP rule and develop a prevention plan without reporting to EPA.

### California Accidental Release Prevention

The California Accidental Release Prevention (CalARP) is a requirement of the California Governor's Office of Emergency Services (Cal OES) rule at Title 19 of CCR, Division 2, Chapter 4.5. Hydrogen is listed as a regulated flammable gas and subject to the CalARP rule if it is stored or used in a process in quantities greater than 10,000 lbs. Similar to EPA's RMP rule, the CalARP rule deals with the prevention of accidental release of hazardous chemicals to the atmosphere. The CalARP rule also may be exempt if the LEC uses all the regulated chemical as a fuel at the facility or the hydrogen is held for sale as a fuel and the LEC is considered a retail facility per the definition in the CalARP rule. This exemption would need to be explored in greater detail to determine if the exemption is valid. Otherwise, the LEC would be subject to the requirements of the CalARP rule.

### OSHA Process Safety Management of Highly Hazardous Chemicals

The Process Safety Management of Highly Hazardous Chemicals (PSM) is a requirement of the Occupational Safety and Health Administration (OSHA) rule at 1910.119. Hydrogen is considered a Category 1 flammable gas and is regulated by the PSM rule if it is stored or used in a process in quantities greater than 10,000 lbs. The PSM plan corresponds closely with the EPA's RMP and Cal OES's CalARP prevention program component of a program level 3 process. A significant difference between the RMP and CalARP versus the PSM rules is that while the RMP and CalARP must be submitted to EPA and Cal OES, respectively, the PSM plan is only required to be maintained at the facility. Additionally, the PSM rule is primarily concerned with the onsite impacts to workers during a chemical release or leaks that may occur at a facility.

The OSHA PSM rule does not contain an exemption for flammable gases used as fuel, since hydrogen is not considered a hydrocarbon fuel. As such, if hydrogen gas will be stored or used in quantities greater than the threshold quantity (i.e. 10,000 lb) then LEC will be required to develop a PSM program in accordance with the requirements prior to any hydrogen used or stored on-site.

### Chemical Facility Anti-Terrorism Standards

The Chemical Facility Anti-Terrorism Standards (CFATS) are found in 6 CFR 27, which is under the US Department of Homeland Security's (DHS) purview. Under the Department of Homeland Security, the Cybersecurity and Infrastructure Security Agency (CISA) manages the CFATS program to identify and regulate high-risk facilities to ensure they have security measures in place to reduce the risk that certain hazardous chemicals are weaponized by terrorists. This regulation will be applicable if LEC will have the capability to store more than 10,000 lb of hydrogen.

The regulation will first require LEC submit to CISA a Top-Screen analysis within 60 calendar days of when hydrogen will be present at the facility, although this can be completed earlier. An employee of LEC will need to complete chemical terrorism vulnerability (CVI) training and register in CISA's online tool to be able to submit a Top-Screen analysis. CISA will review the Top-Screen analysis and send written notification to the LEC if the new hydrogen process is considered a high-risk facility and will assign the facility a risk-based tier level (Tier 1 through 4).

If the hydrogen process is considered high-risk by CISA, the CFATS rule requires development and submittal of a Security Vulnerability Assessment (SVA) within 90 calendar days after written notification from CISA. CISA requires the SVA contain analysis including asset characterization, threat assessment, security vulnerability analysis, risk assessment, and countermeasures analysis. The CFATS rule also requires development and submittal of a Site Security Plan (SSP) within 120 calendar days after written notification from CISA. CISA requires the SSP address each vulnerability identified in the SVA and describe the security measures to address each vulnerability. The SSP would also contain how security measures selected by the facility will address the applicable Risk-Based Performance Standards (RBPS) and potential modes of terrorist attack including, as applicable, vehicle-borne explosive devices, water-borne explosive devices, ground assault, or other modes or potential modes identified by CISA. Facilities also have the option of submitting an Alternative Security Plan (ASP) in place of the SSP. The CISA provides guidance on the RBPS, which the facility will be required to meet or exceed as appropriate based on the Tier classification of the facility.

CISA will review the SSP or ASP to determine if they satisfy the requirements of the CFATS regulation. CISA will issue a letter of authorization to LEC if the CFATS requirements are met. A CISA inspector will then conduct an authorization inspection at the LEC to verify the content listed in the SSP or ASP and that existing and planned measures satisfy the RBPS requirements. CISA will issue a letter of approval if the CFATS requirements are met during the site visit. CISA may conduct reoccurring compliance inspections thereafter, to ensure the LEC continues to implement the approved security measures.

## 3.2 Electricity and Environmental Attribute Pricing

Black & Veatch uses an integrated market assessment approach to determine long-term electric wholesale price projections as part of our Energy Market Perspective (EMP) service offering. The EMP tool was utilized for the purpose of forecasting electricity and REC pricing associated with the LEC hydrogen production and storage project, including all applicable plant closures and other market dynamic trends. It is noted that electrolysis systems also offer the potential to provide electrical grid ancillary services such as capacity/demand response, reserves, and frequency regulation; however, these capabilities are still the subject of significant R&D and are not considered as part of the present study.

Based on the aforementioned methodology, Black & Veatch studied historical electrical pricing to better understand the time of day and seasonal impacts. Figure 3-1 shows the results of this analysis (given in constant 2019 US dollars, or USD, per MWh) and demonstrates that early evening electricity prices spike to the highest levels during Summer and Autumn. It is expected that these trends will become more pronounced over time as additional renewable energy capacity is added to the electrical grid, middle of the day over-generation/ curtailments increase, and evening ramping of dispatchable assets increase. Black & Veatch also studied the projected monthly electrical pricing over a 25-year period from 2020 through 2045 as part of the development of average electricity prices to be used in the economic modeling activity. Figure 3-2 displays the results of this analysis (given in constant 2019 USD/MWh), which suggest that the variations will become more pronounced over time with the difference in maximum “peak” and minimum “off-peak” pricing increasing. It is reasonable to assume, based on these analyses, that the production/storage scenarios developed for the LEC project would be able to achieve annual average values for electricity pricing.

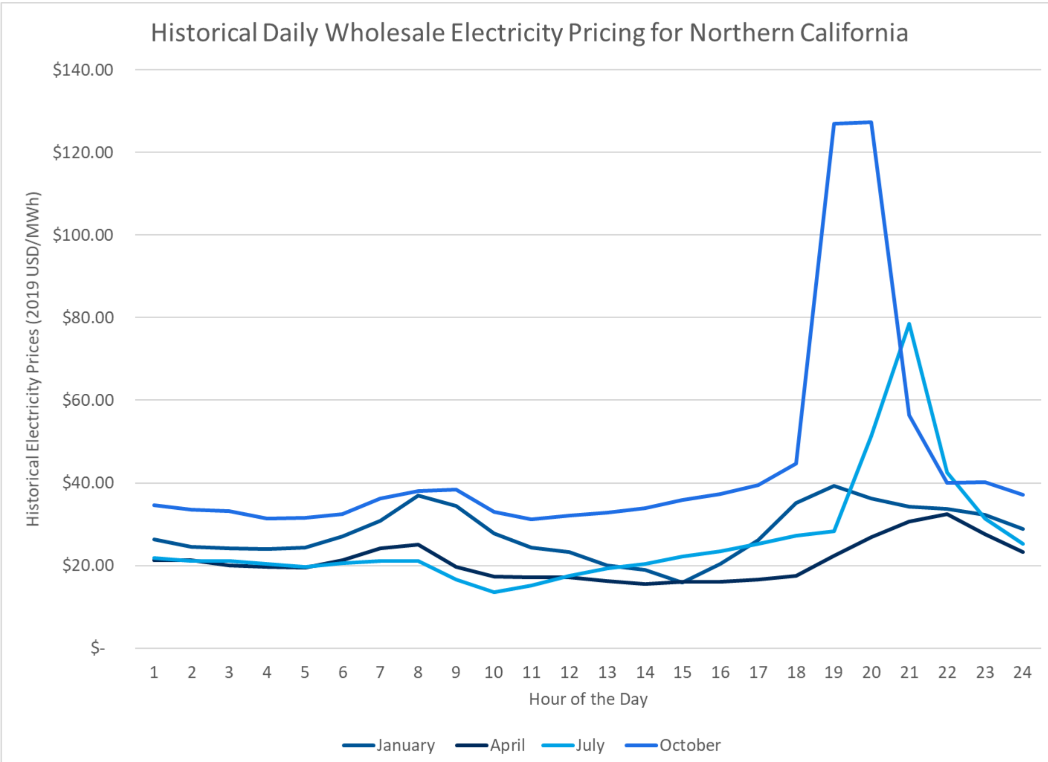


**Figure 3-1 Historical Daily and Seasonal Impacts on Electricity Pricing**

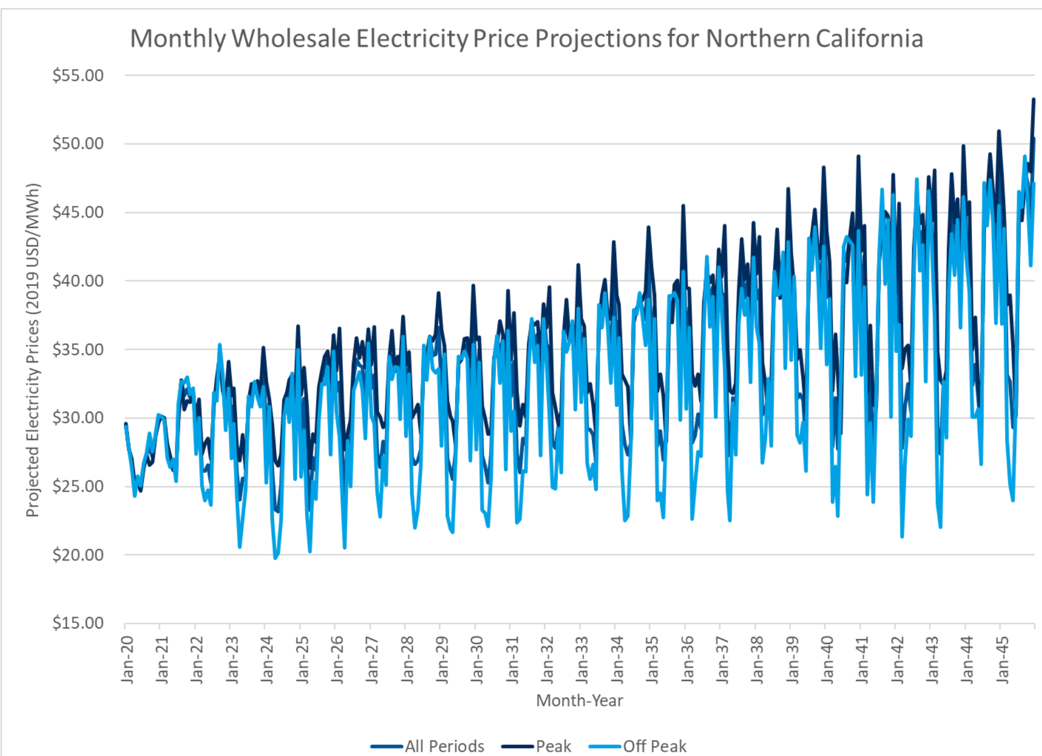


**Figure 3-2 Projected Monthly Variations in Electricity Pricing**

Black & Veatch then developed annual average electricity pricing projections for “all hours,” “peak,” and “off-peak” scenarios from 2020 through 2055, where projections for 2045 through 2055 were developed based on average compound annual growth rate figures from 2020 through 2045 within each category. Figure 3-3 shows the results of this analysis, which is presented in current year USD/MWh by converting from constant 2019 USD using consumer price index projections. Similarly, projected annual average REC pricing was developed and is shown in Figure 3-4, once again presented in current year USD/MWh. Annual average electricity price projections are used directly in the economic model to calculate LCOH, while annual average REC price projections are used directly in the economic model to calculate LEC LCOE.

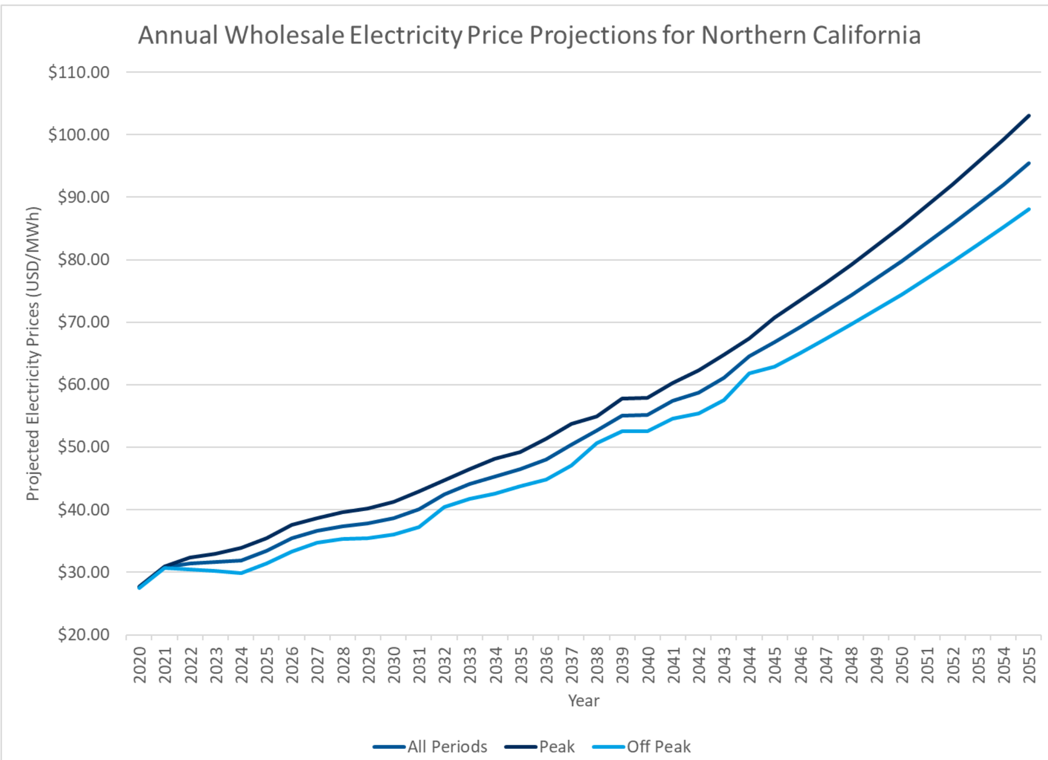


**Figure 3-3 Projected Average Annual Electricity Prices**

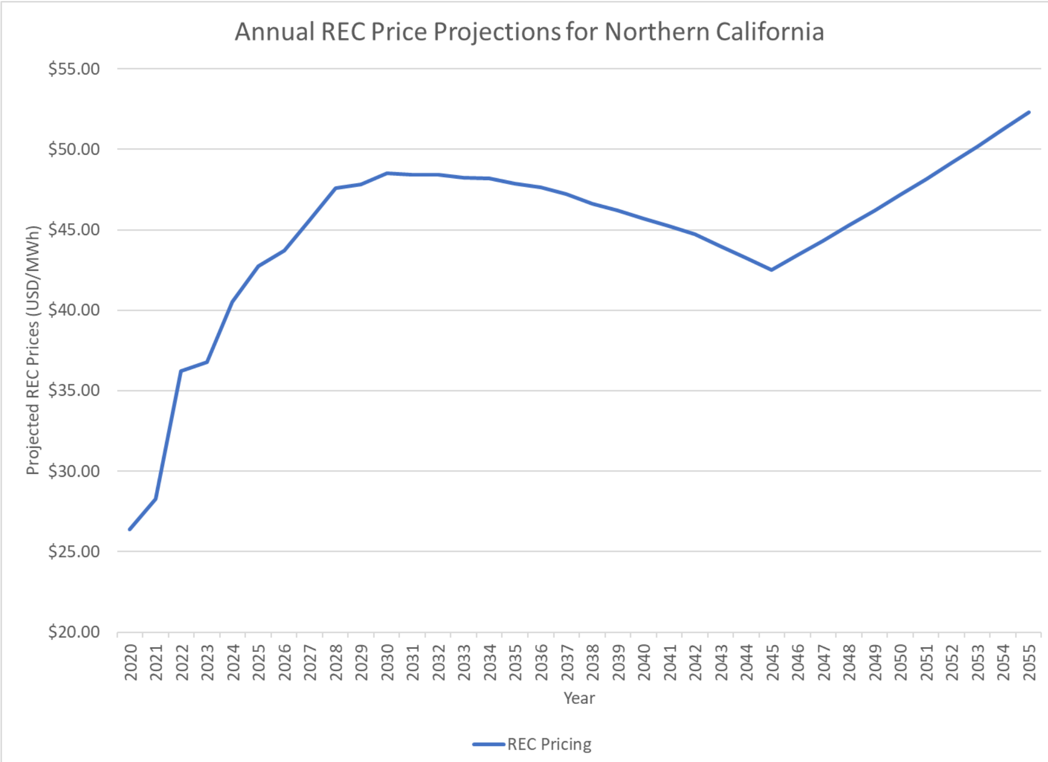


**Figure 3-4 Projected Average Annual REC Prices**

## 3.3 Water Availability

It is expected that demineralized water supplied by the existing LEC demineralized water system will meet the water needs for hydrogen production via electrolysis. LEC currently uses recycled water (i.e. tertiary treated municipal wastewater) from the City of Lodi's White Slough Water Pollution Control Facility (WPCF) for cooling and process water. Additional recycled water from the White Slough WPCF appears to be available based upon publicly-available documents.

The Central Valley Regional Water Quality Control Board authorized the White Slough WPCF under the General Order WQ 2016-0068-DDW-R5007 to construct a new Tertiary Storage Pond for recycled water storage and a Fill Station. The Pond has a design capacity of approximately 98 million gallons. Even though the Pond is permitted to supply recycled water to City trucks and commercial haulers, it will allow additional recycled water to be directed to LEC. Black & Veatch recommends that NCPA verify with the White Slough WPCF that additional recycled water can be diverted to LEC for the purpose of the hydrogen production and storage facility.

It is unlikely that surface water, groundwater, or potable water obtained from the City of Lodi will be approved by the CEC to supply water for hydrogen production at LEC. The California Water Code prohibits the use of potable domestic water for non-potable uses if recycled water is available. Additionally, as provided below, other constraints make the use of surface water, groundwater, and water from the City of Lodi infeasible.

### 3.3.1 City of Lodi Water Service

The proposed project site is located on land that has been incorporated by the City of Lodi. However, based on publicly available information, there are no water supply connection taps located near the site. To connect to the City of Lodi's water service, NCPA would be responsible for the installation of a water main extension to the nearest connection (over 4.5 miles in a straight line from the LEC site) and the associated costs. Installation of a water main would trigger additional permitting requirements. Additionally, the City of Lodi normally does not serve water outside the city limits. Connection to the City's water service may require approval by the City Council since the water main extension would need to extend over a large portion of unincorporated land and the rate may be 150 percent of the typical rate for service.

### 3.3.2 Groundwater

Industrial supply and power generation are both considered beneficial uses of water under state law. LEC's current on-site well for potable water draws from the Eastern San Joaquin Sub-basin. The Sub-basin has been identified by the California Department of Water Resources as being in a state of critical overdraft (groundwater extracted exceeds the long-term average of the groundwater recharged) and identified as a high priority groundwater basin. Withdrawals are not prohibited, but will need to be in accordance with the Eastern San Joaquin Groundwater Authority's Groundwater Sustainability Plan. However, the CEC has prohibited the use of groundwater for any LEC operation activity for which non-potable water is suitable.

### 3.3.3 Surface Water

The proposed project site is located within the Sacramento-San Joaquin Delta. Major waterways located near the site are Bishop Cut, White Slough, and Dredger Cut, which are all tributaries to the San Joaquin River and are considered navigable waters of the US. To withdraw surface water, a water right would need to be established and a permit obtained from the California State Water Resources Control Board (SWRCB), which SWRCB estimates will take three to four years if not contested.

Additionally, Black & Veatch identified numerous constraints to the withdrawal of surface water.

- NCPA would be subject to an appropriative right, which may only be exercised when there is a surplus not needed by riparian water uses. Currently, there are 59 points of diversions on the White Slough. Additionally, NCPA may not receive the allocated water quantity in all years (e.g. during periods of drought).
- LEC and surrounding area is located within a watershed that is fully appropriated for a portion of the year, no withdrawals would be allowed from July 1st to September 30th.
- Withdrawals from the Sacramento-San Joaquin Delta have the potential to negatively impact fishery resources. The area is designated as critical habitat for the delta smelt (federal- and state-listed threatened species) and supports habitat for other special-status fish.

Easements and additional federal, state, and local permits and approvals would be required to install a pump and pipeline from the point of diversion to the project site. Additionally, the pipeline would cross the White Slough Wildlife Area.

## 3.4 Regulatory Incentives and Grant Funding

While a variety of regulatory incentive and grant programs exist in California related to hydrogen, most of the available funding is geared towards the hydrogen transportation sector rather than hydrogen energy storage applications. The former programs include the CEC Clean Transportation Program (formerly known as the Alternative Renewable Fuel and Vehicle Technology Program), which was established to develop and deploy alternative and renewable fuels and advanced vehicle technologies. The grant program is an annual solicitation, with program funding levels adjusted yearly. The California LCFS Program is a GHG emissions reduction strategy administered by the California Air Resources Board that requires oil producers, importers, and other fuel providers to gradually reduce the carbon intensity of their transportation fuel mix. This is typically accomplished through alternative fuels blending and transport technologies. As mentioned previously, the LEC project may be able to operate its electrolysis equipment at a higher capacity factor and sell excess hydrogen into the transportation market to take advantage of additional revenues from LCFS credits. Such an approach would also be applicable to the federal Renewable Fuel Standard (RFS) program administered by the US Environmental Protection Agency, which mandates that refiners and distributors of transportation fuels utilize certain types of renewable fuels and provides volumetric blending targets through 2022.

More recently, the CEC released a solicitation (GFO-19-306) under the auspices of the Electric Program Investment Charge (EPIC) Program for the demonstration of non-lithium ion energy storage technologies, but the power levels considered in this solicitation are far less than the project that is currently being investigated for LEC. The primary focus of EPIC is on pre-commercial technologies, applied research, demonstration, and deployment projects. The Self-Generation Incentive Program (SGIP) may also be applicable to the LEC hydrogen energy storage project. The SGIP provides incentives for the installation of renewable power generation and energy storage systems by customers to increase resilience and there has been mention that the program may be revised to include hydrogen energy storage from electrolysis. Other regulatory incentive and grant funding programs are continuing to emerge as interest in hydrogen energy storage grows.

# 4.0 Cost Estimates

## 4.1 Capital Cost Estimate

Black & Veatch leveraged a combination of publicly available literature, OEM budgetary information, and in-house experience with engineering, procurement, and construction (EPC) projects in both Power and Oil & Gas industries to develop the capital cost estimate for the LEC hydrogen production and storage facility. Since this technology is still fairly new, there may be unforeseen costs not accounted for in this build-up.

### 4.1.1 Estimate Basis Assumptions and Qualifications

The following assumptions and qualifications were used in the capital cost estimate preparation and formulate the basis of the estimate.

- All costs are expressed in USD and are on a Q4 2020 basis.
- The capital cost estimate is presented on an overnight EPC basis.
- A clear site is assumed to be provided by NCPA and ready for construction.
- Where possible, scope has been quantified utilizing modeling, techniques based on equipment sizing and assumed distances.
- All other scope and costs are factored based on estimated equipment prices.
- The estimate includes all foundations, piling structural steel, pipe, electrical, and instrumentation required to construct the new facility.
- All electrical power is provided by two (2) new transformers and a power distribution center supplied by new switchyard additions within the current site boundaries.
- All control system costs are factored based on historical metrics.
- Construction labor and productivity is based on information sourced from the local area and is based on a greenfield execution.
- Where scope definition was available labor man hours have been produced and cost using an “all-in” construction rate of USD $135 per direct staff hour.
- All other construction costs are factored.
- The electrolyzer cost is based on a supply and install price provided by electrolyzer OEMs. No other cost has been included for the electrolyzer beyond these quotations.
- Liquefaction storage capital costs assume a conservative, four-train liquefaction system to enable a relatively low turndown capability. Should higher capacity factors be considered for the project, capital cost reductions may be realized for liquefaction cases.
- Compressed storage capital costs assume a storage scenario with compressors and storage tanks supporting a 2,600 psia tank pressure.
- Home office engineering, procurement, and project management is based on a factor of 7.5 percent of the Total Installed Cost (TIC).

- Shipping and start-up spares have been included at 2.5 percent of the assumed equipment/material cost.
- Contingency is included at 10 percent of the Bare TIC (i.e. TIC minus contingency)
- An EPC fee is included at 15 percent of total project costs.
- The existing plant has sufficient utilities (instrument air, nitrogen, demineralized water) to accommodate the new facility requirements.
- The estimate does not include any work associated with removal of contaminated materials or hazardous waste that may be encountered.
- The estimate does not include growth allowances.
- Suitable space is available on-site for construction laydown.
- No allowance has been included for all risk subcontractor liability insurance.
- No consideration is made for the impact of the COVID-19 pandemic.
- No retrofitting costs to the LEC power plant is considered in the capital cost estimate.

### 4.1.2 Exclusions & Owner's Cost

The following costs are excluded or assumed to be Owner's costs and therefore not included in the estimate. This list is not exhaustive:

- Administrative authorizations, certificates, & operation permits.
- All-Risk insurance.
- Bank guarantees.
- Business management systems.
- NCPA staff and expenses.
- Commissioning & start-up.
- Construction utilities (i.e. water & electricity).
- Contractual risks.
- Consultants.
- Contaminated & hazardous material handling and/or disposal.
- Delta income taxes.
- Escalation.
- Exchange rate risk.
- Financial costs (i.e. bonds).
- First fill and cost of catalysts.
- Geotechnical investigation/report.
- Infrastructure items.
- Land cost.

- Licensor fees.
- Lubricants (i.e. inventory and operating).
- Maintenance equipment and tools.
- Owner's auditing/inspection/witness testing.
- Owner's contingency.
- Owner's escalation.
- Parent company guarantee.
- Permits (i.e. building/environmental).
- Plant operations/maintenance vehicles (i.e. ambulances, fire, switch engine).
- Plant security.
- Site development & site work.
- Spares including capital spares and 2-year operating spares.
- Process simulator.
- Project development costs.
- Taxes and duties.
- Topographical map.
- Training for O&M staff.
- Vendor representatives.

### 4.1.3 Summary of Capital Cost Estimates

Summaries for each of the investigated cases are shown in Table 4-1 and Table 4-2.

**Table 4-1 Compressed Storage Capital Cost Estimate**

| CAPITAL COST ITEM | COST |
|---|---|
| **Direct Costs** | |
| Electrolyzer | \$90.4M to \$130.5M |
| Miscellaneous Mechanical | \$2.5M to \$3.6M |
| Miscellaneous Electrical and Control | \$10M to \$14.4M |
| Balance of Plant | \$15.8M to \$22.8M |
| Fin-Fan Cooling System | \$5M to \$7.2M |
| High pressure storage vessels | \$36.5M |
| High pressure storage compressor | \$3.2M |
| Installation, Site Work, and Civil/Structural | \$13M to \$14.5M |
| Shipping and Start-up Spares | \$4M to \$5.5M |
| **Subtotal Direct Costs** | **\$180.4M to \$238.2M** |

| CAPITAL COST ITEM | COST |
|---|---|
| **Indirect Costs** | |
| Construction Management | $12.6M to $16.7M |
| Engineering and Procurement | $13.5M to $17.9M |
| Contingency | $20.7M to $27.3M |
| EPC Fee | $27.1M to $35.7M |
| **Subtotal Indirect Costs** | **$73.9M to $97.5M** |
| **Total Fixed Capital Cost** | **$254.3M to $335.6M** |

**Table 4-2 Liquefied Storage Capital Cost Estimate**

| CAPITAL COST ITEM | COST |
|---|---|
| **Direct Costs** | |
| Electrolyzer | $90.4M to $130.5M |
| Miscellaneous Mechanical | $2.5M to $3.6M |
| Miscellaneous Electrical and Control | $10M to $14.4M |
| Balance of Plant | $15.8M to $22.8M |
| Fin-Fan Cooling System | $5M to $7.2M |
| Liquefaction Equipment | $297.3M |
| Liquefied Storage | $9.7M |
| Installation, Site Work, and Civil/Structural | $39.7M to $41.2M |
| Shipping and Start-up Spares | $8.5M to $8.9M |
| **Subtotal Direct Costs** | **$478.9M to $535.6M** |
| **Indirect Costs** | |
| Construction Management | $33.5M to $37.5M |
| Engineering and Procurement | $35.9M to $40.2M |
| Contingency | $54.8M to $61.3M |
| EPC Fee | $71.8M to $80.3M |
| **Subtotal Indirect Costs** | **$196.1M to $219.3M** |
| **Total Fixed Capital Cost** | **$675M to $754.9M** |

## 4.2 Operations and Maintenance Cost Estimate

The hydrogen production and storage facility O&M cost estimates are broken out into fixed O&M costs (e.g. labor, fees, corporate, etc.) and non-electricity variable O&M costs (e.g. water, maintenance reserves, etc.). The basis of the estimate for fixed and variable O&M costs are primarily derived from OEM input, publicly-available literature, and Black & Veatch experience.

### 4.2.1 Fixed Operations and Maintenance Costs

The major maintenance associated with the electrolyzers is the stack replacement. For the 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. For the compressed storage option, maintenance associated with the compressor is well established while maintenance associated with the tanks is expected to be minimal. For liquefied storage, the liquefaction train maintenance costs are less known but Black & Veatch has estimated based on expertise related to an LNG train. Fixed O&M costs primarily include labor, fees, corporate management, and planned maintenance actions.

### 4.2.2 Variable Operations and Maintenance Costs

The primary variable O&M costs are the hydrogen production and storage consumables, such as water and nitrogen gas for purging of the electrolyzer and compressors (estimated at approximately 9,900 scfh), as well as unplanned maintenance actions. Electricity has not been directly included in variable O&M costs, due to the significant electrical energy consumption by the electrolyzer.

### 4.2.3 Summary of Operations and Maintenance Cost Estimates

A summary of the O&M cost estimates is shown in Table 4-3.

**Table 4-3 Operations and Maintenance Cost Estimates**

| O&M COST ITEM | O&M COST |
|---|---|
| Electrolyzer Stack Replacements | $18M to $26.1M per Replacement |
| Compressed Storage Fixed O&M Costs | Labor: \$0.16/kg-$H_2$<br>General and administrative: \$0.03/kg-$H_2$<br>Planned maintenance: \$0.13/kg-$H_2$<br>Total: \$0.32/kg-$H_2$ |
| Liquefied Storage Fixed O&M Costs | Labor: \$0.47/kg-$H_2$<br>General and administrative: \$0.09/kg-$H_2$<br>Planned maintenance: \$0.37/kg-$H_2$<br>Total: \$0.93/kg-$H_2$ |
| Variable O&M Costs for All Cases | Water/Nitrogen: \$0.02/kg-$H_2$<br>Unplanned maintenance: \$0.11/kg-$H_2$<br>Total: \$0.13/kg-$H_2$ |

# 5.0 Economic Analysis

For each of the cases selected for evaluation, Black & Veatch developed estimates of the LCOH and LCOE for the LEC plant using a macro-enabled, Excel-based economic model. To estimate these costs, Black & Veatch employed a two-step economic model, which provides a preliminary estimate of the LCOH, both in terms of USD/kg as well as USD/MMBTU, and the LEC LCOE in terms of USD/MWh, 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 project.

## 5.1 Financial Model Assumptions

Financial assumptions affect the results of the economic model. After discussion with NCPA staff, a set of financial assumptions were developed for NCPA and third party ownership cases for the LCOH model as well as the LCOE model, which are defined in Table 5-1.

**Table 5-1 Economic Model Financial Assumptions**

| Financial Model Assumption | LCOH NCPA Ownership | LCOH Third Party Ownership | LCOE |
|---|---|---|---|
| Inflation | 2% | 2% | 2% |
| Debt Percentage | 100% | 60% | 100% |
| Debt Rate | 3% | 6% | 4.66% |
| Debt Term | 30 years | 15 years | 25 years |
| Economic Life | 30 years | 30 years | 25 years |
| Depreciation Term | - | 100% 7-year MACRS | - |
| Depreciation Basis | - | 100% | - |
| Cost of Equity | - | 12% | - |
| Discount Rate | - | 7% | - |
| Tax Rate | - | 40% | - |
| Depreciated Capital Cost | - | - | $310,000,000 |
| O&M Cost | - | - | Fixed: $21,905,240<br>Variable: $3.19/MWh |
| Natural Gas Price | - | - | $5.64/MMBTU |

Black & Veatch developed a number of technical assumptions as part of the economic model to properly depict the cases selected for evaluation. A summary of the LCOH and LCOE technical assumptions for economic modeling are shown in Table 5-2.

**Table 5-2 Economic Model Technical Assumptions**

| Technical Model Assumption | LCOH | LCOE |
|---|---|---|
| Plant Capacity | 155 MW | 300 MW |
| Electrolyzer Energy Efficiency | 52 kWh/kg | - |

| Technical Model Assumption | LCOH | LCOE |
|---|---|---|
| Plant Energy Efficiency | Compression: 4 kWh/kg<br>Liquefaction: 12 kWh/kg | - |
| Electrolyzer Stack Life | 10 years | - |
| Electrolyzer Replacement Timeline | Stack Life x $\frac{(Economic\ Life - Stack\ Life)}{Stack\ Life}$ | - |
| Capacity Factor | Compression: 25%<br>Liquefaction: 50% | 45% |
| Plant Capacity Degradation | 0.5% | 0.5% |
| Co-Product Production Rate | $\frac{144\ kg\ O_2}{MW}$ | - |
| Hydrogen Energy Density | - | 113,700 BTU/kg |
| LEC Plant Heat Rate | - | 6,850 BTU/kWh |
| LEC Transmission Losses | - | 0% |

## 5.2 Base Case Modeling Results

For the base case economic analysis, Black & Veatch used the aforementioned capital/O&M costs, financial assumptions, and technical assumptions for each of the cases selected for evaluation. Table 5-3 displays the results of this analysis. Black & Veatch has also included an assessment of the LEC LCOE without hydrogen co-firing, for comparison. The economic model is designed to minimize the LCOH/LCOE values while returning the target equity to investors.

**Table 5-3 Base Case Economic Analysis Results**

| Case | Capital Cost | O&M Cost | LCOH | LCOE |
|---|---|---|---|---|
| LEC w/o Hydrogen | - | - | - | \$83 to \$98/MWh |
| Compressed Storage | \$254.3M to \$335.6M | Fixed: \$0.32/kg<br>Variable: \$0.13/kg | \$5 to \$7/kg<br>\$46 to \$53/MMBTU | \$108 to \$112/MWh |
| Liquefied Storage | \$675M to \$754.9M | Fixed: \$0.93/kg<br>Variable: \$0.13/kg | \$7 to \$9/kg<br>\$61 to \$65/MMBTU | \$152 to \$156/MWh |

The results show that the liquefied hydrogen storage cases result in a 50 percent increase in the LCOH and approximately 40 percent increase in the corresponding LCOE, indicating that the increased equipment capacity factor does not result in a net advantage over the increase in capital/O&M costs.

## 5.3 Sensitivity Analysis Results

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

- Capital cost: ±50 percent.
- O&M cost: ±50 percent.
- Inflation: 3 percent.
- Electrolyzer stack life: 7 years and 13 years.
- Electricity costs: All Times and Peak (as defined in Section 3.2).
- Oxygen sales: $0.20/kg net revenue for oxygen.
- Debt rate: 5 percent.

In all sensitivity analyses, values for all variables that were not being examined remained as they were in the base case model. The results of the sensitivity analysis are shown in Table 5-4.

Based on these analyses, it can be seen that the LCOH/LCOE values are highly sensitive to capital costs, particularly for the liquefied storage case, given the significant capital investment needed for on-site liquefaction. This is expected given the low electrolyzer capacity factors considered in this study (25 percent for compressed storage cases and 50 percent for liquefied storage cases), which is due to the low amount of on-site storage capacity. As electrolyzer capacity factor increases, it is expected that the LCOH/LCOE values would be more sensitive to electricity prices than capital costs.

Additionally, oxygen sales appear to have a significant impact by lowering LCOH/LCOE values in all cases examined due to the additional revenues from oxygen sales. Black & Veatch understands that the market value for purified oxygen varies significantly by region, thus the identification of potential off-takers in the region who are paying higher prices may be advantageous for the NCPA LEC project. Finally, factors such as inflation and stack life appear to have minimal impact on levelized costs, while the impact of a higher debt rate appears to have a greater impact on higher capital cost cases, as would be expected.

Finally, Black & Veatch briefly investigated the potential for a 5- and 20-percent increase in the GHG emission allowance that is included in the natural gas price for LEC. This abbreviated sensitivity analysis showed that the LEC LCOE without hydrogen co-firing increases by 0.2 percent with a 5 percent increase in GHG emission allowance and 0.8 percent with a 20 percent increase. Similarly, when co-firing hydrogen (assuming Case #1), the LEC LCOE increases by 0.1 percent with a 5 percent increase in GHG emissions allowance and 0.5 percent with a 20 percent increase. Thus, it was not observed that the GHG emissions allowance has a significant impact on LCOE.

## Table 5-4 Sensitivity Analysis

| Sensitivity | Compressed Storage | | Liquefied Storage | |
|---|---|---|---|---|
| | LCOH | LCOE | LCOH | LCOE |
| Capital Cost +50% | $6 to $7/kg (+$1 to $2/kg) | $113 to $119/MWh (+$5 to $7/MWh) | $8 to $9/kg (+$1 to $1.50/kg) | $166 to $171/MWh (+$14 to $16/MWh) |
| Capital Cost -50% | $4 to $5/kg (-$1 to $2/kg) | $103 to $105/MWh (-$5 to $7/MWh) | $5.50 to $6/kg (-$1 to $1.50/kg) | $138 to $140/MWh (-$14 to $16/MWh) |
| O&M Cost +50% | $5 to $6/kg (+$1/kg) | $110 to $113/MWh (+$1 to $2/MWh) | $8/kg (+$0.70/kg) | $159 to $163/MWh (+$7/MWh) |
| O&M Cost -50% | $5 to $6/kg (-$1/kg) | $107 to $110/MWh (-$1 to $2/MWh) | $6/kg (-$0.70/kg) | $145 to $148/MWh (-$7/MWh) |
| Inflation 3% | $5 to $6/kg (-<$0.10/kg) | $109 to $113/MWh (+$1 to $2/MWh) | $7/kg (+<$0.10/kg) | $153 to $156/MWh (+$1/MWh) |
| Stack Life 7 years | $5 to $6/kg (+$0.10/kg) | $109 to $113/MWh (+$1 to $2/MWh) | $7/kg (+<$0.05/kg) | $153 to $156/MWh (+<$1/MWh) |
| Stack Life 13 years | $5 to $6/kg (-$0.10/kg) | $108 to $111/MWh (-<$1/MWh) | $6 to $7/kg (-$0.50/kg) | $147 to $150/MWh (-$5/MWh) |
| Electricity (All Times) | $5 to $6/kg (+$0.15/kg) | $109 to $113/MWh (+$0.82/MWh) | $7 to $8/kg (+<$0.20/kg) | $154 to $157/MWh (+<$2/MWh) |
| Electricity (Peak) | $6 to $7/kg (+$0.30/kg) | $110 to $114/MWh (+$1.66/MWh) | $7 to $8/kg (+<$0.40/kg) | $156 to $159/MWh (+<$4/MWh) |
| Oxygen Sales $0.20/kg | $3 to $4/kg (-$2/kg) | $98 to $101/MWh (-$10.81/MWh) | $5/kg (-$2/kg) | $130 to $134/MWh (-$22/MWh) |
| Debt Rate 5% | $6 to $7/kg (+<$0.50/kg) | $111 to $116/MWh (+$3 to $4/MWh) | $7 to $8/kg (+<$0.60/kg) | $160 to $164/MWh (+$7 to $8/MWh) |

## 5.4 Scenario Building

Black & Veatch investigated a number of scenarios to positively impact overall LCOH/LCOE and attempt to achieve cost parity with the LEC LCOE without hydrogen co-firing. The following scenarios were investigated as part of this study:

- Third-party ownership using set of alternative financial assumptions shown in Table 5-1.
- REC Revenue Sharing: 10, 50 and 100 percent.
- Combinations of REC revenues, oxygen sales, and lower capital costs.

The results of the third-party ownership and REC revenue sharing scenario building investigations are shown in Table 5-5. As can be seen, third-party ownership of the hydrogen project was not studied to a sufficient extent to show value to NCPA, given the fact that a combination of debt/equity is used to finance the project resulting in higher LCOH values. It is important to note that a third-party developer would be incentivized to operate the equipment at a much higher capacity factor than considered here and transport the additional hydrogen off-site for external sales (e.g. sales into transportation fuel market for fuel cell electric vehicles), but a new economic model would have to be developed to consider such a scenario.

The table also shows that revenue sharing associated with RECs could have a highly positive impact on the LCOE. Black & Veatch estimates that REC revenue sharing of 10, 50, and 100 percent could result in an approximate reduction in LCOE of 2, 10, and 20 percent, respectively. This indicates that REC revenue sharing in combination with co-product oxygen sales, offer the best opportunities for lowering overall levelized costs for a hydrogen co-firing project.

**Table 5-5 Scenario Building for Third-Party Ownership and REC Revenue Sharing**

| Case | Third-Party Ownership | | REC Revenue Sharing | |
|---|---|---|---|---|
| | LCOH | LCOE | LCOH | LCOE |
| Compressed | \$8 to \$9/kg | \$125 to \$134/MWh | \$5 to \$6/kg | 10%: \$106 to \$110/MWh<br>50%: \$98 to \$102/MWh<br>100%: \$88 to \$92/MWh |
| Liquefied | \$10 to \$11/kg | \$194 to \$203/MWh | \$7 to \$8/kg | 10%: \$149 to \$153/MWh<br>50%: \$138 to \$141/MWh<br>100%: \$123 to \$126/MWh |

Based on these observations, Black & Veatch developed several scenarios to investigate combinations of capital cost reductions and additional project revenue from co-product oxygen sales and REC sharing. The results of these analyses are shown in Table 5-6 and were performed exclusively for the compressed storage design/costs. The goal of these scenario building investigations was to lower the LCOE at or slightly below the LCOE without hydrogen co-firing.

**Table 5-6 Scenario Building for Combinations of RECs, Oxygen, and Capital Costs**

| Scenario | Capital Cost | RECs/Oxygen | LCOH | LCOE |
|---|---|---|---|---|
| Scenario #1 | $254.3M | $0.28/kg Oxygen<br>RECs: 50% | $2.46/kg | $83.08/MWh |
| Scenario #2 | $127.1M | RECs: 97% | $4.26/kg | $83.27/MWh |
| Scenario #3 | $127.1M | $0.37/kg Oxygen | $0.59/kg | $83.16/MWh |
| Scenario #4 | $190.7M | $0.20/kg Oxygen<br>RECs: 57% | $2.77/kg | $83.31/MWh |
| Scenario #5 | $190.7M | $0.23/kg Oxygen<br>RECs: 50% | $2.47/kg | $83.13/MWh |

Scenario #1 looked exclusively at RECs/oxygen sales without any capital cost reduction and it was determined that a net price of oxygen of $0.28/kg in combination with 50 percent REC sharing would be sufficient. Scenario #2 investigated a 50 percent capital cost reduction with REC sharing only and found that 97 percent of REC revenues would be required. Scenario #3 also included 50 percent reduced capital cost but instead included oxygen sales and found that a $0.37/kg net price of oxygen would be needed. Scenario #4 included a 75 percent reduction in capital cost and assuming $0.20/kg net price of oxygen found that 57 percent REC sharing is required to achieve parity. Similarly, Scenario #5 included a 75 percent reduction in capital cost and assuming 50 percent REC revenue sharing found that $0.23/kg net price of oxygen would be needed to achieve parity. These scenarios demonstrate that a combination of capital cost reductions, REC sharing, and oxygen sales could result in a hydrogen energy storage project that achieves parity with current operations without hydrogen co-firing.

# 6.0 Conclusions and Recommendations

The primary conclusions of this study are as follows:

- Production of hydrogen via water electrolysis and storage as a compressed vapor or cryogenic liquid is technically feasible using commercially-available technology.
- Numerous technology vendors exist for each of the key processes considered in this study, and many of them offer commercial experience.
- Although numerous electrolyzer facilities exist worldwide, hydrogen energy storage facilities on the scale considered in this study are a relatively new phenomenon.
- Capital costs for hydrogen production and storage equipment remain high and contributed significantly to levelized costs.
- Electricity pricing contributes significantly to levelized costs, but projected pricing throughout the life of a potential project at LEC appears reasonable.
- Black & Veatch expects LCOE cost parity could be potential with hydrogen co-firing at LEC in instances where capital costs are minimized to the extent practicable, recovery and sales of oxygen are pursued, and REC revenue sharing with renewable energy providers is pursued.

The following actions are recommended to facilitate the future development of a hydrogen energy storage project at LEC:

- Conduct additional analysis associated with third-party ownership of the LEC hydrogen project to increase capacity factors and allow for off-site sales of hydrogen into transportation and industrial markets.
- Explore options for a combination of dedicated renewable energy resources in combination with curtailed electricity from the electric grid.
- Perform outreach to potential renewable energy developers to discern potential for REC revenue sharing and to potential off-takers/distributors for recovered oxygen.
- Work with local, state, and federal agencies to better understand potential permitting requirements and to highlight the pivotal nature of this project in decarbonization.
- Continue to monitor on-going activity in the California legislative process in regard to carbon markets and incentives/targets for hydrogen energy storage.

# Appendix A. Acronyms

| ACRONYM | DESCRIPTION |
|---|---|
| ASP | Alternative Security Plan |
| ATC | Authority to Construct |
| AWE | Alkaline Water Electrolysis |
| BTU | British Thermal Unit |
| CalARP | California Accidental Release Prevention |
| Cal OES | California Office of Emergency Services |
| CAPEX | Capital Expenditure |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| CFATS | Chemical Facility Anti-Terrorism Standards |
| CISA | Cybersecurity and Infrastructure Security Agency |
| $CO_2$ | Carbon Dioxide |
| DHS | Department of Homeland Security |
| EIA | Energy Information Administration |
| EMP | Energy Market Perspective |
| EPA | Environmental Protection Agency |
| EPC | Engineering, Procurement, Construction |
| EIA | Energy Information Administration |
| EPIC | Electric Program Investment Charge |
| ft | Foot/Feet |
| GHG | Greenhouse Gas |
| hr | Hour |
| kg | Kilograms |
| kWh | Kilowatt Hour |
| LCFS | Low Carbon Fuel Standard |
| LCOE | Levelized Cost Of Energy |
| LCOH | Levelized Cost of Hydrogen |

| ACRONYM | DESCRIPTION |
|---|---|
| LEC | Lodi Energy Center |
| LNG | Liquefied Natural Gas |
| MMBTU | Million British Thermal Units |
| MW | Megawatts |
| NCPA | North California Power Agency |
| $NH_3$ | Ammonia |
| NOx | Nitrogen Oxides |
| O&M | Operations And Maintenance |
| OEM | Original Equipment Manufacturer |
| OPEX | Operating Expenditure |
| OSHA | Occupational Safety and Health Administration |
| PEM | Proton Exchange Membrane |
| ppmvd | Parts per Million by Volume (Dry) |
| psi | Pounds per square inch |
| PSM | Process Safety Management |
| R&D | Research & Development |
| RBPS | Risk-Based Performance Standards |
| REC | Renewable Energy Credit |
| RFS | Renewable Fuel Standard |
| RMP | Risk Management Plan |
| scf | Standard Cubic Foot |
| SCR | Selective Catalytic Reduction |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| SSP | Site Security Plan |
| SVA | Security Vulnerability Assessment |
| SWRCB | State Water Resources Control Board |
| TBD | To Be Determined |
| TIC | Total Installed Cost |
| US | United States |

| ACRONYM | DESCRIPTION |
|---|---|
| USD | US Dollars |
| USACE | US Army Corps of Engineers |
| WPCF | Water Pollution Control Facility |

# Appendix B. Design Basis Memorandum

FINAL – NOT FOR CONSTRUCTION

# LODI HYDROGEN PROJECT DESIGN BASIS

**B&V PROJECT NO. 406377**
**B&V FILE NO. 40.0100**



**PREPARED FOR**

Northern California Power Agency (NCPA)

19 FEBRUARY 2021

BLACK & VEATCH

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## LIST OF FIGURES

# 1.0 General Information

**Client's Name:** Northern California Power Agency (NCPA)
**Facility Location:** Lodi Energy Center (LEC)
**Unit Type:** Hydrogen Production and Energy Storage Facility

## 1.1 OBJECTIVE

The purpose of this document is to:

- Define the basis used for estimating the cost for the Hydrogen Production and Energy Storage Facility to be sited at the LEC plant in Lodi, CA.
- Provide a high-level assessment of the necessary electrolyzer capacity to supply sufficient hydrogen to achieve forty-five (45) percent by volume co-firing of hydrogen with natural gas.
- Record inputs from NCPA that will be used in the subsequent feasibility analysis.

## 1.2 SCOPE

Black & Veatch is assisting with a feasibility analysis for a Hydrogen Production and Energy Storage Facility, which will be used to produce hydrogen from renewable energy resources, store it, and blend it with the natural gas to reduce the carbon intensity of the LEC facility. Black & Veatch's scope is to develop a design basis, develop a cost estimate, perform an economic analysis, and consider any siting/permitting implications for the Hydrogen Production and Energy Storage Facility.

## 1.3 UNITS

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

**Table 1-1 Variables and Engineering Units**

| Variable | Engineering Units |
|---|---|
| Temperature | °F or °C |
| Pressure | |
| Near Atmosphere | Psi or bar |
| Above Atmosphere | Psi or bar |
| Below Atmosphere | inches $H_2O$ |
| Gauge | psig |
| Absolute | psia |
| Level | |
| Process | ft, inches |
| Storage tanks | ft, inches |
| Flow | |
| Gas Volume | SCFM or SCFH |
| Gas Mass | lb/hr or kg/hr |
| Liquid Volume, Process flows | GPM or L/hr |
| Liquid Volume, Utility flows | GPM or L/hr |
| Liquid Mass | lb/hr or kg/hr |
| Solid Mass | lb/hr, kg/hr, or tons/hr (tph) |

| Variable | Engineering Units |
|---|---|
| Electrical | |
| Voltage | V |
| 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 |
| Heat/Thermal Duty | MMBTU/hr |
| Sound Pressure Level | dBA |

## 1.4 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).
- California Building Standards Codes 2019.
- California Electric Code.

- California Plumbing Code 2019.
- 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 Electric Code (NEC).
- National Fire Protection Association (NFPA).
- National Institute of Standards and Technology (NIST).
- Occupational Safety and Health Administration (OSHA).

# 2.0 Site Information

## 2.1 SITE CONDITIONS

Site-specific design criteria are outlined in the LEC Site Data Sheet provided by NCPA and shown in Table 2-1.

**Table 2-1 Site-Specific Design Criteria**

| | |
|---|---|
| Design Barometric Pressure: | 14.68 psi |
| Elevation: | 26 ft |
| Design Minimum Ambient Temperature | 22.2°F |
| Design Maximum Ambient Temperature (Dry-Bulb) | 110.2°F |
| Design Maximum Ambient Temperature (Wet-Bulb) | 88.9°F |

## 2.2 DESIGN BASIS WATER

The Hydrogen Production and Energy Storage Facility will receive demineralized (demin) water from an existing demineralized water system at LEC that is currently used for a steam-injected (STIG) LM5000 gas turbine. On-site demin water is expected to meet electrolyzer quality requirements without additional owner-supplied equipment. The Hydrogen Production and Energy Storage Facility will not require any other water due to the fact that a fin fan cooler will be used to meet the heat rejections needs of the electrolyzer package.

## 2.3 ENVIRONMENTAL EMISSIONS AND EFFLUENTS

The Hydrogen Production and Energy Storage Facility will emit two waste streams: oxygen and water. The oxygen will be vented to a safe location. Based on the guidelines set forth in NFPA 55, Black & Veatch plans to vent oxygen via a 50 foot tall stack so it will not need to be diluted with nitrogen during regular operation.

A small amount of wastewater is expected to be discharged from the electrolyzer system. This stream will be of suitable quality to be recycled to the demineralized water system, raw water system, or the cooling tower basin. Pending input from electrolyzer vendors and NCPA, Black & Veatch is still evaluating which is the better option. If necessary, the wastewater could be discharged to the existing on-site Class I underground injection wells. No additional air, wastewater, or solid effluents are expected.

## 2.4 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.

The hydrogen reciprocating compressor estimated noise level is expected to be approximately 95 to 100 dBA during normal operation. Therefore, basic noise mitigation enclosures will be specified. In order to ensure LEC far-field sound level limits imposed by the California Energy Commission (CEC) are met, the enclosures will be specified to reduce compressor sound levels to 50 dBA or lower when measured under free-field conditions at 400 ft away from the enclosure and 5 ft above compressor/enclosure grade.

## 2.5 SITE ACCESS

A map of the LEC project location is shown in Figure 2-1. The site is located approximately 7 miles southwest of Lodi, California. Major transportation links in the vicinity include Interstate 5 and California Highway 12. Access to the site will be by truck. No rail spurs or waterway access is available. Access to the power generation facility will be controlled by the existing facility security, which includes fenced perimeter and controlled gates. Access to the adjacent expansion parcel will be by the existing unpaved roads adjacent to the power generation facility.


**Figure 2-1 Map of NCPA LEC Site (Courtesy of Google Earth)**

# 3.0 Utility Requirements

Utilities required for the facility are shown in Table 3-1.

**Table 3-1 Utility Requirements**

| Utility | Utility Supply Information |
|---|---|
| Nitrogen | Needed for compressor/electrolysis purge and oxygen vent header purge, to be provided by Nitrogen Package. |
| Instrument Air | Needed for air-operated instrumentation and valves, to be provided by existing Instrument Air. |
| Cooling Water | None. Planning to use a fin fan air cooler for the Hydrogen Production and Energy Storage Facility cooling requirements. |
| Demineralized Water | Supplied to the electrolyzer system for the production of hydrogen. |
| Electrical Power Supply | On-site electric power will be provided via new power distribution center. |

# 4.0 Process Design Basis

## 4.1 PROCESS DATA TABLES

### 4.1.1 Supply Water

Demineralized Water is supplied by the existing demineralized water system assuming the conditions outlined in Table 4-1.

**Table 4-1 Supply Water Conditions**

| Flow Rate | Pressure | Temperature |
|---|---|---|
| 122 GPM | 190 psig | Ambient |

It is assumed the quality of the supplied demineralized water meets electrolyzer requirements, which will be confirmed by the electrolysis system vendors engaged for budgetary pricing. At this time, it is assumed that water treatment equipment is not required to be included within the scope of the vendor. If it is determined that the LEC demineralized water system cannot provide the required flowrate, an alternate source such as potable water will be considered, and water treatment scope will be included within the vendor scope of supply.

### 4.1.2 Effluent Water

The condensed water from product hydrogen gas compression/cooling and unused water from electrolysis will be recycled to the demineralized water system, the cooling tower, or the raw water supply based on estimated quality and available tie in location. Black & Veatch is still investigating the estimated quality of this stream. Return water conditions are shown in Table 4-2.

**Table 4-2 Effluent Water Conditions**

| Flow Rate | Pressure | Temperature |
|---|---|---|
| 4 GPM | To be confirmed by vendors | To be confirmed by vendors |

### 4.1.3 LEC Fuel Gas Composition and Consumption

Black & Veatch analyzed data provided by NCPA and publicly-available data[1] to determine a representative fuel composition and fuel blending flowrate for LEC. Black & Veatch then calculated the monthly maximum consumption based on historical operating data. The fuel gas composition shown in Table 4-3 and maximum monthly fuel consumption shown in Table 4-4 were then used as a basis for calculating required hydrogen production.

**Table 4-3 LEC Fuel Gas Composition**

| N2 | CO2 | Methane | Ethane | Propane | I-Butane | N-Butane | I-Pentane | N-Pentane | C6+ |
|---|---|---|---|---|---|---|---|---|---|
| mole % | mole % | mole % | mole % | mole % | mole % | mole % | mole % | mole % | mole % |
| 0.40 | 0.74 | 94.35 | 3.37 | 0.15 | 0.010 | 0.02 | 0.01 | 0.01 | 0.01 |

[1] "Independent Statistics and Analysis." Form EIA-923 Detailed Data with Previous Form Data (EIA-906/920), U.S. Energy Information Administration, 28 Sept. 2020, www.eia.gov/electricity/data/eia923/.

**Table 4-4 LEC Fuel Consumption**

| Pipeline Fuel Gas HHV (BTU/Lb) | Maximum Monthly MMBtu consumed at LEC (October 2018) | Maximum Monthly Fuel Consumption (lb) |
|---|---|---|
| 23,136 | 1,393,920 | 60,248,963 |

### 4.1.4 Product Hydrogen

The product hydrogen from electrolysis is expected to have 99.5 to 99.9 percent purity and will be dried and cooled by means of fin fan air cooler included within the vendor scope. The electrolysis system produces saturated hydrogen with 0.3 mole percent oxygen under the conditions displayed in Table 4-5. The hydrogen flow rate equates to a 45 molar percent hydrogen blend with the pipeline fuel for the conditions stated above in Section 4.1.3.

**Table 4-5 Product Hydrogen Conditions**

| Flow Rate | Pressure | Temperature |
|---|---|---|
| 6,300 lb/hr | To be confirmed by vendors | To be confirmed by vendors |

### 4.1.5 Oxygen Vent

The saturated oxygen with 0.1 percent hydrogen is produced by the electrolyzer will be vented to the atmosphere at safe location. The oxygen vent composition is estimated to be 98 percent oxygen and 2 percent water. The conditions for the byproduct oxygen are shown in Table 4-6.

**Table 4-6 Byproduct Oxygen Conditions**

| Flow Rate | Pressure | Temperature |
|---|---|---|
| 51,000 lb/hr | To be confirmed by vendors | To be confirmed by vendors |

Per NFPA 55, if the vent stack is greater than 50 feet tall, then nitrogen dilution is not required.

### 4.1.6 Nitrogen Package

The nitrogen package will provide purge gas for the oxygen vent header, hydrogen compressors, and electrolyzer. This is for maintenance/shutdown/emergency scenarios and will not be used regularly. The total estimated required capacity is 1,100 SCFH.

### 4.1.7 Instrument Air Package

The Hydrogen Production and Energy Storage Facility will require instrument quality compressed air. It is assumed that the existing LEC air system is capable of supplying this requirement. Black & Veatch is working with electrolyzer system vendors to determine the quantity of air required. If the existing LEC air system is insufficient, a suitably-sized Instrument Air Package to meet the needs of the Hydrogen Production and Energy Storage Facility will be included.

### 4.1.8 Effluent Pump

The wastewater generated by the Hydrogen Production and Energy Storage Facility will be conveyed back to the adjacent LEC facility using an effluent pump. The water will be returned to the existing demineralized water system, the existing raw water storage system, or the cooling tower basin.

### 4.1.9 Electrolysis

Hydrogen is produced by the electrolysis system provided, the estimated specifications for which is provided in Table 4-7.

**Table 4-7 Electrolyzer Specification**

| | | | |
|---|---|---|---|
| **Electrolyzer type** | PEM/Alkaline | **Rated hydrogen production** | 6,300 lb/hr |
| **Rated power** | 150 – 160 MW | **Module efficiency** | By Vendor |
| **Dimension full array** | By Vendor | **Plant efficiency** | By Vendor |
| **Startup time until full load** | By Vendor | **Stack design life** | By Vendor |
| **Output pressure** | 550 psia | **Weight per module** | By Vendor |
| **Hydrogen purity (depending on operation)** | 99.5% | **CE-Conformity** | By Vendor |
| **Hydrogen quality enhancement** | By Vendor | **Rated water requirement** | By Vendor |
| All values calculated for ISO conditions: $T_{amb}$=15°C, 60% rel. humidity, 1.013 bar, air cooled, new and clean, Higher Heating Value of hydrogen= 39.41 kWh/kg | | | |

It is expected that the hydrogen dehydration and cooling systems will be included in the electrolyzer vendor scope of supply.

### 4.1.10 Hydrogen Gas Compression and Storage

Black & Veatch is still confirming the basis for compression and storage. Hydrogen compression requirements are provided in Table 4-8.

**Table 4-8 Hydrogen Compressor Design Criteria**

| Flow Rate | Suction Pressure / Temperature | Discharge pressure |
|---|---|---|
| 6,300 lb/hr | 16.68 psia / 86°F | >550 psia |

# 5.0 Civil/Structural Design Basis

## 5.1 ENVIRONMENTAL CRITERIA

- Seismic:
  - Mapped Spectral Response Accelerations:
    Ss:0.84g
    S1:0.3g
  - Site Class D
- Wind
  - Speed V3c: 100 mph
  - Exposure Category C
  - Occupancy Category III
- Snow
  - Ground Snow Load: Pg: 30
  - Snow Exposure Factor Ce: 1
  - Occupancy Category: III

## 5.2 DESIGN CRITERIA

### 5.2.1 Structural Steel

Steel framed structures shall be designed in accordance with the AISC Specification for Structural Steel Buildings and in accordance with the criteria discussed in the following subsections.

#### Materials

Construction of steel structures shall use materials as defined below:

- Structural steel wide flange and WT shapes: ASTM A992/A992M
- Structural steel channels: ASTM A992/A992M; ASTM A572/A572M, Grade 50; ASTM A36/A36M
- Structural Steel S shapes: ASTM A36/A36M; ASTM A992/A992M;ASTM A572/A572M, Grade 50
- Structural steel angles and plates: ASTM A572/A572M, Grade 50; ASTM A529/A529M, Grade 50; ASTM A36/A36M
- Steel Tube, rectangular or square: ASTM A500/A500M, Grade B
- High Strength Bolts (imperial): ASTM A325, 3/4 inch, 7/8 inch, or 1 inch diameter, 1/4 inch increment of length, 1/4 inch increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-critical connections are required. Connections with oversized holes or slots in the direction of load are slip critical.
- High Strength Bolts (metric): ASTM A325M, M20, M22, or M24, 5mm increments of length, 4mm increments on bolt diameter when different bolt sizes are used, fully-tensioned bearing type designed with threads included in the shear plane for all connections except where slip-

critical connections are required. Connections with oversized holes or slots in the direction of the load are slip critical.

- Weld Filler Material: 70 ksi (485 MPa) tensile strength.
- Guardrail and Handrail Pile: Steep pipe 1-1/2 inch (38mm) diameter, ASTM A53/A53M, Type E or S, Grade B; HSS 1.9 inch (48mm) diameter, ASTM A500 Grade C; Guardrails only – Steel Angles 2-1/2x2-1/2x1/4 inch (64x64x6.4 mm)
- Kickplate (Toe plate): Fabricated from ASTM A36/A36M plate PL 4x1/4 inches (100x6 mm)
- Steel Grating: 3/16 inch by 1-1/4 inch (5x32 mm) bearing bars, galvanized
- Anchor Rods, sized for design loads: ASTM F1554, Grade 36 or 55, 1/2 inch (13 mm) increments of diameter. In moderate to high seismic region Grade 36 shall be used only. Substitution of higher grade material will not be allowed.
- Anchor Rods, sized for design loads and pretensioned: ASTM F1554, Grade 105, ½ inch (13 mm) increments of diameter.
- Stair Treads: Steel grating, cast abrasive or bent checker plate nosings.
- Metal Deck, roof: 1-1/2 inch (25 mm) profile depth, 24 gauge minimum, painted or galvanized (composite deck form only).
- Ladders: Fabricated from ASTM A36/A36M bar rails 3 inches x 1/2 inch (75x13 mm) with 3/4 inch (19 mm) diameter rungs.

### Structural Steel Design

Construction of steel structures shall use design practices defined by local building codes, but not less than those defined below:

- Lateral Building Drift, rigid frame structures: (story or building height)/100 under wind, ASCE 7 for seismic.
- Lateral Building Drift, braced frame structures: (Story or building height)/200 under wind, ASCE 7 or seismic.
- Vertical Bracing Members: Designed and detailed for concentric loading, unless analyzed for work point and shape eccentricity. Compression and tension capable, “pinned” at all connection points.
- Horizontal Bracing Members: Designed and detailed for concentric work point loading and eccentric shape loading. Compression and tension capable, “pinned” at all connection points.
- Beams – Lateral-Torsional Buckling Brace Points: The following shall be considered as points of lateral-torsional stability bracing for beams:
- Roof deck connections, Lb = Lesser of 3 times deck fastener spacing or the actual shear connector spacing
- Floor deck connections, Lb = Lesser of 3 times deck fastener spacing or the actual shear connector spacing
- Floor grating, welded connections – Use 1 inch (25 mm) fillet welds at 12 inch (300 mm) spacing (min.), add drawing notes to caution against removing grating, Lb = weld spacing

- Horizontal truss panel point incident beams – Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum
- Incident beams axially aligned with horizontal truss panel points – Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum
- Incident beams connected to H-brace stability connections – Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum
- Incident beams connected to floor slabs or roof truss diaphragms – Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum
- Incident beams connecting three or more parallel beams, parallel beams have 20 percent or less difference in weight – Incident beam top of steel offset 3 inches (75 mm) or (1/6) (braced beam depth), maximum
- Incident beams connecting two parallel beams – Verified by calculation only
- Columns – Lateral-Torsional Buckling Brace Points: The following shall be considered as points of lateral-torsional stability bracing for columns:
- Incident beams connected to the space truss – Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement.
- Incident beams connecting three or more adjacent columns--Note for standard column sizes (W14 [W360] and smaller), incident beams connecting to the center of the column web restrain the column flanges against lateral buckling. For deep columns (W16 [W410] and larger), the incident beams may require special connections to restrain the column compression flange(s) against lateral movement.
- Girts with flange braces
- Beams – Major Axis Compression Buckling Brace Points: The major axis compression buckling points for beams shall occur only at the beam supports. Major axis unbraced length for beams, Lx, shall equal the beam span.
- Beams – Minor Axis Compression Buckling Brace Points: The following shall be considered as points of weak-axis compression-buckling stability bracing for beams:
- Horizontal truss panel points with or without incident beams
- Incident beams axially aligned with horizontal truss panel points
- Incident beams connected to the floor slabs or roof truss diaphragms
- Columns – Major and Minor Axis Compression Buckling Brace Points: The following shall be considered as points of compression-buckling stability bracing for columns:
- Incident beams connected to the space truss
- Incident beams connecting two adjacent columns – Verified by calculation only
- Vertical Braces – Compression Buckling Brace Points: the following shall be considered as brace points for the vertical bracing:

- Buckling in the plane of the truss – "X-bracing" or singe side strut
- Buckling out of the plane of the truss – "X-bracing"
- Unbraced length, Pipe bracing in ducts: KL/r ≤ 120, checked for vortex shedding in flow and thermal restraint forces
- Deflection, floors and roofs, dead and live load combined: Span/360, vertical, unless attached to more rigid, brittle members.
- Deflection, floors and roofs, dead and live load combined: Span/240, vertical.
- Deflection girts: Span/180, horizontal. Span/240, vertical. When over and under glass, Span/360 horizontal. Span/960, vertical.
- Deflection, crane and hoist support beams (without "impact"): Span/360, vertical; Span/400, Lateral.
- Deflection, grating (100 psf [4.8 kN/m2] uniform load): 1/4 inch (6 mm) maximum
- Fixed Ladder Fall Prevention (OSHA compliant): Ladders with the top rung more than 24 feet above a lower level will be provided with a fall prevention device. Ladders 24 feet or less above a lower level will have fall protection.

### 5.2.2 Foundations

#### General Criteria

Foundations shall be designed using reinforced concrete to resist the loading imposed by the building, structure, tanks, or equipment being supported. The foundation design shall consider the following:

- Seismic Soil bearing capacities.
- Deep foundation capacities, if applicable.
- Lateral earth pressures.
- Allowable settlements, including differential settlements.
- Structure, equipment, and environmental loadings.
- Equipment performance criteria.
- Access and maintenance.
- Temporary construction loading.
- Existing foundations and underground structures including their current settlement conditions.

Foundations shall be designed using static analysis techniques assuming rigid elements and linear soil pressure distribution so that the allowable settlement and bearing pressure criteria are not exceeded. Foundations shall be proportioned so that the resultant of the soil pressure coincides as nearly as possible with the resultant of the vertical loading. The minimum factors of safety against overturning and sliding shall be 1.5. Factor of safety against sliding for retaining walls shall also be 1.5.

When using ASCE 7 load combinations that apply a 0.6 factor on dead load, the factor of safety for overturning and sliding is automatically set at approximately 1.67. For these special ASCE 7 ASD load combinations, the ratio of resisting forces (0.6 dead load) over driving forces (wind, seismic, or lateral loads) should be greater than 1.0 instead of 1.5.

Geotechnical exploration, testing, and analysis information shall be used to determine the most suitable foundation system. Elastic (short-term) and consolidation (long-term) foundation settlements shall be calculated and limited to the following approximate design values except where loading onto or differential settlements relative to existing structures may require more conservative criteria:

- Total settlement--1-1/2 inches (38 mm).
- Differential settlement--0.1 percent slope between adjacent column support points.

Allowable settlement is higher for tanks. These settlements will be calculated on an individual basis.

### Special Foundation Requirements for Rotating Equipment

The foundation systems for major rotating equipment shall be sized and proportioned so as not to exceed the bearing and settlement criteria and to ensure satisfactory performance of the equipment. In addition to a static analysis, a dynamic analysis may be performed to determine the fundamental frequencies of the foundation system for selected major rotating equipment as determined necessary by Black & Veatch. To preclude resonance, fundamental frequencies of the foundation associated with rigid body motion shall be 25 percent removed from the operational frequency of the equipment. Should the foundation system not meet this criteria, a balance quality grade, appropriate for the equipment, will be determined from ISO 1940, Balance Quality Requirements of Rigid Motors - Part 1. The dynamic behavior of the foundation will be evaluated for this level of unbalance and compared to ISO 10816, Mechanical Vibration-Evaluation of Machine Vibration by Measurements on Nonrotating Parts, Parts 1 through 6. The resultant vibration level shall not exceed the limit for evaluation of this standard. Where required, the foundation shall also be designed to meet manufacturer’s requirements.

### Equipment Bases

All equipment shall be supplied with an equipment base suitable for its operation. Where the equipment could induce vibration problems, the base shall have adequate mass to dampen vibration motions. Special consideration shall be given to vibration and stiffness criteria where specified by an equipment manufacturer. Equipment bases may be concrete or an integral metal skid. Concrete bases shall have minimum temperature and shrinkage reinforcing, unless it is determined that additional reinforcement is required for the equipment loads.

### Insulation

When required by the local code, foundations and below grade portions of space-conditioned buildings above those foundations shall be insulated.

# 6.0 Mechanical Design Basis

## 6.1 PIPING, COMPONENTS, AND ACCESSORIES

Piping, components, and accessories will be in accordance with ASME B31.1 for Power Piping unless otherwise specified. The requirements for piping, components, and accessories are summarized in Table 6-1 by system/process.

**Table 6-1 Piping, Components, and Accessories Requirements**

| System/ Process Area | Flange Rating (B16.5) | Pipe Material | Special Requirements | Post-Weld Heat Treatment (PWHT) | Notes |
|---|---|---|---|---|---|
| Hydrogen | 300 | CS | Fire safe, Hydrogen Service | | G01 |
| Waste Water | 150 | CS | | | G01, G04, G08, 902 |
| Waste Water (U/G) | 200 psi<br>150 | HDPE<br>DI | DI-Cement-Mortar lined | | G01, 501, 505, 603 |
| Condensate | 150 | CS | | | G01, G04, G08, 902 |
| Instrument Air | 150 | 304 | | | G01 |
| Nitrogen | 150 | CS | | | G01, G04, G08, 902 |
| Potable Water | 150 | SS | NSF 61 | | G01 |
| Utility/Service Water | 150 | CS | | | G01, G04, G08, 902 |
| Utility/Service Water (U/G) | 200 psi | HDPE 4710 | | | G01, 501, 505 |
| Fire Protection | 150 | CS | UL/FM Approved - VICTAULIC | | G01, 702, 902 |
| Fire Protection (U/G) | 200 psi | HDPE 4710 | 31PFNF: UL/FM Approved/11PFNF: AHJ to be consulted for fire water application | | G01, 501, 503, *Allowable Stresses for PE4710 pending approval of the AHJ. |

| System/ Process Area | Flange Rating (B16.5) | Pipe Material | Special Requirements | Post-Weld Heat Treatment (PWHT) | Notes |
|---|---|---|---|---|---|
| Notes:<br>G01 – Addition or substitution of components (material A vs. material B, welded vs. seamless, etc.) in this piping class requires approval from the piping engineer.<br>G04 - Threaded components are permitted only at outlet of vent, drain, and instrument valves and to match equipment.<br>G08 - Component wall thickness and end preparation type to be the same as the pipe.<br>201 - Materials in contact with the piped fluid, including solvent cement, shall be suitable for continuous service with aqueous solutions containing up to 12.5% sodium hypochlorite.<br>204 - Non-standard size reducing tees may be produced by solvent cementing reducing bushings with socket tees or reducing socket tees, utilizing the minimum standard components.<br>501 - Pipe and fittings to be manufactured to iron pipe size (IPS) dimensions. Pipe, fittings, and branches shall be joined per ASTM F2620, “Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings” and the “PPI Handbook of Polyethylene Pipe Joining Procedures.”<br>503 - HDPE pipe, fittings, flanges, and gaskets in fire protection water service shall be FM Approved for Fire Protection use.<br>505 - Pipe, fittings, and branches shall be joined in accordance with ASTM D2657, “Standard Practice for Heat Fusion Joining of Polyolefin Pipe and Fittings”, and the “PPI Handbook of Polyolefin Pipe Joining Procedures”.<br>603 – Minimum Type “3” laying conditions require (ANSI/AWWA C151/A21.51)<br>702 - Pipe, fittings, flanges, gaskets, and valves shall be UL Listed or FM Approved for fire water service.<br>902 - A106-B pipe is an acceptable substitute for A53-B pipe. As applicable, seamless fittings are acceptable substitutes for welded fittings. | | | | | |

## 6.2 ROTATING EQUIPMENT

### 6.2.1 Hydrogen Compressor

Compressor sparing philosophy is 1 X 100 percent. The sizing and evaluation criteria are based on a reciprocating compressor based on the process conditions provided in Table 4-8. The selected compressor is five-stage/eight-throw, oil lubricated, water jacketed, 7,600 HP/360 rpm motor-driven reciprocating compressor with a discharge pressure of 550 Psia and discharge temperature of 264°F. The compressor shall be designed to API 618 reciprocating compressor design criteria and shall be oil lubricated. The inter-stage and discharge coolers shall be water cooled shell & tube type and excluded from the vendor’s scope of supply. The cylinder is water cooled and the distance piece shall be Type C, long/long two-compartment distance piece designed to contain flammable, hazardous, or toxic gases. The distance piece compartments shall be purged continuously with nitrogen and connected to safe disposal location. The capacity control will be by suction valve unloaders and recycle. Compressor control and machine monitoring system shall be by local unit control panel.

Nitrogen, instrument air, cooling water and power supply is required for the hydrogen compressor and will be specified at a later time. The compressor shall be modularized to the extent possible to minimize work at site. If possible, the inter-stage coolers & discharge cooler shall be packaged in separate skid. The extent of modularization will depend on shipping size limitation. The compressor shall be installed outdoors on block foundation in shelter with sidings. The shelter shall have necessary permanent cranes for maintenance of the compressor & auxiliaries and laydown area.

### 6.2.2 Pumps

Water service pumps for wastewater and condensate shall be general service horizontal centrifugal pumps of the centerline mounted vertically split type. The pump shall be electric motor driven and installed outdoors. The pump shall be top discharge, and end suction.

## 6.3 SPACE CONDITIONING AND FIRE PROTECTION

The fire protection system of the adjacent LEC facility will be expanded to include the new hydrogen generation plant area and support structures. The extension is expected to include underground loops, yard hydrants, and additional alarm and monitoring. The expansion of the alarm and monitoring would include an independent system capable of communicating with the LEC facility system. The proposed expansion area may include buildings designed for occupancy. Any building that includes occupied space will use the design criteria outlined in Table 6-2.

## 6.4 CLASSIFICATION OF HAZARDOUS AREAS

Hazardous area classification will be determined jointly by the Mechanical and Electrical Project Discipline Engineers, according to NFPA and other applicable codes, at a later stage of design. The existing LEC facility includes hazardous area classification maps. The hazardous area classification maps for the existing facility will be updated for new hydrogen interconnecting piping systems installed to blend hydrogen into the combustion turbine fuel gas supply. The new hydrogen piping system design will account for existing building and electrical systems and leak sources should be located away from existing components to minimize changes to the existing electrical system.

The hydrogen gas storage area shall not be located below electrical power lines. All relief or vent valve in an adequately ventilated location shall be classified as Class I, Division I, Group B (Zone 1, Group IIC) for a distance of 5 feet and Class I, Division 2, Group B (Zone 2, Group IIC) for a distance of 5 to 15 feet. Outdoor hydrogen storage areas and piping leak sources shall be classified as Class I, Division 2, Group B (Zone 2, Group IIC) for electrical equipment within 15 feet. Adequately ventilated separate buildings or dedicated rooms used for the storage of gaseous hydrogen shall be Class I, Division 2, Group B (Zone 2, Group IIC). Hydrogen gas storage space in an adequately ventilated building not dedicated for hydrogen gas storage shall be Class I, Division 2, Group B (Zone 2, Group IIC) for a distance of 25 feet. Other general hydrogen storage design requirements will be designed in accordance to NFPA 55.

**Table 6-2 Heating Ventilation and Air Conditioning Design Criteria**

| Building Area | Max. °F based on Summer ambient design basis | Min. °F based on Winter ambient design basis | Humidity Control, %RH | Minimum Ventilation Rate Based on 13.8°F Rise or ac/h whichever is greater | Minimum Particle Filtration Efficiency, % (MERV) | Pressurization | Redundancy | Noise Criteria |
|---|---|---|---|---|---|---|---|---|
| Occupied Building (No Hydrogen Sources) | 110.2°F | 22.2°F | None | Minimum 6 ACH | 30 (7) | Positive | None | 85 dBA |

# 7.0 Electrical/Instrumentation Design Basis

## 7.1 DESIGN CRITERIA

The following subsections define general design criteria for electrical and instrumentation system designs.

### 7.1.1 Electrical Power Available at Battery Limits

The system voltage levels and design shall be as follows.

- Medium Voltage Distribution 4.16 kV, 3-Phase.
- Low Voltage Distribution 480 V or 208 V 3-Phase, and 120 V 1-phase.
- Lighting, 480/277 V or 208/120 V with light fixtures connected 1-phase.

### 7.1.2 Electric Motors

Motors shall be purchased with the driven equipment, and be in accordance with NEMA MG1 and the following:

- General Purpose Induction Motors, smaller than 250 HP shall meet the following criteria:
  - Rated 460 volt, 3-phase, 60 Hz (motors ¾ HP and above) Class F insulation/B temperature rise, Service Factor = 1.15
  - Rated 115 volt, 1-phase, 60 Hz (motors less than ¾ HP) Class F insulation/B temperature rise, Service Factor = 1.15
  - Rated ambient forty degrees Centigrade (40ºC)
  - TEFC Enclosure
- Induction Motors, 250 HP and Above, shall be Medium Voltage Motors and shall meet the following standards and criteria:
  - IEEE Standard 112 and Standard 275
  - Rated 4000 V, 3-phase, 60 Hz
  - Rated ambient forty degrees Centigrade 40ºC
  - Class F insulation/B temperature rise. VPI insulation and a service factor of 1.15.

### 7.1.3 Uninterruptible Power Supply, Battery Systems, and Emergency Power

Critical plant AC and DC loads will be powered from an interruptible power supply (UPS) or battery system.

### 7.1.4 Grounding

The plant grounding system will be designed in accordance with IEEE 80 and NFPA 70 (NEC). The following components will be used:

- Bare copper. Grounding conductor insulated where installed in conductor required for isolated grounding system.
- Copper-clad, ¾ inch x 10-foot section ground rods.

- Exothermic weld bonding method shall be used for all below grade connections.

### 7.1.5 Lightning Protection

Lightning protection will be provided on any new large buildings. The system will consist of air terminals, interconnecting conductors, down conductors with connection to the grounding system, and bonding of metal objects on or within the structure. Conductors shall be copper except where aluminum is required to avoid galvanic corrosion of metal surfaces on which the conductors are installed. The lightning protection will be designed in accordance with NFPA 780.

### 7.1.6 Lighting

Lighting systems shall be as follows:

- Electrical rooms shall be LED.
- Indoor high bay, outdoor platforms, outdoor above doors, hazardous areas, and any roadway lighting shall be LED.
- Emergency lighting shall be provided for egress utilizing integral fixture battery packs.
- Outdoor lighting shall be controlled by photoelectric controllers and control switch.

### 7.1.7 Wiring and Raceways

Cable and raceway installation shall be in accordance with NFPA 70. Ampacities of cables are based on NFPA 70 (NEC).

Individual tray systems will be established for the following services:

- Medium voltage power cables
- Low voltage power and control cables
- Special noise-sensitive circuits and instrumentation cables.

Further division will be provided where required by individual equipment manufacturers.

### 7.1.8 Plant Communication

The existing plant page party system will be extended to the Hydrogen production area.

### 7.1.9 Programmable Logic Controllers

It is expected that each of the new major pieces of equipment will have their own on-board programmable logic controllers, and an input/output count will be provided for interface with the plant distributed control system.

# 8.0 Utility Rate Design Basis

## 8.1 ELECTRICAL WHOLESALE RATES

Black & Veatch uses an integrated market assessment approach as the basis for the current industry structure as well as a starting point for long-term electric wholesale price projections. Our team draws on a number of commercial data sources, and supplements them with related data and assumptions on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, natural gas finding and development costs, and gas pipeline expansions relative to gas-fired power generation facilities.

The fundamental electric price forecasting process employs an integrated view of the key drivers impacting North American power markets. These critical elements of the price forecasting process include:

- A transparent and internally consistent approach to analyses of the energy markets, industry trends, and the government policies that influence them.
- Incorporation of Black & Veatch's industry engineering and technical expertise across all key assumptions.
- A perspective for generation fuel sources and electric energy markets.

With the above elements, the fundamental electric price forecasting process is designed to capture both the broad policy level assumptions and detailed structural market representations to provide a consistent market view. From a "top down" perspective the current state of energy and environmental policies are assessed at both a US and global level to determine their impact on North American and regional energy markets and prices.

Concurrently, North American commodity markets are assessed with a detailed "bottom up" approach, using structural market models to simulate market participant behavior in terms of new resource development, utilizing model inputs as diverse as power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and projected natural gas pipeline expansions.

Listed below are some of the key inputs that drive the fundamental price forecasting process:

- Regional energy and peak demand forecast based on public data available.
- Industry intelligence and assumptions on coal plant retirements.
- Natural gas price forecasts for different gas trading hubs for gas-fired power plants as developed by Black & Veatch.
- Delivered coal price forecasts for coal-fired power plants in USA as well as mine mouth coal prices for different coal basins.
- Capital cost, operating costs, and dispatch parameters for generating alternatives spread across different technologies (both conventional and renewable resources) developed by Black & Veatch.

- Renewable Energy Portfolio Standards (RPS) requirements by state and forecasts of renewable resources build out developed by Black & Veatch to meet state RPS requirements.
- Inter zonal transmission constraints.
- Tracking of announced unit commissions and retirements.
- Regional expansion plans developed by Black & Veatch to meet regional reliability criteria, considering a mix of units of different technologies.
- Retail prices take into consideration electric and gas transmission and distribution charges based on current tariffs.

## 8.2 WATER UTILITY RATE

Due to the fact that demineralized water will be sourced from existing LEC infrastructure, Black & Veatch expects that NCPA will define the water utility rates to be used in the economic modeling completed for the Hydrogen Production and Energy Storage Facility.

# 9.0 Environmental Permitting Design Basis

The following subsections outline the expected environmental permitting requirements and a discussion of other specific regulations that may be applicable to the Hydrogen Production and Energy Storage Pilot Facility to be sited at LEC.

### 9.1.1 Expected Environmental Permitting Requirements

The following is a preliminary list of the expected federal, state, and local environmental permits that would likely need to be addressed by NCPA.

- **Federal**
  - **US Army Corps of Engineers (USACE) Section 404 Permit** for construction activities impacting waters of the US, including jurisdictional wetlands (may require wetland delineation field visit).
  - US Environmental Protection Agency (EPA) Spill Prevention Control and Countermeasures (SPCC) Plan for on-site storage of >1,320 gallons of oil.
  - **EPA Class I Underground Injection Well Permit** (may need to modify existing permit for wastewater/process water discharges associated with changes in operation).
  - Federal Aviation Administration (FAA) Notice of Proposed Construction or Alteration for tall structures (>200 feet) that affect navigable airspace.
  - **US Fish and Wildlife Service (USFWS) Endangered Species Act Consultation** (and associated desktop and field studies if applicable) to confirm no adverse impact to threatened or endangered species.
- **State**
  - **California Energy Commission (CEC) Certification Amendment** for modifications to the LEC's project design, operation or performance requirements
  - CEC Chief Building Official Engineering Design and Grading Plan Approval
  - **California Department of Fish and Wildlife (CDFW)Consultation** (and associated desktop and field studies if applicable) to confirm no impact to state protected species.
  - **California State Historic Preservation Office Consultation**(and associated desktop and field studies if applicable) to confirm no adverse impact to cultural resources.
  - **Central Valley Regional Water Quality Control Board (RWQCB) Section 401 Water Quality Certification** for construction activities impacting waters of the state of California that require a USACE Section 404 Permit.
  - **California Department of Fish and Wildlife (CDFW) Streambed Alteration Agreement** for changes to the bed, channel, or bank of any body of water, or to deposit material into a body of water.

- **Central Valley RWQCB NPDES Construction General Permit** for stormwater discharges associated with land disturbance >1 acre (requires development of Stormwater Pollution Prevention Plan).
- **Central Valley RWQCB NPDES Industrial General Permit or No Exposure Certification** for stormwater discharges associated with the Hydrogen Production and Energy Storage Facility (requires development of Stormwater Pollution Prevention Plan).
- **California State Water Resources Control Board Water Right Permit** for the withdrawal and beneficial use of surface water and/or groundwater, if applicable (easements would be required for the installation of a pump and pipeline for the diversion of surface water).
- **Caltrans Encroachment Permit** for construction of an access off a State highway or the temporary use of heavy haul routes, if applicable.

- **Local**
    - **San Joaquin Valley Air Pollution Control District Authority to Construct Permit** for Hydrogen Fuel Use.
    - **San Joaquin Valley Air Pollution Control District Modification to Permit to Operate** (also known as Title V Permit).
    - **City of Lodi White Slough Water Pollution Control Facility (WPCF) Recycled Water Use Permit** may need to be modified for the additional use and increase in quantity of recycled water (White Slough WPCF may also be required to obtain State Water Board approval if recycled water is diverted that would otherwise have been discharged to surface water).
    - **San Joaquin County Encroachment Permit** for work within the County right-of-way, including installing a permanent or temporary access, or modifying an existing access.
    - **San Joaquin Council of Governments' (SJCOG) San Joaquin County Multi-Species Habitat Conservation and Open Space Plan (SJMSCP) Compliance or Mitigation** for impacts to giant garter snake habitat and other protected species with potential habitat located within the project area.
    - **San Joaquin County Environmental Health Department Well Permit** for the installation of a water well, if applicable.
    - **City of Lodi Agriculture Land Mitigation Agreement** may be required for the conversion of farmland of local importance to a non-agriculture use
    - **City of Lodi utility service connection authorization** to connect to the City's water service, if applicable (NCPA would be responsible for the costs to install the water main to the nearest connection over 4 miles from the LEC)

### 9.1.2 Other Regulatory Requirements

The following discussion outlines the expected applicability of specific regulations that may need to be addressed by NCPA.

- **Risk Management Plan (RMP) and California Accidental Release Prevention (CalARP)**
  - Hydrogen is listed as a regulated flammable gas and is regulated by EPA's RMP (40 CFR 68) and California Governor's Office of Emergency Services CalARP (Title 19 of CCR, Division 2, Chapter 4.5) rules if it is stored or used in a process in quantities greater than 10,000 lb.
  - However, there is an exemption for facilities that use all the regulated substance as fuel (hydrogen in this case). If <u>all</u> the hydrogen produced by the hydrogen process is used as fuel at the LEC plant, then the process is expected to be exempt from the requirements listed in the RMP and CalARP rules. If the hydrogen gas is used as a non-fuel feedstock then this regulation may be applicable.
  - Even if the hydrogen production and storage system is exempt from RMP requirements, there is the General Duty Clause is still expected to apply. Principally, the General Duty Clause requires that the facility still meet industry standards to prevent accidental releases and undertakes measures designed to minimize the likelihood of an accidental release. Thus, the liability would be on the facility if an accident happened with the hydrogen process.
  - Black & Veatch also notes that some of our clients have decided to voluntarily follow the RMP rule and develop a prevention plan without reporting to EPA.
- **Process Safety Management of Highly Hazardous Chemicals (PSM)**
  - Hydrogen is considered a Category 1 flammable gas and is regulated by the Occupational Safety and Health Administration (OSHA) PSM (1910.119) rule if it is stored or used in a process in quantities greater than 10,000 lb.
  - The OSHA PSM rule <u>does not</u> contain an exemption for flammable gases used as fuel, since hydrogen is not considered a hydrocarbon fuel. As such, if hydrogen gas will be stored or used in quantities greater than the threshold quantity (i.e., 10,000 lb) then LEC will be required to develop a PSM program in accordance with the requirements prior to any hydrogen used or stored on-site.
  - The requirements in the OSHA PSM rule are focused on preventing a release and explosion of the flammable gas. The requirements include having documentation covering the topics of employee participation. process safety information, process hazard analysis, operating procedures, training, contractors, pre-startup safety review, mechanical integrity, hot work permit, management of change, incident investigation, emergency planning and response, compliance audits, and trade secrets.

  - Black & Veatch has assisted clients with developing OSHA PSM documentation that complies with the regulation.

- **Chemical Facility Anti-Terrorism Standards (CFATS)**
  - The Chemical Facility Anti-Terrorism Standards are found in 6 CFR 27, which is under the Department of Homeland Security's (DHS) purview. Under the Department of Homeland Security, the Cybersecurity and Infrastructure Security Agency (CISA) manages the CFATS program to identify and regulate high-risk facilities to ensure they have security measures in place to reduce the risk that certain hazardous chemicals are weaponized by terrorists.
  - Black & Veatch notes that this regulation may be applicable if the facility will store more than 10,000 lb of hydrogen.
  - If applicable, the regulation requires the facility to submit to CISA a Top-Screen analysis within 60 calendar days of when hydrogen will be present at the facility. CISA will review the Top-Screen analysis and send written notification if the new hydrogen process is considered a high-risk facility and will assign the facility a risk-based tier level (Tier 1 through 4).
  - If applicable, the CFATS rule requires development and submittal of a Security Vulnerability Assessment within 90 calendar days after written notification from CISA. CISA requires the SVA contain analysis including asset characterization, threat assessment, security vulnerability analysis, risk assessment, and countermeasures analysis.
  - If applicable, the CFATS rule also requires development and submittal of a Site Security Plan (SSP) within 120 calendar days after written notification from CISA. CISA requires the SSP address each vulnerability identified in the SVA and describe the security measures to address each vulnerability. The SSP would also contain how security measures selected by the facility will address the applicable Risk-Based Performance Standards (RBPS) and potential modes of terrorist attack including, as applicable, vehicle-borne explosive devices, water-borne explosive devices, ground assault, or other modes or potential modes identified by CISA. The CISA provides guidance on the RBPS, which the facility will be required to meet or exceed as appropriate based on the Tier classification of the facility.

# Appendix C. Permit Matrix

| Agency | Permit | Regulatory Citation | Regulated Activity | Required | Project Phase | Estimated Agency Review Time | Comments |
|---|---|---|---|---|---|---|---|
| ***Federal Approvals*** | | | | | | | |
| USACE | Jurisdictional Determination<br><br>Section 404 Permit | 33 CFR Part 323 | Discharge of dredge or fill material into waters of the US, including jurisdictional wetlands. | TBD | Construction | JD - 1-2 months<br><br>Nationwide Permit - 3-6 months<br><br>Individual Permit - 6-9 months | Section 404 Permit will be required if there are any temporary or permanent impacts to the agricultural drainage ditch located immediately south of the proposed project site. The USACE determined the agricultural drainage ditch to be waters of the US.<br><br>A wetland and waterbody delineation of the proposed project site may be required to determine the presence of other jurisdictional waters. |
| FAA | Notice of Proposed Construction or Alteration | 14 CFR Part 77 | Construction of an object or temporary placement of an object, including construction cranes which has a height in excess of 200 feet or located within 20,000 feet of an airport. | Yes | Construction | 45-60 days | The proposed project site is located within approximately 8,400 feet of the Kingdon Airport. |
| USEPA | SPCC Plan | 40 CFR Part 112 | Onsite oil storage tanks with combined capacity of >1,320 gallons, single tanks >660 gallons, or underground tanks >42,000 gallons. | Yes | Construction / Operation | NA | The SPCC Plan does not require the USEPA's approval.<br><br>The LEC's existing SPCC plan for LEC operations will need to be updated accordingly. |
| USEPA | Class I Underground Injection Well Permit Modification | 40 CFR Parts 144-148 | Disposal of non-hazardous wastes underground through injection wells. | TBD | Operation | 3-6 months | LEC's existing UIC permit may need to be modified if there is a change in wastewater/process water discharges associated with the operational changes. |
| USEPA | Hazardous Waste Generator Identification Update | 40 CFR 262.18 | Transportation of hazardous waste generated offsite. Notification and an amendment is required if there is a change to the information provided in the initial filing. | TBD | Operation | 1-2 weeks | EPA Form 8700-12 RCRA Subtitle C Site Identification Form. |
| USEPA | Risk Management Program Plan | 40 CFR 68 | Facilities that produce, handle, process, distribute, or store highly hazardous (toxic, flammable, and/or explosive) chemicals are required to develop a Risk Management Program and to prepare and implement an RMP Plan. | Yes | Operation | 2 - 3 months | The LEC's existing RMP plan for LEC operations will need to be updated accordingly. |
| USEPA | EPCRA Tier II Reporting | 40 CFR 370 | Toxic and hazardous chemical storage reporting. | Yes | Operation | No agency review | Annual reporting to USEPA, Cal OES, and LEPC of any Hazardous Substances or Extremely Hazardous Substances, as listed in EPA's Consolidated List of Chemicals. |
| USFWS | ESA Section 7 Consultation | 50 CFR Part 17 | Potential impacts to federally listed threatened and endangered species and critical habitat. | Yes[1] | Construction | 3 months | USFWS IPaC database identified numerous T&E species and migratory birds that may potentially be impacted by construction of the Project.<br><br>An onsite T&E species survey of the proposed project site may be required to determine the presence of T&E species and/or suitable habitat. |

| Agency | Permit | Regulatory Citation | Regulated Activity | Required | Project Phase | Estimated Agency Review Time | Comments |
|---|---|---|---|---|---|---|---|
| Federal Lead Agency | National Environmental Policy Act Review | 40 CFR Parts 1500 - 1508 | A major federal action affecting the environment. | TBD | Construction | 3 – 12 months | NEPA will be triggered if a Section 404 Permit is required. If the Project qualifies for a Nationwide Permit, the NEPA process has already been completed by the USACE. |
| ***State Approvals*** | | | | | | | |
| CEC | Power Plant Siting Post-Certification Amendment | 20 CCR 1769 | Modifications to the LEC's project design, operation or performance requirements. | Yes | Construction/ Operation | Formal Amendment 6 months – 1 year<br><br>Project Modification 1 month | LEC's existing certification will need to be amended.<br><br>The CEC licensing process encompasses all state, local, and regional agencies' construction requirements. |
| CEC | California Environmental Quality Act (CEQA) | CA Public Resources Code 21000 et. seq. | State or local agency action affecting the environment. | Yes | Construction | Concurrent with CEC Certification review | CEC's licensing process is a certified regulatory program under CEQA. |
| CEC | Phase I & Phase II Environmental Site Assessment | 20 CCR 1704 | A site with existing environmental contamination or the potential for environmental contamination based on the historic or current land use. | Yes | Construction | 4-6 months | The CEC certification CEQA process requires a Phase I ESA be conducted at the proposed site and if warranted a Phase II ESA. Dependent on the findings, the DTSC may require a Preliminary Endangerment Assessment and Remediation Plan. |
| CEC | Civil and Building Construction Design Document Approval | 20 CCR 1704 | Ensure that any development complies with the Lodi Municipal Code, such as storm drainage and technical criteria; grading specifications; erosion and sediment control requirements.<br><br>Construction or installation of a building or structure. Review is required to determine the structural, electrical, plumbing, mechanical, and fire and life safety systems are in compliance with the Building Code. | Yes | Construction | 1-2 months | A Special Flood Hazard Elevation Certification or verification will be required to be submitted to the CEC. |
| Central Valley RWQCB | CWA Section 401 Water Quality Certification | CWA<br>33 USC 1341 | Federal action, such as USACE Section 404 permitting, to ensure compliance with the applicable California water quality requirements. | Not Anticipated | Construction | 3-4 months | |
| Central Valley RWQCB | NPDES Construction General Permit | 40 CFR 122<br>CA Water Code Section 1300 et. seq. | Discharge of stormwater to surface water resulting from land disturbance of 1 or more acres during construction and construction support activities, including dust control and dewatering activities. | Yes | Construction | 1 month | The following documents must be developed and submitted with the Notice of Intent:<br>• SWPPP<br>• Risk Assessment<br>• Post-Construction Calculations<br>• Site Map |
| Central Valley RWQCB | NPDES Industrial General Permit or No Exposure Certification | 40 CFR 122<br>CA Water Code Section 1300 et. seq. | Stormwater discharges associated with the Hydrogen Production and Energy Storage Facility. | Yes | Operation | 1 month | SWPPP |

| Agency | Permit | Regulatory Citation | Regulated Activity | Required | Project Phase | Estimated Agency Review Time | Comments |
|---|---|---|---|---|---|---|---|
| CDFW | CESA Consultation | Fish & Game Code Section 2080 | Activities that could result in the wake of a state-only listed endangered or threatened species. | Yes[2] | Construction | 2-3 months | An onsite T&E species survey of the proposed project site may be required to determine the presence of T&E species, state protected species, and/or suitable habitat. |
| CA OHP | NHPA Section 106 Archaeological & Historical Review & Consultation | NHPA - 54 USC 300101<br>CA Public Resources Code Sections 5020-5029 & 5097 | Activities that could potentially affect archaeological, cultural or historical resources that are listed or eligible for listing on the National Register of Historic Places. | Yes[1, 2] | Construction | 2-3 months | Desktop and field studies may be required to confirm no adverse impacts to cultural resources. |
| CDFW | Streambed Alteration Agreement | Fish & Game Code Section 1602 | Construction activities in a riparian area, including any activity that 1) diverts or obstructs the natural flow of any river, stream or lake; 2) changes the bed, channel, or bank of any river, stream, or lake; 3) use material from any river, stream or lake; or 4) deposit or dispose of material into any river, stream or lake. | Not Anticipated | Construction | 2-3 months | |
| CA SWRCB | Water Right Permit | CA Water Code Sections 1200-1851 | The withdrawal and beneficial use of surface water. | Not Anticipated | Operation | 3-4 years | Additional permits and easements would be required for the installation of a pump and pipeline for the diversion of surface water. |
| Caltrans | Encroachment Permit | CA Streets & Highway Code Section 660 et. seq. | Construction of an access off a State highway or the temporary use of heavy haul routes during construction. | TBD | Construction | 1-2 months | |
| Caltrans | Transportation Permit | CA Vehicle Code Section 35783 | The hauling of oversized and/or overweight loads on state-controlled roads. | Yes | Construction | 1 week – 1 month | Contractors will obtain these permits. |
| ***Local Approvals*** | | | | | | | |
| San Joaquin Valley APCD | Authority to Construct Permit for Hydrogen Combustion | | | Yes | | | |
| San Joaquin Valley APCD | Permit to Operate (Title V Permit) Modification | | | Yes | | | |
| City of Lodi White Slough WPCF | Recycled Water Use Permit Modification | 22 CCR 60301 et. seq. | Existing permit may need to be modified to account for the additional use and/or increase in quantity of recycled water. | TBD | Operation | 2-3 months | White Slough WPCF may also be required to obtain State Water Board approval, which could take 6 to 12 months if additional recycled water is diverted that would otherwise have been discharged to surface water. |

| Agency | Permit | Regulatory Citation | Regulated Activity | Required | Project Phase | Estimated Agency Review Time | Comments |
|---|---|---|---|---|---|---|---|
| San Joaquin County – Environmental Health Department | Well Permit | Lodi Municipal Code Chapter 8.08.050 | Installation, modification or repair of a water well. | Not Anticipated | Construction | 1-2 months | |
| San Joaquin County | Encroachment Permit | County Ordinance Chapter 10-3000 | Work within the County right-of-way, including installing a permanent or temporary access, or modifying an existing access. | TBD | Construction | 1-2 months | |
| San Joaquin County | Transportation Permit | County Ordinance Chapter 4 | The hauling of oversized and/or overweight loads on county-controlled roads. | Yes | Construction | 1 month | Contractors will obtain these permits. |
| San Joaquin Council of Governments | Multi-Species Habitat Conservation & Open Space Plan Compliance | Lodi Municipal Code Chapter 15.68 | Impact of new development on threatened, endangered, rare and unlisted SJMSCP covered species and other wildlife. | TBD | Construction | 2-3 months | Mitigation may be required for impacts to giant garter snake habitat and other protected species with potential habitat in the proposed project area. |
| City of Lodi | Utility Service Connection Authorization | Lodi Municipal Code Chapter 13.08.110 | Connection to the City's water service. | Not Anticipated | Construction / Operation | 1-2 months | NCPA would be responsible for the costs to install the water main to the nearest connection, over 4 miles from the LEC. Additional permits and easements may be required. |
| City of Lodi | Land Mitigation Agreement | Lodi Municipal Code Chapter 15.34.030 | Conversion of farmland of local importance to a non-agricultural use. | Not Anticipated | Construction | 2-3 months | City of Lodi has established a policy to ensure prime farmland is preserved; recommend verifying with the City that no mitigation will be required for the conversion of farmland of local importance. |

[1] Consultation will be initiated by USACE if the NEPA review process is triggered.
[2]Consultation will be initiated by CEC.

**ABBREVIATIONS:**
APCD – Air Pollution Control District
Cal OES – California Office of Emergency Services
Caltrans – California Department of Transportation
CCR – California Code of Regulations
CDFW – California Department of Fish and Wildlife
CEC – California Energy Commission
CEQA – California Environmental Quality Act
CERCLA – Comprehensive Environmental Response, Compensation and Liability Act
CESA – California Endangered Species Act
CFR – Code of Federal Regulations
CWA – Clean Water Act
DTSC – Department of Toxic Substances Control
EPCRA – Emergency Planning and Community Right to Know Act
ESA – Endangered Species Act
FAA - Federal Aviation Administration
LEC – Lodi Energy Center
LEPC – Local Emergency Planning Committee
NA – Not Applicable
NCPA – Northern California Power Agency
NEPA – National Environmental Policy Act
NHPA – National Historic Preservation Act
NPDES – National Pollutant Discharge Elimination System

| Agency | Permit | Regulatory Citation | Regulated Activity | Required | Project Phase | Estimated Agency Review Time | Comments |
|---|---|---|---|---|---|---|---|
| OHP – Office of Historic Preservation<br>RCRA – Resource Conservation and Recovery Act<br>RMP – Risk Management Plan<br>RWQCB – Regional Water Quality Control Board<br>SJMSCP – San Joaquin County Multi-Species Habitat Conservation and Open Space Plan<br>SPCC - Spill Prevention, Control and Countermeasure<br>SWPPP – Stormwater Pollution Prevention Plan<br>SWRCB – State Water Resources Control Board<br>TBD – To Be Determined<br>T&E – Threatened and Endangered<br>UIC – Underground Injection Control<br>USFWS – US Fish and Wildlife Service<br>USC – United States Code<br>USACE – United States Army Corps of Engineers<br>USEPA – US Environmental Protection Agency<br>WPCF – Water Pollution Control Facility | | | | | | | |