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Light Water Reactor Sustainability Program

Pre-Conceptual Design for Boiling Water Reactor Integration with a 500 MW Hydrogen Production Facility

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Pre-Conceptual Design for Boiling Water Reactor Integration with 500 MW Hydrogen Production Facility

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LIMITATIONS OF USE

This design report is provided as a guide and feasibility assessment for coupling a large-scale hydrogen production facility with a commercial boiling water reactor (BWR) nuclear power plant. Site-specific analysis is required to provide the detailed analytical basis for performing this modification. Evaluations within this report are provided for the reference nuclear plant and hydrogen facility described in Section 3. If using a different size or design for the hydrogen production facility and nuclear power plant, the results and conclusions should be carefully analyzed and considered for impact.

VERSION LOG

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ISSUE SUMMARY AND APPROVAL

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ASQ/ANSI/ISO 9001:2015: Quality Management Systems–Requirements.

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ABBREVIATIONS, ACRONYMS, AND INITIALISMS

Abbreviation/Acronym/Initialism	Definition/Clarification
ac	alternating current
AFT	Applied Flow Technology
ALARA	As Low As Is Reasonably Achievable
AOV	air-operated valve
ASME	American Society of Mechanical Engineers
AST	Alternative Source Term
AVR	automatic voltage regulator
AWE	alkaline water electrolysis
BES	bulk electric system
BWR	boiling water reactor
CHX	condensing heat exchanger
CT	current transformer
DAR	Design Attribute Review
dc	direct-current
DOE	United States Department of Energy
EHC	electro-hydraulic control
ETAP	electrical transient analyzer program
FAC	flow-accelerated corrosion
FCV	flow control valve
FPOG	Flexible Plant Operation and Generation
FSAR	final safety analysis report
GE	General Electric
gpm	gallons per minute
GSU	generator step-up
H_2	hydrogen
HDPE	high-density polyethylene
HELB	high energy line break
HMI	human machine interface
HP	high-pressure
hp	horsepower
HSS	hydrogen steam supply
HTE	high-temperature electrolysis
HTSE	high-temperature steam electrolysis
H.V.	high-voltage
I&C	instrumentation and controls
INL	Idaho National Laboratory

Abbreviation/Acronym/Initialism	Definition/Clarification
km	kilometer
lbm	pound mass
LTE	low-temperature electrolysis
LV	low-voltage
LWRS	DOE Light Water Reactor Sustainability
LWR	light water reactor
MCR	main control room
MOD	manually operated disconnect
MPT	main power transformer
MS	main steam
MSIV	main steam isolation valve
MSR	moisture separator reheater
MT	metric tonnes
MTC	moderator temperature coefficient
MV	medium-voltage
MVC	moderator void coefficient
MVA	megavolts ampere
MW	megawatt
MW_{dc}	megawatt direct current
MW_e	megawatt electric (alternating current)
MW_t	megawatt thermal
N-16	Nitrogen-16
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
NPSH	net positive suction head
NRC	United States Nuclear Regulatory Commission
OCA	owner controlled area
OEM	original equipment manufacturer
OPGW	optical ground wire
P&ID	piping and instrumentation diagram
PA	protected area
PDC	power distribution center
PEM	polymer electrolyte membrane
PEPSE	Performance Evaluation of Power System Efficiencies
PRA	probabilistic risk assessment
PSCAD	Power Systems Computer Aided Design
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PWR	pressurized water reactor

Abbreviation/Acronym/Initialism	Definition/Clarification
RG	Regulatory Guide
S&L	Sargent & Lundy, L.L.C.
SDP	Standard Design Process
SOEC	solid-oxide electrolyzer cell
SSC	structures, systems, and components
TB	Turbine Building
TCS	Turbine-Generator Control System
TDH	total developed head
U.S.	United States

EXECUTIVE SUMMARY

With the United States and other countries trying to reduce their dependence on fossil fuels, low-carbon hydrogen production is becoming an increasingly important area of focus. Nuclear-integrated hydrogen production is one method that can support this growing industry, while also improving the flexible operation of existing nuclear power plants.

This report develops a pre-conceptual integration design for a new large-scale high-temperature steam electrolysis (HTSE) hydrogen production facility at an existing boiling water reactor (BWR) nuclear power plant. Previous work has investigated the colocation of an HTSE facility at a pressurized water reactor. While BWR integration is more design-intensive by virtue of the added radiological challenges, this study assesses the feasibility of a modification to extract thermal and electrical power from a BWR for hydrogen production.

The reference nuclear plant used in this study is a GE Type 4 design, which is the most common BWR design in the United States. The hydrogen facility is assumed to be a 500 MW_{dc} HTSE hydrogen production facility, similar to the design developed in previous Sargent & Lundy report SL-018670 [2].

The electrical design is nearly identical to that of a PWR integrated with a H_2 facility. Nuclear-generated electricity is extracted behind-the-meter, downstream of the generator step-up [GSU] transformer. Electrical energy is sent via a 345 kV transmission line to a high-voltage switchyard supporting the H_2 facility process and auxiliary loads. New equipment in the nuclear plant protected area is powered from existing sources.

To support the HTSE steam demand, nuclear plant main steam is extracted upstream of the high-pressure turbine. A new intermediate pressurized water loop is connected via a heat exchanger set inside the Turbine Building and is maintained at pressures (~1,000 psi) above that of the main steam system. In the event of an intermediate loop heat exchanger tube leak, this will prevent the release of main steam (and any entrained radionuclides such as Nitrogen-16) outside of the Turbine Building boundary. Nuclear plant steam is condensed and drained back to the condenser. On the other side of the intermediate loop heat exchangers, the pressurized water is used to heat demineralized water via a second group of heat exchangers to generate the process steam required for electrolysis. The intermediate loop (with the exception of the intermediate loop heat exchangers), secondary reboiler set, and supporting equipment is located in the protected area.

Radiation shielding is provided for new piping and equipment inside the Turbine Building. In the event there is not enough space within the Turbine Building to locate the new intermediate loop heat exchangers, a new building would need to be erected in the protected area with the shielding required for regulatory compliance. This alternate location would complicate the design and licensing work associated with this modification and is therefore undesirable compared to a location inside the Turbine Building. In both cases, area radiation monitoring will be required near extraction steam piping. Additionally, process radiation monitoring is advisable to support system isolation in the event abnormal radioactivity is detected.

Computer modeling was performed to evaluate system thermal hydraulics. At nominal conditions, approximately 3% of main steam flow is extracted to support the hydrogen facility. This level of extraction results in minor transients that are expected to be within the design margins of the reference nuclear plant reactor and turbine control systems. Plant hazards including high energy line break, steam/water hammer, missile protection, fire protection, and radiological should all be considered during the course of design.

This report presents a feasible pre-conceptual design for the integration of a large-scale HTSE hydrogen production facility with an existing BWR. Site-specific studies can be pursued to further understand the extent and cost of potential future modifications in support of a similar design.

1. BACKGROUND

The United States (U.S.) Department of Energy's (DOE) Light Water Reactor Sustainability (LWRS) program is exploring avenues that can extend the operation of the U.S. commercial nuclear power plant fleet. Within the LWRS program, the Flexible Plant Operation and Generation (FPOG) Pathway is working to diversify the revenue streams of light-water reactors (LWRs) through the exploration of nuclear plant operation beyond electricity generation. Nuclear power has been identified as a source of large-scale, carbon-free "clean" steam, with thermal and electrical energy that can be effectively utilized in a variety of cogeneration applications to realize national long-term decarbonization goals.

One area of focus at the DOE's Idaho National Laboratory (INL) has been the thermal power dispatch of nuclear plant clean steam to support the production of hydrogen (H_2) through the emerging technology of high-temperature electrolysis (HTE). Electrolysis is the process through which water or steam is decomposed into oxygen and hydrogen gases via the application of an electrical potential. This process is more efficient at elevated temperatures; HTE can be supported through the use of high-temperature steam as the process fluid for the reaction. The steam is broken down using rectified direct-current (dc) power within a solid-oxide electrolyzer cell (SOEC) to produce H_2 that can then be compressed, stored, and used as desired.

In coordination with Idaho National Laboratory (INL), Sargent & Lundy (S&L) has developed a pre-conceptual design for the integration of a 500 MW_{dc} high-temperature electrolysis (HTE) hydrogen production facility with an existing, generic pressurized water reactor (PWR) nuclear power plant. Both the integration strategy and hydrogen facility designs have been developed [1, 2]. This effort expands upon the previous work by detailing the design of a similar 500 MW_{dc} HTE hydrogen production facility integrated with a generic boiling water reactor (BWR).

2. PURPOSE

The purpose of this report is to develop a pre-conceptual design for the integration of a boiling water reactor (BWR) with a large-scale 500 MW_{dc} high-temperature steam electrolysis (HTSE) hydrogen production facility to illustrate the feasibility of potential future projects. This report develops the design for the thermal power dispatch and electrical interconnection systems, evaluates equipment sizing, and provides considerations of the nuclear plant impacts of modification including transient analysis, control system response, plant hazards, and licensing. The investigation can support utilities in further evaluating plant-specific integration designs.

3. ASSUMPTIONS AND INPUTS

3.1. Pre-conceptual Design Overview

Nuclear-integrated hydrogen production via electrolysis is one of the methods of interest to support clean hydrogen demand in the United States (U.S.). While low-temperature electrolysis (LTE) technologies such as Alkaline Water Electrolysis (AWE) and Polymer Electrolyte Membrane (PEM) are currently more mature than high-temperature steam electrolysis (HTSE) via solid oxide electrolysis cells (SOECs), HTSE can achieve approximately 30% higher efficiencies. This efficiency benefit, particularly when coupled with a local heat source, makes nuclear-integrated HTE a strong candidate for clean, cost-effective hydrogen production.

This generic pre-conceptual hydrogen production facility (H_2 facility) integration design is specifically developed for HTE to assess the feasibility associated with the large-scale development of the technology at an existing generic boiling water reactor (BWR) nuclear power plant site. Previous S&L report SL-016181 [1] has developed a similar investigation of H_2 facility integration with a pressurized water reactor (PWR) reference nuclear power plant. S&L report SL-018670 [2] was also developed for the design of the large-scale hydrogen production facility coupled with the reference PWR. The pre-conceptual hydrogen facility design in that study is used as the design basis for nuclear plant interfaces investigated in this work.

Figure 3-1 displays the integration strategy that is used as the basis for this design. New systems are shown in blue and orange.

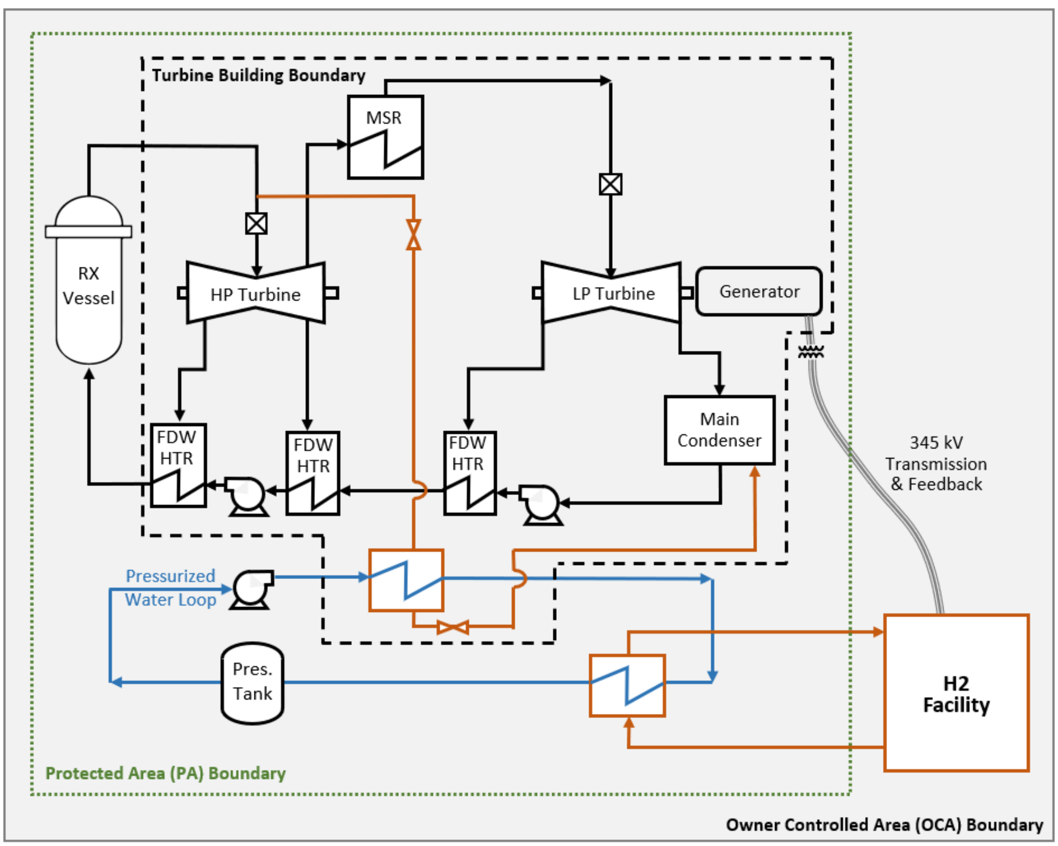


Figure 3-1. Nuclear-Hydrogen Integration Strategy

Nuclear-generated electricity is diverted from the output of the main generator (downstream of the generator step-up [GSU] transformer) to a high-voltage switchyard near the H_2 facility at 345 kV. This extraction point is assumed behind-the-meter. Power is stepped down in the high-voltage switchyard and hydrogen production facility to supply loads for electrolyzers, compressors, and other auxiliaries. Electrolyzers comprise a majority of the facility load, demanding rectified dc power.

To support the process steam demand for electrolysis, extraction steam is tapped off Main Steam, upstream of the turbine stop and control valves and downstream of the main steam isolation valves (MSIVs). Given the radiological concerns associated with the transport of Nitrogen-16 (N-16) and other radionuclides in the extraction steam, a new intermediate pressurized water loop is connected via heat exchangers in the Turbine Building. This loop is maintained at higher pressure than the primary loop to prevent any out-leakage of radionuclides. After passing through these intermediate loop heat exchangers, the extraction steam condenses and drains back to the main condenser. On the other side of the pressurized water loop, the hot pressurized water is used to heat demineralized water (produced at the H_2 facility) to steam using another set of heat exchangers. This process steam is returned to the H_2 facility for high-temperature steam electrolysis (HTSE).

The extraction location is depicted in Figure 3-2. This location is expected to allow this modification to be non-safety related and should minimize operational impacts and transients.

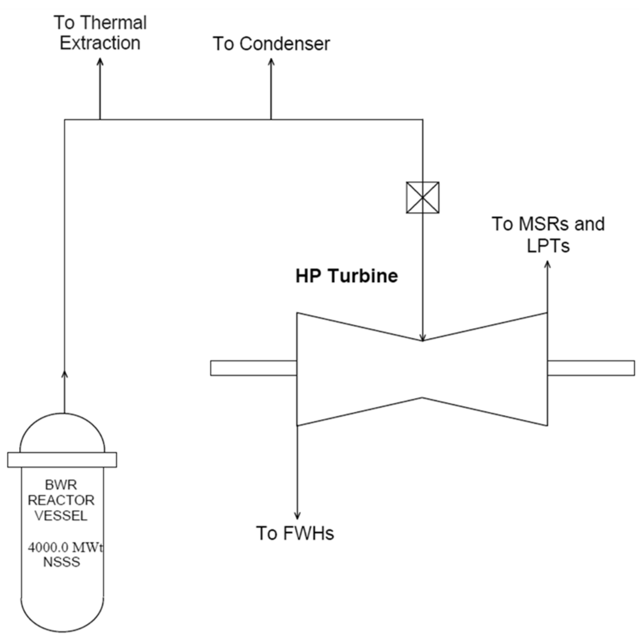


Figure 3-2. BWR Thermal Extraction Location

In addition to steam and electricity interfaces, hydrogen facility water systems are also anticipated to benefit from nuclear plant integration. Raw water can be tapped from existing nuclear plant raw water systems to support service water, makeup water, and demineralized water treatment for hydrogen production. To reduce capital cost, wastewater from water treatment and cooling tower blowdown (if applicable) may be returned to the nuclear plant and combined with existing waste streams. Additionally, plumbing systems can be tied into existing systems. These interfaces are detailed for a PWR design in S&L report SL-018670 [2].

3.2. Reference Nuclear Plant

As of early 2024, a majority (17 of 31) of the currently operating United States (U.S.) boiling water reactors (BWRs) are General Electric Type 4 reactors. Approximately half of these reactors have a rated power around 4000 MW_t (~1365 MW_e). As a result, this reactor type and power level is selected as the basis for the generic reference BWR nuclear power plant used in this study.

Table 3-1 below provides a list of the currently operating BWR units in the US, based on U.S. NRC data.

Table 3-1. List of Operating US BWRs

Plant Name	Licensed MW_t	Reactor Type	# of Units
Nine Mile Point	1850	GE Type 2	1
Monticello	2004	GE Type 3	1
Dresden	2957	GE Type 3	2
Quad Cities	2957	GE Type 3	2
Cooper	2419	GE Type 4	1
FitzPatrick	2536	GE Type 4	1
Hatch	2804	GE Type 4	2
Brunswick	2923	GE Type 4	2
Fermi	3486	GE Type 4	1
Limerick	3515	GE Type 4	2
Hope Creek	3902	GE Type 4	1
Browns Ferry	3952	GE Type 4	3
Susquehanna	3952	GE Type 4	2
Peach Bottom	4016	GE Type 4	2
Columbia	3544	GE Type 5	1
LaSalle	3546	GE Type 5	2
Nine Mile Point	3988	GE Type 5	1
River Bend	3091	GE Type 6	1
Clinton	3473	GE Type 6	1
Perry	3758	GE Type 6	1
Grand Gulf	4408	GE Type 6	1

3.3. Reference Hydrogen Production Facility

S&L report SL-018670 [2] developed a pre-conceptual design for a 500 MW_{dc} HTE hydrogen production facility using SOEC technology. The basis for this BWR nuclear plant integration design utilizes the same parameters as developed in this previous work.

Hydrogen is produced via 52 SOEC blocks for a total of approximately 500 MW_{dc} hydrogen production (at beginning of life). Each 9.6 MW_{dc} block is comprised of 8 SOEC stamps (1.2 MW_{dc} at beginning of life), for a total of 416 electrolyzer stamps.

The total H_2 facility electrical load is 640 MVA. Direct-current electrolyzer loads comprise 80% to 85% of the total facility load, while facility alternating-current (ac) auxiliary loads (e.g., compression and electrolyzer auxiliaries), losses, and margin make up the remainder.

The total H_2 facility thermal load is 107 MW_t, based on heat balance modeling as described in Section 4.1.2.

After production, gaseous H_2 is sent to a pipeline assumed at 1,500 psig and 99.999% purity for further downstream users.

Table 3-2 below lists the key parameters of the reference hydrogen production facility.

Table 3-2. Reference Hydrogen Production Facility Parameters [2]

Parameter	Unit	Value
Hydrogen Production Capacity	MT/day	320
Operating Profile	------	Constant Production
H_2 Facility Stamp Count	------	416
H_2 Facility Block Count	------	52
Electrolyzer Nameplate Power (Beginning of Life)	MW_e	499.2
Electrolyzer Nameplate Power (End of Life)	MW_e	540.8
Facility Auxiliary Loads	MW_e	82
Total Electrical Power	MVA	640
Total Thermal Power	MW_t	107
H_2 Offtake Method	------	Pipeline
H_2 Offtake Pressure	psi(g)	1500
H_2 Offtake Purity	% H_2	99.999

Process modeling developed under SL-018670 [2] assessed the steam supply demand and heat recovery potential within the hydrogen facility for pre-heating process feed water. The thermal hydraulic analysis developed in this report uses similar values to those in the previous work.

Table 3-3 below details the design parameters for thermal integration.

Table 3-3. Hydrogen Facility Thermal Integration Parameters

Parameter	Unit	Value
Mass Flow Rate	lbm/hr	350,000
Process Steam Pressure (2)	psi(a)	99.0
Demineralized Feed Water Pressure	psi(a)	41.0
Demineralized Feed Water Temperature	°F	180

[1] All values are taken at the hydrogen facility boundary.
[2] Process steam is assumed saturated.

3.4. Siting Parameters

High-temperature steam electrolysis is most viable for hydrogen production facility sites near a heat source since integration costs can be kept to a minimum. S&L report SL-016181 [1] assumed a 0.5 kilometer (km) minimum separation between important-to-safety nuclear plant structures, systems, and components (SSCs), and hydrogen facility electrolyzers, based on generic probabilistic risk assessment (PRA) [3].

This study assumes a separation of ½ km between the nuclear plant Protected Area and the hydrogen facility boundary. This fence-to-fence separation is slightly greater than what was assessed previously in SL-016181 [1], and is the same separation used in SL-018670 [2].

Implementing additional preventative (e.g., hydrogen detection, ventilation, and removal systems) and mitigative (e.g., barriers) measures within the H_2 facility, and performing site-specific hazard assessments (e.g., hydrogen explosion overpressures, flammable vapor clouds, heat fluxes from jet fires or fireballs, etc.) could support reduced separation distances. This could be beneficial when considering onsite bulk H_2 storage, which is not included in the reference H_2 facility design.

Regulatory Guide 1.91 [4] provides guidance to support co-location of a hydrogen production facility at a nuclear power plant site and should be consulted when performing site assessment.

4. ENGINEERING AND DESIGN

4.1. Design

4.1.1. Description of Modification

The key differences in developing a hydrogen production facility integration modification for a BWR as opposed to a PWR are the radiological and controls impacts associated with the mechanical interfaces with the nuclear power plant. Functionally, this mechanical design circumvents the radiological challenges of BWR integration by developing a small, intermediate pressurized water loop before heating of the hydrogen electrolysis process stream. This is similar to the separation between the primary and secondary loop in a PWR. A set of intermediate loop heat exchangers, comprised of a condensing heat exchanger and external drain cooler, are used to separate these intermediate loops from the reactor primary. Another two (2) heat exchanger sets (each with a reboiler and a preheater) separate the other side of the intermediate pressurized loop from the hydrogen electrolysis process loop.

Figure 4-1 depicts the flow of energy from right to left, starting with the BWR extraction steam, then to the intermediate pressurized water loop, and finally to the hydrogen process fluid loop. The intermediate loop heat exchangers are located within the Turbine Building boundary, if space allows, to minimize licensing basis and design impacts. The remaining equipment is located out in the protected area. Treated process water is supplied by the hydrogen facility, heated via the preheaters and reboilers, and returned as saturated stream to the hydrogen facility for HTSE.

Additional details are included in the piping and instrumentation diagram (P&ID) provided in Attachment G.

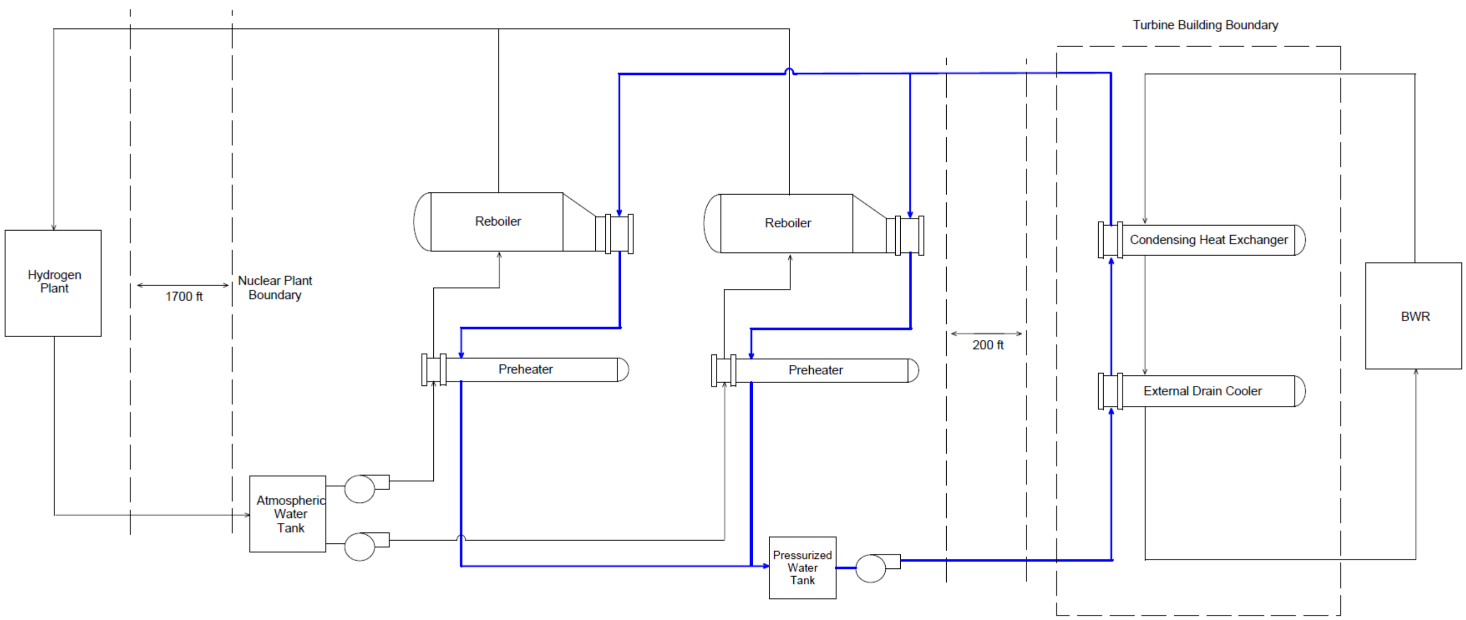


Figure 4-1. Thermal Extraction Flow Diagram

BWR steam extraction is taken off of Main Steam, upstream of the turbine stop and control valves and downstream of the main steam isolation valves (MSIVs). This is anticipated to be the optimal location since it avoids significant impacts to turbine controls, is not spatially restricted, and is expected to be non-safety-related. Manual isolation, along with an air controlled flow control valve (FCV), are included on the extraction line. During a turbine or reactor trip, control logic would result in valve closure and extraction steam line isolation.

Downstream of the FCV, a set of series shell-and-tube heat exchangers isolate the extraction steam from the intermediate pressurized water loop, and transfer heat to the loop. These heat exchangers prevent the transmission of N-16 or any other entrained radionuclides from leaving the primary loop. If a tube leak were to occur, the high pressure (~1,000 psig) in the intermediate water loop would ensure no radionuclides leave the extraction steam lines. After passing through the condensing heat exchanger and external drain cooler, the steam condenses and drains back to the condenser. Both heat exchangers would ideally be located within the Turbine Building to minimize licensing impacts. However, due to the sizable footprint expected for these heat exchangers along with radiation shielding and clearances, many existing BWR Turbine Buildings may be spatially restricted. If this is the case, a new concrete structure adjacent to the Turbine Building would be required to house these heat exchangers and would be subject to similar requirements as the Turbine Building. Attachment M provides a proposed layout of these intermediate loop heat exchangers in either location. If using a horizontal shell-and-tube style heat exchanger arrangement, a footprint of approximately 45’ x 25’ is expected, with additional clearance for removal and replacement. A vertical heat exchanger arrangement may be pursued with more design impacts if floor space is limited; this arrangement could reduce required footprint to approximately 25’ x 25’, but would require more than 30’ vertically, along with shielding. The horizontal arrangement is anticipated to be preferable in most cases.

On the secondary tube-side of the intermediate loop heat exchangers, the heated pressurized water passes to two (2) more heat exchanger sets used to generate steam for electrolysis. To support system maintenance and operational flexibility, there are two (2), 50% capacity heat exchanger trains, each with two heat exchangers in series for the preheating and boiling of demineralized process feedwater for HTSE. After cooling, the pressurized water cycles through a tank and forwarding pump, before reheating by primary extraction steam. The water tank is maintained at pressure through an external compressed air supply. Level and flow control in the intermediate loop and reboilers ensure required hydrogen production facility operating conditions (see Table 3-3) are met.

A water treatment system inside the hydrogen production facility generates the demineralized water needed for electrolysis. This treated water is sent to the nuclear plant for heating by the intermediate water loop. After passing through a buffer holding tank, the flow splits into two trains. Forwarding pumps supply each heat exchanger train. Level control signal is provided by a transmitter on the shell side of the reboilers. After boiling, the process steam lines join to a header and are routed back to the electrolyzers in the H_2 facility.

The above described equipment in the intermediate loop, with the exception of the intermediate loop heat exchangers (located in Turbine Building due to radiological considerations), is all located in the nuclear plant protected area (PA), as shown in Figure 4-1. This hydrogen steam supply (HSS) equipment encompasses an approximate footprint of 100’ x 70’, as shown in Attachment L.

Isolation, relief, and backflow prevention is provided for all major equipment, as suitable, to support system health and maintenance. Control of this equipment is provided through an H2 interface control panel in the Main Control Room (MCR). A relay panel in the Relay Room houses the protective relay components for the transmission line. Local equipment controls are also included adjacent to HSS equipment in the PA.

Piping materials for the nuclear plant integration include carbon steel for steam piping, stainless steel for hot water piping, and high-density polyethylene (HDPE) for ambient water piping. Process steam piping is routed between the nuclear plant and hydrogen production facility above ground on pipe racks. Drains, steam traps, and expansion loops are included. Demineralized water lines and any other piping commodities between the nuclear plant and H_2 facility are expected to be direct-buried. Insulation and heat tracing are added to piping and outdoor equipment where applicable based on expected environmental conditions.

The 345 kV transmission line (H_2 feeder) to the H_2 facility is tapped into the line between the nuclear plant's GSU transformer high-voltage bushing and the switchyard. The transmission line has two manually operated disconnect (MOD) switches and one 345 kV circuit breaker at the beginning of the line. The feeder is ~0.5 km long with the revenue meter at the beginning of the line. The end of the line is located inside the high-voltage switchyard and is terminated at a 345 kV motor operated disconnect switch on the 345 kV bus. Power is further stepped down in the switchyard and H_2 facility to supply the facility electrical loads.

The transmission line 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 plant 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 (using the existing GSU transformer differential relays) is required to be able to trip the high-voltage breaker to the H_2 facility.

A conceptual site plan with the nuclear plant interface is provided in Attachment J.

4.1.2. Mechanical Design

The heat balance diagrams in Attachment A illustrate the expected plant operating conditions for the following two scenarios: (1) no thermal extraction and (2) 107MW$_t$ extraction from Main Steam with condensate return to condenser. The modeling accounts for thermal and hydraulic losses in the system, as described in Attachment A through Attachment F. The final process steam supply conditions the H_2 facility boundary are 350,000 lbm/hr and 99 psia at saturated conditions.

The preferred location of extraction is Main Steam piping, upstream of the turbine stop and control valves and downstream of the MSIVs. Steam conditions at extraction are saturated at 1050 psia. This is anticipated to be the optimal location due to the spatial availability and minimal operational impacts. Extraction downstream of the high-pressure (HP) turbine is not anticipated to meet the process steam temperature requirements for the H_2 facility; therefore, it is not considered a suitable extraction location.

From both an efficiency and operational standpoint, main condenser return is anticipated to be preferred location for condensate return to the nuclear plant.

4.1.2.1. Thermal Analysis

A PEPSE heat balance model of the reference nuclear plant was used to determine the impact on the plant under normal H_2 facility operation. Based on the electrolyzer requirements at the H_2 facility, approximately 107-MW$_t$ extraction is required. Attachment A provides heat balance diagrams illustrating process parameters for the existing BWR primary loop and the new thermal power dispatch system to the H_2 facility.

Table 4-1 details key thermal extraction system parameters.

Table 4-1. Summary of Important System Parameters for 107-MW_t Extraction

Parameter	Unit	Extraction Level		Δ
		0 MW_t	107 MW_t	
Reactor Thermal Power	MW_t	4,000	4,000	-
Generator Output	MW_e	1,365.2	1,326.3	-38.9 MW_e
Final Feedwater Temperature	°F	384.9	382.3	-2.6°F
Main Steam Flow	Mlb/hr	16.42	16.37	-0.33%
Remaining Flow to HP Turbine	Mlb/hr	16.40	15.96	-2.67%
Thermal Extraction Flow	lb/hr	0	384,650	-
Intermediate Loop Flow Rate	lb/hr	0	1,193,337	-
Extracted Steam Fraction of Main Steam Flow	%	0	2.35	2.35%

4.1.2.2. Evaluation of Steam Extraction System Operations

As seen in Table 4-1, the 107-MW_t thermal extraction from Main Steam requires approximately 385,000 lb/hr of steam, corresponding to approximately 2.4% of total Main Steam flow. Normal startup of the hydrogen production facility involves startup of one reboiler train at a time which requires opening of the steam extraction line from Main Steam and reboiler inlet isolation valve in the intermediate loop. This operation diverts a small portion of the total Main Steam flow (~1.2% per train) and reduces flow to the HP turbine by approximately 1.3% per train. These changes result in a nearly 40 MW_e reduction (-2.8%) in main generator output. Minor feedwater temperature changes are observed versus the base case with no extraction.

It is also noted that the extraction of steam from the cycles as described in this report is operationally similar to the use of the turbine bypass system. GE type 4 plants are typically designed with greater than 10% turbine bypass capability. Since plant transients are already analyzed with turbine bypass much greater than the level of steam extraction described in this modification, these transients described herein are expected to be bounded by the existing plant design and licensing bases.

During the detailed design of the thermal steam extraction system, the potential for water hammer or steam hammer must be addressed. These phenomena could occur if steam or water flow rapidly stops; this condition is typically addressed by selecting appropriate valve closing times.

4.1.2.3. Impact on Plant Hazards

Existing nuclear power plants are required to be protected from plant hazards such as high energy line break (HELB), tornado missiles, and fires.

Each plant's licensing basis defines HELB criteria, which state the conditions required to define a high-energy system based on operating temperature and/or pressure limits. The temperature and pressure limits are typically defined as 200°F and 275 psig. Based on the PEPSE heat balance in Attachment A, maximum operating conditions for the modification exceed these values; therefore, the plant HELB program is expected to be impacted. Any piping additions should be routed in such a way as to be separated from any equipment that may be important to safety or station operation.

The H_2 facility can introduce potential tornado missiles to exposed SSCs. Plant separation distance and H_2 facility design need to consider the potential for missile hazards in design to ensure they are sufficiently prevented or mitigated.

Bulk hydrogen at the production facility also poses an explosion and fire risk. While the separation distance between the H_2 facility and nuclear plant is anticipated to mitigate these exposures, formal analysis will be required on a site-specific basis in accordance with Fire Protection licensing requirements.

4.1.2.4. Impact on Core Reactivity

Using steam extraction from a BWR nuclear power cycle to supply thermal energy to a reboiler unit induces multiple reactivity impacts in the core. These impacts are derived from temperature changes (steam extraction, feedwater temperature reduction) and changes to steam void concentration in the core. Both steam extraction and feedwater temperature variation impact core reactivity via the moderator temperature coefficient (MTC). Changes in steam bubble concentration changes are reflected in the moderator void coefficient (MVC).

When the H_2 facility is brought online, temperature and pressure changes produce reactivity effects and elicit control system response. Operating the H_2 facility results in colder feedwater which introduces positive reactivity due to increased density of the reactor moderator. Increased steam flow initially lowers the reactor pressure as additional steam is withdrawn from the core. The main turbine control valves will then throttle closed to maintain constant reactor pressure. Reduced steam flow through the main turbine reduces heating of the feedwater, causing increased feedwater temperature subcooling (lower temperature). Since the MTC is negative, lowering feedwater temperature results in positive reactivity being introduced to the reactor core. This raises reactor power which is the desired response to the added demand of extraction steam for the H_2 facility. When removing the H_2 facility from service the described effects are reversed.

4.1.2.5. Control System Response

The extraction steam requirements to support operation of the H_2 facility are small (~3%) and within the bounds of normal load fluctuation. BWR’s use a Pressure Regulator and Turbine-Generator Control System (TCS) to provide a stable control response to normal load fluctuations. These systems operate to maintain relatively constant reactor pressure using electro-hydraulic control (EHC) of turbine control and bypass valves. Thus, turbine loading is normally set by the steam flow made available at the chosen pressure and the turbine load is "slaved" to reactor power level.

The pressure control unit maintains relatively constant reactor pressure in tandem with turbine speed and load control. It measures steam pressure upstream of the main stop valves, compares it with a preselected pressure reference signal, and produces a compensated pressure error signal. This error drives the response of EHC valve position control units to modulate the position of the main control, bypass, and combined reheat intercept-and-stop valves on the turbine.

The use of extraction steam in the H_2 facility creates additional steam demand and is reflected through changes in the steam pressure. Due to the small amount used, the impacts on system operation are minimal. The control scheme is expected to provide ample response to account for the extraction steam impacts of operating the H_2 facility. Similarly, effects from changes to feedwater temperature are expected to be within the bounds of normal system response.

4.1.3. Electrical Design

The H_2 facility requires 540.8-MW_{dc} power for the electrolysis process and approximately 82-MVA for auxiliary loads. With power factor adjustment and system margin, the total electrical power required is approximately 640 MVA [2]. The H_2 electrolyzers are approximately 0.5 km from nuclear equipment (switchyard), therefore power will be supplied to the hydrogen facility from the nuclear plant via a 345-kV transmission line. The electrical design requirements and analysis for a BWR nuclear power plant feeding an H_2 facility are the same as for a PWR nuclear power plant.

4.1.3.1. Selection of Nuclear Power Plant Electrical Dispatch Location

The electrical physical layout diagram in Attachment K illustrates the preferred electrical system tie-in point, which is the high-voltage side of the nuclear plant main GSU transformer. If limited spatially, a behind-the-meter connection may alternatively be established in the switchyard. The electrical feed to the H_2 facility consists of a high-voltage circuit breaker, two manually operated disconnect switches, and a 0.5-km-high-voltage transmission line. For a total apparent power rating of approximately 640 MVA transmitted to the H_2 facility, the current rating of the high-voltage equipment must be in the range of approximately 763 A to 1600 A, considering a nominal transmission system voltage in the range of 230 kV to 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.

4.1.3.2. Electrical Design and Equipment within Nuclear Power Plant Boundary

The 345-kV transmission line will be tapped to the line between the nuclear plant 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 manually operated disconnect switches for line protection/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 nuclear Protected Area or yard area, depending on available space in the Protected Area. To achieve a plant separation distance of 500 m, the H_2 transmission line will be routed over six transmission towers to reach the H_2 facility area. At the H_2 facility, there are two (2) two-winding step-down transformers rated for 345 kV-delta/34.5 kV-wye, 205/250/340MVA ONAN/ONAF/ONAF, 10% nominal impedance H-X. Within the H_2 facility step-down transformers rated for 34.5 kV-delta/13.8 kV-wye to supply power at the 13.8-kV level to the H_2 electrolyzers. See Attachment K for the electrical physical layout.

Revenue meters are installed in different locations depending on the nuclear plant. Some plants locate revenue meters inside the TB, outside after the GSU transformer, or out in the switchyard. Therefore, the nuclear plants and associated grid operators should have discussions early in the process to review their commitments as to the location of the connecting point of the H_2 feeder. In addition, other issues can affect the location of the H_2 feed connecting point in relation to the meters, such as GSU transformer power losses.

4.1.3.3. 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. Additionally, control and indication for relevant HSS equipment (e.g., feed pumps and control valves) will be performed from the Main Control Room. The two manually operated 345-kV disconnect switches will have indications only 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 installed in the nuclear power plant Relay Room. Coordination between the nuclear plant and hydrogen facility electrical equipment will be required.

4.1.3.4. Power Requirements for Hydrogen Steam Supply Equipment

Hydrogen steam supply equipment located in the Protected Area requires 480 Vac and 125 Vdc to operate the reboiler feed pumps and any required auxiliary loads. The power will be supplied from a 480-Vac load center and 125-Vdc distribution panel in the Turbine Building.

4.1.3.5. Switchyard Arrangement and Offsite Power

The switchyard breaker alignment is not impacted by the addition of the new high-voltage line to the H_2 facility, as the new line is protected by a new high-voltage circuit breaker downstream of the tap point, as shown in electrical single-line diagram (Attachment H). The new H_2 power line has no effect on the switchyard voltage, breaker alignment, generator AVR loading, or the status of offsite power voltage regulating devices.

The hydrogen facility in this design is physically and electrically separated from the offsite power circuits. Therefore, there is no impact to offsite power sources or plant safety loads (normally powered from offsite power sources).

4.1.3.6. Electrical Short-Circuit and Load Flow/Voltage Drop Analysis

An ETAP electrical power system model was prepared to evaluate the power flow and short-circuit impacts of the H_2 facility electrical tie-in. The model was developed based on typical electrical parameters for a nuclear power plant main power system. The ETAP model consists of the following components:

- Thevenin equivalent source representation of the high-voltage transmission system
- Nuclear power plant synchronous generator
- Nuclear power plant main GSU transformer
- 0.5-km high-voltage transmission line to the H_2 facility
- H_2 facility step-down transformers
- Medium-voltage switchgear buses for the H_2 facility
- Electrical auxiliary loads at the H_2 facility

The step-down transformers are specified as a two-winding unit supplying 640 MVA to the H_2 facility.

A short-circuit analysis was performed in ETAP to determine estimated equipment short-circuit ratings and aid in sizing the H_2 facility step-down transformer. The H_2 facility step-down transformers were modeled as 205/256/340MVA 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 10% nominal impedance between the H-X windings (with ±7.5% tolerance) on the 205 MVA self-cooled base of the secondary windings allows for the use of 56-kA 34.5-kV circuit breaker and 46-kA 13.8-kV medium-voltage switchgear at the H_2 facility.

The ETAP model shows that the addition of the H_2 facility has a negligible impact on the existing nuclear plant equipment. The hydrogen facility loads are primarily rectifiers supplying dc power to the electrolyzers (approximately 85% of total load). Diode-based rectifiers permit current to flow only in one direction and, therefore, do not supply short-circuit current back to the power system. The only sources of short-circuit current in the H_2 facility 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 nuclear power plant main generator. The ETAP model shows the hydrogen facility contributes less than 1.3 kA of short-circuit current at 345 kV, compared to approximately 40 kA from the system and approximately 7 kA from the nuclear plant.

The ETAP model was also used to perform a load flow and voltage drop analysis to evaluate sizing of the electrical equipment, including the H_2 facility step-down transformer. The load flow analysis shows the 340 MVA top rating of the H_2 facility step-down transformers is sufficient to carry 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_{dc} H_2 facility, 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 H_2 facility step-down transformer does not require an on-load tap changer if the transmission voltage is maintained within approximately a ±2.5% bandwidth. This would be applicable to nuclear power plants that operate per a voltage schedule and nuclear plants that require strict voltage regulation, for offsite power per NUC-001 (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 H_2 facility step-down transformers would provide additional flexibility for locations where the transmission system operating voltage may vary over a wider range and for locations where the hydrogen facility may operate while the nuclear plant is in a refueling outage.

For the 500-MW_{dc} H_2 facility, capacitor banks are employed on the medium-voltage (13.8kV) switchgear powering the auxiliary loads at the H2 facility to provide power factor correction. The medium-voltage switchgears powering the SOEC rectifier skids don't require capacitor banks since the rectifier skids already have their own power factor correction (p.f. is 1). In the ETAP model, a 12-MVAR capacitor bank is applied on both of the 13.8-kV switchgear power auxiliary loads. The application of these capacitor banks ensures the power factor at the 345-kV line tap is approximately 0.9 lagging.

4.1.3.7. Protective Relaying Design

The electrical tie-in of the hydrogen facility has a significant impact on the nuclear power plant protective relaying scheme. The relay protection single-line diagram in Attachment I shows the conceptual protective relaying scheme design. 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 nuclear plant 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 for 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 H_2 facility.

The high-voltage transmission line to the hydrogen facility is protected by redundant microprocessor-based line-current differential (87L) relays. This scheme requires six 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 nuclear plant generator remains stable should a fault occur on the transmission line. To ensure stability of the nuclear plant 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 are tripped or the generator circuit breaker (if the nuclear plant is equipped with generator circuit breaker) in the event of a failure of the new high-voltage circuit breaker.

The step-down transformers to the hydrogen facility are 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 H.V. Power Distribution Center (PDC), in the H_2 High Voltage switchyard.

It is important to note that with this arrangement of the protection scheme, the only additional exposure of the nuclear plant generator to 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 the additional exposure. There is no impact to the reliability of the offsite power circuits.

Table 4-2 below shows the required trip logic for different fault locations following electrical tie-in of the 500-MW_{dc} hydrogen facility.

Table 4-2. 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 H_2 facility	New high-voltage circuit breaker New high-voltage step-down transformer circuit breaker	Existing high-voltage switchyard circuit breakers Generator circuit breaker (if equipped)
H_2 facility transformer	New high-voltage step-down transformer circuit breaker inside the H_2 island 34.5 kV circuit breakers in the H_2 Island 13.8 kV breakers in the H_2 island	New high-voltage circuit breaker

4.1.3.8. Electrical Transient Analysis

An electrical transient analysis was performed to evaluate the impacts of a trip of the H_2 facility load on the existing nuclear plant generator using Power Systems Computer Aided Design (PSCAD) software.

The PSCAD model was used to simulate a trip of the H_2 facility 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 but rather remain constant. Therefore, upon the trip of the H_2 facility, the excess power from the nuclear plant generator is injected into the transmission system. The model shows that for a 640 MVA electrical load, the nuclear plant generator remains stable for both faulted and unfaulted trips of the H_2 facility. During an unfaulted trip of the line, the generator exhibits a slight increase in mechanical speed (<0.02%), followed by damped oscillations. The mechanical transient decays within 10 seconds. After the H_2 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 H_2 facility 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 mechanical speed increases by approximately 2% during the fault. After the fault is cleared, there are several oscillations in the 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 like 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 amount of power that could be transmitted radially from the nuclear plant to the nearby H_2 facility without impacting the stability of the nuclear plant generator during a loss of load. The additional runs show that the H_2 facility 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 facility, either with or without a fault. Note that this model is based on typical nuclear power plant and transmission system data, which may not be representative of the available capacity for all U.S. nuclear sites.

4.1.3.9. Bulk Electric System Regulatory Impacts

The high-voltage transmission line supplying the H_2 facility 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.

4.1.4. Instrumentation and Controls Design

4.1.4.1. Operator Control Capabilities

The nuclear power plant supplies two principal components for the high-temperature steam electrolysis process: (1) Main Steam extraction upstream of the HP turbine, and (2) 345-kV electrical power. Just like any plant system, it will be important for the nuclear plant Control Room operators to have indications of the H_2 facility supply parameters and system conditions, to effectively evaluate the contributions to nuclear plant operation and perform the necessary actions such as start and stop of steam supply and electrical power to the H_2 facility.

A dedicated set of operator controls with remote human machine interface (HMI) in the nuclear plant MCR will be provided to allow for control, indication, and alarm of the hydrogen power line and steam supply; these controls will be electrically and functionally isolated from nuclear power plant controls. Existing plant fiber optic infrastructure will be used to communicate between the HMI and associated equipment. The operator should be trained in operating the power and steam supplies from the nuclear plant MCR using the new standalone HMI. A special procedure(s) will be developed for this operation.

Additional indication and controls will be provided local to the HSS equipment in the Protected Area.

4.1.4.2. Available Process Parameters for Monitoring

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

- Electrical power consumption on the plant computer system
- Diverted steam flow on the plant computer system
- HSS equipment trouble alarm in Main Control Room
- Hydrogen production facility trip or fire alarm in Main Control Room

4.1.4.3. Response to Faulted Conditions

It is important to understand how the nuclear power plant and affected equipment will respond to postulated faulted conditions associated with this design modification. The below list contains some of the potential failure modes of the installed thermal and electrical extraction components, along with the expected plant and/or operations response to ensure safe plant condition.

- Extraction Steam leak going to condensing heat exchanger (CHX) – With only one CHX, the steam leak must be isolated and hydrogen production would stop. If steam leak isolation is not possible, manual trip of the nuclear plant is needed (analogous to an unisolable main steam line leak). The addition of a remote, manually operated valve (motor- or air-operated) at the extraction point would allow for positive isolation in the event of a steam leak in the extraction line.
- Process Steam leak going to H_2 Facility – The line would be isolated and hydrogen production would stop. Electrical power would still be provided to the H2 facility to support controlled electrolyzer shutdown and the required facility auxiliaries. The nuclear power plant turbine-generator would pick up the additional load. Either the turbine admission valve would throttle down or more power would be supplied to the grid, depending on demand.
- Condensing heat exchanger drain valve fails open – Level in the CHX would drop. A low-level switch should be implemented to close the steam admission valve on low level and drain valve open position. With only one train, hydrogen facility steam supply would stop.
- Extraction Steam supply valve fails closed – Level in the CHX would fall; the condensate drain line would control level by closing. H2 facility steam supply would stop, resulting in similar response to a process steam leak to the H2 facility.
- Intermediate pressurized water loop leak – System operating pressure of the intermediate pressurized water loop is maintained through a pressurized air supply applied to the Pressurized Water Tank. A leak in the intermediate pressurized water loop is indicated by lowering level in the Pressurized Water Tank and excessive pressurized airflow to maintain system pressure. In the event of a leak in the intermediate loop, the extraction steam admission valve would close and hydrogen facility steam supply would stop. The intermediate loop forwarding pumps would turn off and the leak would be isolated for repair or replacement. If the leak cannot be isolated, the intermediate loop would be drained in support of maintenance.
- Intermediate loop heat exchanger tube leak – The mechanical design of the main steam thermal extraction includes maintaining intermediate pressurized water loop pressure above BWR extraction steam pressure. Intermediate loop pressure is maintained at least 50 psi above primary loop pressure. This design ensures that a tube leak in the intermediate loop heat exchangers (Condensing Heat Exchanger or External Drain Cooler) will prevent radioactive steam or water from leaving the primary loop. A tube leak in the heat exchangers will result in rising heat exchanger shell level. The extraction steam admission valve would close, and hydrogen facility steam supply would stop. The affected heat exchanger would be isolated for tube repair.

- Rapid trip of H_2 facility – Steam demand would cease, the process feed water level on the hydrogen-side of the reboilers would increase, and the extraction steam admission valve would close in response. The condensate drain valve would close to maintain level in the CHX, and extraction steam supply would be rerouted to the HP turbine. To support this transient, either the turbine admission valve would throttle down or the generator would pick up the additional load. The electrical transient would be more significant; this response is described in Section 4.1.3.8.
- Short in high-voltage line – Overcurrent protection would trip the H_2 facility. The electrical transient response would be similar to the rapid trip of the H_2 facility.
- Open in high-voltage line – An open in the high-voltage line would trip the H_2 facility. The electrical transient response would be similar to the rapid trip of the H_2 facility.

4.1.5. Design Attribute Review

When performing an engineering change in accordance with IP-ENG-001, “Standard Design Process (EB-17-06)”, the responsible engineer completes a Design Attribute Review (DAR), which is a series of questions that aids in identification of impacted disciplines, stakeholders, and programs.

As part of the pre-conceptual design, a sample DAR will be developed to assess the key design attributes. 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.

Below is a summary of key design attributes based on the draft DAR developed, as seen in Attachment N.

4.1.5.1. Engineering Disciplines

4.1.5.1.1. Electrical

- The protective relays of the H_2 transmission line interface with the plant existing generator and generator step-up (GSU) transformer relays and logic to isolate the generator/GSU during fault between the tap point and the new high-voltage breaker on the line. Therefore, current transformers (CTs) from the high-voltage circuit breaker at the H_2 feeder will be returned to the plant relay room.
- Pumps will require 480 Vac power supply. High-voltage breaker control and protective relay circuits will require 125 Vdc power supply. Therefore, the design affects the plant existing breakers, electrical cables, trays, and raceways in the plant.
- The design affects the existing protective relays for the generator and GSU transformer.
- 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 bus work 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 switchyard voltage due to the 640 MVA electrical load is negligible. Therefore, the status of offsite power voltage regulating devices is not impacted.
- The installation of the H_2 transmission line is around the GSU transformer and the yard. Therefore, it

is near high-voltage power lines.

- New cables will be routed in existing plant raceways.
- Electrical equipment installed in the Protected Area will be connected to the switchyard grounding. The grounding system for the hydrogen facility will be connected back with the plant grounding.
- Underground metallic piping will require cathodic protection. Exposed metals may also require cathodic protection. The nuclear plant will supply the power required for these measures.
- The new 345 kV breaker for the new line will be controlled with all the mechanical pumps from HMI in the MCR. Therefore, MCR heat load calculation will be impacted.
- Lighting pathways in the Turbine Building and Protected Area may be affected. Additional lighting may be required.

4.1.5.1.2. Instrumentation and Controls (I&C)

- 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.
- 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.
- The design includes digital relays that will require review for cyber security program impacts.

4.1.5.1.3. 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, heat exchangers, pumps, tanks, 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 (ASME) code requirements, system design conditions (temperature and pressure), etc.
- Steam piping and drain piping installed by this modification requires 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 hydrogen facility. Nozzle reaction loads require evaluation of vendor-supplied nozzle allowables.
- Pipe support design will be informed by pipe reaction loads output from stress analyses.
- Piping systems will be designed to withstand vibratory motion and high cycle fatigue.
- Depending on the local climate, freeze protection may be required for above ground piping and tanks. Insulation may also be required.
- Piping installed by this modification includes saturated steam and saturated water and should, therefore, 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.
- Heat exchangers and pressurized pipe lines will require pressure relief. Considerations include relieving 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 transients associated with a fault at the H2 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/steam hammer effects should be considered for system transients and for system startup (introducing steam into a cold pipe, etc.).
- Provision for venting and draining piping and equipment will be required.
- 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 needs to be evaluated.

4.1.5.1.4. Structural

- Pipe supports are required for steam and drains piping, including pipe supports to route steam piping 0.5 km to the hydrogen facility.
- Foundation designs are required for heat exchangers, tanks, pumps, transformers, disconnect switches, circuit breakers, etc.
- The addition of new piping, supports, and equipment within the Turbine Building will require floor/wall loading analyses.
- Permanent shielding will be required on new extraction steam piping to intermediate heat exchanger, and in surrounding location.
- Equipment at the H2 facility can present new tornado missile hazards.

4.1.5.2. Programs

- The fire protection program should consider the impact of new cables and conduits on combustible loading. The location of new piping and equipment in the Turbine Building and Protected Area will require review for accessibility by the fire brigade, as well as potential analytical impacts to the program. The standoff distance between the nuclear plant and hydrogen facility is expected to be bounded by a detonation event, therefore jet flame and other fire-events are not anticipated to adversely impact the nuclear plant. Nevertheless, hazard assessment should consider these events in evaluating the impact to the fire protection program.
- Piping added to the Main Steam and Secondary Drains system will need to be evaluated against FAC program criteria.
- The addition of heat exchangers, relief valves, check valves, and air-operated valves require addition to those programs.
- Welding required for modification should be reviewed by material compatibility and welding programs.
- The NERC program should review the impacts of the modification. The protective relays of the H2 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.

4.1.5.3. Stakeholders

- Radioactive steam piping routed through emergency access areas in Turbine Building not previously evaluated for radiation dose can impact Emergency Plan and licensing evaluations.
- New radioactive steam line routing will affect controlled radiation areas (or create new ones), nearby plant equipment, and may influence personnel dose. Radiation Protection and As Low As Is Reasonably Achievable (ALARA) Programs will need to be evaluated for impact. Alternative Source Term (AST) and 10 CFR 100 dose calculations may require evaluation.
- Since 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 being added to the plant.
- The high-voltage aspects of the modification require Industrial Safety and Transmission stakeholders.
- Site-specific design may include transmitting information to the plant computer.
- Security will be required as a stakeholder for the modification due to installation of equipment within the Protected Area. These items affect line-of-sight and lighting in the area. New piping routed through the Protected Area fence will also demand evaluation for Security impacts.

4.1.6. Radiation Monitoring and Protection

To support the process steam demand for electrolysis, extraction steam is tapped off main steam, upstream of the turbine stop and control valves and downstream of the MSIVs. Radiological concerns of extracting steam from the main steam are as follows:

- N-16 contained in the extraction steam. This isotope has a half-life of approximately 7 seconds.
- Fission products in the steam as a result of fission products coming out of the reactor vessel due to leakage from the fuel.

This steam is routed to a new pressurized water loop connected via a new set of heat exchangers in the Turbine Building. The pressurized water loop is maintained at higher pressure than the primary loop to prevent any out-leakage of radionuclides. After passing through these heat exchangers, the extraction steam condenses and drains back to the main condenser (See Section 3.1). Depending on the amount of space available in the Turbine Building, the intermediate loop heat exchangers could be located in the Turbine Building (Option 1) or in an adjacent building (Option 2).

- Option 1 – The intermediate loop heat exchangers are located in the Turbine Building. For this option, the intermediate loop heat exchangers, the steam pipes from the main steam line, and the drain lines to the main condenser would need to be shielded for radiation.
- Option 2 – If there is not enough space in the Turbine Building for the heat exchangers, a building adjacent to the Turbine Building could be erected. It is expected that if the routing of the steam pipes requires a transit time of approximately 49 seconds (leading to less than 1% available N-16) from where it leaves the reactor vessel to a point where the steam leaves the Turbine Building to enter the new adjacent building, shielding would not be expected to be needed in the new adjacent building to provide protection from the N-16. The transit time is expected to be less than 49 seconds, therefore shielding would likely be required. The concentration of fission products in the steam is found in FSAR Chapter 11. Informal MicroShield (or other radiation transport software) program runs could be performed to determine if the dose from the steam pipe, the intermediate loop heat exchangers, and drain pipes to the main condenser would require shielding or limited shielding (less concrete or a metal

plate) in the new adjacent building. Shielding would still be needed along the steam pipe route inside the Turbine Building to provide protection from the N-16.

For both options, area radiation monitors should be installed where the extraction steam pipes are routed from the main steam lines to the heat exchangers. In addition, for Option 2, there should be Process Radiation Monitoring System radiation detectors in the extraction steam line to isolate the line if abnormal radioactivity is detected to prevent an increase in radioactivity in the new adjacent building.

4.1.7. Licensing

The changes related to Option 1 and Option 2 would need to be reviewed per 10 CFR 50.59(c)(1) and (c)(2) to determine if a license amendment request is required.

- Option 1 – The intermediate loop heat exchanger set is located in the Turbine Building.

  This option should not result in the need for a license amendment request for the following reasons:
  - A change to the Technical Specifications should not be required.
  - The change should not result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the final safety analysis report (FSAR). The main steam line break outside containment has been evaluated and bounds the potential extraction line break. The frequency of a break in the extraction steam pipes from the main steam line to the heat exchangers should not be significantly different from that of a main steam line break.
  - The change should not result in more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety previously evaluated in the FSAR.
  - The change should not result in more than a minimal increase in the consequences of an accident previously evaluated in the FSAR. A main steam line break outside containment bounds the break of an extraction steam line break inside the Turbine Building. The source term in the extraction steam line would be the same as that in the main steam line.
  - The change should not result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the FSAR.
  - The change should not create a possibility for an accident of a different type than any previously evaluated in the FSAR.
  - The change should not create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the FSAR.
  - The change should not result in a design basis limit for a fission product barrier as described in the FSAR being exceeded or altered.
  - The change should not result in a departure from a method of evaluation described in the FSAR used in establishing the design bases or in the safety analyses.
- Option 2 – Locate the intermediate loop heat exchangers in a new building adjacent to the Turbine Building.

  A license amendment request may be needed for Option 2 to justify not installing shield walls in the new building adjacent to the Turbine Building. The change could result in the occupational dose limit being exceeded.

4.2. Major Equipment

Equipment sizing is presented in the following sections based on the thermal and electrical analyses discussed in the previous sections. 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 integration cost. Additional equipment sizing information is provided in Attachment A through Attachment F.

4.2.1. Heat Exchanger Sizing

This preconceptual design consists of the following heat exchangers:

- Condensing Heat Exchanger: Used to condense extraction steam for heating of the intermediate pressurized water loop.
- External Drain Cooler: In series with condensing heat exchanger, used to preheat water in intermediate loop and further cool nuclear plant primary drain flow to condenser.
- Reboilers (two trains): Used to boil demineralized process water to steam for HTSE.
- Preheaters (two trains): In series with reboilers, used to preheat demineralized process water for improved system efficiency.

This arrangement can be modified based on the preferences of the site. Performance parameters for the intermediate heat exchanger set (includes condensing heat exchanger and external drain cooler) and HSS heat exchanger sets (includes two trains for reboilers and preheaters) are provided as determined from the PEPSE analysis in Attachment A. Sizing information for the intermediate loop and HSS heat exchanger sets are shown in Table 4-3 and Table 4-4, respectively.

Table 4-3. Intermediate Loop Heat Exchanger Set Sizing Parameters for 107-MW_t Power Extraction

Connection Location	Mass Flow Rate		Temperature		Pressure	
Condensing Heat Exchanger Outlet to Reboiler	1,193,337	lbm/hr	540.8	°F	1,059	psia
Drain Cooler Outlet to Condensing Heat Exchanger	1,193,337	lbm/hr	355.7	°F	1,080	psia
External Drain Cooler Inlet from Pressurized Water Tank	1,193,337	lbm/hr	261.1	°F	1,100	psia
Condensing Heat Exchanger Inlet from Main Steam	384,650	lbm/hr	545.7	°F	1,009	psia
Condensing Heat Exchanger Outlet Temperature to Drain Cooler	384,650	lbm/hr	543.2	°F	989	psia
Drain Cooler Outlet to Condenser	384,650	lbm/hr	271.5	°F	968	psia

Table 4-4. HSS Heat Exchanger Set Sizing Parameters for 107-MW$_t$ Power Extraction

Connection Location	Mass Flow Rate (1)		Temperature		Pressure	
Reboiler Outlet to Hydrogen Production Facility	350,000	lbm/hr	344.3	°F	125	psia
Pre-heater Outlet to Reboiler	350,000	lbm/hr	280.0	°F	135	psia
Pre-heater Inlet from Hydrogen Production Facility	350,000	lbm/hr	180.0	°F	155	psia
Reboiler Inlet from Condensing Heat Exchanger	1,193,337	lbm/hr	540.7	°F	1,055	psia
Reboiler Outlet to Pre-heater	1,193,337	lbm/hr	290.0	°F	1,035	psia
Pre-heater Outlet to Pressurized Water Tank	1,193,337	lbm/hr	260.9	°F	1,016	psia

[1] Flow rate values represent the total extraction and process steam flows. This design utilizes two (2) reboiler/drain cooler trains, therefore ½ flow should be used in the sizing of a two-train system.

4.2.2. Piping and Component Sizing

Integrating the H_2 facility with the existing nuclear plant requires sizing of the various pipelines and in-line components for the thermal extraction design. Steam pipe sizes are determined in Attachment B through Attachment F, using AFT Arrow and AFT Fathom for hydraulic evaluation.

The results of pipe sizing are summarized as follows:

- **Extraction steam piping to intermediate loop heat exchanger set (Attachment B)**

  One, 10-inch, schedule 80, 240-foot long carbon steel line was tied into Main Steam piping. Maximum steam velocity was ~95 feet per second (ft/sec). A design pressure of 1,100 psig and design temperature of 600°F would envelop the observed conditions.

- **Process steam piping to electrolyzers (Attachment C)**

  Two, 18-inch, STD schedule, 50-foot long carbon steel lines were connected to the outlets of the shell side of the two reboilers, before joining to a header and routing out of the nuclear plant protected area to the H_2 facility. The header was 26-inch, STD schedule, 1,710-foot long carbon steel. Maximum steam velocity experienced in the lines was ~131 ft/sec. A design pressure of 150 psig and design temperature of 400°F would envelop observed conditions.

- **Reboiler feed water piping (Attachment D)**

  From the H_2 facility to the nuclear plant, 1720 feet of 6-inch, STD schedule carbon steel was modeled (conservative for roughness), with a maximum pressure of 63 psia and a velocity of ~8 ft/sec, before routing to a water storage tank. A design pressure of 75 psig and design temperature of 200°F would envelop observed conditions. Stainless steel piping was used for the actual design.

  Two tank outlets then split flow to either of the two reboiler trains. Reboiler feed pump suction piping was modeled as 40 feet of 6-inch, STD schedule carbon steel piping with a maximum velocity of 4 ft/sec. Pump discharge lines were modeled as 4-inch, STD schedule, 240-foot long carbon steel pipe, with a maximum velocity of ~9.5 ft/sec. Maximum pressure was 17 psia upstream of the pump and 274 psia downstream of the pump. Maximum temperature was 180°F. A design pressure of 50 psig for suction piping and 300 psig for discharge piping would envelop observed conditions, along with a design temperature of 200°F. Stainless steel piping was used for the actual design.

- **Intermediate loop heat exchanger set drain piping to the main condenser (Attachment E)**

  One 8-inch, schedule 80, 240-foot long carbon steel drain line was modeled from the condensing heat exchanger to the condenser, resulting in a maximum water velocity of approximately 5.8 ft/sec to the level control valve, and ~7.2 ft/sec to the external drain cooler. Maximum pressure and temperature were 990 psia and 544°F, respectively. A design pressure and temperature of 1,000 psig and 600°F, respectively, would envelop the drain conditions. Stainless steel piping was used for the actual design.

- **Intermediate pressurized water loop piping (Attachment F)**

  The full-flow line was modeled as 14-inch, schedule 80, 470-foot long carbon steel piping. The half-flow lines to each HSS heat exchanger set were modeled as 10-inch, schedule 80, 60-foot long carbon steel piping segments with a maximum water velocity of approximately 8.4 ft/sec. Maximum pressure and temperature were 1,100 psia and 545°F, respectively. A design pressure of 1,200 psig and design temperature of 550°F would envelop the drain conditions. Stainless steel piping was used for the actual design.

The results of pump, valve, and tank sizing are summarized as follows:

- **Reboiler feed water pump (Attachment D)**

  The pump sizing was based on a nominal flow rate of 360 gallons per minute (gpm) at 180°F, along with the nominal carbon steel pipe characteristics, resulting in a required pump total developed head of approximately 405 feet, requiring approximately 55 horsepower (hp).

- **Intermediate loop feed water pump (Attachment F)**

  The pump sizing was based on a nominal flow rate of 1,200,000 lb/hr (~2,550 gpm), resulting in a required pump total developed head of approximately 212 feet, requiring approximately 197 hp.

- **Drain control valve size (Attachment E)**

  The drain control valve sizing results in the following requirements:

Drain flow:	385,000 lbm/hr (977.7 gpm)
Valve differential pressure:	~966.6 psid
Valve inlet pressure:	~967.6 psia

  Note that due to a very high valve differential pressure, and vacuum at the valve outlet, flashing across the valve will occur. If a single valve cannot support the required conditions, orifice plate(s) could be used to support the required pressure drop.

4.2.3. Major Equipment List

The major equipment required to implement the thermal integration within the nuclear plant scope of the modification is summarized in Table 4-5 below. This listing is not intended to be all-inclusive, but instead to provide a high-level understanding of the major mechanical and electrical equipment needed in the design. Depending on site-specific design and configuration additional commodities such as tubing, smallbore piping, cable, conduit, etc., must also be considered. Materials needed for piping supports, transmission towers, etc., are also excluded from the equipment list.

Table 4-5. Major Equipment for Nuclear-Hydrogen Integration Design

No.	Item	Quantity	Description/Notes
Mechanical			
1	Steam Reboiler	2	Approximate Shell Size: 5' – 7' x 36'
2	Pre-Heater	2	Approximate Shell Size: 2.5' x 26'
3	Condensing Heat Exchanger	1	Approximate Shell Size: 5' x 30'
4	Drain Cooler	1	Approximate Shell Size: 4' x 30'
5	Atmospheric Water Tank	1	
6	Pressurized Water Tank	1	~1000 psig
7	Reboiler Feed Pump	2	360 gpm @ 405 ft TDH (~55 hp)
8	Forwarding Pump	2	2,550 gpm @ 212 ft TDH (~197 hp) Approximate Base Size: 16' x 5'
9	4", STD Sch. Pipe	520 ft	
10	6", STD Sch. Pipe	1,800 ft	
11	8", Sch. 80 Pipe	240 ft	
12	10", Sch. 80 Pipe	360 ft	
13	14", Sch. 80 Pipe	470 ft	
14	18", STD Sch. Pipe	100 ft	
15	26", STD Sch. Pipe	1,710 ft	
16	4" Manual Isolation Valve	6	
17	4" Non-Return Valve	2	
18	4" Air-Operated Level Control Valve	2	
19	6" Manual Isolation Valve	5	
20	8" Manual Isolation Valve	2	
21	8" Air-Operated Level Control Valve	1	The flow rate through this valve is 978 gpm with a pressure drop of ~967 psid. Note that due to the high dP, flashing across the valve will occur.
22	10" Manual Isolation Valve	9	
23	10" Non-Return Valve	3	
24	10" Air-Operated Flow Control Valve	1	
25	14" Manual Isolation Valve	11	
26	14" Non-Return Valve	2	
27	14" Air-Operated Flow Control Valve	1	
28	16" Pressure Control Valve	2	
29	18" Manual Isolation Valves	8	
30	26" Manual Isolation Valves	1	
31	Process Radiation Monitor	2	
32	Area Radiation Monitor	As Reqd.	

Table 4-5. Major Equipment for Nuclear-Hydrogen Integration Design

No.	Item	Quantity	Description/Notes
Electrical			
1	345 kV, 300A, Manually Operated Disconnect Switch	2	50 kA short circuit
2	345 kV, 300A, 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/120 V
5	Protective Relay 50BF	1	
6	Communication System	1	Cabinet NEMA 4X with meters and Aux. telecommunication for revenue meters
7	Standalone HMI	1	Located in the Main Control Room
8	Breaker failure relay (50BF)	1	
9	Breaker Failure Lockout relay 86BF	1	
10	Line Differential Protection Relay 411L/87	1	
11	Line Differential Protection Relay 311L/87	1	
12	Line Differential Lockout Relay 86	1	
13	Revenue Meter	3	
14	1113 kcmil Bluejay ACSR with OPGW Shield Wire	13500 ft	Transmission line cable outdoor

5. CONCLUSIONS

This study develops a pre-conceptual design for the integration of a large-scale high temperature Electrolysis (HTE) hydrogen production facility with an existing boiling water reactor (BWR) nuclear power plant. The reference design consists of a $500MW_{dc}$ hydrogen facility with a GE Type 4 BWR.

Nuclear-generated electricity is diverted from the output of the main generator (downstream of the generator step-up [GSU] transformer) to a high-voltage switchyard supporting the H_2 facility load at 345 kV. Power is stepped down in the high-voltage switchyard and hydrogen production facility to supply loads for electrolyzers, compressors, and other auxiliaries. The nominal rectifier load for electrolysis is $500MW_{dc}$.

To support the process steam demand for electrolysis, extraction steam is tapped off the Main Steam system, upstream of the high-pressure turbine. To prevent the out-leakage of radioactive steam, a new pressurized water loop is connected via a heat exchanger set in the Turbine Building. This loop is maintained at higher pressure than the primary loop. After passing through these heat exchangers, the extraction steam condenses and drains back to the main condenser. On the other side of the pressurized water loop, the heated pressurized water is used to boil demineralized water produced at the H_2 facility to support the high-temperature steam electrolysis (HTSE) process.

Radiation shielding is provided for the new intermediate loop heat exchangers and piping exposed to the primary steam flows. While desirable to locate this equipment inside the Turbine Building, spatial restrictions may demand that the intermediate loop heat exchangers be contained in a new building adjacent to the Turbine Building. This change may result in additional shielding, along with potential licensing implications. Area radiation monitoring will be needed near extraction steam piping routed to the intermediate loop heat exchangers. Additionally, process radiation monitoring will be needed to support isolation of the system in the event abnormal radioactivity is detected.

Thermal hydraulic system performance was evaluated through computer modeling. It is shown that the mechanical transients on the system are minor, resulting in an ~3% change to main steam flows and a minor temperature delta. These changes are anticipated to be within the design margins of the reactor and turbine control systems.

This pre-conceptual design presents a feasible solution for the modification of an existing BWR to support hydrogen production. The scope of impacts and the associated costs are highly site specific. Therefore, future investigations will need to consider the implications of factors such as reactor design, spatial availability, and existing design/licensing bases to assess whether the H_2 facility integration should be pursued further.

6. REFERENCES

1. SL-016181, Rev. 1, “Nuclear Power Plant Pre-Conceptual Design Support for Large-Scale Hydrogen Production Facility”, Sargent & Lundy, November 2022.
2. SL-018670 Rev. 1, “Pre-Conceptual Design for Large-Scale Nuclear Integrated Hydrogen Production Facility”, Sargent & Lundy, June 2024.
3. INL/EXT-20-60104, Rev. 1, “Probabilistic Risk Assessment of a Light Water Reactor Coupled with a High-Temperature Electrolysis Hydrogen Production Plant,” Vedros/Christian/Rabiti, November 2022.
4. RG 1.91, Rev. 3, “Evaluations of Explosions Postulated to Occur at Nearby Facilities and on Transportation Routes Near Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, November 2021.

7. ATTACHMENTS

Attachment A	PEPSE Modeling
Attachment B	Extraction Steam Pipe Sizing
Attachment C	Process Steam Pipe Sizing
Attachment D	Boiler Feed Pipe Sizing
Attachment E	Drain Pipe Sizing
Attachment F	Intermediate Loop Pipe Sizing
Attachment G	Piping and Instrumentation Diagram
Attachment H	H_2 Feeder Electrical Single-Line Diagram
Attachment I	Relay Protection Diagram
Attachment J	H_2 Site General Arrangement Drawing
Attachment K	H_2 Feeder Electrical Physical Layout
Attachment L	Hydrogen Steam Supply Equipment Arrangement Drawing
Attachment M	Intermediate Loop Heat Exchanger Set Arrangement Drawings
Attachment N	Design Attribute Review

ATTACHMENT A. PEPSE MODELING

(6 Pages)

A1.0 Purpose

The purpose of this attachment is to document the development of a PEPSE model which describes the extraction of steam from the Boiling Water Reactor (BWR) nuclear power cycle to supply thermal energy to a reboiler unit for hydrogen production. Parameters will be summarized to provide input for sizing the necessary piping, heat exchangers, and pumps.

To ensure that radioactive steam does not exit the Turbine Building, a high-pressure intermediate water loop is introduced to transfer energy from the nuclear steam. In this cycle, part of the main steam is diverted and condensed in an intermediate loop heat exchanger set (located in the Turbine Building) before being returned to the nuclear power cycle. This thermal energy is transferred to an intermediate loop which supplies hot water to two sets of reboilers (located outside of Turbine Building) which then produce the steam supplied to the hydrogen production facility.

A2.0 Methodology

A generic BWR station PEPSE model is used as the beginning point of this evaluation. The generic station is a representative BWR with NSSS Power of 4000 MWt and a targeted generator output of ~1365 MWe.

The generic PEPSE model is modified by adding splitters, mixers, and stream components to allow partial diversion of steam from the main steam system and return to the condenser. Pressure and temperature losses to the environment (determined from Arrow and Fathom models in Attachments B through F) are included in the associated stream components. The PEPSE, Fathom, and Arrow models are iterated until pressure and temperature values converge.

The amount of steam extracted is determined by using a demand flow splitter that supplies the intermediate condensing heat exchanger. The extracted steam is then condensed and subcooled before it is returned to the main power cycle.

To achieve a steam quality of 1.0 (saturated steam) out of the reboiler, the flow rate of the intermediate loop is adjusted using a control. The reboiler feed pump discharge pressure is set to maintain the required reboiler pressure.

Heat exchanger components are used to model the intermediate heat exchangers, pre-heaters, and reboilers. A pump component is used to model system pressure increase in the intermediate loop as well as from the water tank supplying the reboiler.

A3.0 Inputs

A3.1 Steam piping pressure and temperature losses are taken from the Arrow and Fathom modeling of these piping systems (See Attachments B through F). The Arrow and Fathom models take into account best estimate pipe lengths, fittings, and components (including modulating valves) when determining expected pressure conditions through the piping network. They also consider insulated piping with extreme cold outdoor temperature for worst case thermal losses through the piping network from the nuclear power station to the hydrogen production facility. The following lists the parameters taken from the Arrow and Fathom modeling. Note, PEPSE modeling is simplified by combining pressure drops and heat loss results for similar flow paths. Also, pressure loss to pump suction is ignored as actual suction pressure will be dependent upon level in tanks.

Table A1: PEPSE Inputs

Description	Attachment	Pressure Drop (psid)	Heat Loss (Btu/hr)
Main Steam to Heat Exchanger	B	41	41,000
Steam Generator H2 Plant	C	26	455,000
H2 Plant to Water Tank	D	26	156,000
Pump to Preheater (per train)	D	31	18,000
Drain Cooler Drain to Condenser	E	see Note 1	27,000
Intermediate Heat Exchanger to Reboiler	F	4	157,000
Reboiler/Preheater to Pressurized Water Tank	F	3	63,000

[1] Control valve will modulate pressure loss to control flow. Therefore, a PEPSE Operation is modeled to set the pressure loss to maintain an outlet pressure equal to the condenser shell pressure.

A4.0 Assumptions

A4.1 Based on agreement with INL, the required process steam conditions at the hydrogen facility are 324°F and 80 psig at a flow rate of 345,000 lbm/hr (conservatively, 350,000 lbm/hr is used). The returned water temperature from the hydrogen facility is ~180°F.

A4.2 The external drain cooler and the reboilers are assumed to have a DCA of ~10°F, and the condensing heat exchanger is assumed to have a TTD of ~5°F. The drain temperature of the pre-heaters is assumed to be 280°F.

A4.3 The shell side of the reboiler is assumed to have a pressure drop of ~10 psid. All other heat exchanger pressure drops are assumed to be ~20 psid for each process side.

A4.4 Pump efficiency is assumed to be 65%.

A5.0 References

A5.1 PEPSE V87 computer software, (S&L Program No. 03.7.551-87.0)

A6.0 Results

System parameters used as input to the Arrow and Fathom models and for sizing equipment are given in the following tables.

Table A2: Summary of Important System Parameters

Parameter	Units	Value
Total Extraction Steam Flow Rate	lbm/hr	384,650
Intermediate Loop Flow Rate	lbm/hr	1,193,337
Temperature from Hydrogen Facility	°F	180
Delivered Pressure to Hydrogen Facility (80 psig required)	psig	84.3
Delivered Temperature to Hydrogen Facility (324°F required)	°F	331.7

Table A3: Pre-heater and Reboiler Sizing Parameters

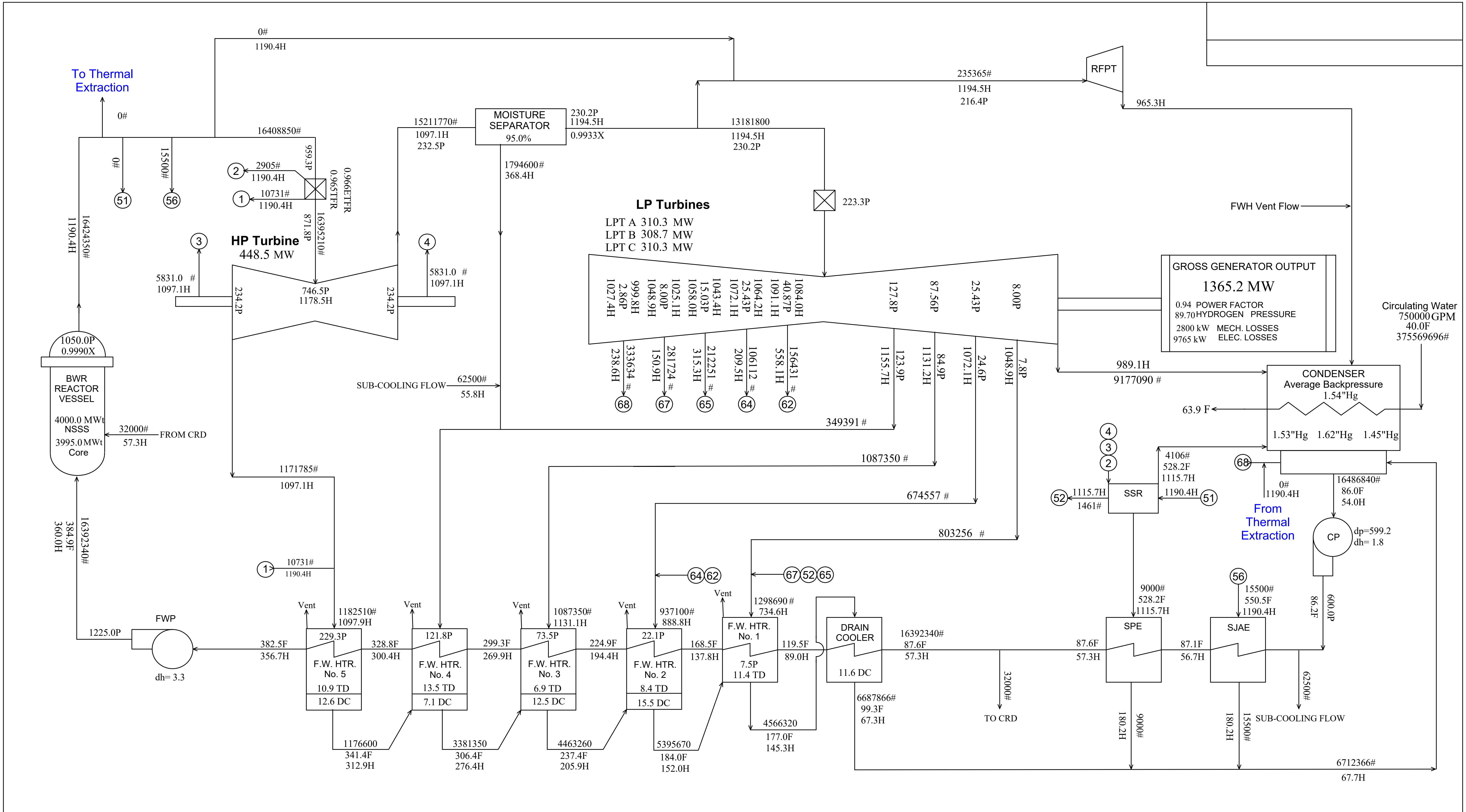
Parameter	Units	Value
Reboiler Outlet Steam Temperature	°F	344.3
Reboiler Outlet Steam Pressure	psia	125.0
Reboiler Outlet Temperature to Pre-heater	°F	290.0
Pre-heater Outlet Temperature to Reboiler	°F	280.0
Pre-heater Outlet Temperature to Pressurized Water Tank	°F	260.9

Table A4: Intermediate Heat Exchanger Sizing Parameters

Parameter	Units	Value
Condensing Heat Exchanger Outlet Temperature to Reboiler	°F	540.8
Condensing Heat Exchanger Outlet Temperature to Drain Cooler	°F	543.2
Drain Cooler Outlet Temperature to Condenser	°F	271.5
Drain Cooler Outlet Temperature to Condensing Heat Exchanger	°F	355.7

Table A5: Pump Sizing Parameters

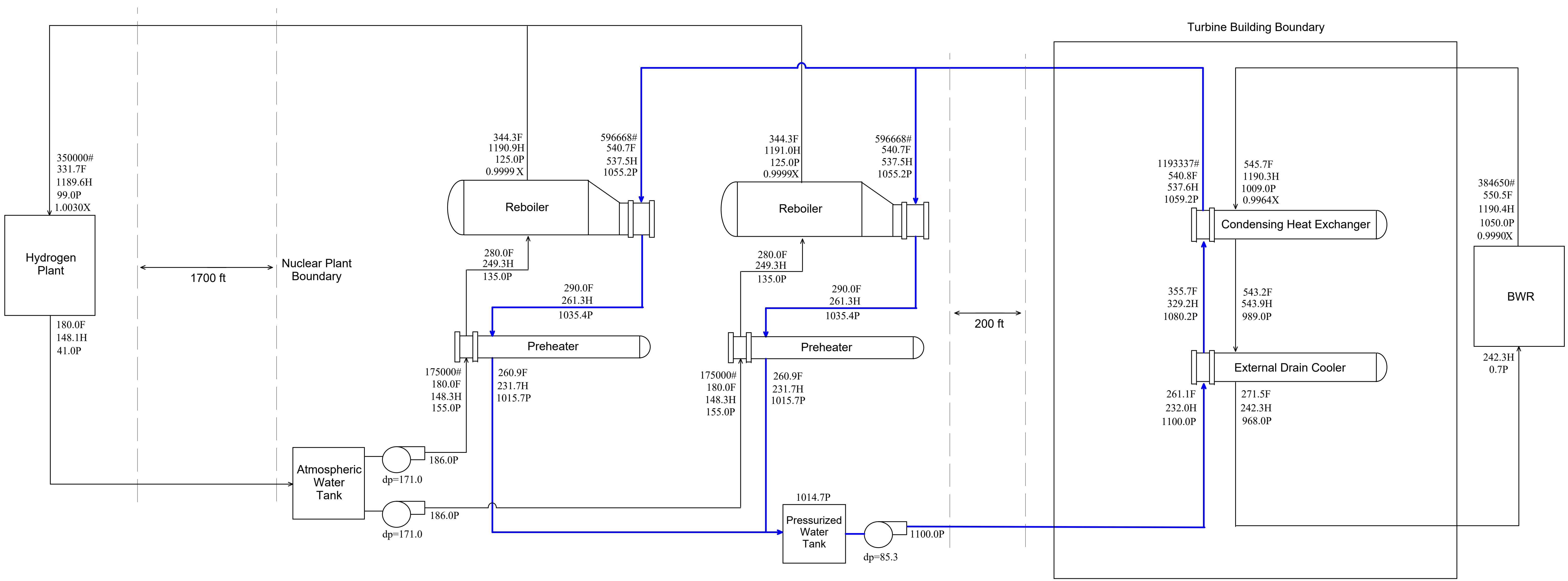
Pump	Parameter	Units	Value
Boiler Feed Pumps (Attachment D)	Flow Rate	gpm	360
	Total Developed Head	ft	405
	Pump Power	hp	55
Intermediate Loop Pump (Attachment F)	Flow Rate	gpm	2,550
	Total Developed Head	ft	212
	Pump Power	hp	197



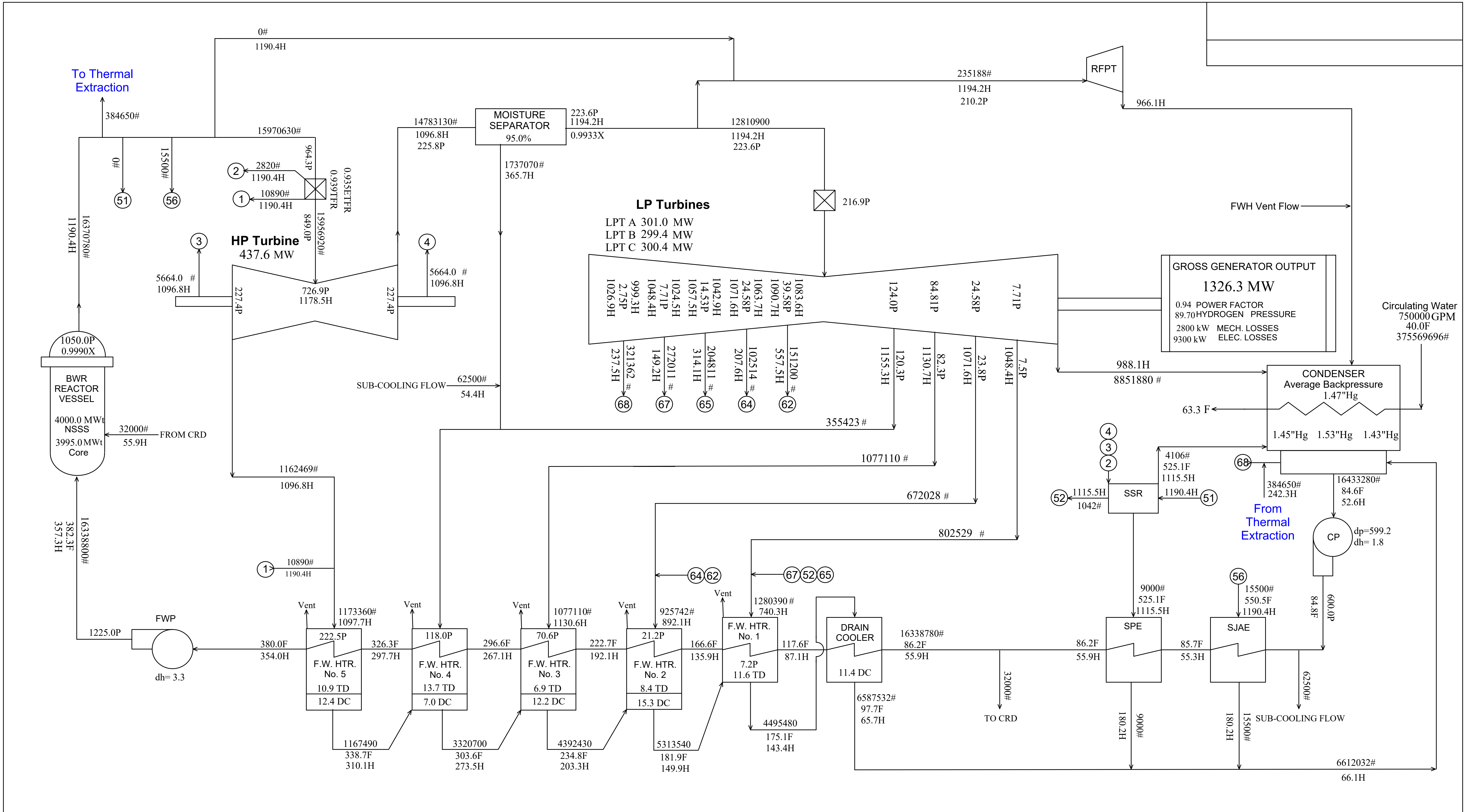
Gross Power:	1365.2 MW	Baseline
Net Power:	1356.6 MW	
Gross HR:	9997 Btu/kWh	P - Pressure, psia
Net HR:	10082 Btu/kWh	F - Temperature, F
		H - Enthalpy, Btu/lbm
		# - Flow rate, lbm/hr
Prepared by:	Date: 05/17/24	

Notes:

1. Only train A enthalpy, temperature and pressure are displayed for FWHs
2. FWH vent flow is 0.5% of extraction steam flow
3. Condensate and Feedwater system pressures are not modeled in detail as the impact on enthalpy is small



Main Steam Thermal Power Extraction



Notes:

1. Only train A enthalpy, temperature and pressure are displayed for FWHs
2. FWH vent flow is 0.5% of extraction steam flow
3. Condensate and Feedwater system pressures are not modeled in detail as the impact on enthalpy is small

Gross Power: 1326.3 MW	Main Steam Thermal Power Extraction	
Net Power: 1317.5 MW		
Gross HR: 10290 Btu/kWh	P - Pressure, psia	
Net HR: 10105 Btu/kWh	F - Temperature, F	
	H - Enthalpy, Btu/lbm	Prepared by: / Date: 05/17/24
	# - Flow rate, lbm/hr	

ATTACHMENT B. EXTRACTION STEAM PIPE SIZING

(3 Pages)

B1.0 Purpose

The purpose of this attachment is to size the thermal extraction steam piping to the Condensing Heat Exchanger. The pipe is sized to deliver the required steam flow based on the PEPSE Heat balance [Ref. B5.1] with a maximum steam velocity of 150 ft/sec [Ref. B5.3].

B2.0 Methodology

The simplified model is developed in the Arrow computer software [Ref. B5.2] to size the extraction steam piping with the maximum steam velocities of 150 ft/sec [Ref. B5.3]. Steam inlet conditions are based on the PEPSE heat balance [Ref. B5.1]. The extraction steam pipe length, valves, and fittings are based on Assumption B4.1. The piping is assumed to be insulated by 4.5 inches of Calcium Silicate based on Assumption B4.2. The turbine building temperature and air velocity are based on Assumption B4.3.

B3.0 Inputs

B3.1 Steam inlet conditions are based on the PEPSE heat balance [Ref. B5.1].

Table B1: Steam Conditions

Description	Value
Flow Rate	385,000 lbm/hr
Pressure	1050 psia
Temperature	555°F

B4.0 Assumptions

B4.1 Extraction piping length, valves, and fittings are assumed based on the diagram shown below. Fitting losses are taken from Reference B5.4 unless otherwise noted:

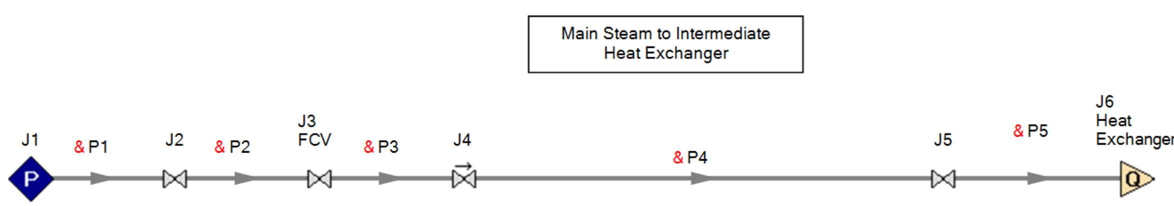


Table B2: Pipe Length and Fitting Assumptions

Pipe	Length (ft)	Losses	Fittings and Losses Total K per Pipe
P1, P2, P3	10	2x 90° Elbows (r/D=1.5)	0.39
P5	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.39
P4	200	10x 90° Elbows (r/D=1.5)	1.96

Table B3: Component Assumptions

Valve Number	Type	Losses
J2, J5	Gate	K=0.11
J3	Flow Control	20 psid
J4	Check	K = 0.7

B4.2 Pipe insulation is assumed to be Calcium Silicate, 4.5 inches in thickness. Insulation properties are based on the Arrow built-in properties [Ref. B5.2].

B4.3 The turbine building temperature is assumed to be 70°F and the air velocity is assumed to be 1 ft/sec (0.7 mph). These conditions are reasonable for a typical Turbine Building.

B4.4 All piping elevations are assumed to be at same elevation of 0 ft, which is reasonable since piping elevations have negligible impact on the system design of steam systems.

B4.5 Pipes with design pressure less than or equal to 500 psig are assumed to be standard (STD) pipe schedule. For pipes with design pressures greater than 500 psig, Schedule 80 is used.

B5.0 References

B5.1 PEPSE Heat Balances as shown in Attachment A

B5.2 Arrow computer software version 7, (S&L Program No. 03.7.722-7.0-08/06/2018)

B5.3 S&L Standard MES 2.11, “Recommended Allowable Velocities in Piping Systems”

B5.4 Crane Technical Paper 410, 2012 Edition

B6.0 Results

The Arrow model for the extraction steam was developed and iterated until the final pipe sizes are determined.

The pipe is modeled as 10-inch, schedule 80 totaling 240 ft, resulting in a maximum steam velocity of ~95 ft/sec.

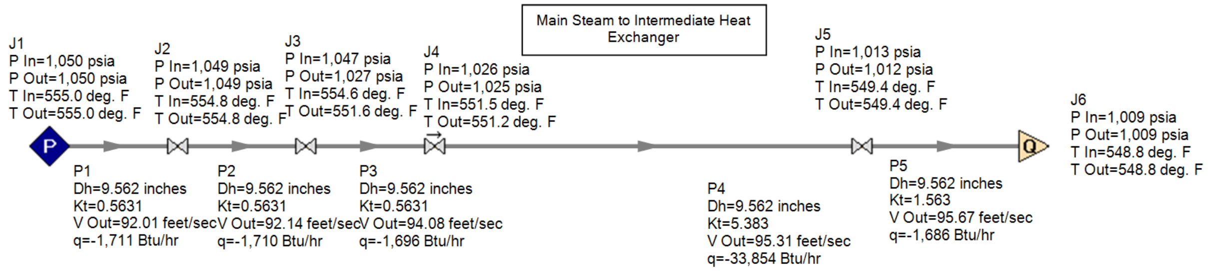
The total pressure drop and heat loss for the extraction steam piping are given in the table below.

Table B4: Pressure Drop and Heat Loss

Pipe Section	Pressure Drop (psid)	Heat Loss (BTU/hr)
Main Steam to Condensing Heat Exchanger	41	41,000

A design pressure of 1100 psig and design temperature of 600°F would envelop the conditions shown.

Detailed results are shown on the diagram below:



ATTACHMENT C. PROCESS STEAM PIPE SIZING

(3 Pages)

Attachment C

Process Steam Pipe Sizing

C1.0 Purpose

The purpose of this attachment is to size the process steam piping to the H2 plant. This process steam is to be taken from the Process Steam Generator/Reboiler and routed to the H2 plant (~500 meters or ~1700 ft away). The pipe is sized to deliver the required steam flow with a maximum steam velocity of 150 ft/sec [Ref. C5.3].

C2.0 Methodology

A simplified model is developed in the Arrow computer software [Ref. C5.2] to size the process steam piping with maximum steam velocities of 150 ft/sec [Ref. C5.3]. The process steam pipe length, valves, and fittings are based on Assumption C4.1. The piping is assumed to be insulated by 4.5 inches of Calcium Silicate based on Assumption C4.2. The outside air temperature and air velocity are based on Assumption C4.3. Heat loss and pressure drop through the piping is input in the PEPSE model [Ref. C5.1].

Note that two flow paths from the boiler combine into one pipe before flowing to the H2 plant.

C3.0 Inputs

C3.1 Reboiler outlet pressure and temperature conditions are based on the PEPSE heat balance [Ref. C5.1]. Steam flow rate is chosen to meet the required steam conditions at the heat user per Assumption C4.5.

Table C1: Process Steam Conditions

Description	Value
Total Process Steam Flow	350,000 lbm/hr
Reboiler Outlet Pressure	125 psia
Reboiler Outlet Temperature	350°F

C4.0 Assumptions

C4.1 Extraction piping length, valves, and fittings are assumed based on the diagram shown below. Fitting losses are taken from Reference C5.4 unless otherwise noted.

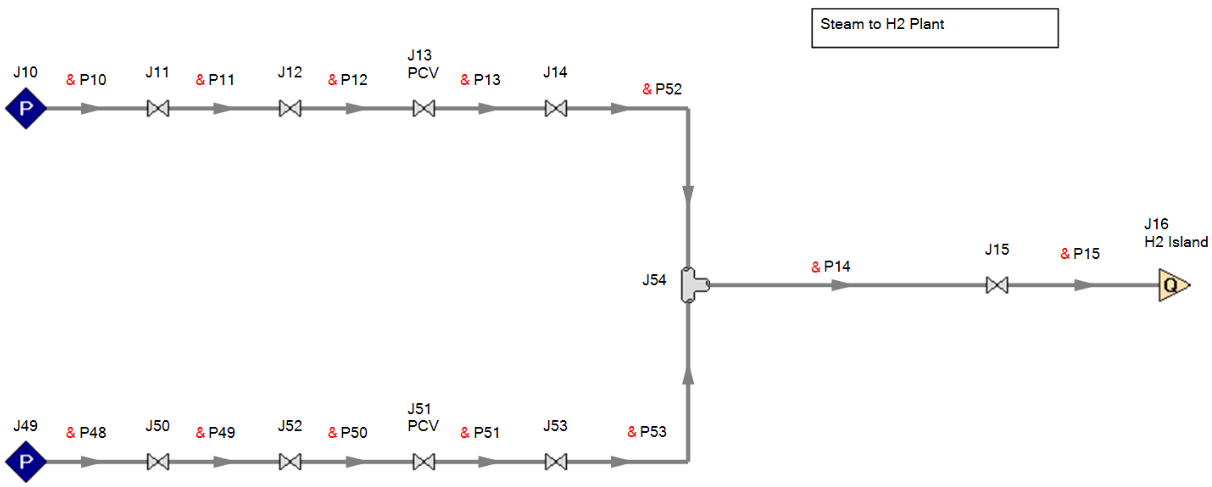


Table C1: Pipe Length and Fitting Assumptions

Pipe	Length (ft)	Losses	Fittings and Losses Total K per Pipe
P10, P11, P12, P13, P48, P49, P50, P51, P52, P53	10	2x 90° Elbows (r/D=1.5)	0.35
P15	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.34
P14	1700	20x 90° Elbows (r/D=1.5)	3.36

Table C2: Component Assumptions

Valve Numbers	Type	Losses
J11, J12, J14, J50, J52, J53, J15	Gate	K = 0.10
J13, J51	Control	20 psid

C4.2 Pipe insulation is assumed to be Calcium Silicate, 4.5 inches in thickness. Insulation properties are based on the Arrow built-in properties [Ref. C5.2].

C4.3 Outside air temperature is assumed to be -10°F and air velocity is assumed to be 50 ft/sec (34 mph). These conditions are reasonable for a typical winter in a cold climate.

C4.4 All piping elevations are assumed to be at same elevation of 0 ft, which is reasonable since the piping elevations for steam systems have negligible impact on the system design.

C4.5 The required steam flow at the industrial heat user is 345,000 lbm/hr based on agreement with INL. For the purposes of this analysis a conservative value of 350,000 lbm/hr is used.

C4.6 Pipes with design pressure less than or equal to 500 psig are assumed to be standard (STD) pipe schedule. For pipes with design pressures greater than 500 psig, Schedule 80 is used.

C5.0 References

C5.1 PEPSE Heat Balances as shown in Attachment A

C5.2 Arrow computer software version 7 (S&L Program No. 03.7.722-7.0-08/06/2018)

C5.3 S&L Standard MES 2.11, “Recommended Allowable Velocities in Piping Systems”

C5.4 Crane Technical Paper 410, 2012 Edition

C6.0 Results

The Arrow model for the process steam to the H2 plant was developed and iteratively changed until the final pipe sizes are determined.

Pipes carrying half of the steam flow are chosen to be STD schedule 18-inch pipe (50 ft per flow path, 100 ft total length), and the pipe carrying the full steam flow to the H2 plant is chosen to be STD schedule 26-inch pipe (1710 ft total length). This results in a maximum steam velocity of ~131 ft/sec.

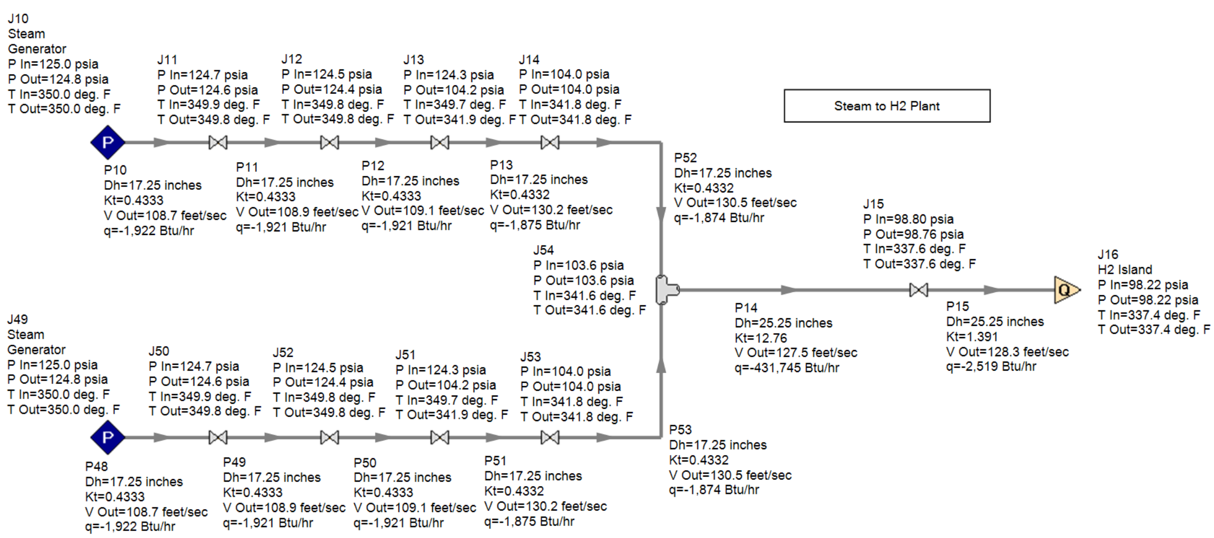
A design pressure of 150 psig and design temperature of 400°F would envelop the conditions shown.

The total pressure drop and heat loss for the process steam piping are given in the table below.

Table C3: Pressure Drop and Heat Loss

Pipe Section	Pressure Drop (psid)	Heat Loss (BTU/hr)
Reboiler to Common Header (per train)	21	10,000
Common Header to H2 Plant	5	435,000

Detailed results are shown on the diagram below:



ATTACHMENT D. BOILER FEED PIPE SIZING

(6 Pages)

D1.0 Purpose

The purpose of this attachment is to size the reboiler feed water pump and piping to the H2 plant steam generator (reboiler), the water return line from the H2 plant to the storage tank, and the tank volume. Water returns to the tank from the H2 plant and is then routed to the two new pumps which deliver the water to the two new heat exchangers (H2 plant steam generators / boilers). Each reboiler feed water pipe is sized to deliver the required water flow with the water velocity below recommended velocity guidelines [Ref. D5.3].

D2.0 Methodology

The simplified model is developed in the Fathom computer software [Ref. D5.2] to keep water velocities in piping below 10 ft/sec and as low as ~4 ft/sec for pump suction lines [Ref. D5.3]. The pipe length, valves, and fittings are based on Assumption D4.1. Results from this attachment are input into the PEPSE model [Ref. D5.1].

Heat loss to the environment is calculated in Excel using the following methodology:

$$q = \frac{\Delta T}{R_{tot}} \qquad \text{[Ref. D5.5, Eq 3.19]}$$

Where:

q	=	Heat rate [BTU/hr]
ΔT	=	Change in temperature [°F or °R]
R_{tot}	=	Total thermal resistance [BTU/hr-ft-°R]

The total thermal resistance for a cylindrical wall can be calculated by adding the resistances for convection and conduction using the following equations. For this system, resistances are calculated for conduction through the pipe wall and insulation layer and for convection between the insulation layer and the air.

$$R_{conv} = \frac{1}{hA} \qquad \text{[Ref. D5.5, Eq 3.9]}$$

$$R_{cond} = \frac{\ln{(r_2/r_1)}}{2\pi Lk} \qquad \text{[Ref. D5.5, Eq 3.28]}$$

Where:

R_{conv}	=	Thermal resistance for convection [BTU/hr-ft-°R]
R_{cond}	=	Thermal resistance for conduction [BTU/hr-ft-°R]
h	=	Convection heat transfer coefficient [BTU/hr-ft^2-°R]
A	=	Surface area [ft^2]
r_2	=	Outer radius [ft]
r_2	=	Inner radius [ft]
L	=	Length [ft]
k	=	Thermal conductivity [BTU/hr-ft-°R]

The convection heat transfer coefficient, is calculated using the Churchill-Bernstein correlation:

$$h = \frac{\mathrm{Nu} * \mathrm{k}}{D} \quad \text{[Ref. D5.5, Eq 7.52]}$$

$$Nu = 0.3 + \frac{0.62 Re^{\frac{1}{2}} Pr^{\frac{1}{3}}}{\left(1 + (0.4/Pr)^{\frac{2}{3}}\right)^{\frac{1}{4}}} \left[1 + \left(\frac{Re}{282000}\right)^{\frac{5}{8}}\right]^{\frac{4}{5}} \quad \text{[Ref. D5.5, Eq 7.54]}$$

$$Re = \frac{\rho V x}{\mu} \quad \text{[Ref. D5.5, Eq 6.23]}$$

$$Pr = \frac{c_p \mu}{k} \quad \text{[Ref. D5.5, Table 6.2]}$$

Where:

Nu	=	Nusselt number [-]
Re	=	Reynolds number [-]
Pr	=	Prandtl number [-]
ρ	=	Density [lbm/ft³]
V	=	Air velocity [ft/sec]
x	=	Characteristic length (diameter for cylindrical systems) [ft]
μ	=	Dynamic viscosity [lbm/ft-sec]
c_p	=	Specific heat [BTU/lbm-°R]
D	=	Diameter [ft]

Using this methodology, heat loss is calculated separately for each section of pipe with the same size and water temperature.

D3.0 Inputs

D3.1 The required steam flow at the industrial heat user is 345,000 lbm/hr based on input from INL. For the purposes of this analysis a conservative value of 350,000 lbm/hr is used.

D3.2 The return water temperature from the H2 Plant is 180°F is based input received from INL.

D3.3 The water supply pressure at the reboilers is ~135 psia based on the PEPSE heat balance [Ref. D5.1].

D3.4 The exit temperature of the preheaters is 280°F based on the PEPSE heat balance [Ref. D5.1].

D3.5 Fluid and material properties are calculated using Fathom's built-in database [Ref. D5.2]. Values for the specific heat and thermal conductivity of air are taken from Arrow's database [Ref. D5.6] as they are not provided in Fathom. Table D2 provides the constants used to calculate these values based on the relation $y(T) = a + bT + cT^2 + dT^3$. The temperature of air used is 250°K

(-10°F) per Assumption D4.6, and the properties of steel and calcium silicate are evaluated at the water temperature per Assumption D4.8.

Table D2: Fluid and Material Properties

Description	Output Units	Input Units	Constants
Density of Air	lbm/ft³	°F	a: 0.086209 b: -0.0001829 c: $3.2717*10^{-7}$ d: $-3.2202*10^{-10}$
Specific Heat of Air	BTU/lbm-°R	°K	a: 0.2309036 b: $2.123811*10^{-5}$ c: $2.166666*10^{-8}$
Dynamic Viscosity of Air	lbf-s/ft²	°F	a: $3.3014*10^{-7}$ b: $8.7135*10^{-10}$ c: $-2.7782*10^{-12}$ d: $6.3826*10^{-15}$
Thermal Conductivity of Air	BTU/hr-ft-R	°K	a: 0.004340785 b: $3.698215*10^{-5}$ c: $-2.171431*10^{-9}$
Thermal Conductivity of Steel (ANSI)	BTU/hr-ft-R	°K	a: 30.55725 b: -0.00801928 c: $8.368627*10^{-7}$
Thermal Conductivity of Calcium Silicate	BTU/hr-ft-R	°F	a: 0.03142449 b: $1.590156*10^{-5}$ c: $2.309058*10^{-8}$

D4.0 Assumptions

D4.1 The reboiler feed water piping length, valves, and fittings are assumed based on the diagram shown below. Fitting losses are taken from Reference D5.4 unless otherwise noted.

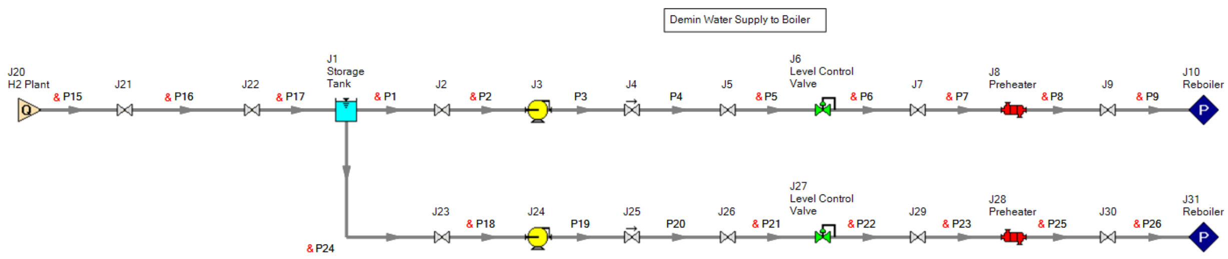


Table D1: Piping Length and Fitting Assumptions

	Pipe	Length (ft)	Losses	Fittings and Losses Total K per Pipe
Suction Piping	P1, P24	20	2x 90° Elbows (r/D=1.5), Entrance Loss	0.92
Suction Piping	P2, P18	20	2x 90° Elbows (r/D=1.5)	0.42
Discharge to Preheater	P3, P4, P19, P20	10	-	-
Discharge to Preheater	P5, P21	200	10x 90° Elbows (r/D=1.5)	2.38
Discharge to Preheater	P6, P22	10	2x 90° Elbows (r/D=1.5)	0.48
Discharge to Preheater	P7, P23	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.48
Preheater to Reboiler	P8, P25	10	2x 90° Elbows (r/D=1.5), Entrance Loss	0.98
Preheater to Reboiler	P9, P26	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.48
Return to Tank	P15	10	2x 90° Elbows (r/D=1.5)	0.42
Return to Tank	P16	1700	20x 90° Elbows (r/D=1.5)	4.19
Return to Tank	P17	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.42

Table D2: Component Assumptions

Valve Numbers	Type	Losses
J2, J23	Gate	K = 0.12
J5, J7, J9, J26, J29, J30	Gate	K = 0.14
J6, J27	Control	20 psid
J4, J25	Check	K = 0.8

D4.2 All piping elevations are assumed to be at same elevation of 0 ft, which is reasonable since the new equipment is expected to be at similar elevations. During the detailed design phase, actual pipe routing and elevations need to be utilized.

D4.3 The pump efficiency is assumed to be 65%.

D4.4 The following storage tank (J1) conditions are assumed:

- Tank Water Level: 5 ft
- Tank Surface Pressure: 0 psig

D4.5 Pipe insulation is assumed to be Calcium Silicate, 2 inches in thickness. Insulation properties are based on the Fathom built-in properties [Ref. D5.2].

D4.6 The air temperature is assumed to be -10°F and air velocity is assumed to be 50 ft/sec (34 mph). These conditions are reasonable for a typical winter in a cold climate.

D4.7 Pump shutoff head is assumed to be 50% higher than pump head at its design flow rate.

D4.8 When calculating heat loss, it is assumed that there is perfect heat transfer between the water and the pipe such that the temperature of the pipe inside surface is equivalent to the water temperature. Additionally, the water temperature is used when calculating thermal conductivity for the insulation. This maximizes heat loss and is therefore conservative.

D4.9 The preheaters are assumed to have a pressure loss of 20 psid. This is a nominal value expected to bound actual component pressure loss.

D4.10 Pipes with design pressure less than or equal to 500 psig are assumed to be standard (STD) pipe schedule. For pipes with design pressures greater than 500 psig, Schedule 80 is used.

D5.0 <u>References</u>

D5.1 PEPSE Heat Balances as shown in Attachment A

D5.2 AFT Fathom computer software version 11, (S&L Program No. 03.7.721-11-06/18/2020)

D5.3 S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

D5.4 Crane Technical Paper 410, 2012 Edition

D5.5 Fundamentals of Heat and Mass Transfer, 6th Edition, Incropera et al

D5.6 Arrow Computer software version 7, (S&L program # 03.7.722-7.0-08/06/2018)

D6.0 <u>Results</u>

The Fathom model was iterated to determine the final pipe sizes.

D6.1 <u>Pipe Size</u>

For the water return line, a 6-inch diameter carbon steel pipe (STD schedule) totaling 1720 ft was modeled, resulting in a maximum water velocity of ~8 ft/sec. A pressure of ~42 psia at the H2 plant exit is required to return water to the storage tank. Assuming a 50% shutoff head margin for the H2 plant pump, the maximum pressure is 63 psia. Given the maximum pressure of 63 psia and maximum temperature of 180°F (Input D3.2), a design pressure of 75 psig and design temperature of 200°F would envelop the above conditions.

For the water supply to the preheater, the pump suction lines are 6-inch diameter carbon steel pipe (STD schedule) totaling 80 ft (40 ft per train) and have a maximum velocity of ~4 ft/sec. The pump discharge lines are 4-inch diameter carbon steel pipe (STD schedule) totaling 520 ft (260 ft per train) and have a maximum velocity of ~9.5 ft/sec. Note that check valve minimum flow velocity should be considered during equipment selection. Given a maximum pressure of 17 psia upstream of the pump and 274 psia downstream of the pump (upstream pressure of 17 psia plus the pump pressure rise with a 50% margin for shutoff head allowance (257 psid), design pressures of 50 psig for the pump suction and 300 psig for the pump discharge would envelop the above conditions. With a maximum temperature of 180°F, a design temperature of 200°F is chosen.

D6.2 Pump Size

The initial pump sizing is based on the nominal flowrate of 360 gpm (at 180°F) along with the nominal carbon steel pipe characteristics and resulted in a required pump total developed head of ~405 ft with a horsepower requirement of ~55 hp (assuming 65% efficiency per Assumption D4.3). Note that the final pump sizing needs to consider appropriate design margin, NPSH requirements, and maximum temperatures.

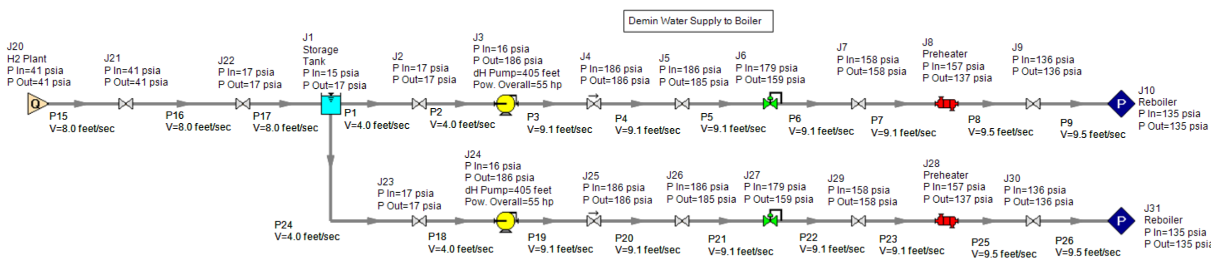
D6.3 Pressure Drop and Heat Loss

The pressure drop and heat loss for each section of piping are given in the table below.

Table D4: Pressure Drop & Heat Loss

Pipe Section	Pressure Drop (psid)	Heat Loss (BTU/hr)
H2 Plant to Tank	26	150,000
Tank to Pump Suction (1 train)	<1	3,000
Pump to Preheater (1 train)	29	16,000
Preheater to Reboiler (1 train)	2	2,000

Detailed results are shown on the diagram below:



ATTACHMENT E. DRAIN PIPE SIZING

(6 Pages)

E1.0 Purpose

The purpose of this attachment is to size the drain piping from the external drain cooler to the main condenser. Additionally, the required differential pressure across the level control valve is determined. The pipes are sized to deliver the required water flow from the PEPSE heat balance [Ref. E5.1] with water velocities below 7 ft/sec based on heater drain piping recommended velocity guidelines [Ref. E5.3].

E2.0 Methodology

The simplified model is developed in the Fathom computer software [Ref. E5.2] to size the drain piping with water velocities below 7 ft/sec [Ref. E5.3]. Although there are three condenser zones, this drain line is only to condenser "C." The required water flow rate, along with drain inlet and condenser conditions, are taken from the PEPSE Heat Balance [Ref. E5.1]. The pipe length, valves, and fittings are based on Assumption E4.1.

Heat loss to the environment is calculated in Excel using the following methodology:

$$q = \frac{\Delta T}{R_{tot}} \qquad \text{[Ref. E5.5, Eq 3.19]}$$

Where:

q	=	Heat rate [BTU/hr]
ΔT	=	Change in temperature [°F or °R]
R_{tot}	=	Total thermal resistance [BTU/hr-ft-°R]

The total thermal resistance for a cylindrical wall can be calculated by adding the resistances for convection and conduction using the following equations. For this system, resistances are calculated for conduction through the pipe wall and insulation layer and for convection between the insulation layer and the air.

$$R_{conv} = \frac{1}{hA} \qquad \text{[Ref. E5.5, Eq 3.9]}$$

$$R_{cond} = \frac{\ln{(r_2/r_1)}}{2\pi Lk} \qquad \text{[Ref. E5.5, Eq 3.28]}$$

Where:

R_{conv}	=	Thermal resistance for convection [BTU/hr-ft-°R]
R_{cond}	=	Thermal resistance for conduction [BTU/hr-ft-°R]
h	=	Convection heat transfer coefficient[BTU/hr-ft^2-°R]
A	=	Surface area [ft^2]
r_2	=	Outer radius [ft]
r_2	=	Inner radius [ft]
L	=	Length [ft]

k = Thermal conductivity [BTU/hr-ft-°R]

The convection heat transfer coefficient, is calculated using the Churchill-Bernstein correlation:

$$h = \frac{\mathrm{Nu} * \mathrm{k}}{D}$$ [Ref. E5.5, Eq 7.52]

$$Nu = 0.3 + \frac{0.62 Re^{\frac{1}{2}} Pr^{\frac{1}{3}}}{\left(1 + (0.4/Pr)^{\frac{2}{3}}\right)^{\frac{1}{4}}} \left[1 + \left(\frac{Re}{282000}\right)^{\frac{5}{8}}\right]^{\frac{4}{5}}$$ [Ref. E5.5, Eq 7.54]

$$Re = \frac{\rho V x}{\mu}$$ [Ref. E5.5, Eq 6.23]

$$Pr = \frac{c_p \mu}{k}$$ [Ref. E5.5, Table 6.2]

Where:

Nu = Nusselt number [-]
Re = Reynolds number [-]
Pr = Prandtl number [-]
ρ = Density [lbm/ft³]
V = Air velocity [ft/sec]
x = Characteristic length (diameter for cylindrical systems) [ft]
μ = Dynamic viscosity [lbm/ft-sec]
c_p = Specific heat [BTU/lbm-°R]
D = Diameter [ft]

Using this methodology, heat loss is calculated separately for each section of pipe with the same size and water temperature.

E3.0 Inputs

E3.1 The required water flow rate and boundary conditions are based on the PEPSE heat balance [Ref. E5.1] and rounded as necessary.

Table E1: Drain Conditions

Description	Value
Drain Flow	385,000 lbm/hr
Condensing Heat Exchanger Outlet Pressure	990 psia
Condensing Heat Exchanger Outlet Temperature	540°F
Drain Inlet Temperature	275°F

Condenser Pressure	0.7 psia

E3.2 Fluid and material properties are calculated using Fathom's built-in database [Ref. E5.2]. Values for the specific heat and thermal conductivity of air are taken from Arrow's database [Ref. E5.6] as they are not provided in Fathom. Table E2 provides the constants used to calculate these values based on the relation $y(T) = a + bT + cT^2 + dT^3$. The temperature of air used is 294°K (70°F) per Assumption E4.3, and the properties of steel and calcium silicate are evaluated at the water temperature per Assumption E4.4.

Table E2: Fluid and Material Properties

Description	Output Units	Input Units	Constants
Density of Air	lbm/ft³	°F	a: 0.086209 b: -0.0001829 c: $3.2717*10^{-7}$ d: $-3.2202*10^{-10}$
Specific Heat of Air	BTU/lbm-°R	°K	a: 0.2309036 b: $2.123811*10^{-5}$ c: $2.166666*10^{-8}$
Dynamic Viscosity of Air	lbf-s/ft²	°F	a: $3.3014*10^{-7}$ b: $8.7135*10^{-10}$ c: $-2.7782*10^{-12}$ d: $6.3826*10^{-15}$
Thermal Conductivity of Air	BTU/hr-ft-R	°K	a: 0.004340785 b: $3.698215*10^{-5}$ c: $-2.171431*10^{-9}$
Thermal Conductivity of Steel (ANSI)	BTU/hr-ft-R	°K	a: 30.55725 b: -0.00801928 c: $8.368627*10^{-7}$
Thermal Conductivity of Calcium Silicate	BTU/hr-ft-R	°F	a: 0.03142449 b: $1.590156*10^{-5}$ c: $2.309058*10^{-8}$

E4.0 <u>Assumptions</u>

E4.1 The reboiler drain piping length, valves, and fittings are assumed based on the diagram shown below. Fitting losses are taken from Reference E5.4 unless otherwise noted:

Table E2: Piping Length and Fitting Assumptions

	Pipe	Length (ft)	Losses	Fittings and Losses Total K per Pipe
Condensing Heat Exchanger to Drain Cooler	P103	10	2x 90° Elbows (r/D=1.5), Entrance Loss	0.90
Condensing Heat Exchanger to Drain Cooler	P104	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.40
Drain Cooler to Condenser	P100	10	2x 90° Elbows (r/D=1.5), Entrance Loss	0.90
Drain Cooler to Condenser	P101	200	10x 90° Elbows (r/D=1.5)	1.99
Drain Cooler to Condenser	P102	10	2x 90° Elbows (r/D=1.5), Exit Loss	1.40

Table E3: Component Assumptions

Valve Numbers	Type	Losses
J101, J105	Gate	K = 0.11
J102	Control	see Note 1

1 Valve pressure drop iterated by Fathom to maintain flow rate of 385,000 lbm/hr

E4.2 All piping elevations are assumed to be at same elevation of 0 ft since it is expected that new equipment will be at a similar elevation. During the detailed design phase, actual pipe routing and elevations need to be utilized.

E4.3 The turbine building temperature is assumed to be 70°F and the air velocity is assumed to be 1 ft/sec (0.7 mph). These conditions are reasonable for a typical Turbine Building.

E4.4 When calculating heat loss, it is assumed that there is perfect heat transfer between the water and the pipe such that the temperature of the pipe inside surface is equivalent to the water temperature. Additionally, the water temperature is used when calculating thermal conductivity for the insulation. This maximizes heat loss and is therefore conservative.

E4.6 Pipe insulation is assumed to be Calcium Silicate, 2 inches in thickness. Insulation properties are based on the Fathom built-in properties [Ref. E5.2].

E4.7 The external drain coolers are assumed to have a pressure loss of 20 psid. This is a nominal value expected to bound actual component pressure loss.

E4.8 Pipes with design pressure less than or equal to 500 psig are assumed to be standard (STD) pipe schedule. For pipes with design pressures greater than 500 psig, Schedule 80 is used.

E5.0 References

E5.1 PEPSE Heat Balances as shown in Attachment A

E5.2 AFT Fathom computer software version 11, (S&L Program No. 03.7.721-11-06/18/2020)

E5.3 S&L Standard MES 2.11, "Recommended Allowable Velocities in Piping Systems"

E5.4 Crane Technical Paper 410, 2012 Edition

E5.5 Fundamentals of Heat and Mass Transfer, 6th Edition, Incropera et al

E5.6 Arrow Computer software version 7, (S&L program # 03.7.722-7.0-08/06/2018)

E6.0 Results

The Fathom model for the condensate return from the reboiler to the main condenser and heater drain tank was developed and iterated until the final pipe sizes were determined.

E6.1 Pipe Size

The drain pipe is modeled as 8 inch, schedule 80, steel pipe totaling 240 ft. This results in a maximum water velocity of ~5.8 ft/sec in the drain to the level control valve and ~7.2 ft/sec from the condensing heat exchanger to the external drain cooler. Although 7.2 ft/sec exceeds the recommended velocity guideline of 7.0 ft/sec, the pipe length is small and only marginally exceeds the criterion. Therefore, it is considered acceptable for this preliminary design, but final selection should be made based on discussion with the condensing heat exchanger and drain cooler vendor.

Fluid downstream of the level control valve is expected to flash to two-phase flow. Pipe length and bends downstream of the drain valve should be minimized with as direct a route to the condenser shell as possible. The maximum pressure is 990 psia, which would be covered by a design pressure of 1000 psig. A design temperature of 600°F would envelop the conditions shown.

The total pressure drop and heat loss for the drain piping are given in the table below.

Table E4: Pressure Drop & Heat Loss

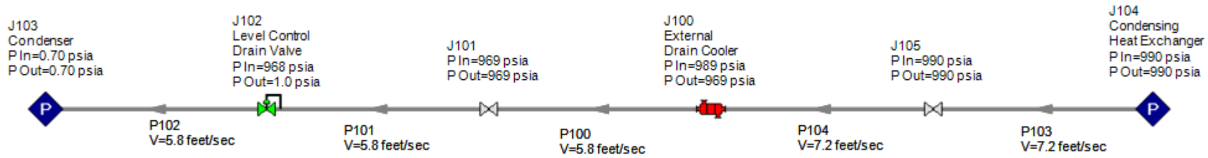
Pipe Section	Pressure Drop (psid)	Heat Loss (BTU/hr)
Condensing Heat Exchanger to Drain Cooler	1	5,000
Drain Cooler Drain to Condenser	969	22,000

E6.2 Drain Control Valve Size

The drain control valve (J102) sizing results in the following requirements:

- Drain Flow: 385,000 lbm/hr (977.7 gpm)
- Valve Pressure Drop: ~966.6 psid
- Valve Inlet Pressure: ~967.6 psia

Note that due to a very high valve dP and vacuum at the outlet, flashing across the valve will occur, which should be considered when specifying the drain control valve. If a single valve cannot support the required conditions, orifice plate(s) could be used to step down the pressure.



ATTACHMENT F. INTERMEDIATE LOOP PIPE SIZING

(7 Pages)

F1.0 Purpose

The purpose of this section is to size the intermediate loop pump and piping. In this loop, water is pumped from a tank to the set of intermediate heat exchangers. It is then split into two trains which deliver water to the reboilers and preheaters before being sent back to the tank. The pipe is sized to deliver the required flow with water velocities below 10 ft/sec based on general service piping recommended velocity guidelines [Ref. F5.3].

F2.0 Methodology

The model is developed in Fathom [Ref. F5.2] to size the piping to maintain water velocities below 10 ft/sec [Ref. F5.3]. The required water flow rate is based on the PEPSE heat balance [Ref. F5.1]. The pipe length, valves, and fittings are based on Assumption F4.1.

Heat loss to the environment is calculated in Excel using the following methodology:

$$q = \frac{\Delta T}{R_{tot}} \qquad \text{[Ref. F5.5, Eq 3.19]}$$

Where:

q	=	Heat rate [BTU/hr]
ΔT	=	Change in temperature [°F or °R]
R_{tot}	=	Total thermal resistance [BTU/hr-ft-°R]

The total thermal resistance for a cylindrical wall can be calculated by adding the resistances for convection and conduction using the following equations. For this system, resistances are calculated for conduction through the pipe wall and insulation layer and for convection between the insulation layer and the air.

$$R_{conv} = \frac{1}{hA} \qquad \text{[Ref. F5.5, Eq 3.9]}$$

$$R_{cond} = \frac{\ln{(r_2/r_1)}}{2\pi Lk} \qquad \text{[Ref. F5.5, Eq 3.28]}$$

Where:

R_{conv}	=	Thermal resistance for convection [BTU/hr-ft-°R]
R_{cond}	=	Thermal resistance for conduction [BTU/hr-ft-°R]
h	=	Convection heat transfer coefficient[BTU/hr-ft^2-°R]
A	=	Surface area [ft^2]
r_2	=	Outer radius [ft]
r_2	=	Inner radius [ft]
L	=	Length [ft]
k	=	Thermal conductivity [BTU/hr-ft-°R]

The convection heat transfer coefficient, is calculated using the Churchill-Bernstein correlation:

$$h = \frac{\mathrm{Nu} * \mathrm{k}}{D}$$ [Ref. F5.5, Eq 7.52]

$$Nu = 0.3 + \frac{0.62Re^{\frac{1}{2}}Pr^{\frac{1}{3}}}{\left(1 + (0.4/Pr)^{\frac{2}{3}}\right)^{\frac{1}{4}}}\left[1 + \left(\frac{Re}{282000}\right)^{\frac{5}{8}}\right]^{\frac{4}{5}}$$ [Ref. F5.5, Eq 7.54]

$$Re = \frac{\rho V x}{\mu}$$ [Ref. F5.5, Eq 6.23]

$$Pr = \frac{c_p \mu}{k}$$ [Ref. F5.5, Table 6.2]

Where:

Nu	=	Nusselt number [-]
Re	=	Reynolds number [-]
Pr	=	Prandtl number [-]
ρ	=	Density [lbm/ft³]
V	=	Air velocity [ft/sec]
x	=	Characteristic length (diameter for cylindrical systems) [ft]
μ	=	Dynamic viscosity [lbm/ft-sec]
c_p	=	Specific heat [BTU/lbm-°R]
D	=	Diameter [ft]

Using this methodology, heat loss is calculated separately for each section of pipe with the same size and water temperature.

F3.0 Inputs

F3.1 The water flow rate, nominal tank pressure, and heat exchanger outlet temperatures are based on the PEPSE heat balance [Ref. F5.1].

Table F1: Inputs

Description	Value
Flow Rate	1,200,000 lbm/hr
Tank Pressure	1000 psia
External Drain Cooler Exit Temperature	355°F
Condensing Heat Exchanger Exit Temperature	545°F

Description	Value
Reboiler Exit Temperature	300°F
Preheater Exit Temperature	265°F

F3.2 Fluid and material properties are calculated using Fathom's built-in database [Ref. F5.2]. Values for the specific heat and thermal conductivity of air are taken from Arrow's database [Ref. F5.6] as they are not provided in Fathom. Table F1 provides the constants used to calculate these values based on the relation $y(T) = a + bT + cT^2 + dT^3$. The temperature of air used is 250 °K (-10 °F) per Assumption F4.5, and the properties of steel and calcium silicate are evaluated at the water temperature per Assumption F4.4.

Table F2: Fluid and Material Properties

Description	Output Units	Input Units	Constants
Density of Air	lbm/ft^3	°F	a: 0.086209 b: -0.0001829 c: $3.2717*10^{-7}$ d: $-3.2202*10^{-10}$
Specific Heat of Air	BTU/lbm-°R	°K	a: 0.2309036 b: $2.123811*10^{-5}$ c: $2.166666*10^{-8}$
Dynamic Viscosity of Air	$lbf\text{-}s/ft^2$	°F	a: $3.3014*10^{-7}$ b: $8.7135*10^{-10}$ c: $-2.7782*10^{-12}$ d: $6.3826*10^{-15}$
Thermal Conductivity of Air	BTU/hr-ft-R	°K	a: 0.004340785 b: $3.698215*10^{-5}$ c: $-2.171431*10^{-9}$
Thermal Conductivity of Steel (ANSI)	BTU/hr-ft-R	°K	a: 30.55725 b: -0.00801928 c: $8.368627*10^{-7}$
Thermal Conductivity of Calcium Silicate	BTU/hr-ft-R	°F	a: 0.03142449 b: $1.590156*10^{-5}$ c: $2.309058*10^{-8}$

F4.0 <u>Assumptions</u>

F4.1 The intermediate loop piping length, valves, and fittings are assumed based on the diagram shown below:

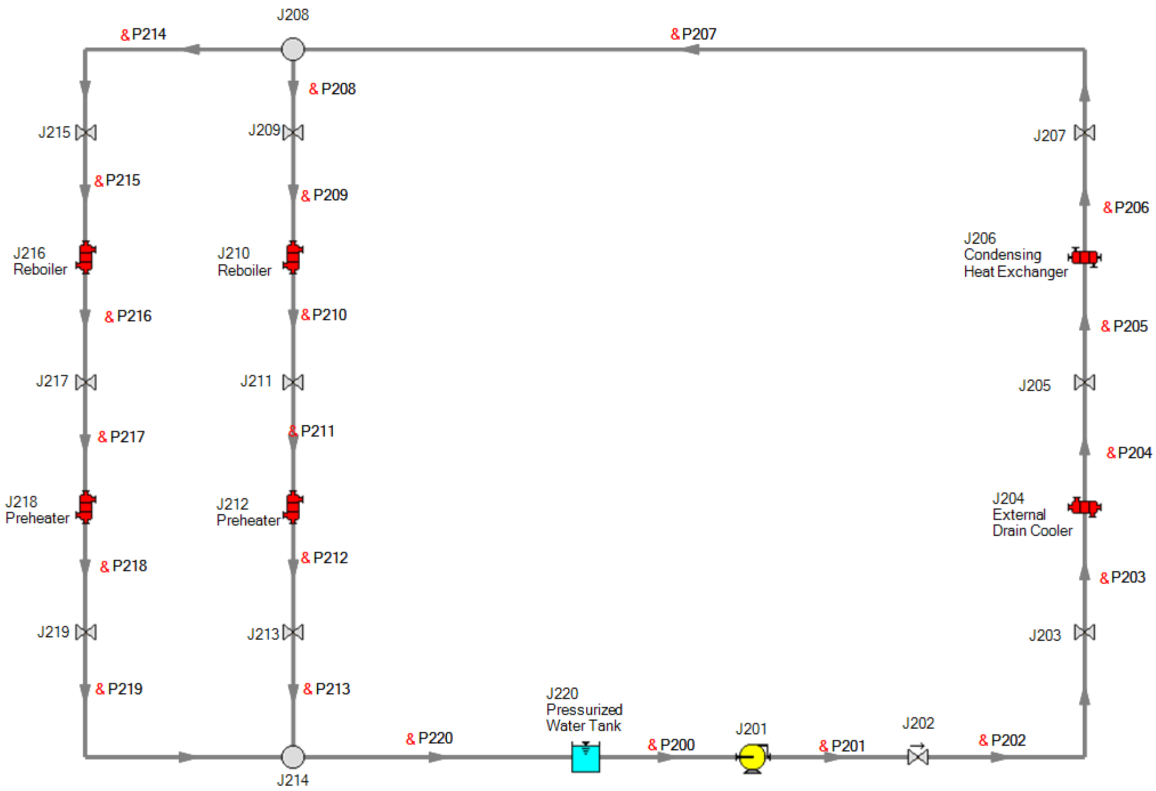

J208
P214
P207
P208
J215
J209
J207
P215
P209
P206
J216
Reboiler
J210
Reboiler
J206
Condensing
Heat Exchanger
P216
P210
P205
J217
J211
J205
P217
P211
P204
J218
Preheater
J212
Preheater
J204
External
Drain Cooler
P218
P212
P203
J219
J213
J203
P219
P213
J220
Pressurized
Water Tank
P220
P200
J201
P201
J202
P202
J214

Table F2: Piping Length and Fitting Assumptions

	Pipe Numbers	Length (ft)	Fittings & Losses	Total K
Pump to Drain Cooler	P201-P203	10	2 - 90 deg (1.5 r/D) elbows	0.36
Drain Cooler to Condensing Heat Exchanger	P204, P205	10	2 - 90 deg (1.5 r/D) elbows	0.36
Condensing Heat Exchanger to Reboiler	P206	10	2 - 90 deg (1.5 r/D) elbows	0.36
Condensing Heat Exchanger to Reboiler	P207	200	20 - 90 deg (1.5 r/D) elbows	3.64
Condensing Heat Exchanger to Reboiler	P208, P209, P214, P215	10	2 - 90 deg (1.5 r/D) elbows	0.39
Reboiler to Preheater	P210, P211, P216, P217	10	2 - 90 deg (1.5 r/D) elbows	0.39
Preheater to Pressurized Water Tank	P212, P213, P218, P219	10	2 - 90 deg (1.5 r/D) elbows	0.39
Preheater to Pressurized Water Tank	P220	200	20 - 90 deg (1.5 r/D) elbows	3.64
Pressurized Water Tank to Pump	P200	10	2 - 90 deg (1.5 r/D) elbows	0.36

Table F3: Component Assumptions

Valve Numbers	Type	Losses
J202	Check	K = 0.65
J203, J205, J207	Gate	K = 0.10
J209, J211, J213, J215, J217, J219	Gate	K = 0.11

F4.2 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.

F4.3 The pump efficiency is assumed at 65%.

F4.4 When calculating heat loss, it is assumed that there is perfect heat transfer between the water and the pipe such that the temperature of the pipe inside surface is equivalent to the water temperature. Additionally, the water temperature is used when calculating thermal conductivity for the insulation. This maximizes heat loss and is therefore conservative.

F4.5 Although some piping will be within the turbine building, all piping is conservatively assumed to be outside to maximize heat loss. An ambient air temperature of -10°F and air velocity of 50 ft/s is used as these conditions are reasonable for a typical winter in a cold climate.

F4.6 Pipe insulation is assumed to be Calcium Silicate, 2 inches in thickness. Insulation properties are based on the Fathom built-in properties [Ref. F5.2].

F4.7 Each heat exchanger (condensing heat exchanger, external drain cooler, reboiler, and preheater) is assumed to have a pressure loss of 20 psid. This is a nominal value expected to bound actual component pressure loss.

F4.8 Pipes with design pressure less than or equal to 500 psig are assumed to be standard (STD) pipe schedule. For pipes with design pressures greater than 500 psig, Schedule 80 is used.

F5.0 References

F5.1 PEPSE Heat Balances as shown in Attachment A

F5.2 AFT Fathom Computer software version 11, (S&L program # 03.7.721-11-06/18/2020)

F5.3 S&L Standard MES 2.11, “Recommended Allowable Velocities in Piping Systems”

F5.4 Crane Technical Paper 410, 2012 Edition

F5.5 Fundamentals of Heat and Mass Transfer, 6th Edition, Incropera et al

F5.6 Arrow Computer software version 7, (S&L program # 03.7.722-7.0-08/06/2018)

F6.0 Results

The Fathom model for the intermediate loop was developed and iteratively changed until the final pipe sizes are determined.

F6.1 Pipe Size

The piping carrying the full flow is sized as 14 inch, schedule 80, steel pipe totaling 470 ft. The piping carrying half of the flow is sized as 10 inch, schedule 80, steel pipe total 120 ft. This results in a maximum velocity of 8.4 ft/s. Given the maximum pressure of 1,100 psia and maximum temperature of 545°F, a design pressure of 1,200 psig and design temperature of 550°F would envelop these conditions.

F6.2 Pump Size

The initial pump sizing is based on the nominal flowrate of 1,200,000 lbm/hr (~2,550 gpm) and resulted in a required total developed head of ~212 ft, with a horsepower requirement of ~197 hp. Note that the final pump sizing needs to consider appropriate design margin and NPSH requirements.

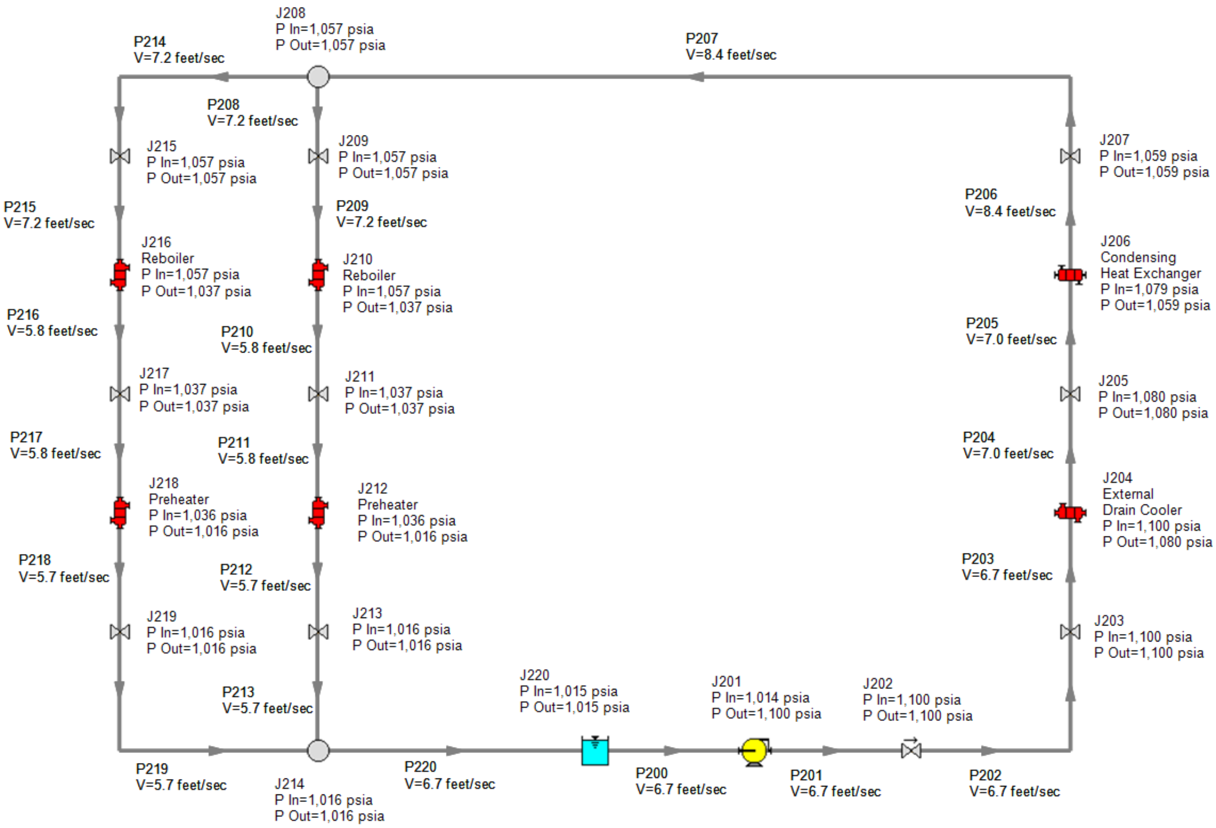
F6.3 Pressure Drop & Heat Loss

The pressure drop and heat loss for each section of piping are given in the table below.

Table F4: Pressure Drop & Heat Loss

Pipe Section	Pressure Drop (psid)	Heat Loss (BTU/hr)
Pump to Drain Cooler	1	7,000
Drain Cooler to Condensing Heat Exchanger	<1	7,000
Condensing Heat Exchanger to Reboiler	2	140,000
Reboiler to Preheater (per train)	<1	5,000
Preheater to Pressurized Water Tank	2	54,000
Pressurized Water Tank to Pump	<1	2,000

Detailed results are shown on the diagram below:



ATTACHMENT G. PIPING AND INSTRUMENTATION DIAGRAM

(1 Page)

NOTES:
1. ADDITIONAL COMPONENTS (VENTS, DRAINS, SAMPLING, CONNECTIONS, RELIEF VALVES, ETC) WILL BE REQUIRED FOR DETAILED DESIGN.
2. ALL STEAM PIPING IS CARBON STEEL, DESIGN IN ACCORDANCE WITH ASME B31.1.
3. ALL HOT WATER PIPING IS STAINLESS STEEL. ALL AMBIENT WATER PIPING IS HDPE. PIPING SHALL BE DESIGNED IN ACCORDANCE WITH ASME B31.1.
4. CONDENSING HEAT EXCHANGER AND EXTERNAL DRAIN COOLER SHOWN IN PREFERRED ARRANGEMENT INSIDE TURBINE BUILDING. ALTERNATIVE PLACEMENT IN THE PROTECTED AREA ADJACENT TO THE TURBINE BUILDING MAY BE PURSUED WITH ADDITION MODIFICATION SCOPE.

LEGEND:
- NEW PIPING
- EXISTING PIPING
- INSTR. AIR (NEW)
- SIGNAL (NEW)

ABBREVIATIONS:

AO – AIR OPERATED
FC – FAIL CLOSED
FO – FAIL OPEN
FCV – FLOW CONTROL VALVE
FT – FLOW TRANSMITTER
LCV – LEVEL CONTROL VALVE
LT – LEVEL TRANSMITTER
PI – PRESSURE INDICATOR
PCV – PRESSURE CONTROL VALVE
RM – RADIATION MONITOR
RV – RELIEF VALVE
SV – SOLENOID VALVE

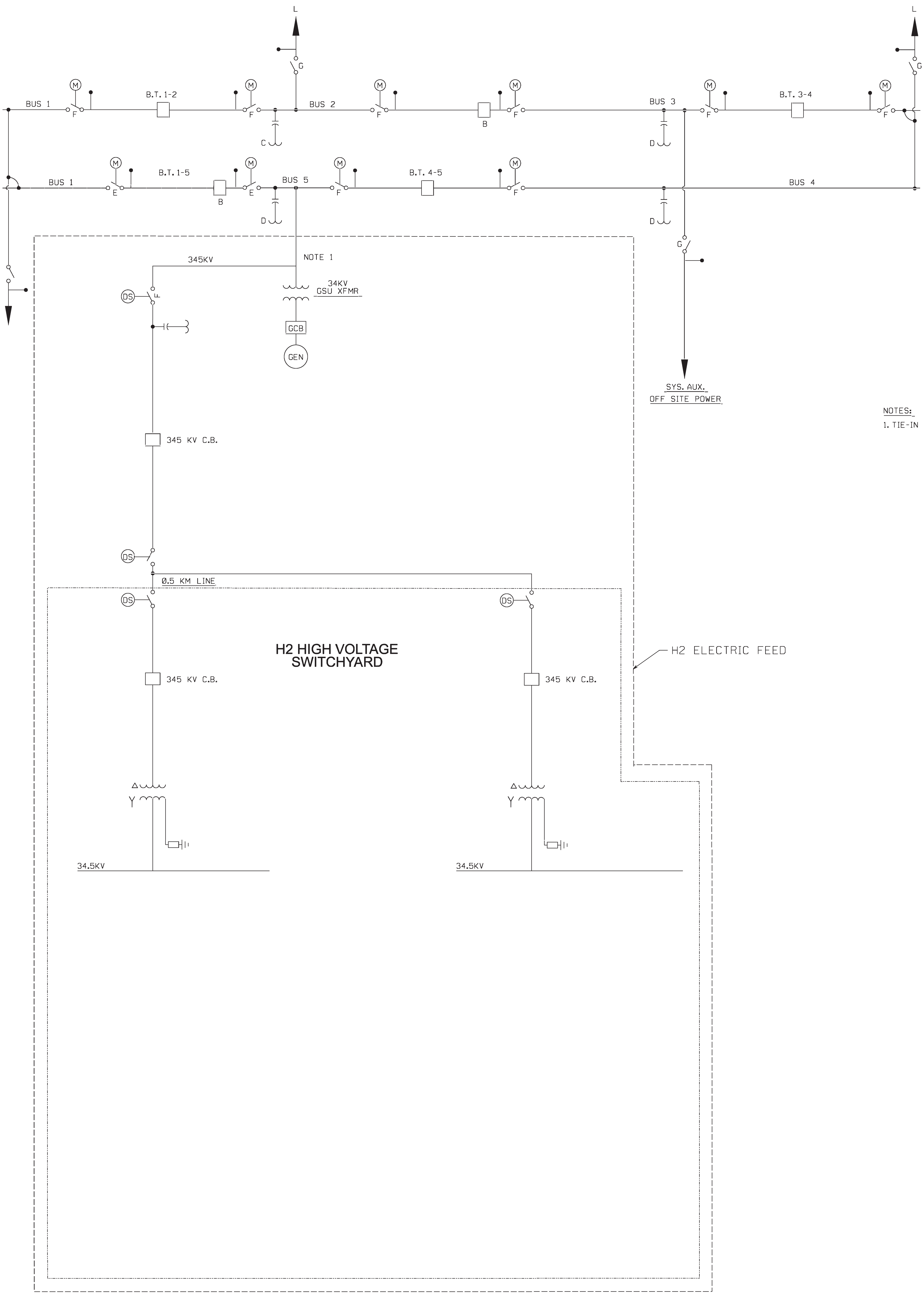
THERMAL EXTRACTION P&ID
500 MW HIGH TEMPERATURE
STEAM ELECTROLYSIS (HTSE)
HYDROGEN PRODUCTION FACILITY

DRAWING NUMBER	SHEET NUMBER	REV
INL-HTE-PID-002	N/A	0

ATTACHMENT H. H_2 FEEDER ELECTRICAL SINGLE-LINE DIAGRAM

(1 Page)

TYPICAL SWITCHYARD RING ARRANGEMENT



NOTES:

1. TIE-IN POINT IS BEHIND THE METER TAP.

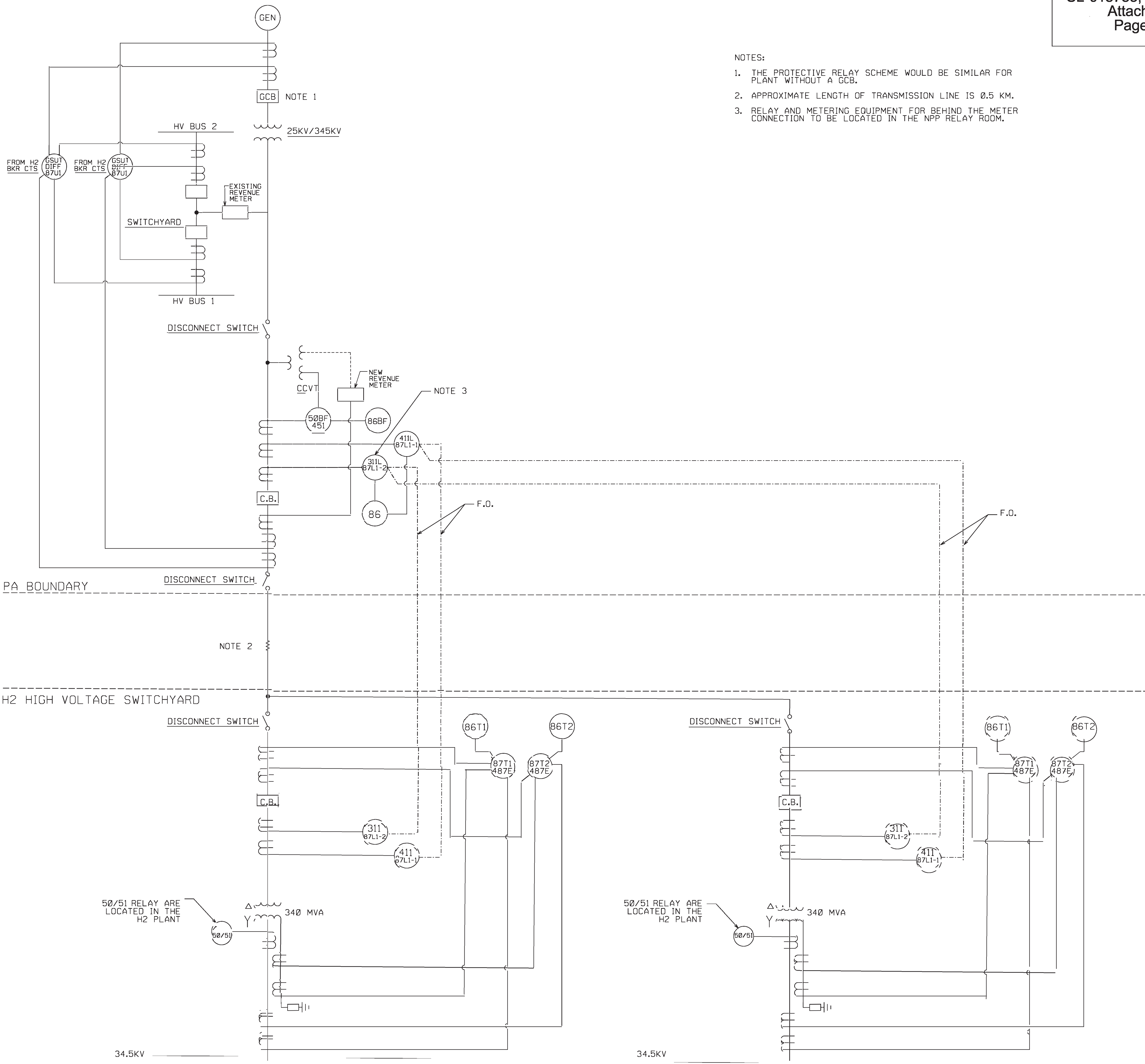
500 MW Single Line Diagram

ATTACHMENT I. RELAY PROTECTION DIAGRAM

(1 Page)

NOTES:

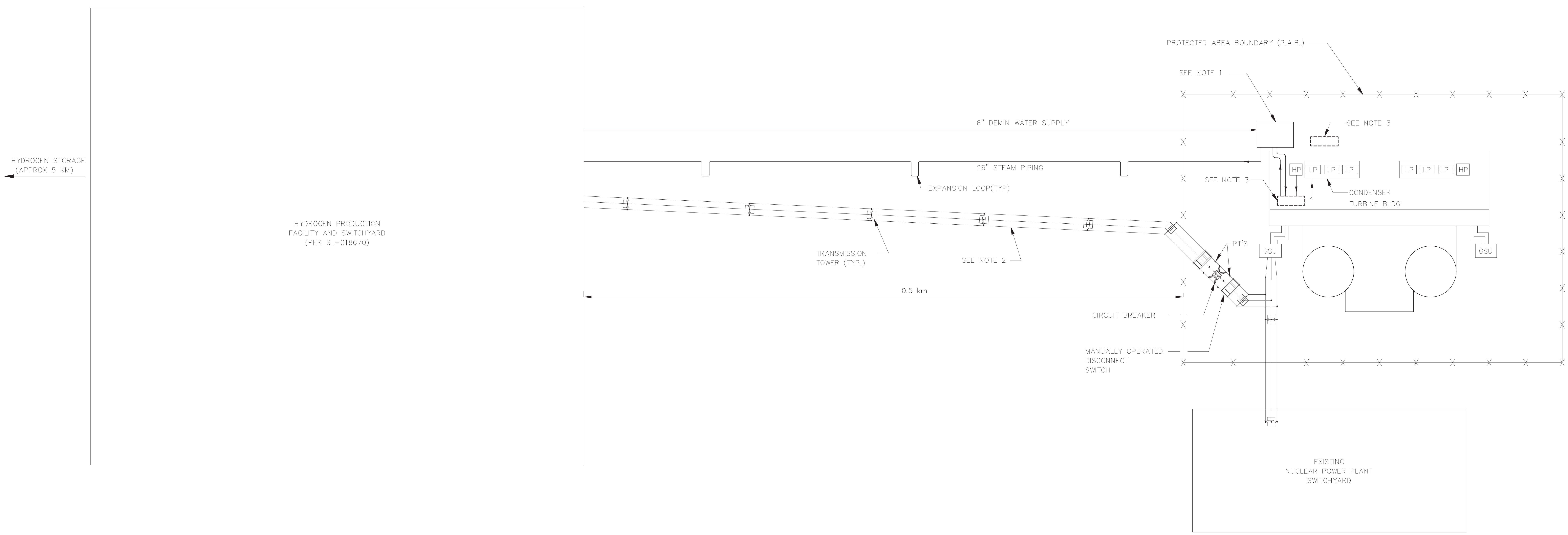
1. THE PROTECTIVE RELAY SCHEME WOULD BE SIMILAR FOR PLANT WITHOUT A GCB.
2. APPROXIMATE LENGTH OF TRANSMISSION LINE IS 0.5 KM.
3. RELAY AND METERING EQUIPMENT FOR BEHIND THE METER CONNECTION TO BE LOCATED IN THE NPP RELAY ROOM.



500 MW Relay Protection Diagram

ATTACHMENT J. H_2 SITE GENERAL ARRANGEMENT DRAWING

(1 Page)



NOTES:
1. SEE "HYDROGEN STEAM SUPPLY EQUIPMENT GENERAL ARRANGEMENT" (ATTACHMENT L)
2. SEE "H2 FEEDER ELECTRICAL PHYSICAL LAYOUT" (ATTACHMENT K)
3. SEE "INTERMEDIATE LOOP HEAT EXCHANGER SET ARRANGEMENT DRAWINGS" (ATTACHMENT M). FOOTPRINTS SHOWN ASSUMES HORIZONTAL HEAT EXCHANGER LAYOUT. THE PREFERRED LOCATION IS INSIDE THE TURBINE BUILDING (OPTION 1). AN ALTERNATE LOCATION OUTSIDE, ADJACENT TO THE TURBINE BUILDING (OPTION 2), IS ALSO PROVIDED.

500 MW
H2 SITE PLAN

DRAWING NUMBER	SHEET NUMBER	REV
INL-GEN-GA-002	N/A	0

06-18-24

ATTACHMENT K. H_2 FEEDER ELECTRICAL PHYSICAL LAYOUT

(1 Page)

SL-018783, REV. 0
ATTACHMENT K
PAGE 1 OF 1

NOTE:

1. CONNECTION LOCATED BEHIND THE METER.

500 MW H2 Feeder Electrical Physical Layout

ATTACHMENT L. HYDROGEN STEAM SUPPLY (HSS) EQUIPMENT ARRANGEMENT DRAWING

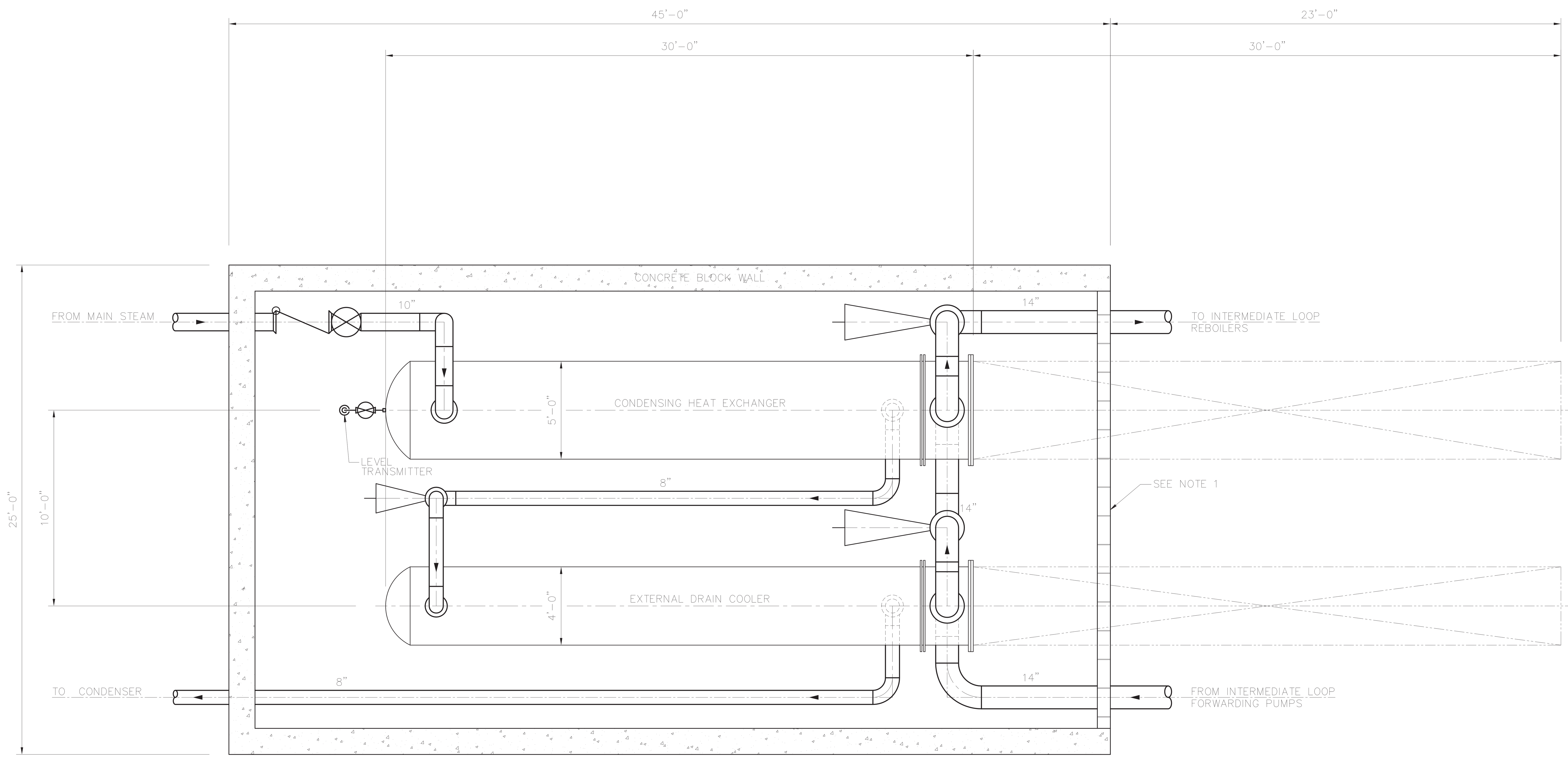
(1 Page)


100'
70'
FROM H2 FACILITY (H2O TREATMENT SYSTEM)
TO H2 FACILITY (ELECTROLYZERS)
26"
6"
18"
3"
PCV
DEMINERALIZED WATER STORAGE TANK
REBOILER FEED PUMP
NRV
LCV
LEVEL TRANSMITTER
KETTLE REBOILER
RELIEF VALVE
RV
4"
10"
14"
PRE-HEATERS
STANDBY PUMP
FORWARDING PUMP
TO EXTERNAL DRAIN COOLER
PRESSURIZED WATER TANK (~1000 PSIG)
14"x10" REDUCER
FROM CONDENSING HEAT EXCHANGER
HYDROGEN STEAM SUPPLY EQUIPMENT GENERAL ARRANGEMENT
DRAWING NUMBER
INL-HX-GA-001
SHEET NUMBER
N/A
REV
0

06-18-24

ATTACHMENT M. INTERMEDIATE LOOP HEAT EXCHANGER SET ARRANGEMENT DRAWINGS

(2 Pages)



PLAN VIEW

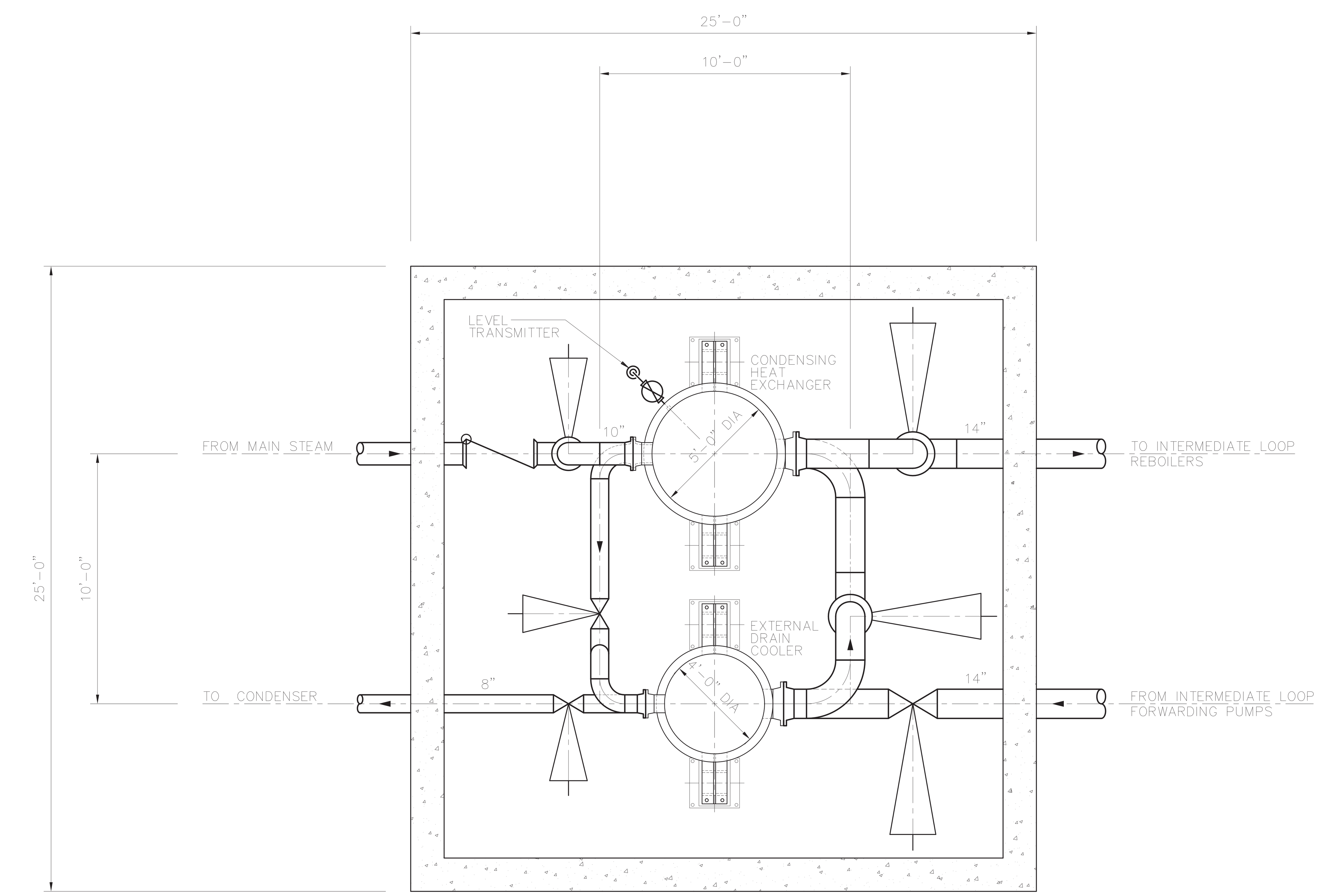
NOTES:

1) REMOVABLE BLOCK WALL PROVIDED TO SUPPORT MAINTENANCE ACTIVITIES (HEAT EXCHANGER REMOVAL/REPLACEMENT).
2) HEAT EXCHANGERS TO BE LOCATED IN TURBINE BUILDING (OPTION 1). AN ALTERNATIVE LOCATION OUTSIDE THE TURBINE BUILDING (OPTION 2) MAY BE PURSUED WITH ADDITIONAL MODIFICATION SCOPE IF LIMITED BY SPATIAL AVAILABILITY INSIDE THE TURBINE BUILDING.

INTERMEDIATE LOOP
HEAT EXCHANGER SET
GENERAL ARRANGEMENT
(HORIZONTAL ORIENTATION)

DRAWING NUMBER	SHEET NUMBER	REV
INL-HX-GA-002	1 OF 2	0

06-18-24



PLAN VIEW

NOTES:

1) HEAT EXCHANGER ORIENTATION TO REQUIRE MORE THAN 30 FEET VERTICALLY.
2) HEAT EXCHANGER ORIENTATION TO REQUIRE ADDITIONAL SUPPORT STRUCTURES (NOT SHOWN).
3) VERTICAL HEAT EXCHANGER ORIENTATION IS PROVIDED AS AN ALTERNATIVE TO THE HORIZONTAL ORIENTATION, WHICH IS PREFERRED.
4) ARRANGEMENT SHOWN DOES NOT INCLUDE CLEARANCES FOR HEAT EXCHANGER REMOVAL AND REPLACEMENT.

INTERMEDIATE LOOP
HEAT EXCHANGER SET
GENERAL ARRANGEMENT
(VERTICAL ORIENTATION)

DRAWING NUMBER	SHEET NUMBER	REV
INL-HX-GA-002	2 OF 2	0

ATTACHMENT N. DESIGN ATTRIBUTE REVIEW

(7 Pages)

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 between the tap point and the new high-voltage breaker 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 640MVA 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.

Design Attribute Review - Engineering Disciplines			
Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	9. Affect current, voltage, or power, with consideration for component or system performance?	No	The new line to the hydrogen facility will have no adverse impact on the plant current, voltage or power.
	10. Affect elevated or degraded supply voltage, with consideration for impact on equipment and components?	No	
	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. Also, the grounding system for the hydrogen facility will be connected back with the plant grounding, since the hydrogen facility is on short distance from the plant.
	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 metallic piping will require cathodic 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?	Yes	The new 345 kV breaker for the new line will be controlled with all the mechanical pumps from HMI in the MCR. Therefore, MCR heat load calculation will be impacted.
	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	

Design Attribute Review - Engineering Disciplines			
Tier 1	Tier 2	Placekeeping	Remarks
	Does the change: (Affect is defined as add, change, or remove)		
	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*	
	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 heat exchangers, pumps, tanks, and isolation & control valves.
	2. Are there requirements for ASME, ASTM and ANSI standards applicable to the design?	*Yes*	Heat exchangers 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.	*Yes*	Evaluation of vibratory motion for piping systems will be required.
	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	*Yes*	Piping systems to be designed to withstand resonance frequencies and high cycle fatigue.
	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, and valve trim considerations may be required.
	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*	Thermal expansion, stress and hydraulic 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*	There is potential for hydraulic transients when bringing cold system into service, or upon a faulted condition.
	16. Affect any mechanical setpoints, setpoint margins, and/or setpoint calculations? (e.g. relief valve settings).	*Yes*	The intermediate loop and 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, intermediate loop, steam piping to H2 island, etc.
	18. Are there code requirements to provide overpressure protection or thermal relief?	*Yes*	The intermediate loop and 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 circulating water system. 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*	Intermediate loop and 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 intermediate heat exchanger(s) and 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 pumps for demineralized water feed to the reboilers.
	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 primary containment 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*	

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 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*	Stress 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, pumps, tanks, 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, supports, and equipment 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?	*Yes*	H2 facility equipment can present tornado missile hazards.
	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?	*Yes*	Permanent shielding will be required on new extraction steam piping to intermediate heat exchanger, and in surrounding location.
	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*	Flood analysis will need to be reviewed against the addition of new tank(s) installed during modification.
	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 piping.
Coatings		*Yes*	Carbon steel components will be coated.
Environmental Qualification (EQ)		*No*	Bounded by MS line break.
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 HSS equipment in Turbine Building and outdoors 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 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*	
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)		*Yes*	H2 facility may introduce new explosive hazards near ISFSI which would require evaluation.
Emergency Plan		*Yes*	Radioactive steam piping routed through emergency access areas in Turbine Building not previously evaluated for radiological dose can impact Emergency Plan.
Industrial Safety		*Yes*	Routing new radioactive steam piping in Turbine Building. 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		*Yes*	10 FCR 50.59 evaluation will be required to assess the need for License Amendment Request.
Maintenance		*Yes*	
Non-Destructive Examination (NDE)		*No*	
Operations		*Yes*	New equipment added to plant with interface in the MCR. The operating procedures of the following systems may be impacted: Main Steam, Radiation Monitoring, Turbine Generator, Condenser, and Condensate/Feedwater. 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. Margins on turbine bypass and steam dump valves may be impacted.
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		*Yes*	New radioactive steam line routing will affect controlled radiation areas, nearby plant equipment, and may influence personnel dose. ALARA Program will need to be evaluated for impact. New radiation shielding and monitoring will be required on new steam lines and intermediate heat exchanger(s). Alternate Source Term (AST) and 10 CFR 100 dose calculations may require reevaluation based on radiological steam pipe routing.
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*	Electrical and Main Steam 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.