Light Water Reactor Sustainability Program

Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100–500 MW$_e$ HTSE Plants

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NOTE:

The body of this report and Appendices A through J are based primarily on report SL-016181, Revision 1, "Nuclear Power Plant Preconceptual Design Support for Large-Scale Hydrogen Production Facility," November 2022, Sargent & Lundy report to the LWRS Program. Appendix K is based on Report WNA-DS-05327-GEN, Rev. 0, "500 MWe Hydrogen Production Facility Control System Implementation for High Temperature Electrolysis for a Pressurized Water Reactor", April 2023, Westinghouse report to the LWRS Program.

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ABSTRACT

This study develops a preconceptual design for the integration between a large-scale high-temperature electrolysis facility and a nuclear power plant (NPP). Two hydrogen-facility sizes are considered: 100 MW$_{nom}$ and 500 MW$_{nom}$, where the subscript "nom" refers to the nominal size of the high-temperature electrolysis facility (HTEF). Both steam-supply designs use cold-reheat steam extraction from the turbine system as a heat source. A brief comparison is also included for steam supply from main steam. In all cases, a reboiler inside the protected area of the power plant transfers steam heat to the demineralized water supply for the HTEF. After the heat transfer, the extracted steam condenses and returns to the condenser while the process steam routes out of the protected area to the HTEF. Electrical power is tapped off from the high-voltage side of the generator step-up (GSU) transformer, where it is then transported via a 345-kV transmission line to the HTEF. Circuit breakers and disconnects are located at both ends of the transmission line. Step-down transformers and miscellaneous switchgear/buses are located at the end of the transmission line inside the HTEF boundary.

Computer modeling was performed for both thermal and electrical designs. The steady-state parameters for thermal power extraction from the turbine cycle were determined using PEPSE, which is a software program for analyzing the steady-state thermal-cycle performance of electric-generating plants. These parameters were used to inform transients and size equipment in combination with Applied Flow Technology (AFT) Arrow and AFT Fathom modeling for steam and water piping, respectively. Electrical transients were analyzed using PSCAD software. An electrical-transient analyzer program model was used to evaluate power flow and short circuit, which enabled the sizing of transformers and protective equipment.

A cost estimate was developed for both integration designs for plant-separation distances of 250 and 500 m. From these estimates, the combined modifications for thermal and electrical interfacing of a first-of-a-kind nuclear-integrated hydrogen facility are anticipated to cost between \$60–250/kW$_{nom}$. On a thermal power basis, the thermal power has an estimated cost of approximately \$9/MWh$_{th}$ for a 500 MW$_{nom}$ HTEF located 500 m away from the NPP. That value decreases to approximately \$8.3/MWh$_{th}$ for a 250 m separation distance between the HTEF and the NPP. This value is lower than previous estimates of the cost of heat extracted from NPPs primarily because in this work the steam is extracted from cold reheat instead of from the main steam line, which reduces the cost of the dispatched steam by approximately \$3.5/MWh$_{th}$. These estimates indicate the cost of heat contributes \$0.06 for each kg of product hydrogen produced by an integrated PWR/HTEF system using this design.

Nuclear steam extraction can provide a profit avenue for many plants and is not restricted to hydrogen production. Ammonia production, oil refining, and paper production, among other industrial processes, all require thermal energy, which can be provided by NPPs. Future work should look further at the details of thermal extraction for a variety of use cases. This can include increased levels of extraction and multiple simultaneous users. Additionally, site-specific studies should be performed to develop industry experience and improve cost accuracy.

EXECUTIVE SUMMARY

Background

The United States and countries around the world are seeking to reduce dependence on fossil fuels to achieve climate goals and ensure national energy security. Policy and economic incentives to reduce fossil-fuel consumption has led to a steady build out of intermittent wind and solar energy, resulting in excess clean generation during some daily hours and deficits of clean energy during other hours. Additional sources of clean-energy storage or energy-generation flexibility are needed to balance daily, weekly, and monthly supply and demand of clean energy. The overlapping impact of the dominant clean-generating sources (variable renewables and baseload nuclear power) exacerbates this challenge during daily supply-and-demand cycles.

Nuclear power has significant near-term potential to change its longstanding operational model by shifting production output away from electrical generation when renewable generation can meet grid demand. During these times, nuclear facilities can flexibly produce real-time usable or storable clean electrical and thermal power to assist in decarbonizing, not only the power grid, but also industry and transportation. Specifically, producing hydrogen by water electrolysis has the potential to favorably influence all these sectors as a storage medium and energy carrier for excess variable carbon-free generation.

Selection of the Hydrogen Production Technology

Promising technologies to produce clean hydrogen from water can be divided into electrochemical and electrothermal processes. Leading electrochemical processes include alkaline, proton-exchange membrane (PEM), and solid-oxide electrolysis cell (SOEC) systems. Leading thermochemical processes include the sodium-oxygen-hydrogen (Na-O-H) cycle, copper-chlorine (Cu-Cl) cycle, and sulfur-iodine (S-I) cycle. Thermochemical cycles typically have high operating temperatures and require heat input at temperatures well above the operating temperature of pressurized water reactors (PWRs), so very high-temperature reactors (VHTRs) with outlet temperatures hotter than 650°C are preferred.

SOEC systems, also known as high-temperature steam electrolysis (HTSE) systems, use high temperature rather than precious-metal catalysts to split water molecules. HTSE technology is less mature than alkaline and PEM technologies; however, multiple companies have announced facilities that can produce HTSE systems at scales greater than 500 MW_{DC}/yr. HTSE systems need power in the forms of direct current (DC) electrical power and heat at approximately 150°C (302°F) to produce saturated steam. Using nuclear heat to generate steam for the HTSE process increases the efficiency of the process. The specific electric- and thermal-energy requirements for HTSE have been reported as 36.8 kWh_e/kg-H_2 and 6.4 kWh_{th}/kg-H_2, respectively, as summarized in Table S-1. The projected electric-specific energy consumption is well aligned with a value of 37.7 kWh/kg-H_2 measured at Idaho National Laboratory (INL) using a 100 kW Bloom Energy SOEC system. As shown in Table S-3 below, extracting heat from a nuclear power plant, reduces the electricity that the plant generates. Dispatching 6.4 kWh_{th} from a PWR reduces electricity energy generation by approximately 1.4 kWh_e, so the effective potential hydrogen production efficiency of an HTSE system using power from a PWR is approximately 38.4 kWh_e/kg-H_2, as indicated by the numbers in parenthesis in Table S-1. Note that the higher heating value of hydrogen is 39.4 kWh/kg, so the effective efficiency of an HTSE system coupled to a PWR is 102% because the PWR provides 6.4 kWh_{th}/kg-H_2 while only losing 1.4 kWh_e of electricity generation per kilogram of product H_2.

Similar to PEM systems, HTSE systems show promising capabilities to flex their power consumption and hydrogen production over a time scale of seconds to minutes to allow coupled nuclear plants flexibility in dispatching power either to the power grid or to hydrogen production.

In comparing the merits of using PWRs to provide power for leading electrochemical water-splitting technologies, it is helpful to compare the power requirements in terms of thermal power. Approximating the conversion efficiency of converting nuclear heat to electrical power by a PWR to be 33%, specific thermal energy requirements of alkaline, PEM, and HTSE systems are estimated to be 164–230, 158, and 118 kWh_{th}/kg-H_2. The benefit of integrating HTSE hydrogen production with nuclear power is apparent. Compared to PEM electrolysis,

HTSE systems using nuclear power can produce 33% more hydrogen for the same nuclear thermal power. The final column of Table S-1 indicates potential benefits of using heat from high-temperature reactors for hydrogen production. Additional details can be found in Section 1.2.2. For HTSE, the improvements in hydrogen-production efficiency are caused exclusively by the higher efficiency of converting nuclear heat to electricity.

Table S-1. Efficiencies of leading hydrogen production technologies for the near-term time horizon.

Hydrogen production technology	Total system electricity input	Total system thermal power input	PWR input thermal power ($\eta_{th \to e} \approx 0.33$)	VHTR input thermal power ($\eta_{th \to e} \approx 0.46$)
	kWh$_e$/kg-H$_2$	kWh$_{th}$/kg-H$_2$	kWh$_{th}$/kg-H$_2$	kWh$_{th}$/kg-H$_2$
Alkaline (near-term)	54–70	0	164–230	117–165
PEM (near-term)	52	0	158	113
HTSE (near-term)	37 (38.4)	6.4 (0)	118	86
Na-O-H cycle[a]	20 (37)	40 (0)	111[b]	83
Hybrid S-I cycle[a]	17	53	Not applicable	91

a Future projection for mid-term time horizon.
b Assumes the temperature of half of the heat load (20 kWh$_{th}$/kg-H$_2$) is raised from 290°C to ~500°C by a future advanced high-temperature heat pump with coefficient of performance of 2. The assumed heat pump may or may not be realized.

Selection of a Representative Nuclear Power Plant

As of the end of 2022, 68 of the 92 commercially operable U.S. nuclear power plant (NPP) units were PWRs. With such a significant portion of the NPP fleet employing this design, it is an appropriate choice for use as the representative reference plant for the preconceptual design. Additionally, the use of nonradioactive steam in the secondary system of a PWR makes PWRs the logical choice for an initial feasibility study. It is noted that a boiling-water reactor (BWR) will require additional design considerations due to the presence of radioactive steam throughout the turbine cycle. Although BWRs are not considered in this feasibility study, a conceptual design for dispatching heat from a BWR for hydrogen production will be developed in future work.

The most common type of PWR in the U.S. is a Westinghouse 4-loop PWR, of which there are 26 units operating as of the end of 2022. Westinghouse also designed 2-loop and 3-loop PWRs, of which there are five units and 15 units operating, respectively, for a total of 46 operating Westinghouse PWRs. Thus, Westinghouse PWRs represent 75% of all operating PWRs in the U.S. (46/68 = 75%). The fundamental designs of Westinghouse PWRs are sufficiently similar, such that a 4-loop PWR is generally representative of 2-loop and 3-loop PWRs as long as the different reactor scales are properly accounted for. Considering that 4-loop Westinghouse PWRs are the most common type, this model has been selected for this study.

Summary of the High-Level Integration Design

This report is based primarily on a preconceptual design report prepared by Sargent and Lundy (S&L) [19] with input from INL. The 4-loop PWR is assumed to have a generating capacity of approximately 1,200 MW$_e$. Steam is extracted from the PWR using one or more new connections in the crossunder (cold-reheat) piping between the high-pressure (HP) turbine and the moisture-separator reheaters (MSRs). A brief comparison is also included for steam supply from main steam. This report considers two large-scale hydrogen-production facilities, with nominal ratings of 100 and 500 MW$_{nom}$, respectively. Detailed information for both designs is in the preconceptual design report prepared by S&L [19]. Table S-2 provides the specific parameters for both designs. The nominal rating corresponds to the DC power input of the high temperature electrolysis facility (HTEF) at full hydrogen production. A 100 MW$_{nom}$ HTEF is expected to produce as much as 55-58 tonnes of hydrogen per day, depending upon the configuration.

The exact amount of heat required to generate steam for hydrogen production depends on heat recuperation and other design choices within the plant. For the purposes of this study, typical heat input requirements are assumed without performing detailed heat-integration designs that depend upon a specific HTEF configuration that is vendor dependent. Steam delivered to the HTEF is required to be at least 150°C (302°F) and 50 lb psig. Analyses performed for this study achieved these requirements, as summarized in Table S-2. Hydraulic analyses were performed to size the piping and auxiliary equipment required to meet thermal extraction demands for the HTEF. For purposes of the preconceptual design, minor additional thermal extraction is needed to cover various thermal losses, inefficiencies, and design margins typically associated with the sizing of piping, pumps, heat exchangers, valves, etc. As noted above, the thermal power required for hydrogen production in an HTEF is approximately 20% of the nominal power. Based on a conservatively assumed 5 MW_{th} of steam margin, the thermal power requirement of the 100 MW_{nom} HTEF is taken to be 25 MT_{th} and that of the 500 MW_{nom} HTEF is taken to be 105 MW_{th}. Both hydrogen facilities are assumed to be located outside of the protected area, but inside the owner-controlled area (OCA). Designs are prepared for distances of 250–500 m between the PWR and both HTEFs. Product hydrogen is transported a safe distance away (e.g., 1+ km) for HP compression and storage.

Within the PWR, piping is installed to route high-temperature steam from the crossunder piping to a steam reboiler that creates steam in a tertiary loop fed from a deionized or demineralized-water source. This steam is provided to the HTEF for use in the HTE process. Condensed drain flow on the secondary side of the steam reboiler is directed to a location within the secondary loop of the plant to minimize thermal losses.

The revenue meter for the NPP is assumed to be at a high-voltage switchyard, adjacent to the NPP protected area. Net metering of the HTEF may be required for cases where the revenue meter is located at the generator terminals or in the turbine building. Electrical energy, in the form of alternating-current (AC) power, is diverted from the output of the main generator to the HTEF, where most of the required power is converted to rectified DC power.

The total electrical loads required for hydrogen production were 140 and 600 MW_e for the 100 and 500 MW_{nom} designs, respectively, including balance-of-plant equipment. As with thermal power, electrical losses and inefficiencies must be considered to supply adequate power to the facility. Additional electrical power must be supplied to the hydrogen facility to support plant auxiliaries and other ancillary loads. The total apparent electric power rating for these two facilities comes to 140 and 600 MVA, respectively.

Table S-2. HTEF parameters by plant size.

Parameter	Unit	HTEF Size (MW_{nom})	
		100	500
Hydrogen Production Capacity[a]	U.S. tons/day	55–58	275–290
H_2 Plant Electric Load MW_e	MW_e	105	500
H_2 Plant Auxiliary Loads + Margin	MW_e	22	50
Power Factor	—	0.92	0.92
Total Electrical Power Requirements	MVA	140	600
H_2 Plant Thermal Load	MW_{th}	20	100
Plant Thermal Losses + Margin	MW_{th}	5	5
Total Thermal Power Requirements	MW_{th}	25	105
Steam Input Temperature[b]	°F	>300 (333)	>300 (333)
Steam Input Pressure[b]	psig	>50 (59.3)	>50 (59.3)
Separation Distance from PWR	m	250 & 500 m	250 & 500 m

a Conservative production capacities are shown based on 2022 values. Technology improvements over the next few years are expected to improve the yields of these plants to approximately 60 and 300 U.S. tons/day, respectively.

b Parameters in parenthesis indicate actual design values.

Summary of the Estimated Integration Costs

An overview of the direct, indirect, and contingency costs for the 100 and 500 MW$_{nom}$ facilities are provided below in Table S-3. A simplified analysis was also performed to account for loss in generator electric power output due to thermal power extraction to enable estimating the impacts of thermal power extraction on hydrogen production. All costs are reported in 2022 U.S. dollars, and it is assumed that electricity sales price is constant throughout the 20-year lifetime of the system at \$30/MWh (in 2022 USD), which operates with a capacity factor of 95%. The estimated total capital investment (TCI) for integrating the NPP hydrogen steam supply equipment and associated electrical infrastructure for the 100 MW$_{nom}$ design with a 500 m separation distance is close to \$246/kW$_{nom}$, while the corresponding 500 MW$_{nom}$ integration modifications are estimated to cost \$78/kW$_{nom}$. Based on these estimates, **the standardized cost of the 500 MW$_{nom}$ design is approximately one-third of the 100 MW$_{nom}$ design**. This reduction can be explained by the consolidation of equipment under the larger design, reducing material and labor costs with respect to production capacity. Changing the number of piping trains, power lines, or integration equipment (mechanical and electrical) for these designs will alter the capital cost of

Table S-3. Cost summary for integrating nuclear and hydrogen plants (2022 U.S. dollars).

		Steam from Cold Reheat		Steam from Main Steam	Steam from Electric Boiler
	100 MW$_{nom}$	500 MW$_{nom}$		500 MW$_{nom}$	500 MW$_{nom}$
	500 m separation	250 m separation	250 m separation		
Total capital investment (TCI) for electric and thermal power coupling					
Direct cost (\$MM) [a]	7.42	13.1	10.2	10.2	-
Indirect cost (\$MM) [b]	8.98	13.1	10.2	10.2	-
Contingency (\$MM)	8.20	13.2	10.2	10.2	-
TCI$_{e+th}$ (\$MM)	24.6	39.0	30.6	30.6	3.0
Std. TCI per nominal HTEF size (\$/kW$_{nom}$)	246	78.1	61.2	61.2	6.0
TCI for thermal power dispatch (does not include electric power coupling)					
TCI$_{th}$ (\$MM)	20.4	35.0	26.7	26.7	3.0
Operating costs for thermal power dispatch					
NPP power reduction (MWe)	5.3	22.4	22.4	37.9	0
20 Year lifetime operating cost (\$MM) [c]	26.5	112	112	189	500
Capital and operating costs for thermal power dispatch					
Std. cost of heat delivery (\$/MWhth)	46.9	147	139	216	503
Standardized (std.) costs associated with thermal power dispatch					
Std. cost of heat delivery (\$/MWhth)	14.1	8.82	8.32	13.0	30.2
Std. H2 production cost contribution (\$/kg-H2)	0.10	0.065	0.061	0.10	0.22

a   Direct costs include labor, materials, subcontracts, construction equipment, and process equipment.
b   Indirect costs include additional labor, site overheads, other construction costs, and project indirects.
c   Assumes an electricity sales price of \$30/MWh.

these modifications accordingly. One potential cost-reduction strategy is to decrease the separation distance between the NPP and HTEF. This adjustment would decrease the length of piping and power lines, which would have subsequent benefits, including reduced excavation and foundation costs, better efficiency (reduced thermal and electrical losses), and potential utilization of smaller, less-expensive equipment. Reducing thermal and

electrical separation by 50%, from 500 to 250 m, is assumed to be physically feasible for some plants (additional hazard analysis and licensing evaluation is in progress in separate work to assess overall regulatory compliance but are not included within this study). Table S-3 shows an approximately 20% reduction in integration cost by reducing plant separation. Additional cost details can be found in Table 13 in the body of the report. The contingency budgets listed in Table S-3 are relatively large and approximately equal to the direct costs. Large contingency budgets are appropriate for first-of-a-kind installations. The contingency funds can likely be decreased by 50% or more for subsequent installations that follow similar engineering designs.

It is helpful to compare the cost estimates in Table S-3 with assumptions that have been made in previous analyses with estimated costs for hydrogen production, assuming a similar production configuration in which an HTEF is coupled to a PWR. In the study by Wendt, Knighton, and Boardman, [2], it was assumed that a 1,000 MW_{nom} HTEF was coupled to an NPP at a distance of 1 km. The direct capital cost of the steam-delivery system from the NPP was estimated to be \$41.1 million, which is in very good agreement with the estimated cost presented in Table S-3, after accounting for differences in scale and assumed steam-delivery distance. Importantly, however, as shown in Table S-3, operating costs are much larger than the capital cost of integration for HTEFs that are 500 MW_{nom} and larger.

The dominant operating cost is the loss of PWR electric power output due to thermal power dispatch to the HTEF. As indicated in Table S-3, the PWR electric power output decreases by 5.3 MW_e and 22.4 MW_e, respectively, for the 100-MW_{nom} and 500-MW_{nom} HTEF cases. These values are lower than estimated in the previous hydrogen production-cost study [2] because extracting steam from cold reheat in the PWR has less impact on electric power production than removing steam from the main steam line, as assumed in the previous work. The previous work assumed that reduction in electric power production was equal to the thermal power delivery to the HTEF divided by the thermal-to-electric conversion efficiency of the PWR, which would have corresponded to 8.5 MW_e for the 100 MW_{nom} HTEF case and 35.7 MW_e for 500 MW_{nom} HTEF case. Importantly, as summarized in Appendix C, a PEPSE analysis was conducted for a case in which steam was extracted from the main steam line. As noted in Table C-2, extracting 105 MW_{th} from the main steam line caused the generator output to decrease by 37.9 MW. This result indicates extracting steam from the main steam line causes an additional loss of 15.4 MW from the generator, compared to extracting the needed steam from cold reheat. **Extracting steam from the cold reheat reduces the operating costs of the thermal power dispatch system by approximately 40%, compared to extracting steam from the main steam line. The lowest standardized (Std.) cost of steam supply is associated with the 500 MW_{nom} HTEF case and is \$8.32/MWh_{th}, which exhibits a marked improvement compared to the estimate of \$11.6/MWh_{th} from [2].** As noted in Table S-3, this cost of heat contributes \$0.06 for each kg of product hydrogen. For comparison, a simplified cost estimate was performed for a case in which steam is provided to the HTEF using an electric boiler. The estimated standardized cost of steam from an electric boiler was estimated to be greater than \$30/MWh_{th}, which would contribute approximately \$0.22 to the production cost of each kg of hydrogen. **Thus, the potential savings from thermally integrating an HTEF to a PWR is approximately \$0.16/kg-H_2.**

As noted above, costs estimated in this study are for a first-of-a-kind installation with large contingency budgets. **Subsequent installations with similar designs may have substantially lower costs if contingency costs can be reduced.**

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ACRONYMS

AACE	Association for the Advancement of Cost Engineering
AC	alternating-current
ACSR	aluminum conductor, steel reinforced
AFT	applied flow technology
AVR	automatic voltage regulator
BES	bulk electric system
BIL	Bipartisan Infrastructure Law
BWR	boiling-water water reactor
CM	construction management
CT	current transformers
DAR	Design-Attribute Review
DOE	U.S. Department of Energy
EPC	Engineering, procurement, and contractor
EPCM	engineer, procure, construction management
ETAP	electrical-transient transient analyzer program
FAC	flow-accelerated corrosion
FCV	flow-control valve
HTE	high-temperature steam electrolysis
G&A	general and administrative
GSU	generator step-up
HMI	human-machine interface
HP	high-pressure
HSS	hydrogen steam supply
I&C	Instrumentation and Controls
INL	Idaho National Laboratory
LP	low-pressure
LWR	Light-water reactor
LWRS	Light Water Reactor Sustainability
NPP	nuclear power plant
MOD	manually operated disconnect
MSR	moisture-separator reheater
NERC	North American Electric Reliability Corporation
NPSH	net-positive suction head

OCA	owner-controlled area
OPGW	optical ground wire
P&ID	process and instrumentation diagram
PI	proportional integration
PRA	Probabilistic Risk Assessment
PT	potential transformers
PWR	pressurized water reactor
RO	reverse osmosis
S&L	Sargent and Lundy
SCWR	super critical water reactors
SOEC	Solid-oxide electrolysis cell
STD	standardized
TB	Turbine Building
TNV	thermoneutral voltage
UFSAR	updated final safety analysis report
VAR	volt-amps reactive

CONTENTS

FIGURES

TABLES

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Preconceptual Designs of Coupled Power Delivery between a 4-Loop PWR and 100–500 MW$_e$ HTSE Plants

1. INTRODUCTION

1.1 Why Nuclear Generated Hydrogen?

The United States and countries around the world are seeking to reduce dependence on fossil fuels to achieve climate goals and ensure national energy security. Policy and economic incentives to reduce fossil-fuel consumption has led to a steady build out of intermittent wind and solar energy, resulting in excess clean generation during some daily hours and deficits of clean energy during other hours. Additional sources of clean-energy storage or energy-production flexibility are needed to balance daily, weekly, and monthly supply and demand of clean energy. The overlapping impact of the dominant clean-generating sources (intermittent renewables and baseload nuclear power) exacerbates this challenge during daily supply-and-demand cycles.

Nuclear power has significant near-term potential to change its longstanding operational model by shifting generation output away from electrical generation when renewable generation can meet grid demand. During these times, nuclear facilities can flexibly produce real-time usable or storable clean energy to assist in decarbonizing, not only the power grid, but also industry and transportation. Specifically, producing hydrogen by water electrolysis has the potential to favorably influence all these sectors as a storage medium and energy carrier for excess intermittent carbon-free generation.

The 2022 Bipartisan Infrastructure Law (BIL), officially known as the Infrastructure Investment and Jobs Act (IIJA) [1], provides up to \$8 billion to help establish regional clean-hydrogen hubs over the next 5–6 years. This bill is key to addressing several barriers for many nuclear reactors to implement hydrogen production.

To qualify as clean hydrogen, the life-cycle emissions of carbon dioxide of the H_2 produced must be less than 2 kg-CO_2e per kg-H_2 [a]. At least one of these hubs must use nuclear energy for some fraction of the hydrogen produced in a given region. The federal cost share of up to 50% of the total project costs (up to \$1.25 billion) should make it possible to realize a favorable return on investment for first-of-a-kind demonstration projects.

Technical and economic assessments of hydrogen production by NPPs indicate that light-water reactors (LWRs) will be able to feasibly produce clean hydrogen through water-splitting electrolysis for an nth-of-a-kind nuclear hydrogen plant. This is based on a hydrogen plant that is integrated with an existing NPP when the price of electrolysis units is consistent with an established supply chain of materials and fabrication year over year. The BIL also intentionally includes \$1 billion to help raise the technology and commercial-scale manufacturing readiness of electrolysis. The assumption is that several large-scale demonstration projects and the required manufacturing industries will make it possible to expand the leading projects at n^{th}-of-a-kind economics.

The technology readiness levels of water-splitting electrolysis systems have dramatically increased in recent years [2] as the global interest in clean hydrogen production and decarbonization of transportation, industry, and other sectors increases. Electrolyzed hydrogen produced by renewables and low-temperature electrolysis is already emerging as a near-term clean stored-energy carrier.

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a CO_2e refers to a unit of greenhouse-gas reductions equivalent to the impact of CO_2. As a reference, the conventional process of producing hydrogen by steam methane reforming emits 7–10 kg CO_2 per kg H_2 produced, depending on the process design and accounting for life-cycle emissions associated with natural gas production.

1.2 Why Integrate Light-Water Reactors with High-Temperature Steam Electrolysis (HTSE) Plants?

Promising technologies to produce clean hydrogen from water can be divided into electrochemical and electrothermal processes. Leading electrochemical processes include alkaline, proton-exchange membrane (PEM) and solid-oxide electrolysis, while leading electrochemical processes include the sodium-oxygen-hydrogen (Na-O-H) cycle, copper-chlorine (Cu-Cl) cycle, and sulfur-iodine (S-I) cycle.

1.2.1 Electrochemical Low-Temperature Electrolysis

Alkaline electrolysis is the most-mature water-splitting process technology with multiple 100+ MW systems installed and operating. It has a relatively low capital cost, but current designs also have relatively low efficiency with system-specific energy consumption for hydrogen production in the range of 54–70 kWh/kg-H_2 [3]. PEM electrolysis is a less-mature technology, but is already available at MW and tens of MW scales. PEM electrolysis systems use rare precious-metal catalysts to achieve a system-specific energy consumption that is anticipated to reach 52 kWh/kg-H_2 by around 2025 [4]. This projected specific energy consumption is slightly better than systems today achieve, as reported by a Nel Hydrogen 1.25 MW PEM system, which recently began producing hydrogen at the Nine Mile Point Nuclear Plant owned by Constellation Energy. The scale of electrochemical water-splitting systems is typically reported on a DC power input basis. For example, a 1.25 MW PEM system operating under normal conditions consumes 1.25 MW of DC power. Constellation Energy reported that the PEM system at the Nine Mile Point Nuclear Plant produced 560 kg/hr, corresponding to a specific energy consumption of 53.6 kWh/kg-H_2 [5]. An advantage of PEM electrolysis is that the systems are capable of rapid dynamic operation between approximately 20 and 100% of their rated capacities.

1.2.2 Electrochemical High-Temperature Electrolysis

Solid-oxide electrolysis cell (SOEC) systems, also known as HTSE systems, use high temperatures rather than precious-metal catalysts to split water molecules. HTSE technology is less mature than alkaline and PEM technologies; however, multiple companies have announced facilities that can produce HTSE systems at scales greater than 500 MW_{DC} per year [6,7]. HTSE systems need power in three forms: (1) DC electrical power, (2) heat at approximately 150°C to produce saturated steam, and (3) heat at approximately 800°C for process topping heat. The ratios of the required power inputs depend upon specific operating conditions. In a typical operating condition, 75–78% of the input power is needed as DC electrical power, 16–19% of the input power is needed to produce steam at approximately 150°C, and 5–8% of the input power is needed for high-temperature topping heat. Typically, the high-temperature topping heat is produced using electrical heaters so that the ratio of the required electric power to thermal power is between four and five. This ratio of electric-to-thermal power can be achieved from a pressurized water reactor (PWR) by extracting slightly less than 10% of the steam from the primary steam supply loop and using heat from this steam to provide the heat needed by the HTSE plant through appropriate heat exchangers.

Using nuclear heat to generate steam for the HTSE process increases the efficiency of the process (Figure 1, Figure 2, and Table 1). The specific electric and thermal energy requirements for HTSE have been reported as 36.8 kWh/kg-H_2 and 6.4 kWh_{th}/kg-H_2, respectively [8]. The projected electric-specific energy consumption is well aligned with a value of 37.7 kWh/kg-H_2, which was measured at INL using a 100 kW Bloom Energy SOEC system [9]. The thermal specific-energy consumption of 6.4 kWh_{th}/kg-H_2 is readily determined from the heat of vaporization of water and by accounting for engineering losses in large-scale systems. As shown in Table 14 in Section 4.3, extracting heat from a nuclear power plant, reduces the electricity that the plant generates. Dispatching 6.4 kWh_{th} from a PWR reduces electricity energy generation by approximately 1.4 kWh_e, so the effective potential hydrogen production efficiency of an HTSE system using power from a PWR is approximately 38.4 kWh_e/kg-H_2, as indicated by the numbers in parenthesis in Table 1. Note that the higher heating value of hydrogen is 39.4 kWh/kg, so the

effective efficiency of an HTSE system coupled to a PWR can be as high 102% because the PWR provides 6.4 kWh$_{th}$/kg-H$_2$ while only losing 1.4 kWh$_e$ of electricity generation per kilogram of product H$_2$. The benefit of integrating HTSE hydrogen production with nuclear power is apparent. Compared to PEM electrolysis, each kilogram of hydrogen can be produced using 33% less thermal power (156–118)/118 = 33%.

Similar to PEM systems, HTSE systems show promising capabilities to flex their power consumption and hydrogen production over a time scale of seconds to minutes to allow coupled nuclear plants flexibility in dispatching power to either the power grid or to hydrogen production.
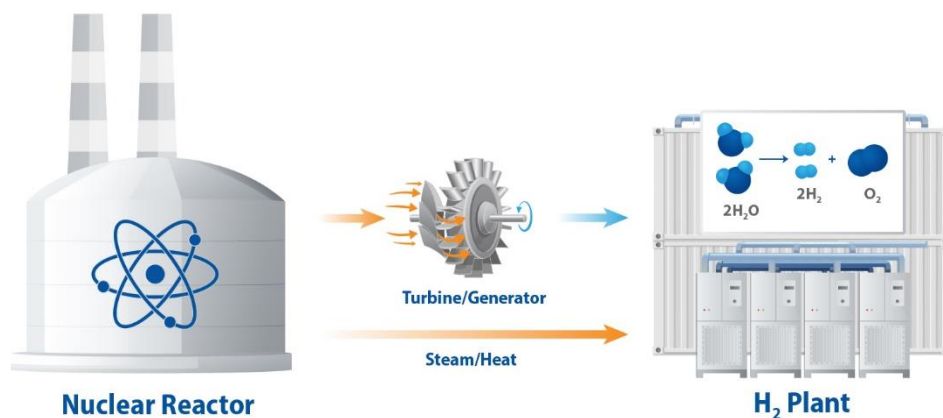
Figure 1. Graphical representation of heat and electricity flowing from a nuclear reactor to an HTEF.

In comparing the merits of using PWRs to provide power for leading electrochemical water-splitting technologies, it is helpful to compare the power requirements in terms of thermal power. Approximating the conversion efficiency of converting nuclear heat to electrical power ($\eta_{th \to e}$) by a PWR to be 33%, specific thermal-energy requirements of alkaline, PEM, and HTSE systems are estimated to be 164–230, 158, and 118 kWh$_{th}$/kg-H$_2$., as summarized in Table 1.

Table 1 also includes a column assuming the electricity is provided by a very high-temperature reactor (VHTR) that can achieve a thermal power to electricity-conversion efficiency ($\eta_{th \to e}$) of approximately 46%. It has been noted that heat from VHTRs can be used to increase the efficiency of HTSE processes because 5–8% of the input power is needed for high-temperature topping heat. In practical applications, however, there are several factors that will likely negate the potential increase in efficiency from utilizing high-temperature heat. First, assuming a VHTR can convert thermal power to electricity with an efficiency of 46%, the potential increase in efficiency that could be gained by using high-temperature heat inside an HTSE facility (HTEF), instead of electrical heaters, would be limited to 1/46% of 5–8% or approximately 3%. Second, transferring high-temperature gas from the VHTR in the HTEF and using heat from the gas in the HTEF would have unavoidable thermal losses that would further limit the potential increase in system efficiency to less than 1–2%. The reason for the high thermal losses is that the high-temperature topping heat is needed locally within the hot boxes that contain the SOECs. These hot boxes contain between 100 kW$_{DC}$ and 1 MW$_{DC}$ of cells and contain heat recuperators such that, in current designs, relatively low-temperature steam and gases enter and exit the hot boxes. Using high-temperature gas to provide the topping heat in the hot boxes would require additional high-temperature piping to transfer the high-temperature gas into and out of the hot boxes as well as additional heat exchangers inside or outside the hot boxes. These additional high-temperature pipes and heat exchangers would substantially increase the system complexity, footprint, capital expense, and thermal losses, such that potential benefits will not likely be justified.

Table 1. Efficiencies of leading hydrogen production technologies for the near-term time horizon.

Hydrogen production technology	Total system electricity input	Total system thermal power input	PWR input thermal power ($\eta_{th \to e} \approx 0.33$)	VHTR input thermal power ($\eta_{th \to e} \approx 0.46$)
	kWh$_e$/kg-H$_2$	kWh$_{th}$/kg-H$_2$	kWh$_{th}$/kg-H$_2$	kWh$_{th}$/kg-H$_2$
Alkaline (near-term)	54–70	0	164–230	117–165
PEM (near-term)	52	0	158	113
HTSE (near-term)	37 (38.4)	6.4 (0)	118	86
Na-O-H cycle[a]	20 (37)	40 (0)	111[b]	83
Hybrid S-I cycle[a]	17	53	Not applicable	91

[a] Future projection for mid-term time horizon.

[b] Assumes the temperature of half of the heat load (20 kWh$_{th}$/kg-H$_2$) is raised from 290°C to ~500°C by a future advanced high-temperature heat pump with coefficient of performance of 2. The assumed heat pump may or may not be realized.

Figure 2 shows an example cell voltage and current relationships of low- and high-temperature electrolysis systems and illustrates an additional factor that limits the practicality of using high-temperature topping heat from a VHTR to increase the efficiency of an HTEF. HTSE systems operate along the solid red line shown in Figure 2, while low-temperature alkaline and PEM electrolysis facilities operate along the solid blue line. Low-temperature electrolysis systems must operate at cell voltages that are greater than the water thermoneutral voltage (TNV) because that is the minimum voltage required to split water molecules. High-temperature electrolysis systems can operate at either above or below the steam TNV although there are strong motivating factors to operate near the steam TNV. Operating at cell voltages below the steam TNV allows thermal power (heat) to replace some of the electrical power in the water-splitting reaction; however, electric current and hydrogen-production rates decrease as the cell voltage decreases. Hydrogen-production costs increase as the hydrogen-production rate decreases because the specific capital-equipment cost increases. Operating at cell voltages above the steam TNV produces Ohmic heating that offsets the high-temperature topping heat that must be provided to the solid-oxide cells during hydrogen production.
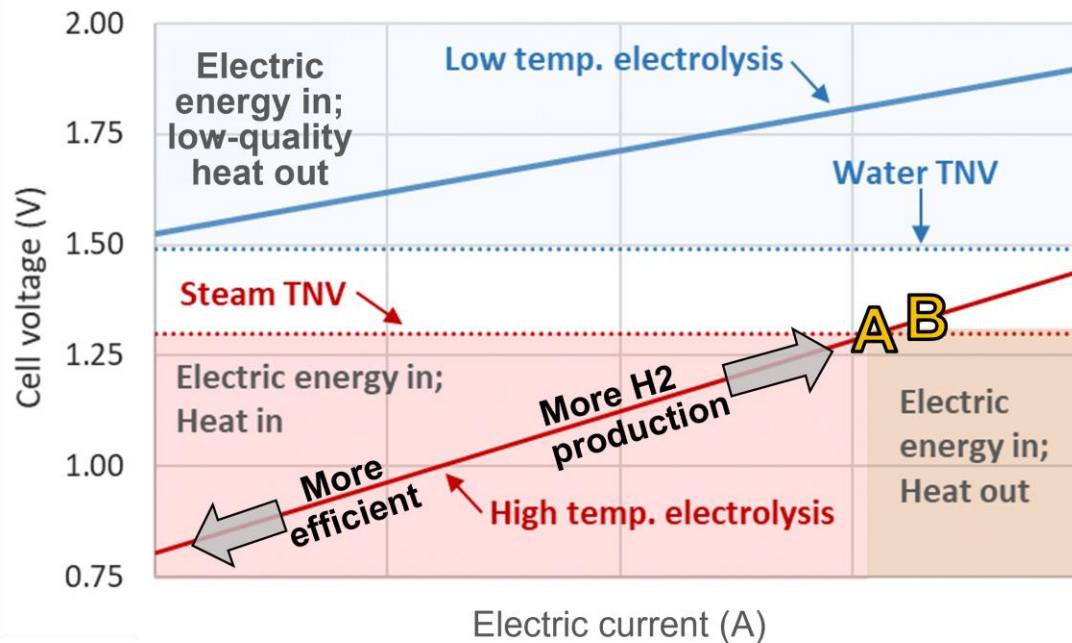
Figure 2. Cell voltage and current relationship for low and high-temperature electrolysis.

The point marked A in Figure 2, which corresponds to operation at the steam TNV, is the point at which 5–8% topping heat is required, as described above. At a cell voltage and electric current slightly higher than point A, the Ohmic heating exactly matches the required topping heat, such that inline topping heaters or heat exchangers are not required. This point is marked B in Figure 2. As noted above, increasing the cell voltage and electric current potentially decreases hydrogen production costs even though cell efficiency is slightly lower because the system capital-equipment expense decreases. A primary objective of HTSE system manufacturers and the U.S. Department of Energy (DOE) is to increase the durability of SOECs, so that they can sustain higher current densities and hydrogen-production rates. Using high-temperature heat from a VHTR to increase the efficiency of an HTEF is counter to present-day goals of HTSE system manufacturers and DOE. The HTEF thermal power input value for HTSE systems in the final column of Table 1 assumes heat from a VHTR is only used to produce electricity and steam at approximately 150°C for the HTSE process (the cycle topping heat is provided using electricity). A further point regarding the information in Table 1 is that the improved efficiency of the thermal-to-electric power-conversion efficiency of the VHTR is not the driving parameter for decreasing the cost of hydrogen production. As discussed in the study by Wendt, Knighton, and Boardman [2], the cost of hydrogen is affected predominantly by the cost of electricity, so NPPs that produce electricity at the lowest cost are favored to produce low-cost hydrogen, regardless of their thermal-to-electric power-conversion efficiency.

1.2.3 Thermochemical-Cycle Technologies

As noted, thermochemical processes are also promising options for hydrogen production although their technological maturity is much lower. Thermochemical cycles typically have operating temperatures and require heat input at temperatures well above the operating temperature of PWRs. Therefore, VHTRs with outlet temperatures hotter than 650°C are preferred [10]. Of the thermochemical cycles, the Na-O-H [11] and Cu-Cl [12,13] cycles have the potential to operate at the lowest temperature—approximately 500°C—while the S-I cycle operates at approximately 800°C [14,15]. Due to their moderate operating temperatures and power requirements, the Na-O-H and Cu-Cl cycles are compatible with receiving heat and electricity from supercritical water reactors (SCWRs) for hydrogen production. Coupling these cycles

to PWRs would require a chemical heat pump to upgrade the temperature of the steam, which decreases the efficiency of the process [16].

For the Na-O-H chemical process, initial studies show that the ideal exergy efficiency of the cycle is 82%, making it a potential candidate for H_2 production [11, 17]. The HTEF thermal power input value for the Na-O-H cycle in the final column of Table 1 assumes that high-temperature heat from a VHTR is used in the thermochemical Na-O-H cycle; therefore, the anticipated high-temperature thermal input power requirements of HTSE and Na-O-H technologies are approximately equal, at 80 kWh_{th}/kg-H_2. It must be noted, however, that Na-O-H cycle technology is not yet mature, and its projected overall system efficiency has relatively high uncertainty. The coupled SCWR Cu-Cl hybrid cycle has been studied extensively in Canada and has been shown to have exergy efficiency of 27.8% [12]. The hybrid S-I cycle has also been studied extensively and has a reported exergy efficiency of 35% [18,14,15].

1.3 Why Select a 4-Loop Westinghouse PWR as a Reference Plant to Integrate with HTSE?

Development of a preconceptual design must begin by establishing a reference plant to describe proposed modifications, analyze impacts, and approximate assigned costs. Individual sites can then compare the attributes of the reference plant to their specific plant to adjust the modifications described or scale the associated costs appropriately.

> *A Westinghouse 4-loop PWR has been selected for this study. Westinghouse*
> *PWRs represent 75% of all operating PWRs in the U.S. (46/68 = 75%). A 4-Loop*
> *PWR is representative of typical Westinghouse PWRs.*

As of the end of 2022, 68 of the 92 commercially operable U.S. NPP units were PWRs. In a PWR, high-pressure (HP) water passes through the reactor core, where it is heated by thermal energy created by nuclear fission. This "primary" water flows to a heat exchanger (called a steam generator), where it boils feedwater in the "secondary" plant cycle to create steam. This steam then drives a series of turbines, which turn a generator to create electricity. This secondary turbine-cycle steam is not radioactive due to its being separated from the reactor coolant within the steam generators. With such a significant portion of the NPP fleet employing this type of design, it is an appropriate choice for use as the representative reference plant for the preconceptual design. Additionally, the use of nonradioactive steam makes a PWR the logical choice for an initial feasibility study. It is noted that a BWR will require additional design considerations due to radioactive steam.

The most common type of PWR is a Westinghouse 4-loop design, of which there are 26 units operating as of the end of 2022. Westinghouse also designed 2-loop and 3-loop PWRs, of which there are 5 units and 15 units operating, respectively, for a total of 46 operating Westinghouse PWRs. Thus, Westinghouse PWRs represent 75% of all operating PWRs in the U.S. (46/68 = 75%). A 2-loop plant has two steam generators and reactor coolant pumps, while 3-loop and 4-loop plants have correspondingly increased numbers of steam generators and reactor coolant pumps. Due to the increased numbers of loops, 3- and 4-loop plants have higher thermal outputs than do 2-loop plants. The rated thermal outputs of 2-, 3-, and 4-loop PWRs are approximately 1800, 2700, and 3500 MW_{th}, respectively. The fundamental designs of the plants are sufficiently similar that a 4-loop PWR is representative of 2- and 3-loop PWRs if the different reactor scales are properly accounted for. Considering that the 4-loop Westinghouse PWRs are the most common type, and that they are representative of 75% of operating PWRs in the U.S., a 4-loop Westinghouse PWR has been selected for this study.

1.4 High-Level Design Parameters

The body of this report and Appendixes A through J are based primarily on a preconceptual design report prepared by S&L with input from INL [19]. Appendix K contains recommendations for the control system implementation and is based on a report by Westinghouse [20]. The plant is assumed to have a

generating capacity of approximately 1200 MW$_e$, which is also reasonable for this design. Steam is extracted from the PWR using one or more new connections in the crossunder (cold-reheat) piping between the HP turbine and the moisture-separation reheaters (MSRs), as shown in Figure 3. This report considers two large-scale hydrogen-production facilities with nominal ratings of 100 and 500 MW$_{nom}$, respectively. Detailed information for both designs is located in the preconceptual-design report prepared by S&L [19]. Table 2 provides the specific parameters for both designs. The nominal rating corresponds to the DC power input of HTEF at full hydrogen production. A 100 MW$_{nom}$ HTEF is expected to produce as much as 55–58 MTs of hydrogen per day, depending upon the configuration.
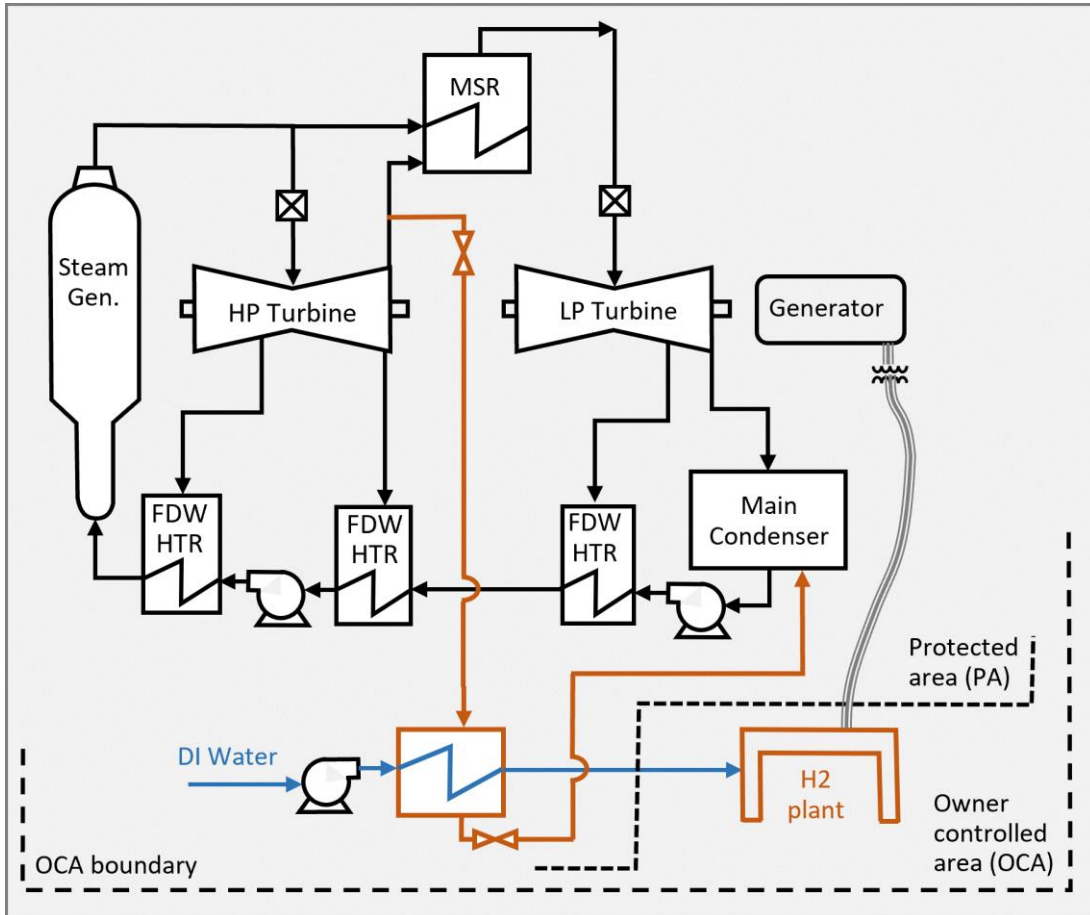
Figure 3. Steam extraction from cold-reheat piping downstream of the HP turbine.

The exact amount of heat required by the HTEF to generate steam for hydrogen production depends on heat recuperation and other design choices within the plant. For this study, typical heat-input requirements are assumed without performing detailed heat-integration designs that depend upon the specific HTEF configuration that is vendor dependent. Steam delivered to the HTEF is required at temperature of at least 300°F and pressure of at least 50 lb/psig. Analyses performed for this study achieved these requirements, as summarized in Table 2. The final steam conditions supplied to the HTEF are approximately 333°F and 74lb/psia. Hydraulic analyses were performed to size the piping and auxiliary equipment required to meet thermal-extraction demands for the HTEF. For the preconceptual design, minor additional thermal extraction is needed to cover various thermal losses, inefficiencies, and design margins typically associated with the sizing of piping, pumps, heat exchangers, valves, etc. As noted, the thermal power required for hydrogen production in an HTEF is approximately 20% of the nominal power. Based on these considerations, the thermal power requirement of the 100 MW$_{nom}$ HTEF is taken to be 25 MT$_{th}$, and that of the 500 MW$_{nom}$ HTEF is taken to be 105 MW$_{th}$. Both hydrogen facilities are assumed to be located outside of the protected area, but inside the OCA, as indicated in Figure 3. Designs are prepared for distances of 250 and 500 m between the PWR and the HTEFs. Product hydrogen is transported a safe distance away, such as 1 km, for HP compression and storage.

Table 2. HTEF parameters by plant size.

Parameter	Unit	HTEF Size	
		100 MW$_{nom}$	500 MW$_{nom}$
Hydrogen Production Capacity[a]	U.S. tons/day	55-58	275-290
H$_2$ Plant Electric Load MW$_e$	MW$_e$	105	500
H$_2$ Plant Auxiliary Loads + Margin	MW$_e$	22	50
Power Factor	—	0.92	0.92
Total Electrical Power Requirements	MVA	140	600
H$_2$ Plant Thermal Load	MW$_{th}$	20	100
Plant Thermal Losses + Margin	MW$_{th}$	5	5
Total Thermal Power Requirements	MW$_{th}$	25	105
Steam Input Temperature[b]	°F	>300 (333)	>300 (333)
Steam Input Pressure[2]	psig	>50 (59.3)	>50 (59.3)
Separation Distance from PWR	m	250 & 500 m	250 & 500 m

1   Conservative production capacities are shown based on 2022 values. Technology improvements over the next few years are expected to improve the yields of these plants to approximately 60 and 300 U.S. tons/day, respectively.

2   Parameters in parenthesis indicate actual design values.

Within the PWR, piping is installed to route the high-temperature steam from the crossunder piping to a steam reboiler that creates steam in a tertiary loop fed from a deionized or demineralized-water source. This steam is then provided to the HTEF for use in the HTE process. Condensed drain flow on the secondary side of the steam reboiler is directed to a location within the secondary loop of the plant to minimize thermal losses.

The revenue meter for the NPP is assumed to be at a high-voltage switchyard, adjacent to the NPP protected area. Net metering of the HTEF may be required for cases where the revenue meter is located at the generator terminals or in the turbine building (TB). It is also assumed there will not be any safety-related or Class I seismic equipment inside the TB.

Transmission-system voltages vary throughout the country, based on utility standard practices, system loading, and area geography. Typical interconnection voltages for commercial NPPs range from 230–500 kV. It is assumed for this report that the transmission-system interconnection voltage for the reference plant is 345 kV. Electrical energy, in the form of alternating-current (AC) power, is diverted from the output of the main generator to the HTEF, where a majority of the required power is converted to rectified DC power.

The DC electrical loads required for hydrogen production were 140 and 600 MW_e for the 100 and 500 MW_{nom}, respectively, including balance-of-plant equipment. As with thermal power, electrical losses and inefficiencies must be considered to supply adequate power to the facility. Additional electrical power needs to be supplied to the hydrogen facility to support plant auxiliaries and other ancillary loads. For the 100 MW_{nom} facility, a power factor of 0.92 was used, in combination with 10% additional power (11 MW_e) for auxiliary power and 10% additional power (11 MW_e) for the margin. The 500 MW_{nom} facility used the same power factor and percent auxiliary power, but no margin (margin is covered by the increased auxiliary power). The total apparent electric power rating for these two facilities comes to 140 and 600 MVA, respectively.

2.   100 MW_{nom} HTEF DESIGN AND EQUIPMENT

2.1   Design

2.1.1   Description of Modification

Process steam from the plant's main steam system is extracted through one or more new connections in the crossunder (cold-reheat) piping between the HP turbine and the MSRs. This insulated carbon-steel steam piping includes manual isolation at tap locations and an air-operated flow-control valve (FCV) before the piping routes out of the TB to the hydrogen steam supply (HSS) steam reboiler. Station instrument air is used for the actuation of this control valve. During a turbine trip, air supply to this valve would stop, causing this valve to close, isolating the steam line. The process and instrumentation diagram (P&ID) provided in Appendix A shows the arrangement of steam extraction for the cycle. HSS equipment, located in an outdoor area adjacent to the TB within the protected area, is composed of a steam reboiler, steam drum, drain receiver, drain cooler, reboiler feed pump, and demineralized-water-storage tank, reboiler feed-level control valve, relief valves, and isolation valves. A potential layout of the HSS equipment is included in Appendix B. Station instrument air is routed from an available header in the TB to supply the control valve.

A H_2 interface-control panel, located in the main control room, provides operational control of the mechanical and electrical equipment that dispatches steam and power to the HTEF. See Section 2.1.4 for details, including the interface with the main control room. The H_2 interface-control panel also houses the protective relay components. On the plant secondary side of the reboiler, stainless steel drain piping is routed from the steam reboiler to the drain receiver, the drain cooler, and finally to the main condenser in the TB. An air-operated level-control valve is in the piping at the condenser, with tie-ins to the station instrument air system and control-signal cables, which are routed from the reboiler drain receiver. A reverse osmosis (RO) system located within the HTEF boundary is required to generate the supply flow of demineralized-water to the steam reboiler. High-density polyethylene (HDPE) piping is direct-buried at a suitable depth and routed from the RO system at the H_2 facility to the demineralized-water storage tank within the protected area of the NPP. Stainless steel piping is routed from the tank to the suction of the reboiler feed pump. From the discharge side of the feed pump, stainless steel piping connects to the drain cooler, which is followed by the steam drum and then the steam reboiler. The drain cooler serves to preheat reboiler feedwater for hydrogen production and cool reboiler drain water headed to the condensers. The rate of demineralized water, which is fed to the drain cooler, is operated by a level-control valve using station instrument air. Control signals are received from the water-level transmitter within the steam drum. Insulation and heat tracing are added to exposed piping and outdoor equipment as needed.

Insulated carbon-steel process-steam piping from the reboiler is provided with a self-contained backpressure-regulating valve before it is routed through the protected area boundary to the HTEF. Drains and steam traps are provided to remove condensed water from the line. Reboiler chemistry is maintained through provision of a blowdown connection that can be routed to a station drain. The ability to sample the reboiler blowdown enables plant personnel to ensure radioactivity has not inadvertently contaminated the flow of steam to the HTEF. The 345-kV transmission line (H_2 feeder) for the H_2 plant is tapped to the line between the NPP's GSU transformer high-voltage bushing and the switchyard. The transmission line has two manually operated disconnect (MOD) switches and a 345-kV circuit breaker at the beginning of the line. The H_2 feeder is 0.5 km long, with the revenue meter at the beginning of the line. Located at the end of the line, inside of the HTEF boundary, are two 345-kV disconnect switches, a 345-kV circuit breaker, and a three-winding stepdown transformer to convert the power down from 345 to 13.8 kV. Medium-voltage power cables are routed from the stepdown transformer to two medium-voltage switchgears inside the HTEF. These cables and switchgear are to be provided as part of the H_2 facility design. The transmission line to the HTEF is protected by redundant microprocessor-based line-current differential (87L) relays. Each pair of relays communicates via fiber-optic cables over the transmission line. The NPP's existing GSU-transformer differential relays will cover the new high-voltage breaker at the H_2 feeder within their zone of protection. Interface with the existing plant tripping scheme of the existing GSU-transformer differential relays is required to be able to trip the high-voltage breaker to the HTEF.

A conceptual site plan showing the thermal and electrical interface between the plants is provided in Appendix B.

2.1.2   Mechanical Design

2.1.2.1   *Selection of NPP steam-dispatch location*

The heat-balance diagrams included in Appendix B illustrate the expected plant operating conditions when considering station operation without thermal extraction and station operation with the thermal extraction specified in Table 3. The modeling accounts for 1750 ft (approximately 530 m) of piping, with multiple fittings to allow a connection from the NPP to the HTEF. The heat-balance model also accounts for heat loss through insulated outdoor piping.

The preferred location of extraction is cold reheat (i.e., downstream of the HP turbine exhaust and upstream of the MSRs). This steam-extraction location provides sufficient thermal energy to heat cold water to the targeted steam conditions while minimizing the impact to both station efficiency and transient operation (i.e., loss of supply steam to the HTEF). Steam extraction at this location also reduces the steam-supply temperature experienced by the reboiler, limiting necessary design considerations for that component. Additional rationale for locating the steam dispatch at the cold reheat is provided in Appendix C.

Table 3. Summary of important system parameters for 25-MW$_{th}$ extraction.

Parameter	Unit	Extraction Level		
		0 MW$_{th}$	25 MW$_{th}$	Δ
Reactor Thermal Power	MW$_{th}$	3659	3659	—
Generator Output	MW$_e$	1239.6	1234.3	-5.3 MW$_e$
Main Steam Flow	Mlb/hr	16.28	16.28	0.00%
Cold-Reheat Flow	Mlb/hr	12.73	12.72	-0.05%
25 MW$_{th}$ Thermal Extraction Flow	lb/hr	0	85,238	—
Extracted Steam Fraction of Cold-Reheat Flow	%	0	0.67	0.67%
Remaining Steam to MSRs	Mlb/hr	12.73	12.64	-0.67%
Hot-Reheat Flow	Mlb/hr	11.26	11.17	-0.76%
Heater Drain Forward Temperature	°F	339.7	339.0	-0.7°F
HP Feedwater-Heater (FWH) Cascading Drain Flow	Mlb/hr	1.39	1.39	-0.23%
Low-pressure (LP) FWH Cascading Drain Flow	Mlb/hr	2.42	2.41	-0.41%
Heater Drain Tank Pressure	psia	185.5	184.0	-1.5 psi

NOTE: Cascading drain conditions are averaged. Individual feedwater heater drain lines may have higher variations in conditions. Changes from 0 to 25 MW$_{th}$ were calculated in Microsoft Excel. There may be slight differences due to truncation of values when entering the values in the table.

2.1.2.2   Selection of NPP drain-return location

The preferred location selected to return the condensed drain flow is at the main condenser. Returning to the main condenser allows sufficient energy removal from the cycle steam while minimizing the amount of steam diversion and resulting impact to the NPP. Returning to other locations at higher temperatures (e.g., the heater drain tank or a location in the feedwater system) would drive up the required mass flow of the diverted steam to achieve the required thermal-extraction level and would result in further impacts to the NPP.

2.1.2.3   Thermal analysis

A PEPSE heat-balance model of a reference Westinghouse 4-loop PWR NPP was used to determine the impact on the station when considering various levels of thermal extraction. As previously discussed, the preferred location for steam extraction is cold reheat, and the preferred location for subcooled-water return is the main condenser. The targeted steam conditions at HTEF are 300°F and 50 psig. Appendix C provides heat-balance drawings that show the impact to the NPP when considering 25-MW$_{th}$ power extraction. Table C-1 provides the station impact to significant parameters throughout the power cycle, considering 25-MW$_{th}$ power extraction.

2.1.2.4   Impact on plant hazards

These consideratons are not included in this report. See Ref. [18].

2.1.2.5   Evaluation of plant transients

Introduction of the HTEF to the existing NPP could cause operational transients that would need to be addressed. Specifically, the startup or shutdown of the HTEF needs to be evaluated to ensure there are no adverse effects on the operation of the existing NPP. Plant response to various electrical transients and faulted conditions is described below. PEPSE heat-balance diagrams (shown in Appendix C) are

developed to evaluate the impact of extracting steam from the nuclear power cycle to supply thermal energy to a reboiler unit used to preheat the process steam for H_2 production. Table 3 provides a summary of the important parameters for the 25-MW$_{th}$ extraction. Note that only parameters exhibiting some degree of change are shown; other values, such as most system temperatures, show virtually no change (see Appendix C).

Table 3 shows the 25-MW$_{th}$ extraction from cold reheat requires 85,238 lb/hr of steam, which corresponds to approximately 0.67% of total cold-reheat flow. Startup of the HTEF requires opening of the steam-extraction line from cold reheat to the reboiler unit. This operation diverts a very small portion, approximately 0.67%, of the total cold-reheat flow and reduces the hot-reheat flow to the low-pressure turbines by approximately 0.76%. These changes are not expected to cause any significant burden on existing plant operation. Note that the main steam-flow conditions remain virtually unchanged, and, therefore, the turbine control-valve position remains unchanged. The only other important change is the slight reduction of the main generator output, approximately 5.3 MW$_e$, but this change represents only approximately 0.4% of total generator output.

It is also noted that the extraction of steam from the cycles, as described in this report, is operationally similar to a low-pressure turbine bypass. Plants are typically designed with approximately 25% or more turbine-bypass capability, and plant transients are already analyzed with turbine bypass that is much greater than the level of steam extraction described.

Similarly, for the shutdown of the H_2 production facility, the changes are insignificant and should not cause any significant burden on the existing plant operation.

2.1.2.6   *Impact on core reactivity*

The impact on core reactivity associated with extracting steam from the secondary cycle must be assessed for any plant-specific modification as described within this report. However, based on the scale of thermal power extraction considered for this preconceptual design (<1% of secondary mass flow), it is expected that there will be a minimal impact on reactivity for the conditions analyzed within this design report.

2.1.3   Electrical Design

The HTEF requires 105 MW$_e$ power for the electrolysis process and approximately 11 MW$_e$ for auxiliary loads. Using a power factor of 0.92 for H_2 plant processes and a 10% margin, the total power required by the HTEF is 140 MVA. Distance between the HTEF and NPP equipment is approximately 0.5 km; therefore, power is supplied from the NPP via a 345-kV transmission line spanning the plant separation.

2.1.3.1   *Selection of NPP electrical-dispatch location*

The electrical-physical-layout diagram in Figure B-7 illustrates the preferred electrical system tie-in point, which is the high-voltage side of the NPP's main GSU transformer. The electrical feed to the HTEF consists of a high-voltage circuit breaker, two MOD switches, and a 0.5-km high-voltage transmission line. For a total apparent power rating of 140 MVA, the current rating of the high-voltage equipment must be in the range of approximately 162–350 A when considering a nominal transmission-system voltage in the range of 230–500 kV. This is well within the typical rating of available high-voltage electrical equipment. The short-circuit rating of the high-voltage circuit breaker should be selected to match the design ratings of the existing electrical switchyard.

An alternative option for the electrical system tie-in location is the generator-isolated phase (isophase) bus. This may be advantageous for NPPs with insufficient space between the GSU transformer and transmission line dead-end structure to tap the high-voltage transmission line. The major drawbacks of connecting to the isolated phase bus are the relatively high cost of tapping the isophase bus, high short-circuit levels, and losses associated with transmitting electrical power 0.5 km at the generator voltage level. The short-circuit levels at the outlet of the NPP isophase bus are typically more than 100 kA, which necessitates a specially designed generator circuit breaker for sufficient short-circuit protection and isolation of the H_2 plant feed from the NPP. Further, it is not practical to extend the isophase bus 0.5 km to the HTEF. Limiting the available fault current to safe levels for transmission of electrical power via overhead lines or underground cable would require current-limiting reactors or a transformer connected between the isophase bus and the feeder to the HTEF, which leads to additional capital costs and electrical losses. Based on the challenges associated with the electrical tie-in at the isophase bus, this option is not investigated further in this report.

2.1.3.2   Electrical design and equipment within the NPP boundary

The 345-kV transmission line will be tapped to the line between the NPP GSU transformer's high-voltage bushing and the switchyard. The H_2 transmission line routes over a transmission tower to a 345-kV circuit breaker and its two MOD switches for line protection and maintenance. Potential transformers will be installed between the MOD switch and the high-voltage breaker for the new line's revenue meters. This equipment will be in the NPP protected area or yard area, depending on available space in the protected area. For a plant-separation distance of 500 m, the H_2 transmission line will be routed over six more transmission towers to reach the H_2 plant area. The line then terminates at a 345-kV circuit breaker and associated disconnect switches and a three-winding, stepdown transformer to step the power down from 345 to 13.8 kV inside the HTEF boundary. These components should be incorporated into the HTEF design and are outside the scope of this report. The two nonsegregated buses or cables that connect the two secondary windings to two medium-voltage switchgears inside the HTEF also are part of the H_2 plant design and outside the scope of this report. See Figure B-7 for the H_2 transmission line electrical-physical layout. The three-winding stepdown transformer is rated for 345 kV-delta/13.8 kV-wye/13.8 kV-wye, 84/112/140MVA oil-natural, air-natural (ONAN)/oil-natural, air-forced (ONAF)/ ONAF, 9.5% nominal impedance H-X, H-Y. The 13.8-kV windings are resistance grounded. Revenue meters are installed in different locations depending on the NPP. Some NPPs locate revenue meters inside the TB, outside after the GSU transformer, or out in the switchyard. Therefore, the NPP and associated grid operators should have discussions early in the process to review their agreement in relation to the location of the connecting point of the H_2 feeder and the issues that can affect the location of the H_2 feed-connecting point in relation to the meters such as GSU-transformer power losses.

2.1.3.3   Transmission line control and protection

The control and indication of the H_2 power line can be performed locally at the equipment or from the main control room for the high-voltage circuit breaker. Also, the control and indication for the reboiler pump and control and position indication of the steam-admission valve associated with the steam line can be performed from the main control room. The two manually operated 345-kV disconnect switches will only have indications in the main control room. It is assumed that the revenue meters for the new H_2-transmission line will be located outdoors, close to their associated 345-kV breaker. Protective relays associated with the new high-voltage circuit breaker to protect the H_2 power line will be located in NPP relay room and use plant DC power sources. The protective relays at the end of the transmission line will be located within the HTEF boundary. Coordination between the NPP and HTEF electrical equipment will be required.

2.1.3.4   Power requirements for hydrogen steam-supply equipment

HSS equipment located in the protected area requires 480 VAC and 125 VDC to operate the reboiler feed pump and any required auxiliary loads. The power will be supplied from a 480-VAC load center and 125-VDC distribution panel in the TB.

2.1.3.5   Switchyard arrangement and offsite power

The switchyard breaker alignment is not affected by the addition of the new high-voltage line to the H_2 plant because the new line is protected by a new high-voltage circuit breaker downstream of the tap point, as shown in electrical single-line diagram (Appendix H). The new H_2 power line has no impact on the switchyard voltage, breaker alignment, generator automatic-voltage-regulator (AVR) loading, or the status of offsite power voltage-regulating devices. The H_2 production facility is physically and electrically separated from the offsite power circuits. Therefore, there is no impact to offsite power sources or plant safety loads, which are normally powered from offsite power sources.

2.1.3.6   Electrical short-circuit and load-flow/voltage-drop analysis

An electrical-transient analyzer program (ETAP) electrical power-system model was prepared to evaluate the power-flow and short-circuit impacts of the HTEF electrical tie-in (Appendix H). The model was developed based on typical electrical parameters for an NPP main power circuit. The ETAP model consists of the following components:

- Thevenin-equivalent source representation of the high-voltage transmission system

- NPP synchronous generator

- NPP main GSU transformer

- 0.5-km high-voltage transmission line to the HTEF

- HTEF stepdown transformer

- Two medium-voltage switchgear buses for the HTEF

- Lumped loads to represent the loading at the HTEF.

The stepdown transformer supplying the HTEF is specified as a three-winding unit to supply 105 MW_e to the H_2 plant, plus additional capacity for auxiliary loads. The application of a three-winding transformer enables the use of standard 3000A, 15-kV-class switchgear. Note that use of a two-winding transformer would be limited to a maximum apparent power supply rating of approximately 70 MVA at 13.8 kV (3000A $\times$ 13.8kV $\times$ sqrt(3) = 71.7 MVA). A short-circuit analysis was performed in ETAP to determine estimated equipment short-circuit ratings and to aid in sizing the HTEF stepdown transformer. The H_2 plant stepdown transformer was modeled as an 84/112/140MVA ONAN/ONAF/OFAF three-winding transformer. The high-voltage winding is connected in delta and the medium-voltage windings connected in wye. The short-circuit analysis model shows that a 9.5% nominal impedance between the H-X and H-Y windings (with $\pm$7.5% tolerance) on the 42 MVA self-cooled base of the secondary windings allows for the use of 40-kA medium-voltage switchgear at the H_2 plant. The ETAP model shows that adding the hydrogen plant has a negligible impact on existing NPP equipment. Hydrogen plant loads are primarily rectifiers supplying direct current to the electrolyzers (approximately 80% of total load). Diode-based rectifiers permit current to flow only in one direction; therefore, they do not supply short-circuit current back to the power system. The only sources of short-circuit current in the HTEF are motor loads in the auxiliary system. The amount of short-circuit current supplied by the motor loads is negligible in comparison with the short-circuit current supplied by the high-voltage transmission system and NPP generator. The ETAP model shows the HTEF contributes less than 0.1 kA of short-circuit current at 345 kV when compared to approximately 38 kA from the system and approximately 7 kA from the NPP.

The ETAP model was also used to perform a load-flow and voltage-drop analysis to evaluate the sizing of electrical equipment, including the HTEF stepdown transformer. The load-flow analysis shows the 140 MVA top rating of the H_2 plant stepdown transformer is sufficient to carry the full load of the HTEF. The thermal load and voltage drop across the 0.5-km high-voltage transmission line is not significant. A typical transmission conductor size—such as a 795 kcmil Drake aluminum conductor, steel reinforced (ACSR) or higher, based on common transmission practices in the area—is recommended.

The voltage-drop analysis performed with the ETAP model shows that the hydrogen-plant stepdown transformer does not require an on-load tap changer if the transmission voltage is maintained within approximately a ±2.5% bandwidth. Per NUC-001, this applies to NPPs that operate per a voltage schedule and to NPPs that require strict voltage regulation for offsite power (assuming the offsite power source is supplied from the same location in the transmission system). In this case, a standard de-energized tap changer (with taps at ±5%, ±2.5%, and 0%) on the high-voltage winding provides flexibility to adjust the high-voltage winding voltage based on the target transmission-system operating voltage. An on-load tap changer on the HTEF stepdown transformer would provide additional flexibility for locations where the transmission system's operating voltage may vary over a wider range and for locations where the hydrogen facility may operate while the NPP is in a refueling outage.

2.1.3.7   Protective relaying design

The electrical tie-in of the HTEF has a non-negligible impact on the NPP protective-relaying scheme. The relay protection single-line diagram in Appendix H shows the design of the conceptual protective-relaying scheme. In this design, the existing main GSU-transformer differential-protection scheme is restrained from operating for a fault on the high-voltage transmission line by summing a set of bushing current transformers (CTs) from the new high-voltage circuit breaker with the existing switchyard CTs. This arrangement turns the transmission line to the NPP into a three-terminal line. Note that this requires careful evaluation of the existing CTs and relaying scheme to ensure that the new CTs on the high-voltage circuit breaker are properly matched (including CT ratio and accuracy class) and the scheme will function properly. In some instances, it may be required to upgrade the existing transformer or line protection package to a microprocessor-based relaying scheme to mitigate mismatch between the existing and new CTs. Additionally, the trip output of the existing line and GSU-transformer protection scheme should be tied into the trip circuit of the new high-voltage circuit breaker protecting the line to the HTEF.

The high-voltage transmission line to the HTEF is protected by redundant microprocessor-based line-current differential (87L) relays. This scheme requires four redundant line-current differential relays, two on each end of the transmission line. Each pair of relays communicates via fiber-optic over the transmission-line optical ground wire (OPGW). High-speed protection is required per North American Electric Reliability Corporation (NERC) protection requirements for bulk electric system (BES) elements and to ensure the NPP generator remains stable should a fault occur on the transmission line. To ensure the stability of the NPP generator during fault clearing, the total clearing time of the line-protection package needs to be less than the critical clearing time identified in the transient stability analysis. Additionally, breaker failure protection must be implemented so that the switchyard breakers or the generator circuit breaker (if the NPP is equipped with a generator circuit breaker) trip in the event of a failure of the new high-voltage circuit breaker.

The stepdown transformer to the HTEF is protected by redundant transformer-differential relays (87T). Overcurrent relays (50/51) are employed on the low-voltage windings for overload protection and backup overcurrent-fault protection. The redundant transformer differential relays (87T) and the overcurrent relays are located inside the HTEF.

It is important to note that, with this arrangement of the protection scheme, the only additional exposure for the NPP generator for a single failure is the very short length of conductor bus from the electrical tap point to the new high-voltage breaker. The length of this bus should be as short as practical to minimize additional exposure. There is no impact on the reliability of the offsite power circuits. Table 4 shows the required trip logic for different fault locations following the electrical tie-in of the hydrogen plant.

Table 4. Electrical-fault-condition trip logic.

Fault Location	Initial Trip Device	H_2 Breaker Failure Trip Device
Existing high-voltage line and line tap to new high-voltage circuit breaker	Existing high-voltage switchyard circuit breakers Generator circuit breaker (if equipped) New high-voltage circuit breaker	None
New high-voltage line to HTEF	New high-voltage circuit breaker New high-voltage stepdown transformer circuit breaker	Existing high-voltage switchyard circuit breakers Generator circuit breaker (if equipped)
HTEF transformer	New high-voltage stepdown transformer circuit breaker inside the HTEF	New high-voltage circuit breaker

2.1.3.8   Electrical-transient analysis

An electrical-transient analysis was performed to evaluate the impacts of a trip of the hydrogen plant load on the existing NPP generator using PSCAD software. The ETAP model is described in Section 2.1.3.6 on the electrical short circuit and load-flow/voltage-drop analysis. The model consists of the following components:

- A representation of the surrounding high-voltage transmission system, including dynamic-boundary bus source to capture governor response to a loss of large load in the area

- The NPP synchronous generator, including the AVR and governor-control models

- The NPP main GSU transformer

- The 0.5-km high-voltage transmission line to the HTEF

- The HTEF stepdown transformer

- Lumped loads to represent the loading at the HTEF.

The PSCAD model was used to simulate a trip of the hydrogen-plant load under both faulted and unfaulted conditions. It is conservatively assumed that during the event, the turbine mechanical power will not ramp down in response to the transient; rather, it will remain constant. Therefore, upon the trip of the HTEF, the excess power from the NPP generator is injected into the transmission system. The model shows that for a 105-MW_e electrical load with 10% auxiliary power and margin, the NPP generator remains stable for both faulted and unfaulted trips of the HTEF. During an unfaulted trip of the line, the generator exhibits a slight increase in mechanical speed (<0.02%), which is followed by damped oscillations. The mechanical transient decays within 10 seconds. After the hydrogen facility load is tripped, there is a slight increase in grid voltage (<0.5%) due to the loss of load. The generator-excitation system responds to reduce the field current and return the grid voltage back to the pre-trip value. For a faulted trip of the HTEF load, the simulations show that a three-phase fault on the high-voltage transmission line must be cleared within 0.2 seconds to ensure the generator remains stable. For a three-phase fault on the high-voltage transmission line, cleared in 0.2 seconds, the generator's mechanical

speed increases by approximately 2% during the fault. After the fault is cleared, there are several oscillations in generator speed as the mechanical transient decays within 10 seconds. The generator-excitation system responds by increasing the field current during the fault and subsequent voltage recovery. After the voltage recovers, the excitation system restabilizes within several seconds. Note that the generator response during a faulted trip of the high-voltage transmission line is comparable to the response expected for a fault on any other transmission line connected to the high-voltage switchyard.

Additional sensitivity analysis was performed to determine the maximum power that could be transmitted radially from the NPP to the nearby HTEF without impacting the stability of the NPP generator during a loss of load. The additional runs show that the H_2 plant load can be increased up to the maximum output power rating of the generator without causing the generator to become unstable following a trip of the high-voltage transmission line feeding the hydrogen facility, either with or without a fault. Note that this model is based on typical plant and transmission-system data, which may not be representative of the available capacity for all plants. To lessen the impact on the grid during a high-voltage line trip for larger loads (near the rating of the generator), the H_2 plant loads may be accommodated by using redundant transmission lines and stepdown transformers to distribute the load across multiple circuits. Note that redundant lines should not have a common failure mode such as using multicircuit transmission towers.

2.1.3.9   Bulk electric system regulatory impacts

The high-voltage transmission line supplying the HTEF is classified as a BES element because the line is connected to a radial system with a generator that has a gross individual-nameplate rating greater than 25 MVA and a voltage of 100 kV or above. Note that the BES classification includes only the high-voltage transmission line and excludes the stepdown transformer supplying the HTEF. The BES classification subjects the transmission line and connected facilities—e.g., circuit breakers, disconnect switches, instrument transformers, and protective relays—to compliance with NERC Reliability Standards. Table 5 provides a summary of the applicable reliability standards. Note that the NPP is already subjected to the following standards.

Table 5. Applicable NERC Reliability Standards.

Number	Title	Description
CIP-014	Physical Security	Physical security of the line and switchyard must be maintained to mitigate a physical attack that could result in instability of the nuclear facility.
FAC-001	Facility Interconnection Requirements	The reliability impacts of the interconnection of the facility must be studied to ensure no negative impacts on the generator.
FAC-008	Facility Ratings	The high-voltage transmission facility ratings and rating methodology must be documented and maintained.
MOD-032	Data for Power System Modeling and Analysis	Steady-state, dynamic and short-circuit modeling data must be maintained and communicated with the transmission owner.
PRC-005	Transmission and Generation Protection System Maintenance and Testing	A protection system maintenance and testing program shall be maintained.
PRC-023	Transmission Relay Loadability	The protective relay settings shall be reviewed to ensure they do not affect line loadability.
PRC-027	Coordination of Protections Systems for Performance During Faults	The transmission-line protection shall be coordinated with the generator and transmission owner. A baseline short-circuit study shall be maintained.
TPL-001	Transmission System Planning Performance Requirements	The relay protection systems shall be redundant such that failure of a single relay system does not impact the generator.

2.1.4   Instrumentation and Controls Design

2.1.4.1   *Operator-control capabilities*

As described in Section 4.1, the NPP supplies two principal components for the HTE process: (1) cold-reheat steam from the HP turbine exhaust and (2) 345-kV electrical power. NPPs are usually loaded to 100% capacity; hence, the steam and electrical supplies to the HTEF are expected to contribute to this total. As with any plant system, it will be important for the NPP control-room operators to have indications of the HTEF supply parameters and system conditions. This information is needed to effectively evaluate HTEF contributions to overall NPP operation and take any necessary actions. Actions that the operators may need to take include the ability to start and stop steam supply and electrical power to the HTEF. Additional guidance for the implementation of the control system can be found in Appendix K.

To facilitate HTEF operation, a dedicated set of operator controls with remote human-machine interface (HMI) will be provided. The HMI will allow for control, indication, and alarm of the H_2 power line and steam supply. These controls will be electrically and functionally isolated from NPP controls, but the remote HMI will be collocated in the NPP main control room. Existing plant fiber-optic infrastructure will be used to communicate between the HMI and equipment associated with H_2 power line and steam supply. This permits the status of the HTE process parameters to be available to NPP control-room operators to evaluate the impact of HTEF loading on NPP operation. It also allows necessary on and off control for operators to enable or isolate the HTEF supply-steam and electrical power. Additional indication and controls will be provided locally to the HSS equipment.

The operator should be trained in operating the power and steam supplies from the NPP to the HTEF using the new standalone HMI. A special procedure should be prepared for this operation.

2.1.4.2   Available process parameters for monitoring

The following process parameters are expected to be available to allow plant personnel to monitor performance of the thermal- and electrical-extraction systems:

- Electrical power consumption on the plant computer-logging system

- Steam flow diverted from the plant on the plant computer system (for plant performance engineer)

- HSS equipment trouble alarm in main control room

- Hydrogen plant trip or fire alarm in main control room.

2.1.4.3   Response to faulted conditions

An understanding of how the plant and equipment will respond to postulated faulted conditions is critical when moving forward with a design change to plant equipment. The following is a summary of potential failure modes of the installed thermal and electrical-extraction components and a brief description of the plant and operations response to ensure that the plant can be maintained in a safe condition:

- Extraction-steam leak to reboiler—Response depends on the severity and location of leak. If possible, extraction-steam line is isolated through manual or remote closure of the steam admission valve to the reboiler. Without extraction steam supply, H_2 plant shutdown would occur. If isolation is not possible, manual trip of the NPP would occur, similar to the response to an unisolatable main steam line leak.

- Process-steam leak to HTEF—Leak can be isolated through manual closure of process-steam supply valve leaving the reboiler. H_2 plant shutdown would occur. The NPP turbine generator would pick up load, and the grid would absorb the additional load.

- Reboiler drain valve fails closed—This should not occur because the valve is set to fail open. However, if this event were to occur, reboiler drain level would rise in the reboiler. Either the extraction steam-supply valve would close on high-high level or an emergency dump valve would open to the lower level.

- Reboiler drain valve fails open—Level in the reboiler would drop and, potentially, steam would be passed to the condenser. An automatic comparison of level-to-valve position could be implemented to close the steam admission valve.

- Extraction-steam supply valve fails open—This should not occur because the valve is set to fail closed. However, if this event were to occur, the design pressures of both sides of the reboiler are equal to or greater than the steam conditions. The amount of condensation would be controlled by demand from the HTEF. The condensate level would be controlled by the condensate drain valves. With normal operation of the reboiler feed supply, the plant would continue to operate normally.

- Extraction-steam supply valve fails closed—The reboiler level would fall; the condensate-drain line would control the level by closing down. Process steam to the HTEF would cease flowing, and the H_2 plant would shut down. The closure of the steam line would divert the steam flow to the turbine. The turbine-steam admission valve would either slightly close or the generator would produce more power, which would be absorbed by the grid.

- Rapid trip of HTEF—Steam demand from the NPP to the HTEF would cease, the level on the hydrogen-side of the reboiler would increase, and the supply-water admission valve would close in response. This would remove cooling from the plant-side of the reboiler, and steam condensation would decrease. The condensate-drain valve would close to maintain the level until it completely closed. The steam that would have gone to the reboiler would be available to the low-pressure turbines. Either the turbine admission valve would throttle down or more power would be supplied to the grid.

- Short in high-voltage line—Overcurrent protection, as discussed in this report, would trip the hydrogen plant, and the balance of the transient would be like the rapid trip of the hydrogen plant.

- Open in high-voltage line—An open in the high-voltage line would trip the HTEF, and the NPP would respond in the same manner as a rapid trip of the HTEF.

2.1.4.4   Design-attribute review

A strategic plan called "Delivering the Nuclear Promise: Advancing Safety, Reliability and Economic Performance," was developed to ensure the financial viability of the commercial nuclear power industry through a partnership of U.S. nuclear utilities. The Nuclear Strategic Issues Advisory Committee created a series of initiatives related to the Delivering the Nuclear Promise plan. One of the initiatives was development of a standard process to streamline design changes for plants through adopting a standardized process, applying a graded approach to modifications, and alleviating some of the administrative burden associated with the existing processes.

The Design Oversight Working Group developed industry procedure IP-ENG-001, "Standard Design Process" [21], which was subsequently adopted by the industry because of this initiative. Consistent with its stated goals, the procedure provides a graded approach for selecting from multiple types of engineering changes (e.g., commercial, equivalent, and design change), which streamlines the modification process. When performing an engineering change in accordance with IP-ENG-001, the responsible engineer completes a design-attribute review (DAR), which is a series of questions that aids in the identification of impacted disciplines, stakeholders, and programs. As part of the preconceptual design, a sample DAR has been completed [Appendix J]. While this effort must be performed on a plant- and design-specific basis when performing a similar modification, the information is provided as an example to guide the process. Key design attributes to consider are discussed below.

2.1.4.5   Electrical

This conceptual design covers the installation of 0.5 km of 345-kV transmission line between the GSU transformer and the HTEF. A 345-kV high-voltage circuit breaker and two associated disconnect switches, potential transformers (PTs), and transmission-line tower will be installed in the plant protected area or the yard area, depending on available space around the GSU transformer. A stepdown transformer 345-13.8 kV, with two disconnect switches, will be installed at the end of the transmission line in the HTEF.

- The control/indications of the 345-kV circuit breaker and indication only for the breaker-associated disconnect switches for the H_2 transmission line are from the main control room. All the required protective relays for the H_2 power line are located in the plant relay room. The local control and monitoring for the electrical equipment associated with the H_2 steam line, such as a water pump, are from the main control room. A standalone HMI for control and indications of the H_2 power line and

steam supply is available in the main control room, using existing fiber-optic infrastructure in the plant to communicate between the HMI and equipment associated with H_2 power line and steam line.

- CTs at the H_2 feeder high-voltage circuit breaker will be brought back into the existing GSU-transformer differential relays to cover the new high-voltage breaker within their zone of protection. Interface with the existing plant-tripping scheme of the existing GSU-transformer differential relays is required.

- Low-voltage AC power (480 VAC) is supplied from the plant AC auxiliary power system to HSS equipment for the reboiler feed pump. Also, 125 VDC is supplied from the plant for the high-voltage breaker control and protective relay circuits.

- The installation of a new power line to supply power to the HTEF has no effect on the switchyard voltage, breaker alignment, generator AVR loading, or status of offsite power voltage-regulating devices.

- All added electrical equipment and the towers for the transmission line are connected to the station's grounding.

- The added power cables (480 VAC and 125 VDC) and CT cables in the TB should meet plant design and materials requirements. The added cables require evaluation against the plant's fire requirements or raceway capacity.

- The load-flow analysis demonstrates the change in the switchyard voltage due to the addition of the 105-MW$_e$ load plus auxiliaries is negligible. As such, there is no impact to generator volt-amps reactive (VAR) loading, which is controlled based on switchyard voltage.

- The switchyard breaker alignment is not impacted by the addition of the new high-voltage line to the hydrogen plant because the new high-voltage line is protected by a new high-voltage circuit breaker downstream of the tap point. The only additional exposure for the NPP generator and switchyard breakers to trip for a single failure is for a fault on the very short length of the conductor bus from the electrical tap point to the new high-voltage breaker. The length of this bus work is designed as short as practical to minimize the additional exposure.

- Generator electrical characteristics are a function of the synchronous machine design and construction and are not impacted by the addition of the hydrogen production facility. The impact is comparable to the addition of a new line or load fed directly from the transmission switchyard.

- The hydrogen production facility is physically and electrically separated from the offsite power feed. Therefore, there is no impact to offsite power loading for the post-trip scenario.

- The load-flow analysis demonstrates the change in the switchyard voltage from the addition of the 105-MW$_e$ electrical load plus auxiliaries is negligible. Therefore, the status of offsite power voltage regulating devices is not impacted.

2.1.4.6   Instrumentation and controls

The use of digital controls is an integral component of the proposed coupling of an HTEF to an NPP. Standard Design Process IP-ENG-001 directs that any NPP modification that involves digital equipment must assign a digital engineer in accordance with Nuclear Industry Standard Process NISP-EN-04, "Standard Digital Engineering Process." This procedure supplements the Standard Design Process by addressing additional engineering activities applicable to modifications involving programmable electronic equipment.

- A goal of the proposed design is to minimize the modification of existing digital controls, or the addition of new digital components, to the NPP. This is accomplished through use of a dedicated set of operator controls and remote HMI. The DAR process will identify and document the appropriate design inputs and bounding technical requirements. A determination must be made to classify the digital controls components to determine whether the requirements of NISP-EN-04 apply.

- For digital controls subject to meeting these requirements, additional engineering activities are needed to demonstrate compliance. These additional activities are described and explained in Electric Power Research Institute (EPRI) 3002011816, "Digital Engineering Guide."

- Adopting nuclear cybersecurity rules for those components installed at the HTEF may impose additional costly and unnecessary requirements. Commercial cybersecurity may be used in lieu of nuclear cybersecurity depending on component locations, digitalization of vendor-procured instrumentation and controls (I&C), and impacts on plant safety, among other considerations. Site-specific reviews should be conducted to determine whether hydrogen projects demand nuclear cybersecurity requirements.

2.1.4.7   *Mechanical*

This modification includes a range of new mechanical components that will be added to the plant, including manual valves, check and relief valves, control valves, a heat exchanger (reboiler), a pump, a tank, and steam traps. Inclusion of these components involves hydraulic considerations such as pump sizing, available net-positive suction head (NPSH), fluid velocity, pressure drop, American Society of Mechanical Engineers code requirements, and system design conditions (temperature and pressure).

- Detailed design of the discharge piping for the reboiler feed pump should consider the potential for vibration. Use of industry best practices, such as short vent/drain cantilevers and 2-1 socket weld profiles, should limit the potential for piping-vibration susceptibility. Post-modification testing will validate the adequacy of the design.

- Steam piping and drain piping installed by this modification require analysis to evaluate expected primary and secondary pipe stress. Provisions for thermal flexibility (expansion loops) will be required in the steam piping routed to the HTEF. Nozzle reaction loads require evaluation to vendor-supplied nozzle allowables.

- Pipe-support design will be informed by pipe-reaction loads output from stress analyses.

- Depending on the local climate, freeze protection may be required for demineralized-water piping when above ground and for the demineralized-water storage.

- Piping installed by this modification includes saturated steam and saturated water and; therefore, it should be evaluated for inclusion in the plant flow-accelerated corrosion (FAC) program. Portions of the drains piping from the reboiler to the condenser could include two-phase flow and should be evaluated for potential erosion concerns.

- The reboiler will require pressure relief. Considerations include relieving the pressure setpoint, relieving capacity, and code requirements.

- Air-operated valves included in this modification are expected to use the plant instrument air system. This impact requires evaluation to ensure that the system maintains adequate positive operating margin.

- Based on site-specific analysis results, impacts on reactivity will require assessment due to potential changes in final feedwater temperature and expected transient associated with a fault at the H_2 facility or control failure of the steam/drains piping flow. No significant impacts are anticipated based on the thermal analysis and transient discussions previously provided.

- Water- or steam-hammer effects should be considered for system transients and for system startup (e.g., introducing steam into a cold pipe). It is noted that adequate steam-pipe drainage is critical with such a long run of outdoor steam pipe. Several drain pots may be needed along the pipe route and at low points to avoid water slug accumulation that could cause water or steam hammer.

- Provision for venting and draining piping and equipment will be required.

- The design should include the ability to sample the dispatched steam (or, at a minimum, the reboiler blowdown) to ensure that the steam flowing to the HTEF does not include radiological contamination.

- A new condenser connection will be added with this modification. Protection of condenser internals (e.g., tube impingement) should be considered when choosing the connection location, baffle, or sparger design, etc. Impacts to nozzle loading on the condenser walls need to be evaluated.

2.1.4.8   Structural

- Pipe supports are required for steam and drain piping, including pipe supports to route steam piping 0.5 km to the HTEF.

- Foundation designs are required for HSS equipment, transformers, disconnect switches, circuit breakers, etc.

- The addition of the demineralized-water tank should be evaluated as a potential flood source.

2.1.4.9   Programs

- The piping added to the MS and secondary drains system will need to be evaluated against FAC program criteria.

- The fire protection program should consider the impact of new cables and conduits on combustible loading. Additionally, the location of the HSS equipment will require review for accessibility by the fire brigade.

- The heat exchanger (steam reboiler), relief valves, check valves, and air-operated valves will need to be added to the FAC and fire-brigade program criteria.

- The welding required by the modification should be reviewed by the material compatibility and welding programs.

- The NERC program should review the impacts of the modification. The protective relays of the H_2-transmission line will interface with the plant existing generator and GSU-transformer differential relays to cover the new high-voltage breaker within their zone of protection.

2.1.4.10   Stakeholders

- Because the PRA model is affected by the modification, PRA is required as a stakeholder

- System Engineering, Operations, Training, and Maintenance groups are required as stakeholders due to the new equipment added to the plant

- The high-voltage aspects of the modification require Industrial Safety and Transmission as stakeholders

- Site-specific design may include transmitting information to the plant computer

- Security will be required as a stakeholder for the modification due to the installation of HSS equipment within the protected area. These items affect line-of-sight and lighting in the area.

It should be noted that routing the 12-in. steam piping from within the station protected area to the HTEF does not meet the definition of a three-dimensional pathway, as defined in NEI 09-05 [21];

therefore, it will not require a physical barrier or intrusion detection. Site-specific security input will be used in the design of pipe routing through protected-area fencing.

Site security may also take actions to accommodate the additional personnel and vehicles needed onsite if the HTEF happens to be located within the OCA.

The DAR provided in Appendix J and summarized above has not identified any concerns or obstacles beyond what would be expected for a typical nuclear modification of this magnitude. One key area of note, however, is the consideration of impacts on security as a stakeholder routing electrical and mechanical commodities across the protected-area boundary is not typical of general plant modifications.

2.1.4.11   Considerations of alternate designs

These considerations are not included in this report. See Ref. [19].

2.1.5   Additional Design Options and Considerations

2.1.5.1   Additional circuit breaker

An alternative option for H_2-line protection and the minimization of a single-point vulnerability (SPV) is the installation of two 345-kV circuit breakers in series to protect the hydrogen power line. This design prevents a generator trip; if one of the 345-kV breakers fails to trip and clears the line fault, the second breaker can trip before the generator protection trips. This option depends on the protection philosophy of the NPP and available land.

2.1.5.2   Shell-and-tube reboiler option

The design presented in this section uses a welded plate-and-frame heat exchanger as the extraction-steam reboiler. Other heat exchangers may also be used at the discretion of the plant. Discussions with different heat exchanger vendors have revealed that a kettle-style shell-and-tube reboiler may provide an alternate design solution. The kettle-style design simplifies the HSS arrangement by removing the need for an external steam drum at the expense of a larger physical footprint when compared to the welded plate-and-frame heat exchanger with a steam drum. The cost of this option is comparable to the welded plate-and-frame design; therefore, the option should be considered during detailed design.

In Section 3.1.5.2, a kettle-style shell-and-tube reboiler is used to illustrate the feasibility of the design implemented within the 500-MW$_{nom}$ preconceptual design. The contrasting complexity and size of these designs are illustrated through the respective P&IDs and physical reboiler arrangements (Appendix A).

2.1.5.3   Chrome-molybdenum or stainless steel steam piping to H_2 facility

In this section, carbon-steel piping is used to provide reboiler steam to the HTEF (refer to Section 2.2.2). Extended use of carbon steel under expected conditions may increase refurbishment or replacement frequency and could require the installation of a filter before the SOECs to avoid rust contamination. To reduce contaminants, alternative piping materials may be used. Both chrome-moly and stainless-steel piping are reasonable choices, which would reduce corrosive wear at the expense of higher material and labor costs. All piping selections in the plant protected area should follow nuclear piping codes and standards.

2.1.5.4   Net Metering in place of 100-MW$_{nom}$ electrical dispatch

Net metering uses several revenue meters in the power plant to measure power delivered in different areas and on separate transmission lines. An NPP can use net metering to supply energy to the HTEF behind the meter, avoiding the restrictions of a poorly placed revenue meter that would require power to be supplied to the grid before it reaches the HTEF.

NPP revenue meters are installed in different locations depending on the plant. They can be located inside TBs, on the high-voltage side of the GSU transformer, or out in the switchyard. The power line for

the hydrogen facility supply should be tied in behind the NPP's revenue meters. If a plant's revenue meters are located inside the TB or immediately after the GSU transformer, net metering should be considered.

The NPP and associated grid operators should have discussions early in the process to reach agreement regarding the tie-in location of the connecting point of the H_2 feeder. NPPs should consider net metering if they have limitations connecting the hydrogen feeder before the plant existing revenue meter.

2.1.5.5 *Decreased separation between NPP and HTEF*

The 500-m separation selected for this design was based on a generic PRA, assuming a large hydrogen detonation from a production facility approximately five times larger than this 100-MW_{nom} design (see Ref. [19] Section 3.3.2). There is a strong likelihood that relocating the 100-MW_{nom} HTEF adjacent to the NPP would be safe and would adhere to regulatory requirements, with the further addition of barriers or protective measures as needed. Decreasing the separation between the NPP and HTEF provides one cost-saving strategy since thermal piping and electrical transmission costs are reduced. Based on expected spacing of components within the protected-area boundary and the HTEF boundary, the minimum separation distance is anticipated to be approximately 250 m.

Section 4.3 illustrates the cost difference between this reduced separation option and the original 500-m spacing. Note, the location of the HTEF is highly dependent on available land and on the location of plant equipment, including the switchyard. Section 5.3 discusses siting limitations for the hydrogen-production facility.

Detailed cost breakdowns for the integrating a PWR with a 100-MW_{nom} HTEF with standoff distances of 250 and 500 m can be found [19; Attachment L]. Appendix I provides a detailed cost breakdown for 500 MW_{nom} HTEF option located 500 m from the NPP. Appendix B illustrates potential site arrangements for these options.

2.2 Major Equipment Required for Preconceptual Design

Equipment sizing is presented in the following sections based on the thermal and electrical analyses discussed in Sections 2.1.2 and 2.1.3, along with analyses included in Appendices C through G. As a site-specific project moves into the detailed design phase, the considerations for final pipe sizing and location of major equipment would be evaluated with a focus on constructability and overall integration cost.

Further design optimization related to the delivered temperature and pressure of the steam extracted from the NPP can be performed based on the site-specific requirements to enable the least cost of the NPP auxiliary equipment and connection commodities. Additionally, site-specific research into the location of the hydrogen plant with respect to the NPP may provide avenues for cost optimization through the reduction of electrical transmission, steam piping, and demineralized-water commodities. Continued optimization of this preconceptual design could drive further cost reductions.

2.2.1 Reboiler Sizing

Performance parameters for the steam reboiler are determined using the PEPSE analysis provided in Appendix C. Sizing information for input to reboiler vendors is provided considering 25-MW_{th} thermal power extraction in Table 6. Note that the parameters in Table 6 are at the connections to/from the reboiler.

Table 6. Reboiler sizing parameters for 25-MW$_{th}$ power extraction.

Connection Location	Mass Flow Rate		Temperature		Pressure	
Steam Supply from Cold Reheat	85,238	lbm/hr	364	°F	161	psia
Drain to Main Condenser	85,238	lbm/hr	120	°F	by Vendor	
Demineralized-Water Supply	73,777	lbm/hr	60	°F	140	psia
Steam Supply to H$_2$ Production Facility	73,777	lbm/hr	350	°F	120	psia

2.2.2   Piping and Reboiler-Feed-Pump Sizing Summary

Adding the hydrogen production facility to the existing NPP requires sizing of the various pipelines, which is performed based on the 25-MW$_{th}$ thermal extraction. Steam pipe sizes are determined in Appendixes D and E. Water-pipe sizes are determined in Appendixes F and G. Additionally, the reboiler feed pump is sized, and the reboiler drain-control-valve conditions are determined.

The results of pipe sizing are summarized as follows:

- Extraction steam piping to the H$_2$-plant steam reboiler (Appendix D)

Pipe size of 10-in., standard thickness (STD)-schedule carbon steel, 240 ft long was modeled, resulting in a maximum steam velocity of ~120 ft per second (ft/sec). Design pressure of 250 psig and design temperature of 400°F were selected to envelop the steam conditions.

- Process steam piping to the HTEF (Appendix E)

Pipe size of 12-in., STD-schedule carbon steel, 1750 ft long was modeled from the steam boiler to the H$_2$ plant, resulting in a maximum steam velocity of ~130 ft/sec. Design pressure of 150 psig and design temperature of 400°F were selected to envelop the steam conditions.

- Reboiler feedwater pump and piping (Appendix F)

For the pump discharge, a pipe size of 2.5-in., STD-schedule carbon steel, 240 ft long was modeled, resulting in a maximum water velocity of approximately 10 ft/sec. In the actual design, stainless steel was used. Later refinement of this design reduced this pipe length to ~50 ft (refer to Ref. [19, Attachment K]). Design pressure of 250 psig and design temperature of 150°F were selected to envelop the water conditions, including an additional 50% in pump-head rise to shutoff conditions.

For the pump suction, a 3-in. pipe size (one size larger than the discharge to lower suction velocity was selected), STD-schedule carbon steel, 40 ft long was modeled, and it resulted in a maximum water velocity of approximately 6.4 ft/sec. Stainless steel was used in the actual design. Design pressure of 50 psig and design temperature of 150°F were selected to envelop the water conditions.

- Pump size

Pump sizing is based on the nominal flow rate of 147.5 gpm and the nominal carbon steel pipe characteristics, resulting in a required pump total developed head of approximately 379 ft, requiring approximately 18 hp.

- Drain piping from the reboiler to the main condenser (Appendix G)

The drain-pipe size of 3.5-in., STD-schedule carbon steel, 220 ft long was modeled, resulting in a maximum water velocity of approximately 5.6 ft/sec. In the actual design, stainless steel was used. Design pressure of 200 psig and design temperature of 400°F were selected to envelop the drain conditions.

- Drain control-valve size

The drain control-valve sizing results in the following requirements:

- Drain flow: 85,238 lbm/hr (~172 gpm)
- Valve differential pressure: ~155.7 psid
- Valve inlet pressure: ~158 psia.

Note that due to a very high valve differential pressure, there is a high potential for valve flashing and cavitation; therefore, a severe-duty drain control valve should be considered for this application and for an internal baffle plate to protect condenser internals.

2.2.3 Demineralized-Water Storage Requirement

Onsite storage of demineralized water provides reserve capacity for periods when supply flow from the H_2 facility RO system is unavailable. The appropriate onsite capacity of stored demineralized water is at the discretion of plant engineering and management to ensure continued operation during maintenance evolutions, for example. This decision would likely consider the length of time that the HTEF is expected to be in use, the expected availability of the RO water supply, and upfront costs associated with installation of a large storage tank. The size (and therefore capacity) of the tank may also be limited by the available space near the H_2 steam reboiler, where a tank could be located. For this preconceptual design, a reserve capacity of 110,000 gallons was chosen. Appendix C shows that a demineralized-water flowrate of approximately 150 gpm is required to generate the desired steam flow to the HTEF. Therefore, a storage tank of 110,000 gallons would provide reserve capacity for approximately 8–12 hours of continuous operation. A tank of this size could be approximately 25 ft in diameter and 30-ft tall.

2.2.4 Major Equipment List

The major equipment required to implement the preconceptual modification as described in this report is summarized in Table 7. This listing is not intended to be all-inclusive, but to provide a high-level understanding of the major equipment needed in the design. Depending on site-specific design and configuration, additional commodities—such as tubing, small-bore piping, cable, and conduit—must also be considered. Materials needed for piping supports, transmission towers, among others are also excluded from this equipment list, but are included in the cost estimate in Appendix I.

Table 7. Major equipment needed for 100 MW_{nom} integration design.

No.	Item	Quantity	Description/Notes
1	Steam Reboiler	1	Refer to Section 4.3.1 for sizing information
2	Drain Cooler	1	
3	Steam Drum Tank	1	Approximately 4 ft diameter
4	Drain Receiver	1	Approximately 2 ft diameter
5	Demineralized-Water Storage Tank	1	10,000-gallon capacity
6	Reboiler Feed Dump	1	150 gpm at 380 ft TDH ($\cong$ 18 hp)
7	8-in. Steam Dispatch Air-Operated FCV	1	—
8	10-in. Non-Return Valve	1	—
9	10-in. Steam Manual Isolation Valves	3	Double isolation from crossunder pipe and isolation at reboiler
10	3.5-in. Air-Operated Level Control Valve	1	Refer to Section 2.2.2 for design conditions

No.	Item	Quantity	Description/Notes
11	2.5-in. Air-Operated Level Control Valve	1	Refer to Section 2.2.2 for design conditions
12	10-in. Self-Contained Backpressure-Regulating Valve	1	—
13	12-in. Steam Manual Isolation Valves	3	Isolation at reboiler and upstream/downstream
14	10-in. Carbon-Steel Piping with Fittings	~240 ft.	Schedule STD
15	12-in. Carbon-Steel Piping with Fittings	~1800 ft.	Schedule STD
16	2.5-in. Stainless Steel Piping with Fittings	~50 ft.	Schedule STD
17	3 in.-Stainless Steel Piping with Fittings	~40 ft.	Schedule STD
18	3.5 in.-Stainless Steel Piping with Fittings	~220 ft.	Schedule STD
19	3 in.-HDPE Piping with Fittings	~1800 ft,	Schedule 40
Electrical			
1	345-kV MOD Switch	2	45 kA short circuit
2	345-kV high-Voltage Circuit Breaker	1	45 kA short circuit
3	Transmission Towers for 345-kV Line	6	—
4	Coupling Capacitor Voltage Transformer	3	345 kV/120V
5	Protective Relay 50BF	1	—
6	Breaker Failure Lockout relay 86BF	1	—
7	Line-Differential Protection Relay 411L/87	2	—
8	Line-Differential Protection Relay 311L/87	2	—
9	Line-Differential Lockout Relay 86	1	—
10	Revenue Meter	3	—
11	795-kcmil Drake ACSR with OPGW Shield Wire	1600 m	—

3. 500 MW_{nom} HTEF DESIGN AND EQUIPMENT

Note: Text that is substantially different from the 100 MW$_{nom}$ HTEF Design and Equipment (Section 2) is marked with italics.

3.1 Design

3.1.1 Description of Modification

Similar to the 100-MW$_{nom}$ preconceptual design, process steam from the crossunder (cold-reheat) piping of the MS system will be extracted for the 500-MW$_{nom}$ design. *Given the larger volume of steam needed, extraction is taken from two crossunder lines, one on each side of the HP turbine, to avoid turbine imbalances. Manual isolation is provided for both carbon-steel lines at the tap location before the lines combine into a common header inside the TB. After routing out of the building, the header branches into two lines to supply the steam to the HTEF in two independent, identical reboiler loops. Each line is equipped with a station instrument air controlled-FCV before passing into the respective steam reboiler. The FCVs are used to admit cold reheat steam to the HTEF during operation and to isolate the steam supply when the HTEF is not in operation. Isolation of the steam supply is performed through manual operation of the FCVs during the normal HTEF shutdown sequence or can occur automatically in the event of a turbine trip. During a turbine trip, an interlock tied to the turbine trip logic will isolate the air supply to the HTEF steam supply FCVs, causing the valves to close and isolate the steam supply to the HTEF. This isolation function is desirable due to the use of cold reheat steam as the supply to the HTEF. When a turbine trip occurs, this steam supply is no longer available for electrolysis. Isolating the steam supply supports the shutdown of the HTEF. Turbine trip logic is discussed further in Appendix K.*

The P&ID provided in Appendix A shows the arrangement of steam extraction for this 500-MW$_{nom}$ design. *The two independent loops help to improve gradual startup of the system, reduce pipe sizing, and enable partial hydrogen production during system maintenance. Using a single reboiler loop would require larger, more-expensive equipment while increasing the potential for operating issues associated with startup and shutdown transients of the NPP and HTEF.*

The layout of the HSS equipment is the same as for the 100 MW$_{nom}$ HTEF design.

The 345-kV transmission line (H$_2$ feeder) and other electrical equipment for the HTEF is identical to that of the 100 MW$_{nom}$ HTEF design. A conceptual site plan showing the interfaces between the HTEF and the NPP is provided in Ref. [19, Attachment U].

3.1.2 Mechanical Design

3.1.2.1 *Selection of NPP steam-dispatch location*

The heat-balance diagrams included in Appendix C illustrate the expected plant operating conditions when considering station operation without thermal extraction and station operation with 105-MW$_{th}$ extraction to the HTEF. As previously noted, it is expected that only approximately 100 MW$_{th}$ are required by the HTEF while the remaining 5 MW$_{th}$ are extracted to account for thermal losses and potential inefficiencies in the HSS system.

The design conditions for the 105 MW$_{th}$ extraction system are the same as for the 25 MW$_{th}$ dispatch design, except as noted below.

3.1.2.2 *Selection of NPP drain-return location*

The preferred location selected to return the condensed drain flow is at the main condenser. The rationale is the same as for the 25-MW$_{th}$ dispatch design.

3.1.2.3   Thermal analysis

A PEPSE heat-balance model of a reference 4-loop Westinghouse PWR NPP was used to determine the impact on the plant considering various levels of thermal extraction. The analysis methodology and approach are the same as for the 25-MW_{th} dispatch design. Appendix C provides heat-balance drawings showing the impact to the NPP considering 105-MW_{th} power-extraction levels. Table C-2 in Appendix C provides the station impact to significant parameters throughout the power cycle, considering 105-MW_{th} power extraction.

3.1.2.4   Impact on plant hazards

Impact is the same as for the 25 MW_{th} dispatch design.

3.1.2.5   Evaluation of plant transients

The methodology and approach for the evaluation of plants transients are the same as for the 105 MW_{th} dispatch design. PEPSE heat-balance diagrams (shown in Appendix C) are developed to evaluate the impact of extracting steam from the nuclear power cycle to supply thermal energy to a reboiler unit used to preheat process steam for H_2 production. Table 8 provides a summary of the important parameters for the 105-MW_{th} extraction. Note that only parameters exhibiting some degree of change are shown. Other values, such as most system temperatures, show virtually no change. Additional details are presented in Appendix C.

Table 8. Summary of important system parameters for 105-MW_{th} extraction.

Parameter	Unit	Extraction Level		Total Δ for 2 Trains
		0 MW_{th}	105 MW_{th}	
Reactor Thermal Power	MW_{th}	3659	3659	—
Generator Output	MW_e	1239.6	1217.2	-22.47 MW_e
Main Stream Flow	Mlb/hr	16.28	16.28	0.00%
Cold-Reheat Flow	Mlb/hr	12.73	12.70	-0.20%
105 MW_{th} Thermal Extraction Flow	lb/hr	0	355,193	—
Extracted Steam Fraction of Cold-Reheat Flow	%	0	2.80	2.80%
Remaining Steam to MSRs	Mlb/hr	12.73	12.35	-2.99%
Hot-Reheat Flow	Mlb/hr	11.26	10.90	-3.18%
Heater Drain Forward Temperature	°F	339.7	337.0	-2.7°F
HP FWH Cascading Drain Flow	Mlb/hr	1.39	1.38	-0.92%
LP FWH Cascading Drain Flow	Mlb/hr	2.42	2.37	-1.72%
Heater Drain Tank Pressure	psia	185.5	179.5	-6.0psi

NOTE: Cascading drain conditions are averaged. Individual FWH drain lines may have higher variations in conditions. Changes from 0 to 105 MW_{th} are calculated in Microsoft Excel. There may be slight differences due to truncation of values when entering the values in the table.

As displayed in Table 8, the 105-MW$_{th}$ extraction from cold reheat requires 355,193 lb/hr (~177,597 lb/hr per train) of steam; this corresponds to approximately 2.80% (1.4% per train) of total cold-reheat flow. Normal startup of the HTEF involves startup of one reboiler train at a time, which requires opening of the steam-extraction line from cold reheat to the reboiler unit. This operation diverts a small portion, approximately 1.4% (for one train), of the total cold-reheat flow and reduces the hot-reheat flow to the low-pressure (LP) turbines by approximately 1.6% (for one train). These changes result in a 22.4-MW$_e$ (11.2 MW$_e$ per train) reduction in main generator output, which represents approximately 1.8% of the total generator output.

It is also noted that the extraction of steam from the cycles, as described in this report, is operationally similar to an LP turbine bypass. Plants are typically designed with approximately 25% or more turbine-bypass capability, and plant transients are already analyzed with turbine bypass greater than the level of steam extraction described. Similarly, for normal shutdown (shutting one reboiler train at a time) of the H$_2$ plant, the changes are relatively small and should not cause a significant burden on the existing plant operation. Only during an unexpected event, such as total loss of power to the HTEF, could a transient involving the shutdown of two reboiler trains at the same time be expected. However, even under this event, the impact on the nuclear plant is not of significant concern. Nuclear plant response to this type of transient is described in the next section.

3.1.2.6   Impact on core reactivity

The impact on core reactivity associated with extracting steam from the secondary cycle must be assessed for any plant-specific modification as described within this report. Based on 2.8% of secondary mass flow extraction, reactivity impacts are not anticipated to be insignificant. *However, even sudden perturbations resulting from events at the HTEF should not exceed the capabilities of the normal NPP controls-system response. From a mechanical-design perspective, the largest impact to the NPP would come from an event in the HSS. An event that suddenly halts the HSS would impact the NPP in a manner similar to a load-rejection event. That is, a loss of HTEF steam demand would result in a plant control-systems response similar to that which occurs when there is a loss of generator load. In the case of a ~3% load rejection, the NPP rod-control system should provide ample control capability to prevent the need for any protective functions to actuate or the need for any immediate operator actions. Operators would follow their indications to take actions appropriately using alarm response or other plant operating procedures. In the case of a steam-line break in the HSS piping, there is no discernible difference from a break in other areas of steam piping in the NPP. If a break occurs, the automated and operator responses will be the same as they would be for another steam break somewhere in the NPP steam systems. The HTEF steam piping will be equipped with isolation valves that will enable isolation of the HSS system and continued operation of the NPP. As with a loss of HTEF steam demand, operators would follow their indications to take actions appropriately using an alarm response or other plant operating procedures.*

3.1.3   Electrical Design

The HTEF requires 500 MW$_e$ power for the electrolysis process and approximately 50 MW$_e$ for auxiliary loads. Using a power factor of 0.92 for HTEF processes, the total power required for by the HTEF is 600MVA. Spacing between the electrolyzers and NPP equipment is approximately 0.5 km; therefore, power is supplied from the NPP via a 345-kV transmission line spanning the plant separation.

3.1.3.1   Selection of NPP electrical-dispatch location

The methodology and approach for the evaluation of plant transients is the same as for the 100 MW$_{nom}$ HTEF, except as noted below. The electrical-physical layout diagram in Appendix B illustrates the preferred electrical system tie-in point, which is the high-voltage side of the NPP's main GSU transformer for the 500 MW$_{nom}$ HTEF.

3.1.3.2 Electrical design and equipment within the NPP boundary

The design and equipment for the 500 MW$_{nom}$ HTEF is identical to the 100 MW$_{nom}$ HTEF, except as noted below.

The 345-kV transmission line will be tapped to the line between the NPP GSU transformer's high-voltage bushing and the switchyard. The H$_2$ transmission line routes over a transmission tower to a 345-kV circuit breaker and its two MOD switches for line protection and maintenance. PTs will be installed between the MOD switch and the high-voltage breaker for new line's revenue meters. This equipment is in the NPP protected area or yard area, depending on available space in the protected area. For a plant-separation distance of 500 m, the H$_2$ transmission line will be routed over six more transmission towers to reach the HTEF area.

At the HTEF, there are two two-winding stepdown transformers rated for 345 kV-delta/ 34.5 kV-wye, 190/253/306MVA ONAN/ONAF/ONAF, 9% nominal impedance H-X. The 34.5-kV windings are resistance grounded. Within the H$_2$ plant are nine two-winding stepdown transformers rated for 34.5 kV-delta/13.8 kV-wye, 42/56/70 MVA ONAN/ONAF/ONAF, 7.5% nominal impedance H-X 34.5kV/ 13.8 kV to supply power at the 13.8-kV level to the H$_2$ electrolyzers. The equipment at the HTEF is part of the HTEF design and is outside the scope of this report. See Ref. [19, Attachment V] for the H$_2$ transmission-line electrical-physical layout.

3.1.3.3 Transmission-line control and protection

Control and protection are identical to that the 100 MW$_{nom}$ HTEF design.

3.1.3.4 Power requirements for hydrogen steam supply equipment

Power requirements are identical to the 100 MW$_{nom}$ HTEF design.

3.1.3.5 Switchyard arrangement and offsite power

Switchyard arrangements and offsite power are identical to the 100 MW$_{nom}$ HTEF design.

3.1.3.6 Electrical short-circuit and load-flow/voltage-drop analysis

The design and analysis for the 500 MW$_{nom}$ HTEF design is identical to that of the 100 MW$_{nom}$ HTEF design, except as noted below. The stepdown transformer supplying the HTEF is specified as a *two-winding unit to supply 500* MW$_e$ to the HTEF, plus 10% additional capacity for auxiliary loads.

A short-circuit analysis was performed in ETAP to determine estimated equipment short-circuit ratings and aid in sizing the HTEF stepdown transformer. The HTEF stepdown transformers were modeled as *190/253/306MVA ONAN/ONAF/ONAF two-winding* transformers. The high-voltage winding is connected in delta and the medium-voltage winding is connected in wye. The short-circuit analysis model shows that a *9% nominal impedance between the H-X windings* (with ±7.5% tolerance) on *the 190 MVA* self-cooled base of the secondary windings allows for the use *of 40-kA 34.5-kV circuit breaker and 40-kA 13.8-kV* medium-voltage switchgear at the HTEF.

Similar to the 100-MW$_{nom}$ HTEF, an ETAP model shows that the addition of the HTEF has a negligible impact on the existing NPP equipment. The analysis and results for the 500 MW$_{nom}$ HTEF design is identical to the 100 MW$_{nom}$ HTEF design, except as noted below.

The load-flow analysis shows the *316 MVA* top rating of the HTEF stepdown transformers is sufficient to carrying the full load of the HTEF. The voltage drop across the 0.5-km high-voltage transmission line is not significant. *For the 500-MW$_{nom}$ HTEF, a two-conductor bundle, such as a 2-1113 kcmil Bluejay ACSR or higher, based on common transmission practices in the area, is recommended based on the line thermal loading.*

The voltage-drop analysis performed with the ETAP model shows that the hydrogen-plant stepdown transformer does not require an on-load tap *changer if the transmission voltage is maintained within approximately a ±2.5% bandwidth.* Per NUC-001, this applies to NPPs that operate per a voltage schedule and to NPPs that require strict voltage regulation for offsite power (assuming the offsite power source is supplied from the same location in the transmission system).

3.1.3.7   Protective relaying design

The design is nearly identical to the 100 MW_{nom} HTEF design. Table 9 shows the required trip logic for different fault locations following electrical tie-in of the hydrogen plant.

Table 9. Electrical fault condition trip logic.

Fault Location	Initial Trip Device	H_2 Breaker Failure Trip Device
Existing high-voltage line and line tap to new high-voltage circuit breaker	Existing high-voltage switchyard circuit breakers Generator circuit breaker (if equipped) New high-voltage circuit breaker	None
New high-voltage line to HTEF	New high-voltage circuit breaker New high-voltage stepdown transformer circuit breaker	Existing high-voltage switchyard circuit breakers Generator circuit breaker (if equipped)
HTEF transformer	New high-voltage stepdown transformer circuit breaker inside the H_2 island *34.5 kV circuit breakers in the HTEF* *13.8 kV breakers in the HTEF*	New high-voltage circuit breaker

NOTE: Same as Table 4 for 100 MW_{nom} HTEF design, except for the addition of the last two lines.

3.1.3.8   Electrical-transient analysis

Sensitivity analysis shows that the HTEF load can be increased up to the maximum output power rating of the generator without causing the generator to become unstable following a trip of the high-voltage transmission line feeding the HTEF, either with or without a fault. This bounds the design being considered for the 500-MW_{nom} HTEF. Note that this model is based on typical plant and transmission system data, which may not be representative of the available capacity for all plants.

3.1.3.9   Bulk electric system regulatory impacts

Similar to the 100-MW_{nom} design, the high-voltage transmission line supplying the HTEF is classified as a BES element because the line is connected to a radial system with a generator that has a gross individual-nameplate rating of greater than 25 MVA and a voltage of 100 kV or above. The BES classification subjects the transmission line and connected facilities—e.g., circuit breakers, disconnect switches, instrument transformers, and protective relays—to compliance with NERC Reliability Standards. Table 4 provides a summary of the applicable NERC Reliability Standards. Note that the NPP is already subjected to the following standards.

3.1.4   Instrumentation and Controls Design

3.1.4.1   *Operator-control capabilities*

The operator-control capabilities for this 500-MW$_{nom}$ design are identical to those capabilities described in the design for the 100 MW$_{nom}$ HTEF. Given the duplication of HSS equipment (e.g., reboilers, pumps, and tanks), equipment-specific controls will need to be duplicated in this area based on the new equipment. A single HMI can still be used in the main control room for indication and control of steam-supply and electrical-transmission equipment.

3.1.4.2   *Available process parameters for monitoring*

Available processing parameters for monitoring are identical to the 100-MW$_{nom}$ design.

3.1.4.3   *Response to faulted conditions*

Overall response to faulted conditions is similar to the 100-MW$_{nom}$ design, with differences as noted below.

Extraction-steam leak to reboiler—Response depends on the severity and location of the leak. With two trains of reboilers, the leak could be isolated to the affected train, allowing the second train to operate. HTEF steam supply would be halved. If the leak is located so that both trains must be isolated, then H$_2$ plant shutdown would occur. If isolation is not possible, a manual trip of the plant NPP would occur, which is similar to the response to an unisolatable MS line leak. The addition of a remote manual (motor- or air-operated valve) at the extraction point would allow for the online construction of parts of the steam-extraction line and would facilitate positive isolation in the event of a steam leak in the steam-extraction line. Steam-isolation transients are described in this report.

- Process steam leak to HTEF—With two separate trains of process steam, it may be possible to isolate the affected train. The leak could be isolated to the affected train, allowing the second train to operate. HTEF steam supply would be halved. This transient is described in the transient section of this report. The generator would pick up load from the affected train and the grid would absorb the additional load.

- Reboiler drain valve fails closed—This should not occur because the valve is set to fail open. However, if this event were to occur, the level would rise in the affected reboiler. Either the extraction steam-supply valve for the affected train would close on high-high level, or an emergency dump valve would open to the lower level. It is recommended to have a drain-bypass valve open on high level and the steam line isolated on high-high level. The affected train could be isolated, allowing the second train to operate. HTEF steam supply would be halved.

- Reboiler drain valve fails open—The level in the affected reboiler would drop and steam could be passed to the condenser. A low-level switch should be implemented to close the steam-admission valve on low-level and drain valve open position. The affected train could be isolated, allowing the second train to operate. HTEF steam supply would be halved.

- Extraction steam supply valve fails open—This should not occur because the valve is set to fail closed. However, if this event were to occur, the design pressure of both sides of the reboiler are equal to or greater than the steam conditions. The amount of condensation would be controlled by the demand from the HTEF. The condensate level would be controlled by the condensate drain valves. With normal operation of the reboiler feed supply, the plant would continue to operate normally.

    - Extraction steam supply valve fails closed—With two trains of extraction steam supply and reboilers, a closed valve will only affect one train. The level in the affected reboiler level would fall; the condensate drain line would maintain level by closing. One train of process steam to the H_2 plant would cease to flow. Steam flow to the LP turbines would increase by ~1.7%. The closure of the steam line may start to increase the level in the steam generator. The feedwater control system would reduce feedwater flow to match the reduced steam demand and stabilize the level. The transient to the grid is described below. In the longer term, the generator output could be reduced to match the grid demand.

    - Rapid trip of HTEF—Steam demand would cease, the process feed level on the hydrogen-side of the reboiler would increase, and the supply-water admission valve would close in response. This would remove cooling from the plant-side of the reboiler, and steam condensation would decrease. The condensate drain valve would close to maintain level, and the HSS going to the reboiler would be rerouted to the LP turbines. Steam flow to the LP turbines would increase by 3.3%. The closure of the steam line would immediately start to increase the level of the steam generator. The feedwater-control system would reduce feedwater flow to match the reduced steam demand and stabilize level. The transient to the grid is described below. In the longer term, the generator output could be reduced to match grid demand.

    - Short in high-voltage line—Overcurrent protection, as discussed in this report, would trip the HTEF, and the balance of the transient would be like the rapid trip of the HTEF.

    - Open in high-voltage line—An open in the high-voltage line would trip the HTEF and the NPP would respond in the same manner as a rapid trip of the HTEF.

3.1.4.4   Design-attribute review

When performing an engineering change in accordance with IP-ENG-001, the responsible engineer completes the DAR, which is a series of questions that aids in identifying impacted disciplines, stakeholders, and programs. As part of the preconceptual design, a sample DAR has been completed and provided as Appendix J. While this effort must be performed on a plant- or design-specific basis when performing a similar modification, the information is provided as an example to guide the process.

The following design attributes are unique to the 500-MW$_{nom}$ design.

3.1.4.5   Electrical

- This conceptual design covers the installation of 0.5 km of 345-kV transmission line between the GSU transformer and H_2 plant. A 345-kV high-voltage circuit breaker and two associated disconnect switches, PTs, and transmission-line tower will be installed in the plant's protected area or the yard area, depending on the available space around the GSU transformer. *End of the line, inside the HTEF will have two stepdown transformers to step the power down from 345 to 34.5 kV. Each transformer will have one 345-kV circuit breaker and two 345-kV disconnect switches. Also, two outdoor 34.5-kV buses with nine 34.5-kV breakers, each connected to stepdown transformer, will step the power down from 34.5 kV to 13.8 kV switchgears.*

  - The load-flow analysis demonstrates the change in the switchyard voltage due to the addition of the *500-MW$_e$* electrical load plus auxiliaries is negligible. Thus, there is no impact to generator VAR loading, which is controlled based on switchyard voltage.

  - The load-flow analysis demonstrates the change in the switchyard voltage due to the addition of the *500-MW$_e$* electrical load plus auxiliaries is negligible. Therefore, the status of offsite power voltage regulating devices is not impacted.

3.1.4.6   Mechanical

Mechanica considerations are identical to the 100 MW$_{nom}$ HTEF design.

3.1.4.7   Instrumentation and controls

I&C are identical to the 100 MW$_{nom}$ HTEF design.

3.1.4.8   Structural

Structural considerations are identical to the 100 MW$_{nom}$ HTEF design.

3.1.4.9   Programs

Program considerations are identical to the 100 MW$_{nom}$ HTEF design.

3.1.4.10   Stakeholders

Stakeholders are identical to the 100 MW$_{nom}$ HTEF design.

3.1.5   Additional Design Options and Considerations

3.1.5.1   Additional circuit breaker

Developing site-specific design criteria may include alternatives to the design proposed within this report. Options for an additional circuit breaker, different piping materials, onsite RO, and net metering are all discussed in reference to the 100 MW$_{nom}$ HTEF design and are equally relevant for the 500 MW$_{nom}$ design. Further alternate design options are described below.

3.1.5.2   Plate-and-frame reboiler option

The preconceptual design put forth in this section uses a shell and tube-style heat exchanger as the extraction steam reboiler. Other heat exchangers may also be used at the discretion of the plant. Discussions with other vendors have revealed that a plate-and-frame reboiler may provide an alternate design solution. The plate-and-frame design is more compact compared to the kettle-style reboiler, but it is at the expense of a more-complex arrangement required through the addition of an external steam drum. The cost of this option is comparable to the kettle-style shell-and-tube heat exchanger and should be considered during detailed design for a similar modification.

In Section 2, a plate-and-frame reboiler was provided for the 100-MW$_{nom}$ preconceptual design to show its feasibility. The contrasting complexity and size of these designs is illustrated through the respective P&IDs and physical reboiler arrangements in Appendix A.

3.1.5.3 Main steam extraction

Section 5.4 discusses in detail the limitations of cold-reheat extraction. Of notable importance is the potential for imbalances and stresses on the turbines with large volumes of extraction and available space within the TB for the routing of two 14-in. steam lines. Main steam extraction is a viable alternative to the location used for this report. Table 10 highlights the benefits and drawbacks of both locations. The improved efficiency of cold reheat is expected to make this option financially preferable at this scale, but other factors, such as spatial availability and turbine loading, should be considered in detail to determine which extraction location is best for a given plant. Turbine manufacturers should be consulted to validate conclusions of the site. Appendix C provides detailed thermal analysis of both extraction locations.

Table 10. Pros and cons of different extraction locations for 500-MW$_{nom}$ design.

	Pros	Cons
Cold-Reheat Extraction	Greatest plant efficiency (+15.5 MW$_e$ vs. main steam extraction) Lower-temperature extraction than Main Steam can lower material and maintenance costs	Larger piping is more expensive and harder to route through the TB Reduced mass flow to LP turbines can cause wear on the turbines and may reduce the life span of equipment
Main Steam Extraction	Smaller piping is less expensive and easier to route through the TB No turbine imbalances	Lower plant efficiency than cold-reheat extraction high-energy line-break analysis will be required due to steam conditions Higher temperature extraction requires more resilient materials for piping and greater HSS equipment costs HP turbine operating pressure may drop below minimum-pressure limit due to lower mass flow

Main steam and cold reheat are the best locations for steam extraction based on the steam properties. Extracting steam too far upstream will result in losses to plant efficiency by removing high-quality steam from the NPP power cycle. Extractions too far downstream provides low-quality, low-energy steam for the HTEF, decreasing electrolyzer efficiency. It is anticipated that cold reheat will be the preferable location at low extraction levels (i.e., 3% of mass flow).

3.1.5.4 Decreased separation between NPP and HTEF

The separation is identical to the 100 MW$_{nom}$ HTEF design.

3.2 Major Equipment Required for Preconceptual Design

The approach and methodology are identical to the 100 MW$_{nom}$ HTEF design.

3.2.1 Reboiler Sizing

Performance parameters for the steam reboiler are determined using the PEPSE analysis provided in Appendix C. Sizing information for input to reboiler vendors is provided considering 105-MW$_{th}$ thermal power extraction in Table 11. Note that the parameters in Table 11 are at the connections to/from the reboiler.

Table 11. Reboiler sizing parameters for 105-MW$_{th}$ power extraction.

Connection Location	Mass Flow Rate		Temperature		Pressure	
Steam Supply from Cold Reheat	355,193	lbm/hr	~360	°F	~154	psia
Drain to Main Condenser	355,193	lbm/hr	120	°F	by Vendor	

Demineralized-Water Supply	306,980	lbm/hr	60	°F	140	psia
Steam Supply to HTEF	306,980	lbm/hr	350	°F	120	psia

3.2.2 Piping and Reboiler-Feed-Pump Sizing Summary

Adding the hydrogen production facility to the existing NPP requires sizing the various pipelines, which is performed based on the 105-MW$_{th}$ thermal extraction. Steam-pipe sizes are determined in Ref. [19, Attachment B] and Ref. [19, Attachment C]. Water-pipe sizes are determined in Ref. [19, Attachment D] and Ref. [19, Attachment E]. In addition, the reboiler feed pump is sized and reboiler drain-control valve conditions are determined.

The results of pipe sizing are summarized as follows:

- Extraction steam piping to the H$_2$ plant steam reboiler Ref. [19, Attachment N].

  Two 14-in. pipes were connected to the cold-reheat pipes on either side of the HP turbine for extraction. Each of these lines was STD-schedule carbon steel and 40 ft long. These lines joined to a 20-in., STD-schedule carbon-steel header that was 200 ft long. After routing out of the TB, the header once again split into two 14-in., STD-schedule carbon-steel lines that spanned 20 ft each until reaching their respective steam reboilers. Maximum steam velocity was ~153 ft/sec. Design pressure of 250 psig and design temperature of 400°F were selected to envelop the steam conditions.

- Process steam piping to the HTEF Ref. [19, Attachment O].

  Pipe size of 18-in., STD-schedule carbon steel and 1750 ft long was modeled from the steam boiler to the HTEF, resulting in a maximum steam velocity of ~130 ft/sec. Design pressure of 150 psig and design temperature of 400°F were selected to envelop the steam conditions.

- Reboiler feedwater pump and piping Ref. [19, Attachment D].

  For the pump discharge, a pipe size of 3.5-in., STD-schedule carbon steel and 240 ft long was modeled, resulting in a maximum water velocity of approximately 10 ft/sec. *Stainless steel piping was used for the actual design, resulting in a conservative pump sizing.* Design pressure of 250 psig and design temperature of 150°F were selected to envelop the water conditions, including an additional 50% in pump head rise to shutoff conditions.

  For the pump suction, a *4-in. pipe size—*one size larger than the discharge to lower suction velocity was selected—of STD-schedule carbon steel and 40 ft long was modeled, and it resulted in a maximum water velocity of approximately *7.7 ft/sec*. Stainless steel was used in the actual design, *resulting in a conservative pump sizing*. Design pressure of 50 psig and design temperature of 150°F were selected to envelop the water conditions.

- Pump size

  Pump sizing is based on the *nominal flow rate of 306.8 gpm* and the nominal carbon-steel pipe characteristics, resulting in a required pump total developed head of approximately *367 ft, requiring approximately 36 hp*.

- Drain piping from the reboiler to the main condenser Ref. [19, Attachment E].

  The *drain-pipe size of 5-in.*, STD-schedule carbon steel and 220 ft long was modeled, resulting in a maximum water velocity of *approximately 6 ft/sec*. In the actual design, stainless steel was used. Design pressure of 200 psig and design temperature of 400°F were selected to envelop the drain conditions.

- Drain control-valve size

Drain control-valve sizing results in the following requirements:

- Drain flow: 177,597 lbm/hr (~358.8 gpm)
- Valve differential pressure*: ~1552.0 psid*
- Valve inlet pressure: *~154.1 psia.*

Note that due to a very high valve differential pressure, there is a high potential for valve flashing and cavitation. Therefore, to protect condenser internals, a severe-duty drain control valve and an internal baffle plate should be considered for this application.

3.2.3   Demineralized-Water Storage Requirement

Design considerations are similar to those for the 100 MW$_{nom}$ HTEF design. For the purposes of this preconceptual design, a reserve capacity of 110,000 gal was chosen. Ref. [19, Attachment A] shows that a demineralized-water flowrate of approximately *310 gpm per loop* is required to generate the desired steam flow to the HTEF. Therefore, a storage tank of 110,000 gal would provide reserve capacity for *approximately 4–6 hours* of continuous operation. A tank of this size is expected to be approximately 25 ft in diameter and 30 ft tall.

3.2.4   Major Equipment List

The approach and considerations are similar to those for the 100 MW$_{nom}$ HTEF design. The major equipment required to implement the preconceptual modification as described in this report is summarized in Table 12.

Table 12. Major equipment needed for 500 MW$_{nom}$ integration design.

No.	Item	Quantity	Description/Notes
1	Steam Reboiler	2	Refer to Section 3.2.1 for sizing information
2	Drain Cooler	2	
3	Drain Receiver	2	Approximately 3 ft diameter
4	Demineralized-Water Storage Tank	2	10,000-gallon capacity
5	Reboiler Feed Dump	2	310 gpm at 367 ft TDH (approximately 36 hp)
6	12-in. Steam Dispatch Air-Operated FCV	2	—
7	14-in. Non-Return Valve	2	—
8	14-in. Steam Manual Isolation Valves	10	Double isolation at both crossunder tie-ins, double isolation after header branches, and isolation to reboiler
9	5-in. Air-Operated Level Control Valve	2	Refer to Section 3.2.2 for design conditions
10	3.5-in. Air-Operated Level Control Valve	2	Refer to Section 3.2.2 for design conditions
11	14-in. Self-Contained Backpressure-Regulating Valve	2	—
12	18-in. Steam Manual Isolation Valves	6	Isolation at reboiler and upstream/downstream isolation PCV
13	14-in. Carbon-Steel Piping with Fittings	~120 ft.	Schedule 30

No.	Item	Quantity	Description/Notes
14	18-in. Carbon-Steel Piping with Fittings	~3500 ft.	Schedule STD
15	20 in. Carbon-Steel Piping with Fittings	~200 ft.	Schedule 20
16	3.5 in. Stainless Steel Piping with Fittings	~480 ft.	Schedule STD
17	4 in. Stainless Steel Piping with Fittings	~80 ft.	Schedule STD
18	5 in. Stainless Steel Piping with Fittings	~440 ft.	Schedule STD
19	3.5 in. HDPE Piping with Fittings	~3600 ft,	Schedule 40
Electrical			
1	345-kV, 300-A MOD Switch	2	50 kA short circuit
2	345-kV, 300-A High-Voltage Circuit Breaker	1	50 kA short circuit
3	Steel Poles for 345 kV line	6	Transmission line tower
4	Coupling Capacitor Voltage Transformer (CCVT)	3	345 kV/120V
5	Protective Relay 50BF	1	—
6	Communication System: Cabinet NEMA 4X with meters and auxiliary telecommunication for revenue meters	1	—
7	A standalone HMI for control and indications of the H_2 power line and steam supply, in the main control room	1	—
8	Breaker Failure Relay (50BF)	1	—
9	Breaker Failure Lockout Relay (86BF)	1	—
10	Line-Differential Protection Relay 411L/87	3	—
11	Line-Differential Protection Relay 311L/87	3	—
12	Line-Differential Lockout Relay 86	1	—
13	Revenue Meter	3	—
14	1113 knmil Bluejay ACSR with OPGW Shield Wire	3200 m	Transmission line cable outdoor

4. PLANT INTEGRATION COST ESTIMATING

The development of an accurate cost estimate for a nuclear-integrated hydrogen-production facility requires a detailed understanding of plant specifications, vendor price estimates, and indirect costs associated with the project construction and development. For each of these general preconceptual designs, a cost estimate is developed for the integration activities within the scope of the NPP only; costs associated with design and construction of the equipment inside the HTEF boundary are excluded from these estimates. The Association for the Advancement of Cost Engineering (AACE) has developed a classification system for assessing the expected accuracy of cost estimates (see Ref. 21). Based on the maturity level of project's definition deliverables and the use of this report as a preconceptual guide, these cost estimates fall into Class 5. Following the methodology described by this class, the accuracy of these estimates is expected to vary between -50% and +100%. The actual value depends on the risk and suitability of assumptions associated with each cost item. Plant-specific studies are required to improve these assumptions and increase estimated accuracy. Vendor estimates should be included on a plant-specific basis. The purpose of these estimates is to allow plant owners to understand the magnitude of capital costs required for the NPP-associated modifications with pursuing a 100-MW_{nom} and 500-MW_{nom} HTEF addition. This study provides a quantifiable reference for engineering, installation, and turnover and procurement costs for a project of a similar magnitude. This study can be used to inform plant-specific feasibility studies and assess the capital necessary to pursue nuclear-integrated hydrogen at the scale investigated.

4.1 Scope of Included Costs

These estimates aim to consider all costs associated with NPP modifications included in Table 7 and Table 12. A cost-analysis breakdown was performed for each of the following activities:

- HSS
- Civil work (e.g., excavation, disposal, backfill, and caisson)
- Concrete work (e.g., foundation, embedment, formwork, and reinforcing)
- Mechanical equipment (e.g., reboiler and demineralized-water storage tank)
- Piping (e.g., above-ground, buried, supports, valves, and insulation)
- Electrical equipment (e.g., heat tracing, control panel, and transformer)
- I&C
- Steel supports
- Electrical and transmission line
- Civil work (e.g., excavation, disposal, backfill, and caisson)
- Concrete work (e.g., foundation, embedment, formwork, and reinforcing)
- Switchyard (e.g., transmission-tower pole and hardware, breakers and disconnects, transformers, and wiring)
- Electrical equipment (e.g., revenue meter, grounding, and control panels)
- Cables and conduits
- HMI
- Steel supports.

4.1.1   Methodology

Estimates are based on an engineer, procure, construction management (EPCM) multiple contract approach. This approach has one main contractor, typically an architect/engineer firm to produce the design, assist in the procurement of goods and services, and provide construction-management (CM) services during construction. The EPCM contractor generally acts as an agent for the owner when purchasing such goods and services, meaning contracts and purchase orders are written on the owner's letterhead.

These cost estimates are developed using a mix of semi-detailed unit costs with assembly-level line items and detailed unit costs with forced detailed takeoff (i.e., detailed-takeoff quantities generated from preliminary drawings and incomplete design information). As such, these estimates are generated using a deterministic estimating method with many unit-cost line items. These estimates were developed with a factored approach using previous HTEF costs estimates and other relevant cost estimates as a basis.

Quantity development is dependent on the method used to create the line-item estimate. Item quantities are identified based on the major equipment identified in Table 7 and Table 12, which was determined through thermal and electrical analyses (see Sections 2.1.2, 2.1.3, 3.1.2, and 3.1.3). Capacity-factored or equipment-factored cost estimates do not use quantities of materials for cost estimation.

4.1.2   Cost Items

To further break down project costs, items were categorized into direct, indirect, and contingency costs; escalation costs were not included. Direct costs are those expenses directly tied to the construction of HSS and electrical and transmission line equipment identified in Section 3.1.3. To support project-construction and labor efforts, indirect costs were also considered. A buffer for unanticipated issues is covered through contingency costs. Each of these categories is described in greater detail below.

4.1.3   Direct Costs

The cost associated with the addition of new permanent equipment is broken down into five subcategories: labor, materials, subcontract, construction-equipment, and process-equipment costs. The cost of each item is made up of one or more of each of these costs.

4.1.3.1   Labor

Construction-labor cost considers wage rates, installation hours, labor productivity, labor availability, and construction indirect costs. Installation hours represent the labor-hours to install an item and collectively all craft hours to install the entire scope of facilities. Labor productivity is evaluated based on factors such as jobsite location, job position, and site congestion. A regional nuclear power labor-productivity multiplier of 1.6 is included to account for the additional effort, oversight, and requirements associated with work performed within an NPP in a congested area without radiation protection, and a portion of the work that must be performed during an outage. This productivity factor has been developed based on historical data and is dependent upon several factors, such as congestion, outage or non-outage activities, and the level of radiation protection. Installation hours are increased proportional to this productivity factor. The labor wage rate was selected using the prevailing wage in Bloomington, Illinois. This data was obtained from "RS Means Labor Rates for the Construction Industry," 2022 edition. Costs have been added to cover Social Security, worker's compensation, and unemployment insurance.

4.1.3.2   Material

The pricing for permanently installed materials are based on S&L in-house data, vendor catalogs, industry publications, and other related projects. Major material quantities are described in Table 7 and Table 12.

4.1.3.3 Subcontract

Subcontract costs as defined within this estimate are all-inclusive costs. This means there are no additional markups, such as general conditions, overheads, or other indirect construction costs associated with the line item.

4.1.3.4 Construction equipment

Construction-equipment cost is included on each line item, as needed, based on the type of activity and construction-equipment requirements to perform the work. This includes costs for rental of all construction equipment, fuel, oil, and maintenance. Equipment operators are included in direct labor costs.

4.1.3.5 Process equipment

Pricing for permanently installed equipment is based on S&L in-house data, vendor catalogs, industry publications, and other related projects. Equipment pricing was reviewed to ensure that the following criteria were addressed and taken into consideration where necessary.

4.1.3.6 Indirect costs

All accompanying costs that do not result from the direct installation of NPP equipment to support hydrogen production are considered indirect costs. These costs are categorized into additional labor costs, site overhead, other indirect construction, and indirect project costs.

4.1.3.7 Additional labor costs

To support the labor associated with the construction and implementation of equipment, there are several ancillary labor costs to consider. These include the additional pay of labor supervisors beyond the prevailing wage rate, show-up time, and overtime. The cost of overtime pay and extended hours caused by worker inefficiency are included based on a 50-hour work week (5–10-hour days). Further overtime and *per diem* costs are not considered in this estimate.

4.1.3.8 Site overheads

To ensure the smooth execution of the project, the following overheads are considered: construction management, field-office expenses, material and quality control, material handling, safety-program administration and personnel, temporary facilities, indirect craft labor, mobilization or demobilization, and legal expenses.

4.1.3.9 Other construction indirect costs

Additional construction costs required include small tools and consumables, scaffolding, general-liability insurance, construction equipment mobilization and demobilization, material freight, contractor general and administrative (G&A) expenses, and contractor profit. The freight on process equipment and sales tax are not considered in this section.

4.1.3.10 Project indirect costs

Project indirect costs are required to ensure the project is carried out in a timely and high-quality manner. Professional engineering and CM services are required to monitor project schedules, costs, quality, safety, and scope. Startup and commissioning services provided the procedures and testing necessary to ensure proper function of the systems prior to plant operation. Startup spare parts are also included in this section. Excess liability insurance, indirect sales tax, owner's cost, and engineering, procurement, and contractor firm (EPC) fees are not included in this estimate.

4.1.4   Contingency Costs

Based on project definitions, contingency costs are treated as separate line items and are described as a percentage of costs as described below. A 50% contingency was used to account for a first-of-a-kind project type (all calculated at 50% of costs):

- Labor contingency costs

- Material contingency costs

- Subcontract contingency costs

- Construction-equipment contingency costs

- Process-equipment contingency costs

- Indirect contingency project costs.

4.2   Excluded Items

These estimates represent only the costs contained above; the estimate does not include allowances for any other costs not listed and incurred by the owner. Additionally, the cost of the hydrogen facility (and all equipment within the HTEF boundary) is not included.

There may be additional costs that the owner should consider. The following are some considerations:

- Lost electricity-generation revenue due to extraction steam beyond those covered in Table 14.

- Financing

- Licensing

- Insurance

- Owner staff and facility support

- Safety incentives

- Power consumption due to temporary grid connection

- *Per diem*/travel expenses

- Spare parts

- Applicable taxes

- Permitting

- Plant-staff training

- Legal or accounting fees

- Schedule acceleration or delay costs.

4.3   Nuclear-Hydrogen Integration Cost-Estimate Summary

A complete overview of the methodology and breakdown of cost estimating for the 100-MW$_{nom}$ and 500-MW$_{nom}$ integration designs is provided in Appendix I, which also includes a detailed breakdown of the costs of the 500-MW$_{nom}$ integration for a distance of 500 m between the HTEF and the NPP. Detailed cost breakdowns for the other cases can be found in [19]. This section briefly summarizes key results. An overview of the direct, indirect, and contingency costs for the 100-MW$_{nom}$ and 500-MW$_{nom}$ facilities are provided below in Table 13. The estimated total capital investment (TCI) for integrating the NPP hydrogen steam supply equipment and associated electrical infrastructure for the 100 MW$_{nom}$ design with a 500 m separation distance is close to \$246/kW$_{nom}$, while the corresponding 500 MW$_{nom}$ integration

modifications are estimated to cost $78/kW_{nom}$. Based on these estimates, the standardized cost of the 500-MW$_{nom}$ design is approximately one-third of the 100-MW$_{nom}$ design. This reduction can be explained by the consolidation of equipment under the larger design and reduced material and labor costs with respect to production capacity. Changing the number of piping trains, power lines, or (mechanical and electrical) integration equipment for these designs will alter the capital cost of these modifications accordingly. One potential cost-reduction strategy is to decrease the separation distance between the NPP and HTEF. This adjustment decreases the length of piping and power lines and has additional benefits, including reduced excavation and foundation costs, better efficiency (reduced thermal and electrical losses), and the potential utilization of smaller, less-expensive equipment. Reducing thermal and electrical separation by 50%, from 500 m to 250 m, is assumed to be physically feasible for some plants (additional hazard analysis and licensing evaluation is necessary to assess overall regulatory compliance but is not considered within this study). Table 13 shows an approximately 20% reduction in integration cost across both designs by reducing plant separation. Another important point regarding Table 13 is that the funds set aside for contingencies are relatively large, roughly equal to the direct costs. Large contingency budgets are appropriate for first-of-a-kind installations. The contingency funds can likely be decreased by 50% or more for subsequent installations that follow similar engineering designs.

Table 13. Installation cost summary for integration of nuclear and hydrogen plants (2022 USD).

	Steam from Cold Reheat				Steam from Main Steam
	100 MW$_{nom}$		500 MW$_{nom}$		500 MW$_{nom}$
Parameter	500 m separation	250 m separation	250 m separation	250 m separation	250 m separation
Direct costs					
Steam direct cost ($MM) [a]	6.12	4.28	11.7	8.95	8.95
Electric direct cost ($MM) [b]	1.31	1.14	1.40	1.21	1.21
Total direct cost ($MM)	7.42	5.42	13.1	10.2	10.2
Indirect costs					
Steam indirect cost ($MM) [a]	7.49	5.78	11.6	8.84	8.84
Electric indirect cost ($MM) [b]	1.49	1.37	1.49	1.37	1.37
Total indirect cost ($MM)	8.98	7.15	13.1	10.2	10.2
Contingency					
Steam contingency ($MM)	6.78	4.92	11.7	8.92	8.92
Electric contingency ($MM)	1.42	1.28	1.42	1.28	1.28
Total contingency ($MM)	8.20	6.20	13.2	10.2	10.2
Total capital investment (TCI) for electric and thermal power coupling					
TCI for steam integration ($MM)	20.4	15.0	35.0	26.7	26.7
TCI for electric integration ($MM)	4.21	3.79	4.31	3.86	3.86
TCI for all integration ($MM)	24.6	19.0	39.0	30.6	30.6
Std. TCI per nominal HTEF size ($/kW$_{nom}$)	246	190	78.1	61.2	61.2

a   Direct costs include labor, materials, subcontracts, construction equipment, and process equipment.
b   Indirect costs include additional labor, site overheads, other construction costs, and project indirects.

It is helpful to compare the cost estimates in Table 13 with assumptions that have been made in previous analyses that have estimated the costs of hydrogen production, assuming a similar production configuration in which an HTEF is coupled to a PWR. In a study by Wendt, Knighton, and Boardman [2],

it was assumed that a 1,000 MW$_{nom}$ HTEF was coupled to an NPP at a distance of 1 km. The direct capital cost of the steam-delivery system from the NPP was estimated to be $41.1 million, which is in good agreement with the estimated cost presented in Table 13, after accounting for differences in scale and assumed steam-delivery distance. As summarized in Table 14, a simplified analysis was performed to estimate operating costs associated decreased electricity sales from the PWR due to thermal power extraction. All costs are reported in 2022 U.S. dollars, and it is assumed that electricity sales price is constant throughout the 20-year lifetime of the system at $30/MWh (in 2022 USD), which operates with a capacity factor of 95%. Not surprisingly, operating cosst associated with loss of PWR electric power output due to thermal power dispatch to the HTEF dominate the total costs for HTEFs that are 500 MW$_{nom}$ and larger.

As indicated in Table 3 and Table 8, the PWR electric power output decreases by 5.3 MW$_e$ and 22.4 MW$_e$, respectively, for the 100-MW$_{nom}$ and 500-MW$_{nom}$ HTEF cases. These values are lower than estimated in the previous hydrogen-production cost study [2] because extracting steam from cold reheat in the PWR has less impact on electric power production than removing steam from the main steam line, as assumed in the previous work. The previous work assumed that the reduction in electric power production was equal to the thermal power delivery to the HTEF divided by the thermal-to-electric conversion efficiency of the PWR, which would have corresponded to 8.5 MW$_e$ for the 100 MW$_{nom}$ HTEF case and 35.7 MW$_e$ for 500 MW$_{nom}$ HTEF case. As noted in Table C-2, extracting 105 MW$_{th}$ from the main steam line caused the generator output to decrease by 37.9 MW. This result indicates extracting steam from the main steam line causes an additional loss of 15.4 MW from the generator, compared to extracting the needed steam from cold reheat. **Extracting steam from the cold reheat reduces the operating costs of the thermal power dispatch system by approximately 40% in each case, compared to extracting steam from the main steam line. The lowest standardized cost of steam supply is associated with the 500 MW$_{nom}$ HTEF case and is $8.46/MWh$_{th}$, which exhibits a marked improvement compared to the estimate of $11.6/MWh$_{th}$ from [2].** For comparison, a simplified cost estimate was performed for a case in which steam is provided to the HTEF using an electric boiler. **The estimated standardized cost of steam from an electric boiler was estimated to be greater than**

Table 14. Simplified total-cost summary for integration of nuclear and hydrogen plants (2022 U.S. dollars).

	Steam from Cold Reheat				Steam from Main Steam
	100 MW$_{nom}$		500 MW$_{nom}$		500 MW$_{nom}$
Parameter	500 m separation	250 m separation	250 m separation	250 m separation	250 m separation
Operating costs for thermal power dispatch (does not include electric power coupling)					
NPP power reduction (MW$_e$)	5.3	5.3	22.4	22.4	37.9
20 Year lifetime operating cost ($MM) [a]	26.5	26.5	112	112	189
Capital and operating costs for thermal power dispatch					
20 Year lifetime total cost ($MM)	46.9	41.5	147	139	216
Standardized (std.) costs for hydrogen production					
Std. cost of heat delivery ($/MWh$_{th}$)	14.1	12.4	8.82	8.32	13.0
Std. H$_2$ production cost contribution ($/kg-H$_2$)	0.10	0.09	0.065	0.061	0.10

a   Assumes an electricity sales price of $30/MWhe.

$30/MWh_{th}$, which would contribute approximately $0.22 to the production cost of each kg of hydrogen. Thus, the potential savings from thermally integrating an HTEF to a PWR is approximately $0.16/kg-H$_2$.

As noted, costs estimated in this study are for a first-of-a-kind installation with high contingency budgets. **Subsequent installations with similar designs may have substantially lower costs if contingency costs can be reduced.**

4.3.1   HTE via Electrical Only with Electric Steam Boiler

For the purpose of reducing costs and modifications to the NPP, an additional case was considered where only electrical power is delivered from the NPP to the HTEF. The steam extraction and delivery system is replaced by an electrical boiler that converts deionized or demineralized water to high-temperature steam for use in the HTE process and provides the electrical power required for electrolysis. The initial costs associated with implementing this option are expected to be significantly lower due to the amount of mechanical equipment that will be eliminated. Additionally, the equipment listed in Table 14 would either move from the NPP to the HTEF or be removed from the design as described below.

For the 100-MW$_{nom}$ scale, this option was found to incur a much-lower initial capital cost because the HSS equipment used to supply thermal energy from the NPP was not needed for this electric-only option. However, lower efficiency for the electric-only option would result in considerably higher operating costs, which more than offsets the reduced capital costs. This same behavior is observed for a 500-MW$_{nom}$ design.

Table 15 also shows simplified costs associated with replacing the thermal power extraction and delivery system with an electric boiler located at the HTEF. The simplified analysis includes direct capital costs and annual inflation of 2%, but neglects financing and tax costs. The operating costs of the electric boiler are much higher than the capital cost, which means the standardized cost is approximately $25/MWh_{th}$ for all cases, regardless of separation distance or HTEF nominal size. The standardized cost of operating the electric boiler could be reduced by approximately 10% by regenerative cooling of the product stream to preheated to feedwater entering the electric boiler to 250°F. For an exact comparison, sites will need to conduct a formal evaluation of the relative performance between an electric reboiler and a steam reboiler.

Table 15. Equipment changes for electrical integration only.

Equipment	Required	Description
Reboiler	Yes	The lack of steam input from the plant through the use of an electric reboiler allows reboiler siting within the HTEF boundary. This allows for regenerative drain cooling. The electric reboiler is expected to be more expensive than its steam reboiler counterpart and will require more maintenance for long-term operation.
Demineralized-Water Tank	No	The demineralized-water tank is intended to enable continued hydrogen production in the event the RO system is down for maintenance. For this reason, it is recommended that a tank be included and located within the HTEF boundary. Depending on the expected frequency of RO maintenance, it may be desirable to remove the tank.

Interface Piping between NPP and HTEF	No	In the absence of plant steam extraction, piping can be routed within the HTEF, from the RO system to the electric reboiler and subsequently the electrolyzers. This additionally reduces heat and pressure losses caused by pipe routing between the NPP and HTEF.
Flow and Level Control Valves	No	No thermal-energy transfer will occur between the NPP and HTEF, removing any process control interface between the NPP and HTEF.

4.4   Total Project Cost

According to the study by Wendt, Knighton, and Boardman [2], expected costs for the construction cost of large-scale HTE facilities are discussed. Adjusted for inflation (2022 U.S. dollars), the baseline hydrogen facility balance-of-plant equipment was expected to cost approximately $650/kWe DC ($1/kWe DC is approximately equal to $1/kW$_{nom}$ for both designs considered in this report), with cost-reduction strategies enabling facility costs as low as $350/kWe DC. Slight increases in standardized cost were projected for facilities smaller than 250 MW$_e$ DC; hence, it is expected that the 100-MW$_{nom}$ design HTEF balance-of-plant equipment would be more expensive than the 500-MW$_{nom}$ balance-of-plant equipment.

Total facility capital costs were projected to be between $750–1,250/kWe DC for a 1,000 MW$_e$ DC hydrogen plant. Scaling these costs to the 100-MW$_{nom}$ and 500-MW$_{nom}$ designs, the total project costs are expected to be at the medium-to-high ends of that range. As with the balance-of-plant costs, the standardized total project cost of the 100-MW$_{nom}$ design is expected to be greater than the total project cost of the 500-MW$_{nom}$ design. This is further supported by the larger standardized integration costs for the 100-MW$_{nom}$ design (see Table 13).

Based on the estimates of Section 4.3, integration costs are expected to comprise approximately 5–20% of the total project cost for a 100- and 500-MW$_{nom}$ facility, although these values can change considerably with different integration designs and site-specific conditions. Based on these estimates and the conclusions of Bloom Energy [6], it is expected that the addition of a 500-MW$_{nom}$ HTEF to an NPP similar to the reference plant used in this study will have a lower dollar-per-kilowatt-nominal cost than the addition of a 100-MW$_{nom}$ hydrogen plant to a similar NPP.

5. HYDROGEN PLANT CONSIDERATIONS

5.1 Maximum Achievable Electrical Diversion from Power Plant

An additional sensitivity analysis was performed to determine the maximum power that can be transmitted radially from the NPP to a nearby HTEF without impacting the stability of the NPP generator during a loss of load. The additional runs show that the HTEF load can be increased up to the maximum output power rating of the generator without causing the generator to become unstable following a trip of the high-voltage transmission line feeding the H_2 plant, either with or without a fault. Note that this model is based on typical plant and transmission-system data, which may not be representative of the available capacity for all plants.

5.2 Minimum Power Requirements for Hydrogen Facility

To protect solid-oxide cells in the HTEF and prolong their lifespans, a hot-standby state should be used when electricity is diverted from the HTEF to the grid. During hot standby, the electrolyzers maintain steady-state temperature, but electrolysis temporarily halts. Sustaining hot standby requires a small but non-negligible portion of the thermal and electrical power used for electrolysis. This requirement depends on the specifications of the HTEF vendor. Alternatively, the solid-oxide cells may be allowed to cool; however, a small amount of electrical power and steam are consumed during the cool-down process. Additionally, if freezing conditions exist, the HTEF components must be thoroughly dried or maintained at a temperature above freezing.

The NPP is expected to supply these minimum demands during normal plant operation while also handling the transients associated with flexible operation of the HTEF. However, in the event of a faulted condition, a loss of offsite power or reactor shutdown (e.g., planned outage), a safe HTEF shutdown may be required. During unplanned events, one or more sources of emergency power (thermal and electrical) will be needed to ensure the electrolyzers are cooled without damage. The hydrogen vendor should work with the NPP to ensure the necessary emergency power is provided to the HTEF in the event of a loss of thermal or electrical power.

5.3 Hydrogen-Facility Siting

From a project cost perspective, minimizing the spacing between the NPP and HTEF is ideal, as shown in Section 4.3. Nevertheless, there are several limitations to the adjacent siting of the TB and the HTEF. The primary limitation is the explosion risk an HTEF presents to the safety-related systems, structures, and components of the NPP. Depending on the size of the HTEF and the extent of its protective measures, minimum-separation requirements between the HTEF and NPP can be determined by performing a hazard assessment. The size of the HTEF itself also poses limitations on siting. An HTEF is anticipated to require an area on the order of half an acre per megawatt-nominal. As a result, it is unlikely there will be sufficient space within the NPP's protected area for siting of the facility. Existing pathways, plant structures, and topographic features inside of the OCA (but outside of the protected area) may further restrict the siting of the HTEF and increase the separation between plants.

5.4   Thermal power Extraction

While cold reheat is preferable for this preconceptual design because it maximizes plant efficiency, there are several limitations. The first is pipe routing. Plants will need to find the space available to route new extraction piping through the TB, and structural modifications may be needed to support these additions. Of similar or greater importance are the effects of extraction on the main turbines. For the 500-MW$_{nom}$ design, a 6-psi pressure reduction is observed at the discharge of the HP turbine relative to no thermal extraction. This reduction in mass flow downstream of the HP turbine is expected to be within the design margins of the equipment. However, with large degrees of cold-reheat extraction, there is a potential for turbines to operate outside of their intended design capabilities; plants should work with original-equipment manufacturers to ensure the turbines can perform in accordance with their design specifications. Turbines should be evaluated for shaft imbalance, blade loading, and thrust verification. Additional modifications can be implemented to ensure turbines operate within their intended design capabilities. One such modification would be the installation of a control valve downstream of extraction to maintain upstream pressures (at the HP turbine discharge). Alternatively, some plants already perform cold-reheat extraction for equipment such as feedwater heaters. If the turbines are unable to handle extraction for HTE, other extraction flows can be reduced or taken out of service to reduce turbine imbalances. These changes would reduce plant efficiency, but may still be the optimal solution for safe operation from cost and efficiency standpoints. To eliminate turbine stability concerns, extraction steam could be drawn from main steam; Section 3.1.5.3 discusses the benefits and drawbacks of extraction from main steam as opposed to cold reheat.

6. CONCLUSIONS

This study develops a preconceptual design for the integration between a large-scale HTEF and an NPP. Two hydrogen-facility sizes are considered: 100 MW_{nom} and 500 MW_{nom}. Both steam-supply designs use cold-reheat steam extraction as a heat source. A reboiler inside the protected area of the power plant transfers steam heat to the demineralized-water supply for the hydrogen plant. After heat transfer, the extracted steam condenses and returns to the condenser while the process steam routes out of the protected area to the electrolyzers. Electrical power is tapped off from the high-voltage side of the GSU transformer, where it is then transported via a 345-kV transmission line to the hydrogen facility. Circuit breakers and disconnects are located at both ends of the transmission line. Step-down transformers and miscellaneous switchgear/buses are located at the end of the transmission line inside the HTEF boundary. Control capabilities for the steam-interfacing equipment and electrical dispatch are accessible from the main control room, and protective relays for the transmission line are located inside the relay room.

Computer modeling was performed for the thermal and electrical designs. PEPSE analysis provided the steady-state parameters for thermal extraction from the turbine cycle. These parameters were used to inform transients and size equipment in combination with AFT Arrow and AFT Fathom modeling for steam and water piping, respectively. Electrical transients were analyzed using PSCAD. An ETAP model was used to evaluate power flow and short circuit, which enabled the sizing of transformers and protective equipment.

A cost estimate was developed for both integration designs when considering plant-separation distances of 250 m and 500 m. From these estimates, the modifications for thermal and electrical interfacing of a first-of-a-kind nuclear-integrated hydrogen facility are anticipated to cost between \$60 and $250/kW_{nom}$. With a total project cost in the range of $\$750–1,250/kW_{nom}$ [7], integration costs account for up to 20% of the total project cost. The standardized cost of heat supplied from the NPP was found to range from approximately $\$8.5/MWh_{th}$ to $\$14/MWh_{th}$. The estimated standardized cost of steam from an electric boiler was estimated to be greater than $\$30/MWh_{th}$, which would contribute approximately \$0.22 to the production cost of each kg of hydrogen. **Thus, the potential savings from thermally integrating an HTEF to a PWR is approximately \$0.16/kg-H_2.** Standardized integration costs were shown to decrease with larger hydrogen facilities and reduced separation distances.

Nuclear steam extraction can provide a profit avenue for many plants and is not restricted to hydrogen production. Ammonia production, oil refining, and paper production, among other industrial processes, require thermal energy that can be provided by NPPs. Future work should look at the details of thermal extraction for a variety of use cases. This can include increased levels of extraction and multiple simultaneous users. Additionally, site-specific studies should be performed to develop industry experience and improve cost accuracy.

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Appendix A: Process and Instrumentation Diagrams
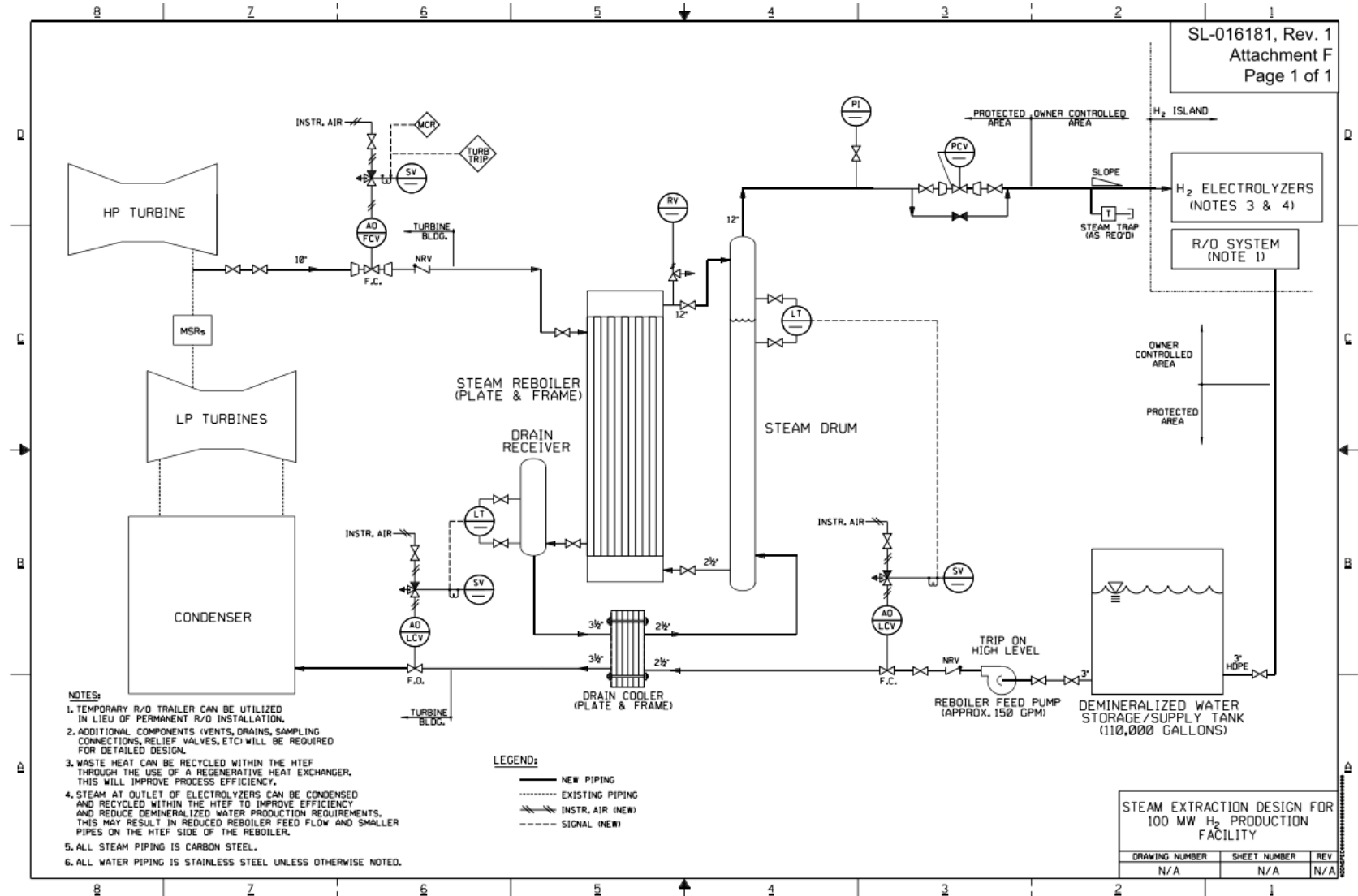
Figure A-1. 100 MW$_{nom}$ P&ID.
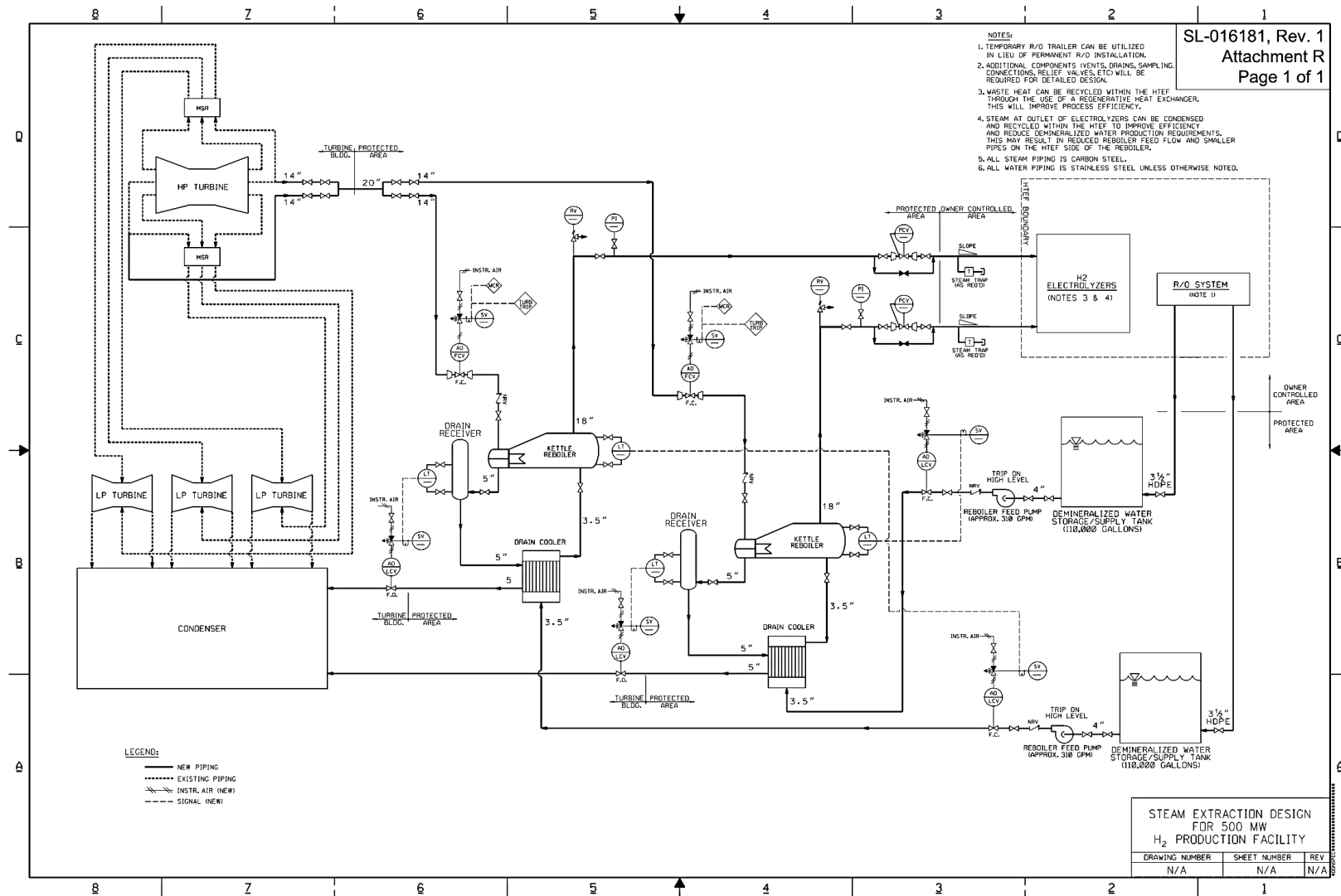
Figure A-2. 500 MW$_{nom}$ P&ID.

Appendix B: Preconceptual Design Layouts
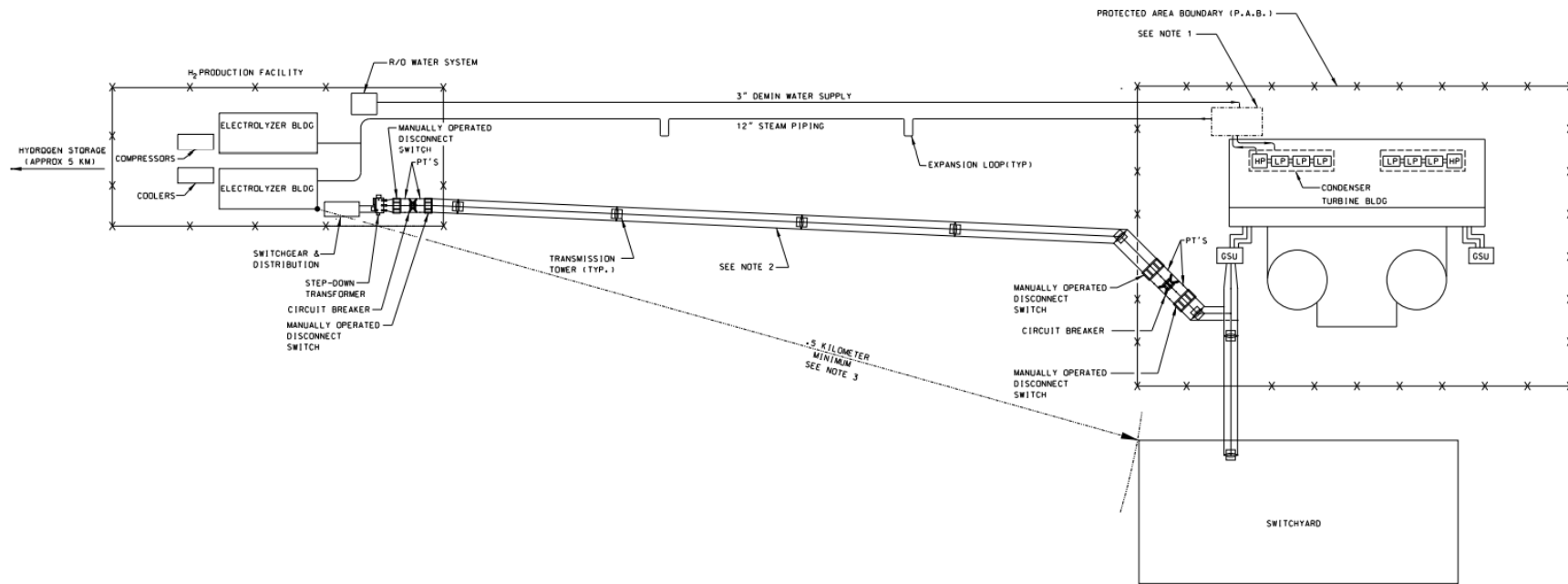
Figure B-1. Layout of preconceptual design with 100 MW$_{nom}$ HTEF, located 500 m from the PWR.
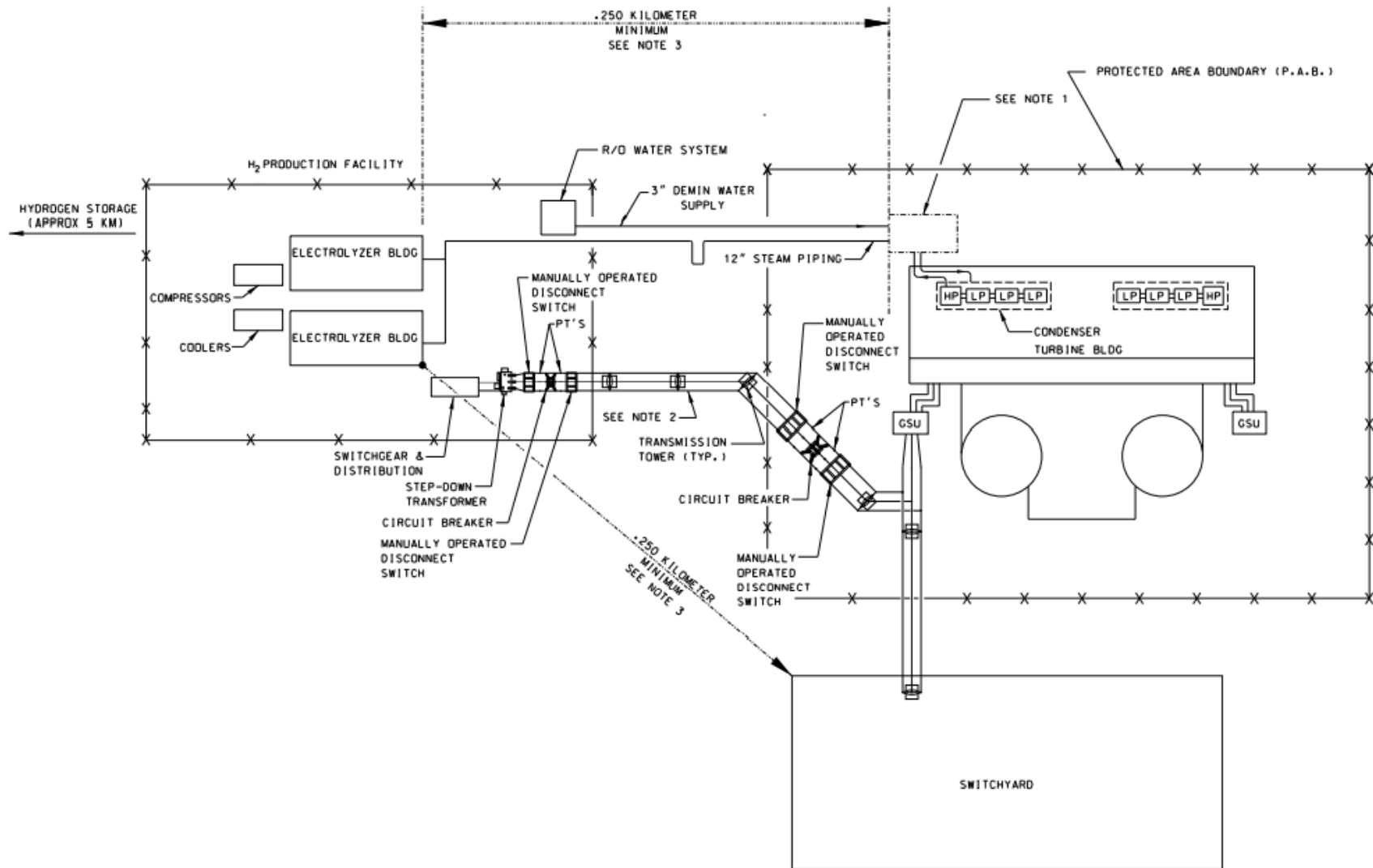
Figure B-2. Layout of preconceptual design with 100 MW$_{nom}$ HTEF, located 250 m from the PWR.
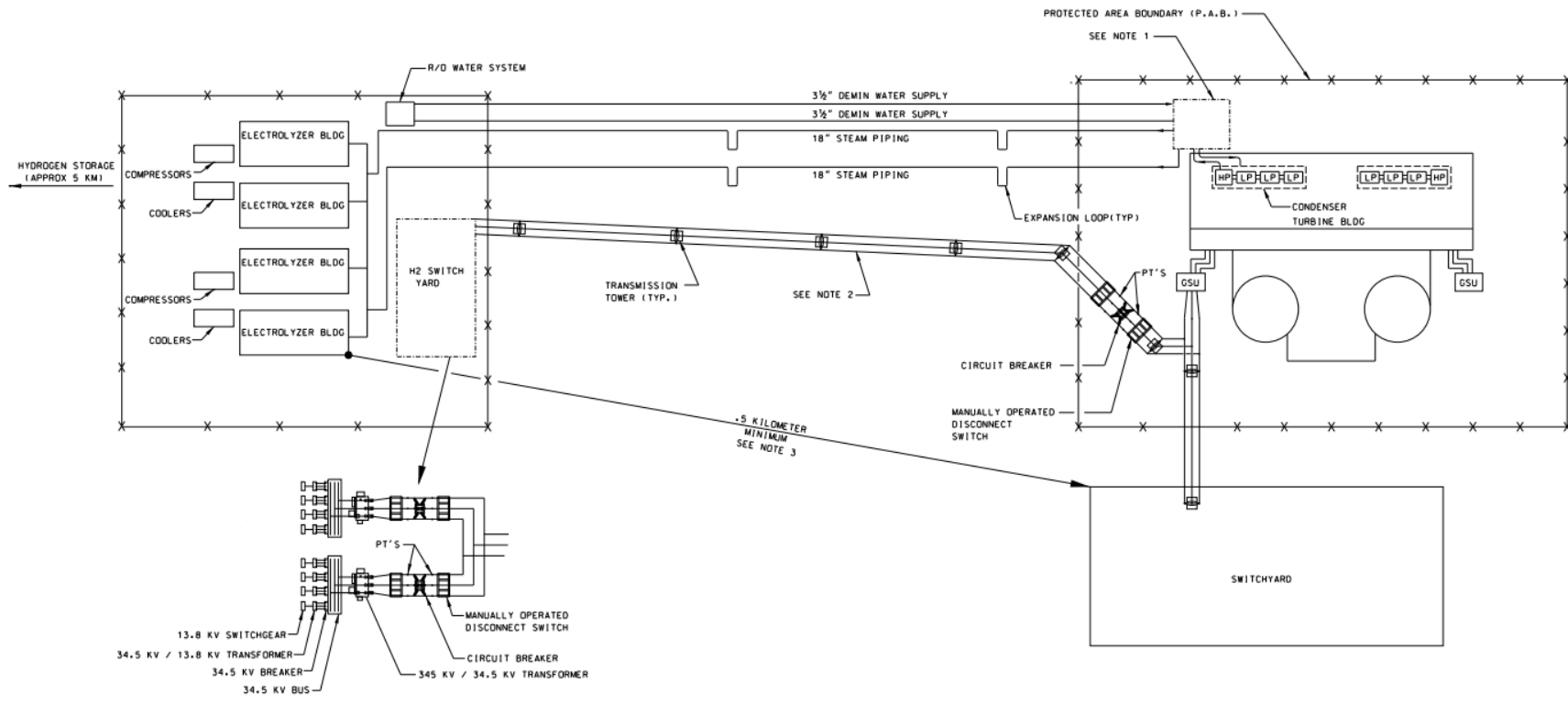
Figure B-3. Layout of preconceptual design with 500 MW$_{nom}$ HTEF, located 500 m from the PWR.
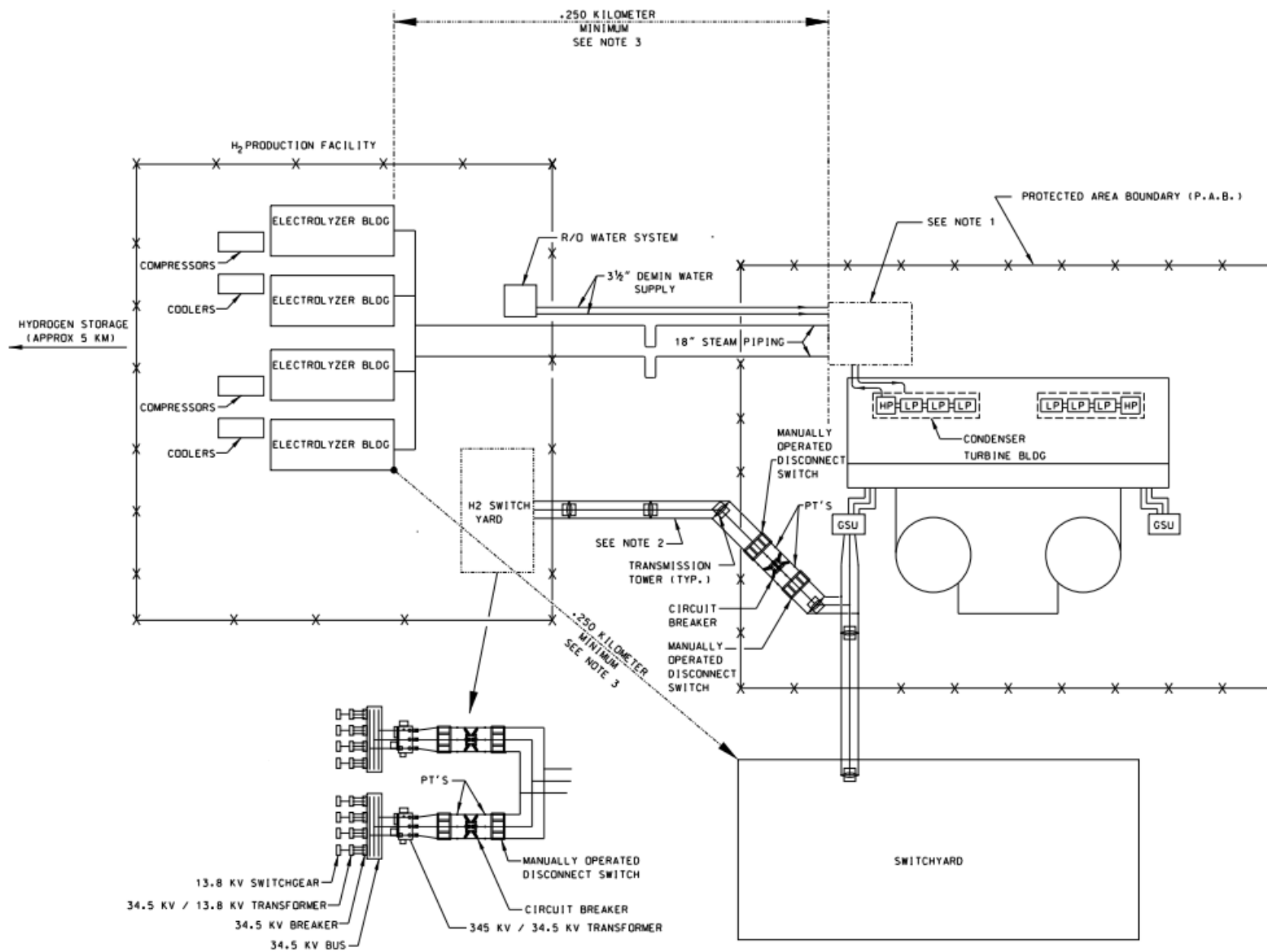
Figure B-4. Layout of preconceptual design with 500 MW$_{nom}$ HTEF, located 250 m from the PWR.
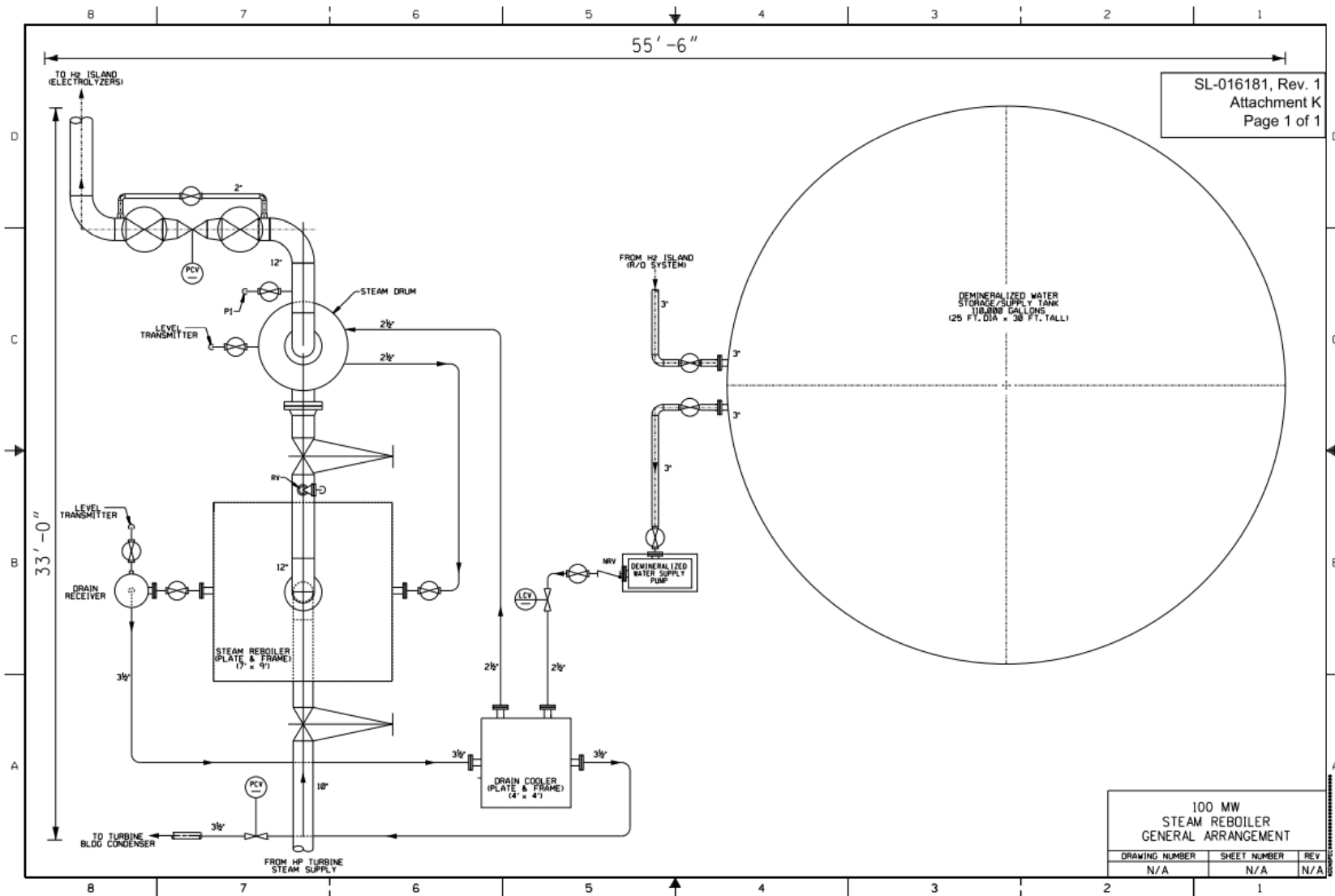
Figure B-5. 100 MW$_{nom}$ steam reboiler arrangement.
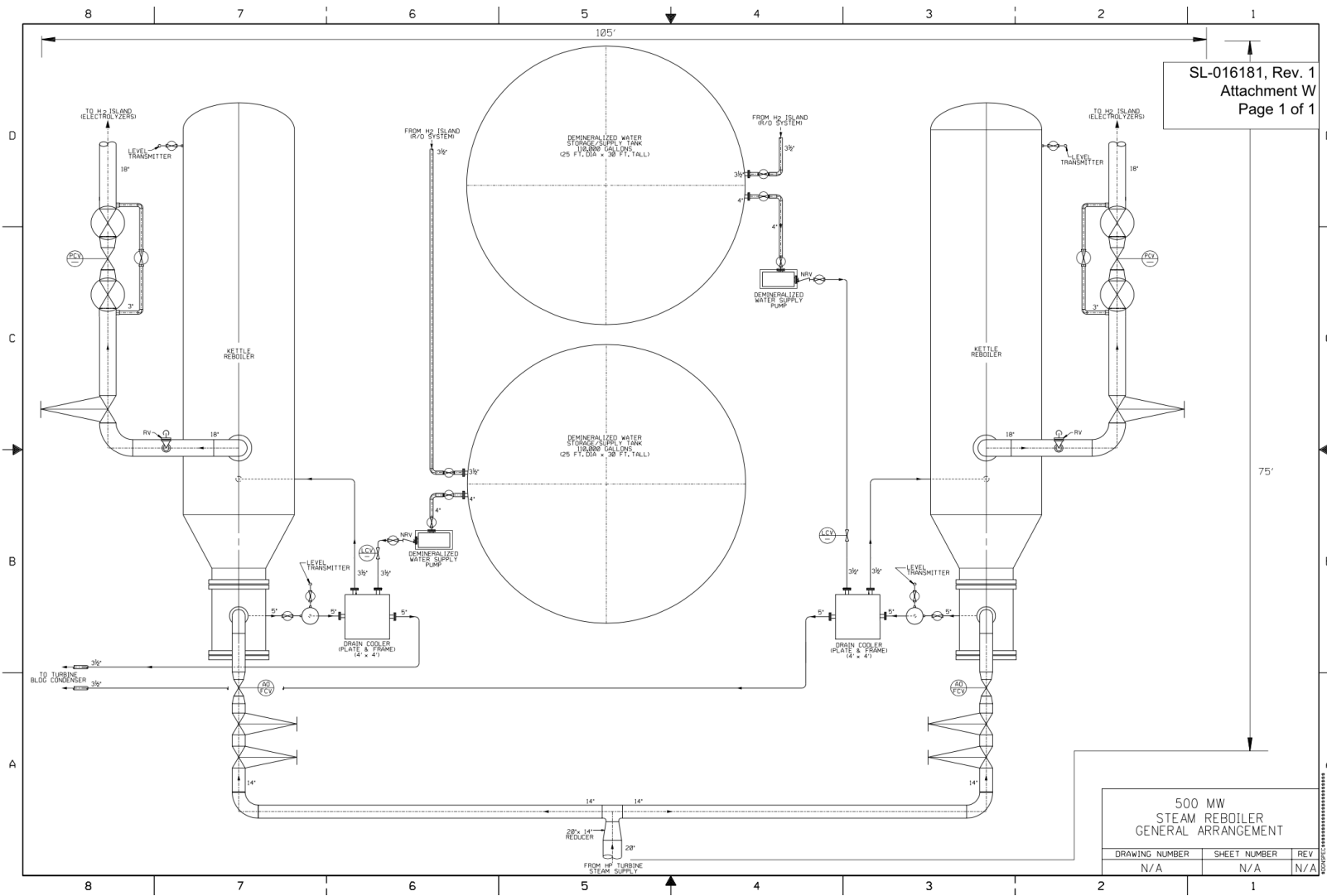
Figure B-6. 500 MW$_{nom}$ steam reboiler arrangement.
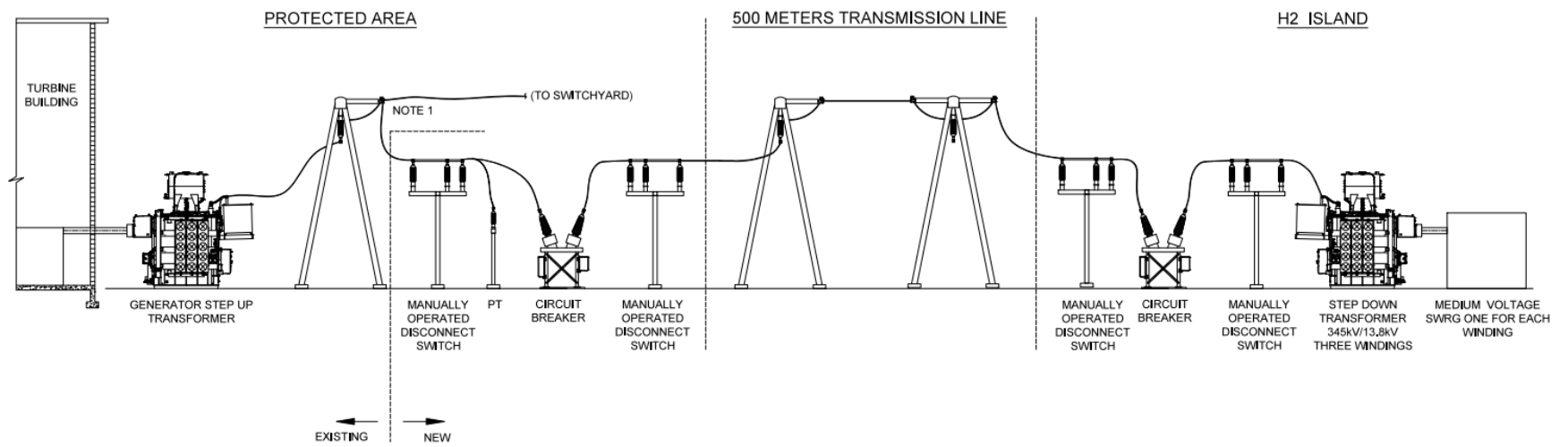
Figure B-7. 100 MW$_{nom}$ HTEF feeder electrical-physical layout.
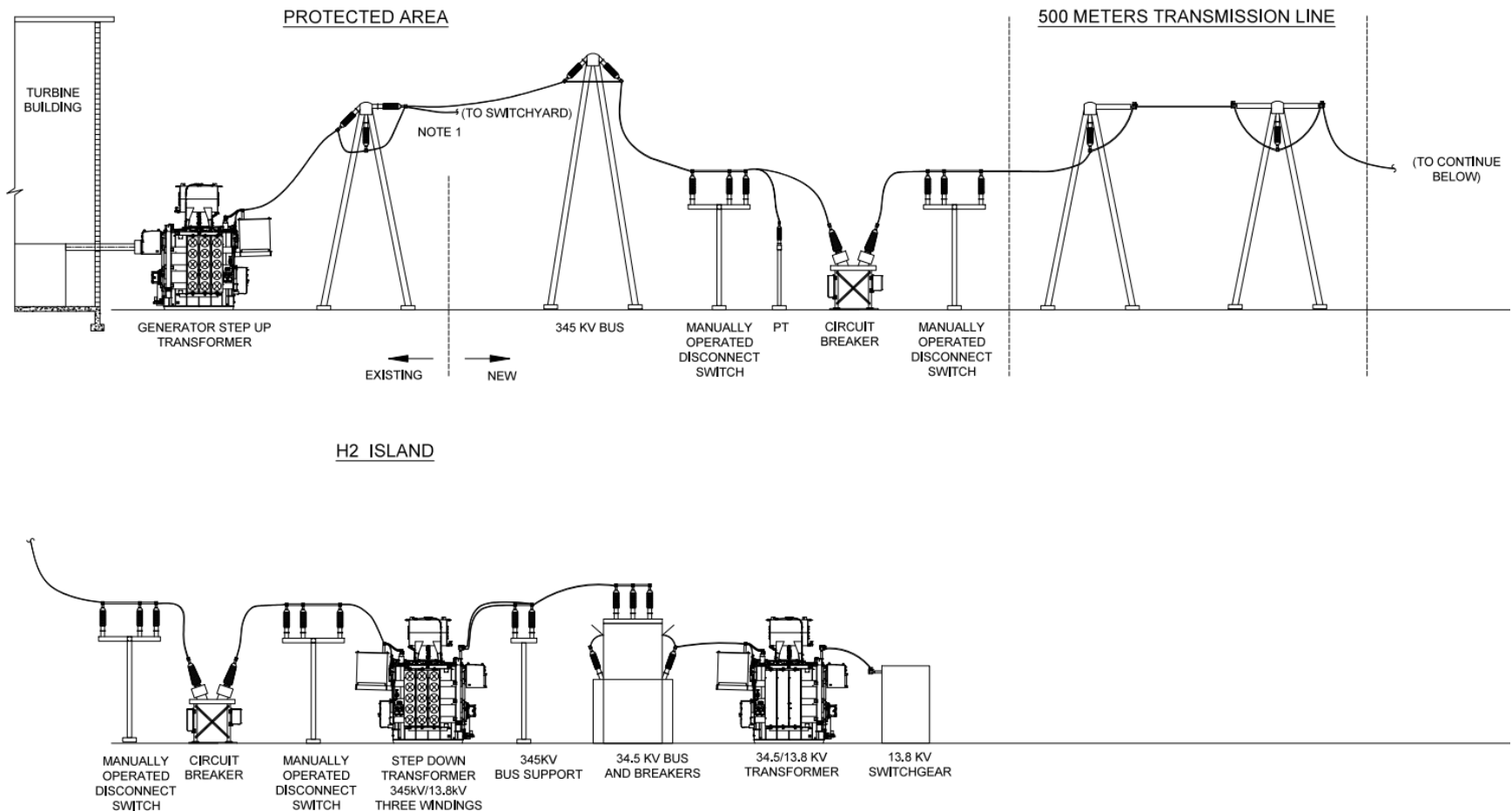
Figure B-8. 500 MW$_{nom}$ HTEF feeder electrical-physical layout.

Appendix C: PEPSE Modeling

C-1. PURPOSE

The purpose of this section is to evaluate the impact of extracting steam from the nuclear power cycle to supply thermal energy to a reboiler unit for hydrogen production. The steam is condensed in the reboiler unit and returned to the nuclear power cycle. The thermal energy used by the reboiler unit is used to boil water to steam, which is then directly supplied to the hydrogen production facility. This appendix evaluates ~25 MWth and ~105 MWth extraction of thermal energy from the main power cycle.

C-2. METHODOLOGY

A generic station PEPSE model is used as the beginning point of this evaluation. The generic station is a representative 4-loop Westinghouse PWR with a targeted generator output of ~1250 MWe. Various extraction locations are considered, including the following locations: (1) main steam, (2) cold reheat, and (3) feedwater. PEPSE case results and diagrams for the preferred extraction (cold reheat) and preferred return (main condenser) location are developed and documented here.

The generic PEPSE model is modified by adding splitters, mixers, and stream components to allow diversion of steam from the preferred extraction location and to return to the main condenser. Pressure and temperature losses to the environment (determined from Arrow models in the Appendices for the case of ~25 MWth thermal extraction to the HTEF). Similar Arrow models are available in Ref [18] for the case of ~105 MWth thermal extraction to the HTEF. Note that the pressure and temperature losses are developed in Arrow to size the associated piping and components.

A heat exchanger component is used to model the steam reboiler thermal performance. The extracted steam is condensed and subcooled before it is returned to the main power cycle.

A pump component is used to model system pressure increase from a demineralized-water supply tank supplying water to the reboiler, which boils this water to steam and is then supplied to the hydrogen production facility. The amount of thermal energy extracted is calculated within PEPSE using operational variables. The amount of thermal energy extracted is controlled by changing the flow fraction out of the splitter supplying the reboiler.

C-3. INPUTS (ARROW MODELING)

C-3.1   Steam Piping and Pressure

Steam-piping pressure and temperature losses are taken from the Arrow modeling of these piping systems (see Appendices D and E and Ref. [18]). The Arrow models consider the best estimate of pipe lengths, fittings, and components (including modulating valves) when determining expected pressure conditions through the piping network. The Arrow model also considers insulated piping with extremely cold outdoor temperatures for worst-case thermal losses through the piping network from the nuclear power station to the HTEF.

100 MWnom HTEF receiving ~25 MWth thermal extraction

The following lists the parameters taken from the Arrow modeling:

- The pressure in the plant steam-supply piping at the steam-boiler inlet is 161.3 psia at 367.3°F with a pressure drop of 27.3 psid and estimated heat loss of 18,350 Btu/hr.

- The pressure in the steam-supply piping to the hydrogen production facility at the reboiler outlet is 120 psia at 350.1°F.

500 MWnom HTEF receiving ~105 MWth thermal extraction

The following lists the parameters taken from the Arrow modeling:

- The pressure in the plant steam-supply piping at the steam-boiler inlet is 153.5 psia at 364.2°F with a pressure drop of 30.6 psid and estimated heat loss of 33,000 Btu/hr. The same pressure drop and heat losses are assumed for the extraction from the main steam.

- The pressure in the steam-supply piping to the HTEF at the reboiler outlet is 120 psia at 350.0°F.

- The pressure in the steam-supply piping at the hydrogen production facility is 92.5 psia at 335.7°F with a pressure drop of 27.5 psid and estimated heat loss of 623,000 Btu/hr.

C-4. ASSUMPTIONS

The required steam conditions at the hydrogen production facility are assumed at 300°F and 50 psig, based on agreement with INL. Temperature of the condensed and subcooled extraction steam is assumed to be 120°F before it is returned to condenser.

Only for the case of 500 MWnom HTEF receiving ~105 MWth thermal extraction:

- The PEPSE case with extraction from main steam maintains the same pressure and temperature losses as the case with extraction from cold reheat. This is reasonable since the steam pipes are sized to limit steam velocity to 150 ft/sec. This velocity criteria would be maintained for both cold-reheat and main steam extraction.

- The pipe lengths, fittings, and insulation thickness are assumed the same between the cold reheat and main steam extraction cases. Therefore, using the same pressure and temperature losses is a reasonable approximation inlet.

C-5. REFERENCES

PEPSE V84 Computer software, (S&L program # 03.7.551-84.0).

C-6. RESULTS

To determine the preferred location for thermal extraction and return, various factors were considered. As discussed in the purpose, extraction from the main steam lines was considered. This location was not considered a preferred location due to the following reasons:

- Main steam temperature approaches 500–550°F for typical nuclear power stations. However, the steam conditions required by the hydrogen-production facility are only around 300°F. Therefore, the temperature differential between the heating steam (i.e., main steam) and the steam supply to the hydrogen production facility is ~200°F. This high differential temperature is not necessary and may cause additional design requirements for the reboiler to sustain these high temperatures.

- Extraction from the main steam piping will impact turbine throttle-valve operation.

- Potential transient operation (i.e., loss of supply steam to the hydrogen-production facility) would be more severe at this location since it would directly impact the operation of the turbine throttle valve.

- Last, there is a significant (15.5 MWe) reduction in electrical power production from the nuclear station considering extraction from main steam compared to cold reheat.

Thermal extraction within the feedwater system was also considered. However, the low enthalpy and associated thermal energy available from feedwater required significantly higher flow rates to accomplish the targeted thermal power extraction levels. Therefore, the impact on the nuclear power station is more severe and was disregarded as a potential extraction location.

The preferred extraction location was determined to be at cold reheat (i.e., between the HP turbine outlet and the MSRs). This location provides sufficient supply temperature (~375°F) and associated differential temperature to the required steam condition at the targeted thermal-extraction levels. With sufficient reboiler sizing, the returning fluid temperature can be reduced to near the condenser operating temperature to minimize thermal inefficiencies in the nuclear power station, making the main condenser the preferred return location.

With the preferred extraction and return locations determined, the base PEPSE model is modified as discussed in Section C-2 to allow the targeted thermal extraction level to be achieved. The following PEPSE diagrams show the results considering (1) no thermal power extraction (i.e., no hydrogen production), (2) thermal extraction of 25 MWth, and (3) thermal extraction of 105 MWth. Additionally, Table C-1, Table C-2, and Table C-3 compare important operating parameters within the nuclear power cycle to determine possible significant impact to station equipment.

Table C-1. Summary of important system parameters for 25 MW$_{th}$ extraction.

| Parameter | Unit | Extraction Level | | |
		0 MWth	25 MWth	Δ
Reactor Thermal Power	MWt	3659	3659	—
Generator Output	MWe	1239.6	1234.3	-5.3 MWe
Main Steam Flow	Mlb/hr	16.28	16.28	0.00%
Cold-Reheat Flow	Mlb/hr	12.73	12.72	-0.05%
Extracted Steam Portion	%	0	0.67	0.67%
Remaining Steam to MSRs	Mlb/hr	12.73	12.64	-0.67%
Hot-Reheat Flow	Mlb/hr	11.26	11.17	-0.76%
Hot-Reheat Temperature	°F	502.4	502.4	0.0°F
Condensate-Hotwell Flow	Mlb/hr	11.28	11.28	-0.01%
Condensate-Hotwell Temperature	°F	121.6	121.6	0.0°F
Heater Drain Forward Flow	Mlb/hr	5.00	5.00	0.01%
Heater Drain Forward Temperature	°F	339.7	339.0	-0.7°F
HP FWH Cascading Drain Flow	Mlb/hr	5.00	5.00	-0.23%
HP FWH Cascading Drain Temperature	°F	339.7	339.0	-0.1°F
LP FWH Cascading Drain Flow	Mlb/hr	2.42	2.41	-0.41%
LP FWH Cascading Drain Temperature	°F	131.6	131.6	-0.41%
Heater Drain Tank Pressure	psia	185.5	184.0	-1.5 psi
Final Feedwater Temperature	°F	447.6	447.6	0.0°F

NOTE 1: Cascading drain conditions are averaged. Individual FWH drain lines may have higher variations in conditions.
NOTE 2: Changes from 0 to 25 MW$_{th}$ are calculated in Microsoft Excel. There may be slight differences due to truncation of values when entering the values in Table C-1.

Table C-2. Summary of important system parameters for 105 MWth extraction.

Parameter	Unit	Extraction Level		Δ	105 MW$_{th}$	Δ
		0 MW$_{th}$	105 MW$_{th}$			
Extraction Location	-	-	Cold Reheat	Cold Reheat	Main Steam	Main Steam
Reactor Thermal Power	MW$_t$	3659	3659	-	3659	-
Generator Output	MW$_e$	1239.6	1217.2	- 22.47MW$_e$	1201.7	- 37.9MWe
Main Steam Flow	Mlb/hr	16.28	16.28	0.00%	16.23	-0.35%
Flow to HP turbine	Mlb/hr	15.61	15.63	0.15%	15.22	-2.46%
HP-Exhuast Pressure	psia	192.1	185.9	-6.2psi	187.3	-4.8psi
Cold-Reheat Flow	Mlb/hr	12.73	12.70	-0.20%	12.39	-2.65%
Extracted-Steam Portion	lb/hr	0	355,193	355,193	324,396	324,396
Extracted-Steam Portion	%	0	2.80	2.80%	2.00	2.00%
Remaining Steam to MSRs	Mlb/hr	12.73	12.35	-2.997%	12.39	-2.65%
Hot-Reheat Flow	Mlb/hr	11.26	10.90	-3.18%	10.98	-2.50%
Hot-Reheat Temperature	°F	502.4	502.4	0.0°F	502.4	0.0°F
Condensate-Hotwell Flow	Mlb/hr	11.28	11.28	-0.03%	11.33	0.38%
Condensate-Hotwell Temperature	°F	121.6	121.6	0.0°F	121.6	0.0°F
Heater Drain Forward Flow	Mlb/hr	5.00	5.00	0.04%	4.90	1.99%
Heater Drain Forward Temperature	°F	339.7	337.0	-2.7°F	337.5	-2.2°F
HP FWH Cascading Drain Flow	Mlb/hr	1.39	1.38	-0.92%	1.38	-0.79%
HP FWH Cascading Drain Temperature	°F	423.0	422.5	-0.5°F	420.7	-2.3°F
LP FWH Cascading Drain Flow	Mlb/hr	2.42	2.37	-1.72%	2.39	-1.02%
LP FWH Cascading Drain Temperature	°F	131.6	131.6	0.0°F	131.6	0.0°F
Heater Drain Tank Pressure	psia	185.5	179.5	-6.0 psi	180.8	-4.7psi
Final Feedwater Temperature	°F	447.6	447.6	0.0°F	445.2	-2.4°F

NOTE 1: Cascading drain conditions are averaged. Individual FWH drain lines may have higher variations in conditions.

NOTE 2: Changes from 0 to 105 MW$_{th}$ are calculated in Microsoft Excel. There may be slight differences due to truncation of values when entering the values in Table C-2.

NOTE 3: Main steam flow is the flow rate taken from the steam generator. Flow to the HP turbine is the steam into the HP turbine and does not include hot-reheat steam flow to the MSRs.

From the above comparison, it is expected that there will be no significant impact to station components when considering 25 MWth or 105 MWth thermal extraction. Important considerations are noted below for each case.

100 MWnom HTEF receiving ~25 MWth thermal extraction

Aside from the cold-reheat flow and MSRs, which are directly impacted, the only parameter that is moderately impacted is the heater drain tank pressure, which is slightly reduced. This will slightly reduce

the NPSH margin on the heater drain pumps. Therefore, if existing NPSH margin is low on station heater drain pumps, margins will be further reduced and will require further investigation.

500 MWnom HTEF receiving ~105 MWth thermal extraction

The turbine vendor should be consulted to ensure the reduced HP turbine-exhaust pressure for extraction from either cold-reheat or main steam is acceptable. The cold-reheat case is selected as the primary option since it has virtually no impact on the steam flow to the HP turbine and final feedwater temperature; plus, it saves 15.5 MWe of generator output. Therefore, the follow-on discussions are presented for the cold-reheat case only.

The cold-reheat flow and MSRs are directly impacted (~3% lower flow). The other parameter that is moderately impacted is the heater drain tank pressure, which is slightly reduced (6 psi lower). This will slightly reduce the NPSH margin on the heater drain pumps. Therefore, if existing NPSH margin is low on station heater drain pumps, margins will be further reduced and will require further investigation.

Additionally, the HP turbine exhaust pressure is lower by ~6 psi. The turbine vendor should be consulted to ensure turbine operation is acceptable with the reduced HP turbine exhaust pressure at essentially the same steam flow rate through the turbine.

Table C-3 summarizes the important system parameters for sizing the reboiler for a duty of 25 MWth thermal power extraction for use at the hydrogen-production facility. Note that the parameters defined in Table C-1 are at the connections to and from the reboiler.

Table C-3. Summary of parameters for reboiler sizing for 25 MW_{th} thermal power extraction.

	Mass Flow Rate		Temperature		Pressure	
Steam Supply from Cold Reheat	85,238	lbm/hr	364	°F	161	psia
Drain to Main Condenser	85,238	lbm/hr	120	°F	by Vendor	
Demineralized-Water Supply	73,777	lbm/hr	60	°F	140	psia
Steam Supply to H_2 Production	73,777	lbm/hr	350	°F	120	psia

Table C-4 summarizes the important system parameters for sizing the reboiler for a duty of 105 MW_{th} thermal power extraction (from cold reheat) for use at the hydrogen-production facility. Note that the parameters defined in Table C-4 are at the connections to and from the reboiler.

Table C-4. Summary of parameters for reboiler sizing for 105 MW_{th} thermal power extraction.

	Mass Flow Rate		Temperature		Pressure	
Steam Supply from Cold Reheat	355,193	lbm/hr	360	°F	154	psia
Drain to Main Condenser	355,193	lbm/hr	120	°F	by Vendor	
Demineralized-Water Supply	306,980	lbm/hr	60	°F	140	psia
Steam Supply to H_2 Production	306,980	lbm/hr	350	°F	120	psia
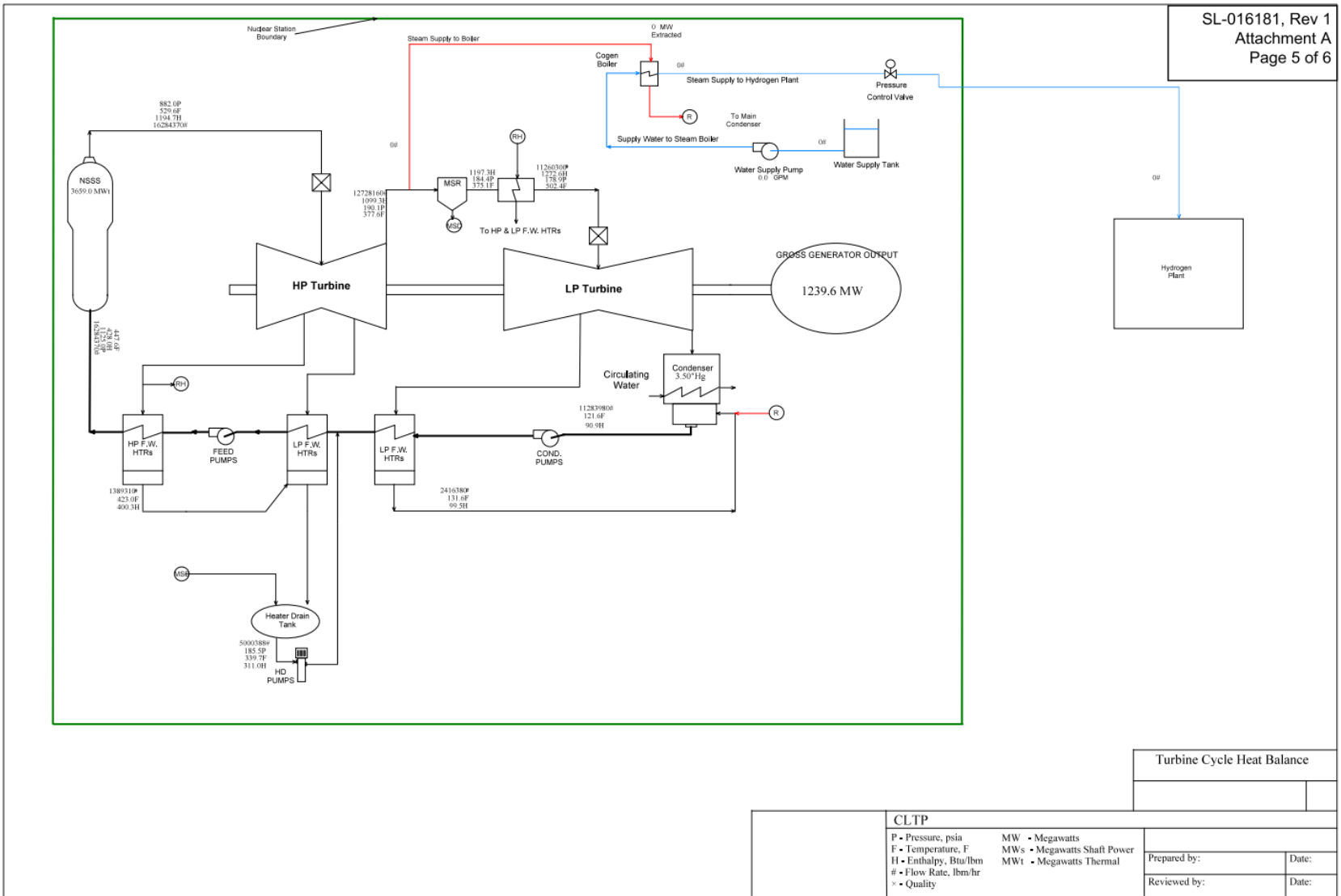
Figure C-1. Process diagram of the PWR secondary system, with connection to an HTEF. The steam extraction valve is closed.
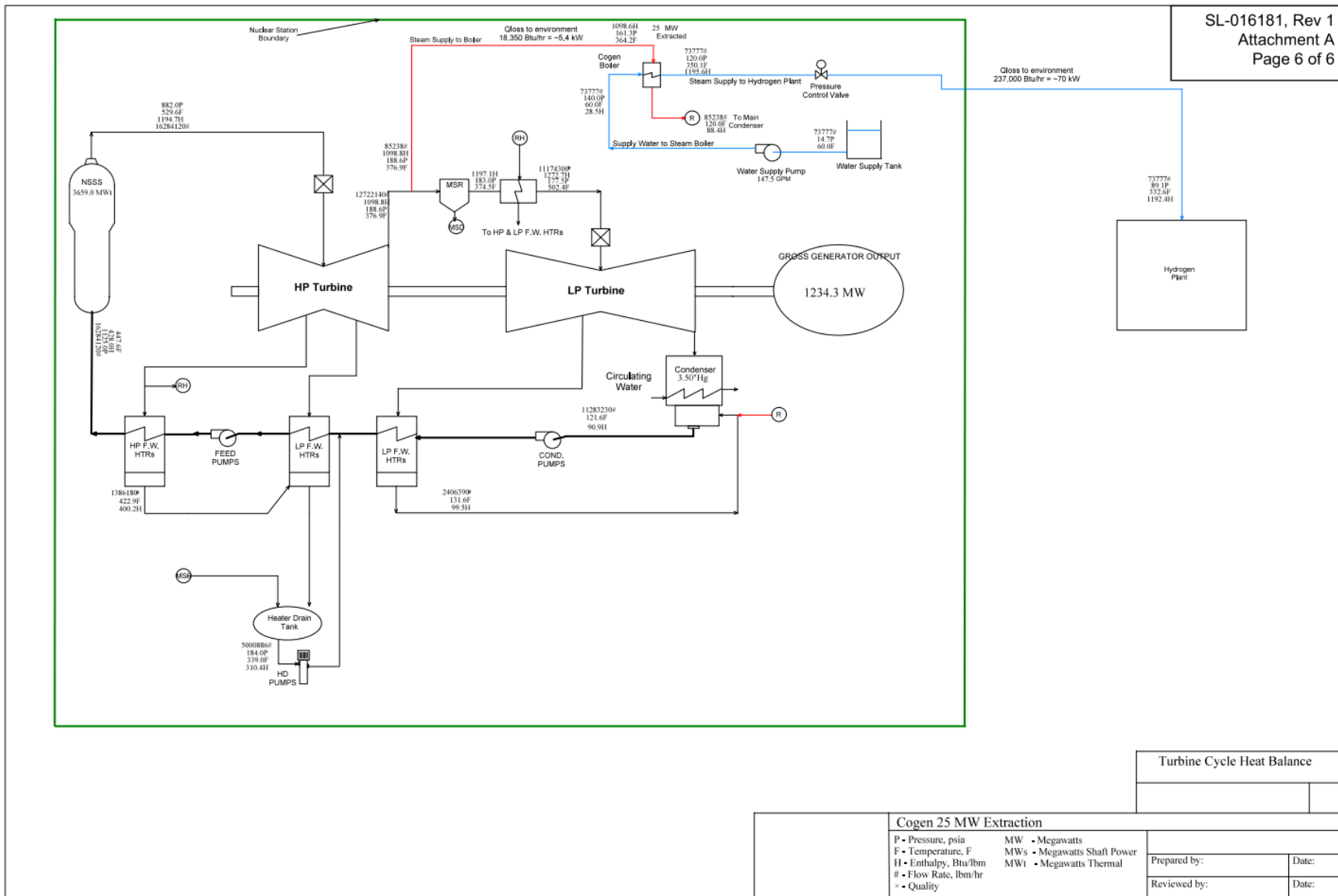
Figure C-2. Process diagram of the PWR secondary system, with connection to a 100 MW$_{nom}$ HTEF operating at full capacity.
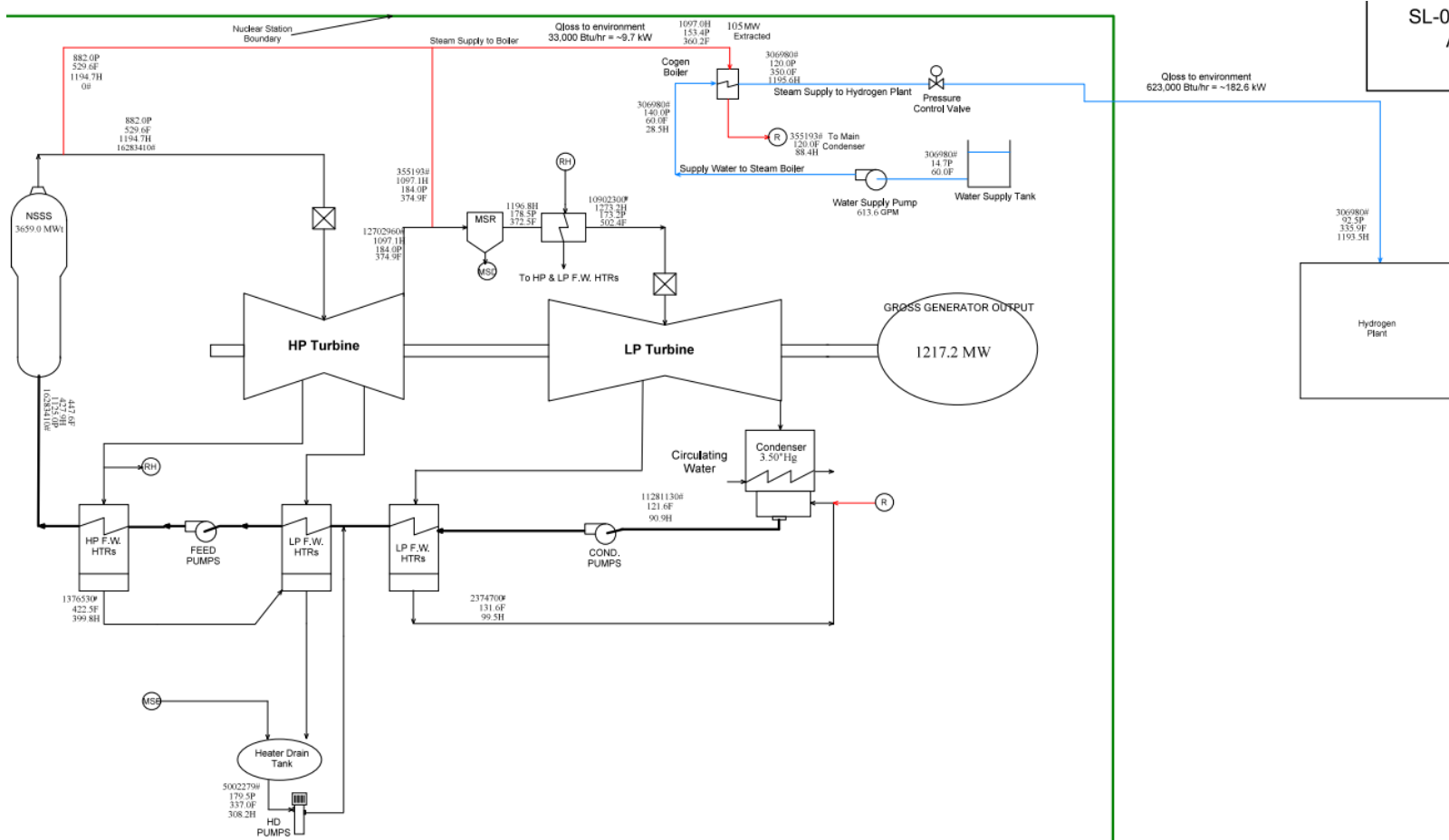
Figure C-3. Process diagram of the PWR secondary system, with connection to a 500 MW$_{nom}$ HTEF operating at full capacity.

Appendix D: 100 MW$_{nom}$ Extraction Steam Pipe Sizing

D-1. PURPOSE

The purpose of this section is to size the extraction steam piping to the HTEF steam generator based on the 25 MW thermal extraction. This extraction steam is to be taken from the HP turbine exhaust and routed to the new heat exchanger (HTEF steam generator/boiler). The pipe is sized to deliver the required steam flow based on the PEPSE heat balance [Ref. D5.1] with the steam velocity below 150 ft/sec [Ref. D5.3].

D-2. METHODOLOGY

The simplified model is developed in the Arrow computer software [Ref. D5.2] to size the extraction steam piping with the steam velocities below 150 ft/sec [Ref. D5.3]. Steam inlet conditions are based on the PEPSE Heat Balance [Ref. D5.1]. The process steam pipe length, valves, and fittings are based on Assumption D4.1. The piping is assumed to be insulated by 4.5 inches of calcium silicate based on Assumption D4.2. The TB temperature and air velocity are based on Assumption D4.3.

D-3. INPUTS

Steam inlet conditions are based on the PEPSE Heat Balance [Ref. D5.1]. Steam conditions are conservatively chosen to ensure margin to the required steam conditions at the HTEF of 300°F and 50 psig per Assumption D4.5:

- Flow: 85,238 lbm/hr
- Pressure: 188.6 psia
- Temperature: 376.9°F.

D-4. ASSUMPTIONS

Extraction piping length, valves, and fittings are assumed based on the diagram shown as Figure D-1:

1. Pipes: P1, P2, P3 and P5 are each 10 ft long with 2 - 90 deg (1.5 r/D) elbows (K: 0.2 [Ref. D5.4])

2. Pipe: P4 is 200 ft long with 10 90 deg (1.5 r/D) elbows (K: 0.2 [Ref. D5.4])

3. Valves: J2 and J5 are gate valves (K: 0.11 [Ref. D5.4])

4. FCV: J3 is assumed to have a constant pressure drop of 20 psid

5. Check valve: J4 is a stop check 90 deg. globe valve (K: 5.6 [Ref. D5.4]).
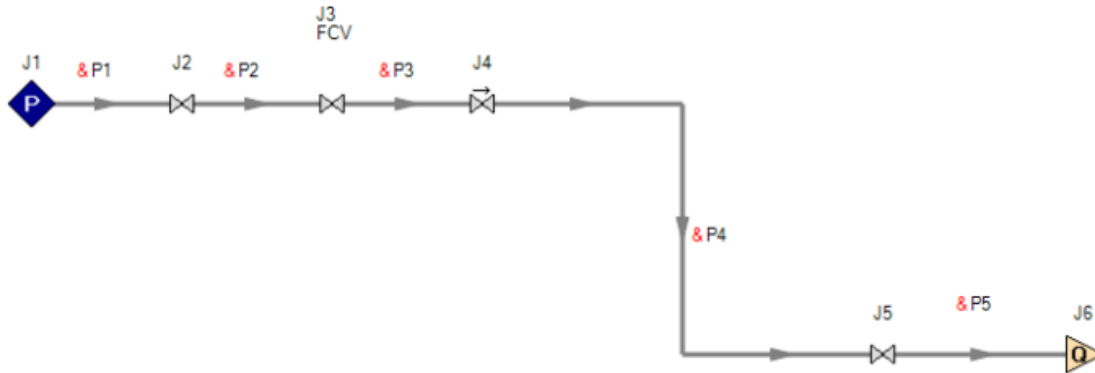
Figure D-1. Extraction piping diagram.

Pipe insulation is assumed to be calcium silicate, 4.5 inches in thickness. Insulation properties are based on the Arrow built-in properties [Ref. D5.2]. Insulation is reduced in cost estimate.

Outside air temperature is assumed to be - 10 deg. F and air velocity assumed to be 5 ft/sec. These conditions are reasonable for the typical winter in cold climate.

All piping elevations are assumed to be at same elevation of 0 ft, this is reasonable since for the steam systems the piping elevations have negligible impact on the system design.

The required steam conditions at the HTEF are assumed at 300°F and 50 psig based on agreement with INL.

D-5. REFERENCES

Arrow Computer software version 7, (S&L program # 03.7.722-7.0-08/06/2018)

Crane Technical Paper 410, 2012 Edition.

PEPSE Heat Balances as shown in Appendix C

S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

D-6. RESULTS

The Arrow model for the extraction steam to the HTEF steam generator was developed and iteratively changed until the final pipe sizes were determined. A final pipe size of 10 in. STD-schedule, 240 ft in length, was modeled and it resulted in a maximum steam velocity of ~120 ft/sec. Design pressure of 250 psig and design temperature of 400°F would envelop the conditions shown. Detailed results are shown as Figure D-2:
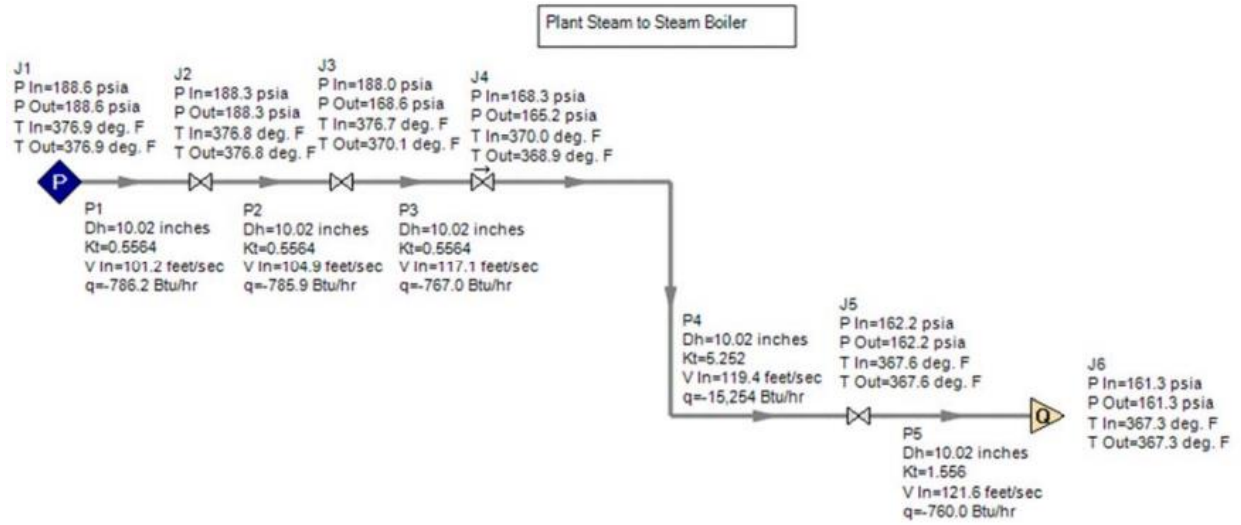
Figure D-2. Pressure and temperature diagram.

Appendix E: 100 MW$_{nom}$ Process Steam Pipe Sizing

E-1. PURPOSE

The purpose of this section is to size the process steam piping to the HTEF based on the 25 MW thermal extraction. This process steam is to be taken from the process-steam generator/boiler and routed to the HTEF (~500 meters away). The pipe is sized to deliver the required steam flow based on PEPSE heat-balance analysis [Ref. E5.1] with the steam velocity below 150 ft/sec [Ref. E5.3].

E-2. METHODOLOGY

The simplified model is developed in the Arrow computer software [Ref. E5.2] to size the extraction steam piping with steam velocities below 150 ft/sec [Ref. E5.3]. Steam-inlet conditions are based on the PEPSE heat-balance analysis [Ref. E5.1]. The process-steam pipe length, valves, and fittings are based on Assumption E4.1. The piping is assumed to be insulated by 4.5 inches of calcium silicate based on Assumption E4.2. The TB temperature and air velocity are based on Assumption E4.3.

E-3. INPUTS

Steam inlet conditions are based on the PEPSE Heat Balance [Ref. E5.1]. Steam conditions are conservatively chosen to ensure margin to the required steam conditions at the HTEF of 300°F and 50 psig per Assumption D4.5:

- Flow: 73,777 lbm/hr

- Pressure: 120.0 psia

- Temperature: 350.1°F.

E-4. ASSUMPTIONS

Extraction piping length, valves, and fittings are assumed based as Figure E-1.

1. Pipes: P10, P11, P12, P13, and P15 are each 10 ft long with 2 - 90 deg (1.5 r/D) elbows (K: 0.2 [Ref. E5.4])

2. Pipe: P14 is 1700 ft long with 20 90 deg (1.5 r/D) elbows (K: 0.2 [Ref. E5.4])

3. Valves: J11, J12, J14, and J15 are gate valves (K: 0.10 [Ref. E5.4])

4. Pressure Control Valve: J13 is assumed with constant pressure drop of 20 psid.
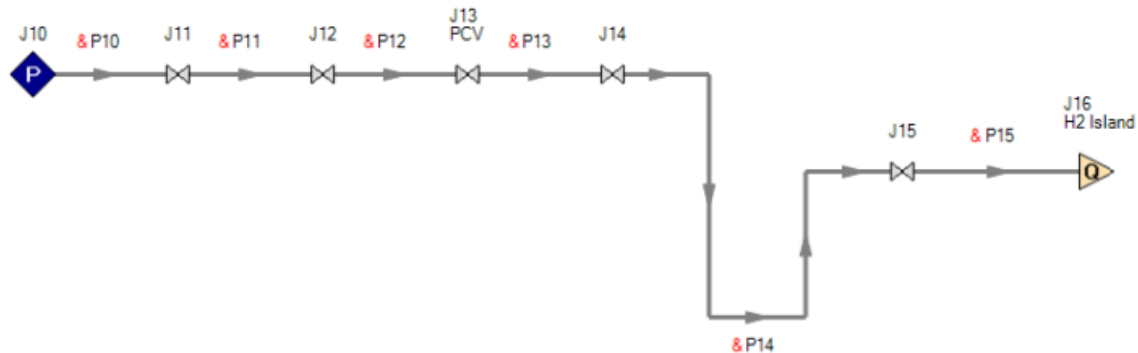
Figure E-1. Piping diagram.

Pipe insulation is assumed to be calcium silicate, 4.5 inches in thickness. Insulation properties are based on the Arrow built-in properties [Ref. E5.2]. Insulation is reduced in cost estimate. Outside air temperature is assumed to be 10°F and air velocity is assumed to be 5 ft/sec. These conditions are reasonable for the typical winter in cold climate.

All piping elevations are assumed to be at same elevation of 0 ft; this is reasonable because, for the steam systems, the piping elevations have negligible impact on the system design.

The required steam conditions at the HTEF are assumed at 300°F and 50 psig based on agreement with INL.

E-5. REFERENCES

Arrow Computer software version 7, (S&L program # 03.7.722-7.0-08/06/2018)

Crane Technical Paper 410, 2012 Edition.

PEPSE Heat Balances as shown in Appendix C

S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

E-6. RESULTS

The Arrow model for the extraction steam to the HTEF was developed and iteratively changed until the final pipe sizes were determined.

Boiler to HTEF

A final pipe size of 12 in. STD-schedule, 1,750 ft in length was modeled from the steam boiler to the HTEF and it resulted in a maximum steam velocity of ~130 ft/sec. Design pressure of 150 psig and design temperature of 400°F would envelop the conditions shown. Detailed results are shown as Figure E-2.
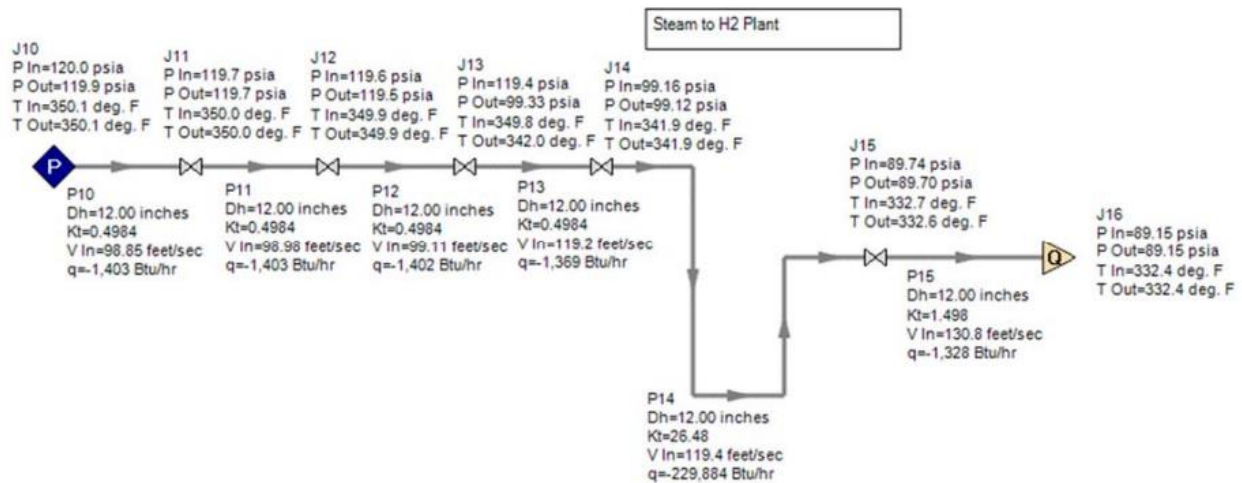
Figure E-2. Pressure and temperature diagram.

Appendix F: 100 MW_{nom} Reboiler Feed Pipe Sizing

F-1. PURPOSE

The purpose of this section is to size the reboiler feedwater pump and piping to the HTEF steam generator (reboiler) based on the 25 MW thermal extraction. This water is to be taken from the new demineralized-water storage tank and routed to the new pump which will deliver the water to the new heat exchanger (HTEF steam generator/boiler). The pipe is sized to deliver the required water flow based on PEPSE heat balance [Ref. F5.1] with the water velocity below 10 ft/sec based on general service piping recommendation [Ref. F5.3].

F-2. METHODOLOGY

The simplified model is developed in the Fathom computer software [Ref. F5.2] to size the reboiler feedwater piping with the water velocities below 10 ft/sec [Ref. F5.3]. The required water flow rate is taken from the PEPSE Heat Balance [Ref. F5.1]. Water storage tank inlet conditions are based on Assumption F4.2. The pipe length, valves, and fittings are based on Assumption F4.1. For this analysis no heat transfer is modeled from the water piping.

F-3. INPUTS

The required water flow rate is based on the PEPSE Heat Balance [Ref. F5.1]. The flow rate is 73,777 lbm/hr (~147.5 gpm)

F-4. ASSUMPTIONS

The reboiler feedwater piping length, valves, and fittings are assumed based Figure F-1:

- Pipes: P1 and P2 are each 20 ft long with 2 - 90 deg (1.5 r/D) elbows (K: 0.25 [Ref. F5.4]), note that the pump suction piping was selected one size larger than the discharge to lower suction velocity

- Pipes: P3 and P4 are each 10 ft long with no fittings

- Pipe: P5 is 200 ft long with 10 - 90 deg (1.5 r/D) elbows (K: 0.25 [Ref. F5.4])

- Pipes: P6 and P7 are each 10 ft long with 2 - 90 deg (1.5 r/D) elbows (K: 0.25 [Ref. F5.4])

- Valves: J2, J5, and J7 are gate valves (K: 0.14 [Ref. F5.4])

- Level Control Valve: J6 is assumed with constant pressure drop of 20 psid, this value should enable reasonable controllability of the control valve.

- Check Valve: J4 is a swing check with 90 deg. seat (K: 0.9 [Ref. F5.4])
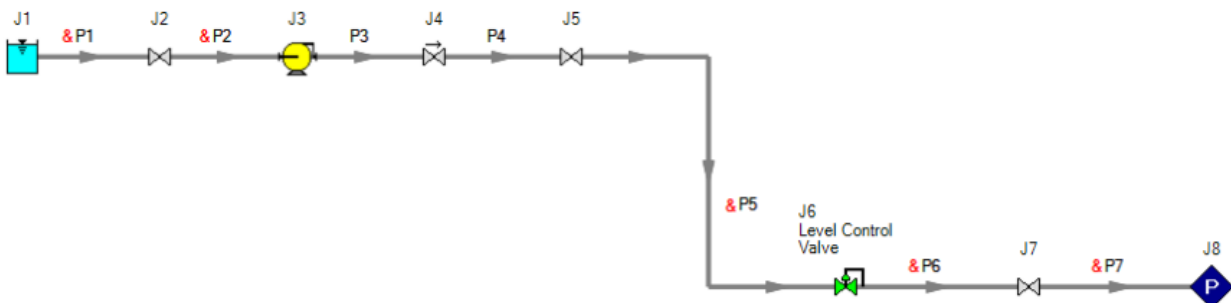
Figure E-1. Piping diagram.

Demineralized Storage Tank conditions are assumed as follows:

- Tank Water Level: 5 ft

- Water Temperature: 60°F

- Tank Surface Pressure: 0 psig.

Note that for detailed design purposes, an additional case needs to be developed with the expected maximum water temperature to determine the pump NPSH available.

The reboiler pressure is set at 140 psia to allow for the assumed pressure change 20 psid. This is consistent with the PEPSE heat-balance diagram (Appendix C) and the sizing of the steam-supply piping to the HTEF (Appendix E). All piping elevations are assumed to be at same elevation of 0 ft, this is reasonable since for the it is expected that new equipment will be at similar elevation. During the detailed design phase, actual piping routing and elevations need to be utilized. The pump efficiency is assumed at 80%.

F-5. REFERENCES

AFT Fathom Computer software version 11, (S&L program # 03.7.721-11-06/18/2020)

Crane Technical Paper 410, 2012 Edition.

PEPSE Heat Balances as shown in Appendix C

S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

F-6. RESULTS

The Fathom model for the demineralized water to the HTEF steam generator (reboiler) was developed and iteratively changed until the final pipe sizes are determined.

F-6.1   Pipe Size

For the pump discharge a pipe size of 2.5 in. STD-schedule carbon steel (for conservatism), 240 ft in length was modeled and it resulted in a maximum water velocity of ~10 ft/sec. Design pressure of 250 psig and design temperature of 150°F would envelop the conditions shown including up additional 50% in pump head rise to shutoff conditions.

For the pump suction a pipe size (was selected one size larger than the discharge to lower suction velocity) 3 in. STD-schedule carbon steel (for conservatism), 40 ft in length was modeled and it resulted in a maximum water velocity of ~6.4 ft/sec. Design pressure of 50 psig and design temperature of 150°F would envelop the conditions shown.

F-6.2   Pump Size

The initial pump sizing is based on the nominal flowrate of 147.5 gpm along with the nominal carbon-steel pipe characteristics resulted in a required pump total developed head of ~379 ft, with horsepower requirement of ~18 hp. Note that the final pump sizing needs to consider appropriate design margin and NPSH requirements.

Detailed results are shown on the diagram below:
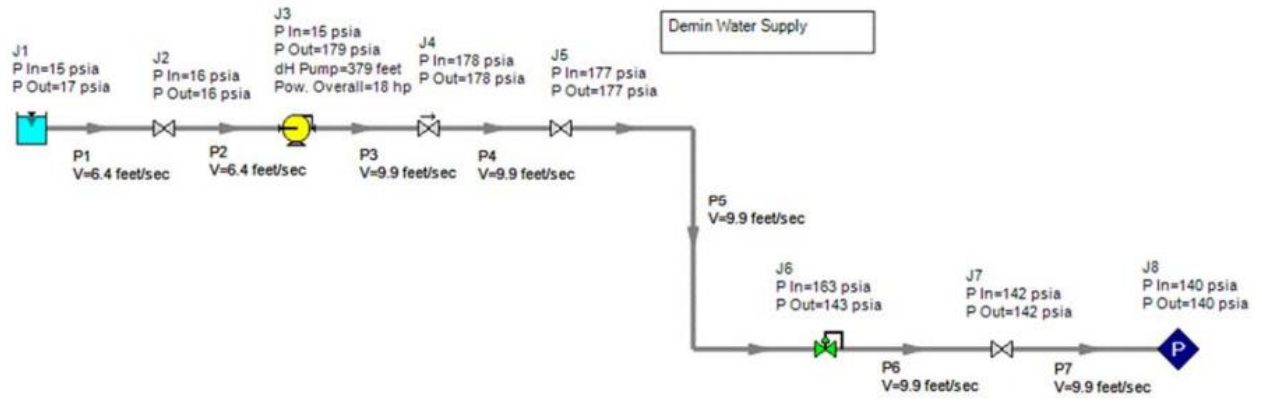
Figure F-2. Pressure and temperature diagram.

Appendix G: 100 MW$_{nom}$ Reboiler Drain-Pipe Sizing

G-1. PURPOSE

The purpose of this section is to size the reboiler drain piping from the HTEF steam generator (reboiler) to the main condenser based on the 25 MW thermal extraction. Additionally, the required differential pressure across the level control valve is determined. The pipe is sized to deliver the required water flow based on PEPSE heat balance [Ref. G5.1] with the water velocity below 7 ft/sec based on heater drain piping recommendation [Ref. G5.3].

G-2. METHODOLOGY

The simplified model is developed in the Fathom computer software [Ref. G5.2] to size the reboiler drain water piping with the water velocities below 7 ft/sec [Ref. G5.3]. The required water flow rate is taken from the PEPSE Heat Balance [Ref. G5.1]. Drain inlet and condenser conditions are taken from the PEPSE Heat Balance [Ref. G5.1]. The pipe length, valves, and fittings are based on Assumption G4.1. For the purpose of this analysis no heat transfer is modeled from the water piping.

G-3. INPUTS

The required water flow rate and boundary conditions are based on the PEPSE heat-balance analysis:

- Drain Flow: 85,238 lbm/hr (~172 gpm)

- Drain Inlet Pressure: 161.3 psia (to maximize the DP, boiler shell inlet pressure is used)

- Drain Inlet Temperature: 120°F

- Condenser Pressure: 1.7 psia (3.5 in HgA)

G-4. ASSUMPTIONS

The reboiler feedwater piping length, valves, and fittings are assumed based on Figure G-1.

- Pipes: P10 and P12 are each 10 ft long with 2 - 90 deg (1.5 r/D) elbows (K: 0.24 [Ref. G5.4])

- Pipe: P11 is 200 ft long with 10 - 90 deg (1.5 r/D) elbows (K: 0.24 [Ref. G5.4])

- Valve: J11 is a gate valve (K: 0.14 [Ref. G5.4])

- Drain Control Valve: J12 modeled to control the required drain flow.
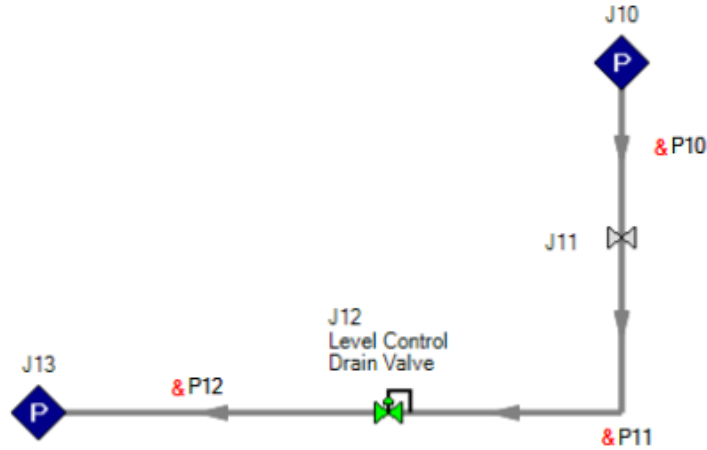
Figure G-1. Reboiler-feedwater piping diagram.

All piping elevations are assumed to be at same elevation of 0 ft; this is reasonable since for the it is expected that new equipment will be at similar elevation. During the detailed design phase, actual piping routing and elevations need to be utilized.

G-5. REFERENCES

AFT Fathom Computer software version 11, (S&L program # 03.7.721-11-06/18/2020)

Crane Technical Paper 410, 2012 Edition.

PEPSE Heat Balances as shown in Appendix C

S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

G-6. RESULTS

The Fathom model for the condensate return from the reboiler to the main condenser was developed and iteratively changed until the final pipe sizes were determined.

G-6.1 Pipe Size

The final drain-pipe size of 3.5 in. STD-schedule carbon steel (for conservatism), 220 ft in length was modeled and it resulted in a maximum water velocity of ~5.6 ft/sec. Design pressure of 200 psig and design temperature of 400°F would envelop the conditions shown.

G-6.2 Drain Control Valve Size

The drain control-valve sizing results in the following requirements:

- Drain Flow: 85,238 lbm/hr (~172 gpm)
- Valve DP: ~155.7 psid
- Valve inlet Pressure: ~158 psia

Note that due to a very high valve DP, there is a high potential for valve cavitation. This needs to be considered when specifying the drain control valve. Detailed results are shown in Figure G-1.:
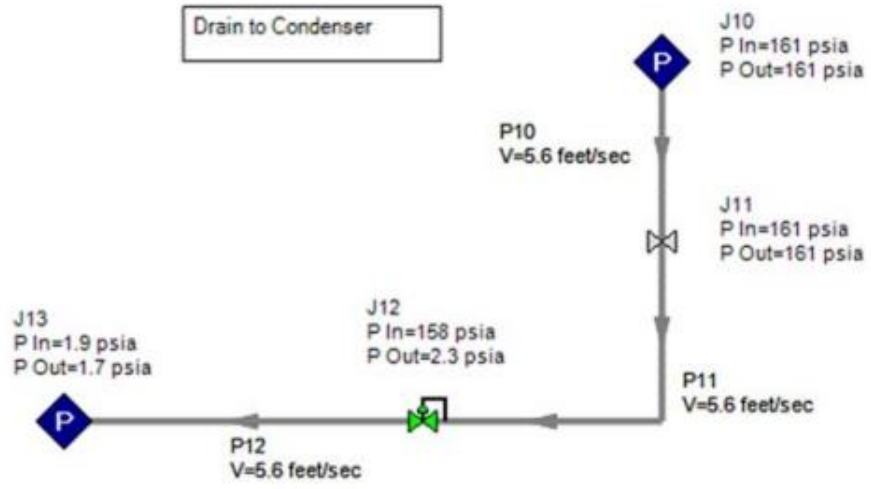
Figure G-1. Reboiler-feedwater piping temperature and pressure diagram.

Appendix H: 100 MW$_{nom}$ HTEF Feeder Electrical Single-Line Diagram and ETAP Model
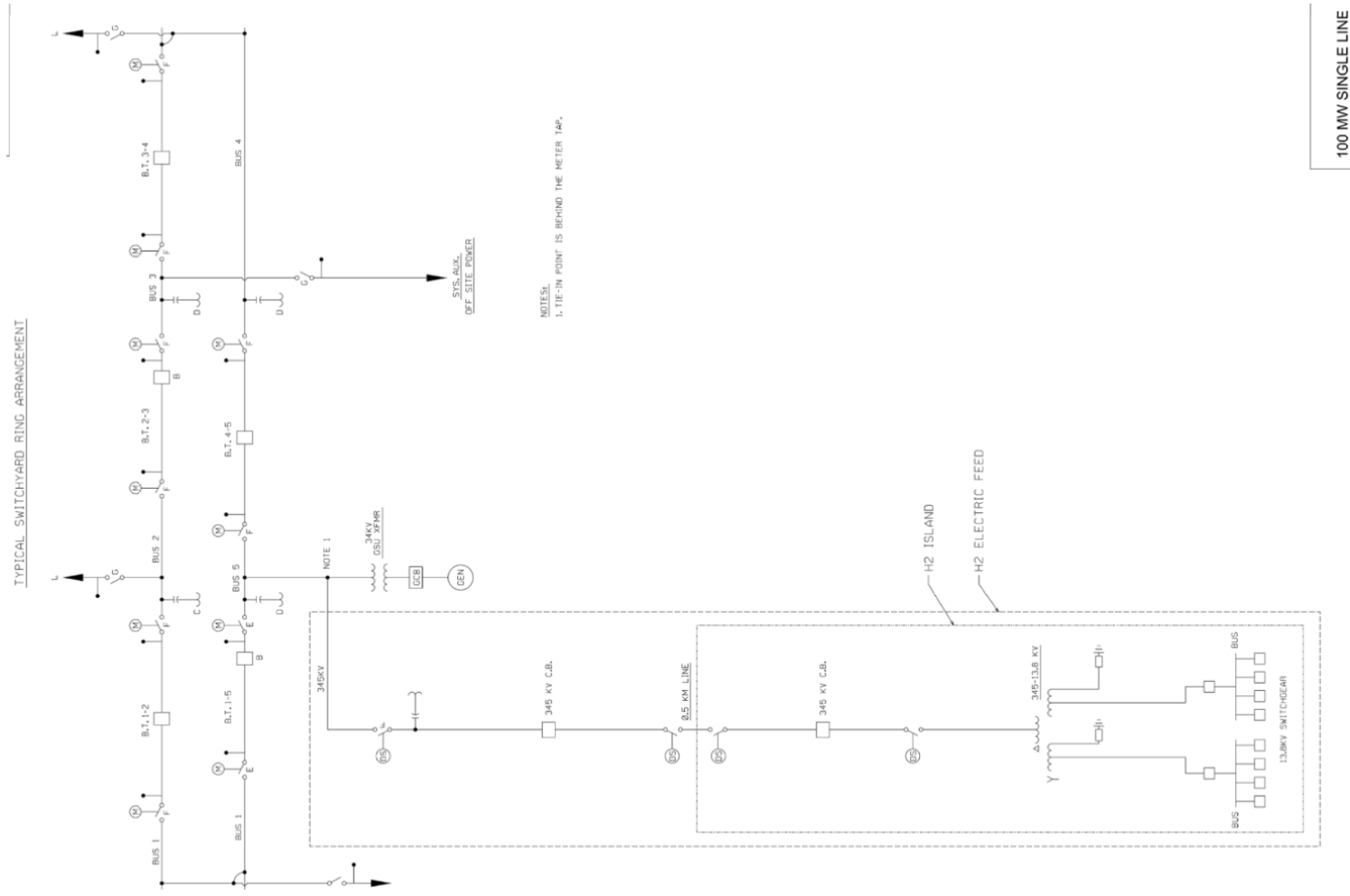
Figure H-1. 100 MW$_{nom}$ HTEF one-line electrical diagram showing typical switchyard ring arrangement.
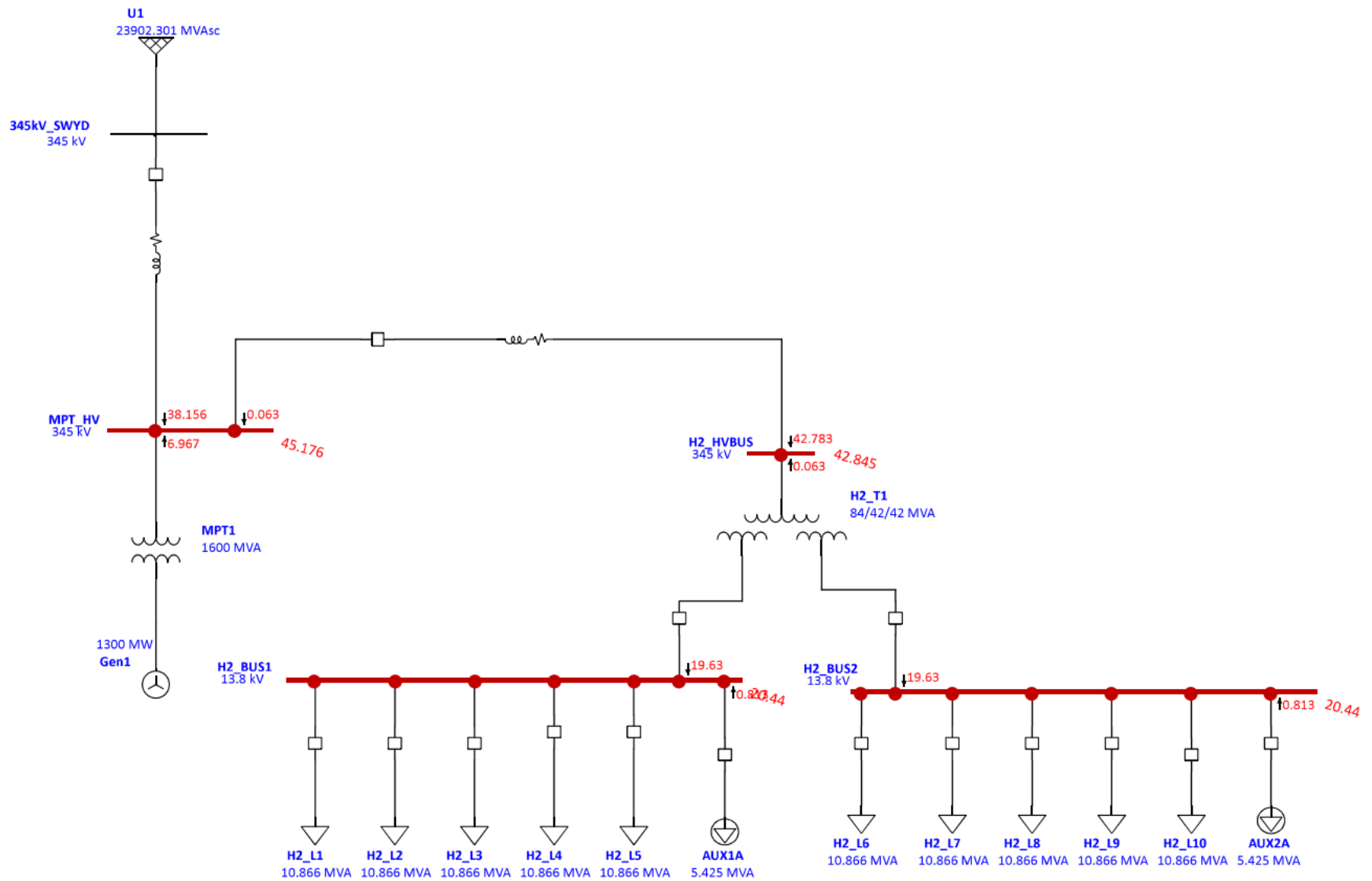
Figure H-2. 100 MW_{nom} HTEF one-line diagram OLV1 short circuit analysis.
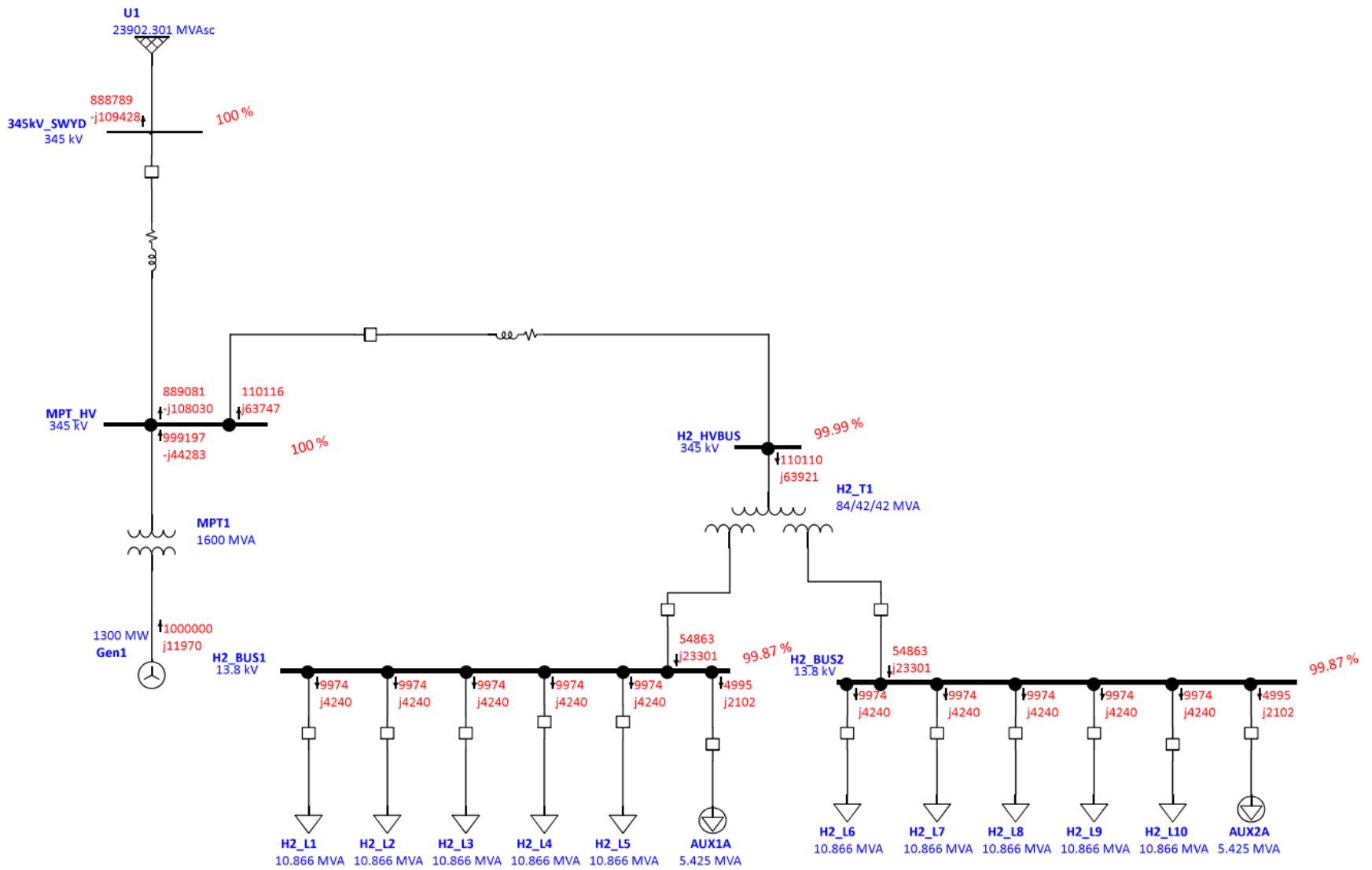
Figure H-3. 100 MW$_{nom}$ HTEF one-line diagram OLV1 load-flow analysis

Appendix I: Basis of Estimate

I-1. INTRODUCTION

This document describes and identifies the basis upon which cost estimates mentioned herein were developed by documenting the purpose, scope, methods, parameters, cost-estimating methodology, strategy, assumptions, source information, and exclusions. The purpose of the estimate is to provide capital-cost information for project planning, screening and feasibility, budgeting, or project-alternative evaluations. It is expected that the estimate be used so that end usage takes into consideration both the estimate's classification and the accuracy of the represented costs.

This cost estimate was developed using engineering-scope information. It is based largely on experience on similar projects, conceptual-design layout and configuration, equipment- and system-component sizing, and material takeoffs. Detailed engineering has not been performed to firm the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

I-2. GENERAL INFORMATION

Estimates are based on the following information:

- Estimate Numbers—35995A, 36103A, 36104A, 36105A
- Facility Location—Not identified
- Facility Type—Nuclear
- Capacity Rating—Not required
- New or Existing Facility—Existing site
- Unit of Measurement—U.S. Imperial
- Currency—U.S. Dollar.

I-3. ESTIMATE SCOPE DESCRIPTION

Listed below is a summary-level (not all inclusive) scope of facilities included in the estimate. See cost estimates for a detailed listing of the work-breakdown structure and scope:

- Civil work
- Structural work
- Concrete work
- Mechanical work
- Electrical work
- I&C.

I-4. METHODOLOGY

This cost estimate is developed using a mix of semi-detailed unit costs with assembly-level line items and detailed unit cost with forced detailed takeoff (i.e. detailed-takeoff quantities generated from

preliminary drawings and incomplete design information). As such, it can be said that this estimate is generated using a deterministic estimating method with many unit-cost line items.

In general, the estimate plan and execution process involve:

1. Preliminary engineering and project definition

2. Prepare estimate

3. Review.

I-5.   ESTIMATE CLASSIFICATION

Based on the maturity level of the project definition deliverables and the estimating methods used, this estimate can be categorized as a Class 5 Estimate and assigned a probable accuracy range -50% to +100%. Accuracy range is calculated on the total-cost estimate after the application of appropriate contingency.

The AACE has established a classification system for cost estimates listed in the following table.

Table I-1. AACE classification system for cost estimates.

Source: (AACE International Recommended Practice No. 18R-97)

Estimate Class	Maturity Level of Project Definition Deliverables % of complete definition	End Usage Typical purpose of estimate	Methodology Typical Estimating Method	Expected Accuracy Range
Class 5	0% to 2%	Concept screening	Capacity factored, parametric model, judgement, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 70%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	50% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

This table illustrates typical ranges of accuracy ranges that are associated with the process industries. The +/- value represents typical percentage variation at an 80% confidence interval of actual costs from the cost estimate after application of contingency (typically to achieve a 50% probability of project overrun versus underrun) for given scope. Depending on the technical and project deliverables (and other variables) and risks associated with each estimate, the accuracy range for any estimate is expected to fall into the ranges identified (although extreme risks can lead to wider ranges).

The purpose of the estimate is to provide capital-cost information for project planning, screening and feasibility, budgeting, or project-alternative evaluations. It is expected that the estimate be used so that the end use takes into consideration the estimate's classification and the accuracy of the represented costs.

I-6.   QUANTITY DEVELOPMENT

Quantity development is dependent on the estimating method used to create the estimate. Capacity factored or equipment-factored cost estimates do not use quantities of materials for cost estimation. Conceptual/preliminary designs and layouts were developed as needed to establish a basis to quantify the equipment and bulk materials to cost-estimate the defined scope of facilities. The quantities and scope of

facilities to be cost estimated were based on input from engineering consistent with the level of project definition required by the estimate plan. Input was received by the following disciplines:

- Mechanical engineering
- Electrical engineering
- Project management.

Detailed engineering for any of the disciplines has not been performed to firm project details, and specific site characteristics have not been fully analyzed. Allowances have been assigned where necessary to cover issues that are likely to arise, but are not clearly quantified at this time.

I-7. STRUCTURE AND CODING OF THE ESTIMATE

Based-standard coding and structure within the estimating system have been used in preparing the estimate. The structure of the estimate follows a predefined format whereas the cost information is organized and presented by grouping costs with similar attributes. The basic presentation of the overall estimate hierarchy follows:

- Direct costs
- General-conditions costs
- Project indirect costs
- Contingency
- Escalation.

Within the direct-cost group, the costs are segregated into five categories of costs in columnar format in the estimate. The direct-cost line items may further be grouped by areas or sub-areas and are evident on the summary page if this formatting structure is used.

1. Subcontract cost
2. Material cost
3. Equipment cost
4. Labor cost
5. Construction-equipment cost.

A standard coding structure has been used to categorize each direct-cost line item within the estimate. A sample of the commonly used codes in the standard coding structure of the estimating system at its highest level of the hierarchy follows. (Any estimate may contain one or more of these codes.)

11.00.00 DEMOLITION

21.00.00 CIVIL WORK

22.00.00 CONCRETE

23.00.00 STEEL

24.00.00 ARCHITECTURAL

27.00.00 PAINTING AND COATING

31.00.00 MECHANICAL EQUIPMENT

35.00.00 PIPING

36.00.00 INSULATION

41.00.00 ELECTRICAL EQUIPMENT

42.00.00 RACEWAY, CABLE TRAY & CONDUIT

43.00.00 CABLE

44.00.00 CONTROL & INSTRUMENTATION.

I-8.   DIRECT COSTS

Direct field costs represent the permanently installed facilities and include subcontract, material, process-equipment, labor, and construction-equipment costs. Each line item in the estimate may have any combination of these cost categories.

I-8.1   Process-Equipment

Pricing for permanently installed equipment is based on S&L in-house data, vendor catalogs, industry publications, and other related projects, with exception of the following items for which a budgetary vendor quote was received. Vendor quotes are furnish-only unless otherwise noted.

Equipment pricing was reviewed to ensure that the following criteria were addressed and taken into consideration where deemed necessary:

- Allowance for attendance by vendor representatives for technical field assistance

- Freight

- Spare parts

- Startup spares.

I-8.2   Material

Pricing for permanently installed materials are based on S&L in-house data, vendor catalogs, industry publications and other related projects, with exception of the following items for which a budgetary vendor quote was received. No quotes were solicited for this estimate.

I-8.3   Labor

Development of construction labor cost takes into account the quantity, wage rates, installation hours, labor productivity, labor availability, and indirect construction costs. A more-detailed description and methodology follows.

Installation Hours

Installation hours represent the labor man-hours to install an item and, collectively, all craft hours to install the entire scope of facilities. These include the time of all craft personnel and supervisors and include time spent in inductions, training, toolbox meetings, cleanups, and the time of bus drivers. S&L maintain a database of standard unit-installation hours. The database represents standard installation rates for U.S. Gulf Coast Region. Standard unit-installation rates were applied to the quantities and equipment in the estimate. The resultant hours were further adjusted for local productivity (described below). Man-hours associated with subcontract labor cost are not represented in the estimate.

Equipment-setting labor man-hours were developed using a combination of several techniques. Installation was developed using equipment weights, equipment sizes, and fabrication completeness upon

delivery. Both bulk material and equipment installation labor/man-hours may also be based on anyone of the many public domain resources readily available and at our disposal.

Labor Productivity

In evaluating productivity, factors such as jobsite location, type of work, and site congestion were considered. A labor-productivity multiplier of 1.6 is included for work performed at a nuclear facility. Productivity multiplier does not include weather-related delays. Effectively, this factor increases the installation hours (or decreases productivity) in proportion to the factor.

Labor Wage Rates

Labor profile: Prevailing wages for Bloomington, Illinois.

Craft labor rates were developed in part from the publication "RS Means Labor Rates for the Construction Industry," 2022 edition. These prevailing rates are representative of union or non-union rates, whichever is prevailing in the area. Costs have been added to cover Social Security, workmen's compensation, and federal and state unemployment insurance. A composite of one or more burdened craft rates are combined based on their participation to form a crew suitable for the task being performed. Composite crew rates are used in the estimate, not the individual craft rates. Construction-indirect and general-conditions cost allowances are not included in the crew rates. These cost allowances are itemized separately.

I-8.4 Construction Equipment

Construction equipment cost is included on each line item as needed, based on the type of activity and construction-equipment requirements to perform the work. It includes costs for rental of all construction equipment, fuel, oil and maintenance. Equipment operators are included with direct labor costs.

Depending on the nature of the work, additional cost for construction equipment and operators such as heavy-lifting cranes may be required to perform the work activities, which would then be included as a separate line item and included in the subcontract cost category. For this project, supplemental construction equipment cost is not necessary.

I-8.5 Subcontract

Subcontract costs, as defined within this estimate, are all-inclusive costs. These costs have nothing to do with the contracting strategy or subcontractors. A subcontract cost simply does not include any additional markups, i.e., general conditions, overhead, or other construction indirect costs. Subcontract costs, however, are subject to and included in the contingency and escalation calculations if applicable. Subcontract costs may or may not have a labor component; thus, they do not identify associated installation labor man-hours.

I-9. Construction Direct and Indirect Costs and General Conditions

The estimate is constructed in such a manner that the direct construction costs are determined directly, and several direct construction-cost accounts are allowances and determined indirectly by taking a percentage of the directly determined costs. These percentages are based on our experience with projects of similar type and size. Listed below are the additional costs included, unless noted as not included.

I-9.1 Additional Labor Costs

- Labor supervision (additional pay over that of a journeyman)
- Showup time

- Cost of overtime pay and inefficiency due to extended hours is included, on the basis of working a 50-hour work week (5–10 hour days)
- *Per diem* is not included or deemed required.

No additional incentives, such as bonuses, have been included to attract labor. The estimate is based an adequate supply of qualified craft personnel being available to staff this project.

I-9.2   Site Overhead

Site-overhead costs include:

- CM (includes project manager, superintendents, project controls, site clerical)
- Field-office expenses (trailer rental, furniture, office equipment, computers, site communication, office supplies)
- Material and quality control (inspectors, quality assurance personnel)
- Material handling
  - Labor cost to receive, unload, and properly store material and equipment delivered to the site, and materials management
  - Labor to retrieve materials and equipment from storage and deliver to the worksite
- Safety program administration and personnel (safety manager, personal protective equipment, drug testing kits including lab fees, jobsite orientation materials and materials required to maintain a safe jobsite)
- Temporary facilities (any temporary structures or utilities required at the job site, such as temporary warehouse, change trailers, site security, temporary electric grid, water consumed during construction, trash hauling fees, sanitary facilities)
- Indirect craft labor (tool control, training, welder certification, fire watch, site cleanup, dust control)
- Mobilization/demobilization to the jobsite
- Legal expenses and claims.

I-9.3   Other Construction Indirects

Other construction indirect costs include:

- Small tools and consumables
- Scaffolding (includes rental, erection, and removal)
- General-liability insurance (covers premiums likely to be incurred)
- Construction equipment
- Mobilization and demobilization
- Freight on material
- Freight on process equipment
- Sales Tax – not included
- Contractors G&A expense
- Contractors profit.

Contractors G&A and Profit are markup that contractors will apply to materials and labor services provided under their respective contracts regardless of the contracting approach for the overall project.

I-10. Project Indirect Costs

Listed below are additional indirect project costs included. Regardless of the contracting approach or which (owner or non-owner) organization provides them, professional services are required and itemized to show transparency and the incremental cost value associated with each. These costs are included:

- Professional engineering services

- Professional CM services (management of the project schedule, cost, quality, safety, scope and function)

- Professional startup and commissioning support services (development and implementation of the procedures and testing to energize plant systems and turnover a fully operational facility to the owner)

- Startup spare parts.

These costs are not included:

- Owner's cost

- EPC fee

- Allowance for funds used during construction.

I-11. Contingency

Based on project definition, contingency costs are included in the estimate as separate line items as

- Material contingency cost—Calculated @ 50% of cost

- Process equipment contingency cost—Calculated @ 50% of cost

- Labor contingency cost—Calculated @ 50% of cost

- Construction equipment contingency cost—Calculated @ 50% of cost

- Subcontract contingency costs—Calculated @ 50% of cost

- Indirect contingency costs—Calculated @ 50% of cost.

The rates relate to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope or exclusions outside of what has been estimated, only variation within the defined scope. The rates neither represent the high range of all costs, nor is it expected that the project will experience all actual costs at the maximum value of their range of variation. The addition of contingency improves the probability of not having a cost overrun. Even with the inclusion of contingency, the estimate is still subject to cost a cost overrun in accordance with the accuracy range previously defined.

I-12. Escalation

Escalation is not included.

I-13. Contracting Approach

Estimatess are based on an EPCM multiple contract approach. This approach basically has one main contractor, typically an architect/engineer firm to produce the design, assist in the procurement of goods and services and provide CM services during construction. The EPCM contractor generally acts as an agent for the owner when purchasing goods and services, meaning contracts and purchase orders are written on the owner's letterhead.

There may be several purchase orders to purchase the necessary engineered equipment and engineered bulks for the project. These items would be handed to the installation contractors to install. There are no markups by the EPCM contractor on any of the purchase orders or construction contracts.

Installation is achieved using multiple subcontractors. Contractors are responsible for purchasing nonengineered bulk materials. Contractors will apply a markup on the value of nonengineered bulk materials for overhead and profit.

Estimates are based on warranties provided by equipment manufacturers. Additionally, the EPCM contract does not include plant performance, pricing, or schedule guarantees.

I-14. Items Excluded

All known or conceptual scope of required physical facilities as provided by the project team to encompass a complete project has been included in the estimate. Any known intentional omissions are documented in the "Notes/Assumptions/Clarifications" section.

The cost estimate represents only the costs listed in the estimate. The estimate does not include allowances for any other costs not listed and incurred by the owner. Excluded costs are any that are not listed in the estimate.

There may be additional costs that the owner should consider, such as (the list below is not all-inclusive, see Table I-1):

- Owner's staff (project management, engineering support, procurement services, IT support, clerical staff)

- Site facilities for owner's personnel, CM, and startup and commissioning (offices and trailers, guard houses, furniture, signage, staff parking, vehicles, access control, computer network/servers, safety equipment, etc.)

- Site services for owner's personnel, CM, and startup and commissioning (telephone, electricity, natural gas, potable water, sewage, sanitary, garbage collection, recycled materials/metals collection [may also be collected from contractors, depending on owner's policy], snow removal, dust control, janitorial services, internet, cable services, reprographics, etc.)

- Land acquisition/rights-of-way costs

- Project development costs

- Safety incentives (any owner's safety incentive, over and above contractor's programs)

- Lock-out/tag-out program (personnel, procedures, and hardware)

- Power consumption costs from temporary power grid connection, if any

- First fills

- Spare parts

- Furnishings for new office, warehouse, and laboratory

- Plant staff training (time for personnel being trained) is owner's cost (also includes owner's time for preparation and/or modification of plant operating procedures)

- Legal and accounting fees

- *Per diem*/travel expenses for owner's personnel assigned to site

- Applicable taxes

- Independent inspection company to perform code-required testing and inspection

- Permitting

- Insurance

- Owner's bond fees

- Owner's contingency

- Project financing, AFUDC

- Community relations (if applicable, costs associated with any special provisions or facilities required by the local community, such as support for schools, fire department, police due to increased temporary population, etc.)

- Schedule-acceleration costs

- Schedule delays and associated costs caused by

  - Unexpected site conditions
  - Unidentified ground conditions
  - Labor disputes
  - Lack of labor resources
  - Weather related conditions
  - Force majeure
  - Permit applications.

I-15. Notes/Assumptions/Clarifications

None.

Table I-1. Detailed cost breakdown for integrating a PWR with a 500 MW$_{nom}$ HTEF with 500 m standoff distance. Detailed costs for other designs are in [19].

Estimate Totals

Description	Amount	Totals	Hours
Labor	3.596.659		47.146
Material	3.896.426		
Subcontract	1.795.951		
Construction Equipment	814.510		
Process Equipment	2.956.660		
	13,060,206	13,060,206	
General Conditions			
Additional Labor Costs			
90-1 Labor Supervision	215,800		
90-2 Show-up Time	71,933		
90-3 Cost Due To OT 5-10's	703,694		
90-4 Cost Due To OT 6-10's			
90-5 Per Diem			
Site Overheads			
91-1 Construction Management	1,553,757		
91-2 Field Office Expenses	478,596		
91-3 Material&Quality Control	121.310		
91-4 Site Services	99,635		
91-5 Safety	76,736		
91-6 Temporary Facilities	58,382		
91-7 Temporary Utilities	63,976		
91-8 Mobilization/Demob.	61,529		
91-9 Legal Expenses/Claims	9,089		
Other Construction Indirects			
92-1 Small Tools & Consumables	116,532		
92-2 Scaffolding	271,907		
92-3 General Liability Insur.	38,844		
92-4 Constr. Equip. Mob/Demob	81,451		
92-5 Freight on Material	194,821		
92-6 Freight on Process Equip	147.833		
92-7 Sales Tax			
92-8 Contractors G&A	1.736.741		
92-9 Contractors Profit	2.481.058		
	8,583,624	21,643,830	
Project Indirect Costs			
93-1 Engineering Services	3.500.000		
93-2 CM Support	649.315		
93-3 Start-Up/Commissioning	216,438		
93-4 Start-Up/Spare Parts	9.313		
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	4,375,066	26,018,896	
Contingency			
94-1 Contingency on Const Eq	586,447		
94-3 Contingency on Material	2,741,136		
94-4 Contingency on Labor	5,044,110		
94-5 Contingency on Subcontr.	897,976		
94-6 Contingency on Process Eq	1,552,247		
94-7 Contingency on Indirect	2,187,533		
	13,009,449	39,028,345	
Escalation			
96-1 Escalation on Const Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Subcontract			
96-6 Escalation on Process Eqp			
96-7 Escalation on Indirects			
		39,028,345	
98 Interest During Constr			
		39,028,345	
Total		39,028,345	

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Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
1			**STEAM SUPPLY**									
	21.00.00		**CIVIL WORK**									
		21.17.00	**EXCAVATION**									
			FOUNDATION EXCAVATION, CLAY USING 1 CY BACKHOE	HYDROGEN INTERFACE EQUIPMENT	194.22 CY	-	-		53	4,224	935	5,158
			FOUNDATION EXCAVATION, CLAY USING 1 CY BACKHOE	(2) DRAIN COOLER FOUNDATIONS	39.56 CY	-	-		11	860	190	1,051
			FOUNDATION EXCAVATION, CLAY USING 1 CY BACKHOE	(2) DEMINERALIZED WATER TANK AND PUMP	203.33 CY	-	-		55	4,422	978	5,400
			FOUNDATION EXCAVATION, CLAY USING 1 CY BACKHOE	(2) STEAM REBOILER	217.33 CY	-	-		59	4,726	1,046	5,772
			TRENCH EXCAVATION 6FT TO 10FT DEEP, DENSE HARD CLAY USING 0.75 CY EXCAVATOR	BURIED R/O SUPPLY PIPE	1,174.46 CY	-	-		106	8,451	1,870	10,321
			EXCAVATION						284	22,683	5,019	27,701
		21.19.00	**DISPOSAL**									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	HYDROGEN INTERFACE EQUIPMENT	194.22 CY	-	-		19	1,491	330	1,821
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	(2) DRAIN COOLER FOUNDATIONS	39.56 CY	-	-		4	304	67	371
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	BURIED R/O SUPPLY PIPE	422.93 CY	-	-		30	2,435	539	2,973
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	(2) DEMINERALIZED WATER TANK AND PUMP	203.33 CY	-	-		20	1,561	345	1,906
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	(2) STEAM REBOILER	217.33 CY	-	-		21	1,668	369	2,037
			DISPOSAL						93	7,458	1,650	9,108
		21.20.00	**BACKFILL**									
			FOUNDATION BACKFILL, SELECT STRUCTURAL FILL	HYDROGEN INTERFACE EQUIPMENT	70.02 CY	-	-	2,241	17	1,344	297	3,882
			FOUNDATION BACKFILL, SELECT STRUCTURAL FILL	(2) DRAIN COOLER FOUNDATIONS	36.29 CY	-	-	1,161	9	696	154	2,012
			FOUNDATION BACKFILL, SELECT STRUCTURAL FILL	(2) DEMINERALIZED WATER TANK AND PUMP	87.51 CY	-	-	2,800	21	1,679	372	4,851
			FOUNDATION BACKFILL, SELECT STRUCTURAL FILL	(2) STEAM REBOILER	122.16 CY	-	-	3,909	29	2,344	519	6,772
			TRENCH BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	BURIED R/O SUPPLY PIPE	1,045.14 CY	-	-		125	10,027	2,219	12,246
			TRENCH BACKFILL, SAND BEDDING	BURIED R/O SUPPLY PIPE	400.66 CY	-	-	6,811	63	4,997	1,106	12,914
			BACKFILL					16,923	264	21,087	4,666	42,676
		21.43.00	**FENCEWORK**									
			SECURITY AND FENCING MODIFICATIONS		1.00 LS	200,000	-					200,000
			FENCEWORK			200,000						200,000
		21.54.00	**CAISSON**									
			3 FT DIA X 6 FT DEEP CAISSON	PIPE RACK PIERS - EACH CAISSON = 1.57CY X $1,300 = $2,041 EA.	180.00 EA	367,380	-					367,380
			CAISSON			367,380						367,380
			CIVIL WORK			567,380		16,923	641	51,227	11,335	646,865
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5 FT THICK, 4500 PSI	HYDROGEN INTERFACE EQUIPMENT	133.33 CY	-	-	19,333	267	18,216	3,472	41,021
			MAT FOUNDATION LESS THAN 5 FT THICK, 4500 PSI	(2) DRAIN COOLER FOUNDATIONS	8.00 CY	-	-	1,160	16	1,093	208	2,461
			MAT FOUNDATION LESS THAN 5 FT THICK, 4500 PSI	(2) DEMINERALIZED WATER TANK AND PUMP	127.24 CY	-	-	18,449	254	17,383	3,313	39,145
			MAT FOUNDATION LESS THAN 5 FT THICK, 4500 PSI	(2) STEAM REBOILER	111.11 CY	-	-	16,111	222	15,180	2,893	34,184
			CONCRETE					55,053	759	51,872	9,887	116,812
		22.15.00	**EMBEDMENT**									
			EMBEDMENTS, STAINLESS STEEL	HYDROGEN INTERFACE EQUIPMENT	1,333.33 LB	-	-	14,000	107	7,484	201	21,684
			EMBEDMENTS, STAINLESS STEEL	(2) DRAIN COOLER FOUNDATIONS	80.00 LB	-	-	840	6	449	12	1,301
			EMBEDMENTS, STAINLESS STEEL	(2) DEMINERALIZED WATER TANK AND PUMP	1,272.35 LB	-	-	13,360	102	7,141	191	20,692
			EMBEDMENTS, STAINLESS STEEL	(2) STEAM REBOILER	1,111.11 LB	-	-	11,667	89	6,236	167	18,070
			EMBEDMENT					39,866	304	21,311	571	61,748
		22.17.00	**FORMWORK**									
			BUILT UP INSTALL & STRIP	HYDROGEN INTERFACE EQUIPMENT	420.00 SF	-	-	1,050	134	9,815	1,107	11,973
			BUILT UP INSTALL & STRIP	(2) DRAIN COOLER FOUNDATIONS	144.00 SF	-	-	380	46	3,365	380	4,105
			BUILT UP INSTALL & STRIP	(2) DEMINERALIZED WATER TANK AND PUMP	508.94 SF	-	-	1,272	163	11,894	1,342	14,508
			BUILT UP INSTALL & STRIP	(2) STEAM REBOILER	720.00 SF	-	-	1,800	230	16,826	1,899	20,525
			FORMWORK					4,482	574	41,900	4,728	51,110
		22.25.00	**REINFORCING**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	HYDROGEN INTERFACE EQUIPMENT	10.00 TN	-	-	11,200	288	20,485	3,263	34,948
			UNCOATED A615 GR60	(2) DRAIN COOLER FOUNDATIONS	0.60 TN	-	-	672	17	1,229	196	2,097
			UNCOATED A615 GR60	(2) DEMINERALIZED WATER TANK AND PUMP	9.54 TN	-	-	10,688	275	19,549	3,114	33,351
			UNCOATED A615 GR60	(2) STEAM REBOILER	8.33 TN	-	-	9,333	240	17,071	2,719	29,123
			REINFORCING					31,893	820	58,334	9,292	99,519
			CONCRETE					131,295	2,457	173,417	24,477	329,190
	23.00.00		STEEL									
		23.25.00	ROLLED SHAPE									
			MEDIUM WEIGHT MEMBERS, 21 LB/LF TO 40 LB/LF, TWO COAT PAINTED	PIPE RACK	400.00 TN	-	-	1,392,400	8,160	720,936	231,336	2,344,672
			ROLLED SHAPE					1,392,400	8,160	720,936	231,336	2,344,672
			STEEL					1,392,400	8,160	720,936	231,336	2,344,672
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			STEEL PAINTING ALLOWANCE		1.00 LS	10,000	-					10,000
			PAINTING			10,000						10,000
			PAINTING & COATING			10,000						10,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.65.00	HEAT EXCHANGER									
			STEAM REBOILER		2.00 EA	-	2,000,000	-	448	32,516	5,389	2,037,905
			HEAT EXCHANGER				2,000,000		448	32,516	5,389	2,037,905
		31.75.00	PUMP									
			CENTRIFUGAL PUMP, 310 GPM, 367 FT, 36 HP	DEMINERALIZED FEEDWATER	2.00 EA	-	60,000	-	288	20,903	3,465	84,368
			PUMP				60,000		288	20,903	3,465	84,368
		31.83.00	TANK									
			110,000 GAL FIELD FABRICATED TANK, STAINLESS STEEL	DEMINERALIZED WATER TANK	2.00 EA	900,000	-	-				900,000
			TANK			900,000						900,000
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			DRAIN COOLER		2.00 EA	-	400,000	-	288	20,903	3,465	424,368
			DRAIN RECEIVER, 3 FT DIA		2.00 EA	-	22,000	-	128	9,290	1,540	32,830
			MECHANICAL EQUIPMENT, MISCELLANEOUS				422,000		416	30,193	5,004	457,198
			MECHANICAL EQUIPMENT			900,000	2,482,000		1,152	83,612	13,859	3,479,471
	35.00.00		PIPING									
		35.13.01	SS 304, ABOVE GROUND, PROCESS AREA									
			3 IN DIA, SCH 40S	PCV-206A BYPASS LINE	8.00 LF	-	-	310	42	3,074	782	4,166
			3 IN DIA, SCH 40S	PCV-206B BYPASS LINE	8.00 LF	-	-	310	42	3,074	782	4,166
			3.5 IN DIA, SCH 40S	"A" FEEDWATER PUMP DISCHARGE TO STEAM REBOILER	240.00 LF	-	-	11,268	1,252	92,211	23,472	126,951
			3.5 IN DIA, SCH 40S	"B" FEEDWATER PUMP DISCHARGE TO STEAM REBOILER	240.00 LF	-	-	11,268	1,252	92,211	23,472	126,951
			4 IN DIA, SCH 40S	TANK-001A DISCHARGE LINE TO FEEDWATER PUMP PMP-001A	40.00 LF	-	-	2,204	233	17,160	4,368	23,732
			4 IN DIA, SCH 40S	TANK-001B DISCHARGE LINE TO FEEDWATER PUMP PMP-001B	40.00 LF	-	-	2,204	233	17,160	4,368	23,732
			5 IN DIA, SCH 10S	"A" REBOILER DRAIN TO CONDENSER	220.00 LF	-	-	15,664	641	47,190	12,012	74,866
			5 IN DIA, SCH 10S	"B" REBOILER DRAIN TO CONDENSER	220.00 LF	-	-	15,664	641	47,190	12,012	74,866
			SS 304, ABOVE GROUND, PROCESS AREA					58,893	4,334	319,267	81,269	459,429
		35.13.10	CARBON STEEL, ABOVE GROUND, PROCESS AREA									
			14 IN DIA, 3/8" STD	HP TURBINE REHEAT STEAM TO REBOILER	120.00 LF	-	-	30,492	551	40,590	10,332	81,414
			20 IN DIA, 3/8" STD	JOINED HP TURBINE REHEAT LINES TO SPLIT FOR STEAM REBOILERS	200.00 LF	-	-	100,080	1,501	110,549	28,140	238,769
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					130,572	2,052	151,139	38,472	320,183
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			18 IN DIA, 3/8 IN STD	"A" REBOILER TO H2 PLANT	1,750.00 LF	-	-	430,325	4,914	361,965	92,138	884,428
			18 IN DIA, 3/8 IN STD	"B" REBOILER TO H2 PLANT	1,750.00 LF	-	-	430,325	4,914	361,965	92,138	884,428

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
			CARBON STEEL, STRAIGHT RUN					860,650	9,828	723,930	184,275	1,768,855
		35.15.30	**HDPE, BURIED**									
			3.5 IN DIA, DR 11	BURIED R/O SUPPLY LINE FROM HYDROGEN PLANT	3,600.00 LF	-	-	17,802	1,987	146,377	37,260	201,439
			HDPE, BURIED					17,802	1,987	146,377	37,260	201,439
		35.35.00	**PIPE SUPPORTS, HANGERS**									
			SUPPORT W/ BEAM FOR 3 IN PIPE		2.00 EA	-	-	302	21	1,556	396	2,254
			SUPPORT W/ BEAM FOR 3.5 IN PIPE		44.00 EA	-	-	6,864	465	34,225	8,712	49,801
			SUPPORT W/ BEAM FOR 4 IN PIPE		8.00 EA	-	-	1,288	97	7,166	1,824	10,278
			SUPPORT W/ BEAM FOR 5 IN PIPE		30.00 EA	-	-	4,950	365	26,871	6,840	38,661
			SUPPORT W/ BEAM FOR 14 IN PIPE		4.00 EA	-	-	1,876	97	7,166	1,824	10,866
			SUPPORT W/ BEAM FOR 18 IN PIPE		100.00 EA	-	-	59,000	1,620	119,329	30,375	208,704
			SUPPORT W/ BEAM FOR 20 IN PIPE		6.00 EA	-	-	4,728	167	12,304	3,132	20,164
			PIPE SUPPORTS, HANGERS					79,008	2,832	208,617	53,103	340,728
		35.45.00	**VALVES**									
			6 X 8 IN RELIEF VALVE, CAST IRON, CLASS 250, MANUAL, FLANGE END		2.00 EA	-	-	20,912	33	2,451	624	23,987
			8 IN GATE VALVE, CS, CLASS 150, MANUAL, WELD END		2.00 EA	-	-	4,800	31	2,286	582	7,668
			12 IN GLOBE VALVE, CS, CLASS 300, AIR OPERATED, WELD END		2.00 EA	-	-	180,000	62	4,573	1,164	185,737
			14 IN GATE VALVE, CS, CLASS 300, MANUAL, WELD END		10.00 EA	-	-	145,000	269	19,800	5,040	169,840
			14 IN CHECK VALVE, CS, CLASS 300, MANUAL, WELD END		2.00 EA	-	-	21,120	54	3,960	1,008	26,088
			16 IN PRESSURE CONTROL VALVE, CS, CLASS 150, MANUAL, WELD END		2.00 EA	-	-	100,000	63	4,667	1,188	105,855
			18 IN GATE VALVE, CS, CLASS 150, MANUAL, WELD END		6.00 EA	-	-	78,000	221	16,264	4,140	98,404
			VALVES					549,832	733	54,002	13,746	617,580
		35.46.00	**STAINLESS STEEL VALVES**									
			0.75 IN BALL VALVE, CLASS 600, MANUAL, WELD END		14.00 EA	-	-	2,800	69	5,115	1,302	9,217
			0.75 IN GATE VALVE, CLASS 600, MANUAL, WELD END		2.00 EA	-	-	670	10	731	186	1,587
			3.5 IN GATE VALVE, CLASS 150, MANUAL, WELD END		6.00 EA	-	-	18,000	70	5,127	1,305	24,432
			3.5 IN CHECK VALVE, CLASS 150, MANUAL, WELD END		2.00 EA	-	-	6,000	23	1,709	435	8,144
			3.5 IN GATE VALVE, CLASS 150, AIR OPERATED, WELD END		2.00 EA	-	-	35,000	33	2,428	618	38,046
			4 IN VALVE, CLASS 150, MANUAL, WELD END		4.00 EA	-	-	14,000	52	3,866	984	18,850
			5 IN VALVE, CLASS 150, MANUAL, WELD END		4.00 EA	-	-	22,000	73	5,374	1,368	28,742
			STAINLESS STEEL VALVES					98,470	331	24,349	6,198	129,017
		35.49.00	**MISCELLANEOUS VALVES**									
			STAINLESS STEEL TUBING, COMPRESSION FITTINGS, VALVE, SUPPORT, FILTER, REGULATOR	AIR SUPPLY FOR AIR OPERATED/ACTUATED VALVE	6.00 EA	-	-	3,600	115	8,486	2,160	14,246
			STEAM TRAP 1" INVERTED BUCKET		2.00 EA	-	-	1,440	13	943	240	2,623
			MISCELLANEOUS VALVES					5,040	128	9,428	2,400	16,868
			PIPING					1,800,267	22,225	1,637,109	416,723	3,854,099
36.00.00			**INSULATION**									
		36.17.03	**PIPE, MINERAL WOOL W/ALUMINUM JACKETING**									
			1 IN THICK, 3 IN PIPE		16.00 LF	-	-	118	15	1,275	128	1,520
			1 IN THICK, 3.5 IN PIPE		480.00 LF	-	-	3,840	246	20,258	2,032	26,130
			1 IN THICK, 3.5 IN PIPE	BURIED R/O SUPPLY LINE FROM HYDROGEN PLANT	20.00 LF	-	-	160	19	1,593	160	1,913
			1 IN THICK, 4 IN PIPE		80.00 LF	-	-	722	88	7,259	728	8,710
			1 IN THICK, 5 IN PIPE		440.00 LF	-	-	4,400	260	21,471	2,154	28,026
			3 IN THICK, 14 IN PIPE		120.00 LF	-	-	5,701	296	24,373	2,445	32,519
			3 IN THICK, 18 IN PIPE		3,500.00 LF	-	-	201,480	3,801	313,316	31,434	546,211
			3 IN THICK, 20 IN PIPE		200.00 LF	-	-	12,664	319	26,298	2,638	41,601
			PIPE, MINERAL WOOL W/ALUMINUM JACKETING					229,066	5,045	415,844	41,721	686,630
			INSULATION					229,066	5,045	415,844	41,721	686,630
41.00.00			**ELECTRICAL EQUIPMENT**									
		41.33.00	**HEAT TRACING**									
			3.5 IN PIPE HEAT TRACING		480.00 LF	-	-	11,496	730	49,066	11,871	72,432
			3.5 IN PIPE HEAT TRACING	BURIED R/O SUPPLY LINE FROM HYDROGEN PLANT	20.00 LF	-	-	479	61	4,089	989	5,557
			4 IN PIPE HEAT TRACING		80.00 LF	-	-	2,009	251	16,872	4,082	22,962
			5 IN PIPE HEAT TRACING		440.00 LF	-	-	13,200	690	46,397	11,225	70,822
			CONTROL PANEL		1.00 EA	-	-	8,000	38	2,963	617	11,580
			TRANSFORMER		1.00 EA	-	-	3,000	26	1,975	412	5,387

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
		41.33.00	HEAT TRACING									
			HEAT TRACE ENGINEERING		1.00 LS	20,000	-					20,000
			HEAT TRACING			20,000		38,184	1,795	121,361	29,196	208,740
			ELECTRICAL EQUIPMENT			20,000		38,184	1,795	121,361	29,196	208,740
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.30	LEVEL DEVICES									
			LEVEL TRANSMITTER, RADAR LIQUID LEVEL TYPE, FLANGE MOUNT	ROSEMOUNT MODEL NO. 5408A1SHA1NA1R2AACAA2	4.00 EA	-	-	18,320	128	8,484	650	27,454
			LEVEL DEVICES					18,320	128	8,484	650	27,454
		44.21.40	PRESSURE DEVICES									
			PRESSURE TRANSMITTER, GAUGE TYPE, WITH 2 VALVE MANIFOLD	ROSEMONT MODEL NO. 3051S1CG1A2A11A1AL2M5Q4	2.00 EA	-	-	8,710	35	2,333	179	11,222
			PRESSURE DEVICES					8,710	35	2,333	179	11,222
			CONTROL & INSTRUMENTATION					27,030	163	10,817	829	38,676
	61.00.00		CONSTRUCTION INDIRECT									
		61.15.00	CRAFT PERSONNEL									
			CRAFT PERSONNEL FOR STARTUP SUPPORT		1.00 EA	-	-		800	58,064	0	58,064
			CRAFT PERSONNEL						800	58,064	0	58,064
			CONSTRUCTION INDIRECT						800	58,064	0	58,064
			1 STEAM SUPPLY			1,497,380	2,482,000	3,635,164	42,438	3,272,388	769,475	11,656,406
2			ELECTRICAL & TRANSMISSION LINE									
	21.00.00		CIVIL WORK									
		21.17.00	EXCAVATION									
			FOUNDATION EXCAVATION, COMMON EARTH USING 1 CY BACKHOE	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	38.96 CY	-	-		9	748	165	913
			EXCAVATION						9	748	165	913
		21.19.00	DISPOSAL									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	38.96 CY	-	-		4	299	66	365
			DISPOSAL						4	299	66	365
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, SELECT STRUCTURAL FILL	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	34.16 CY	-	-	1,093	8	655	145	1,894
			BACKFILL					1,093	8	655	145	1,894
		21.54.00	CAISSON									
			3 FT DIA X 13 FT DEEP CAISSON	FOR 345KV DISC. SW. - EACH CAISSON = 3.4CY X $1,300 = $4,420	2.00 EA	8,840	-					8,840
			5.5 FT DIA X 40 FT DEEP CAISSON	FOR 345KV STEEL POLES - EACH CAISSON = 35.19 X $1,300 = $45,734	6.00 EA	274,404						274,404
			3 FT DIA X 15 FT DEEP CAISSON	FOR (3) 345KV CCVT's. - EACH CAISSON = 3.93CY X $1,300 = $5,109 EA.	3.00 EA	15,327						15,327
			CAISSON			298,571						298,571
			CIVIL WORK			298,571		1,093	21	1,702	377	301,743
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5 FT THICK, 4500 PSI	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	18.52 CY	-	-	2,685	37	2,530	482	5,698
			CONCRETE					2,685	37	2,530	482	5,698
		22.15.00	EMBEDMENT									
			EMBEDMENTS, STAINLESS STEEL	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	4.00 EA	-	-	100	13	898	24	1,022
			EMBEDMENT					100	13	898	24	1,022
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	(1) 345KV CIRCUIT BREAKER FOUNDATION - 25'L X 10'W X 2'D	140.00 SF	-	-	350	45	3,272	369	3,991
			FORMWORK					350	45	3,272	369	3,991
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	(1) 345KV CIRCUIT BREAKER FOUNDATION	1.39 TN	-	-	1,556	40	2,845	453	4,854

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
		22.25.00	**REINFORCING**									
			UNCOATED A615 GR60	- 25'L X 10'W X 2'D	1.39 TN	-	-	1,556	40	2,845	453	4,854
			REINFORCING					1,556	40	2,845	453	4,854
			CONCRETE					4,691	135	9,545	1,329	15,565
	23.00.00		**STEEL**									
		23.99.00	**STEEL, MISCELLANEOUS**									
			STEEL - STRUCTURAL SUPPORT FOR 345KV DISCONNECT SWITCH	FOR 345KV DISC. SW. - EACH SUPPORT = 8,052 LBS X 2 = 16,104	16,104.00 LB	-	-	44,286	206	18,212	5,844	68,342
			STEEL - STRUCTURAL SUPPORT FOR CCVT	FOR (3) 345KV CCVT - EACH SUPPORT = 450LBS X 3 =1,350 LBS TOTAL	1,350.00 LB	-	-	3,713	17	1,527	490	5,729
			STEEL, MISCELLANEOUS					47,999	223	19,738	6,334	74,071
			STEEL					47,999	223	19,738	6,334	74,071
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.17.00	**COMMUNICATION SYSTEM**									
			COMMUNICATION SYSTEM - CABINET NEMA 4X	WITH METERS & AUX. TELECOMMUNICATION FOR REVENUE METERS	1.00 LS	-	50,000		192	14,813	3,087	67,900
			COMMUNICATION SYSTEM				50,000		192	14,813	3,087	67,900
		41.31.00	**ELECTRICAL EQUIPMENT, GROUNDING**									
			4/0 BARE COPPER CONDUCTOR	GROUNDING	492.00 LF	-	-	2,091	15	1,019	247	3,357
			500 AWG GROUNDING CABLE		1,970.00 LF	-	-	19,700	102	6,849	1,657	28,206
			ROD, GROUND, CONICAL POINT, 5/8" DIA. X 15' LGTH, COPPERCLAS, NOT THREADED	(6) 345KV STEEL POLES	18.00 EA	-	-	4,680	50	3,329	805	8,814
			5/8" X 10'-0" COPPER WELD GROUND ROD		6.00 EA	-	-	1,050	13	888	215	2,152
			#2 CU BARE STRANDED GROUND WIRE	(6) 345KV STEEL POLES	240.00 LF	-	-	288	3	222	54	564
			ELECTRICAL EQUIPMENT, GROUNDING					27,809	183	12,307	2,977	43,093
		41.47.00	**PANEL: CONTROL, DISTRIBUTION, & RELAY**									
			PROTECTIVE RELAY 50BF	RELAY WILL BE MOUNTED IN EXISTING RELAY PANEL	1.00 LS	-	300		26	1,975	412	2,687
			BREAKER FAILURE LOCKOUT RELAY 86BF	RELAY WILL BE MOUNTED IN EXISTING RELAY PANEL	1.00 LS	-	800		26	1,975	412	3,187
			LINE DIFFERENTIAL PROTECTION RELAY 411L/87	RELAY WILL BE MOUNTED IN EXISTING RELAY PANEL	3.00 LS	-	30,450		115	8,888	1,852	41,190
			LINE DIFFERENTIAL PROTECTION RELAY 311L/87	RELAY WILL BE MOUNTED IN EXISTING RELAY PANEL	3.00 LS	-	17,910		115	8,888	1,852	28,650
			LINE DIFFERENTIAL LOCKOUT RELAY 86	RELAY WILL BE MOUNTED IN EXISTING RELAY PANEL	1.00 LS	-	1,000		26	1,975	412	3,387
			PANEL: CONTROL, DISTRIBUTION, & RELAY				50,460		307	23,700	4,940	79,100
			ELECTRICAL EQUIPMENT				100,460	27,809	682	50,820	11,005	190,094
	42.00.00		**RACEWAY, CABLE TRAY & CONDUIT**									
		42.15.33	**CONDUIT, PVC**									
			4" PVC CONDUIT	ROUTED UNDERGROUND	492.00 LF	-	-	2,706	80	5,062	111	7,879
			CONDUIT, PVC					2,706	80	5,062	111	7,879
		42.15.37	**CONDUIT, RGS**									
			2" RGS CONDUIT	CONDUIT FOR CT's & CONTROL CABLES ROUTED INSIDE TB	1,148.00 LF	-	-	11,423	647	41,166	899	53,487
			CONDUIT, RGS					11,423	647	41,166	899	53,487
			RACEWAY, CABLE TRAY & CONDUIT					14,129	726	46,228	1,009	61,366
	43.00.00		**CABLE**									
		43.10.00	**CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION**									
			24 FIBER OPTIC GROUND WIRE	CABLE FOR LINE DIFFERENTIAL RELAYS ACROSS THE LINE	2,297.00 LF	-	-	11,761	184	12,358	2,990	27,108
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					11,761	184	12,358	2,990	27,108
		43.20.00	**600V CABLE & TERMINATION**									
			12/C #12 AWG SHLD	INDICATION CABLE FOR 345KV BREAKER CONTROL	1,640.00 LF	-	-	3,805	131	8,823	2,135	14,763
			12/C #12 AWG SHLD	CONTROL & INSTRUMENTATION FOR MECH EQUIP TO CONTROL RM	328.00 LF	-	-	761	26	1,765	427	2,953
			4/C #10 AWG SHLD	CABLES FOR (5) CT's FROM BREAKER TO RELAY ROOM	6,562.00 LF	-	-	14,305	283	19,064	4,612	37,981

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
		43.20.00	**600V CABLE & TERMINATION**									
			4/C #8 AWG	CABLE FOR PUMP	656.00 LF	-	-	1,975	47	3,176	768	5,919
			600V CABLE & TERMINATION					20,845	488	32,828	7,942	61,616
			CABLE					32,606	672	45,186	10,932	88,724
	44.00.00		**CONTROL & INSTRUMENTATION**									
		44.13.00	**CONTROL SYSTEM**									
			HUMAN MACHINE INTERFACE (HMI)	STAND ALONE HMI FOR CONTROL & INDICATIONS OF H2 POWER LINE & STEAM SUPPLY IN THE MCR	1.00 LS	-	30,000		128	8,150	178	38,328
			CONTROL SYSTEM				30,000		128	8,150	178	38,328
			CONTROL & INSTRUMENTATION				30,000		128	8,150	178	38,328
	51.00.00		**SUBSTATION, SWITCHYARD & TRANSMISSION LINE**									
		51.13.00	**CONDUCTOR & WIRE**									
			OPTICAL GROUND WIRE (OPGW) - SHIELD WIRE		10,500.00 LF	-	-	17,640	58	3,677	80	21,397
			CONDUCTOR & WIRE					17,640	58	3,677	80	21,397
		51.13.02	**CONDUCTORS**									
			CONDUCTOR, 1113 KCMIL, ACSR (2) PER PHASE, BLUEJAY	TRANSMISSION LINE CABLE OUTDOOR	10,500.00 LF	-	-	53,760	347	23,302	5,638	82,700
			CONDUCTORS					53,760	347	23,302	5,638	82,700
		51.15.27	**CIRCUIT BREAKER**									
			345KV, 3000A, MANUALLY OPERATED DISCONNECT SWITCH, 50 KA SHORT CIRCUIT	345KV DISC. SW.	2.00 EA	-	50,000		352	23,894	1,155	75,048
			345KV, 3000A, HV - CIRCUIT BREAKER		1.00 EA	-	257,600		192	13,033	630	271,263
			CIRCUIT BREAKER				307,600		544	36,927	1,784	346,311
		51.15.37	**COUPLING CAPACITOR VOLTAGE TRANSFORMER (CCVT)**									
			COUPLING CAPACITOR VOLTAGE TRANSFORMER (CCVT)		3.00 EA	-	29,100		192	13,033	630	42,763
			COUPLING CAPACITOR VOLTAGE TRANSFORMER (CCVT)				29,100		192	13,033	630	42,763
		51.15.43	**METERING**									
			REVENUE METER	METERS TO BE RATED FOR 345KV TRANSMISSION LINE	3.00 EA	-	7,500		77	5,213	252	12,965
			METERING				7,500		77	5,213	252	12,965
		51.15.67	**INSULATOR**									
			INSULATOR, POST, CLAMP TOP, 138KV, POLYMER, GRAY, HORIZONTAL MOUNT	(6) 345KV STEEL POLES	18.00 EA	-	-	4,422	10	666	161	5,249
			INSULATOR					4,422	10	666	161	5,249
		51.21.00	**TRANSMISSION TOWER, HARDWARE ASSEMBLY**									
			DAMPER, CONDUCTOR, STOCKBRIDGE VIBRATION, 1590 MCM ACSR, 45X7 STRANDING, CODE NAME-LAPWING	(6) 345KV STEEL POLES	18.00 EA	-	-	612	13	892	216	1,720
			DAMPER, CONDUCTOR, SPIRAL VIBRATION, 336.4 KCM ACSR, 159 KCM ACSR, 66" LENGTH, COLOR CODE-GREEN	(6) 345KV STEEL POLES	12.00 EA	-	-	234	3	222	54	510
			CLAMP, CABLE, SUSPENSION U-BOLT, 5A, ALUMINUM ALLOY	(6) 345KV STEEL POLES	24.00 EA	-	-	1,182	3	222	54	1,458
			ROD, ARMOR, SINGLE ARM/SUPPORT, 2156 KCM ACSR, 84X19 STRANDS, 0436 DIA. X 100 IN. LONG, 14 RODS PER SET, ALUMINUM ALLOY, PREFORMED	(6) 345KV STEEL POLES	24.00 EA	-	-	1,290	30	1,997	483	3,771
			TRANSMISSION TOWER, HARDWARE ASSEMBLY					3,318	50	3,333	806	7,458
		51.25.00	**TRANSMISSION TOWER, POLE (STEEL)**									
			85' ENGINEERED STEEL MONOPOLE (H6)	(6) 345KV STEEL POLES	6.00 EA	-	-	53,544	46	3,107	752	57,403
			TRANSMISSION TOWER, POLE (STEEL)					53,544	46	3,107	752	57,403
		51.99.00	**SUBSTATION, SWITCHYARD & TRANSMISSION LINE, MISCELLANEOUS**									
			SIGNS AND MARKERS (WARNING, STRUCTURE NUMBER, AERIAL PATROL, ETC.	(6) 345KV STEEL POLES	6.00 LT	-	-	252	20	1,344	65	1,661
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE, MISCELLANEOUS					252	20	1,344	65	1,661

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE				344,200	132,936	1,343	90,602	10,168	577,906
	61.00.00		CONSTRUCTION INDIRECT									
		61.15.00	CRAFT PERSONNEL									
			CRAFT PERSONNEL FOR STARTUP SUPPORT		1.00 EA	-	-		550	36,988	0	36,988
			CRAFT PERSONNEL						550	36,988	0	36,988
		61.99.00	MISCELLANEOUS									
			SET UP TIME	(6) 345KV STEEL POLES	24.00 EA	-	-		66	4,439	1,074	5,512
			AUXILIARY ARMS	(6) 345KV STEEL POLES	6.00 EA	-	-		10	666	161	827
			DRILLING AND FRAMING	(6) 345KV STEEL POLES	6.00 EA	-	-		13	888	215	1,102
			BLOCK & TAGS	(6) 345KV STEEL POLES	18.00 EA	-	-		7	443	107	551
			STEEL ASSEMBLY	(6) 345KV STEEL POLES	6.00 EA	-	-		132	8,877	2,148	11,025
			MISCELLANEOUS						228	15,312	3,704	19,017
			CONSTRUCTION INDIRECT						778	52,300	3,705	56,004
			2 ELECTRICAL & TRANSMISSION LINE			298,571	474,660	261,262	4,708	324,272	45,035	1,403,800

Appendix J: IP—ENG-001 Design-Attribute Review

Design Attribute Review - Engineering Disciplines			
Tier 1	**Tier 2**	**Placekeeping**	**Remarks**
	Does the change: (Affect is defined as add, change, or remove)		
Electrical			
	1. Affect electrical components including motors, breakers, fuses, relay, electrical cables, conduits, trays raceways, tubing tracks, skid mounted equipment, large power transformers etc.? (SOER 10-1)	Yes	The protective relays of the H2 transmission line interface with the plant existing generator and GSU transformer relays and logic to isolate the generator/GSU during fault on the line. Therefore, CTs from the HV circuit breaker at the H2 feeder will be brought back to the plant relay room. The reboiler feed pump requires 480 Vac. 125 Vdc is required for the high-voltage breaker control and protective relay circuits. Therefore, the design effects the plant existing breakers, electrical cables, trays, and raceways in the plant.
	2. Affect electrical protective devices or their settings such as fuses, breakers, protective relays, or thermal overloads?	Yes	The design affects the existing protective relays for the generator and GSU transformer.
	3. Affect electrical loads? • Affect emergency diesel loading? • Add or remove station battery loading? • Add or remove load to a vital bus? • Add or remove load to a non-vital bus? • Compatible with transformer capacities? • Impact and Station Blackout Loadings or commitments? • Compatible with other associated electrical equipment capacities? • Have the dynamic effects as well as the static effects on bus voltage, current, and setpoints been considered, such as a large motor start, large motor trip, or bus transfer?	Yes	The 480 Vac and 125 Vdc power required for the H2 interface equipment are non-safety related and they will add additional loads to the plant electrical system.
	4. Affect motor driven pump or fan load, horsepower or efficiency?	No	
	5. Affect transformers, breakers, protective devices, the main turbine, and/or generator that could impact the transmission system (studies, protective settings, etc.)? • Affect switchyard voltage, switchyard breaker alignment, generator VAR loading? • Affect changes to generator electrical characteristics? • Affect changes to POST TRIP offsite power loading? • Affect status of offsite power voltage regulating devices (e.g. capacitor bank availability)?	Yes	There is no impact to generator VAR loading, which is controlled based on switchyard voltage. The switchyard breaker alignment is not impacted by the addition of the new high-voltage line to the hydrogen plant as the new high-voltage line is protected by a new high-voltage circuit breaker downstream of the tap point. The only additional exposure for the nuclear plant generator and switchyard breakers to trip for a single failure is for a fault on the very short length of conductor bus from the electrical tap point to the new high-voltage breaker. The length of this buswork is designed as short as practical to minimize the additional exposure. The hydrogen production facility is physically and electrically separated from the offsite power feed. Therefore, there is no impact to offsite power loading for the POST TRIP scenario. The hydrogen production facility is physically and electrically separated from the offsite power circuits. The load flow analysis demonstrates the change in the switchyard voltage due to the addition of the 128MWe/570MWe electrical load is negligible. Therefore, the status of offsite power voltage regulating devices is not impacted.
	6. Add structures in a strong electrical field (e.g., near high voltage power lines)? Special grounding may be required.	Yes	The installation of the H2 transmission line is around the GSU transformer and the yard. Therefore, it is near high voltage power line.
	7. Affect electrical cables: • Assure that all added cables meet fire retardancy requirements, and if required, EQ requirements? (Reference IEEE 383, IEEE1202, or approved equivalent) • Be compatible with existing electrical insulation and wiring? • Affect ampacity of existing cables? • Affect voltage drop? • Add cables to existing electrical raceways? • Be routed through fire wrapped raceways? • Routed in and/or through manholes? • Meet train separation requirements?	Yes	The cables added in the power block from the design will meet fire retardancy requirements.
	8. Affect ampacity or voltage drop, with consideration for component or system performance?	Yes	Complete system analysis performed on the power feeder between the NPP and the H2 plant for cable ampacity and voltage drop.
	9. Affect current, voltage, or power, with consideration for component or system performance?	Yes	
	10. Affect elevated or degraded supply voltage, with consideration for impact on equipment and components?	Yes	

Design Attribute Review - Engineering Disciplines

Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	11. IF relays are used, are any relay contacts appropriate for the operating voltage? (Also, CONSIDER the impact of low voltage on CONTACT operation and coil pickup/ drop out.)	Yes	
	12. Affect containment penetration protection?	No	
	13. Affect UL (or equivalent) listings?	No	
	14. Affect raceways (including seismic analysis)?	Yes	New cable added will be routed in the plant existing raceways.
	15. Affect the station grounding or lightning protection system?	Yes	Electrical equipment installed in the PA or the yard will be connected to the switchyard grounding.
	16. Affect electromagnetic interference between new/existing equipment and electromagnetic coupling interactions between circuits? (Reference EPRI 102323 and NRC RG 1.180)	No	
	17. Affect motor selection, including requirements for torque, voltage, frequency, and insulation class?	No	
	18. Affect plant communication system including phones, paging, cell phones, radio systems, etc?	No	
	19. Affect SSC protected by the cathodic protection system or freeze protection / heat tracing?	Yes	Underground piping will require heat tracing and outdoor components will require freeze protection. Exposed metals may also require cathodic protection. The nuclear plant will supply the power required for these measures.
	20. Affect environmental conditions in areas containing EQ qualified equipment?	No	
	21. Affect heat load calculations including Control Room, Battery Room, etc?	No	
	22. Affect normal/emergency lighting including potential obstructions to light paths?	Yes	Lighting within the Turbine Building and in the yard near the H2 interface equipment may be affected. More lighting would be required.
Instrument and Controls (I&C)			
	1. Affect any instrumentation and controls including controllers, actuators, transducers, indicators, transmitters, gauges, other instruments, system interlocks, start trip signals, annunciators, set points or margins, ranges, accuracy, time constants, response time, location, associated tubing, skid mounted equipment, wiring, control logic, etc. because of modifications or installation of new SSCs?	Yes	A standalone HMI for control, indications and alarm of the H2 power line and steam supply installed in the MCR, utilizing existing Fiber Optic backbone in the plant to communicate between the HMI and H2 interface equipment / protection panel.
	2. Affect critical characteristics of instrument or control equipment including voltage, power to an instrument, current, pressure, temperature ratings, switch development, coil or contact on a switch or relay associated with an instrument, critical dimensions or materials, instrument range, accuracy, Setpoint or tolerance, replacement of analog devices with digital devices, etc.?	No	
	3. Affect indicating instruments, controls and alarms used for operation, testing or maintenance, type of instruments, installed spares, range or measurement, calibration, accuracy, response time, and location of indication.	Yes	Existing alarms may be modified through the addition of H2 steam supply and electric feeder equipment. New indication, controls, and alarms will also be added for this equipment.
	4. Affect instrument piping, tubing, or supports?	No	
	5. Affect I&C setpoints, setpoint margin and/or setpoint calculations?	No	
	6. Affect requirements for measurement and test equipment, or test equipment accuracy evaluations?	No	
	7. Have the instruments been properly selected for the application? (i.e. range, accuracy, time response, pressure/ temperature rating, etc.)	No	
	8. Require alarms for off-normal conditions?	Yes	
	9. Are there requirements for remote and/or local operation?	Yes	See detail in question 1.
	10. Are there requirements for manual and/or automatic operation?	No	
	11. Are there calibration and maintenance requirements for the instruments?	No	
	12. Are there requirements for testing (e.g. permanent test features, indication, restoration, connections)?	No	
	13. Affect response characteristics of any existing instrumentation?	No	
	14. Are there requirements for electro-magnetic Interference (EMI) / Radio Frequency Interference (RFI), including adding equipment to existing plant configuration and/or need to address solid state vulnerability to RFI?	No	
	15. Affect software and programming/programmable settings of digital or electronic equipment?	No	
	16. Affect digital equipment upgrades? (Ref: EPRI TR 102348, GL 95 02, and EPRI TR 107339)	No	
	17. Could a transient result if the equipment is bumped?	No	
	18. Affect grounding of the instrument signal loop and/or power source?	No	
	19. Affect the air supply, fail position, regulator type, stroke or action of a valve or damper associated with an instrument?	No	
	20. Affect an instrument loop action or wiring associated with an instrument loop?	No	
	21. Are there requirements for power supplies, or modification affects loading on instrument loops?	No	
	22. Are there requirements for special post installation setup? • Setting of gain for full power that may be unstable at low power? • Tuning of a controller to account for a new control valve trim?	No	

Design Attribute Review - Engineering Disciplines

Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	23. Affect acceptance criteria for data such as pressure, flow, temperature, etc, used for calculations, or measurement and test equipment uncertainty?	No	
	24. Affect the cyber security program or affect digital assets such as communication pathways, computer equipment, networks, systems, data transmission, modems, etc.?	Yes	The design includes digital relays that will require review.
	25. Affect Reg Guide 1.97 equipment?	No	
Mechanical			
	1. Affect mechanical SSCs, including tanks, pumps, valves, heat exchangers, piping, supports, skid mounted equipment, etc. and attachments because of modifications or installation of a new SSCs.?	Yes	Tie-ins to existing steam & drains piping, installation of reboiler/s, demin pump/s, demin tank/s, and isolation & control valves.
	2. Are there requirements for ASME, ASTM and ANSI standards applicable to the design?	Yes	Reboiler/s designed to ASME code.
	3. Affect design limits (i.e., pressure, temperature, limits on number of various temperature/pressure cycles required by ASME to be considered) to be placed on the hydraulic properties of a system or component?	No	
	4. Are there requirements for vibration, stress, shock, and reaction forces?	Yes	Stress requirements for piping, reaction loads on Hx nozzles. Steam piping will need to meet requirements for stress and reaction forces.
	5. Does the design involve piping subject to vibration or piping near to/ connected to rotating equipment? If so, the design should consider impacts on branch lines and other connected equipment (i.e. 2-1 taper welds, piping support design, vibration analysis, etc.).	Yes	Demin pump discharge piping will need to consider vibration in its design.
	6. Affect cantilevered branch lines created by new installations or by re-configuration or removal of existing piping?	No	
	7. Affect class II/I conditions associated with non-safety class piping?	No	
	8. Affect the frequency forcing function created by rotating equipment such as a pump, fan or compressor (e.g. change in speed, number of cylinders, etc.)? If so, the post-modification testing should monitor surrounding piping and tubing for excessive vibration to be evaluated for additional support if necessary.	No	
	9. Affect equipment or components in locations prone to inducing low stress/ high cycle fatigue failures? ASSESS the potential for high cycle fatigue caused by • Changes in the system structural frequency content, • Changes in operating speeds of rotating equipment or operating speeds, • Changes in hydraulic control systems, • Changes in system flow characteristics, e.g. flow velocities, • Changes in system flow control and pressure drop devices	No	
	10. Require freeze protection or does the modification affect existing freeze protection?	Yes	Demin water lines and associated equipment may require freeze protection.
	11. Affect normally stagnant non-isolable RCS branch lines (e.g. length, size, and configuration)? If so, the guidance provided in EPRI Document MRP-146 Revision 1, Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines" and EPRI MRP-146S, Supplemental Guidance, shall be considered in implementing the plant change.	No	
	12. Does the modification need to consider hydraulic requirements such as PUMP net positive suction heads, allowable pressure drops, allowable fluid velocities and pressures, valve trim requirements, packing/seal requirements?	Yes	Pump sizing, hydraulic analysis of piping, valve trim considerations for level control to condenser.
	13. Affect any piping erosion (cavitation, impingement, abrasive wear, etc.), or corrosion (FAC, general corrosion, etc.) concerns?	Yes	Evaluate flow conditions between reboiler and condenser connections for FAC.
	14. Affect any pipe stress, pipe support, thermal expansion, seismic movement, or hydraulic analysis?	Yes	Stress analysis for piping mods, pipe supports for stream/drains piping.
	15. Affect a potential for causing hydraulic transients or water hammer that can have damaging impact on piping or plant operation?	Yes	When bringing the external loop into service potential exists to flow high pressure steam through a cold pipe.
	16. Affect any mechanical setpoints, setpoint margins, and/or setpoint calculations? (e.g. relief valve settings).	Yes	The reboiler/s will require pressure relief. Feed pump discharge may also require a relief valve for pump protection.
	17. Are there requirements to provide vents, drains, and sample points to accommodate operational, maintenance and testing needs?	Yes	MS system piping changes, steam piping to H2 island, etc.
	18. Are there code requirements to provide overpressure protection or thermal relief?	Yes	The reboiler/s will require pressure relief. Feed pump discharge may also require a relief valve for pump protection.
	19. Affect line pressure, differential pressure, or temperature at which a valve functions?	Yes	Applies to new piping runs to new external closed loop.

Design Attribute Review - Engineering Disciplines

Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	20. Affect loading on HVAC systems or ventilation flow during or after installation? • Continually energized equipment has been added to a room. • Changes to equipment that will increase the heat load in a room during post-accident conditions. • Changes in system flows of cooling water or chilled water that may reduce existing cooling flow rates to HVAC units. • Changes to wall and floor penetrations, doors, barriers that could short circuit air flow and limit cooling/heating to specific areas. Consider both temporary conditions during installation as well as final configurations. • Changes to the Control Room, Fuel Building, Auxiliary Building, and BWR Turbine Building boundaries that could affect the ability of the HVAC to provide pressurization and filtration requirements.	No	
	21. Affect quantities, storage, or location of chemicals that may impact Control Room Habitability issues?	No	
	22. Affect loading on any other support system such as instrument air, service air, circulating water, fire water, demineralized water, or other system?	Yes	Demin water is assumed to be supplied from offsite. New AOVs will affect loading on station instrument air system.
	23. Affect insulation?	Yes	New piping will be insulated.
	24. Are there requirements for independent means of pressure relief?	Yes	Reboiler/s will require pressure relief.
	25. Affect the assigned system design pressure or temperature?	Yes	New piping added to plant, increasing extracted mass flow.
	26. Affect a gas-to-fluid system interface that may ALLOW gas intrusion? If so, the design shall be revised to preclude or mitigate the gas intrusion.	No	
	27. Does the design provide means to ensure full pipes (high point, etc.), IF required due to the assumptions of the pressure drop, NPSH, water hammer, or pump gas binding analyses? When installing or modifying piping, is the piping system properly sloped and are sufficient vent valves installed to prevent gas accumulation? (Reference Generic Letter 2008-01)	Yes	Piping design will have to consider gas accumulation.
	28. Affect HEAT exchangers, such as INCREASE fouling, tube vibration, erosion?	Yes	Installation of new reboiler/s.
	29. Does the modification need to consider utilizing cathodic protection for new underground SSCs?	No	
	30. Affect Hydrogen (H2) piping? IF so, THEN welded joints are preferred, especially where leakage cannot be tolerated or are in areas difficult to INSPECT. Back-welding of threaded fittings should be considered and compression fittings should not be used in a system or areas subject to cyclic stresses. (Reference ASME B31.12, "Hydrogen Piping and Pipeline, NFPA 55 2013 Edition, NUREG/CR-3551, NUREG-1364 for further guidance).	No	
	31. Affect systems that connect or discharge to the main condenser? If so, modification should consider potential impacts to condenser internals when normally closed lines are allowed to discharge continuously (i.e. erosion of tubes, deflectors, baffles, shell, etc.).	Yes	Installing new connection for continuous drain into condenser. Condenser nozzles will need to be considered to ensure the condenser walls can handle the forces of new piping.
	32. Affect the design, performance or operation of pumps?	Yes	New pump for demineralized water feed to the reboiler.
	33. Affect operation of a valve or the sequence in which the valves are operated so that thermal binding or pressure locking is possible?	No	
	34. Affect plant barriers including doors, walls, floors, special barriers, etc. that perform primary containment boundary, secondary containment boundary, Control Room boundary, flood, HELB, fire, Halon, CO2, security, depressurization, missile protection, ventilation, or other barrier functions used to support plant evaluations?	Yes	Routing cables into the MCR through Control Room boundary. Also routing piping out of the Turbine Building.
	35. Affect containment (PWR)/ primary containment (BWR) design requirements, including: • Adding or removing components in containment? • Change the amount of exposed aluminum in containment? • Change the amount of exposed zinc in containment? • Introduce materials into containment that could affect sump performance or lead to equipment degradation (ref. GSI-191)? • Decrease free volume of containment? • Require addition or modification of a containment penetration boundary? • Repair, replace or install coatings inside of primary containment, including installing coated equipment?	No	
	36. Affect high/moderate energy line break analysis?	Yes	Impact evaluated in report.
	37. Affect time critical operator actions?	Yes	Control room operators may need to evaluate transients and impacts to plant equipment/procedures.
	38. Affect reactivity management or core design?	Yes	Modification will affect final feedwater temp. Faulted condition of the H2 plant could cause a thermal transient in the FW flow. Additional reactivity management activities required for large-scale design.
	39. Affect nuclear safety analysis?	No	Bounded by FW malfunction.

Design Attribute Review - Engineering Disciplines

Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	40. Affect foreign material that would require cleaning to prevent degradation of downstream components? What cleaning methods are to be used? What cleanliness criteria are required?	No	Modifications to the MS and CN flowpath, including the condenser hotwell. Normal FME practices.
	41. Affect thermal performance including steam flows, feed water flows, condenser performance , heat exchanger performance, or circulating water?	Yes	Impact evaluated in report.
Structural			
	1. Affect piping routing, component location, support location, support load, support type, etc.?	Yes	Pipe supports required.
	2. Affect stress calculations of pipe supports or whip restraints?	Yes	Stresss calculations for piping.
	3. Affect snubbers, a process parameter in a line that contains a snubber, or personnel access to any safety related snubber?	No	
	4. Affect the loading or require changes to existing equipment foundations?	No	No impact on existing foundations. New foundations will be required for transformers, demin tank/s, demin pump/s, and reboiler/s.
	5. Affect wall stress calculations for pressurized concrete cubicles or structures (PWR)?	No	
	6. Require a floor or wall loading analysis?	Yes	The addition of new piping and supports within the Tubine Building will require floor/wall loading analyses.
	7. Affect supports, hangers, or foundations or add weight to or between existing supports, hangers, embedment, or foundations during installation or post installation?	Yes	Supports required for new piping. Also foundations required for demin water tank, hydrogen steam supply equipment, and electrical equipment.
	8. Require core drills, expansion anchors, or re-bar cuts?	Yes	Pipe supports within the Turbine Building will likely require expansion anchors.
	9. Affect an external or internal missile hazard, or an existing missile barrier?	No	
	10. Affect wind and storm loading on external structures?	No	
	11. Affect dynamic requirements such as live loading, vibration, and shock/impact?	No	
	12. Require masonry wall analysis/ evaluation? Consider the following: • Modification will add a masonry wall. • Modification will delete a wall, floor or ceiling affecting a masonry wall. • Modification will locate safety-related components/systems near a masonry wall. • Modification will attach to or route safety-related systems/components through a masonry wall.	No	
	13. Affect permanent radiological shielding or temporary shielding?	No	
	Heavy Loads / Lifting and Rigging		
	14. Affect load handling systems (cranes, hoists, lifting devices, lift points) including their load path limits?	Yes	H2 interface equipment will require the use of cranes, hoists, etc. for installation.
	Seismic Qualification / Review		
	15. Affect seismically qualified equipment or affect seismic boundaries? (Including currently seismically qualified components, new components requiring seismic qualification, or existing components required to be seismically qualified.)	No	
	16. Require clearance review for seismic movement?	No	
	17. Affect raceways in seismic areas of the plant?	No	
	18. Are there requirements for seismic mounting/orientation?	No	
	19. Affects spans between two separate seismic areas/buildings? (The effect of the relative movement must be addressed).	No	
	Flood Protection		
	20. Affect potential flooding sources to a flood zone and thereby increase the direct and/or indirect flooding vulnerability of essential equipment? Check for proximity of piping not subject to HELB to piping subject to pipe whip from HELB.	Yes	New demineralized water tank/s. Flood analysis will need to be reviewed against the addition of the tank/s.
	21. Affect existing flood barriers or flood mitigation features providing unanalyzed pathway for flooding to propagate?	No	
	22. Affect new penetrations or openings through existing flood barriers?	No	
	23. Affect plant drainage/backfill requirements?	No	
	24. Affect essential equipment or supporting systems where it would be susceptible to flooding? (Flooding conditions may also impact Environmental Qualification.)	No	
	25. Affect new plant construction and/or infrastructure modifications or changes to site geology/topography that could potentially alter the site's geo-hydrological characteristics (ground water flow, direction, pressure, etc.)?	No	

Design Attribute Review - Programs Engineering			
Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
10 CFR 50 Appendix J		No	
ASME Code		No	
Boric Acid		No	
Buried Components		Yes	New buried HDPE piping.
Coatings		Yes	Carbon steel components will be coated.
Environmental Qualification (EQ)		No	
Fire Protection, Appendix R, and NFPA 0805		Yes	Add cables in the power block will add more combustible loads to different fire zones. Location of H2 Interface Enclosure and Demin Tank outside will require review from fire brigade to ensure access is not restricted.
FLEX		Yes	New H2 interface equipment and the H2 plant addition may affect existing FLEX management. FLEX strategies will need to be reviewed for impact.
Flow Accelerated Corrosion (FAC)		Yes	New piping added to MS and SD systems.
Heat Exchangers (HX)		Yes	New heat exchanger being added to the plant. Will be added to the Hx program.
License Renewal and Aging Management		No	
Maintenance Rule		No	
Material Compatibility		Yes	Piping and fabrication of pipe supports will require welding.
MOVs, AOVs, Relief Valves, and Check Valves		Yes	New manual valves, air-operated valves, and check valves included in the design. AOV's may be added to the program.
North American Electric Reliability Corporation (NERC)		Yes	The protective relays of the H2 transmission line will interface with the plant existing generator and GSU transformer differential relays to cover the new HV Breaker within their zone of protection. There is no adverse impacts to generation, transmission operator's protective system.
Nuclear Electric Insurance Limited (NEIL)		Yes	Insurance for modification will be required.
Obsolescence		No	
Station Blackout (SBO)		No	
Steam Generators		No	
Thermal Fatigue		No	
Vessel Internals		No	
Welding		Yes	Piping and pipe supports will require welding.

Design Attribute Review - Stakeholders

Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
Chemistry/ Environmental		No	
Dry Fuel Storage (ISFSI)		No	
Emergency Plan		No	
Industrial Safety		Yes	Routing steam out of Turbine Building. Dispatching large electrical load at high voltage to new location. New high voltage power lines required for design.
Information Technology		No	
Licensing		No	
Maintenance		Yes	
Non-Destructive Examination (NDE)		No	
Operations		Yes	New equipment added to plant with interface in the MCR. Operator training will be required for the operation of the new HMI associated with the H2 power line and steam supply. Operator will interface with standalone HMI for the control, indication and alarm associated with the H2 power line and steam supply.
Plant Computer		Yes	Information may be fed into plant computer based on site-specific design.
Probabilistic Risk Assessment (PRA)		Yes	PRA impacted by modfication. Siting of H2 plant can impact CDF.
Radiation Protection / ALARA Program		No	
Refueling Equipment & Reactor Assembly		No	
Security		Yes	Steam piping will breach the Protected Area boundary. Installation of H2 interface enclosure and demineralized water tank may impact security line-of-sight, pathways, etc.
Supply Chain		Yes	Equipment will need to be procured with Supply Chain input.
System Engineering	The applicable system engineering(s) should be included as stakeholder(s).	Yes	MS and SD system engineers should be involved as stakeholders.
Training		Yes	New equipment being added to the plant, along with interface in the MCR.
Transmission		Yes	New high-voltage transmission lines are required to be installed, in accordance with NERC reliability standards.
Work Planning		Yes	Installation will be implemented through Work Planning.

Appendix K: Control-System Implementation

K-1. High-Level Design Basis

K-1.1   Purpose

The purpose of this appendix is to identify and document the high-level control system requirements associated with the 500 MW$_{nom}$ HTEF. This design basis is limited to cold-reheat steam extraction only and the associated controls for the hydrogen production steam extraction. The use of HP steam would require additional control-system modifications to the nuclear plant which are more involved and could be addressed in a separate report.

The intent of the design basis is the following:

1. Identify the control system considerations to be implemented in the plant so end users can determine whether to use existing I&C or employ a digital control system.

2. Identify operational considerations for how operators shall enable the dispatch of steam to the hydrogen-generation island.

3. Provide a control-system design basis of the system which allows more-detailed functional requirements to be developed.

K-1.2   Design Basis

K-1.2.1   Operating Controls and Monitoring

1. The nuclear-plant operator shall manually initiate the activation of the steam-extraction portion of the HTEF (warm-up and normal operation).

2. The nuclear-plant operator shall have the capability to monitor and control the steam-extraction portion of the HTEF and the associated field equipment (i.e., pumps and valves).

3. The nuclear-plant operator shall be alerted to abnormal operating conditions within the steam-extraction portion of the HTEF.

4. The nuclear-plant operator controls shall be easily accessible to the operator and provide for both automatic and manual operation.

5. The operator controls may be either dedicated controls per controlled component or graphic, soft controls that are a part of a digital control system.

6. The nuclear-plant operator shall have the capability of initiating a warm-up cycle for the steam-extraction portion of the HTEF.

K-1.2.2   Warm Up

1. A means to initiate and control the warming of the steam-extraction portion of the HTEF may be performed via a small warm-up line or by modulating the steam-extraction valve.

2. For automatic warm-up controls within a digital control system, a warm-up rate and target temperature shall be employed, with the warm-up initiation implemented by the nuclear-plant operator.

3. Following a system warm-up or shutdown, the system shall have the capability to maintain standby conditions with the components in the warmed condition and ready state.

K-1.2.3 Drains

1. The control of the system piping drains within the steam-extraction portion of the HTEF shall be either manual (local), manual (control room), or a part of the control system.

K-1.2.4 Permissive Interlocks

1. A permissive interlock shall be part of the controls to permit the opening of the steam admission valve for the HTEF portion of the steam extraction.

2. The interlock shall be a function of nuclear power, such as nuclear instrumentation system power or the reactor-coolant system delta-temperature power.

3. The permissive interlock shall be maintained, and if plant conditions are no longer met, the steam-extraction valve associated with the HTEF shall rapidly close.

4. A separate permissive interlock may exist for system warm-up and standby operations.

K-1.2.5 Operator Graphics

1. A visual representation that presents process measurements and depicts the control elements associated with the system (e.g., fluid lines, pumps, and valves) shall be available to the operator.

2. The visual representation may be either a computer graphic or a control-board mimic.

3. Computer graphics shall use the "Systems Engineering Human-System Interface Display Implementation Guidelines" provided in WNA-DS-04213-GEN, [Ref. 4] for the development of graphic displays.

K-1.2.6 Design-Basis Transients

1. The controls associated with the steam-extraction portion of the HTEF shall not negatively impact the nuclear steam-supply system design-basis transients identified in the plant updated final safety analysis report (UFSAR).

K-1.2.7 Chapter 15 UFSAR Impacts

1. The controls associated with the steam-extraction portion of the HTEF shall not negatively impact the transient-analysis events analyzed in the plant UFSAR (typically Chapter 15, "Analysis").

K-1.2.8 Existing Plant Controls

1. The existing nuclear-plant control systems shall not be negatively impacted nor require an upgrade for the steam-extraction portion of the HTEF.

2. The existing nuclear-plant control systems may require some tuning to accommodate the conditions associated with the steam-extraction portion of the HTEF.

K-2. Control-System Considerations

K-2.1 Considerations for Control System Implementation

Careful consideration should be given to the control system when implementing the steam-extraction and reboiler controls. If the plant has an older, analog control system, it could be possible to implement the design, but it can present some limitations and challenges. Incorporating the controls into an existing analog system would require significant space on the main control board to implement a hard-wired HMI. On the other hand, a digital system can incorporate all necessary controls into a single touchscreen display that would require much less main-control-board real estate. Implementing Boolean logic within analog control systems typically requires the use of relay logic circuits that require significant cabinet space. A digital control system can perform the same logic with a greatly reduced footprint. A digital control system also provides the flexibility to easily make modifications without requiring physical wiring changes. If the plant has an existing digital control system, the design could be implemented on that system, or a new dedicated digital system could be used.

The control system chosen for implementation will need to interact with the following components:

- Steam-extraction FCV
- Steam-extraction FCV, interlock solenoid
- Steam-extraction flow transmitter
- Reboiler level-control valve
- Reboiler level-control valve, interlock solenoid
- Reboiler level transmitter
- Drain receiver level-control valve
- Drain receiver level-control valve, interlock solenoid
- Drain receiver level transmitter
- Reboiler outlet-pressure transmitter
- Reboiler feed-pump breaker
- HTEF breaker
- HTEF power meter

The below component descriptions are for one reboiler loop. The details should be considered for two reboiler loops.

K-2.1.1   Steam-Extraction Flow-Control Valve, Interlock Solenoid and Flow Transmitter

This control is manual only. In an analog control system, it will require the addition of a manual loader (potentiometer) to throttle the valve and an analog meter to display steam flow to the reboiler to the main control board. The manual loader and steam flow indications can be implemented on graphics in a digital control system.

A new steam-flow transmitter and associated analog input will need to be added to the control system. A turbine-trip status from the nuclear plant will need to be wired into the steam-extraction FCV interlock solenoid to immediately close the valve on a turbine trip.

K-2.1.2   Reboiler Level-Control Valve, Interlock Solenoid and Level Transmitter

This control is a manual or automatic closed-loop level control. In an analog control system, it will require the addition of a manual or automatic station and an analog meter to display reboiler level to the main control board. The manual/automatic station and reboiler level indications can be implemented on graphics in a digital control system.

A new reboiler-level transmitter and associated analog input will need to be added to the control system. A digital output from the control system will need to be wired into the reboiler-level control valve interlock solenoid to immediately close the valve on a reboiler high-level condition. A high-level alarm and low-level alarm will need to be added to the plant alarm system. The alarms can be presented graphically in a digital control system.

K-2.1.3   Reboiler Feed Pump

This control is manual on-off control of the reboiler feed pump. In an analog control system, it will require start and stop buttons and running and stopped indicators for the pump. These controls can be implemented through graphics in a digital control system.

A digital output from the control system will need to be wired into the reboiler feed pump controls to immediately stop the pump on a reboiler high-level condition. A pump trip alarm will need to be added to the plant alarm system. The alarm can be presented graphically in a digital control system.

K-2.1.4 Drain Receiver Level-Control Valve, Interlock Solenoid and Level Transmitter

This control is manual or automatic closed-loop level control. In an analog control system, it will require the addition of a manual/automatic station and an analog meter to display drain receiver level to the main control board. The manual/automatic station and reboiler level indications can be implemented on graphics in a digital control system.

A new drain receiver level transmitter and associated analog input will need to be added to the control system. A digital output from the control system will need to be wired into the drain receiver level-control valve, interlock solenoid to immediately open the valve on a drain receiver high-level condition. A low-level alarm will need to be added to the plant alarm system. The alarm can be presented graphically in a digital control system.

K-2.1.5 Miscellaneous Indications

A new reboiler outlet-pressure transmitter and associated analog input will need to be added to the control system. An analog control system will require the addition of an analog meter to display reboiler outlet pressure to the main control board. The pressure indication can be implemented through graphics in a digital control system.

A new HTEF power-consumption transmitter and associated analog input will need to be added to the control system. In an analog control system, it will require an analog meter to display HTEF Power consumption be added to the main control board.

K-2.1.6 Common Component Descriptions

The component descriptions in the following subsections are common across the two reboiler loops.

K-2.1.7 HTEF Electrical Dispatch

This is a manual on/off control of the HTEF electrical-dispatch breaker. In an analog control system, it will require close and open buttons and closed and open indicators for the breaker. These controls can be implemented on graphics in a digital control system. A breaker trip alarm will need to be added to the plant alarm system.

K-2.1.8 Miscellaneous Alarms

A new HTEF trip or fire input will need to be added to the analog control system. An HTEF general alarm will need to be added to the plant alarm system. Implementation using a new or existing digital control system will require significantly less impact. The required control-board space can be greatly reduced by implementing the controls on graphics on a single HSI.

K-3. Functional Requirements

The purpose of the thermal power extraction control system is to maintain a steady supply of steam to the HTEF. The thermal power extraction control system will extract cold-reheat steam from the crossunder piping between the HP turbine and MSRs. To provide isolation between the HTEF and the NPP, the steam extracted from the NPP will be supplied to two reboiler loops to provide high-quality steam to the HTEF. Each reboiler loop will have a reboiler feed pump and a demineralized-water storage tank. The control system will control all components required to provide steam extraction from the NPP to the HTEF.

K-3.1 Functional Description

K-3.1.1 Control System Functions

The control system provides the means to start or stop thermal dispatch from the nuclear plant by opening or closing the FCVs from the cold-reheat piping to the two reboiler loops. The control system provides the interface for starting and stopping the reboiler feed pumps. It also provides the capability for

energizing and de-energizing power supplied to the HTEF. The control system provides process values used to evaluate the performance of the thermal and electrical-extraction systems and provides alerts and alarms of the HTEF. The control system provides two-level control loops in each reboiler loop. One for the reboiler level and one for the drain receiver level.

Nuclear Plant Steam Extraction

The nuclear-plant steam extraction is controlled by one flow-control valve in each reboiler loop. The valve can be opened to any position to account for the necessary steam supply to the reboiler. A turbine-trip interlock shall cause the valve to close, isolating steam extraction.

Reboiler Feed Pump Control

The reboiler feed pumps can be manually started or stopped by the nuclear-plant operator. The pump will trip when the level in the reboiler exceeds a high-level trip setpoint.

Reboiler Level Control

The purpose of the reboiler level regulator is to maintain the reboiler level at its setpoint. There are two reboiler loops. The requirements listed here are for one loop. The other loop is identical.

Requirement K-3.1.1-2: There shall be an algorithm for the following required proportional integral (PI) transfer function:

$$K_{5\bullet1} + \frac{1}{\tau_{5\bullet1}s}$$

where

$K_{5\bullet1}$ is the controller proportional gain

$\tau_{5\bullet1}$ is the controller integral time constant.

Drain Receiver Level Control

The purpose of the drain receiver level regulator is to maintain the drain receiver level at its setpoint. Each reboiler loop has its own drain receiver. The requirements listed here are for one loop. The other loop is identical.

Requirement K-3.1.1-2: There shall be an algorithm for the following required PI transfer function:

$$K_{8\bullet1} + \frac{1}{\tau_{8\bullet1}s}$$

where

$K_{8\bullet1}$ is the controller proportional gain

$\tau_{8.1}$ is the controller integral time constant.

K-3.2 INTERLOCKS AND PERMISSIVES

K-3.2.1   Turbine-Trip Interlock

Requirement K-3.2.1-1: A turbine trip shall generate an interlock causing the nuclear-plant steam-dispatch flow-control valves to go closed.

K-3.2.2   Reactor Power Interlock

Requirement K-3.2.1-2: Power below a specified level shall generate an interlock causing the nuclear-plant steam dispatch flow-control valves to go closed. Reactor power can be measured from the nuclear instrumentation or the reactor coolant system average temperature.

K-3.2.3   Reboiler High-Level Interlock

Requirement K-3.2.1-3: When the level in the reboiler exceeds the high-level interlock, the reboiler feed pump shall trip and the reboiler level control valve shall close.

K-3.2.4   Drain Receiver High-Level Interlock

Requirement K-3.2.1-4: When the level in the drain receiver exceeds the high-level interlock, the drain receiver level control valve shall open.

K-3.3   Input/Output Interfaces

Table K-1. Input/output interfaces

Signal Name	Signal Type	Number of Signals
Reboiler Level	Analog Input	2 (1 per reboiler loop)
Drain Receiver Level	Analog Input	2 (1 per reboiler loop)
Reboiler Outlet Pressure	Analog Input	2 (1 per reboiler loop)
Steam Extraction Flow	Analog Input	2 (1 per reboiler loop)
HTEF Electrical Power Consumption	Analog Input	2 (1 per reboiler loop)
Reactor Power	Analog Input	1
Reboiler Level Control Demand	Analog Output	2 (1 per reboiler loop)
Drain Receiver Level Control Demand	Analog Output	2 (1 per reboiler loop)
Steam Extraction Flow-Control Demand	Analog Output	2 (1 per reboiler loop)
Reboiler Feed Pump Running	Digital Input	2 (1 per reboiler loop)
Reboiler Feed Pump Stopped	Digital Input	2 (1 per reboiler loop)
HTEF Breaker Closed	Digital Input	1
HTEF Breaker Open	Digital Input	1
HTEF Trip or Fire	Digital Input	1
Reboiler Level Control Valve Interlock	Digital Output	2 (1 per reboiler loop)
Drain Receiver Level Control Valve Interlock	Digital Output	2 (1 per reboiler loop)
Reboiler Feed Pump Start	Digital Output	2 (1 per reboiler loop)
Reboiler Feed Pump Stop	Digital Output	2 (1 per reboiler loop)
HTEF Breaker Open	Digital Output	1
HTEF Breaker Close	Digital Output	1
HTEF Alarm	Digital Output	1

K-3.3.1   Ranges

Signal	Range
Reboiler Level	0-100%

Drain Receiver Level	0-100%
Reactor Power	0-100%
Reboiler Outlet Pressure	TBD PSI
Steam Extraction Flow	TBD lbm/hr
HTE Electrical Power Consumption	TBD MW

K-3.4   Control Interfaces

K-3.4.1   Manual/Auto (M/A) Interface

Steam Extraction Flow-Control M/A Station

Requirement K-3.4.1-1: Capability to manually control the steam extraction flow shall be provided.

Requirement K-3.4.1-2: The following features shall be provided:

- Manual valve control
- Indication of valve position demand.

Reboiler Level M/A Station

Requirement K-3.4.1-3: Capability to manually control the reboiler level shall be provided.

Requirement K-3.2.1-4: The following features shall be provided:

- Ability to switch between automatic and manual
- Indication of valve position demand (automatic and manual)
- Indication of reboiler level
- Ability to change the level setpoint
- Indication of setpoint.

Drain Receiver M/A Station

Requirement K-3.4.1-5: Capability to manually control the drain receiver level shall be provided.

Requirement K-3.4.1-6: The following features shall be provided:

- Ability to switch between automatic and manual
- Indication of valve position demand (automatic and manual)
- Indication of drain receiver level
- Ability to change the level setpoint
- Indication of setpoint.

K-3.4.2   On/Off Controls

HTEF Power Feed Control

Requirement K-3.4.2-1: Capability to control the power feed shall be provided.

Requirement K-3.4.2-2: The following features shall be provided:

- Ability to energize/de-energize power supplied to the HTEF.
- Indication of HTEF breaker status (Open and Closed).

Reboiler Feed-pump Control

Requirement K-3.4.2-3: Capability to control the reboiler feed pump shall be provided.

Requirement K-3.4.2-4: The following features shall be provided:

- Ability to start/stop the reboiler feed pump.

- Indication of reboiler feed pump status (running and stopped).

K-3.5 Indications

K-3.5.1   Steam Extraction Flow

Requirement K-3.5.1-1: There shall be indication of steam extraction flow in the MCR.

K-3.5.2   Reboiler Outlet Pressure

Requirement K-3.5.2-1: There shall be indication of reboiler outlet pressure in the MCR.

K-3.5.3   HTE Power Consumption

Requirement K-3.5.3-1: There shall be indication of HTEF Power consumption in the MCR.

K-3.6 Alarms and Annunciators

K-3.6.1   Reboiler Feed Pumps

Requirement K-3.6.1-1: The following conditions shall actuate an alarm:

- Pump trip

    - Reboiler feed pump tripped due to level greater than reboiler level trip setpoint.
    - Pump trip due to motor overload.

K-3.6.2   Reboiler

Requirement K-3.6.2-1: The following conditions shall actuate an alarm:

- High Level

    - Reboiler level greater than the high alarm setpoint

- Low-Level

    - Reboiler level less than the low alarm setpoint.

K-3.6.3   Drain Receiver

Requirement K-3.6.3-1: The following conditions shall actuate an alarm:

- High Level

    - Reboiler level greater than the high alarm setpoint

- Low-Level

    - Drain receiver level less than the low alarm setpoint.

K-3.6.4   HTEF Alarm

Requirement K-3.6.4-1: The following conditions shall actuate an alarm:

- HTEF trip or fire

- HTEF Breaker Trip

- HTEF Equipment trouble.

K-4. References

1. WNA-PS-00016-GEN, Rev. 8, "Standard Acronyms and Definitions", Westinghouse Electric Company LLC.

2. SOW-19894, Rev. 0, "Statement of Work, Integration of Digital Control Systems of Nuclear Power Plants and Hydrogen Production Plants", Idaho National Laboratory.

3. Report SL-016181, Rev. 1, "Nuclear Power Plant Pre-Conceptual Design Support for Large-Scale Hydrogen Production Facility", Nov. 18, 2022, Sargent & Lundy

4. WNA-DS-04213-GEN, Rev. 1, "GI&C Control & Information Systems Engineering Human-System Interface Display Implementation Guidelines", Westinghouse Electric Company LLC.