INL/RPT-24-76271
Revision 1

Preliminary Process and Instrumentation Design of Advanced Reactor Integration with Refineries and Hydrogen Production Facilities

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Idaho National Laboratory
Integrated Energy Systems
Idaho Falls, Idaho 83415

http://www.ies.inl.gov

Prepared for the
U.S. Department of Energy
Office of Nuclear Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

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EXECUTIVE SUMMARY

With the ongoing push to decarbonize energy use across all energy sectors, there are incentives to investigate how nuclear reactors may be used to generate clean energy and in various energy economies beyond the electrical grid. Two initial integrations, high-temperature steam electrolysis (HTSE) and oil refineries, are investigated in this first report on DOE Integrated Energy Systems (IES) program's detailed industrial integration design. The authors intend to publish increasingly detailed reports for the industries discussed in this report and for additional industries in the future of the program. This report is a robust starting point, showing how the integration of thermodynamic analysis establishes the requirements on the reactor and methods, by which those requirements can be evaluated for specific reactor designs. Two government supported reactor designs are selected as representative designs for their respective technologies: NuScale (funded through the Carbon Free Power Project) for light water reactors (LWRs) and X-Energy (funded through Advanced Reactor Demonstration Project) for high-temperature gas reactors (HTGRs). Other reactor technologies or specific reactor configurations would require analysis similar to what is done in this report. Thus, this report can be a reference point to extend this work to other nuclear plant designs.

The first industrial technology integration studied is HTSE. The HTSE plant is sized so that the reactor is dedicated to the production of hydrogen, and the net-grid interaction should be zero at nominal conditions. All the electricity is consumed in the generation of hydrogen, thus allowing the atomic energy within the nuclear system to be converted into transportable chemical energy in the form of hydrogen. This leads to modular systems sized to enable the 250 MWth LWR to produce 0.517 kg/s of hydrogen, while the 203 MWth HTGR produces 0.566 kg/s hydrogen.

The reference oil refinery for integration is assumed to be a 100 kilobarrels-per-day (kbbl/day) refinery. Due to the brownfield nature of the integration, the thermal integration of the nuclear systems is taken to be at the steam headers within the oil refinery. Replacing the hydrogen production of the refinery (nominally done via steam methane reforming) with nuclear power HTSE systems provides a significant opportunity to introduce nuclear energy into the refinery system. Three to four small modular reactors would be needed to supply the reference refinery.

The heat and electricity balances are reported to describe the demands that the outside industries will place on the nuclear systems. The report also describes how the systems will meet those balances of heat and electricity and describes the four preliminary processes and instrumentation diagrams (P&ID), showing each of HTGR and LWR integrated with an HTSE plant and an oil refinery. One example is shown in Figure ES 1. This report leverages work executed across the DOE IES program and will be the basis for additional cross-program efforts.

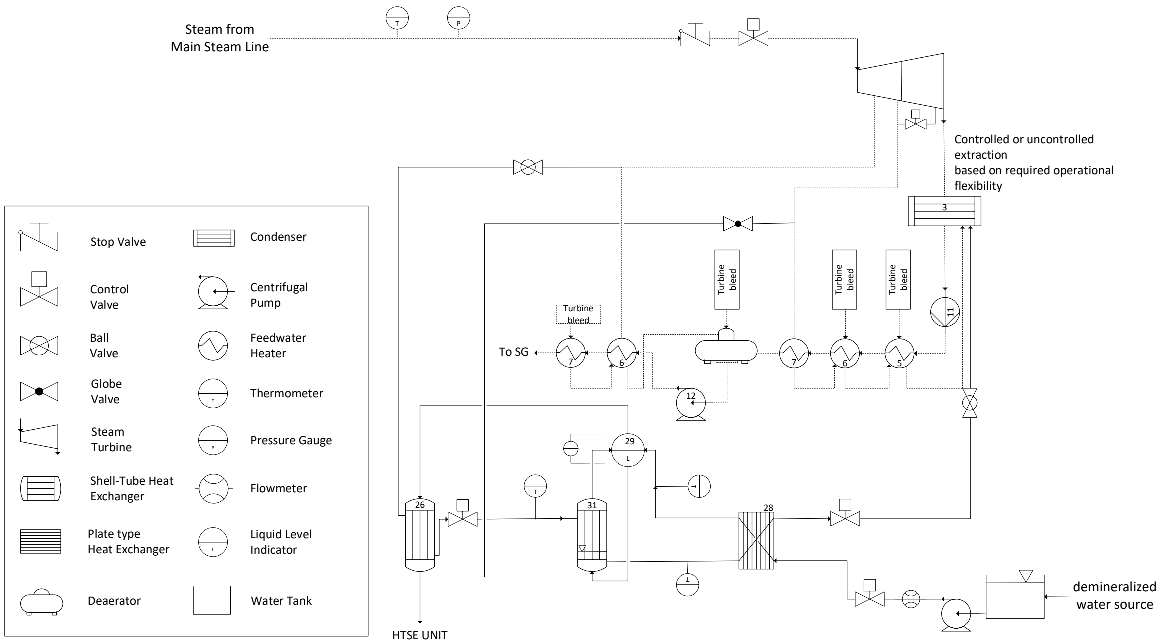

Figure ES 1. P&ID integrating HTSE and HTGR.

This research provides reactor designers and potential energy consumers with preliminary designs and thermodynamic data for deploying advanced reactors in IES configurations.

- System-wide thermodynamic and electrical balances are demonstrated for HTSE and refineries and have a reference HTGR and LWR configuration.
- These balances are leveraged to demonstrate P&ID and the initial proposed control schemes detailing the changes, especially on the nuclear side, that may be anticipated to nominal operation.
- The system flows and diagrams establish component requirements that must be used to generate detailed engineering diagrams that include information such as valve types, heat exchanger sizes and types, and pumps. This information can be cataloged and leveraged for the applications within this report and extended to additional applications.

The designs detailed within this report will be used across projects within the IES program to identify research gaps, propose potential integrated systems, and be a basis for continued IES designs for additional energy consumers and reactor types.

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FIGURES

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LIST OF ACRONYMS

BOP	balance of plant
BP	British Petroleum
BST	Baker-Strehlow-Tang
CHP	combined heat and power
DCA	drain cooler approach temperature difference
DI	deionized
FWH	feedwater heater
HP	high-pressure [steam]
HPT	high-pressure turbine
HTGR	high-temperature gas-cooled reactor
HTSE	high-temperature steam electrolysis
IES	integrated energy system
INL	Idaho National Laboratory
LP	low-pressure [steam]
LPT	low-pressure turbine
LOOP	loss of offsite power
LWR	light-water reactor
NPM	NuScale power module
NPP	nuclear power plant
P&ID	process and instrumentation diagram
PRA	probabilistic risk assessment
RFG	refinery fuel gas
SDA	standard design approval
SG	steam generator
SSC	systems, structures, and components
TTD	heater terminal temperature difference
VCE	vapor cloud explosion
VWO	valve wide open

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1. INTRODUCTION

The Department of Energy's Integrated Energy Systems (IES) program at Idaho National Laboratory (INL) is researching methods to expand the use of nuclear energy beyond traditional grid electricity generation strategies by introducing dedicated nuclear energy into industrial processes. Recent global initiatives to reduce greenhouse gas emissions, most notably carbon dioxide emissions, have added an incentive to replace certain fuels and energy feedstocks with non-emitting sources, including nuclear energy. For nuclear energy to be integrated in new ways, a variety of challenges must be overcome, including technological, regulatory, economic, and environmental.

This report is part of the IES program's continued focus on analyzing the technical aspects of integrating nuclear power with non-grid applications to inform the analyses of regulatory and economic issues of IES. A preliminary integration strategy is demonstrated that would allow for low-impact, relative-to-nominal electricity generation configurations, thermal integration of advanced reactor systems with industrial partners. Oil refineries and hydrogen electrolysis systems have been identified as valuable initial IES targets. Wood McKenzie's 2023 Energy Transition Outlook indicates that peak will likely occur at approximately 108 million barrels of oil per day in 2032 and that oil will represent approximately half of all global energy demand through about that same time [1]. Carbon emissions from the use of oil include both refining crude oil, which requires large amounts of heat, and also subsequent use of the oil as transportation and other fuels. Typically, the heat needed to refine oil is obtained by burning a portion of the lower quality refining products to produce steam, which results in emissions of carbon dioxide. Utilizing nuclear heat in the oil refining process to produce steam can reduce emission of carbon dioxide as well as other pollutants. It is also recognized that nuclear power can reduce the dependence on fossil fuels by supporting clean hydrogen production. Approximately 10 million metric tons of hydrogen are produced annually in the United States practically all of which comes from natural gas via steam methane reforming [2]. For every ton of hydrogen that is produced, more than 5 tons of carbon dioxide are generated [3]. Generating clean hydrogen from water using carbon-free nuclear power offers an attractive and cost-effective way to reduce the negative impacts of generating hydrogen from fossil fuels. These benefits are especially important because the demand for hydrogen is expected to increase to between 20 and 50 million tons of hydrogen by 2050 [2].

Nuclear energy can be an abundant and dispatchable source of energy for these processes. As large heat generators, nuclear reactors have some logical applications within energy consuming industries. There are multiple avenues by which nuclear-generated heat is most likely to be introduced in the near and medium terms. The first avenue replaces boiler-produced steam within large industrial system steam headers and distribution networks. This should be a straightforward and effective manner of reducing emissions within industrial systems as these predominately natural gas-fired boilers would be replaced with a non-emitting source. The second avenue investigates heating within subprocesses that use local firing to provide heat. Understanding the processes and the specifics of reaction residence time, heat application methods (radiation vs. convection vs. conduction), reactant sourcing, and product use must be combined to identify specifically if and how nuclear heat generation could be used. The third avenue is electrification of an industrial process and powering the electrified process using dedicated nuclear electricity generation via behind-the-grid coupling.

This report investigates a layout for the first avenue of using nuclear heat: replacing the energy source of the system's steam network with nuclear-generated steam. Nominal nuclear conditions are based on openly available information of DOE-supported reactor concepts from X-Energy (Xe-100) and NuScale (VOYGR). The nominal refinery and electrolysis conditions are based on work conducted within the IES program, much of which has been reported in more detail in focused reports [4] [5].

This report focuses on the technological challenge of using nuclear heat within industrial processes. Regulatory, economic, and environmental questions are mostly used to calculate the bounding conditions of the designs and layouts within this report.

2. PROCESS INTEGRATION REQUIREMENTS

In this section, the thermal and electrical requirements for reference high temperature steam electrolysis (HTSE) and refineries are presented. Small modular reactors (SMRs) are typically installed in batches of multiple units to reduce power production costs. For the following HTSE analysis, the total H_2 production from a single SMR is calculated. For oil refinery integration, multiple SMR units at a single facility would supply sufficient thermal and electric power to meet the needs of the plant including clean hydrogen production.

Figure 1 shows a generic heat exchanger configuration used throughout the analyses of this report. Tracking the process steam entering from the right-hand side of Figure 1, a feed stream of deionized (DI) water enters the preheater to increase the temperature to near, but still under, the saturation temperature (also acting as a subcooler of the main steam). After the preheater, the condensate enters a drum boiler, which can have forced or natural circulation. Saturated liquid enters the heat exchanger via downcomer and returns to a drum with 20-40% vapor fraction in the riser. Saturated steam is separated from the liquid in the drum and exits through the top of the drum. Regarding the boiling side, this approach allows for relatively simple flowrate control maintaining the drum level. The condensing steam is placed in a shell of the exchanger and the heat transfer rate can be controlled by flooding. Finally, the superheater is a simple counter-flow heat exchanger, leveraging sufficient temperature differences. This configuration allows for superheated fluid from the nuclear plant to produce a secondary superheated fluid within the heat application plant. Specific pressures, sizes, and temperatures depend on the exchange application.

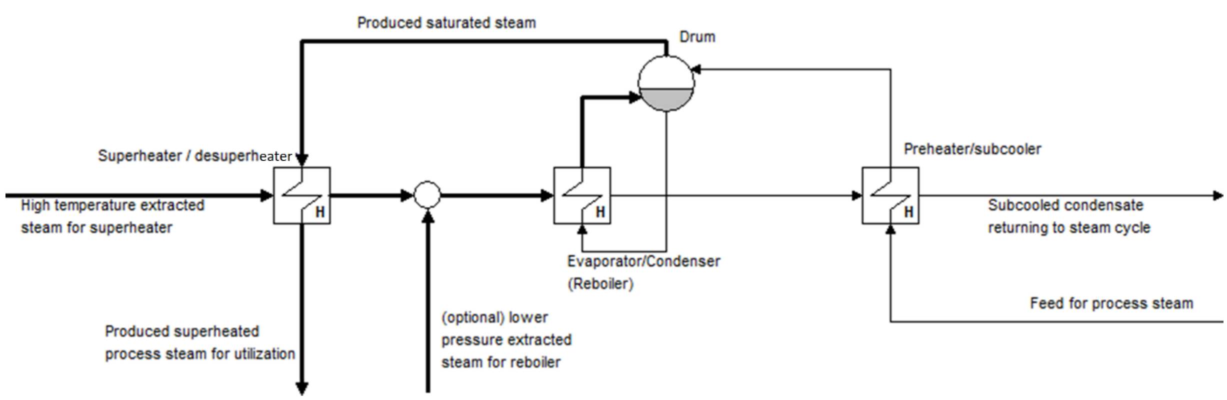


Figure 1. A generic schematic representation of a heat exchanger configuration for production of a superheated process steam from the steam cycle extracted steam.

2.1 High Temperature Steam Electrolysis

HTSE is selected as hydrogen production technology to pair with nuclear generators because it has higher efficiency and potentially lower hydrogen production costs compared to other technologies, such as proton exchange membrane. A variety of heat sources can provide moderate-temperature heat that can increase the efficiency of HTSE. Those sources include low temperature solar, heat pump, geothermal and nuclear systems. Even though the reaction takes place near 750°C, most of the heat gets recuperated; small electric trim heaters provide the remaining needed heat. Required steam inlet parameters are usually considered around 120-200°C [4]. In this study, we use 155°C.

One disadvantage of HTSE relative to other hydrogen production systems is atmospheric operation. This means that HTSE systems must use more compression power than other systems including the nominal steam methane reforming system currently deployed in refineries. The power of compression must be accounted for in any hydrogen substitution schemes in which pressurized hydrogen is required.

Various values of electrical efficiency are reported for current and future target systems, ranging from 35–40 kWhe/kg-H_2 [5] [6] [7]. We use a value of 36.8 kWhe/kg-H_2, which includes auxiliary systems such as trim heaters, drying, purification, and DC conversion but this value does not add compression [8]. This value is specific to given manufacturers and might also change during the time due to a stack degradation, the fundamentals of the technical solution presented in this work will not be broadly impacted by electrical work variances. Calculations in Cycle-Tempo show that compression to 20 bar requires around 2.2 kWhe/kg-H_2, raising total electrical input to 39.0 kWhe/kg-H_2. DI water is assumed to come at 15°C and is to be delivered at 155°C, 1.05 bar. This operating assumption equates to 6.8 kWth/kg-H_2. These values provide a preliminary view on a general HTSE system's size and layout, and subsequent studies with more detailed proprietary details can adjust these requirements as needed.

The flowrate of feedstock and product is a result of the system designs shown in Section 3 and summarized in Table 1. The term "HTSE Total Specific Neutronic Energy" is defined as the total, which includes core thermal power plus the thermal power converted to electrical, power that is consumed per unit mass of hydrogen produced.

Table 1. Summarized HTGR and LWR supply values to meet 100% of HTSE requirements using a single SMR. Calculation details shown in Section 3.1 and Section 3.2.

HTGR		**LWR**	
Rated Core Power	203 MWth	Rated Core Power	250 MWth
HTSE Electricity Demand	79.5 MW	HTSE Electricity Demand	72.63 MW
HTSE Process Steam Demand	5.45 kg/s	HTSE Process Steam Demand	7.854 kg/s
Produced H_2 Rate	0.566 kg/s	Produced H_2 Rate	0.517 kg/s
HTSE Total Specific Neutronic Energy	99.6 kWh-nuclear-thermal/kg-H_2	HTSE Total Specific Neutronic Energy	134.3 kWh-nuclear-thermal/kg-H_2

2.2 Oil Refinery

A summary of energy requirements and energy sources within a reference oil refinery has been developed previously and is summarized in Table 2 [9]. The table provides power and heating duty demands for high-pressure (HP) and low-pressure (LP) steam, heating duty from fuel combustion, hydrogen demand, and refinery fuel gas (RFG) production. The power and heating duty demands of steam are divided into high and low pressure (HP, LP). The high-pressure system operates around 42 bar (600 psig) and the low-pressure system operates as 5 bar (55 psig) or less. Note that a negative number for steam consumption indicates steam production in specific unit operation. The reference refinery has a capacity of approximately 100 kbbl/day and operates on Arab Medium Stratiev crude oil [10]. The Petroleum Refinery Life Cycle Inventory Model (PRELIM) on which our analysis is based shows a 28 MWe demand for a refinery of this size. While other information sources may report demand values up to 100MWe, a lower electricity demand value is justified given the anticipated energy efficiency measures that will precede nuclear integration.

Table 2. Overall energy requirements for the reference refinery.

Refinery Overall Energy Requirement							
PO #	Process Unit	Power Consumption	Heat from Fuel Combustion	Steam Consumption	Steam Quality	Total Hydrogen Requirement	Total RFG for Onsite Use
		Mwe	MWt	MWt		Kg/d	MW
A	Desalter	0.1					
B	Atmospheric Tower Furnace		70.1				
C	Atmospheric Tower	3.8		11.3	LP		
D	Vacuum Tower Furnace		19.8				
E	Vacuum Tower	0.6		7.4	LP		
F	Naphtha Hydrotreater	1.9	27.1	2.0	HP	8,396	2
G	Kerosene Hydrotreater	2.5	36.6	2.7	HP	9,647	3
H	Kerosene Merox Unit	0.1					
I	Gas Oil Hydrocracker	5.0	22.9			83,799	30
J	Gas Oil Hydrocracker Fractionator	1.4		19.4	HP		
K	Diesel Hydrotreater	3.1	29.9	2.1	HP	12,464	2
L	Coker Furnace		47.0				
M	Coker	1.7					211
N	Coker Fractionator	0.4		1.0	Superheated, LP		
O	Coker Naphtha Hydrotreater	0.8	11.4	0.8	HP	3,678	1
P	Fluid Catalytic Cracking Post Hydrotreater	1.0	14.6	1.2	HP, LP	3,789	2
Q	Fluid Catalytic Cracker	0.5	22.8				40
R	Fluid Catalytic Cracker Main Fractionator	0.4		0.4	HP, LP		
S	Alkylation Unit	0.2		3.8	LP		
T	Catalytic Naphtha Reformer	1.9	53.8	7.7	HP, LP		95
U	Isomerization Unit	0.2	12.6			7,496	3
V	Fuel Gas Treatment and Sulphur Recovery	1.6	22.2	-20.2	HP		
W	Gasoline Blending						
X	Steam Methane Reformer	1.3	16.1	-0.9	HP		
	Total	28	407	39		129,268	388

Beyond steam usage, the reference refinery requires high-temperature heating for a variety of processes and high hydrogen demand. The high-temperature heating is supplied by combusting primarily RFG and imported natural gas. Conceptually, it may be possible for an HTGR to supply some of this high-temperature duty; however, there are several challenges that would make the implementation of this idea possible, presented by both the nuclear plant and refinery, including the need for a very high temperature delivery system, major equipment refurbishment, new process controls etc. [9]. Additionally, the refinery heating demand and heating potential from RFG produced are well balanced, especially when substitute hydrogen production is introduced. The difference between the heating demand and RFG production is only 3 MWth. Without hydrogen production substitution, the imported fuel demand is 19

MWt, which likely precludes the economic effort required to introduce a novel high-temperature delivery system.

Refineries consume large amounts of hydrogen for a variety of operations, so it is logical to closely couple hydrogen production to oil refining. Sharing condensed water sources and storage, steam, heat and cooling loads between refineries and hydrogen plants potentially provides additional motivation to couple hydrogen production with oil refining. The water/steam connections between the refinery and the nuclear and hydrogen plants include (1) receiving steam from the nuclear power plant, (2) returning condensate to the nuclear plant, (3) providing steam to the hydrogen plant, and (4) accepting condensate from the hydrogen plant. Those connections represent the boundary limits for the refinery. A simplified process steam model reflecting the refinery steam demand and additional HTSE steam demand is shown in Figure 2. It consists of existing refinery steam system and steam-using equipment, enclosed in the orange section, including steam reboilers, turbines with dedicated condensers for direct drives of selected compressors and pumps, steam injected into the chemical processes in distillations columns, and existing letdown turbine(s) and reduction valve(s) between HP and LP steam headers. New auxiliary equipment, enclosed in the blue section, for HTSE is included in the right side of the figure consisting of an additional letdown turbine, heat exchanger system for HTSE feedstock steam and compression of produced hydrogen. Lastly, the condensate pump integrating the refinery DI water into the process steam generation system is shown. This system is heated using extracted steam from the nuclear secondary circuit.

Included in Figure 2 are preliminary pressure drops for the steam and condensate transport between the nuclear and refinery plants. The steam used for HTSE feedstock comes from a dedicated deionized water stream that needs to be vaporized. The steam to that provides this heating demand is drawn from an LP header, with a small letdown turbine to 1.4 bar, providing additional power. A small superheat is then provided by HP steam. Refineries have current H_2 distribution system around 2 MPa. HTSE provides H_2 near atmospheric condition, and so compressor of H_2 is also included to account for the required power. Since the HTSE replaces the steam methane reformer, the overall energy balance is slightly changed relative to the values in Table 1, with the refinery electrical demand of 27 MWe.

Regarding the heat source considerations, it was decided to move the deaerator from the refinery side towards the nuclear source. Reasons for moving the deaerator include benefits in transporting condensate below boiling point at atmospheric pressure, decreasing thermal losses, pressures, enabling the use of the deaerator as a buffer tank and limiting potential issues such as water hammer. The process steam model includes the relocated deaerator and heat exchanger configurations specific for integration with HTGR; these aspects will be discussed in their respective sections below.

The essential information for this work is the required steam flowrate (36.3 kg/s) and conditions at HP steam header (42.4 bar, 300°C), return condensate temperature (87°C), hydrogen compressor power demand (11.8 MW), and letdown turbines power production (6.3 MW).

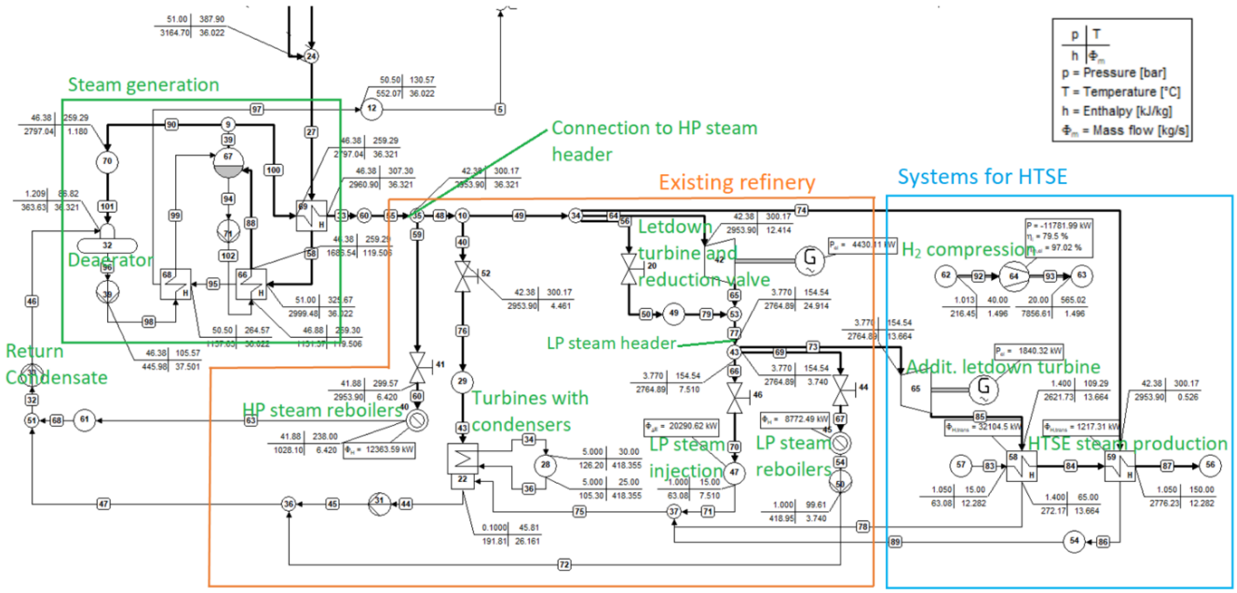


Figure 2. Simplified process steam system for refinery, including steam demand for H_2 production and H2 compression. State value tables are read in pressure (bar), temperature (°C), enthalpy (kJ/kg), and mass flow rate (kg/s). Note that the HTSE with hydrogen compression would be physically dislocated from refinery for safety reasons.

3. NUCLEAR INTEGRATION

To develop integration strategies using the requirements discussed previously and through adjusting the nominal plant configurations, constraints must be established to frame the engineering design. The first constraint imposed on the design is the restricted use of secondary nuclear steam. The steam used in the nominal balance of plant (BOP) is strictly controlled chemically and can have increased levels of some forms of radiation due to possible mixing from steam generator leaks and physical proximity to primary nuclear coolant. Tritium migration is a typical concern within nuclear systems. To reduce the possibility of tritium migration outside of the nuclear fence beyond the typical release levels, nuclear steam is restricted to the nuclear island. Thus, an intermediate heat exchanger must be introduced to move energy from the nuclear island to the industrial island. Within the nuclear island, a few different fluid conditions are assumed to have safety relevance; thus designs must accommodate them and ensure that they are unchanged. These parameters of interest are steam pressure, feedwater mass flow rate, and final feedwater temperature. By maintaining changes to these three parameters within acceptable limits, it is anticipated that the nuclear reactor could still be operated within existing or pending operating licenses to avoid potentially unsafe conditions as well as the necessity of expense license amendment requests.

3.1 HTGR Integration Strategy

The steam cycle for the HTGR has a turbine inlet pressure near 16 MPa, and steam is superheated to 565°C, which exceeds the temperature demands of refineries or HTSE. The extracted heat corresponds to only a portion of the overall steam flowrate. Therefore, a standard cogeneration approach using extraction condensing steam turbines is adopted here. In both applications, superheated steam is required and process steam evaporation takes heat from the main cycle steam condensation, putting certain requirements on heat exchanger configuration and system control as was seen in Figure 1.

Figure 3 depicts a combined heat and power (CHP) system including both the steam cycle and a simplified models of the process steam system for integration with a reference refinery. An extraction pressure of around 50 bar (accounting for pressure drop during steam distribution) for providing the refinery with a 42-bar steam, is higher than existing extractions in the reference design.

Refineries are typically considered to operate in a very steady mode. Even so, to address any fluctuations, a controlled extraction is considered to maintain the required pressure of the process steam even at varying flow. Since the refinery operation requires high reliability, a bypass from the main steam line via a reduction valve and desuperheater (process flow diagram (PFD) does not show desuperheater) helps ensure steam delivery even when the main steam cycle is not operational.

For brevity, failsafe and additional start-up or shut-down bypasses are not shown in this diagram. This is also dependent on the specific design and capabilities of the nuclear reactor to handle transient states. Such systems may include bypass from the main steam line into condenser or other emergency cooling system, connection between a heat demand extraction and condenser, and start-up bypass into the deaerator from the main steam line.

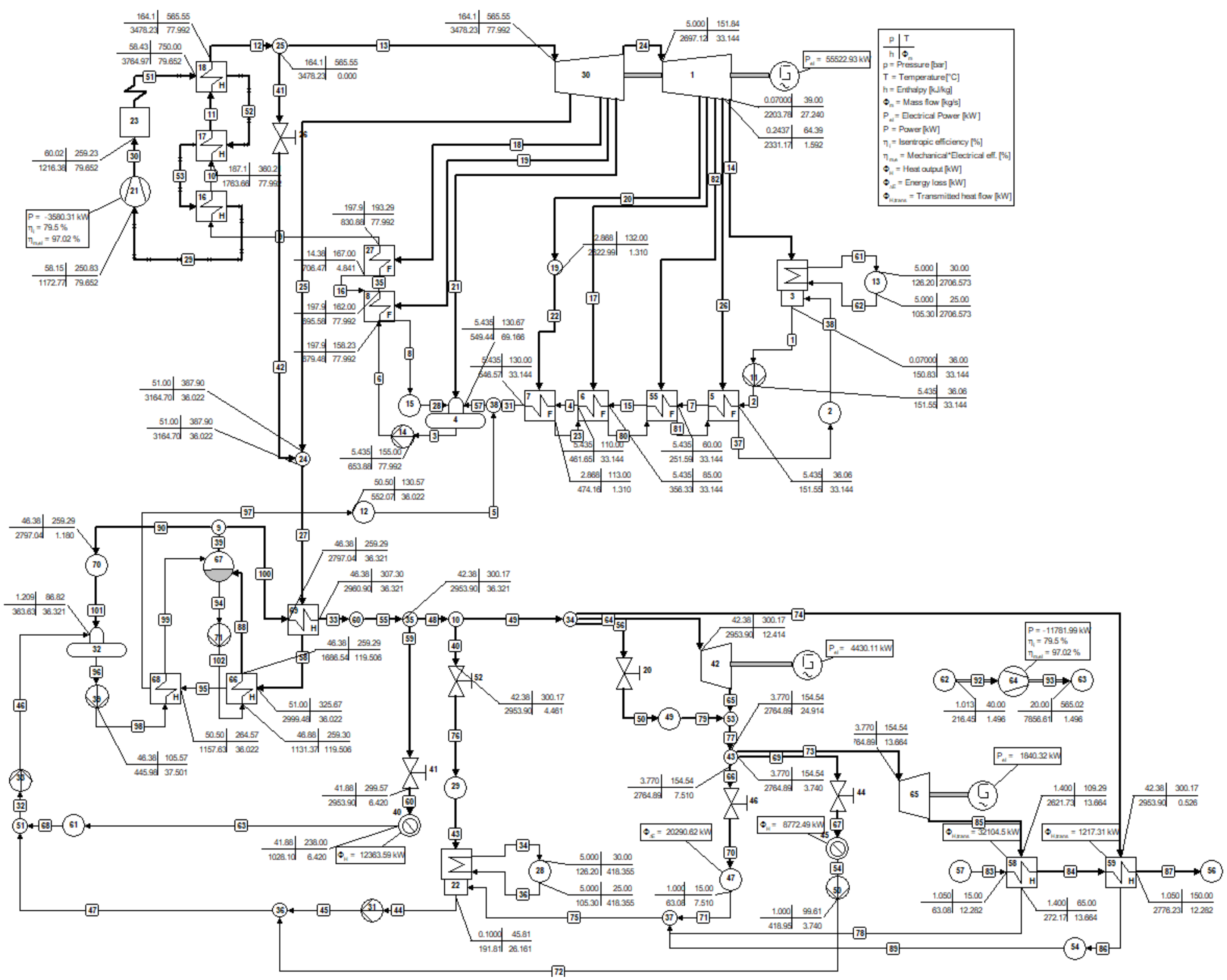


Figure 3. HTGR CHP system coupled to the refinery for providing power, process steam and steam for HTSE. System model configuration was developed using Cycle-Tempo.

Figure 4 shows a Q-T diagram of the heat transfer process. The temperature difference between the condensing primary and boiling secondary steam can be very small, typically around 3–5K, as the heat transfer is intensive on both sides. The de-superheating portion of heat transfer is practically absent in the counterflow manner as in Q-T representation as the condensation takes place in the full volume of the exchanger. Preheating the condensate cannot be performed all the way to the saturation temperature. Superheating requires a notably higher temperature difference than other heat transfer processes.

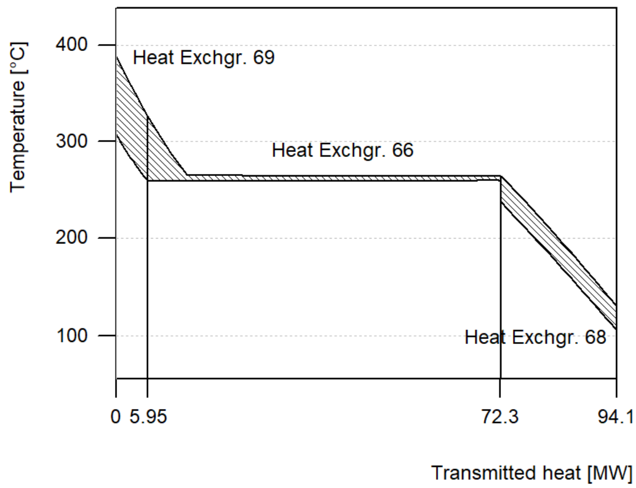


Figure 4. Q-T diagram of heat exchange for the refinery process steam.

It is obvious that a single reactor system suffices to provide all the process steam including the increased steam demand for the HTSE. A summary of the steam cycle parameters, including in circumstances when hydrogen supply would not be provided from the nuclear source, is provided in Table 3. Table 4 displays integration scenarios regarding numbers of reactor systems, steam cycles and overall electricity balance.

Table 3. Parameters of HTGR systems for refinery with different CHP configurations.

	W_{net} (MWe)	$Q_{delivered}$ (MWth)	Direct Heat Usage	CHP Efficiency
Baseline cycle	81.3	0	0	40.0%
CHP cycle, steam only	65.4	38.8	19.1%	51.3%
CHP cycle, steam plus H_2	45.3	73.0	35.9%	58.3%

Table 4. Resulting parameters of integration scenarios of HTGR with reference refinery.

Scenario	No. of Reactors with CHP Cycle	No. Reactors Supplying Only Power	Electricity Demand (MW)	CHP Syst. Power supply (MW)	Baseline Syst. Power supply (MW)	Net Electricity Balance (MW)
Steam + power only	1	0	28.3	65.4	0	37.0
Steam + power + H_2, net export	1	3	225.3	45.3	243.8	63.8
Steam + power + H_2, net import	1	2	225.3	45.3	162.5	-17.4

Note that in the overall system a net export has advantages for cases of maintenance on the nuclear system on one of the reactor systems. Additionally, it is suggested that for contingency, there would be interconnections between reactor units and steam cycles so that the CHP cycle can be operated even when its dedicated reactor is under maintenance. For similar reasons, when the CHP cycle is under maintenance, reduction and desuperheater station from the steam between the steam generator and the turbine ensure uninterrupted steam supply.

Considering the standalone HTSE system, existing extraction points of the reference steam cycle are utilized as seen in Figure 5. A question for a later design phase is whether the extraction should be controlled, which would depend on the operation regime and grid connection status. Since the design considered is a baseload hydrogen producer running constantly at (or near) nominal parameters, uncontrolled extraction is suitable at this point. (Note; uncontrolled extraction does preclude having means of control such as limiting the flow through the extraction line. Controlled extraction maintains constant extraction pressure during large heat demand fluctuations.) The high-pressure extraction for the superheater requires a very small flowrate; implementing controlled extraction would not be feasible. The overall energy balance of the HTGR-HTSE integrated system is provided in Table 5.

Table 5. Overall energy balance of the HTGR-HTSE integrated system.

	kW		kg/s
CHP cycle net power production	79 483	Main steam flowrate	77.99
HTSE unit power consumption	75 024	Total steam extracted for HTSE	5.45
Compression power consumption	4 459	HTSE feedstock steam flowrate	4.65
Net export	0	H_2 product flowrate	0.566

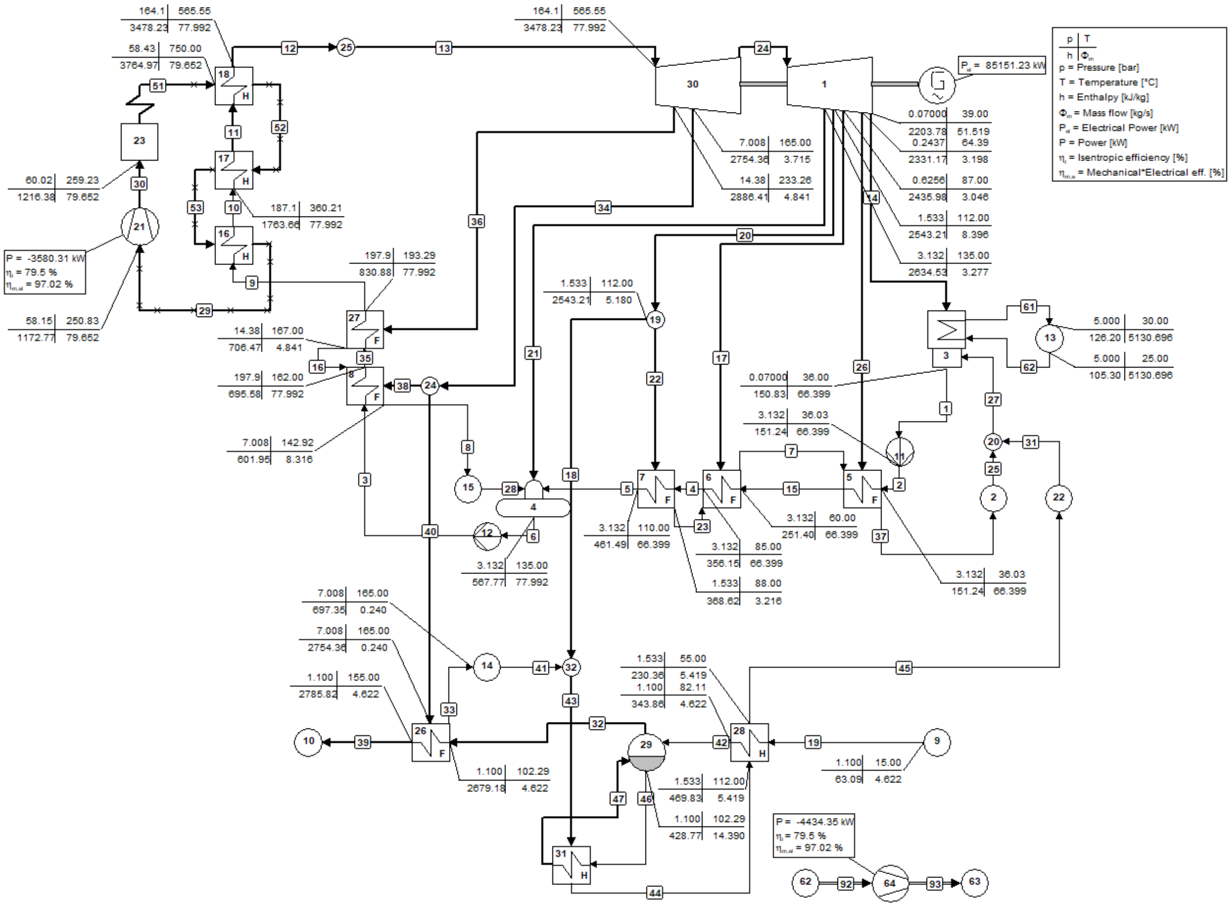


Figure 5. HTGR CHP system coupled with HTSE only.

Figure 6 shows a Q-T diagram of the heat transfer process. A difference from the previous case is that the LP extracted steam is wet, therefore the superheater heat is provided from condensation of steam extracted at higher pressure.

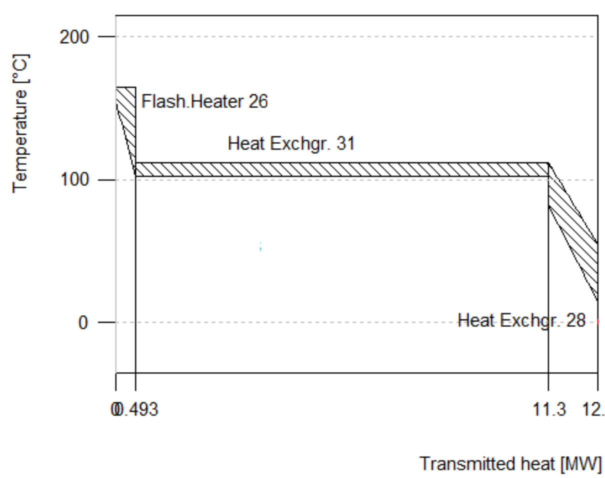


Figure 6. Q-T diagram of heat exchange for HTSE.

3.1.1 HTGR PIPING AND INSTRUMENTATION DIAGRAM – HTSE

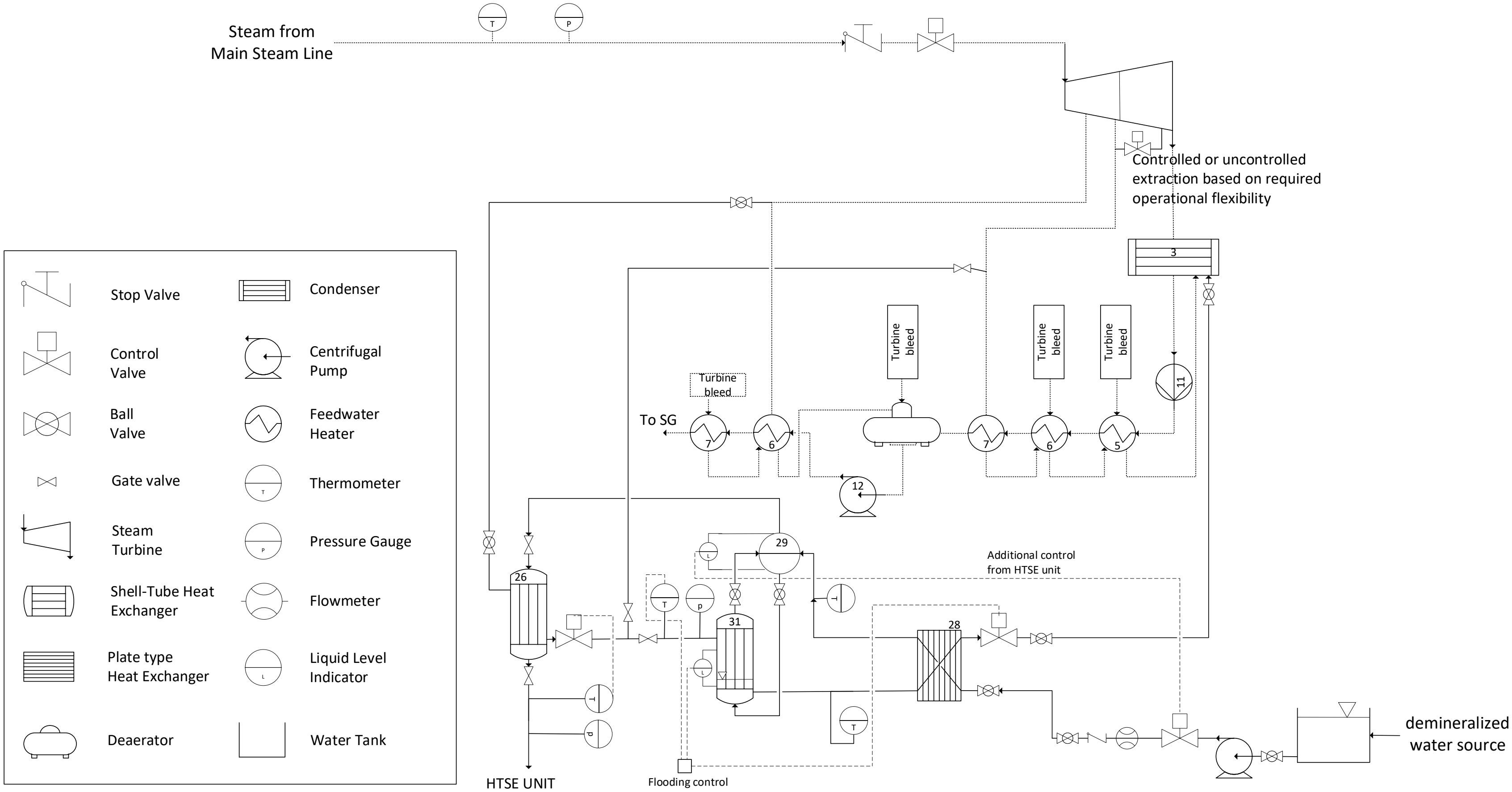
The piping and instrumentation (P&ID) diagram of the heat extraction system coupled with HTGR for providing the HTSE with required steam is shown in Figure 7. Note that the diagram excludes auxiliary and emergency bypasses, drains, sludge etc., which would be considered in a more detailed engineering design. The existing piping of the baseline steam cycle, which would not change in a system layout from the baseline plants, is shown in dotted line. The control signal is illustrated by a dashed light line.

In the HTSE system integration into a nuclear plant, most operations are conducted under near-ambient conditions with slight overpressure, making the design relatively simple. This design parameter uses a flat plate heat exchanger for preheating the DI water. Given that steam occupies a relatively large volume in other heat exchangers, a shell and tube type remain the assumed configuration for these particular components. However, it is worth noting that a more detailed design incorporating pressure drop and volume calculations might suggest alternative types of heat exchangers for optimized cost.

The DI water evaporator is vertically oriented and has a drum type. This design choice aligns with the system characteristics, as the risers leading to the drum exhibit a gradual increase in vapor fraction. In this configuration, natural circulation is currently selected, although it remains subject to potential modification for forced circulation in subsequent, detailed design phases. Additionally, heat transfer within this system is controlled through a flooding mechanism on the shell side in which the extraction steam is condensing, thus various required control strategies can be met.

Lastly, the small volumetric flowrates of the liquid streams and extraction of higher-pressure steam feeding the superheater allows ball valves for component isolation, required for maintenance. The remaining steam lines have relatively large volumetric flowrates, though at near-ambient pressure, gate valves are sufficient for component isolation.

System control comprises the above-mentioned flooding during condensation of the extracted steam, typically used in feedwater heaters (FWH) and process steam applications. On the HTSE feed side, feed flowrate is controlled for maintaining the drum level while the HTSE unit itself is assumed to maintain required backpressure.



Note: Drains and sludge not included

Figure 7. P&ID of heat extraction system coupled with HTGR and HTSE.

3.1.2 HTGR P&ID – Refinery

Figure 8 shows the P&ID diagram of heat extraction system coupled with HTGR for providing the HTSE with required steam. Note that it excludes auxiliary and emergency bypasses, drains, sludge, etc., which would be considered in more detailed engineering designs. The existing piping of the baseline steam cycle, which would not change in system layout from the baseline plants, is shown by dotted line. The control signal is illustrated by dashed light line.

The steam pressures in the refinery integration are mostly near 4–5 MPa and mass flowrates are significantly higher than for the HTSE integration. All heat exchangers are of shell and tube design, while fluid placement into shell or tube is driven by physical phenomena in the exchanger rather than pressures.

The evaporator producing the process steam is vertically oriented and has a drum type with forced circulation. This design choice aligns with the system characteristics, as the risers leading to the drum exhibit a gradual increase in vapor fraction. Additionally, heat transfer within this system is controlled through a flooding mechanism on the shell side in which the extraction steam is condensing, thus various required control strategies can be met. The process steam superheater may be horizontal or vertical based on preferred draining of the condensate for off-design operation and for shutdown.

In places of relatively higher pressures (or high-pressure differences), globe valves are used for equipment isolation to allow for maintenance. At the point of lower pressure differences during partial shutdown and maintenance, gate valves are sufficient for component isolation.

System control comprises the above-mentioned flooding during condensation of the extracted steam, typically used in FWH and process steam applications. On the process steam feed side, the flowrate is controlled for maintaining the drum level while the refinery's existing process steam system is assumed to maintain required backpressure. Since the deaerator was placed into the steam cycle site, it has also its control system.

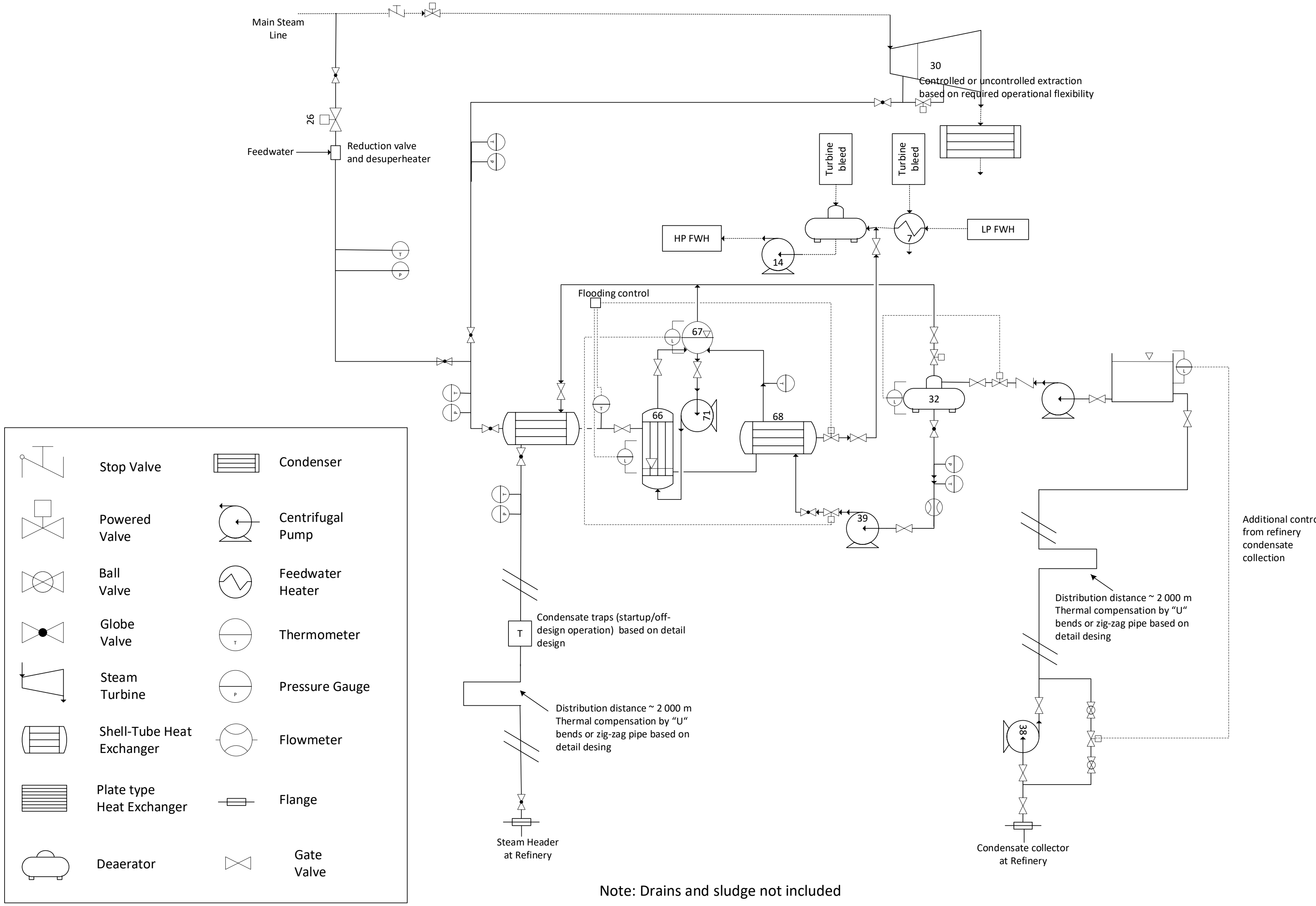


Figure 8. P&ID of heat extraction system coupled with HTGR and oil refinery.

3.2 LWR Integration Strategy

NuScale's original design, called the US600 Design, was for a 160 MWth, 50 MWe NuScale power module (NPM) [11]. The flow and heat balance diagram for US600 Design is part of its Nuclear Regulatory Commission design certification package [12]. The current design of interest is for a 250 MWth, 77 MWe NPM [13]. Six 77 MWe reactors can be bundled in a design, which is referred to as the US460. There is open-source material about the US600; however. there is no flow diagram or heat balance diagram publicly available for the US460. There are only a few values published for the US460: the main steam header parameters of mass flow rate, temperature, and pressure [14]. Table 6 shows key steam and feedwater conditions for both designs. Without a publicly available heat balance, a US460 heat balance was constructed combining known US460 data and assumptions made in the US600 Design. PEPSE [15] and Aspen HYSYS [16] were used to develop the BOP and thermal extraction models. Additional specific modeling details can be found in Appendix A-2.

Table 6. Main steam header conditions for the NuScale 50 MWe and 77 MWe design [11], [17].

Parameter	US600 (50 MWe Design)	US460 (77 MWe Design)
Mass Flow Rate (kg/s)	67.07	102.8
Steam Pressure (bar)	33.98	32.8
Steam Temperature (main steam line) (℃)	306.89	283
Feedwater Temperature (℃)	147	121
Feedwater Pressure (bar)	35.2	37.8

The LWR steam cycle has a turbine inlet pressure of 32.8 bar and an inlet temperature of 283℃. A CHP, including the steam cycle and the steam inlet to the refinery, is shown in Figure 11. The extraction pressure of the steam is 32.8 bar, whereas at least 46.4 bar delivery pressure is used for the refinery to produce steam at 42.4 bar and higher pressures. To raise the pressure to the desired amount, a compressor is added. Whether the compressor should be before or after the IHX was investigated. Using the values in Table 7, a configuration with the compressor after the IHX was chosen since there is less electricity needed for this configuration. Additionally, the steam conditions are more energetic using this configuration. This can also be seen in the Aspen models in Figure 9 and Figure 10. Aspen HYSYS was used to calculate the compression work necessary to use LWR steam to supply refinery demand. The steam flow rates and conditions were manually supplied to the PEPSE model to appropriately accommodate the bypassed flow.

Table 7. The comparison of duties needed for different compressor locations for refinery integration.

Compressor Location	Compressor Duty	IHX Duty
Before IHX	3.250 MW	53.94 MW
After IHX	2.507 MW	52.04 MW

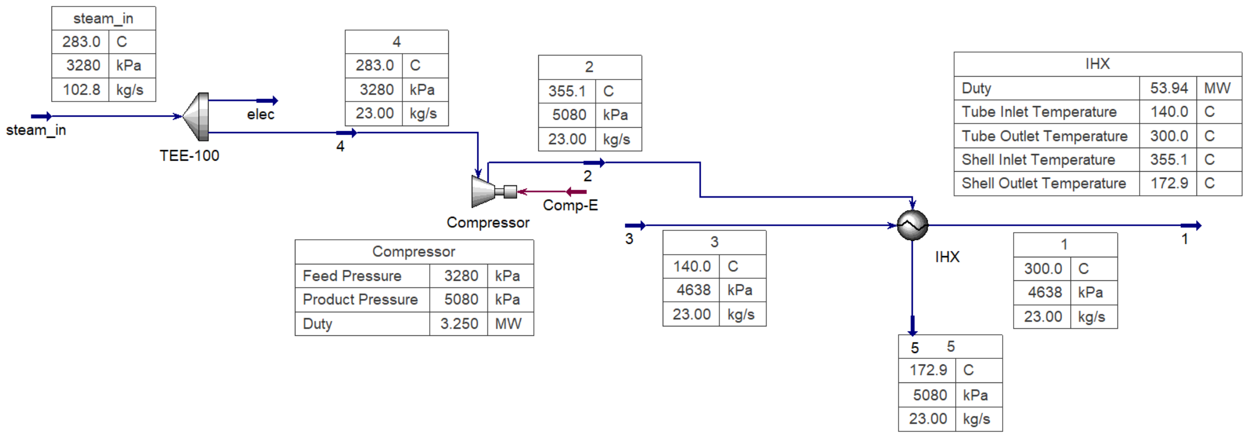


Figure 9: The refinery thermal extraction with the compressor before the IHX for a refinery.

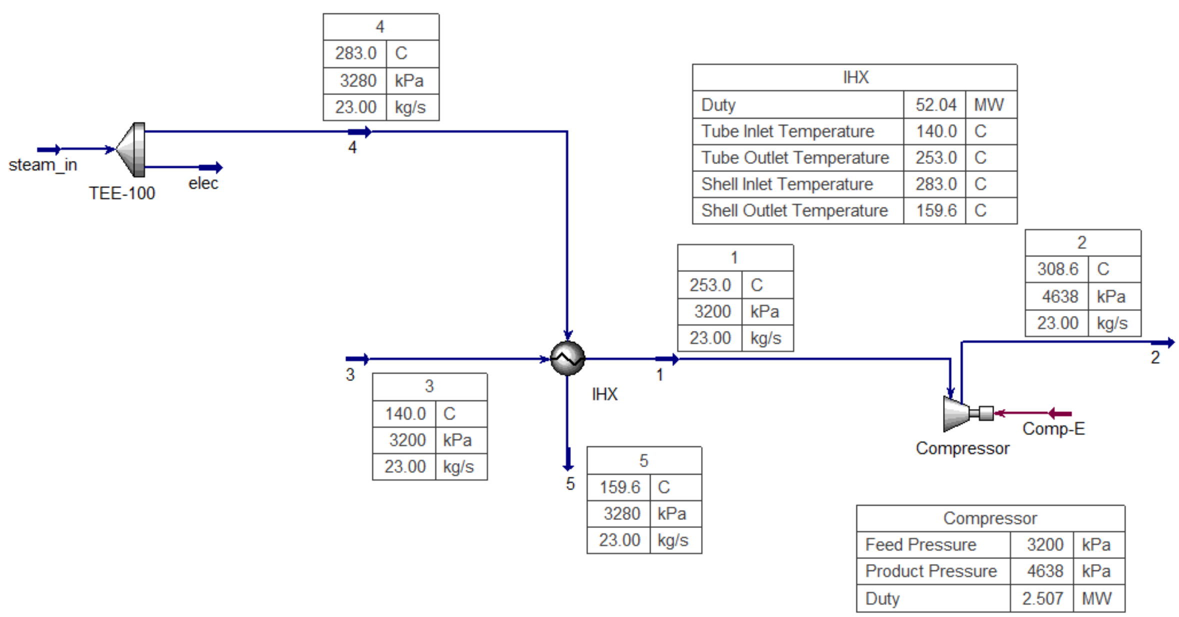


Figure 10: The refinery thermal extraction with the compressor after the IHX for a refinery, which was determined to be the better design.

For HTSE, two extraction points were utilized. The first point was at the steam header and the other point was at a pressure close to that needed for HTSE, which is 1.1 bar. The PEPSE model for refinery integration is shown in Figure 11 and the model for HTSE integration can be seen in Figure 12 using steam extraction at 1.4 bar.

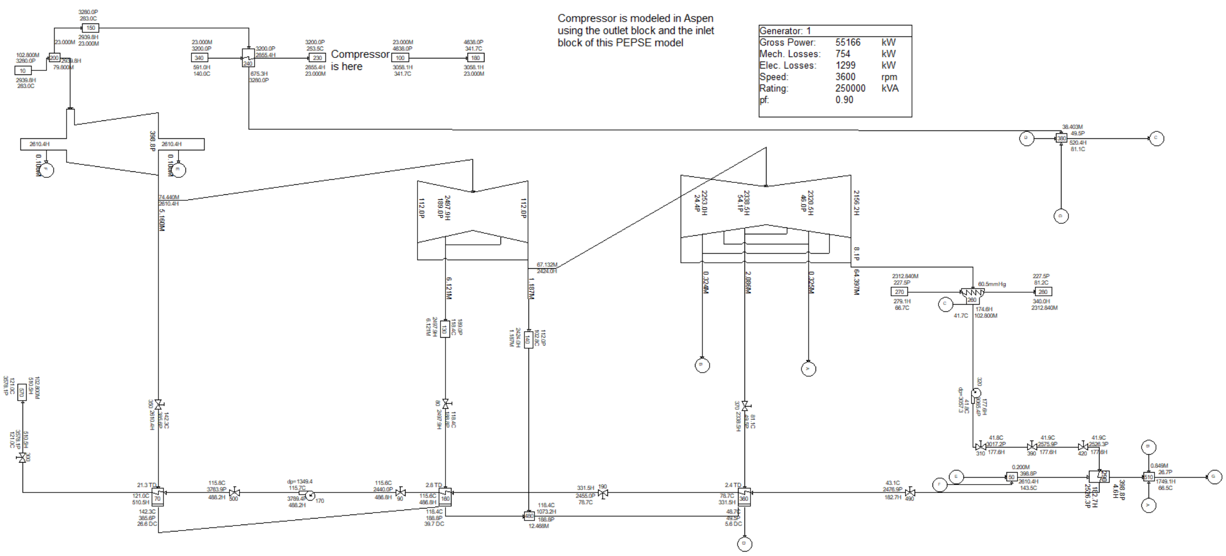


Figure 11: PEPSE model for the refinery with extraction at the steam header.

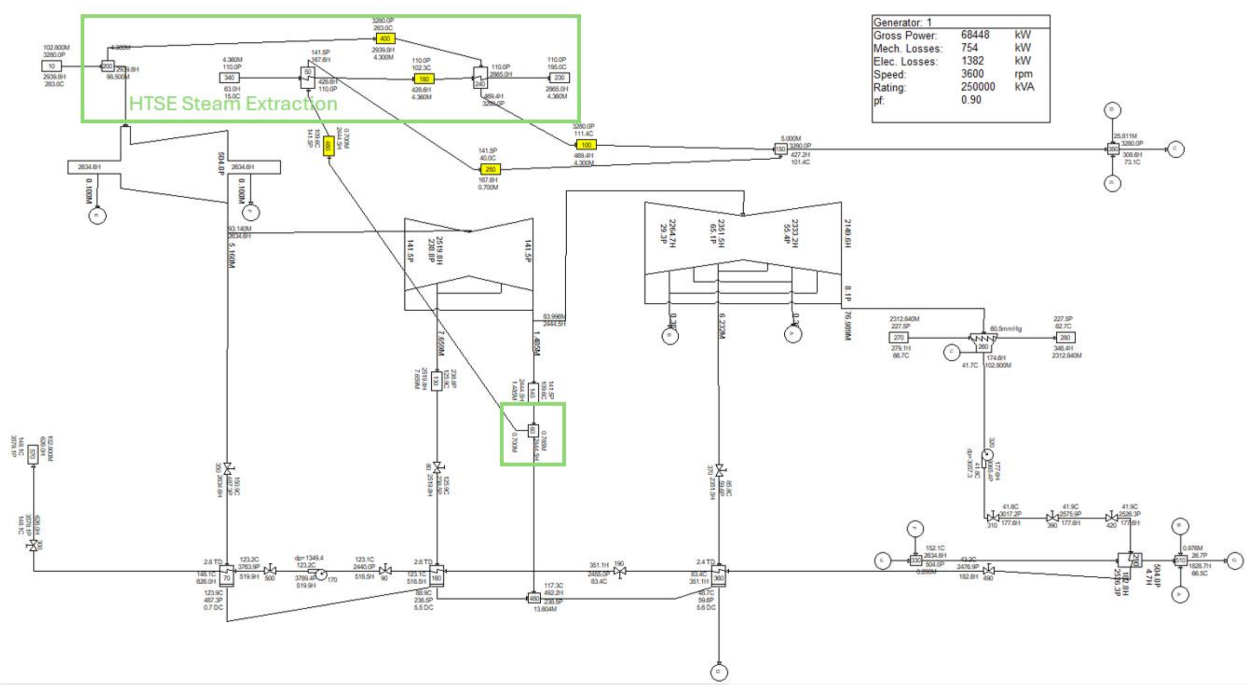


Figure 12: PEPSE model with the extraction at the steam header and 1.4 bar. The green boxes indicate the aspects added to the base US460 model that account for HTSE extraction.

3.2.1 LWR P&ID – HTSE

Figure 13 shows the P&ID of the LWR-HTSE integration. Similar to the prior HTGR integration designs, the P&ID presently excludes auxiliary and emergency bypasses (aside from the standard nuclear turbine bypass line), drains, sludge, etc., which would be considered in increasingly detailed engineering designs. The interface points for the P&ID are the feed sent to the steam generator, the main steam coming from the steam generator, the DI water source for the HTSE unit, and the steam lines returning steam to the HTSE unit.

Extraction control is anticipated to meet demand signals for the steam flow rate and temperature of the vaporized DI transported to the HTSE system. Controlled extraction flow rate out of the turbine would be used to control the mass flow rate on the HTSE side based on input demand, and the diaphragm valve on the high-pressure steam extraction line would be modulated to meet required HTSE DI steam temperature. The feed flow rate of DI into the boiler heat exchanger would be modulated to maintain the heat exchanger level.

The DI boiler heat exchanger is assumed to be of some shell and tube configuration, likely a u-tube boiler, or vertical once-through configuration with DI water within the boiler vessel. The DI superheater section also has an assumed shell and tube configuration. Optimization of heat exchanger design based on thermodynamic and economic metrics will be a part of future work.

A controllable diaphragm valve is selected to control the superheater steam flow. Control valves are placed on both lines connecting the nuclear system to the hydrogen heat exchangers to stop the flow in case of catastrophic failures.

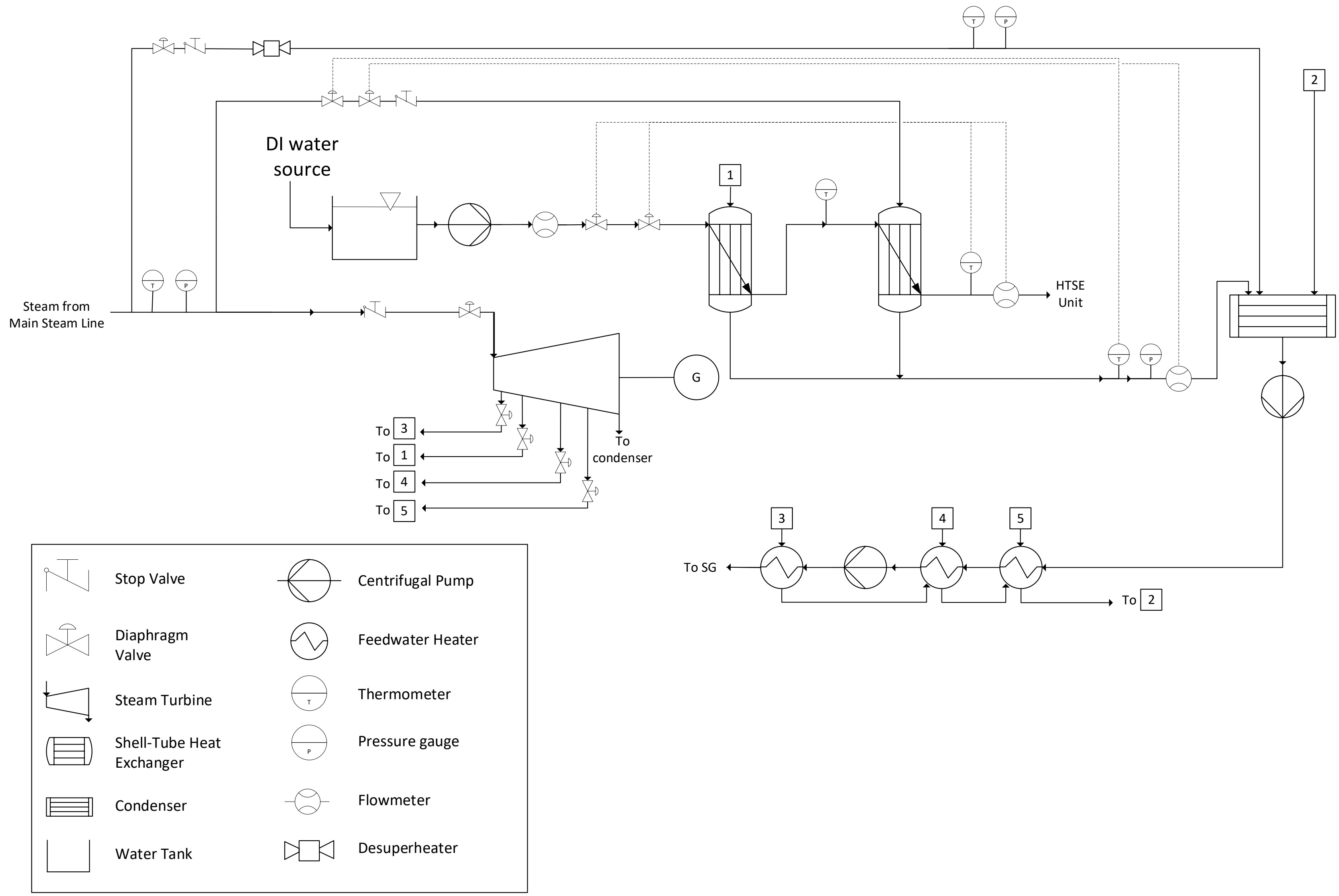


Figure 13. P&ID of heat extraction system coupled with NuScale SMR and HTSE.

3.2.2 LWR P&ID – Oil Refinery

Figure 14 shows the P&ID of the LWR-refinery integration. Similar to the prior integration designs, the P&ID presently excludes auxiliary and emergency bypasses (aside from the standard nuclear turbine bypass line), drains, sludge, etc., which would be considered in increasingly detailed engineering designs. Control signal is illustrated in dashed light line. The interface points for the P&ID are the feed sent to the steam generator, the main steam coming from the steam generator, the refinery condensate collector, and the refinery steam header.

As discussed in Section 3.2, the steam generated within the nuclear steam generator is insufficient to meet the requirements of the refinery steam header. As such, a steam compressor is placed in the nuclear secondary side steam line upstream of the intermediate heat exchanger that is producing steam for the refinery. To generate superheated steam within a single heat exchanger, this heat exchanger would likely be a vertical once-through shell and tube type heat exchanger. The mass flow rate would be controlled via valves on the nuclear steam line while the level is controlled via the pumps on the refinery steam line.

The remainder of the steam system within the LWR turbogenerator system would be largely unchanged when compared to the nominal BOP configuration. A design choice that would need to be determined later would be whether to reduce the turbine size while meeting an assumed consistent thermal demand from the refinery or whether to operate the turbine in a reduced power mode consistently. Flexibility and economic tradeoffs can be investigated in future work.

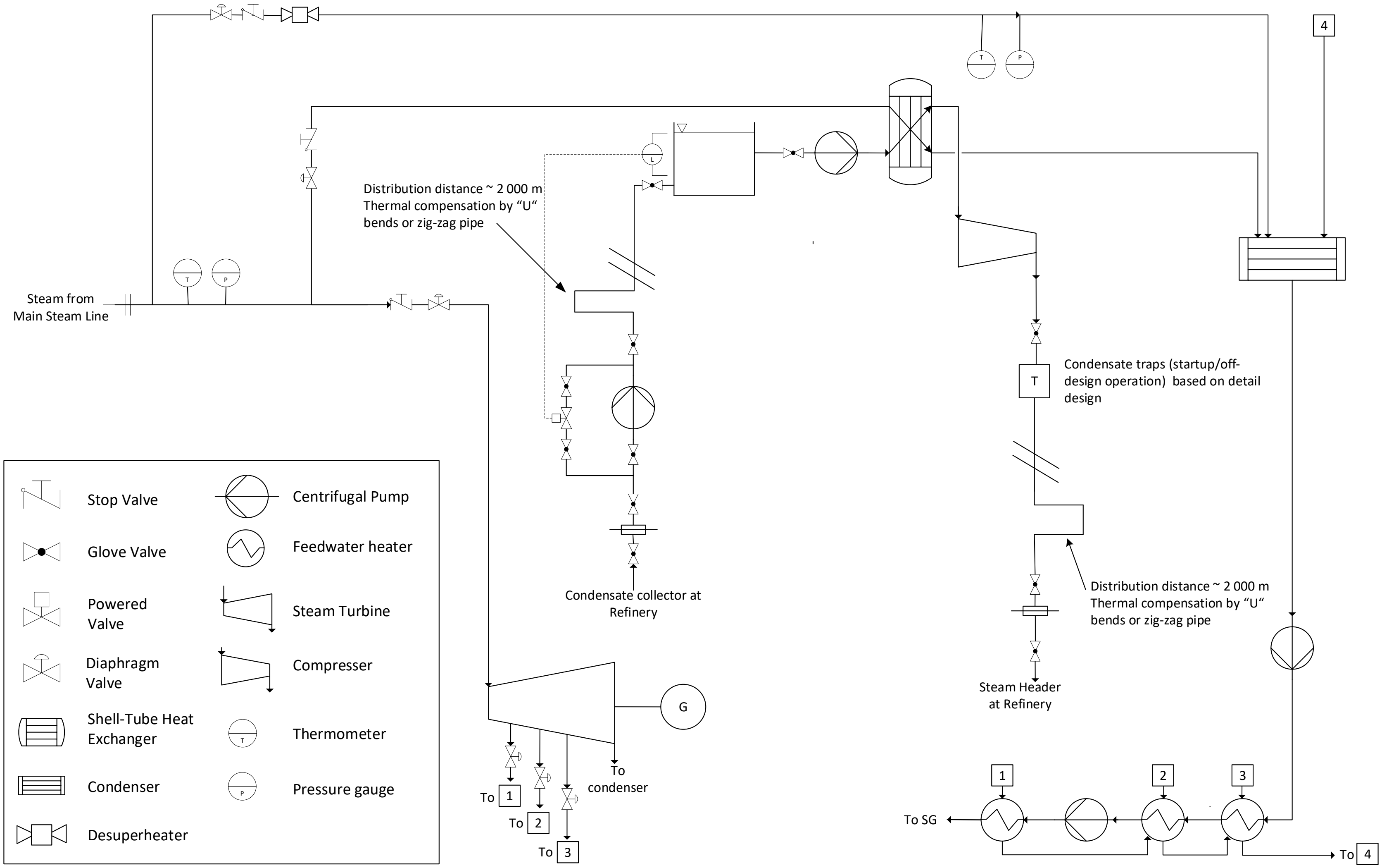


Figure 14. P&ID of heat extraction system coupled with NuScale SMR and oil refinery.

4. FUTURE WORK

This work shows preliminary process designs for the integration of HTGRs and LWRs with refineries and hydrogen production facilities. While this early design is highly regarded by the research team, additional rigor and optimization will be pursued to identify the energetically most efficient systems. Nominally, increased efficiency should reduce the levelized cost of heat within the systems. Additionally, start up and shutdown of the combined systems must be accounted for in future detailed designs.

Heat exchanger designs will be evaluated through collaboration across the IES program to identify ideal heat exchanger configurations that meet the requirements established in this work. Idealization will be based on cost minimization while meeting established conditions and duties.

Additionally, a Level-5 (+/- 50%) cost estimate is planned for the near future to obtain figures that can be used across the IES program for various economic studies and optimization strategies for future deployment studies.

This work will also be extended into dynamic modeling and evaluation in future studies to show how changing conditions due to either changes in net demands or unforeseen circumstances may impact the combined system operations.

5. CONCLUSIONS

Greenhouse gas emissions reduction is crucial to meeting global climate change mitigation goals. The introduction of reliable and clean nuclear energy may be a critical step in achieving emission reduction goals. The IES program at INL has produced a preliminary P&ID showing how early, anticipated operating advanced reactors, LWRs and HTGRs, may be able to provide the energy required to produce hydrogen from HTSE plants and provide significant amounts of energy for oil refineries. These two potential integrations can allow for the energy market to take increased advantage of nuclear energy in significant quantities in its cheapest form (i.e., thermal) by effectively converting the nuclear energy into chemical energy that can be distributed more easily and consumed later.

The designs within this report have showcased a starting point for future detailed designs. The preliminary P&ID leverages a cogeneration approach backed by rigorous energy balance and analysis. The designs are of high efficiency and should ensure operational flexibility. The proposed systems will provide reliable solutions to refineries and HTSE plants seeking to integrate clean and reliable nuclear power.

6. ACKNOWLEDGEMENTS

This work was supported by the IES program at Idaho National Laboratory under the Department of Energy Operations contract no. DE-AC07-05ID14517. This research made use of Idaho National Laboratory computing resources, which are supported by the Office of Nuclear Energy of the U.S. Department of Energy and the Nuclear Science User Facilities under contract no. DE-AC07-05ID14517.

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Appendix A

Nominal Balance of Plant Conditions

ARDP awardee X-Energy (developing the Xe-100) and Carbon Free Power Project participant NuScale (developing VOYGR) are likely to be among the first SMRs constructed and available for integration with industrial systems. The nominal system configurations for these reactors are available in publicly disseminated data from the companies, allowing for open-source models of the anticipated plant conditions the IES team will engineer. From these nominal systems, adjustments are introduced and analyzed to calculate the anticipated operational impact of shifting from electricity generation to combined heat and power operations.

A-1. High-Temperature Gas Reactor

The base case model is modeled for a 203 MWth core thermal output to represent a single Xe-100 unit from X-Energy, which provides 81.3 MWe electrical output. INL developed the reference PFD of the HTGR power conversion system, shown in Figure 15, based on information available in a simplified PFD by Mulder (Mulder 2021), which has been reproduced in Figure 16. To match the cycle efficiency and outlet steam enthalpy, the expansion curve is modified by splitting the steam expansion into two turbine sections, each with different isentropic efficiency. The feedwater configuration follows a typical configuration accounting for feedwater temperature and system size. The system also includes the pressure drop of the helium as a heat transfer fluid and power required for the blower.

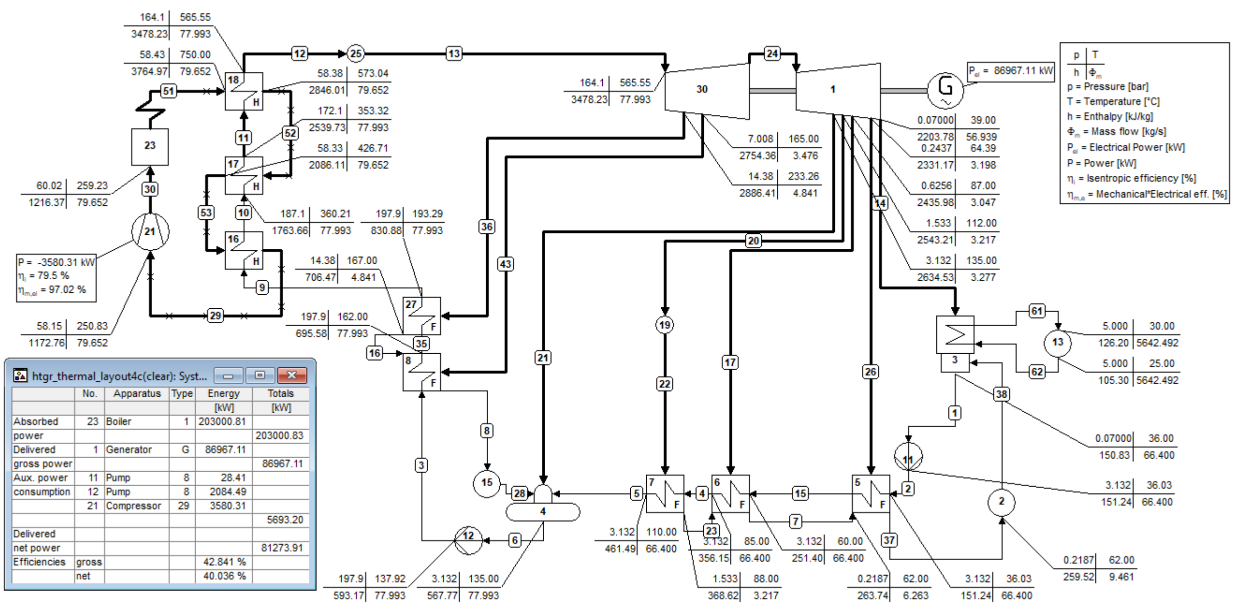

Figure 15. An HTGR reference plant as developed by INL.

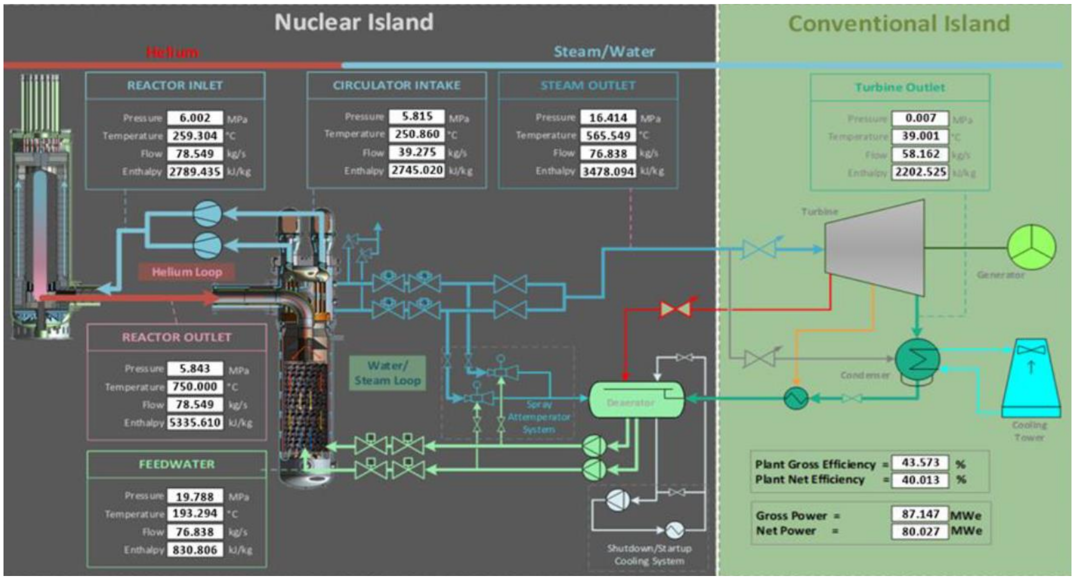

Figure 16. An HTGR reference plant of X-Energy's XE-100 (Mulder 2021).

When considering the system feedwater heating system and extraction for process steam, it is important to understand what the turbine offers. The design parameters for the steam cycle correspond with an existing offer of the industrial steam turbine. These turbines are offered as modular frames (thus lower costs) with the customer-specified flow rate, inlet, outlet, and controlled and uncontrolled extractions within the limits of the specific frames. Siemens advertises nearly off-the-shelf industrial turbines, and their frame SST-600 fits exactly within the limits of inlet parameters and offers up to two controlled and six uncontrolled extractions, fitting within the requirements of the modeled systems (Siemens Energy Inc., 2021).

Additional arguments for the SST-600 are provided by Mulder (Mulder 2021) showing a rendering of a high-speed turbine with a gearbox and axial exhaust, reproduced in Figure 17, fitting also into the range of the SST-600.

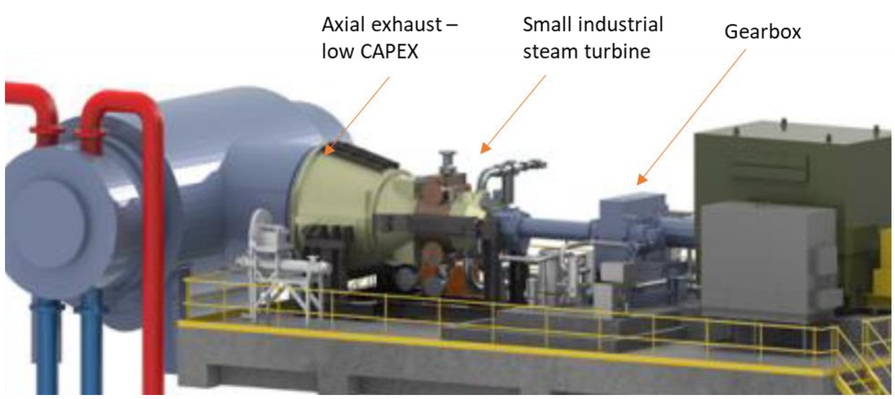

Figure 17. A render of turbogenerator system of the X-Energy's XE-100, modified from [18].

A1. Light Water Reactor

On July 13, 2020, NuScale submitted a letter (Agencywide Documents Access and Management System [ADAMS] Accession No. ML20195C766), requesting approval of the NuScale US600 Design. In response to the NuScale letter, the NRC provided the standard design approval (SDA) on September 11, 2020, for the NuScale reactor standard design (ADAMS Accession No. ML20247J564). NuScale US600 Design has up to 12 nuclear power modules, with each module having an output of 50 MWe, for a total output of up to 600 MWe gross. Figure 18 shows a flow diagram and heat balance diagram for the NuScale US600 Design. Detailed steady-state operating conditions of the NuScale US600 Design served as a baseline for developing the BOP model in Aspen HYSYS [19]. Figure 19 illustrates the Aspen HYSYS model.

By letter, dated November 21, 2022 (ADAMS Accession No. ML22325A349), NuScale informed NRC of its intent to submit another SDA application in stages, along with supporting technical reports, by December 31, 2022. By letter, dated November 23, 2022, NuScale submitted the first part of its application for an SDA of the NuScale US460 design. For the NuScale US460 design, each NuScale power module (NPM) has a rated thermal output of 250 megawatts thermal and an electrical output of 77 MWe; accordingly, a plant containing six modules would have a total capacity of 462 Mwe gross. Currently, only NPM steam and feedwater conditions are publicly available (see Table 8). Given operating conditions, the BOP model in Aspen HYSYS was developed by INL with reasonable engineering judgements, as shown in Figure 20. The 77 MWe NuScale BOP model has slightly less thermal efficiency due to increased power consumption from two feedwater pumps. A PEPSE model was also developed for the 77 MWe design to more easily model extraction for HTSE and refinery applications (Figure 21).

In the PEPSE model for the US460, which can be seen in Figure 11, the high-pressure turbine (HPT) was assumed to have two leakages, which were each assumed to be 0.1 kg/s. PEPSE works best when one has a detailed flow and heat balance diagram, which is available for the 50 MWe NPM. However, there is not sufficient information publicly available to model the 77 MWe NPM in PEPSE without making several assumptions. Note that it is anticipated that SMRs will likely have single-casing turbines. Pressure section differentiation is used within PEPSE and is used in this description, but the actual turbine in for the NPM is likely to be in a single casing without piping between pressure sections. The input block in PEPSE, which is located between the steam generator and HPT is needed to give the initial conditions. The HPT is set to have a governing stage without governing stage leakage, valve leakage, extractions, or moisture separator reheater extraction (since a single-casing turbine is assumed, no reheating takes place). There are two shaft leakages mentioned previously that are equal to 0.1 kg/s each. There is also an extraction taking place at the exhaust. The required values at the throttle inlet for the HPT are 32.8 bar, 2939.8 kJ/kg, and 102.8 kg/s. The exhaust pressure is set to 5.13 bar. The extraction at the exhaust was set to 5.16 kg/s. For the intermediate pressure turbine, the valve wide open (VWO) design for the bowl pressure is set to 5.13 bar, the bowl enthalpy is set to 2633.1 kJ/kg, and the bowl flow rate is set to 94.73 kg/s. The exhaust pressure at VWO design is 1.35 bar. The conditions for the first extraction within the turbine were set to 2.43 bar, 2560.7 kJ/kg, and 7.79 kg/s. The flow rate for the extraction at the end was set to 1.51 kg/s. Additionally, shaft leakages and incoming N_2 leak were not assumed. For the low-pressure turbine (LPT), at VWO design, the bowl pressure is 1.35 bar, bowl enthalpy is 2433.2 kJ/kg, and bowl flow rate is 80.54 kg/s. The exhaust pressure at VWO design is 0.08 bar. There are three extractions in the LPT, these occur at a pressure of 0.62, 0.52, and 0.27 bar, respectively. The enthalpy of these three extractions are 2345, 718.97, and 600.57 kJ/kg, respectively. The steam mass flow rate is 6.18, 1.83, and 2.11 kg/s, respectively. For the condenser, the shell pressure was set to 0.0807 bar. No other performance data was specified. For all the feedwater heaters (FWH), the calculation mode was set to performance mode. For the LP FWH, the heater terminal temperature difference (TTD) was set to 2.4°C, and the drain cooler approach temperature difference (DCA) was set to 5.56°C. No other performance data was specified. For the IP FWH, the TTD was set to 2.4°C, and the DCA was set to 5.56°C. No other performance data was specified. For the LP FWH, the TTD was set to 2.78℃, and the DCA was set to 5.56℃. No other performance data was specified. The steam generator on the primary side for the thermal power was set to 250 MWth.

Table 8. NuScale power unit feed steam parameters (NuScale Power, 2022).

Parameter	Values
Steam Energy (MWth)	250
Mass Flow Rate (kg/s)	102.8
Steam Pressure (bar)	32.8
Steam temperature (main steam line) (℃)	283
Feedwater temperature (℃)	121
Feedwater pressure (bar)	37.8

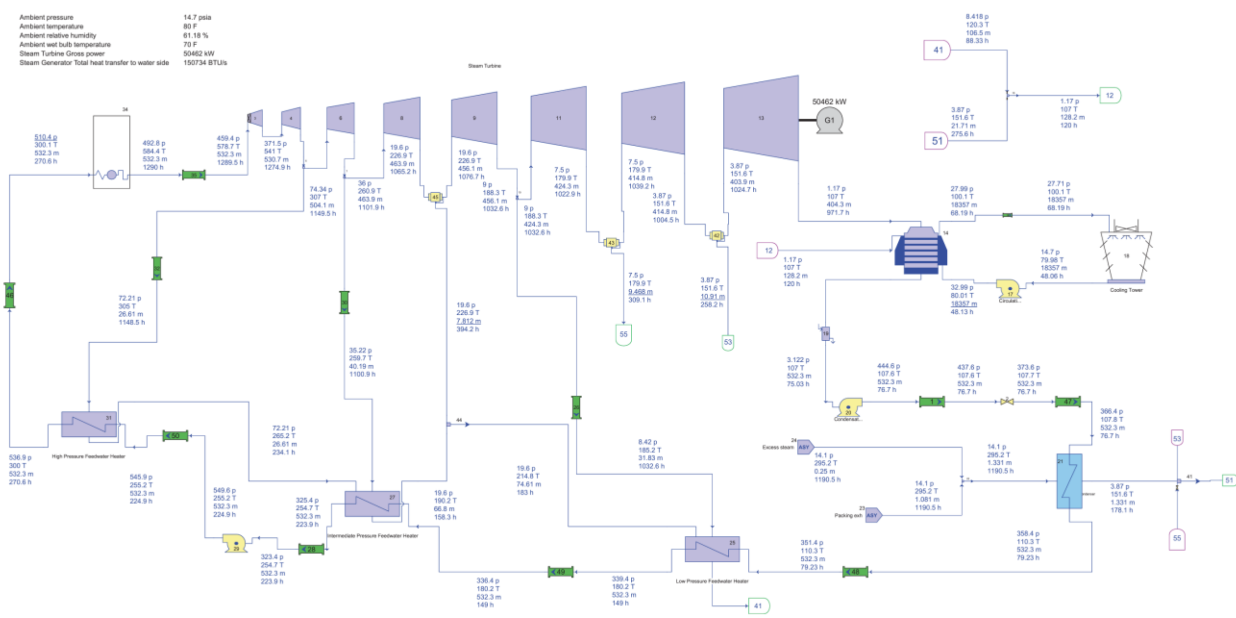

Figure 18. Flow diagram and heat balance diagram for the NuScale US600 (50 Mwe) design (NuScale Power 2020). Pressure is in psia, temperature in Fahrenheit, mass flow rate in Mb/hr.

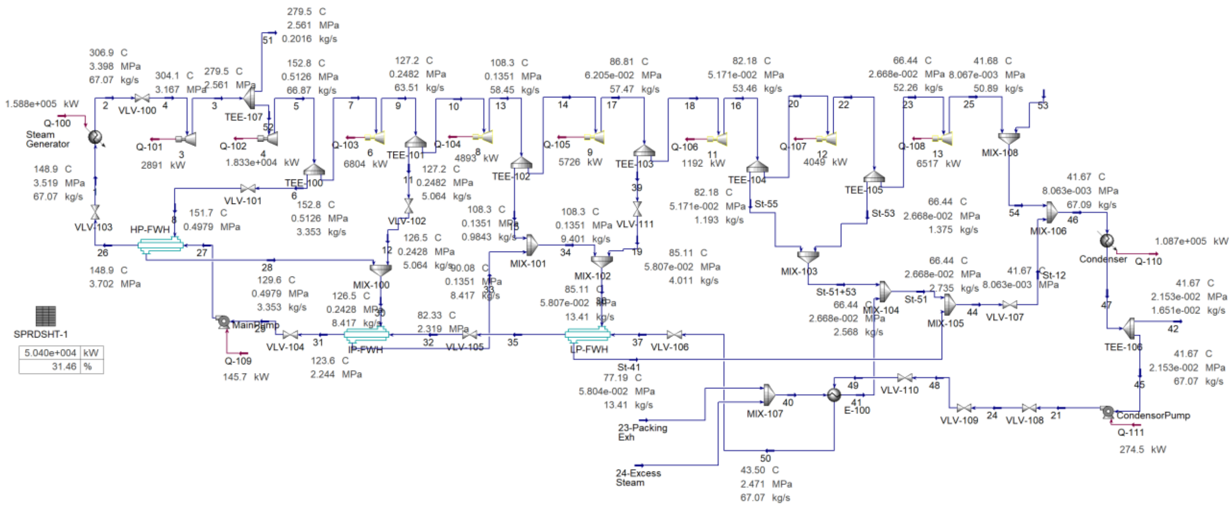

Figure 19. Aspen HYSYS® models of the 50 MWe NuScale BOP system [19].

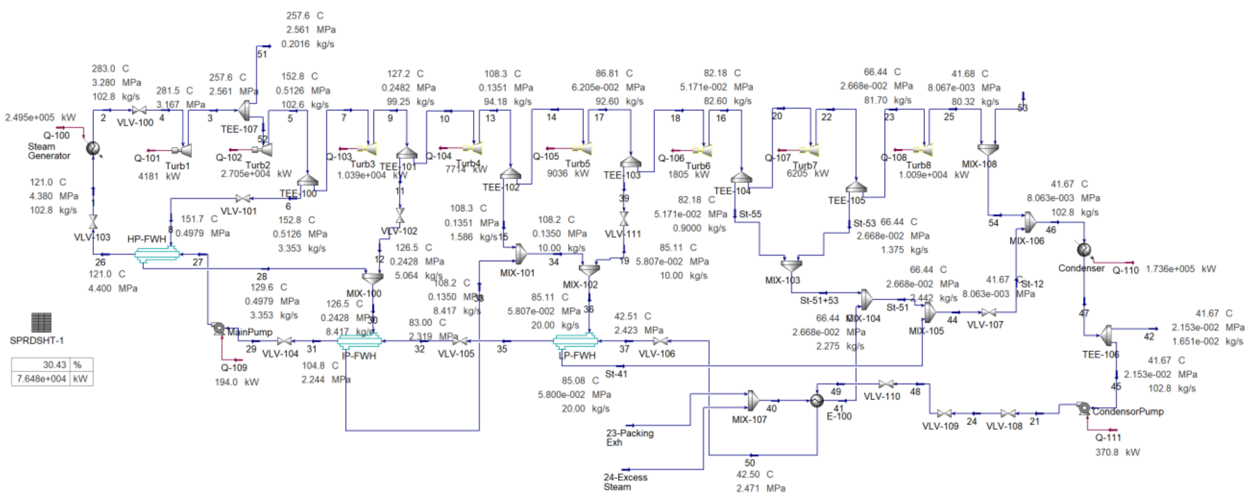

Figure 20. Aspen HYSYS® model of the 77 MWe NuScale BOP system.

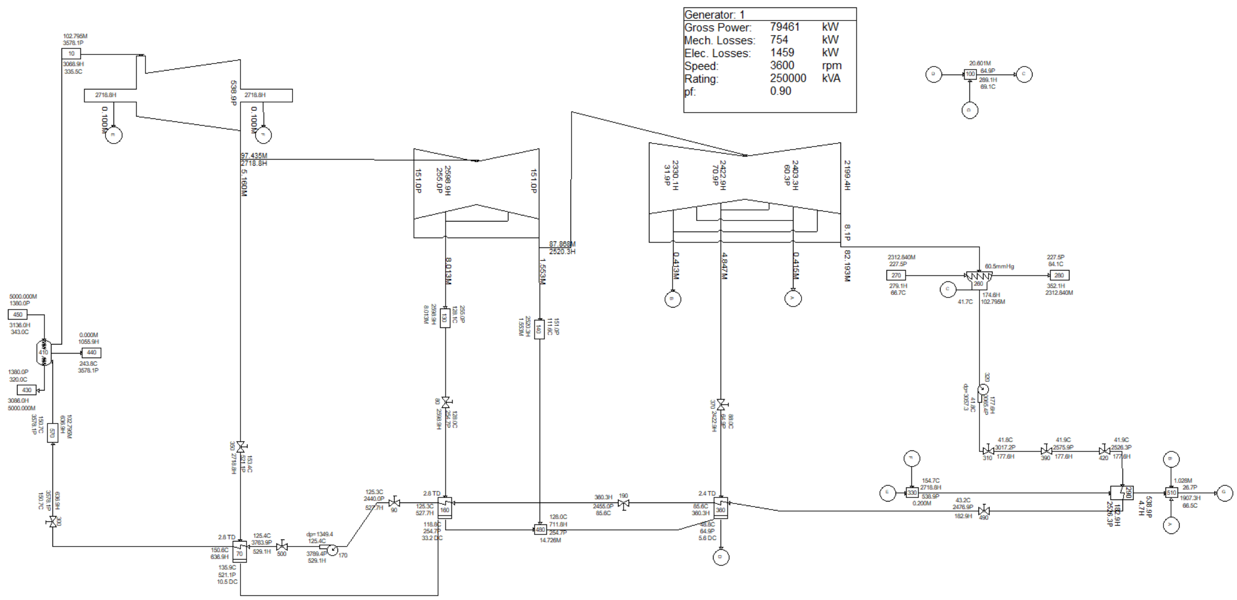

Figure 21. PEPSE Model for the 77 MWe NuScale SMR BOP.

A note that clarifies in part why two codes were used to generate energy balances in the LWR-refinery integration: Aspen HYSYS was used for the compressor models since PEPSE has a limitation in which the compressor does not work properly with pure steam. A user can add N_2 or O_2 to the fluid, but it was decided that making calculations in HYSYS and manually inputting results into PEPSE using input and output blocks would be simpler.

Appendix B

Siting Requirements for Colocating Advanced Reactors with Industrial Processes

Siting and licensing considerations for reactors are interdependent on nuclear reactors used for industrial requirement and types of industrial facilities coupled with nuclear power plants (NPPs). Because of the desire to closely site, even collocate, industrial facilities with NPPs to improve heat usage, there is an increased risk from external threats, which are dependent on design features of collocated nuclear reactors and site-specific industrial processes.

From a design perspective of nuclear reactors, advanced reactors and SMRs have some advantages that may facilitate colocation with industry (Worsham et al. 2023). First, recent advanced reactor concepts are considering creating a separation between the nuclear island and the BOP. This is intended to separate the regulatory complexity of the power plant by minimizing the number of safety-related nuclear systems. This requires careful design and a clear definition of what is and is not included in the nuclear island and requires ensuring the external system has limited effect on the nuclear plant. The well-defined nuclear system would allow a simplified analysis to demonstrate the safe separation of the nuclear island. Second, there could be fewer structures to protect from external hazards. Additional water sources, electrical grid components, pumps, and valves that are not needed in an SMR do not require protection.

From an external threat’s perspective, the existence of an industrial facility near an NPP introduces various hazards that need to be considered during the siting process. These considerations fall under the "nearby hazardous land uses" criteria in 10 CFR 100.21(e). RG 4.7 (U.S. Nuclear Regulatory Commission 2014) refers to this set of criteria as "industrial, military, and transportation facilities," which specifies that these facilities "must be evaluated and site parameters established such that potential hazards from such routes and facilities will pose no undue risk to the type of facility proposed to be located at the site". Worsham et al (2023) postulated the potential hazards to the NPP introduced by collocating an industrial facility as follows:

- Vibratory hazards: If the presence of the industrial facility introduces a vibratory hazard, it should be accounted for during colocation. Many industrial facilities (e.g., oil refinery or hydrogen production) have a risk of explosions, which can introduce vibratory hazards through the ground, shockwaves (vibratory hazards through the air), airborne missiles, fire, etc., which should all be accounted for.
- Geotechnical hazards: The presence of an industrial facility can also introduce geotechnical hazards such as ground instability. One example is siting an NPP near a mine—ground instability due to the existence of the mine will need to be evaluated in this scenario.
- Flooding: Flooding near the NPP due to operations or accidents at the industrial facility should be considered. An example might be pipe breakage in a desalination facility that results in flooding.
- Fire: Many chemical facilities have a risk of explosions that result in fires. Such accidents and the resulting risk of fires at the NPP should be considered during siting.
- Transportation routes: The existence of an industrial facility may introduce new transportation routes around the NPP and increase the amount (and nature) of the traffic around the NPP. These increases and their impact on the security of the NPP, emergency preparedness, transient population increases, etc., should be considered during siting.

The hazards considered potentially affect the frequency of internal and external NPP events. To define internal events in an NPP connected through a thermal loop to industrial facilities, the jurisdictional boundary must be first defined where the NRC's regulation of the nuclear facility ends. Preliminary review for establishing jurisdictional boundaries at collocated advanced reactor facilities has been performed (Moe and Hicks, 2020). The review concluded that a regulatory base already exists for establishing jurisdictional boundaries between a nuclear plant and non-nuclear industrial facilities collocated at the same site. It suggested that energy-conversion systems located within the nuclear-protected area boundary are integral to the nuclear facility and/or are operated by the nuclear facility control room should be considered part of the nuclear facility. It is also suggested that energy-conversion systems located outside of the protected area boundary and separated from the nuclear facility by a transfer system with appropriate interface criteria could be excluded from the nuclear facility scope. Nuclear safety analysis, including probabilistic risk assessment (PRA), would be required by all nuclear and industrial systems with respect to potential missiles, security issues, flooding issues, or any other impacts that may influence systems, structures, and components (SSC) that perform a nuclear safety function. As a preliminary study of generalized siting requirements for selected advanced reactors (i.e., Xe-100 of X-Energy and US460 or US600 of NuScale) near a hydrogen production facility and oil refinery, this section will focus on vibratory hazards due to explosions from the collocated industrial process and analyze the required distance between the boundaries of an NPP and a target industrial facility.

Table 9. Different damages caused by different levels of overpressure (Lobato et al. 2009).

Overpressure (bar)	Damage
0.00204	Occasional breakage of large windows already under strain.
0.00275	Loud noise. Breakage of windows due to sound waves.
0.00681	Breakage of small panes of glass already under strain.
0.0204	20% windows broken. Minor structural damage to houses.
0.068	Partial demolition of houses, which become uninhabitable.
0.136	Partial collapse of house roofs and walls.
0.131 ~ 0.204	Destruction of cement walls of 20-30 cm width.
0.162	1% of eardrum breakage.
0.17	Destruction of 50% of brickwork of houses. Distortion of steel frame building.
0.204 ~ 0.277	Rupture of storage tanks.
0.34 ~ 0.476	Almost total destruction of houses.
0.477 ~ 0.544	Breakage of brick walls of 20-30 cm width.
0.689	Probable total destruction of buildings. Machines weighing 3,500 kg displaced and highly damaged.
1.01	1% death due to lung hemorrhage.
1.692	90% death due to lung hemorrhage.

The reactor building is the primary critical structure at an NPP. It is also the most well-protected from any external forces such as blast impulse shock waves. It is reported that the lowest static pressure capacity of nuclear concrete identified is 0.10342 bar (Vedros and Otani 2019). This value is also close to the structural damage level against overpressure found in (Lobato et al. 2009)The review concluded that a regulatory base already exists for establishing jurisdictional boundaries between a nuclear plant and non-nuclear industrial facilities collocated at the same site. It suggested that energy-conversion systems located within the nuclear-protected area boundary are integral to the nuclear facility and/or are operated by the nuclear facility control room should be considered part of the nuclear facility. It is also suggested that energy-conversion systems located outside of the protected area boundary and separated from the nuclear facility by a transfer system with appropriate interface criteria could be excluded from the nuclear facility scope. Nuclear safety analysis, including probabilistic risk assessment (PRA), would be required by all nuclear and industrial systems with respect to potential missiles, security issues, flooding issues, or any other impacts that may influence systems, structures, and components (SSC) that perform a nuclear safety function. As a preliminary study of generalized siting requirements for selected advanced reactors (i.e., Xe-100 of X-Energy and US460 or US600 of NuScale) near a hydrogen production facility and oil refinery, this section will focus on vibratory hazards due to explosions from the collocated industrial process and analyze the required distance between the boundaries of an NPP and a target industrial facility.

(see *destruction of cement walls of 20–30 cm width*). Refueling water storage tanks, condensate storage tanks, auxiliary feedwater heater tank, emergency feedwater tank, service water intakes, and switchyard are critical external structures of conventional NPPs (Glover, Baird, and Brooks 2020). For critical structures outside of the reactor building, switchyard components can be a target component of analysis for overpressure events with assumption that other safety-critical external structures are covered in concrete walls. The most fragile component in the switchyard is the transmission tower (Vedros, Christian, and Otani 2022) and the probability for damaging a transmission tower goes to zero at approximately 0.01103 bar.

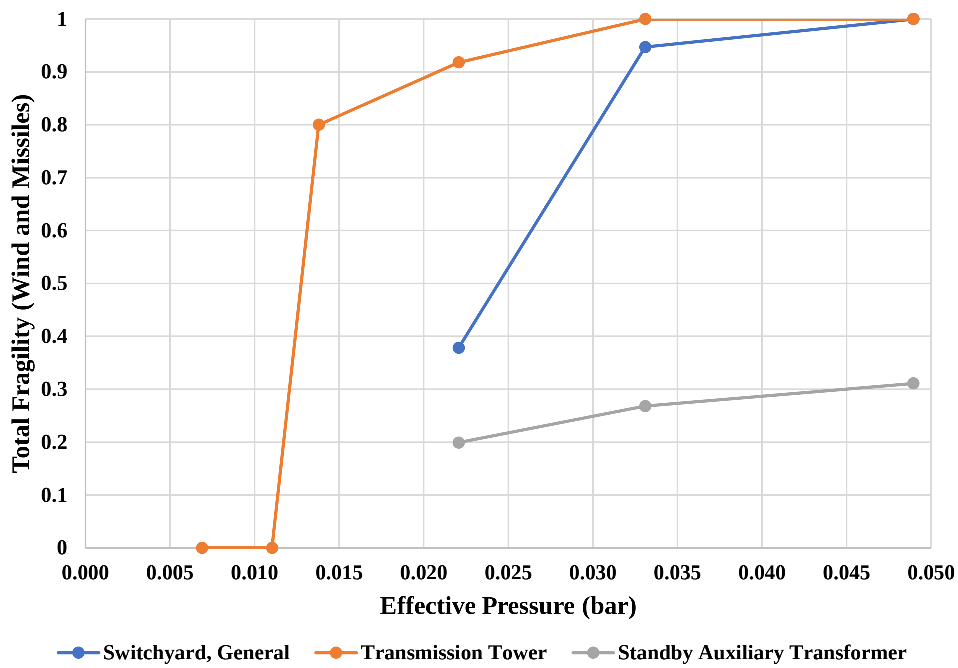

Figure 22. Blast overpressure fragilities of switchyard components. Data retrieved from (Fu, Li and Li 2016) and (Glover, Baird and Brooks 2020).

Loss of switchyard components means a loss of offsite power (LOOP) event which challenges the NPP to shut down safety. A recent white paper of plant control and data acquisition system of Xe-100 noticed that the Xe-100 I&C systems are designed to respond to different plant initiating events including LOOP (X-Energy, LLC, 2023). In contrast, For NuSacle's SMR designs, the role of 'offsite power' is not required. The reliance on natural circulation for normal operation and safety system performance reduces the impact to the core from a loss of electric power relative to a design with forced circulation (NuScale Power 2022).

One could also find an appropriate and conservative fragility criterion on which to evaluate the consequence of an explosive overpressure on NPP structures, systems and components (U.S. Nuclear Regulatory Commission 2013). It reported that the incident overpressure below which critical targets of an NPP are expected to experience no significant damage is conservatively 0.06895 bar (=1 psi). For those nuclear power plants which do not require offsite power for safety, this criterion could be also used to determine whether failure is expected to occur after exposure to overpressure from explosion.

B-1. Hydrogen Detonation and Separation Distance

The risk of hydrogen detonation is a significant concern when collocating an NPP with hydrogen generation or utilization facilities. The pressure caused by these detonations at a given distance was used to determine if there would be damage to the most fragile component in the switchyard: the transmission tower. Two types of hydrogen detonation events can occur: high-pressure jet detonation (HPJD) and hydrogen cloud detonation (Vedros, Christian, and Otani 2022). Even though the overpressure experienced from a hydrogen cloud detonation would be much higher than that of a HPJD, the event frequency of cloud detonation is very low (Vedros, Christian and Otani 2022). This means it could be effectively screened out of the analysis as a hazard and used as the bounding event for the detonation hazard to determine the appropriate siting distance. In HPJD, the probability of transmission tower damage was zero at an overpressure below 0.01103 bar (Fu, Li and LI 2016. and the critical siting distance where the probability of component failure from an overpressure event is 100% becomes 845 m (Worsham, et al. 2023). By applying 0.06895 bar (=1 psi) fragility failure criterion, the required separation distance could be reduced. Table 10 shows the separation distance for each of the different scenarios. The largest separation distance is ~120 meters away from the NPP.

Table 10. Accident impact scenarios and corresponding separation distance (Glover, Baird and Brooks 2020).

Scenario Number	System Section	Scenario Description	Separation Distance (m)
1	Mix-100 thru HX-KO1	203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	18.0
2		254.0 mm break with a temperature 735°C and pressure of 0.52 MPa	23.7
3		300.0 mm break with a temperature 735°C and pressure of 0.52 MPa	28.9
4	HX-KO1 thru HX-KO2	152.4 mm break with a temperature 75°C and pressure of 0.48 MPa	17.4
5		203.2 mm break with a temperature 75°C and pressure of 0.48 MPa	24.9
6		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	32.6
7		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	39.8
8	HX-KO2 thru HX-KO3	203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	14.0
9		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	16.5
10		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	37.7
11		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	50.1
12	HX-KO3 thru K-301	203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	24.3
13		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	63.6
14		203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	84.5
15	K-301 thru System Output	203.2 mm break with a temperature 735°C and pressure of 0.52 MPa	119.8

See “Final Report on Hydrogen Plant Hazards and Risk Analysis Supporting Hydrogen Plant Siting near Nuclear Power Plants SAND2020-10828” (Glover, Baird, and Brooks 2020) and “Expansion of Hazards and Probabilistic Risk Assessments of a Light-Water Reactor Coupled with Electrolysis Hydrogen Production Plants” (Vedros, Christian, and Otani 2023) more details on hydrogen plant hazards and risk analysis supporting hydrogen plant siting near nuclear power plants.

B-2. Oil Refinery Explosion and Separation Distance

There are several types of explosions, which can happen in oil refinery facilities, including vapor cloud explosion (VCE), deflagration to detonation transition, and boiling liquid expanding vapor explosions, considered for gas explosion in the chemical process industry, and VCE is one of the most dangerous and destructive accidents (Shamsuddin, et al. 2023). There are several VCE overpressure prediction models, including a trinitrotoluene equivalency model, Toegepast Natuurwetenschappelijk Onderzoek multi-energy model, and Baker-Strehlow-Tang (BST) model. The BST model is one of the most common methods used to estimate overpressures for the purpose of locating buildings in relation to process units (Melton and Marx 2009). The explosion occurred on March 23, 2005, at Texas British Petroleum (BP) refinery could be considered as an exemplary case, showing how much distance that an NPP should be placed away at least from the oil refinery facilities. With some inputs for BST model shown in Table 11, one can draw a curve "distance vs. overpressure," as shown in Figure 23. Figure 23 illustrates that the minimum separation distance should be at least 550 m if one applies 1 psi criterion. The minimum separation distance could also be around 1400 m if one would like to maintain transmission tower damage probability to be zero.

Table 11. Inputs of the BST model for drawing overpressure versus distance diagram (Ma, Huang and Li 2019).

Input Parameter	Value
Material	Hydrocarbon
Flammable mass in cloud	13,644 kg
Flame expansion	3D
Obstacle density	High
Fuel reactivity	High
Mach number	0.588

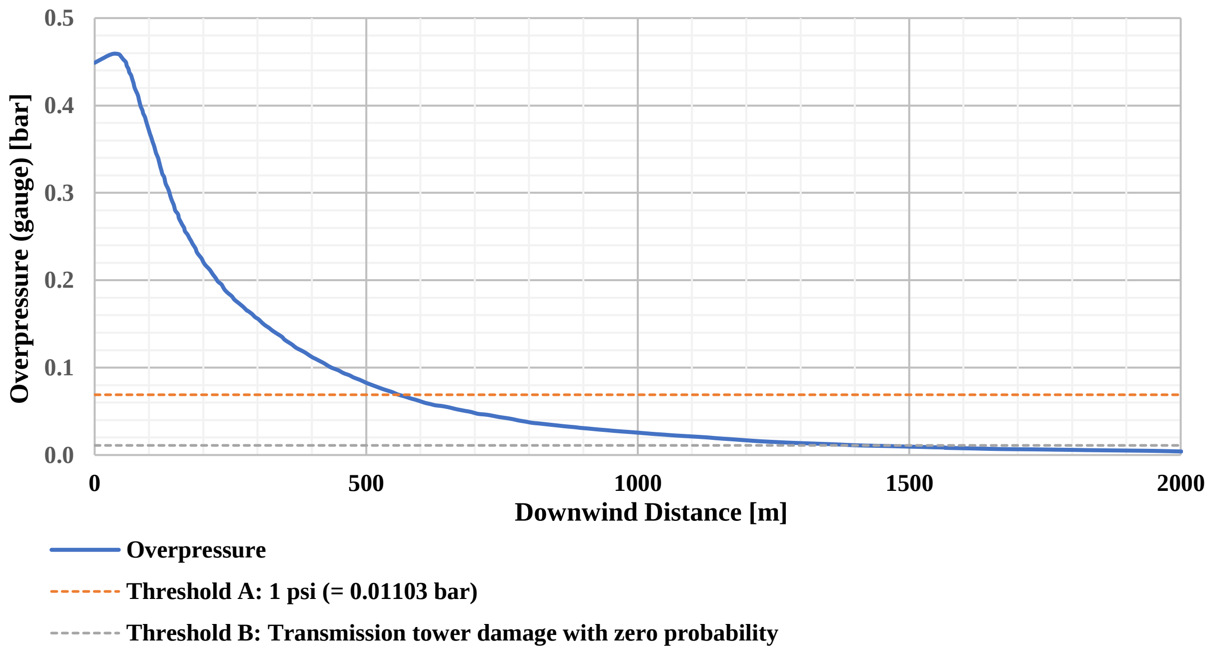

Figure 23. Overpressure versus distance: Texas BP refinery explosion analysis using the BST Model (Ma, Huang and Li 2019)

B-3. Sensitivity Analysis – Heat Transport Modeling

Understanding how much pressure drop and heat loss occur to transport steam from a nuclear power plant site to industrial facilities is important. Thermal extraction and delivery models (Williams et al. 2023) for quantifying the impact of transferring heat across are archived in the IES HYBRID repository (Frick, et al. 2022). The thermal delivery model can flex parameters to calculate thermodynamic losses across many design dimensions, including power rating, piping length, piping diameter, heat transfer fluid, inlet temperature/pressure, insulation thickness, insulation material conditions, and ambient conditions. Figure 24 shows a one-way heat transfer model with a control scheme. Control logics work to find steam extraction conditions to satisfy industrial steam demand (i.e., temperature and enthalpy) in consideration of pressure drops and heat loss.

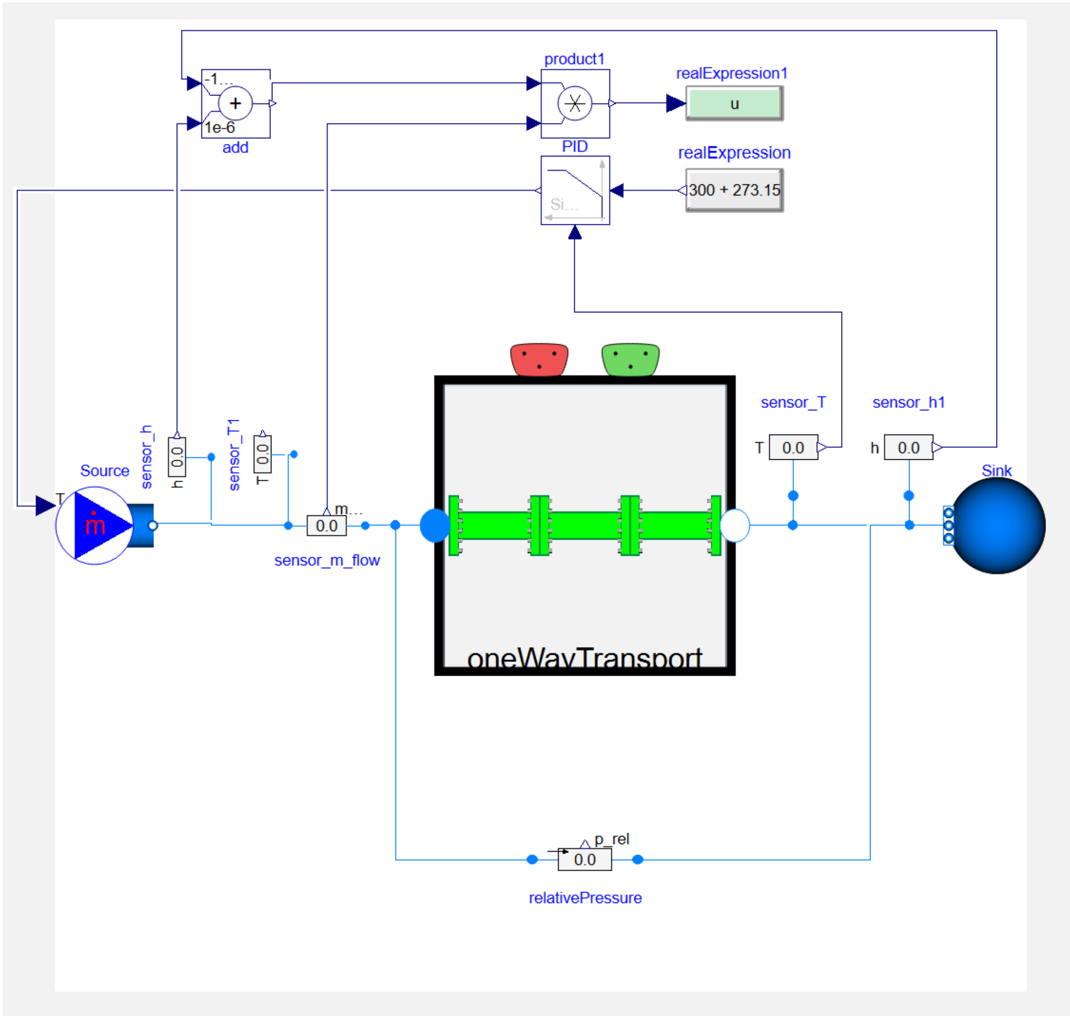

Figure 24. One-way heat transfer model with a control scheme. The model can be found in the HYBRID repository at: NHES.Systems.HeatTransport.Example.SteamTransOil.

Using a thermal heat transport model in HYBRID, the pressure drop and heat loss were calculated for the steam delivery and condensate return for multiple distances and several standard pipe sizes. U-shaped bends in the form of a local loss coefficient of 2.8 were placed every 125 meters to compensate for thermal expansion of the pipe. The simulations were set up to solve for the inlet conditions required to achieve the desired exit conditions. For steam delivery the exit conditions were set to be 300°C and 42.3 bar, and for the condensate return 87.6°C and 1.1 bar were used. A mass flow rate of 42 kg/s was used for both sets of simulations.

Two pipe sizes were tested for steam delivery—12 inch and 14 inch–and each size was tested at seven different pipe lengths ranging from 120 m to 2 km. Pipe sizes for the steam delivery were chosen to obtain a max fluid velocity of approximately 30 m/s. For condensate return, three pipe sizes (i.e., 4 inch, 5 inch, and 6 inch) were tested, targeting <5m/s. fluid velocity. Each size was tested at seven different pipe lengths ranging from 120 m to 2 km. A fiber-glass insulation that was 3-in. thick was used to help prevent heat loss for steam delivery, and a 1/2 inch of fiber-glass insulation was used to help prevent heat loss on the condensate side due to the low temperatures. Pressure drops from each simulation for steam delivery and condensate return can be found in Table 12 and Table 13, respectively. In addition, the heat loss for each case is also tabulated in Table 14 and Table 15 for steam delivery and condensate return, respectively. The heat loss for each simulation can be seen in Table 14 and Table 15.

The pressure drop for steam delivery is quite significant as distance increases between the main steam extraction point and the industrial process. It implies that one may extract a higher pressure in the BOP or consider installing a compressor in the steam transport system of HTGR, depending on the required steam demand from a target industrial process. Expected pressure drops may reduce if one introduces a larger pipe size but deterioration of economics of thermal energy extraction and delivery could not be avoidable. Pressure drops on the condensate return side is less of an issue as pumping liquid water is much easier than compressing steam. Further economic analysis may be needed to compare different options for condensate returns (e.g., large pipe and small pump vs. small pipe and large pump). Heat loss shows a different trend as pressure drop, with longer and larger pipes resulting in larger heat losses. This heat loss will again inform the extraction point or the amount of compression needed to obtain the required steam temperature at the industrial process. Heat loss can be mitigated with additional insulation though this would increase the cost of the system. The thermodynamic impact of heat delivery will need to be weighed against the economics of the pipe sizes and insulation thicknesses to determine the optimal configuration.

Table 12. Pressure drop (bar) within steam transport system delivering steam to industrial process under above conditions.

	Pipe Size	
Distance	Schedule 40 12 in. DN300 mm	Schedule 40 14 in. DN350 mm
120 m	4.5	3.1
200 m	4.7	3.2
500 m	5.7	3.9
750 m	6.5	4.4
1,000 m	7.3	4.9
1,500 m	8.9	6.0
2,000 m	10.5	7.0

Table 13. Pressure drop (bar) within condensate transport system returning condensate to the SMR under above conditions.

Distance	Pipe Size		
	Schedule 40 4 in. DN100 mm	Schedule 40 5 in. DN150 mm	Schedule 40 6 in. DN200 mm
120 m	8.4	3.2	1.5
200 m	10.0	3.7	1.7
500 m	15.8	5.5	2.4
750 m	20.7	7.1	3.0
1,000 m	25.6	8.6	3.6
1,500 m	35.4	11.7	4.8
2,000 m	45.1	14.7	6.0

Table 14. Heat loss (kW) within the steam transport system delivering steam to the industrial process under above conditions.

Distance	Pipe Size	
	Schedule 40 12 in. DN300 mm	Schedule 40 14 in. DN350 mm
120 m	109	109
200 m	181	182
500 m	456	458
750 m	688	689
1,000 m	921	923
1,500 m	1395	1397
2,000 m	1878	1879

Table 15. Heat loss (kW) within the condensate transport system returning condensate to the SMR under above conditions.

Distance	Pipe Size		
	Schedule 40 4 in. DN100 mm	Schedule 40 5 in. DN150 mm	Schedule 40 6 in. DN200 mm
120 m	38	40	43
200 m	63	67	71
500 m	157	168	178
750 m	235	252	267
1,000 m	313	337	356
1,500 m	471	505	534
2,000 m	628	674	713

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