ABSTRACT

DANIELS, MAHLON TUCKER. Integration of Large-Scale Steam Accumulators for Energy Storage in Nuclear Hybrid Energy Systems. (Under the direction of Dr. Stephen D. Terry.)

Currently, there are not many practical technologies to store power or heat a large scale. The front runners are batteries and pumped hydro for power, but there are many challenges associated with both technologies. This study aims to assess the performance and economics of installing large-scale steam accumulators in nuclear hybrid energy systems for thermal storage. The stored steam can be used to generate electricity or provide process heat.

Small Modular Reactors (SMR) are nuclear reactors with less than 300 MW of electrical output. Coupling a steam accumulator to an SMR is a good way to take advantage of excess energy available when the reactor is not producing its full rated output. Since the variable costs of operating a nuclear plant are low, $0.0186/kWh, operating at full power output is most economical. This research is focused around the NuScale SMR which has a nominal power output rating of 45 MWe. This system is coupled to an appropriately sized steam accumulator so that it can store steam when electrical demand is low and tap into the steam when demand is high.

Simulations were designed to understand the thermodynamic effects on the accumulator and its interaction with the NuScale Rankine cycle. A model was developed that supplied a specified electrical demand curve and calculated the state of the system. Demand data was collected from North Carolina and South Carolina for winter and summer, scaled down to have a peak of 45 MW. Then, the demand data was then scaled up to simulate serving a larger grid. When power was lower than 45 MW, the accumulator was being charged, when power exceeded 45 MW, the accumulator was being discharged. The grid could be scaled up by 20%

through the installation of a 2.8-million-gallon steam accumulator. Steam that was flashed from the accumulator was sent through a 12 MW peaking turbine separated from the main Rankine loop. Capacity factors increased from 76.0% to 91.2% in the summer, 51.4% to 61.7% in the shoulder months, and 67.5% to 81.0% in the winter. Energy was lost due to efficiency reductions in the steam turbines at part load.

Another application considered was using the stored steam for some constant process heat. Steam was withdrawn from the accumulator at 100 psia for a constant heat demand. This could be used in a desalination plant as an example. While the SMR was producing the required, unscaled electrical demand, excess steam was directed to the accumulator while a constant steam supply was withdrawn and sent to the process. The accumulator could supply 24 MW of heat in the summer and 33 MW in the winter. To keep the heat rate constant, the mass flow was adjusted slightly as the enthalpy of the steam diminished with falling pressure.

The economics of the system were also assessed. With the end-user paying $0.0941/kWh, the SMR was found to have an effective revenue of $26.7 million after considering the cost savings of load-following. The SMR with an accumulator had an effective revenue of $28.9 million. The additional revenue brought in by the accumulator was $2.25 million annually. Comparing to a natural gas turbine with a gas cost of $3.00/MMBtu, the accumulator would have a simple payback period of ten years if the implementation cost was $10.4 million. Similarly, if a boiler system was installed instead of the accumulator for process heat, the ten-year payback could be achieved with an accumulator system cost of $39.6 million. With the actual implementation cost unknown, these estimates show what the alternatives may cost and where the accumulator cost needs to be to make financial sense.

Integration of Large-Scale Steam Accumulators for Energy Storage in Nuclear Hybrid Energy Systems

by
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DEDICATION

I would like to dedicate this thesis to my supportive family and my girlfriend. My father, Tim Daniels has always encouraged me to push myself and never turned away from any crazy project idea that I needed help with. He was always proud of my achievements and was never surprised when I succeeded. My mother, Denise Daniels, has also encouraged me to do more and helped prepare me for what's ahead. My older brother and sister, Fella and Lauren, were there for me too, making sure I had fun along the way. And last but not least, my girlfriend, Josefina Puello, has been by my side along the way. I would not be where I am today without any of these amazing people.

BIOGRAPHY

Tucker Daniels was born in Hampton, Virginia the youngest of three children. He attended elementary school and half of middle school in Virginia. At the end of 7th grade, he moved to Wanchese, a small town on the Outer Banks of North Carolina. He finished out middle school and then attended Manteo High School, where he quickly befriended many of the math and science teachers. Their influence and unmatched education led Tucker to choose engineering when it came time for college. North Carolina State was an obvious choice for him and was the only school where he applied.

Tucker was accepted into the engineering undecided program in the Fall of 2011. He quickly learned that mechanical engineering was where he fit in, which was no surprise. Tucker took pretty much everything apart that had screws or bolts holding it together. He even was able to put them back together, most of the time. A love of moving machines and parts made the decision easy. Tucker matriculated into the mechanical engineering program at the end of his first semester at State. He survived the rigorous curriculum and graduated Magna Cum Laude in May of 2015.

After receiving a Bachelor of Science degree in mechanical engineering, Tucker immediately started working under Dr. Stephen Terry in pursuit of a Master's Degree in the same discipline. He focused on the thermal fluids side of mechanical engineering and worked in the Industrial Assessment Center while researching energy storage methods.

ACKNOWLEDGMENTS

I would like to acknowledge Corey Misenheimer for all his assistance with FORTRAN coding and modeling techniques. His contributions helped dramatically improve the efficiency of the model without sacrificing accuracy. He helped develop the Newtonian solvers used to find iterative solutions, and he provided the framework for a steam properties lookup subroutine that was used extensively throughout the model. I would also like to acknowledge Dr. Peter Corson. He provided his real-world power plant experience and helped me work through some of the unknown characteristics of the system. He was able to draw on his past experiences to provide a "sanity check" on some the missing values that were calculated. David Wilson is an engineer with Duke Energy and works at the Oconee Nuclear Power Plant. He provided me with some valuable plant data to help understand what happens at part load. He also was able to direct me to some literature that contained information needed to complete the research. In addition, I would like to thank the United States Department of Energy and the Industrial Assessment Center program.

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1 Introduction

1.1 Project Objective

The global shift towards carbon-free and renewable power has created many challenges that today's scientists and engineers must solve. This study aims to address the challenges of integrating a large percentage of nuclear power into the energy grid. In 2016, France was one of the world leaders in nuclear power generation. The country produces about three-quarters of all its power from nuclear reactors. [1] Having such a high percentage of nuclear capacity means that the reactors must be able to "load follow," or change output quickly in response to demand.

While nuclear reactors can be designed with load following capabilities, the most economical and reliable operation is base load, or producing maximum power all the time. Installing a nuclear reactor is a high capital project. The reactor is only profitable when it is producing power. Therefore, the quickest way to get a return on the investment is to make as much power as possible. Operating this way becomes problematic when the power demand on the grid varies throughout the day or seasonally. An energy storage method could be used to shift demand and reduce the severity of varying demand.

This research will investigate the feasibility of installing steam accumulators for energy storage in nuclear energy plants. It will assess the economics and scale required to make a significant contribution to trimming the peaks in demand. The proposed system will be modeled and analyzed to determine the benefits of installing a large-scale steam accumulator system.

1.2 Background

Electricity has an invisible hand in most products and devices in the modern world. Many aspects of everyday life rely on electricity to function. As a result, society has developed a high demand for energy. In 2012, the U.S. Energy Information Administration reported that the world energy consumption was 549 quadrillion BTU from market suppliers. [2] This consumption was predicted to steadily increase in the years to come. Increasing demand requires increasing supply. This means energy suppliers are forced to do one of two things: increase the size of the infrastructure to supply energy or provide energy more efficiently. The real solution to the ever-increasing demand is a combination of the two options.

The primary energy sources that power the world do so by generating heat. Then, the heat is either used directly or converted to mechanical work, usually in the form of rotational motion. Most of the world's electric plants convert heat from a fuel source into rotary motion used to drive an electrical generator. Research has been thoroughly funded to optimize these large electric production facilities to make power more efficiently and cheaper. The ultimate goal is to use as much of the heat provided by the fuel source as possible. Effective use of the fuel can take many forms such as thermodynamic cycle optimization, equipment tuning, heat recovery, combined heat and power, and much more.

1.2.1 Electric Demand Profile

One challenge with meeting the energy need of the world is variability. Electrical demand demonstrates this problem clearly. Electric demand in the United States follows different hourly and seasonal trends, primarily determined by work schedules of the public and space conditioning needs. Data was collected using the EIA U.S. Electric System Operating Data

tool to get an average demand profile in the Carolinas Region over several weeks. [3] The region is comprised of several utilities and covers most of the state of North Carolina and the majority of South Carolina.

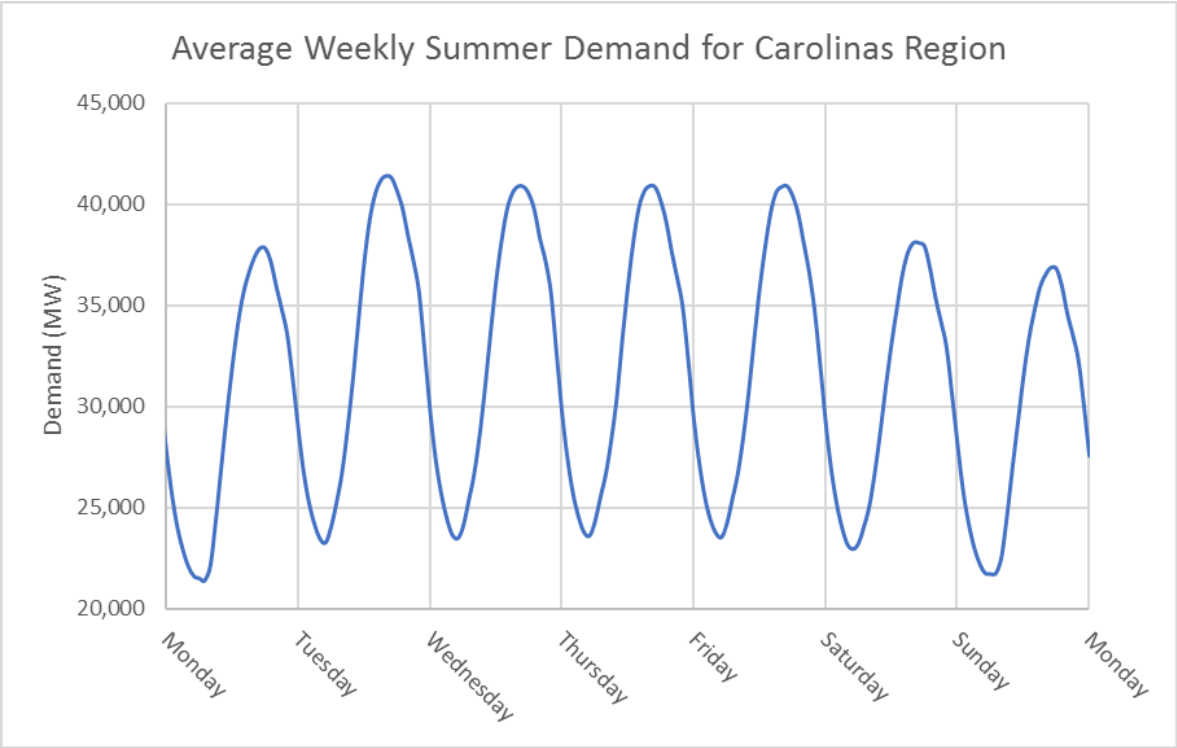

Figure 1 Typical Summer Weekly Demand in North Carolina and South Carolina

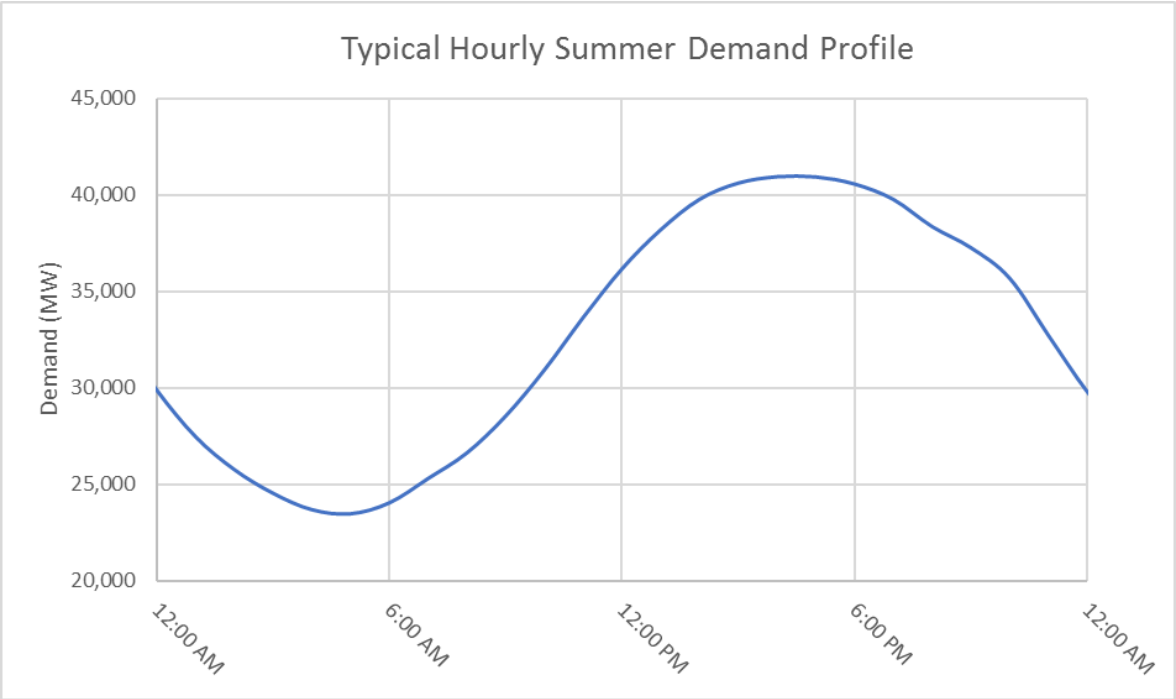

Figure 2 Hourly Summer Demand Profile in North Carolina and South Carolina

Figure 1 and Figure 2 show the cyclic nature of the summer electric demand in the Carolinas. It can be seen that the weekdays have higher peaks than weekends and that the daily peak occurs somewhere around 5:00 p.m. This is typically the hottest part of the day and when many businesses send their employees home. High air conditioning loads and more active households are likely the reason for the spikes shown.

Winter data for the region was also analyzed for trends. The following figures depict the daily and hourly cycles during the winter months.

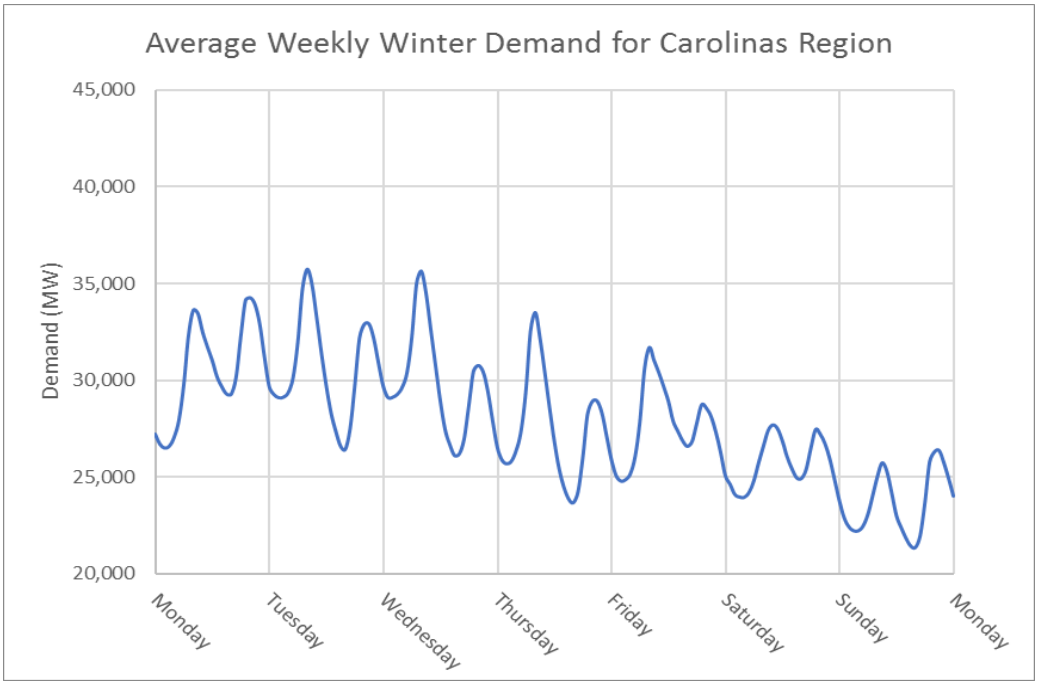

Figure 3 Typical Winter Weekly Demand in North Carolina and South Carolina

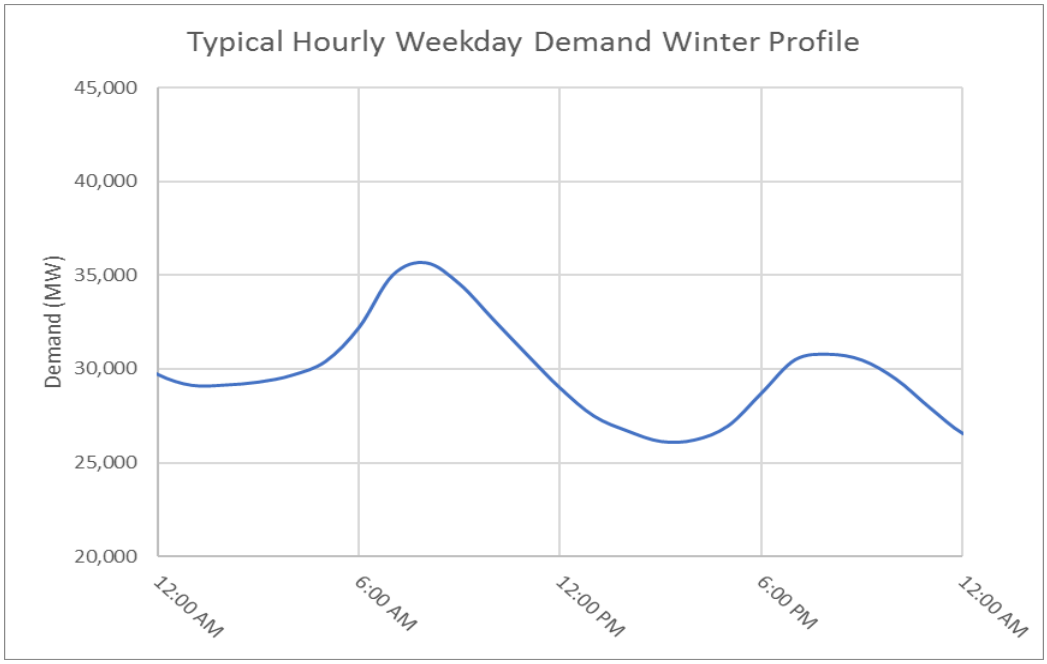

Figure 4 Hourly Winter Demand Profile in North Carolina and South Carolina

Figure 3 shows the electrical demand for a typical winter week. Winter has two distinct peaks per day compared to the single peak of a summer day. Figure 4 shows the two peaks that occur during a typical winter day. At night, most people are sleeping, and businesses are shut down, so typical electric usage is low, but since residential heating is often electric (heat pump or resistance) in this region, there is still some significant electrical usage due to the low outdoor temperatures. As people are getting ready for work, the peak is set in the morning when it is still cold outside, and there are more and more electrical devices being used. Then, the outdoor temperature rises and heating loads plummet, which can be seen as the dip in the middle of the day. Usage peaks again in the evening when more households are active after returning home at the end of the work day. Many people are preparing meals and watching television as the heating ramps up due to falling outdoor temperatures.

Last, the shoulder months were considered. The shoulder months are months when there is little heating or cooling loads, typically around Spring and Fall. These months require minimal heating and cooling meaning the overall demand is generally lower than either summer or winter. The profile can be irregular, sometimes looking more like a summer day, or sometimes looking like a winter day depending on the weather. Three weeks a data from the Carolinas regional electric data were averaged to get a shoulder demand profile. This data is shown in Figure 5 below. Averaging the data makes the shoulder seasons daily profile look like a blend of summer and winter. These are the trends that electricity suppliers must cope with day in and day out.

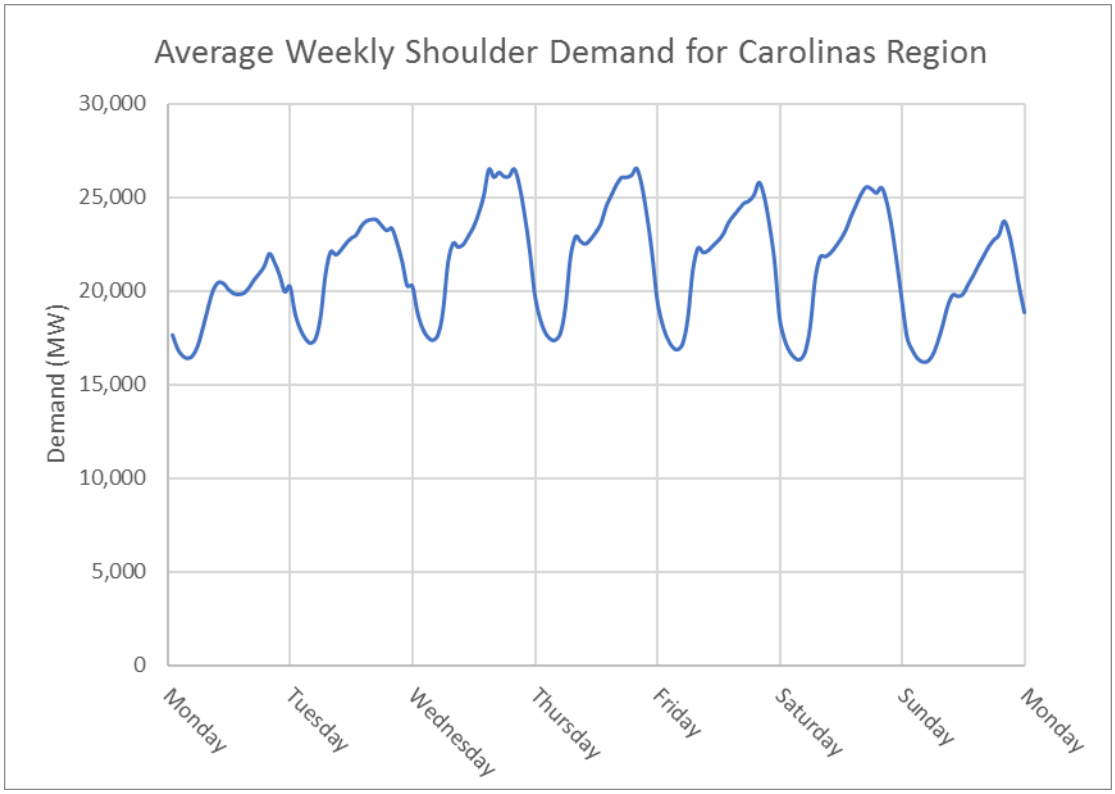

Figure 5 Typical Shoulder Weekly Demand in North Carolina and South Carolina

Currently, supply and demand are kept in check by varying the output of electrical production facilities (dispatching) and allowing power to flow to and from a particular region based on local demand and the demand of the neighboring grid. When demand exceeds supply, power can be "borrowed" from the neighboring grid and when there is excess supply, power and be transferred back to the neighboring grid. This delicate balancing act is required because there is not an effective way to store energy on a large scale.

Factoring in the variability of renewable energy sources, such as wind and solar, can add even more complexity to the equation. Large scale solar and wind generation installations require backup power generation capacity using conventional fuel sources. Many times, this backup

source must be sufficiently sized and available to handle the demand when the renewable source is completely ineffective. The impact of increasing photovoltaic power generation is studied in the master's thesis "The Effect of Adding Solar Photovoltaic Electricity Generators to the Duke Energy Service Area in North Carolina on the Emissions of Fossil Fueled Generators." [4]

1.2.2 Energy Storage Devices

Energy storage methods have been around since there were ways to use energy. A simple example of an energy storage device is a flywheel. In this example, rotational energy is stored when excess power is available from the power source, and the energy is used when more power is required. The flywheel also serves to smooth out power fluctuations in cyclic power sources by absorbing power surges and supplementing deficits. This energy storage device is a necessary component of the 4-stroke internal combustion engine since the piston only provides work every other rotation of the crankshaft. The applications for energy storage devices can be widespread and diverse.

Energy storage device can be mechanical or thermal. This study will focus on the thermal energy storage devices. Some examples of thermal energy storage include chilled water storage, ice storage, molten salt reservoirs, sensible heat storage in a thermal mass, and steam accumulation. These devices are designed to accept energy when excess is available and supply energy when there is a deficit. Chilled water and ice storage focus on storing the ability to absorb heat when "discharging," or depleting the thermal reservoir. The high-temperature devices absorb heat when charging and supply it when discharging. These devices are already

in use throughout different industries when it is desirable to have a constant supply of energy even though demand may be sporadic.

1.3 Literature Review

Steam accumulators and other types of thermal energy storage systems have been studied before, with a strong focus on process related steam systems. These accumulators are smaller than those that could be used in an industrial power generation plant. Some studies look into the effects of non-equilibrium conditions while others choose to ignore them.

1.3.1 Thermal Energy Storage (1984)

Beckmann and Gilli are the authors of *Thermal Energy Storage,* a book published in 1984 about various thermal energy storage techniques and their potential uses. Under the chapter "Power Plants with Thermal Energy Storage," they discuss using thermal storage for nuclear power plants [5]. The authors mention that thermal energy storage is beneficial to use in nuclear power plants for four main reasons: less dependency on fossil fuels, high capital cost warrant for the most economical operation of the plant, low-cost fuel, and inefficient load cycling. Feed water thermal storage and steam storage systems are discussed in the chapter. The steam storage system has advantages over the feed water systems since it can be isolated from the main reactor loop, minimizing the effect on reactor performance.

The energy stored in the steam accumulators can either be fed into the main turbine if it is capable of overload performance or fed to a separate turbine set. The authors state that a separate system has the advantage of not having a power output limit while staying connected to the main system can provide a spinning reserve. Another option for thermal energy storage

is to combine feed water thermal storage with steam storage. This system has the potential to double the output of a standard feed water storage system.

The ideas presented in this chapter of *Thermal Energy Storage* are potential system implementations. No comparisons are made to existing systems or experiments performed. The ideas listed are a good start for investigating what thermal storage system is useful for the power plant in question. Further work needs to be done to quantify how adding thermal storage affects the overall system.

1.3.2 Buffer storage for direct steam generation (2006)

One area where the application of steam accumulators is being explored is in solar thermal power plants. Due to the variability of solar energy, steam accumulators can help maintain a more constant energy supply to the power generation equipment in these plants [6]. Condensing steam is an economical way to store energy due to the phase change energy when converting from vapor to liquid and vice versa.

Energy storage capacity of saturated water ranges from 20 to 30 kWh/m^3. Charging can utilize superheated steam, where the pressure of the tank increases, or saturated water, where pressure is held constant. The authors point out that the overall pressure in the accumulator can affect the steam production rate. As pressure increases, the change in saturation temperature decreases, which reduces the sensible heat change of the liquid. A lower pressure in the accumulator decreases the energy density of the liquid water due to a density increase.

When coupled with direct steam generating solar plants, steam accumulators act as a buffer between steam generated at the solar collectors and consumed by the turbines. When

production exceeds demand, excess steam is stored in the accumulator to be used during a period of intermittent isolation. Solar thermal plants are often operated in recirculation mode where vapor and liquid are expelled from the collectors. This configuration requires a separator to isolate the vapor from the liquid and then send it to the turbine or another set of collectors to be superheated. An advantage of integrating a steam accumulator is that it can serve as storage and the separator for a plant operating in recirculation mode. The charging process for the system described holds the pressure constant in the accumulator. Saturated liquid collects in the tank when the amount added to the vapor/liquid mixture exceeds the amount leaving the tank to supply the collectors. Discharge is achieved by lowering the pressure to flash the saturated liquid.

Rather than operating the accumulator on a sliding pressure range, the authors offer some suggestions on possible constant pressure systems. The first way discussed to achieve constant pressure is to pull saturated water from the accumulator and flash it externally by lowering the pressure. The pressure that is supplied will be lower than the accumulator pressure, but it will be constant throughout the discharging process. The accumulator must be charged with water to maintain a constant level and pressure. The authors warn that the introduction of cold water into the accumulator can cause thermal stresses in the tank. Another constant pressure option discussed uses a phase change material to store more heat in the accumulator than saturated water alone. The heat of fusion in certain materials can provide a heat source for feed water to be reheated so that a sustained pressure of steam can be supplied.

Next, a model was developed to characterize steam accumulator operations. For this model, the heat of vaporization was averaged between the high-pressure value and the low-pressure

value. Thermal equilibrium between the vapor and liquid was also assumed. The model was then compared to values taken from a test solar thermal power plant which utilized an accumulator/separator system mentioned above. The pressure range for testing was 30 to 100 bar, and the peak power output was 2 MW. With a 4 m^3 accumulator tank, the system was able to operate for 5 minutes without solar input.

This focus of this study was to investigate how steam accumulators could be used to supplement a solar thermal power plant during a brief period without insolation. The authors explored various types of steam accumulators that could be used and demonstrated how one type could provide steam for about 5 minutes without sun. No long-term storage methods were discussed to supplement power production for an extended period of time, such as during the night hours. This represents an area that can be explored further.

1.3.3 Dynamics of steam accumulation (2012)

In 2012, Stevanovic et al. investigated the effects of non-equilibrium conditions in steam accumulators used as a buffer between production and process demand. The study aims to address the assumptions of previous studies that model the system in equilibrium. Accumulators operate on a sliding pressure, increasing the pressure to condense steam and reducing the pressure to flash condensate [7]. Accumulators are useful when demand is variable so that production can be levelized. Without accumulators, production equipment must be sized to accommodate the highest steam demand, even if the maximum demand only lasts for a short period of time. This means that the boiler is running partially loaded most of the time and is typically suffering from a reduction in efficiency as a result.

Stevanovic et al. validate their model by comparing it to a steam accumulator used in a coal drying plant. The first model used a desuperheater to charge the accumulator with saturated steam at a constant rate. In this scenario, the pressure fluctuates between a near-constant high and low pressure while the accumulator charges and discharges. A model was also simulated where the accumulator was charged at a constant rate with superheated steam and verified with data from the coal drying plant. This system steadily increased the high and low pressures reached during the cycles. This is attributed to the excess energy in the steam that evaporates condensate when mixed. Charging with superheated steam leads to a reduction of the liquid phase in the accumulator and must be charged with subcooled water to achieve balance.

The investigation found that there are evaporation and condensation relaxation times that strongly influence the operating conditions of the steam accumulator. Accounting for non-equilibrium conditions, the accumulator will need to be charged at a higher pressure than the equilibrium model predicts to accumulate a prescribed amount of steam. Conversely, to discharge a desired amount of steam, the accumulator must be brought to a lower pressure than predicted with the equilibrium model.

The study performed provides good information on when to consider non-equilibrium effects in steam accumulators. The information can be used to more accurately build a model of a proposed system and what to expect in real world conditions. This study does not go in depth about overall system performance due to the addition of a steam accumulator. More work can be done to apply the results of the study to a complete steam system and analyzes the effects of non-equilibrium conditions on the overall cycle.

2 Steam Accumulator Theory

2.1 Hardware and Terminology

The steam accumulator has been used in industrial processes for many years. It acts as a buffer between generation and consumption. Physically, the accumulator is simply an insulated pressure vessel that is capable of storing high pressure, saturated liquid. Figure 6 below shows the basic components of the device. High-pressure charge steam enters the accumulator and is distributed through a header. Charge steam is injected into saturated water that is maintained at a pressure lower than the charge steam pressure. The distribution header increases the surface area of the vapor that is in contact with the liquid to improve the heat transfer rate.

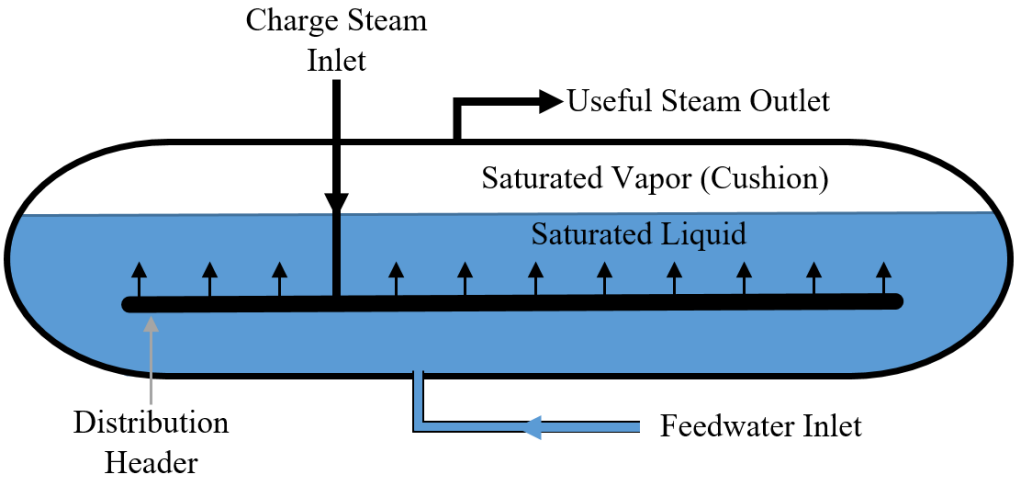

Figure 6 Steam Accumulator Depiction

Depending on the conditions in the accumulator, the volume of vapor changes to fill available space. This saturated vapor layer is called the "cushion." Excess steam that flashes during discharging is vented out of the top and will be sent through a turbine or used for a process.

This is the useful output of the device. High-pressure liquid can be added directly to the accumulator through a feedwater inlet located at the bottom. The amount of feedwater added will depend on the desired liquid level and operating point. Feedwater may need to be added or removed from the accumulator to maintain a desired liquid level. The condition of the charging steam and heat loss from the system will determine how much feedwater is required. Superheated steam contains more energy than the heat of vaporization and has the effect of evaporating liquid water in the accumulator when it is used to charge. Conversely, losing heat through the shell of the accumulator has the opposite effect. Heat loss will condense more of the vapor into liquid and will increase the liquid level in the tank. Heat loss should be minimized since it represents a source of energy loss in the system.

2.2 Thermodynamics

Analysis of the operation of a steam accumulator, like many other engineering problems, starts with an energy balance. A vessel that contains a mixture of saturated liquid water and vapor contains internal energy that depends on the percentage of each phase and the internal pressure. Equation 1 [8] is the evaluation of $E_A(t)$, the energy in the accumulator at time, t, which was described by D. A. Shnaider et al. in "Modeling the Dynamic Mode of Steam Accumulator."

$$E_A(t) = \int_0^t \left(Q_1(t) - Q_2(t) - Q_{loss}(t) + Q_s(t)\right)dt \tag{1}$$

The energy is the integration of the heat added to the vessel, $Q_1(t)$, the heat removed, $Q_2(t)$, the heat lost to the environment, $Q_{loss}(t)$, and the heat associated with the feedwater adjustment, $Q_s(t)$. The integration of all these terms with respect to time results in total energy in the closed

system. In this analysis, $Q_{loss}(t)$ will be neglected to assess the performance of the system without external losses. Actions would be taken during implementation to minimize these losses.

Shnaider et al. also defined the heat terms listed in Equation 1 as the product of the respective mass flow rates and their associated enthalpies. In general terms, this is defined as:

$$Q(t) = \dot{m}(t)h(t) \tag{2}$$

Where $\dot{m}(t)$ is the mass flow rate and h(t) is the specific enthalpy at time t. The mass flow and enthalpy are constantly changing in the accumulator as the pressure fluctuates during operation.

At any given time, the energy in the tank can be described by the specific internal energies of each phase, u_f and u_g, and the mass of each phase, m_f and m_g. Equation 3 describes this relation.

$$E = u_f m_f + u_g m_g \tag{3}$$

Another important parameter to consider is the volume balance in the accumulator. Since the volume of the accumulator is fixed and known, the mass of each phase can be found for any given mixture percentage. Equation 4 shows this relationship. Uppercase "V" indicates volume while lowercase "v" indicates specific volume.

$$\mathrm{V_{total}} = \mathrm{V_{liquid}} + \mathrm{V_{vapor}} = v_f m_f + v_g m_g \tag{4}$$

2.2.1 Discharging Thermodynamic Analysis

When the accumulator is discharging, the saturated liquid is flashed to steam with the excess internal energy that results from lowering the pressure. At equilibrium, the liquid in the vessel is saturated, and its internal energy is determined by the pressure. When the pressure is reduced, the energy storage capacity of the liquid is reduced resulting in a conversion from liquid to vapor. At the same time, the energy storage capacity of the saturated vapor is also reduced. This causes the saturated vapor to become slightly superheated as the pressure falls. The accumulator contains a saturated mixture of vapor and liquid, meaning that superheated vapor cannot exist at equilibrium in the vessel. This excess energy will also convert some of the liquid to vapor.

Water vapor has a much higher specific volume than liquid water and this property changes with pressure whereas the specific volume of liquid water remains approximately constant. For this system, that means the mass of vapor is dependent on the available space and the specific volume of the vapor at a given pressure. The complicated interaction between the two phases at varying pressures means that an analytical relationship is difficult to develop. Iterative methods can be used to determine final conditions based on initial conditions and desired steam output or pressure drop. Considering the entire system, discharging the accumulator results in steam flow at a certain pressure and specific enthalpy, or the internal energy plus flow work. This enthalpy will be what provides work out of the turbine and will determine the energy leaving the accumulator.

For sufficiently small changes in time, the energy contained within the accumulator at the end of discharging, E_{2D}, will be the initial energy before the pressure is reduced, E_{1D}, minus the energy that left the accumulator. Equation 5 shows this relationship.

$$E_{2D} = E_{1D} - h_{out}(m_{out}) \tag{5}$$

The term h_{out} represents the specific enthalpy of the steam leaving the accumulator and m_{out} is the mass of steam exhausted to maintain the lower pressure of the final state.

The specific enthalpy leaving the accumulator is constantly changing with pressure. Small incremental pressure changes and the average specific enthalpies across the two pressures will be used for h_{out}. A mass balance will be used to ensure conservation of mass is maintained in the system.

$$m_{f2} + m_{g2} = m_{f1} + m_{g1} - m_{out} \tag{6}$$

The mass balance can be combined with the energy balance to get two equations and three unknowns. Rearranging the combination results in the following equation that solves for the mass of the liquid at the end of discharging.

$$m_{f2} = \frac{E_1 + u_2\left(m_{out} - m_{f1} - m_{g1}\right) - m_{out}h_{out}}{u_{f2} - u_{g2}} \tag{7}$$

The mass found in Equation 7 is dependent on the pressure at state 2, which is the third unknown. An iterative solving method can be used to find the mass required by an energy

balance and compare it to the mass that will "fit" in the tank based on the volume balance. The simultaneous solving of these two equations will determine the pressure at state 2 for a given mass that is withdrawn from the accumulator.

2.2.2 Charging Thermodynamic Analysis

Charging the accumulator involves injecting steam that is either saturated or superheated into the liquid already in the tank at a pressure higher than the fully charged pressure. High surface area contact between the charging steam and the liquid is desired to minimize response time. The vapor condenses in the liquid, adding energy and raising the pressure. If the charging steam is superheated, then the excess energy above saturated vapor contained in the steam is used to evaporate liquid within the accumulator. When charging with superheated steam, feedwater must be used to bring the energy of the charging steam down. Otherwise, the accumulator will not reach the same liquid level for a given pressure after charging. The energy associated with charging the accumulator can be described by Equation 8. The subscript "C" denotes charging, and the summation is used to account for inlet steam and feedwater if needed.

$$E_{2C} = E_{1C} + \sum h_{in}(m_{in}) \tag{8}$$

Charging occurs when steam with a known pressure and enthalpy is added to the vessel. The pressure of the charging steam must be higher that the pressure in the accumulator to establish flow. With the enthalpy known, a fixed amount of mass can be added to the tank to calculate the pressure rise. To simplify the analysis, the equations will be shown using saturated steam,

but superheated steam can also be used to with the correct amount of feedwater to lower the enthalpy.

Adding mass at a known specific enthalpy adds a fixed quantity of energy to the system. The new energy after charging will be the sum of the initial energy and the added energy. Then, the proportions of liquid and vapor must be found. Equation 1 can be used to relate these masses to the energy within the tank. The u_f and u_g terms are dependent on pressure which is not known, leaving the two mass terms unknown. This results in one equation with two unknowns.

The second equation that can be used to describe the system in the volume balance shown in Equation 4. Since the volume of the accumulator is fixed, the mass can be described by the amount of space it occupies at a given pressure. After mass is added to the tank, a mass balance can be used to determine the sum of the liquid and vapor masses. Equation 9 shows this balance.

$$m_{f2} + m_{g2} = m_{f1} + m_{g1} + m_{in} \tag{9}$$

Combining Equations 1 and 9 results in an equation that describes the mass of liquid in the tank as a function of pressure, mass added, and energy added.

$$m_{f2} = \frac{E_2 - u_{g2}(m_{in} + m_{f1} + m_{g1})}{u_{f2} - u_{g2}} \tag{10}$$

All the specific properties in Equation 10 are dependent on the final pressure after charging. Equation 10 can be expressed in terms of m_{g2} if desired, but with the mass of the liquid known, the mass of the vapor can alternatively be found by solving for m_{g2} using Equation 9 as shown below.

$$m_{g2} = m_{f1} + m_{g1} + m_{in} - m_{f2} \tag{11}$$

Next, the volume must be checked. Since the equations shown up until this point are only dependent on energy, they can differ based on the specific properties of the steam at the final pressure. Different pressures will result in different mass calculations; therefore, an additional constraint is needed. The volume of the accumulator is constant and is the final constraint needed. Substituting the mass terms calculated and the appropriate specific volume terms for the final pressure into Equation 4 results in the calculated volume. Iterative solvers can be used to find the required final pressure for a given amount of steam added.

3 Small Modular Reactors

3.1 Introduction

Small Modular Reactors (SMRs) are small-scale nuclear reactors that are optimized for safety, ease of installation, and flexibility. When denoting power plant sizes, typically two numbers are used: electrical output (MWe) or thermal output of the fuel source (MWth). A typical base load nuclear power plant has a generation capacity over 1,000 MWe while SMRs are generally under 300 MWe. [9] The design is preassembled in modular sections that can be trucked to a site and assembled. Since the design is the same for each reactor, the approval process is expedited. One SMR that is close to becoming commercialized is the NuScale reactor. This reactor is advertised to be constructed in individual, 45 MWe units. Larger power plants can couple multiple units together to appropriately match capacity to demand or add modules if demand rises in the future.

SMRs are gaining popularity because of their small size and flexible operation. Generating electricity from a heat source is nothing new, but this process is not very efficient in terms of heat input vs. electrical energy output. Nuclear fuel is cheap and very energy dense, so in the past, the heat lost in conversion was minimized only by optimizing the heat engine that converted the heat into work. Research is now being conducted on how to use the heat more effectively by looking at the whole energy consuming system. This means that not only are researchers looking into the efficiency of the thermodynamic cycle, but they are also looking into what happens to the energy that leaves the plant. SMRs are a unique power source that can likely be combined with energy storage devices, renewables, and integrated into combined heat and power systems.

3.2 Economics of Operation

The method typically used to compare the cost of electricity from differing power sources is the Levelized Cost of Electricity (LCOE). The EIA defines the LCOE as "the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." [10] Many of the factors in this equation for nuclear power plants are fixed costs, factored in to compare across the energy sources. Nuclear power can be generated with very low fuel costs, but the capital cost is high. The LCOE factors the capital cost into the cost to produce electricity over the lifetime of the plant. This method is good to compare energy sources over the lifetime of the facilities required to use them, but not good for estimating the variable cost associated with producing one more kilowatt hour. For this, the LCOE can be deconstructed to pull out only the variable costs associated with the power production of the plant.

Table 1 Cost of UO_2 Fuel per kg as of July 2015 [11]

Uranium:	8.9 kg U_3O_8 x $97	US$ 862	46%
Conversion:	7.5 kg U x $16	US$ 120	6%
Enrichment:	7.3 SWU x $82	US$ 599	32%
Fuel fabrication:	per kg (approx)	US$ 300	16%
Total, approx:		US$ 1880	

Table 1 shows the approximate cost of the nuclear fuel as of July 2015. Upon first glance, this price appears high, but when considering the amount of energy that can be produced from a single kg of fuel, the cost becomes reasonable. The World Nuclear Association provided the data in Table 1 and also estimated the electrical energy production per kg of the fuel at 360,000 kWh/kg. [11] The cost to produce one kWh of energy with respect to the fuel cost becomes

$0.0052/kWh. Considering that consumer prices are can be an order of magnitude higher, nuclear fuel represents a low-cost, carbon-free source of energy. According to the EIA website, the average electrical energy end-user cost in the entire United States was found to be $0.1041/kWh for the year 2015. [12] The nuclear fuel cost represents about 5% of the consumer cost if this was energy was supplied using nuclear power. The reason the consumer cost remains high for nuclear power is due to the high fixed cost to install and operate the plant. This factors into the end-user price so that the plant can be profitable over its lifetime, which means the plant has the highest rate of return when it is producing maximum energy output.

Fuel is not the only variable cost of operating a power plant. Operation and Maintenance (O&M) factor into the variable cost of the plant as well. This covers equipment repair or replacement and any other variable costs associated with operating the plant. In an ideal scenario, one would expect the O&M costs to scale with plant load. More load would logically translate to more equipment failure and higher operating costs. For a nuclear plant, this may not be the case. Maintenance intervals are usually scheduled every 18 to 24 months for refueling and inspection. [13] Many times the refueling outages are scheduled for the Spring or Fall when electrical demand is low. Timing and seasonal demand will likely determine the refueling schedule for nuclear power plants rather than fuel consumption rate or equipment load. To be conservative, this research will assume the variable cost associated with fuel and O&M can be reduced if the plant is operating at reduced load, even though this may not be the case in reality.

The fuel cost for a nuclear power plant is not as variable as some of the other fossil fuels used for power generation. An article posted by the Atomic Insights estimated the fuel cost to be

$0.0049/kWh and the non-fuel O&M cost to be $0.0137/kWh back in 2008. [13] Comparing to the fuel cost estimation for 2015 shown above, the difference is only two-hundredths of a cent over 7 years. The variable costs found by the Atomic Institute, totaling $0.0186/kWh, will be used to estimate the cost reduction when operating at a reduced load.

On the revenue side, power is billed to the customer based on different factors such as peak demand, time of use, energy consumption, customer type, etc. Residential customers do not pay the same electricity rates as commercial or industrial customers. The U.S. Energy Information Administration has compiled data on the average price of electricity to all ultimate end-use customer for each state in the United States. Table 2 shows this compiled data for the states of concern to this study.

Table 2 Average Monthly Cost of Electricity to the End-User [14]

Month	NC ($/kWh)	SC ($/kWh)
Dec-16	$0.0914	$0.0932
Nov-16	$0.0889	$0.0917
Oct-16	$0.0936	$0.0925
Sep-16	$0.0954	$0.1007
Aug-16	$0.0963	$0.1019
Jul-16	$0.0965	$0.1030
Jun-16	$0.0931	$0.1013
May-16	$0.0904	$0.0919
Apr-16	$0.0903	$0.0910
Mar-16	$0.0916	$0.0932
Feb-16	$0.0916	$0.0938
Jan-16	$0.0912	$0.0941

Averaging the data in Table 2 yields the average power cost to the consumer for the year 2016. This was found to be $0.0941/kWh, which will be used to estimate the revenue brought in by the power generated from the system.

3.3 Rankine Cycle

The power generation side of the SMR plant being investigated operates using a standard Rankine cycle with feedwater heaters. Many large-scale power generation systems use the Rankine cycle to convert heat into mechanical work, then ultimately, electricity. The cycle has four main components: the steam generator, the turbine, the condenser system, and the feedwater system. Typically, about one-third of the heat added to the Rankine cycle is converted to mechanical work; the rest is rejected to the environment through the condenser.

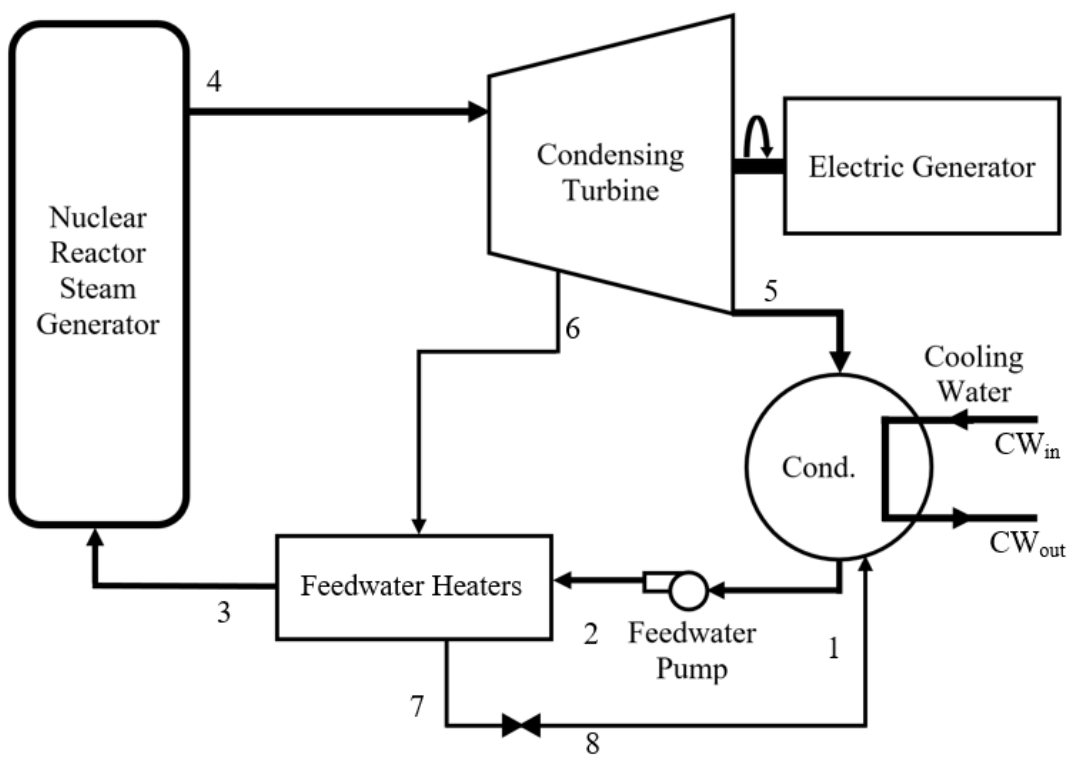

Figure 7 Simplified Rankine Cycle Depiction

Starting at the top right-hand side of Figure 7, steam leaves the steam generator at a high pressure and temperature. Some cycles are designed to use superheated steam, which is steam that is sensibly heated beyond the vaporization temperature. The NuScale reactor uses helix steam generator coils that boil the water in the bottom and superheat it all within the same heat exchanger. Superheated steam is often desired to prevent damage to the blades in the turbine. Water droplets can impact the turbine blades with sufficiently high speed to cause damage to the metal blades over time.

The steam then enters a steam turbine where it expands and does work on turbine blades attached to an output shaft. The output shaft is connected to a generator where rotational work is converted to electricity. Since no piece of machinery is perfect, every turbine has an associated efficiency. The isentropic efficiency of a turbine is defined as the actual work out divided by the maximum possible work that could have been realized, dictated by the thermodynamics. The output shaft and generator also have an efficiency associated with them, but in big systems, these efficiency losses are not usually more than a percent or two and are typically neglected.

The condenser is where the steam travels next. The condenser is maintained at a very low pressure (generally well below atmospheric pressure) so that the turbine can extract as much work as possible. Once the steam enters the condenser, it is cooled to condense the vapor back into low-pressure liquid. Many times, the condensers for nuclear reactors are sized to completely handle the thermal output of the plant in case of an emergency. Steam can also

bypass the turbine and go directly to the condenser if the generator is producing more power than can be consumed.

The feedwater pump then brings the pressure of the liquid water in the condenser up to the pressure in the steam generator. This high-pressure liquid is then sent to the steam generator to be vaporized and start the cycle all over again. Multiple feedwater pumps may be needed to prevent cavitation, but the effect is the same. From an energy perspective, it is much more efficient to raise the pressure of a liquid rather than trying to increase the pressure of a gas. This is one of the advantages of using water as the working fluid in a Rankine cycle.

Many different devices can be added to make the cycle more efficient but must be balanced with installation costs. Feedwater heaters are commonly added to make the overall cycle more efficient and simply take steam off of the turbine at some intermediate pressure and use it to heat up the feedwater before it enters the steam generator. A trap is used to ensure the steam entering the feedwater heater is condensed before it exits the heat exchanger. For nuclear power systems, feedwater heaters and other heat recovery devices are used to increase output and maintain specific reactor conditions. The condition of the feedwater entering the steam generator may affect the operation of the reactor.

3.4 System Characteristics

System characteristics are based on publicly available information on the NuScale SMR system. Each NuScale module consists of a 45 MWe generator set that is coupled to the 160 MWth fission powered steam generator. The steam side uses a single stage 45 MW condensing turbine that receives nominal full-load steam at 500 psia, 575°F, and at a rate of 536,200 lb/hr. The condenser operates at 0.75 psia, and the feedwater is heated to 300°F before entering the

steam generator. [15] Performance characteristics of the turbine or feedwater train were not available but were calculated using some assumptions.

3.4.1 Full Load Operation

First, full load operating parameters were used to determine the unknown full load characteristic. Since the steam generator is rated at 160 MW thermal output, a quick check can be performed to judge the accuracy of the numbers found. Using a mass flow rate, $\dot{m}$, of 536,200 lb/hr and the given enthalpies of the inlet and outlet conditions, heat input can be calculated. The inlet enthalpy, h_3, was found to be 271 Btu/lb for 300°F water at 500 psia. Leaving the steam generator, the steam was described as superheated at 500 psia and 575°F. The saturation temperature of water at 500 psia is 467°F, which confirms that the steam is superheated. The enthalpy of this steam, h_4, was found to be 1,283 Btu/lb. Heat input, Q_{in}, can be described by Equation 12 below.

$$Q_{in} = \dot{m}(h_4 - h_3)(Unit\ Converion) \tag{12}$$

$$Q_{in} = \left(536{,}200\,\frac{\text{lb}}{\text{hr}}\right)\left(1{,}283\,\frac{Btu}{lb} - 271\,\frac{Btu}{lb}\right)\left(\frac{1\ MW}{3.413x10^6\,\frac{Btu}{hr}}\right)$$

$$Q_{in} = 159.0\ MW$$

The resulting heat input calculated from known parameters is 159 MW which is less than 1% difference from the proclaimed heat rate of 160 MW, therefore the mass flow rate, inlet and outlet conditions seem reasonable. From here, the other parameters of the cycle can be calculated.

One main parameter of interest that was unavailable is the isentropic efficiency of the turbine. For steam turbines, this efficiency is a measure of how much work was extracted from the steam compared to the available work. In a perfect turbine, the steam expands isentropically from the inlet to the exit of the turbine. This means that the outlet conditions can be found based on the outlet entropy, which is the same as the inlet entropy, and the pressure. Since the turbine exhausts into the condenser, the outlet pressure is also known. Therefore, with a pressure of 0.75 psia and a specific entropy of 1.544 Btu/lb-°F the isentropic specific enthalpy of the turbine exhaust will be 849 Btu/lb, based on saturated water properties. The output of the turbine is 45 MW and can be used to find what the actual efficiency of the turbine will be. If the system did not have a feedwater heater, this would be the next step, but since steam is extracted from the turbine, this must be accounted for.

The feedwater heater takes the steam out of the turbine at some intermediated pressure that is unknown. The feedwater enters the steam generator at 300°F which dictates the minimum steam pressure used in the feedwater heater. The saturation pressure of water at 300°F is about 67 psia. This represents the lower limit of the pressure range required for the feedwater heater. The pressure required will be determined by the heat exchanger geometry, which is also unavailable. Various steady-state analyses of the cycle revealed that increasing the tap pressure consumed more steam for a given work output. To be conservative, a tap pressure of 67 psia was chosen to move forward. Steam consumption found using an energy balance on the feedwater heater. The trap ensures that only condensate leaves with a specific enthalpy of 270 Btu/lb. Steam enters the feedwater heater at 67 psia with an enthalpy determined by the conditions in the turbine.

The condition of the feedwater entering and exiting the feedwater heater is known. Therefore the amount of energy required by the heater can be calculated. Using Equation 12, the heat transferred to into the feedwater heater can be calculated and compared to the energy available in condensing the steam from the turbine tap. The specific enthalpy of the feedwater entering the heater, h_2, will be that of saturated liquid water at the condenser pressure plus the pump work required to raise the pressure. Equation 13 describes the energy added by the pump. Since the water is in liquid form, the specific volume, v, is assumed to be approximately constant.

$$w_{in} = v(P_2 - P_1)(Unit\ Conversion) = h_2 - h_1 \tag{13}$$

$$h_2 = v(P_2 - P_1)(Unit\ Conversion) + h_1$$

$$h_2 = 0.0161\frac{ft^3}{lb}\left(500\ \frac{lb}{in^2} - 0.75\frac{lb}{in^2}\right)\left(144\frac{in^2}{ft^2}\right)\left(\frac{1\ Btu}{778.17\ ft * lb}\right) + 60\frac{Btu}{lb}$$

$$h_2 = 62\frac{Btu}{lb}$$

Going back to Equation 12, the heat added by the feedwater heater will be 111.9×10^6 Btu/hr. By assuming the feedwater drain is trapped back into the condenser, the mass of steam required by the feedwater heater can be found. The amount of heat picked up by the feedwater must be the same amount of heat lost by the steam when it condenses. Since the isentropic efficiency of the turbine depends on the mass flow and the feedwater heater steam consumption depends on isentropic efficiency, an iterative solver was used to find the unknown turbine efficiency.

The isentropic efficiency determines the enthalpy of the steam leaving the tap. Based on the calculated efficiency, which will be shown later in the report, the enthalpy of steam leaving the turbine tap was found to be 1,150 Btu/lb. Rearranging Equation 12 allows for the mass flow

rate of steam to be found, therefore, feedwater heater steam consumption can be determined and is shown below.

$$\dot{m}_{FWH} = \frac{Q_{in}}{h_6 - h_7}$$

$$\dot{m}_{FWH} = \frac{111.9x10^6 \frac{Btu}{hr}}{1{,}150 \frac{Btu}{lb} - 270 \frac{Btu}{lb}}$$

$$\dot{m}_{FWH} = 127.2x10^3 \frac{lbs}{hr}$$

With this information, the total mass flow through all turbine parts is known. All of the mass flow will go through the turbine up until the extraction steam; then some steam will be bled off and go a different path, not providing any useful work. Now, the isentropic efficiency of the turbine can be found. Isentropic efficiency of a turbine is defined by:

$$\eta_{turb} = \frac{Actual\ Work\ Out}{Isentropic\ Work} = \frac{\dot{m}(h_{in} - h_{out-a})}{\dot{m}(h_{in} - h_{out-s})} \tag{14}$$

The isentropic efficiency of the turbine can now be calculated by comparing the rated output to the theoretical maximum, or isentropic work output. Actual enthalpy is denoted by the subscript “a” while isentropic enthalpy is denoted by the subscript “s.” The mass that leaves the turbine through the tap must be accounted for since it does not go through the lower stages of the turbine. Using Equation 14, the isentropic efficiency of the turbine was found.

$$\eta_{turb} = \frac{(45\ MW)\left(\frac{3.413x10^6\frac{Btu}{hr}}{1\ MW}\right) + Pump\ Work}{\dot{m}_{total}(h_4 - h_{6s}) + (\dot{m}_{total} - \dot{m}_{tap})(h_{6s} - h_{5s})}$$

$$\eta_{turb} = \frac{(45\ MW)\left(\frac{3.413x10^6\frac{Btu}{hr}}{1\ MW}\right) + 536{,}200\frac{lb}{hr}\left(61.8\frac{Btu}{lb} - 60.3\frac{Btu}{lb}\right)}{536{,}200\frac{lb}{hr}\left(1{,}283\frac{Btu}{lb} - 1{,}111\frac{Btu}{lb}\right) + \left(536{,}200\frac{lb}{hr} - 127{,}202\frac{lb}{hr}\right)\left(1{,}111\frac{Btu}{lb} - 849\frac{Btu}{lb}\right)}$$

$$\eta_{turb} = 77.4\%$$

Now, all the necessary characteristics of the steam cycle are known to assess the performance across varying loads.

All full-load system properties have been found with this information and are displayed in Table 3 below.

Table 3 Full-Load Rankine Cycle Properties

State	Pressure (psia)	Enthalpy (Btu/lb)	Temperature (°F)
1	0.75	60	92
2	500	62	99
3	500	271	300
4	500	1,283	575
5	0.75	947	92
6	67	1,150	300
7	67	270	300
8	0.75	270	92

3.5 Integration of Steam Accumulator

Adding a steam accumulator to the Rankine cycle changes the way the system operates under part load. In a power generation plant without storage, electrical energy is produced only when demanded by the grid. In large scale grids that are served by many power plants, the operators

can distribute the load efficiently by choosing which plants are operating and in what manner. When the demand is much larger than any individual power generation plant, the control scheme can take advantage of base-loading some stations while modulating others. This control technique ensures that the plants which are more efficient at part load are being used to trim while larger units that are not as efficient under partial load or cannot react quickly are run fully loaded to handle the base load. Figure 8 shows how the demand can be divided.

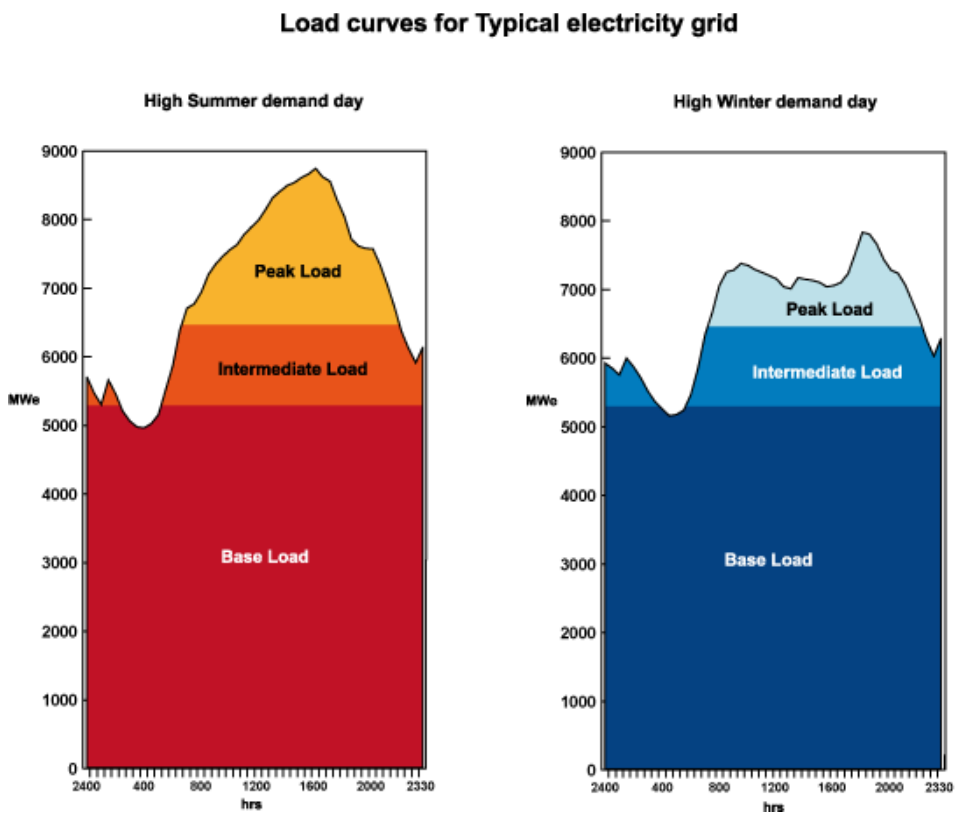

Figure 8 Electrical Demand Classification [16]

Using multiple units to handle a large load is fairly well understood and is common practice to improve energy efficiency in industrial equipment such as air compressors and chillers. The problem arises when the demand is small, only requiring one piece of supply equipment. In

the case of power generation, this would be the case if a small power plant was serving an isolated grid or individual site. In this situation, the power plant must regulate its output to match the demand of the grid it is serving. Without energy storage, any power that is required by the customers must be exactly supplied. Excess power has nowhere to go and would cause problems on the grid such as voltage and frequency fluctuations. The plant electrical output must rise and fall to meet the ever-changing demand. Depending on the type of power plant, large portions of thermal energy from the fuel source may be wasted in order to meet the required demand. The addition of a steam accumulator aims to store some of the excess energy available when the power plant is operating at part load and use it at a later time when demand exceeds maximum supply capacity. Demand data from Chapter 1 was scaled down so that one power plant with a peak output of 45 MWe would be able to meet the peak demand. All three seasons considered are shown below in Figure 9.

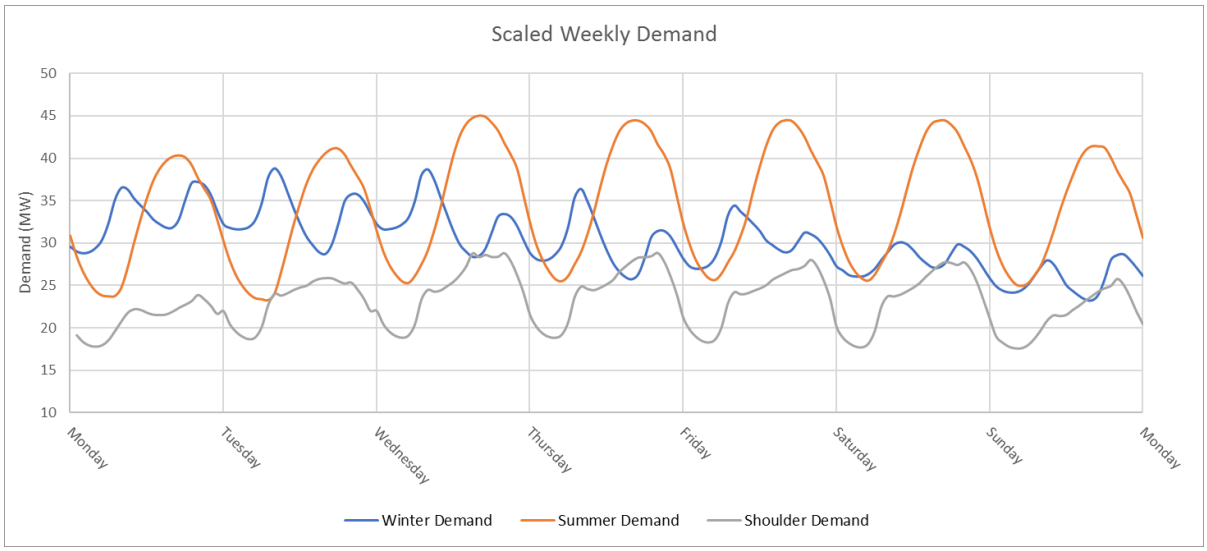

Figure 9 Scaled Weekly Demand for Summer, Winter, and the Shoulder Season

A steam accumulator can be used to store steam when there is excess energy available from the reactor and supply steam to a turbine when excess electrical capacity is needed. The following figure depicts how the steam accumulator would be integrated with the existing steam system. The accumulator receives steam from the main steam header leaving the steam generator through a valve. Any steam that is not needed by the accumulator is bypassed into the condenser. The accumulator also is connected to a feedwater line that would be used to adjust the conditions in the tank. Steam comes out of the accumulator after flashing from liquid to vapor and is then sent through a peaking turbine, which is smaller than the main plant turbine. The steam that passes through the turbine is exhausted into the main condenser where it re-enters the main loop. There would also have to be a condensate receiver (not shown) to accumulate any excess condensate at times when the main steam loop cannot accept any additional mass.

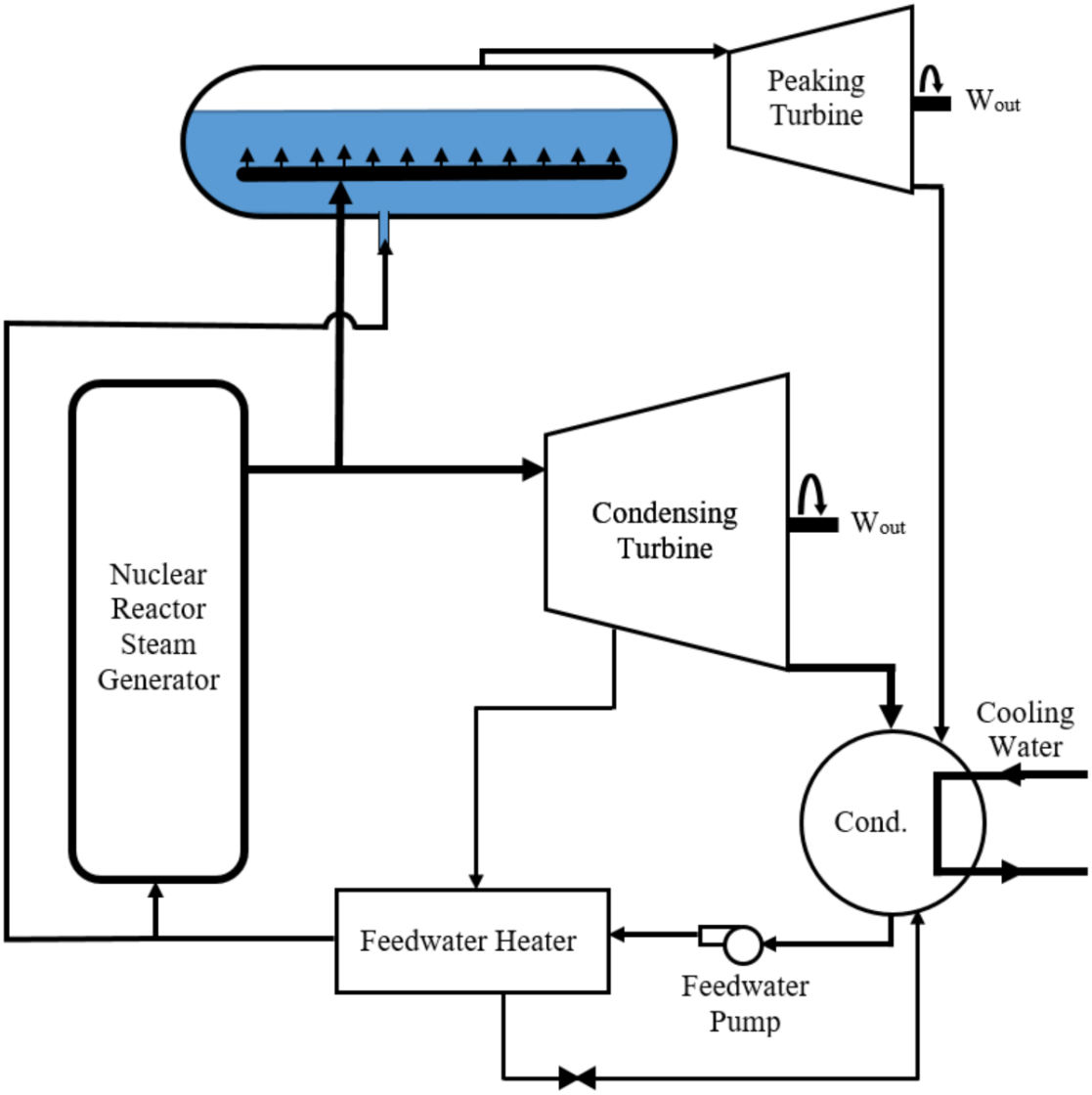

Figure 10 Rankine Cycle with Steam Accumulator and Peaking Turbine

In a standard Rankine cycle without a steam accumulator, mass flow rate of steam decreases with a reduction in power output. As the supply steam flow decreases, the condensate and feedwater flow rates also decrease. In devices like feedwater heaters, the decrease in supply steam flow means a reduction in heat that it can provide, but the feedwater flow is also reduced,

requiring less heat. This means that the device is able to maintain the feedwater conditions close to the full load operating points. With the addition of a steam accumulator, the steam flow out of the steam generator will be higher than that entering the turbine. The mass flow rates of steam through the turbine will be reduced while the steam generator will still be operating at close to full capacity. This means that feedwater flow is high and the steam available for heating the feedwater is reduced.

Assuming the feedwater heaters are appropriately designed to handle the new conditions, feedwater will leave the heaters with less enthalpy when compared to the full load operating conditions. Since the heat added in the steam generator is more or less fixed, the effect of supplying colder feedwater is reduced superheat in the steam leaving the steam generator. Caution must be used to prevent the enthalpy of the steam leaving the generator from dropping too far into the saturated mixture region. As the quality of the steam entering the turbine drops, the blade erosion increases leading to maintenance outages. This constraint limits how low the output of the system can go while bleeding steam into the accumulator. A further reduction in power output will require a reduction in feedwater flow or some other control technique to prevent turbine damage.

3.5.1 Partial Load Operation with Full Feedwater Flow

As the load changes on a steam turbine, the steam flow must be throttled to prevent a change in operating speed. If electrical demand on the generator drops, then the steam flow must be adjusted accordingly to maintain steady operation. The relationship between steam consumption and power output for a throttle governed turbine is linear, described by the Willans Line. [17] One point on the Willans line is the full load steam consumption and its

associated power output while the second point is the steam consumption required to keep the turbine spinning at the rated speed, producing no useful output. This relationship applies directly when the turbine does not have any extraction points, and all the steam flow must go through the turbine. The steam cycle, in this case, has at least one tap that pulls a portion of steam off for the feedwater heater. This steam must be considered when the turbine is operated at part load.

Another characteristic of steam turbines that is of interest for this research is the steam pressure in the turbine. The pressure of the steam extracted for the feedwater directly related to its saturation temperature. A falling steam temperature will negatively affect the feedwater heater performance and thus the overall cycle efficiency. The result is that as the load is reduced, the cycle efficiency goes down, meaning that the steam consumption per MW of electricity produced goes up. The next step is to determine how much steam is required for a given load reduction.

The Willans line estimates the performance of a turbine that has no extraction points. For this application, it is known that the turbine has at least one extraction line. The Willans line was calculated for the full steam through the turbine up until the extraction point; then a separate Willans line calculation was performed on the remaining steam that passes through the turbine after the extraction point. This allowed the full turbine efficiency to be calculated as well as the effects on the feedwater heater.

The feedwater heater performance will drop as the main turbine load goes down. This is because the extraction pressure drops with turbine load, resulting in a lower condensation temperature in the heat exchanger. The flow rate through the feedwater heater remains

unchanged since the steam generator is producing full output at all times. This leads to a drop in feedwater temperature and subsequently a drop in superheat temperature of the steam leaving the reactor. Falling superheat temperature, and the associated enthalpy will lead to higher steam consumption for a given work output, meaning the main turbine will need more steam than a simple linear reduction on steam flow rate would have predicted. All these considerations were modeled in Excel, and the steam consumption at varying power outputs was plotted. Figure 11 shows this relationship and the associated 2nd order equation that will be used for the computer simulations.

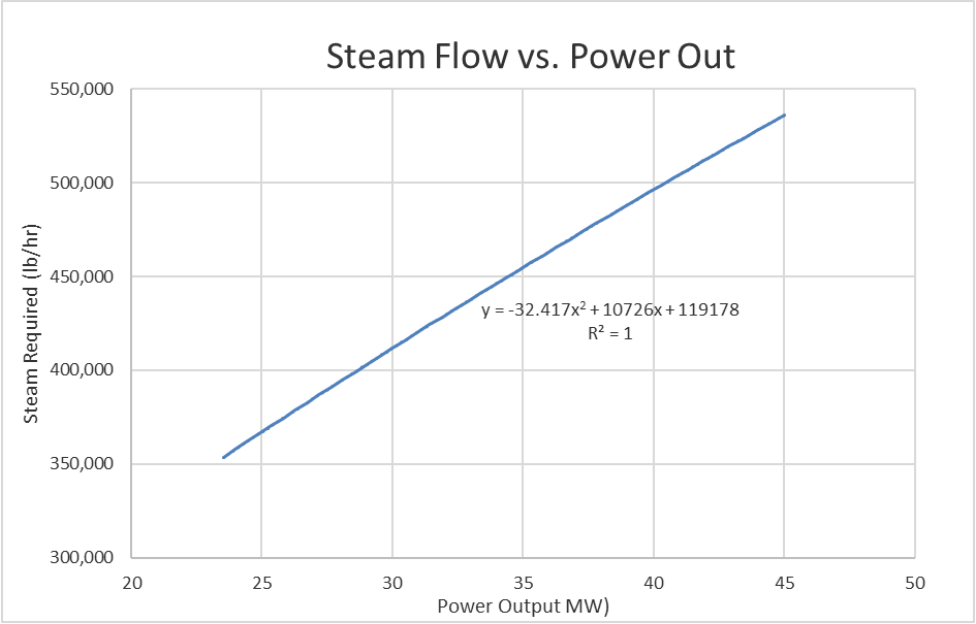

Figure 11 Steam Flow Required by the Main Turbine for a Given Power Requirement

The simulations will also need to know how enthalpy leaving the steam generator changes with respect to load on the main turbine. This was also found in the Excel load reduction model

used to find steam flow. This relation was found to be linear due to the linear reduction in feedwater performance. The relationship is shown in the following equation.

$$h\left(\frac{Btu}{lb}\right) = 3.5803\big(Power\ Req'd(MW)\big) + 1122.1 \tag{15}$$

The trendlines found above are only valid for loads between 100% and 50% because a further load reduction will result in a quality of less than 1.0 leaving the steam generator. A saturated mixture entering the high-pressure turbine can lead to blade erosion or other issues in the nuclear steam generator.

3.5.2 Accumulator Usage

Steam stored in the accumulator can be used in two main ways: process and space heating or additional power generation. If the power plant is located near a site that requires heating, then the accumulator can store energy when there is excess electrical capacity and expel steam to the process constantly or intermittently depending on the heating requirements. This method would involve installing a piping network to get the energy from the power plant to the site that needs heat.

Alternatively, the steam in the accumulator can be expanded through a turbine and used to generator more power, effectively increasing the generation capacity of the plant. Power plants designed with accumulators may use oversized turbines and generators that would be able to handle higher steam flow than the steam generator can supply. During times of high demand, the accumulator can supply steam to boost the turbine output for a certain amount of time. Retrofitting an accumulator to a working power plant design may also be a possibility with the

addition of a separate peaking turbine. This additional turbine could be used to supply extra electricity rather than overdriving an existing turbine. This system configuration was chosen for analysis since it can be added to existing power generation systems.

The peaking turbine will likely be smaller than the main turbine and exhaust into the same, or a similar condenser. The efficiency of this turbine will be less than that of the main turbine. This represents one of the main efficiency losses of the energy storage system. One analysis of energy storage system was performed by Andrei Ter-Gazarian in his book called "Energy Storage for Power Systems." [18] He mentions that the overall efficiency of variable pressure thermal storage system is around 70% to 80% due mainly to pipe friction during charging and the difference in efficiency between the main turbine and the peaking turbine.

3.6 Operating Points of Steam Accumulator

The steam accumulator can operate across a wide band or pressures and liquid levels. These inputs need to be researched and optimized to get the most efficient operation for the application. To fully understand how to optimize a system, one needs to have a goal in mind to work toward. The goal or purpose of installing a steam accumulator is to store excess energy and be able to recover it at a later time. This goal will determine how the accumulator should be operated.

3.6.1 Steam Input

The steam generator in the application is fixed and the pressure maintained in the steam generator is held constant by the turbine control valve. The accumulator will be charged with this steam, which has a fixed pressure and maximum temperature. Therefore, the maximum pressure of the device is specified. Factoring in potential losses, the maximum pressure used

for this system will be 450 psia, which would be connected to the 500 psia steam line coming from the steam generator. Now that the upper bound is known, the next step is to determine what the accumulator pressure should be to get the most work out of it.

Since the turbine exhaust will be at the condenser pressure, steam inlet conditions will determine the work output. The steam coming from the accumulator will be saturated at the pressure of the accumulator. Then, this steam may or may not be throttled depending on the power requirements of the peaking turbine. The higher steam pressure that has a higher specific enthalpy going into the turbine will logically result in more work output. This is deduced from Equation 13, which says the specific work is simply the difference in enthalpy. Therefore, it is reasonable to conclude that higher enthalpy input over the operating time of the turbine will result in more work being generated. This means that the accumulator should be operated at the maximum pressure to recover the maximum amount of work.

3.6.2 Minimum Operating Pressure

The theoretical minimum pressure that could be achieved in the accumulator is the pressure of the condenser. The pressure difference between the accumulator and the condenser will continue to draw out steam until a valve is closed or the pressure difference is equalized. As the pressure in the accumulator approaches the pressure in the condenser, the mass flow will be reduced due to the lack of a pressure difference to push the steam. The power output from a turbine at such low flow rates would likely not be enough to maintain operating speed with no load. Therefore, there should be some low-pressure cutoff after which the accumulator will be considered fully discharged.

When coupled to a steam turbine, the minimum pressure will need to take into account the operating parameters of the turbine and its required steam supply. Since steam turbines generally have a minimum load, this requirement will determine the minimum steam pressure. It is assumed that the steam turbine should not operate below 25% load based on literature. [19] This means that there will be a minimum flow rate of steam required by the turbine to satisfy the minimum load. Factors such as valve selection and turbine design will determine this minimum flow and the corresponding pressure. After a valve is selected, the steam turbine will require a certain pressure and flow to maintain the minimum load. The pressure upstream of the valve (the accumulator pressure) can be found by calculating the pressure drop through the fully open valve.

If the system is providing steam to a process heat exchanger, then the minimum pressure will be determined by the working pressure of the heat exchanger. The geometry and area of the heat exchanger will be selected based on some constant pressure condensation. To work effectively, the steam supply must always remain at the design pressure. As the pressure drops, the saturation temperature will drop, and heat exchanger performance will diminish. For this reason, the cutoff pressure of the accumulator, in this case, would be some pressure higher than the required heat exchanger pressure. The higher pressure would leave room for losses between the accumulator and the process.

3.6.3 Liquid Level

Another operating point for the accumulator is the amount of liquid that is in the tank at full charge. The liquid serves as the thermal storage media since it has a high specific heat and a higher density than vapor. To effectively store energy, there must be enough liquid in the vessel

to absorb the energy within the steam. If the starting liquid level is too low, then during the discharge phase, the accumulator could run out of water. Without liquid in the tank, the accumulator will simply be storing steam under pressure rather than taking advantage of a phase change. The required volume of storage to effectively store steam would be much higher than the volume required to store saturated liquid. This requirement provides the lower bound for the minimum amount of liquid in the tank.

The maximum theoretical liquid level that could be contained within the tank would be 100%, but there are practical reasons why this would not be desirable. When the pressure is reduced in the accumulator, the saturated liquid will boil. Unlike a pan on a stove where the heat source is at the bottom, the saturated water will be above the boiling temperature everywhere once the pressure is reduced. This will cause rapid boiling throughout the liquid that could be violent depending on the rate of depressurization. The vigorous bubbling would likely cause some liquid to exit the vessel with the exhausted steam. Steam that is leaving should be saturated and not contain much liquid to prevent water hammer, which can damage equipment damage. The accumulator design will incorporate a moisture separator to help remove liquid water that tries to leave the vessel. This device will likely be overwhelmed if the liquid level is too close to the top of the tank.

The next considerations to factor in is what the liquid level does for the system. From a high level, the liquid contains the excess energy that will go into generating steam. It stands to reason that more liquid means more steam that can be generated from a given pressure difference. To maximize the energy and minimize the volume of the device, the liquid level needs to be a high as possible without causing steam quality problems. A maximum liquid

level of 90% by volume was chosen to move forward. The minimum liquid level was selected as 0% or when the tank runs out of liquid. This would be a flag to stop all simulations since the accumulator cannot continue to store high-pressure liquid. Once the level reaches 0%, the accumulator is no longer effective. In practice, the minimum liquid level will be determined as a result of the minimum pressure and not a set parameter.

3.6.4 Feedwater

The last operating point to consider in steam accumulator systems is the condition of the feedwater used to trim the liquid level. The feedwater is used to adjust the condition of the steam entering the vessel. When the steam is superheated, the feedwater can be used to bring the overall enthalpy entering the system down to prevent liquid loss. The feedwater used will be pulled from some high-pressure feedwater line after the feedwater pump. The main feedwater line can be used so that an additional feedwater pump is not needed to overcome the pressure in the tank. Next, the conditions of the feedwater must be specified.

Since the feedwater system is already in place, a simple connection to the feedwater line is required. The conditions of the feedwater used will be determined by the part load operation of the main reactor loop. A valve would be used to throttle the feedwater and continuously add the required amount of feed water based on the flow rate and condition of the steam. Superheated steam will require feedwater while saturated steam will not. The amount of feedwater added depends on the condition of the feedwater which is dependent on main turbine load. This parameter is completely dependent on the cycle and cannot be selected by the designer.

4 FORTRAN Modeling

4.1 Assumptions

Every computer simulation must make some assumptions. The fewer assumptions that are made, the more accurate the model will be. That being said, models still make predictions which are not always going to be true. Models can be useful if the user knows the limitations and assumptions the model makes. Computer simulations for steam accumulators will be used to assess the performance of an installed system. The simulations are run written in FORTRAN, a computer programming language ideal for its ability to process mathematical operations quickly. Additionally, in the future, this model may be coupled to an advanced, comprehensive model that simulates the entire SMR plant operation. The model considered for coupling was developed at North Carolina State University in the Nuclear Engineering department and is written in FORTRAN.

4.1.1 Negligible Heat Loss from the Accumulator Shell

The first assumption is that there will be little to no heat lost from the outside of the steam accumulator. The device will contain high-pressure liquid at a high temperature, but insulation and other techniques should be used to minimize heat loss. The energy lost will strongly depend on the construction details of the accumulator. Heat loss is energy that is being rejected to the environment without doing any useful work and heat transfer for the application. In general, heat loss should be minimized everywhere to prevent financial loss.

In the steam accumulator, heat loss will reduce the internal energy of the tank. This leads to an increase in liquid as more steam is condensed to maintain saturated conditions. The pressure in the tank will either fall as heat is rejected or the accumulator will consume more steam,

depending on availability. If heat loss in minor, feedwater controllers can mitigate the problem by discharging excess liquid if the tank is already full or not adding as much feedwater when required, anticipating the heat loss. The complicated nature of this control problem and small contribution to the overall system is why it has been neglected in the modeling.

4.1.2 The Reactor Power is Unaffected by the Accumulator

Nuclear reactors are complicated devices with a whole branch of engineering devoted to them. The study of these reactors has led to a high level of understanding of how to safely and effectively use them to provide clean, carbon-free power. The goal of this study is to add a device that consumes any excess energy available from a nuclear reactor and use it at a later time. Ideally, the reactor would see full load conditions all the time even though the power generation side might not. This is why we will assume the reactor power is constant. In reality, the changing feedwater conditions will affect the reactor power slightly. This can be accounted for by coupling the device to the comprehensive SMR model in the future. For standalone simulations, the thermal output of the reactor is assumed to be constant.

4.1.3 The Accumulator Consumes and Supplies Steam at the Required Rate

The geometry and construction of a steam accumulator will determine how fast the device can receive or supply steam when needed. Larger, single vessels will likely take more time to charge and discharge due to thermal mass and smaller surface area for heat transfer from the steam to the liquid. Many small, shallow vessels can likely be charged and discharged quickly but require more complicated connections and more space than a single tank. The simulation assumes that the geometry is designed such that the accumulator system can supply and take

the maximum steam flow rate required by the system. These flow rate requirements would be dictated by the electrical demand profile the reactor is following.

4.1.4 Rankine Cycle Assumptions

Since some of the information about the operation of the steam consumption side of the SMR plant was unavailable, assumptions had to be made. These assumptions were made to get a baseline for comparison. The plant operation before and after the addition of the steam accumulator is of interest. Therefore, the assumptions made are not as important as the consistency between models. Every effort was made to get as close as possible to what the actual plant operation may be by contacting various professional that work or have worked in the power generation industry. Table 4 below shows the assumptions made on the Rankine cycle.

Table 4 Rankine Cycle Assumptions

Rankine Cycle Assumptions	Justification
Feedwater heater is closed	Found in depiction of system [20]
Feedwater condensate trapped into condenser	Used to simplify feedwater analysis
Extraction steam at pressure is saturation temperature of water leaving feedwater heater	Best case scenario
Extraction steam is pulled from a single turbine tap	Found in depiction of system [20], and also simplifies the turbine part load analysis
Feedwater heat exchanger sized to handle lower pressure steam and same feedwater flow	The SMRs will be required to have load following capabilities and will likely have equipment sized to handle different loading conditions
Steam supplied to the turbine cease if it falls into the saturated mixture range	Damage to turbine blades will likely appear with less than superheated steam
Specific volume of feedwater is constant across feedwater pump	Difference in the specific volume of liquid water is negligible unless it is under high pressure
The heat output of the nuclear steam generator remains constant	Reactor power is known to increase with falling feedwater temperature, so this assumption will make the model more conservative

4.2 Accumulator Cycles with No Level Control

The initial model constructed used pressure as the independent variable and calculated the mass of the liquid, the mass of the vapor, mass entering or exiting the tank, and internal energy as dependent variables. The liquid level in the tank at any given pressure was a result of how much mass and energy was added or removed from the accumulator. Numerous cycles are simulated successively between the pressure limits to observe the effect of not controlling liquid level. Output conditions were calculated using the thermodynamic relations developed in Chapter 2. The simulations were designed to stop if the mass of the liquid in the container goes to zero. When this happens, a wet steam accumulator becomes a dry accumulator and is only storing compressed vapor.

Since the system relies on constantly changing steam properties, the model needed to have access to saturated water properties over a range of temperatures. This was accomplished with the help of X Steam version 2.6 by Magnus Holmgren, a function set for Microsoft Excel that generates steam properties for various inputs using the IAPWS IF97 Excel Steam Tables. [21] The functions in X Steam were used to generate a CSV file that contained the required steam properties from 33°F to 705°F. This data was then stored in a subroutine that used linear interpolation to calculate the saturated steam properties for a given input. Steam requires two properties to fully define it at a given state. The properties subroutine returned saturated liquid or saturated vapor properties depending on what the user requests. This is one property, and the other can be any of the other properties in the array but was primarily pressure. With this subroutine in place, the model could call upon it at any time to get updated steam properties.

This allowed the model to take advantage of iterative solvers in an effort to improve calculation efficiency.

4.2.1 Discharging

The model constructed was designed to return pressure for a given mass or energy requirement from the accumulator. This enabled the accumulator model to be used with other models that either need or give steam flow in terms of mass per unit time. In the case of discharging, the accumulator starts with a given volume of saturated liquid and the resulting saturated vapor that occupies the remaining space in the tank. As pressure is reduced, energy in the tank falls due to excess energy in the saturated liquid converting liquid to vapor. The excess vapor that cannot occupy the space left in the top of the tank is expelled, reducing the mass and energy in the accumulator. The total energy in the accumulator can be described with Equation 3 mentioned earlier, at the initial pressure.

The difference in the specific internal energy of the saturated liquid at the starting pressure, P_1, and at a reduced pressure, P_2, results in excess energy that cannot be contained in the liquid. This energy then flashes some of the liquid to steam. In order to maintain the desired lower pressure, excess steam must be vented out of the tank where it can be used for useful work. The mass that leaves the accumulator goes from a closed system to an open system when it starts flowing. This means that the enthalpy of the exiting steam can be used to determine the energy removed from the tank. Next, Equation 7 that was developed in Chapter 2 to determine the mass of the liquid left in the tank after the specific amount of energy was removed.

In Equation 7, energy and both masses at the initial state, state 1, are known. The remaining terms are specific properties that are functions of pressure. The mass removed, m_{out} will be

determined based on the requirements of the steam user. A constant discharge flow rate was selected to assess the performance of multiple discharged and charge cycles. Steam flow rates were determined based on a percentage of the total steam flow rate of the unmodified SMR plant. One-third of the SMR steam flow rate was chosen as the charge steam flow rate. This value is likely to be more than the average available or required steam but can provide insight into the operation of the accumulator.

The mass calculated in Equation 7 will differ depending on the selected final pressure at state 2. The model uses an iterative solver to pick a pressure for state 2, initially as a guess. A mass balance is then used to determine the mass of the other phase. The volume balance shown in Equation 4 can be used after the masses are known to calculate the total volume the two phases occupy. The calculated volume can be compared to the volume of the accumulator tank to check the pressure guess. The error is then used to go back and make a better guess until the difference between the calculated volume and the accumulator volume converge within a prescribed amount of resolution. Results of the modeling are discussed in Chapter 5.

4.2.2 Charging with Superheated Steam and No Level Control

Once discharged to the desired minimum pressure of 100 psia, the system was then charged with superheated steam from the boiler at 500 psia, and 575°F. Steam was added to the tank at a constant flow rate, and the resulting conditions were calculated for each increment of time. The same flow rate used in discharging was used to charge the accumulator.

The pressure of the accumulator at the end of some time difference will be determined by the thermodynamic equations set forth in Chapter 2. Two main equations are used to determine the final state conditions and both have multiple pressure dependent properties. One way to

solve these two equations is to use iterative methods to approximate the answer after some change. The method calculated the volume occupied by the liquid and vapor after choosing an arbitrary final pressure value that is higher than the initial pressure. Then, a Newtonian solver computed the error and residual error to better estimate the next pressure guess. Once the residual error drops several orders of magnitude, the solver exits with the final pressure computed. The conditions at this state now become the initial conditions for the next time step and the process is repeated until the tank reaches the specified cut-off pressure.

In this initial trial, feedwater is not used to observe the effects of charging with superheated steam. The excess energy in the steam above saturated vapor should result in a round trip accumulator cycle that contains more vapor (or less liquid) than the starting of the cycle. Continuing this pattern on successive charge and discharge cycles will result in complete loss of liquid, given enough time. The enthalpy of the charge steam in the complete system model will change depending on main turbine load due to reduced feedwater heating capacity. This effect is not considered in this cycles model. Worst case scenario would be using the full load enthalpy of the system which is the maximum superheat achievable.

4.3 Accumulator Cycles with Feedwater Control

Next, feedwater control was added to the model to maintain the level in the accumulator at the end of each cycle. The model was able to add or remove feedwater in order to reach the same liquid level after every discharge and charge cycle. Rather than adding a lump sum at the end of a cycle, a real system would likely have a control system in place that aims to hit some goal in charging enthalpy by measuring pressure and temperature. Since the goal is to desuperheat the charge steam to match the discharge enthalpy, this can be done on a continuous basis

whenever the system is charging. With this control method in place, the system will always reach the desired liquid level when fully charged. Ignoring other losses, there should not be a reason to remove feedwater from the system.

Feedwater control was added to the model previously used before to run accumulator cycles. The control parameter was enthalpy of the inlet steam, and the response variable was the mass of feedwater added. The enthalpy of the feedwater was chosen to be the enthalpy of the feedwater that supplied the nuclear steam generator. This water is maintained at 500 psia and preheated to 300°F. Once steam is pulled off before the main turbine, the feedwater performance will go down, resulting in lower temperature feedwater. Again, this effect is not considered in the cycle testing of the accumulator model.

The amount of feedwater can be calculated by comparing the enthalpy of the feedwater, h_{fw}, and the enthalpy of the charge steam, h_{in}. Equation 16 shows how the amount of feedwater can be calculated from an energy balance.

$$h_{in}m_{in} + h_{fw}m_{fw} = (m_{in} + m_{fw})h_{g,avg} \tag{16}$$

Rearranging Equation 16 allows the for the mass of feedwater to be found based on the amount of charge steam.

$$m_{fw} = m_{in}\left(\frac{h_{g,avg} - h_{in}}{h_{fw} - h_{g,avg}}\right) \tag{17}$$

Adding in this amount of feed water will bring down the overall enthalpy entering the system from superheated to saturated at the working pressure. This approach uses the average saturated vapor enthalpy between the starting pressure and the ending pressure. There will be more error introduced as the pressure difference is increased. For this reason, caution must be used when running the model with large pressure changes.

4.4 Integration with NuScale SMR Power Plant

The next step in modeling was to see how the accumulator can be used to meet a peak electrical demand higher than the SMR in question can satisfy alone. This is the main topic of interest in this study. The excess steam that is not needed by the SMR turbine, referred to as the "main turbine," will be sent to the accumulator to be stored and used at a later time when power demand is higher than the main turbine can supply. The goal is to estimate how big of a grid could be served compared to the maximum grid size that a single SMR can serve. This is dictated by the peak demand the grid needs. A 45 MW power plant can only serve a grid that has a peak of 45 MW even though most of the time the demand is below 45 MW. That limitation will be the baseline of comparison between the system with and without an accumulator. The first step in modeling the system is to input the demand data.

Hourly demand data that will be used in the simulations was collected and is described in Chapter 1. The hourly data was extrapolated to second data by linear interpolation. This allows the model to use smaller time steps with gradual changes rather than abrupt jumps. Gradual changes will translate to smaller pressure differences at each time step. With this data in the model, the next step is to determine how much steam is available from the SMR.

4.4.1 Charging with Excess Steam

Excess steam will be diverted to the accumulator when demand is low. Therefore, the model needs a way of estimating the quantity and condition of the steam available. For this, X-Steam for Microsoft Excel was used to model the Rankine cycle that drives the main turbine. Full load conditions were a starting point from which part load data was collected. Turbine output was incrementally reduced, and steam flow required by the turbine was calculated. This required that the flow rate of feedwater through the steam generator remain constant since the accumulator would be absorbing any excess steam available. The steam consumption data that will be used in the model is shown in Chapter 3.

The FORTRAN model can use the steam consumption and enthalpy data to determine the available steam for charging. Next, the model will take this steam and add it to the accumulator. Using the same iterative methods as before, the model adds in the excess steam for a given time period and computes the resulting conditions in the accumulator. Feedwater is used continuously to prevent undercharging.

The condition if the feedwater is computed based on the reduced feedwater heater performance found in the Excel model. When more feedwater is used, less feedwater flows through the steam generator. The lower flow rate translates to a higher steam temperature leaving the steam generator since it is assumed that the heat output is constant. This will, in turn, affect the amount of feedwater and thus sets up another iterative problem. The amount of feedwater needed is calculated and then sent back through a loop to check the enthalpy of the steam leaving the reactor, adjusting the feedwater flow as necessary. This process is repeated until some accuracy level is reached and then the model can move forward. With the known steam

a feedwater flow rates and properties, the iterative solver can be used to add steam and calculate the resulting pressure and liquid volume.

4.4.2 Discharging the Accumulator to Generate Power

When demand is higher than the main turbine can supply, the accumulator is used to send stored steam through a peaking turbine to generate more power. This process involves reducing the pressure in the accumulator to flash the stored liquid into steam. The steam is then sent through a small turbine where it generates power. The exhaust from the turbine goes into the main condenser to be condensed and stored since the main turbine condensate and feedwater condensate is matching the steam flow rate. The required power output of the peaking turbine is used to calculate the amount of steam needed from the accumulator and the resulting pressure drop.

The efficiency of the peaking turbine at varying loads and valve performance are stored in subroutines that the discharging function can call upon. This structure allows the model to iterate until it calculates the amount of steam needed from the accumulator. Then, the model removes this amount of steam and computes the resulting pressure, using the same technique described in the discharging period of the cycle tests. The model receives demand data and computes how much power is required by the peaking turbine at any given second. This demand is then converted to steam flow per second, and that amount is removed from the accumulator, if possible. If the accumulator does not have enough energy to supply this steam, then the valve is set to fully open, and the work output is computed from there. This is the case is the system cannot meet the required demand.

Valve flow was found using the following equation: [22]

$$G(H_{rel}) = \sqrt{\frac{2\rho\Delta P_{valve}}{K(H_{rel})}} \tag{18}$$

The mass flux through the valve, $G(H_{rel})$ is described in terms of the density, ρ, the pressure drop across the valve, ΔP_{valve}, and the loss coefficient K, which is a function of valve position, H_{rel}. The term $K(H_{rel})$ is defined in the next equation for linear valves.

$$K(H_{rel}) = \frac{K_0}{(H_{rel})^2} \tag{19}$$

The term K_0 is the loss coefficient of the valve when it is fully open and was calculated using an Excel spreadsheet to model various valve conditions. K_0 and the area of the valve were used to determine the mass flow for a given valve position. K_0 was calculated based on the maximum required flow rate and the assumed pressure drop across the valve. A pressure drop of 50 psi was chosen since this was the pressure drop reported across the main turbine control valve. With this information known, the speed of sound was used to calculate the maximum velocity of flow through the valve, which is the maximum choked flow. This information allowed for the area to be determined and thus the valve size was selected. This valve was then used to regulate the flow of steam into the peaking turbine.

The steam accepted by the turbine and the steam passed by the valve need to be correlated together. The steam turbine has an associated mass flow through it based on the load. Turbine pressure drops approximately linearly with turbine load meaning the flow accepted by the turbine for a given pressure input could be calculated. This was found and compared to the maximum choked flow through the valve for all operating conditions. The steam accepted by

the turbine was found to be less than the choked flow through the valve, meaning the model could use turbine requirements to iterate the conditions after the valve.

Many of the parameters discussed are left as variables that can be altered to optimize the performance of the accumulator and peaking turbine set. The valve characteristic, peaking turbine specifications, and accumulator dimensions are all adjustable to get the desired output from the system. The valve can be oversized or partially open initially if so desired to improve response. The user must be cautious when setting parameters that could cause physical issues that may not manifest in the model. An example of this is sizing the valve so that it is operating mostly closed. This could result in control issues in a real system making the project impractical.

4.4.3 Using Stored Steam for Process Heating

The last area of interest is using stored steam during off-peak hours to provide some constant source of process heat. The power generation system would be unmodified, other than a bleed valve to send excess steam to the accumulator and a condensate return line. This could be applicable if the SMR was located near a large manufacturing facility or another industrial process that requires heating. The accumulator acts as a buffer to smooth out the variability in supply steam and provide a constant, supply of steam to the process. The modeling of this system involves the input of demand data, similar to the previous peaking model. This time, the demand data is not scaled, and the nuclear plant is providing the same amount of electricity that it would if there is not thermal storage in place. Now, the excess steam that is available will go to charging the accumulator while at the same time, a constant steam flow is being pulled out of the accumulator. The rate at which the steam is being drawn off is based on the

average amount of energy added to the tank. The amount of steam bypassing the turbine times its enthalpy was averaged to determine the average heat content of the available steam.

The model looks ahead at the demand data to determine how much steam it can supply at a constant heating rate. This method could not be used in a real-world application, but demand predictions could get the operators close. The total excess available heat is computed and the steam drawn out is based on this value. The mass flow rate is not constant and is determined by the average energy divided by the enthalpy of the vapor leaving the accumulator at a given pressure. This means that the amount of mass leaving the tank increases slightly with falling pressure in the accumulator. A constant heat supply will be sent to the process continuously. This could be the case if a water treatment plant or desalinization plant was located close to the reactor and operating some constant process.

The simulations assume the steam required for the process is being used at a constant pressure. The steam that leaves the accumulator is at a higher pressure than the process requires. Throttling the steam down to the process will result in superheated steam that enters the process. It was assumed that all the energy in the superheat could be absorbed by the process without negative effects. Most of the energy is transferred at the saturation temperature through condensation. The condensate will be returned to the power plant and flashed in the condenser so that it can be added back to the main reactor steam loop when needed.

The energy added to the accumulator will be a product of the mass and enthalpy entering the accumulator. The energy added to the process can be described in terms of the enthalpy difference between the steam entering the process heat exchanger and the saturated liquid that leaves as condensate. These simulations ignore losses in between the accumulator and the

process heat exchanger. Therefore, the inlet to the heat exchanger will be the outlet of the steam accumulator. The remaining enthalpy difference between the high-pressure condensate and the low-pressure condensate in the condenser will be the heat that is rejected to the environment.

The simulations were designed to stop if the accumulator steam pressure dropped below some low-pressure cutoff, which was chosen to be a pressure above the required steam pressure to account for pipe and valve losses. The system also needed to handle excess steam, which was accomplished by first discharging the tank and then adding the available amount of steam back. If the pressure was higher than the maximum pressure, the model reinitialized the state one variables to their respective values before the charging period was run. Then the mass added to the vessel is reduced and the charge simulation re-run to find the new pressure. This process is repeated until the mass added to the tank results in a pressure equal to the fully charged pressure. The bypassed steam is then recorded to keep track of how much energy was not absorbed by the system. An ideal system would not have any bypass to get the most out of the stored energy and the energy available from the reactor.

The simulations were then run for multiple weeks to assess the long-term performance. Because the demand profile is irregular, the system may not be able to sustain operation daily but might be able to sustain weekly operations, recovering on the weekends. The parameters of interest were recorded to an output file and analyzed to highlight trends.

5 Analysis and Results

5.1 Cycles with Superheated Charge Steam and No Level Control

The initial models constructed were designed to run multiple accumulator cycles in order to confirm the equations used in the model and assess the performance with varying input conditions. Superheated steam was used to charge the system, and no level control was in place.

The first model constructed used a 1,000,000-gallon tank as the accumulator size. The size of the accumulator will be determined based on the available excess steam. Since the steam flow to the accumulator is constant in the initial cycle tests, the size needed to be large enough to ensure sufficiently small pressure changes. 1,000,000-gallons was chosen to keep pressure changes low and to make the charging and discharging times sufficiently long. The accumulator will need to accept steam and supply steam for multiple hours.

The upper pressure bound is fixed by the reactor and chosen to be 50 psi lower than the reactor steam outlet pressure. This pressure is maintained by the turbine control valve at 500 psia to ensure reactor steam pressure is constant. The pressure drop assumed will account for friction losses and valves between the steam tap and the accumulator. The low-pressure cut-off was arbitrarily chosen to be 100 psia (85 psig) in these cycle trials. When the steam is used for an application, this will determine what the minimum pressure. The accumulator would not likely be run below atmospheric pressure to eliminate the need to withstand a vacuum on the vessel. This would change the material and geometry requirements for safe operation and likely add unnecessary cost to the project.

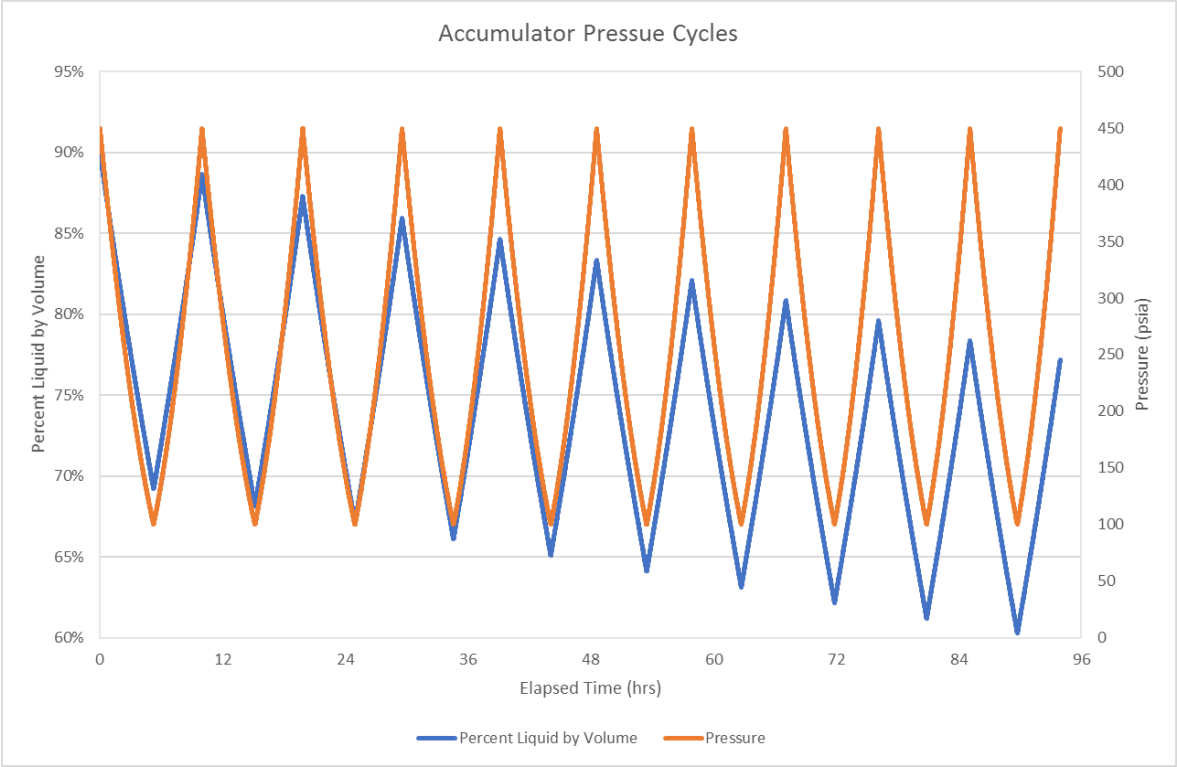

Figure 12 Accumulator Pressure Cycles, No Level Control

Figure 12 shows the results of charging with superheated steam. Pressure, shown in orange, started at 450 psia and 90% of the tank's volume was occupied by saturated liquid. Then, 50 lbs of steam were removed from the tank every second, and the resulting pressure drop was calculated at the end of each second. The average pressure change for this simulation was found to be 0.195 psi. After the accumulator reaches the minimum pressure, the system switches from discharging to charging at the same rate. Steam is added to the accumulator at a rate of 50 lb/sec, and the steam is superheated from the nuclear steam generator. Charging stops when the pressure comes back up to 450 psia, then this cycle is repeated, nine more times, in this case, to observe trends.

The first interesting trend that can be observed is the time of discharging and charging. This system uses a 1,000,000-gallon tank to store the high-pressure liquid. At the constant flow rates assumed, the amount of time for each cycle can be estimated. From the figure above, the time per cycle appears to be slightly less than 10 hours. Looking into the data reveals that the average time of discharging is 4.93 hours while the average time of charging was found to be 4.45 hours. Due to the higher energy of the charge steam and failure to reach the same liquid level at the end of charging, this result is to be expected. Less mass overall enters the tank when charging compared to discharging, therefore less time is spent charging. Another finding is that the time of each cycle decreases when compared to the previous cycle. For example, the first cycle took 9.98 hours to discharge and charge while the last cycle took 8.81 hours to complete the same cycle. Again, this is attributed to the decreasing mass in the tank as the cycle advances.

The volume of liquid was plotted in Figure 12, shown as a percentage of the total accumulator volume in blue. Trends in the liquid level will reveal whether or not the accumulator can be run indefinitely or if it will run out of saturated liquid. Based on literature review, the liquid level should decrease if the accumulator is repeatedly charged with superheated steam. This trend is confirmed by the simulations. For a given discharge and charge cycle, the liquid level does not return to the initial starting level once the system has completed the cycle. Over the course of multiple simulations, the liquid level tracks downward, losing a little more than 1% every cycle for the first 10 cycles modeled. The amount of liquid lost per cycle appeared to be diminishing as the cycles advances. Therefore, more data was collected to observe the trend.

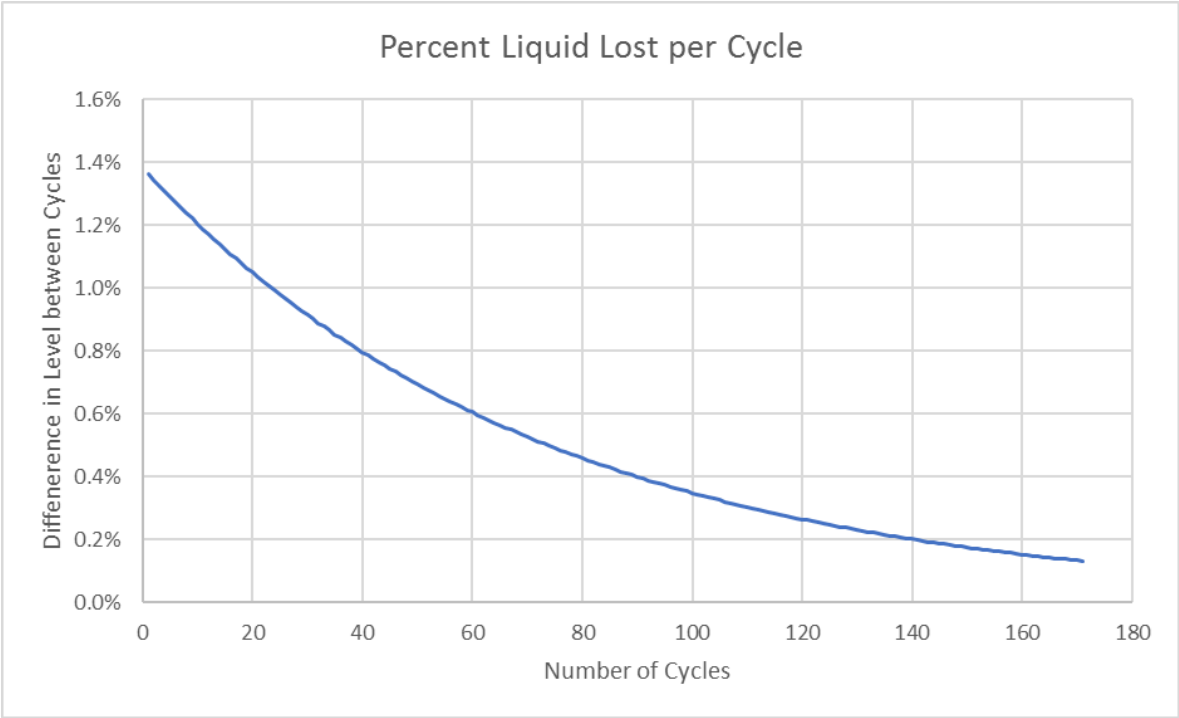

Figure 13 Percent Saturated Liquid Lost When Charging with Superheated Steam

Figure 13 was generated to observe the trend in liquid lost from the accumulator. The y-axis shows the volume percentage of liquid lost from one cycle to the next at full-charge pressure. The amount of liquid lost approaches zero as the cycles progress. This pattern would continue until the amount of liquid in the accumulator reaches zero while discharging. The model used to generate the data for Figure 13 was designed to stop when the amount of liquid in the tank reaches zero at any point in the cycle. This is why the graph does not reach zero. A good way to verify the model is performing as expected is to analyze the results from a big picture point of view and determine if they make sense.

As the accumulator is operating without level control, the liquid level is continually going down with successive trials. This means there is less liquid in the tank at the beginning of a

new discharge period. Since the energy contained in the liquid is used to flash liquid into steam, less liquid means less flashed steam. A lower amount of steam exhausted from the accumulator will equate to less steam needed to charge the device. The amount of liquid lost would be proportional to the amount of excess energy that is added to the accumulator, which comes from the steam added. This means that as the liquid level is falling, the accumulator will require less steam to reach a given pressure, bringing less excess energy with it, and evaporating less of the liquid in the tank. This conclusion agrees with the results of the model and is grounds for further model advancement.

5.2 Cycles with Superheated Charge Steam and Feedwater

In order to operate the accumulator continuously, some control mechanism needs to be added to ensure the liquid will not run out. One way to control the level in the tank is by adding or removing feedwater. Since the issue with the previous model is a loss of liquid, the capability to add feedwater while charging was added. The model used feedwater to bring the enthalpy of the mass entering the accumulator down to the average mass that would have left the vessel over the charging pressure range. With no external losses, adding back the same energy that left the control volume over a given pressure range should bring the system back to the same point at any given pressure. This is not as simple as just adding the correct amount of steam because the volume balance will prevent the system from reaching the correct level before the maximum pressure is reached. Feedwater must be used to bring down the energy in the charging steam. After implementing this control method, data was collected from the model. This can be seen in the following figure.

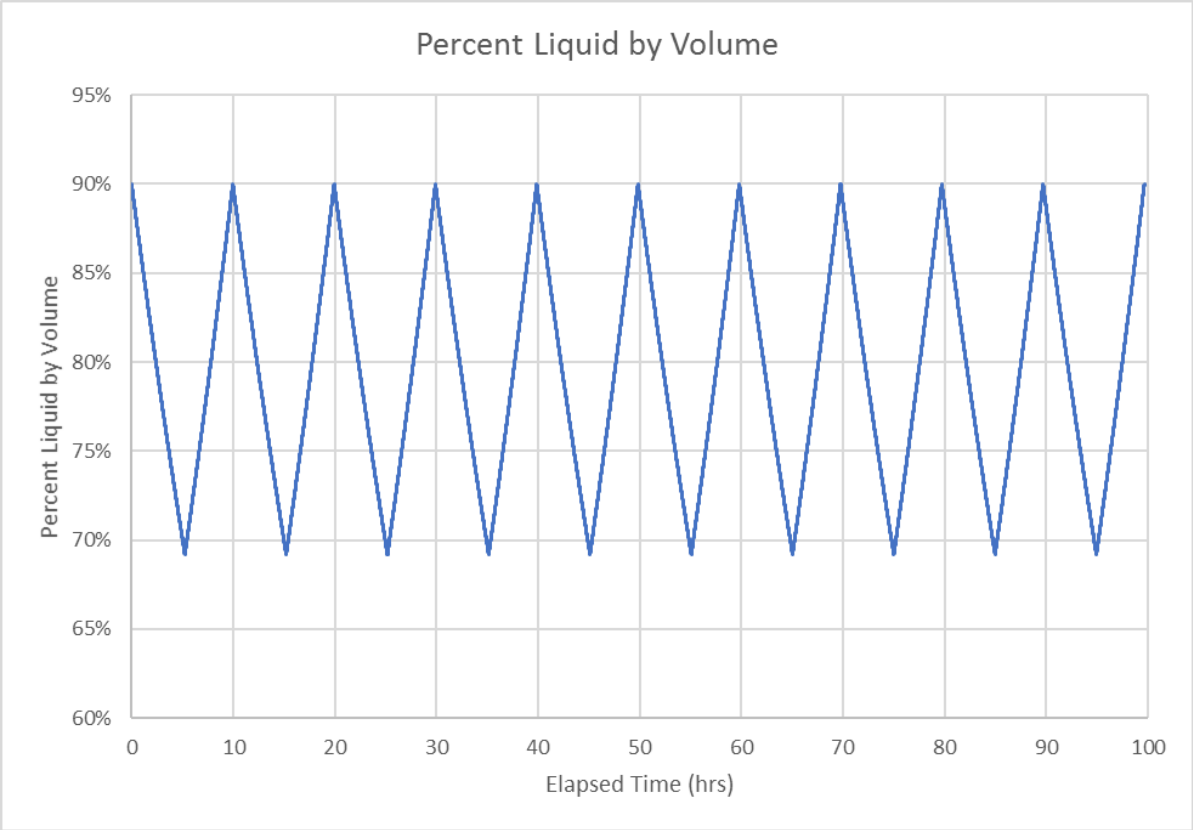

Figure 14 Accumulator Pressure Cycles with Level Control

Figure 14 shows the results of adding the correct amount of feedwater. Pressure is not shown in this figure but remains unchanged from the previous figure. On average, the amount needed for this simulation was about 5.58 lbs/sec, or 43.5 gal/min which is 11.2% of the total steam flowing into the accumulator. As the pressure in the accumulator drops, the amount of feedwater needed increases. This is due to a lower average enthalpy of the saturated vapor in the accumulator. Taking the results from a single charging cycle, initially, the pressure is 100 psia and the calculated feedwater needed for the first second is 6.49 lbs. During the last second of the same charging period, the pressure approaches 450 psia and the required feedwater drops to 5.17 lbs for that second. The feedwater enthalpy is not changing in this simulation.

Therefore, the only parameter affecting this result is the change in average enthalpy. This relation is shown in Equation 17, which also shows as the charging enthalpy approaches the average enthalpy of the vapor in the accumulator, the amount of necessary feedwater approaches zero. Since the charge steam is significantly superheated, this explains why the feedwater requirements are so high.

The timing of the adjusted cycles has become more regular and repeatable. Total cycle time was identical for each cycle and found to be 9.96 hours. The charging period took 4.72 hours and the discharging period lasted for 5.24 hours. The difference in time between the two periods can now be explained by the addition of feedwater. Since the mass flow rate of the steam entering the accumulator is supplemented with feedwater, the total mass flow rate in is higher that the mass flow rate out, explaining the timing difference. This system would likely need to be larger to handle a 24-hour cycle period, which could be implemented with a larger tank.

Now that the computer simulations have been checked for accuracy and repeatability, the accumulator model can be applied to an application. The two applications considered in this study are additional electricity generation and process heat storage.

5.3 Accumulator Integration with Nuclear Power Plant

With a working model of a steam accumulator, steps can now be taken to model the interaction with a small modular reactor. The two applications for thermal storage mentioned above were modeled and studied to assess the performance on the thermodynamic level.

5.3.1 Storing Steam to Assist with Electrical Demand Peaks

The first application considered stored steam in the accumulator when the nuclear power plant is running below its full load rating and used the steam when the demand exceeded the capacity of the nuclear plant. This was accomplished by running steam from the accumulator through an appropriately sized peaking turbine. This will effectively allow a smaller plant to service a larger grid. The simulations were run to find out how much more demand can be met if the grid follows the predicted hourly trends.

The original maximum electrical capacity that could be served by the standalone nuclear plant was scaled up by 125% to assess the performance of the accumulator. The upscaling required a valve and appropriately sized turbine to be selected. A 12 MW turbine was modeled as the peaking turbine to minimize inefficient operation of a large turbine running partially loaded. The valve dimensions were calculated for the maximum pressure possible and full load steam flow required by the turbine. Part load operation was then investigated to ensure the valve is not encountering choked flow over the operating range.

A 3,000,000-gallon tank was selected for the accumulator size. This number was picked based on the hours of storage predicted in the cycle testing. If the tank is too large, the system would likely still function as intended, but the excess cost might make the project unfavorable. Alternatively, if the tank is too small, the required electrical demand of a larger grid cannot be met, and the nuclear system will be bypassing a large amount of steam or forced to slow the reaction. An ideal vessel would be sized such that the highest demand over the course of a year can just be met with the amount of storage. The parameters discussed were modeled, and the results are shown in the following figures.

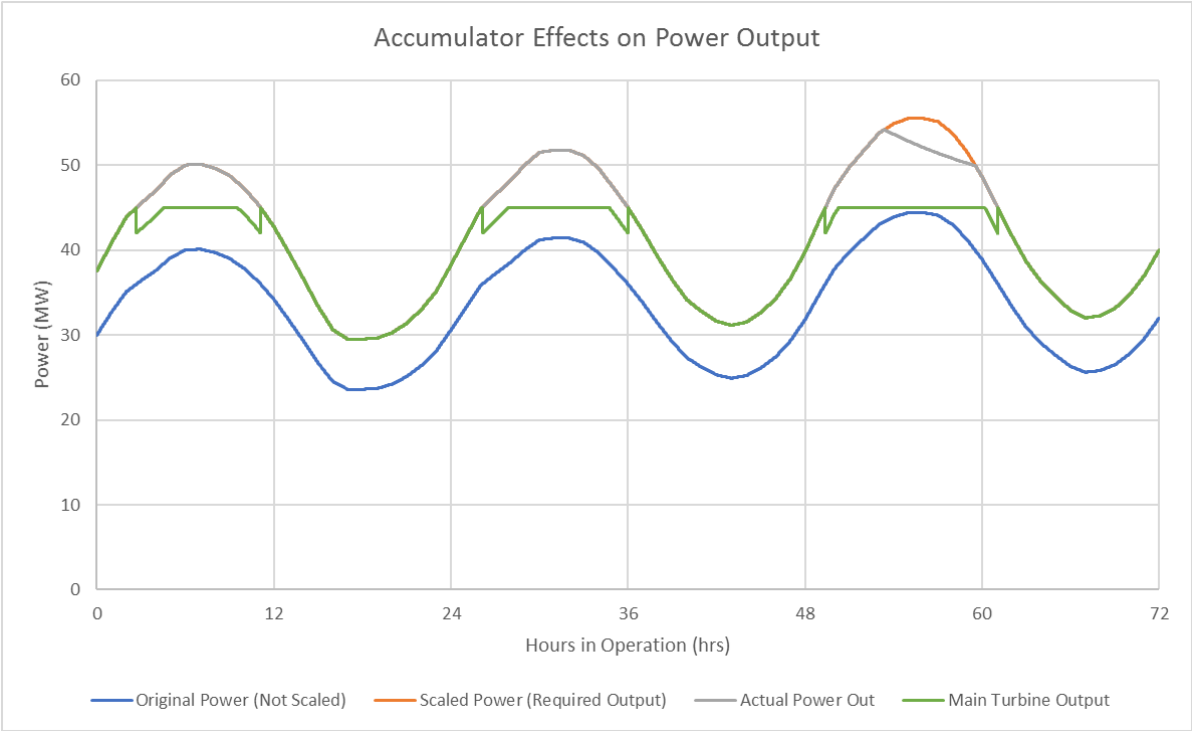

Figure 15 Accumulator Performance: 3 Million Gallon Vessel, 125% Demand Scaling

Figure 15 depicts the results of operating the accumulator for 72 hours with the scaled demand profile. The figure shows how the output of the main turbine, in green, is reduced as load falls below 42 MW. Between 45 MW and 48 MW, both the main turbine and peaking turbine are in operation to prevent low loading of the peaking turbine. In this range, the peaking turbine is brought up to 3 MW, or 25% output, and the main turbine throttles back to match the demand output required. Any demand requirements over 48 MW requires the main turbine to run fully loaded and the peaking turbine to make up the difference in supply and demand. The orange line is the scaled power required by the grid, which is simply the original demand, shown in blue, times 1.25. The gray line is what leaves the plant, whether it be from the main turbine or from the main and peaking turbines combined.

The first two days shown in Figure 15 match the output with the required demand as expected. The third day is where issues with the system are revealed. Storage in the accumulator was not adequate to meet the demand. This would require the dispatch of standby equipment if the grid is standalone or the purchase of power from a nearby grid if they are interconnected. Both of these options are cost prohibitive. To understand why this model was unable to match demand, valve position, steam bypassed, and percent liquid by volume was plotted in Figure 16.

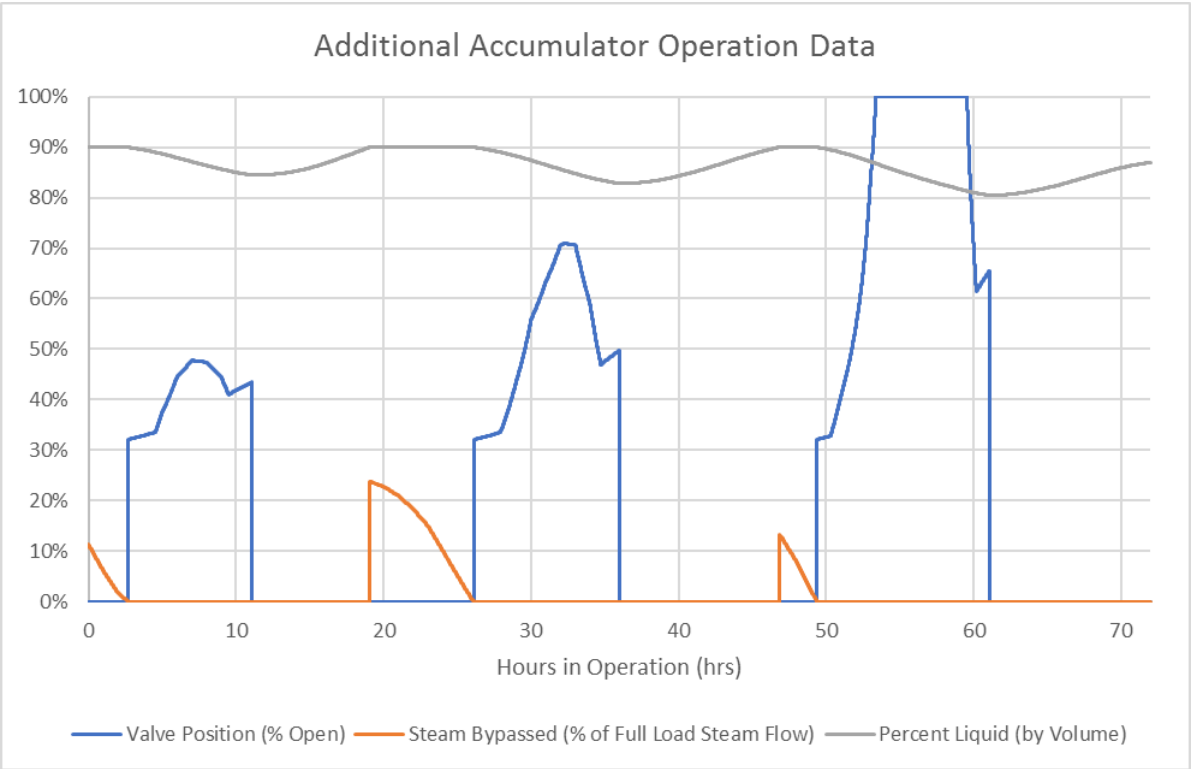

Figure 16 Valve Position, Steam Bypassed, Percent Liquid by Volume Data

On the third day, the valve opened until it was completely open, after this, the output started to fall below the requirements. This could mean that the valve is too small and not allowing

the proper flow rates at reduced pressure, the turbine sizing parameters are not correct for the pressure range, or that the accumulator is too small. The amount of steam that needed to be bypassed also sheds some light on why the system underperformed. Steam is bypassed when the accumulator is at full pressure and cannot accept any more steam. This indicates that there is not enough storage capacity for the available steam from the SMR. The next step was to change valve and peaking turbine input sizing parameters to see if the discrepancy can be fixed.

As the pressure drops in the accumulator, the specific volume of the vapor goes up, limiting the amount of steam that can flow through a valve. In addition, when the system is calling for high peaking turbine output, the accumulator must supply more and more steam as the pressure falls due to the falling enthalpy. This means the accumulator is unable to supply the required steam and flow rate well before the minimum pressure is reached. The system could continue to supply power but at a reduced capacity. This is problematic for isolated grids that are unable to pull more power from a nearby grid. In an attempt to address this problem, changes were made to the valve and the steam turbine.

The valve was doubled in size to compensate for the lower specific volume and to reduce the pressure drop when the valve is full open. Control valves become very sensitive to changes when required to throttle large pressure drops. This will be the case if the valve is oversized too much. Caution was used in the valve sizing, and the minimum valve position of the bigger valve was 29% for the worst-case scenario of maximum pressure and minimum load. The turbine was originally sized using an assumed pressure drop from the maximum pressure in the accumulator. This was reduced for 400 psia to 250 psia. If this change was performed on an existing turbine, it would suffer severe performance issues, but if a new turbine is being

specified, manufacturers can design them to operate at a specific pressure to get optimum performance. For this reason, it was assumed that this change does not come at a significant cost to performance. The changes were made to the model, and new simulations run. The results are shown in the following figure.

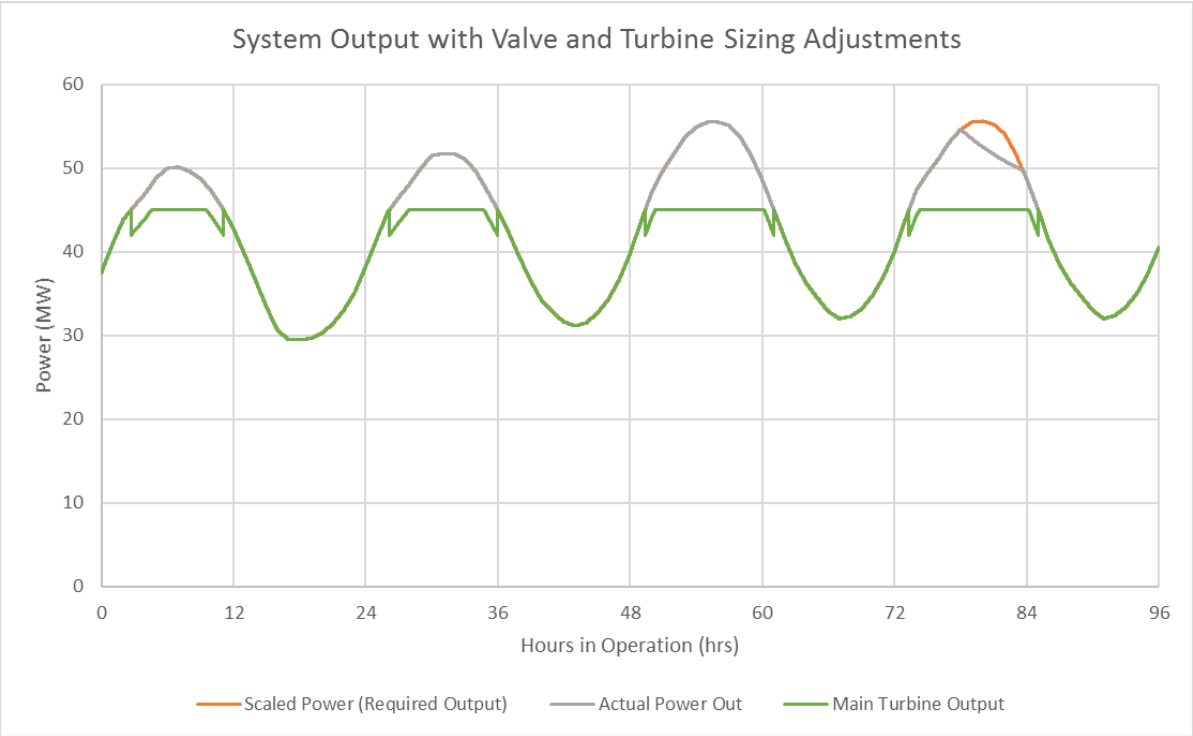

Figure 17 Power Output Results After Modifying Valve and Turbine

Figure 17 shows an improvement over the previous attempt. The system was able to match the demand of the third day but fell short on the fourth day. This means that despite the changes made, the system was still unable to perform the required task. To understand why the system underperformed on the fourth day, the conditions leading up to the discharging period were investigated. The pressure in the accumulator was at 372 psia, meaning the accumulator was

not fully charged. This data indicates that the scaling is too large for the amount of excess steam from the reactor. Less scaling was implemented, and new simulations run.

The new scaling was chosen based on the average power used for the whole demand period and the percent reduction it was from the full load power output. The average was calculated to be a 24% reduction from full load. Since efficiencies drop with power output, there will be less than 24% excess steam flow available and the peaking turbine will use more steam when generating power. Therefore, the new scaling factor was chosen to be a 22% increase in the original demand.

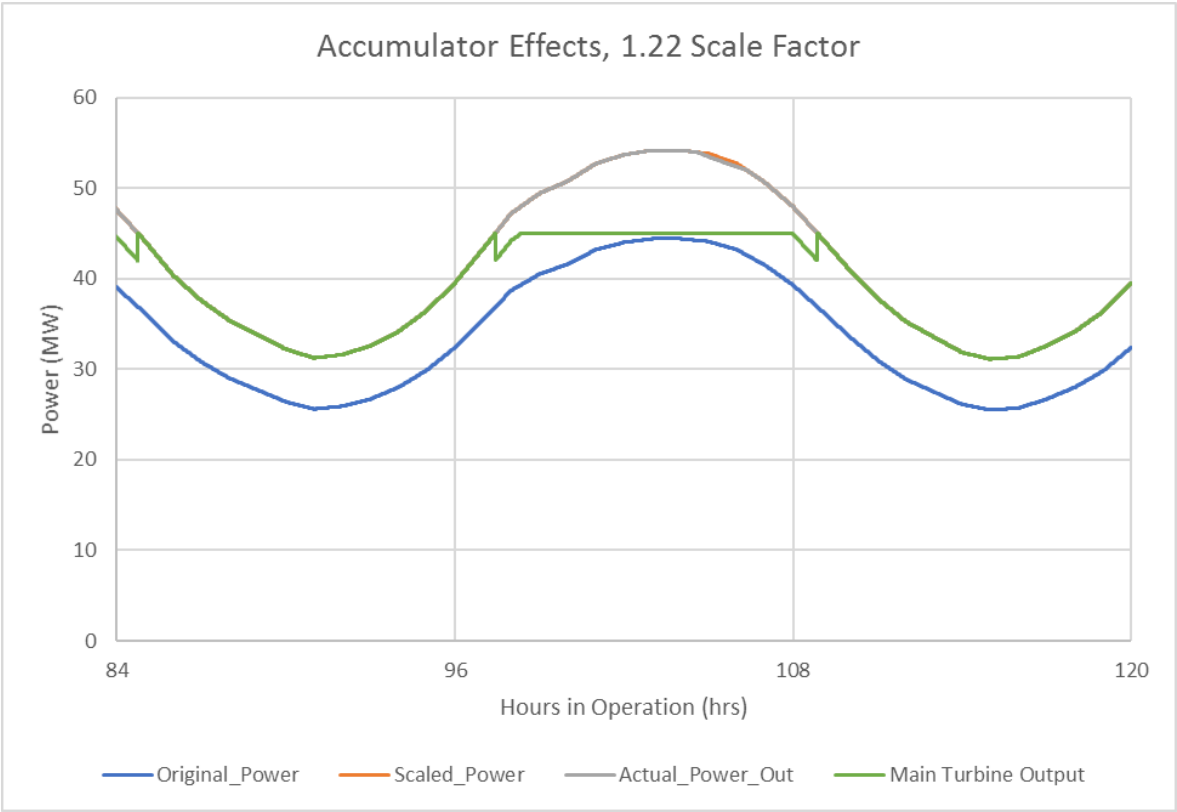

Figure 18 Accumulator Performance with a Scale Factor of 1.22

The accumulator was able to hit the first three peaks without issue, but the fourth peak still has a small portion that fell short. A small sliver of orange can be seen in Figure 18, representing the shortcoming of the device in its current configuration. Further investigation into the model was used to move forward.

The accumulator was found to contain less than 85% liquid at the time of the switch from charging to discharging on the fourth day. This means that despite the reduction, the accumulator was still unable to reach a full charge, leaving inadequate steam to meet the peak energy requirements. Ultimately, it was found that a scale factor of 1.20 resulted in satisfactory performance across all peaks during an eight-day demand period. Now that the peaks can be met, the accumulator size was scaled down to minimize bypass steam while still meeting the required output. The final tank size selection was selected to be 2.8 million gallons.

With the physical parameter set, the system was run for a typical winter demand profile. The scaling factor and sizes are all left as is since they were sized for the maximum demand in the summer time. If the SMR was interconnected to a grid, then the number of customers could increase in the winter since the peak is lower than summer peak, but if the system was serving a standalone grid, then the demand would not be scaled differently depending on the season.

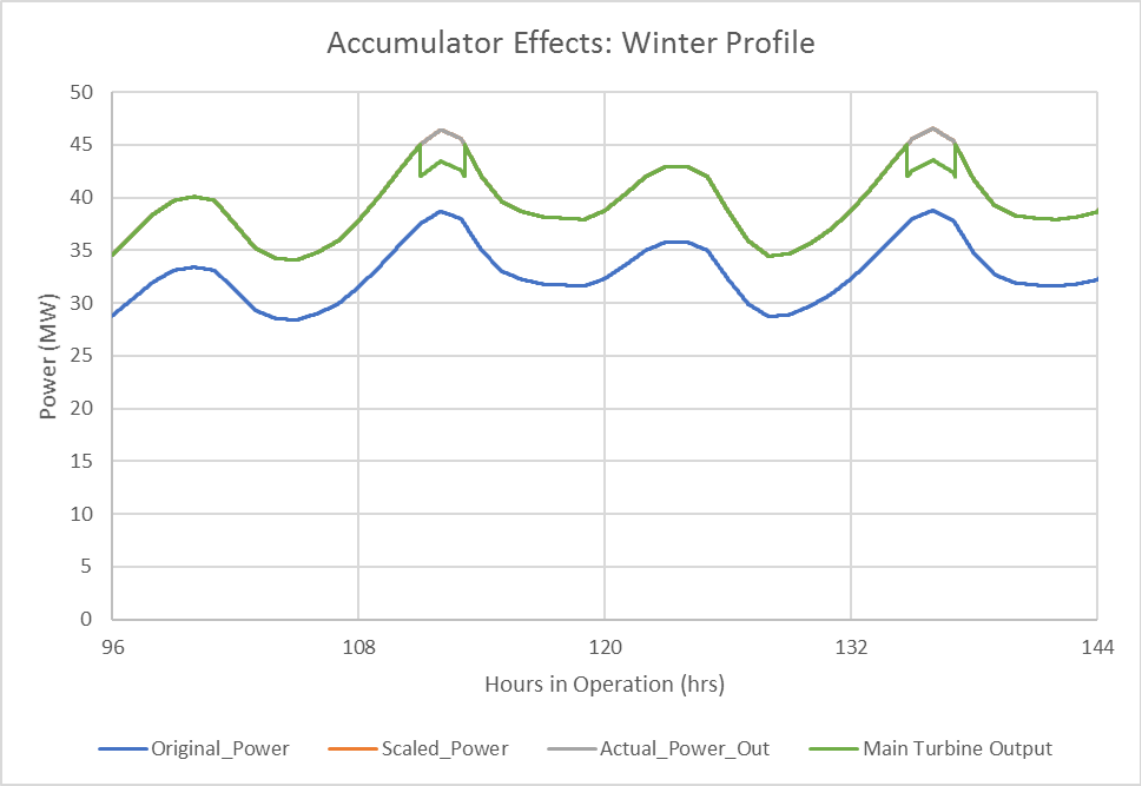

Figure 19 Accumulator Usage During Winter

As expected, the scaling is far too low to have any significant storage applications during the winter. Over the weeklong simulation, there were only two times that the demand exceeded 45 MW, highlighted in Figure 19. The accumulator is barely used, and the peaking turbine does not exceed it minimum load when running. Using the accumulator for peak storage in the winter would not be an economical use of the system. The same is true for the shoulder season which was found to never require the accumulator. The steam stored in the accumulator could be used for space heating if a campus was close enough to the plant during these seasons.

When compared to summer, winter demand is less variable. The demand during winter peaks in the morning hours, dips during the day, and peaks again at night. The morning peak is

typically the highest demand for the day since space heating is being utilized and people are preparing for work. The morning peak is still not as high as the summer peak and the two peaks per day act to level out the demand. The accumulator sized to handle the summer peak and variability is more than sufficient to handle the winter demand trend. The data used for winter demand represents a region that has a significant amount or electric heating. The demand curve could be even less variable in a region with lower dependence on electricity in the winter.

5.3.1.1 Efficiency of Using the Accumulator for Peak Power Generation

One way to quantify the effects of adding the accumulator to the system is to look at the capacity factor before and after the accumulator is in place. The capacity factor is defined as the amount of energy the plant generated compared to the maximum that it could produce. For the system before the addition of the accumulator, the maximum energy output achievable would be when the plant it operating at full output, 45 MW, for every hour of the year. On a weekly basis, this is calculated by the following equation.

$$CF = \frac{Actual\ Energy\ Output\ (MWh)}{Maximum\ Energy\ Output\ (MWh)} \tag{20}$$

$$CF = \frac{Actual\ Energy\ Output\ (MWh)}{45\ MW\ x\ 7\frac{days}{week}\ x\ 24\frac{hrs}{day}}$$

The actual energy output mentioned in Equation 20 will come from the simulation data. The actual energy output for the original system for one week was found to be 5,746.6 MWh, which equates to a capacity factor of 76.0%. In nuclear reactors, the reduction in energy output does not translate to a significant drop in operating cost. A capacity factor of 76% would be good,

but anything less than 100% is not ideal for a nuclear plant. The steam accumulator aims to address this issue by storing any energy available when the plant is operating less than full load and recovering a portion of it when more power is needed. The maximum peak capacity of the plant is increased while the maximum energy remains the same. The means the reactor is generating steam for more time than the original SMR would be. Over the course of a week, the accumulator equipped model was able to output 6,896.0 MWh of energy, which is a capacity factor of 91.2%. There was still some excess energy that was bypassed to the condenser when the accumulator was unable to accept all the steam available. Bypassed steam, lower efficiency of the peaking turbine, lower part-load efficiencies of both turbines, and irregular demand periods explain why the capacity factor could not reach 100% for the week investigated. Details of the accumulator and the associated performance comparisons for all three seasons are shown in Table 5 below.

Table 5 Capacity Factor Information

	Original SMR	SMR with Accumulator
Maximum Energy Production (MWh/wk.)	7,560.0	7,560.0
Actual Summer Energy (MWh/wk.)	5,746.7	6,896.0
Capacity Factor (Summer)	76.0%	91.2%
Actual Shoulder Energy (MWh/wk.)	3,885.9	4,663.1
Capacity Factor (Shoulder)	51.4%	61.7%
Actual Winter Energy (MWh/wk.)	5,102.9	6123.5
Capacity Factor (Winter)	67.5%	81.0%

The capacity factor still improves in the winter when compared to the original winter demand profile, but most of the change is because the SMR is producing supplying more power due to the larger grid being supplied. Most of the energy is generated below 45MW which is handled by the original system. Most of the excess steam is bypassed in the winter since the accumulator is already full. That being said, the scale of the grid did increase, improving the capacity factor significantly. This could not have been achieved if the accumulator was not in place, increasing the peak demand capacity in the summer. A similar result was found for the shoulder months, and it was determined that the accumulator was not needed at all but the capacity factor increased due to overall demand scaling.

5.4 Using Stored Steam for Process Heating

The last application considered drew a constant flow rate of steam out of the accumulator all the time and charged it simultaneously when there was excess steam available from the power generation steam loop. The first attempt looked at the entire demand data available to calculate an average flow rate into the system. This flow rate was then selected as the constant flow rate that could be supplied to a process. For the summer demand, this flow rate was found to be just under 25 lbs/sec. Then, the model was run with the constant flow rate out and the available flow rate from the reactor going into the accumulator simultaneously. If the vessel was fully charged and the inlet steam was high than the outlet steam flow, excess steam was bypassed to the condenser. The summer demand data was looped and multiple weeks were simulated.

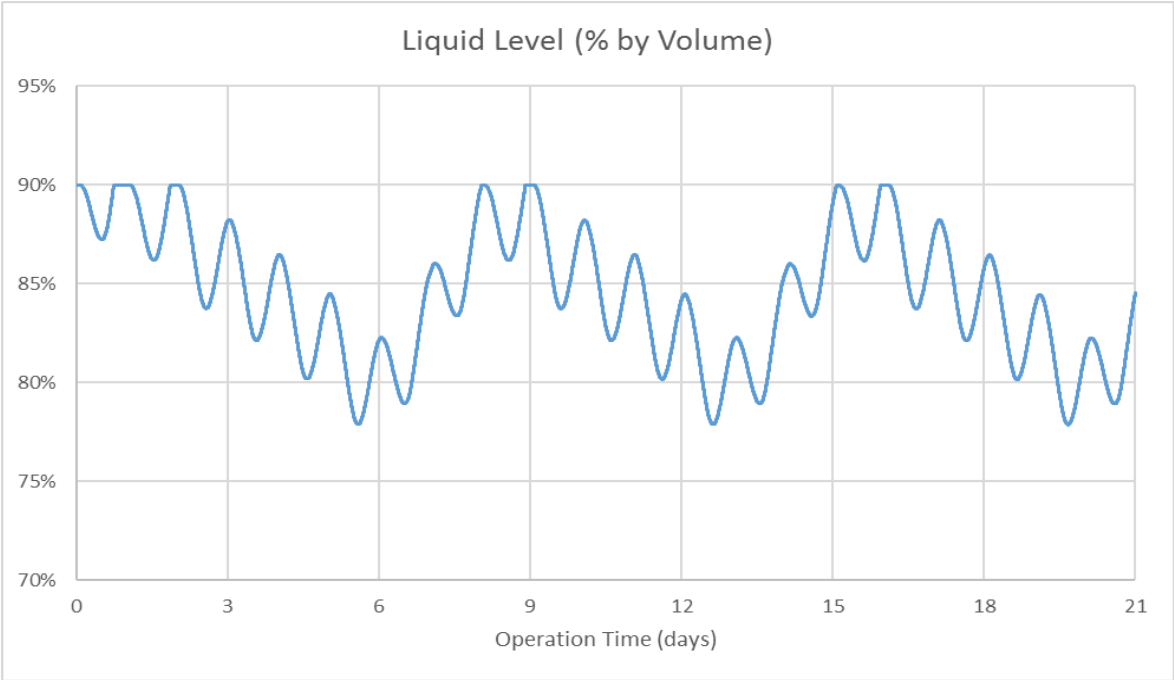

Figure 20 Liquid Level in Accumulator with Constant Flow Rate Out – Summer

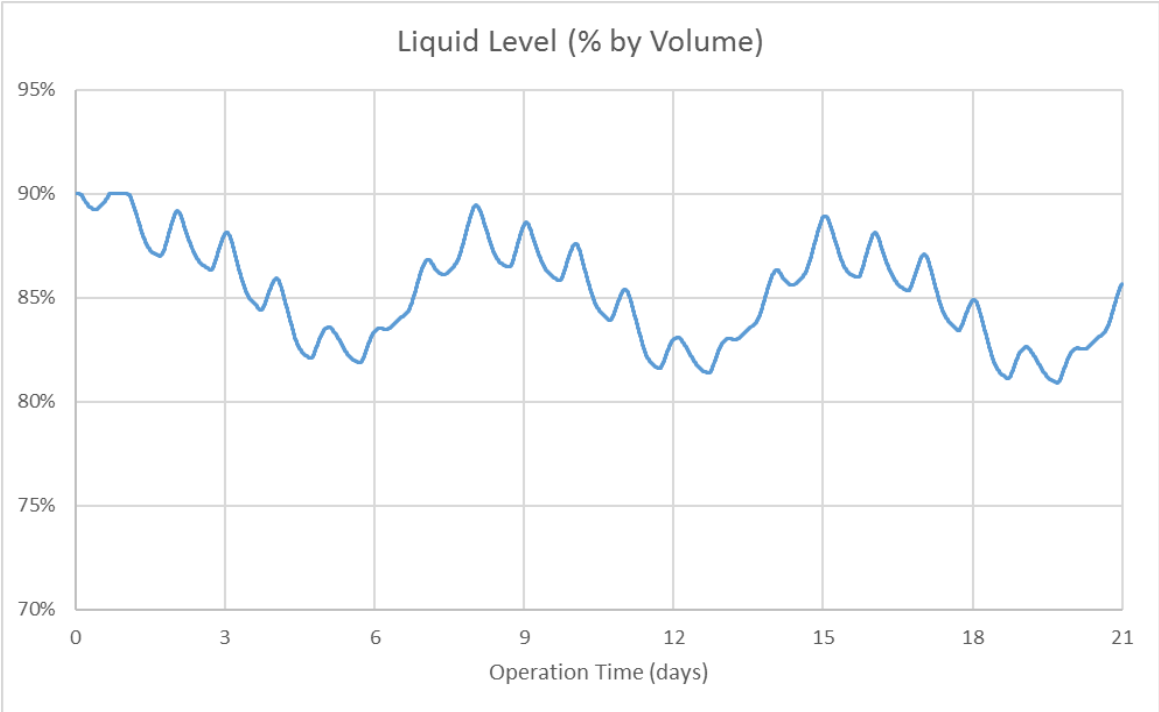

Figure 21 Liquid Level in Accumulator with Constant Flow Rate Out – Shoulder

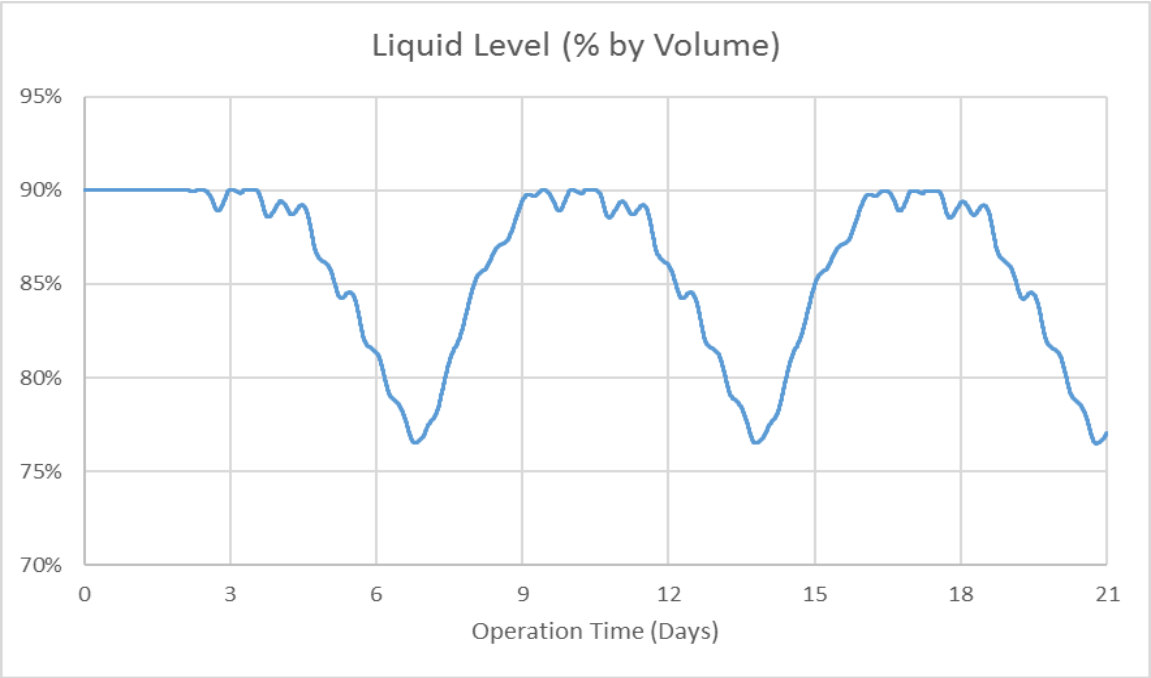

Figure 22 Liquid Level in Accumulator with Constant Flow Rate Out – Winter

Figure 20, Figure 21, and Figure 22 show the effects of the selected flow rate out of the accumulator with the available steam flow from the reactor charging. The system appears to be able to meet the demand from the constant flow rate leaving the accumulator. The liquid level tracks downward, failing to recover fully each weekday but is able to completely recover during the weekend. The flat spots at 90% indicate that the accumulator is full and some steam is being bypassed. This indicates that the accumulator could supply more steam than it currently is in this simulation. Ideally, one would expect to see the accumulator briefly hit 90% at some point in the week. This would indicate that it can continue to operate indefinitely since it reaches full charge and does not experience a low-pressure shutoff at any point.

The process was assumed to require steam at 100 psia, and therefore, the low-pressure shutoff was selected to be 150 psia. The lowest pressure reached in this trial was found to be 244.8 psia. This means the accumulator has addition capacity to supply steam at 100 psia, but continuous operation should only supply the amount of steam to the process that is the average amount of steam stored from the reactor. Running more than this amount will cause the accumulator to run out of steam. This is what happens during the week, but the difference is made up during the weekend. Without an extended period of low demand, the accumulator would run out of steam if the weekday pattern was continued.

The winter demand shows more weekly trends rather than daily trends. Since the daily trend has a double peak and is overall, less variable than the summer daily trend, the pattern is to be expected. The system still recovers over the course of the week, indicating indefinite operation. The shoulder month simulation shows a mix of the summer and winter results. The accumulator still needs a whole week cycle to fully recharge, but the daily patterns are more visible than the winter simulation. This trend is to be expected as well since the demand curve looks like a blend of summer and winter at a lower value than either.

5.4.1 Energy Provided as Process Heat

The pressure leaving the accumulator will be throttled down to the pressure required by the process heat exchangers, or 100 psia in this simulation. The enthalpy of the steam leaving the accumulator before throttling and the reduced pressure steam will be the same since the throttling process is isenthalpic. Typically, steam heat exchangers are fitted with steam traps that prevent vapor from leaving the heat exchanger until it condenses into liquid. Therefore, the thermal energy that will be supplied to the process will be the difference in enthalpy of the

inlet steam and the leaving condensate multiplied by the mass flow rate. In this case, the exiting enthalpy was assumed to be that of saturated liquid at 100 psia, or 298.57 Btu/lb.

When a heat exchanger is connected to a controller, the steam pressure can be regulated through a valve to maintain conditions in the process. In practice, the enthalpy leaving the heat exchanger may be lower due to a lower pressure after the control valve and lower pressure saturated liquid condensate. Using a saturation pressure of 100 psia could be slightly conservative since the actual enthalpy leaving the device will depend on the process and the control system. In addition, the model was designed to supply a constant heat rate to the process. Therefore, the mass and pressure will fluctuate to maintain a constant rate of heat addition.

The heat supply rate to the process was found to be 82.76 MMBTU/hr or the equivalent of 24.25 MWth while meeting the summer electrical demand. The maximum theoretical output that a heat exchanger operating at 100 psia could supply to a process was found to be 126.7 MWth. This heat rate was found by assuming no steam goes through the turbine and consequently the feedwater heater is not supplied with steam either. The mass flow rate through the system was reduced until the steam leaving the steam generator is saturated. Producing saturated steam is as low as the steam generator is allowed to operate in this scenario. The mass flow had to be reduced to 477,047 lbs/hr, resulting in the previously mentioned maximum heat rate. The summer simulation was able to serve all the electrical requirements of the grid with a peak of 45 MWe all the while providing 24.25 MWth of high-quality heat to a process. The accumulator recovers 19.1% of the total possible thermal energy supplied from a heat exchanger without affecting electrical supply.

The winter demand profile was also simulated to assess the usefulness of the accumulator. As expected, the rate of heat could be supplied was higher in the winter since the electrical demand was lower. The calculated thermal output of a heat exchanger operating at the same pressure mentioned before was 32.9 MWth or 26.0% of the thermal energy available. Shoulder months are able to supply an even higher heat rate than summer and winter providing 49.4 MWth amounting to 39.1% of the total available heat. Since the heat and cooling loads are low in these months, the electrical demand is low resulting in high excess steam. The following table summarizes the results found in the process heating models:

Table 6 Process Heating Results

	Summer Demand	Shoulder Demand	Winter Demand	Theoretical Max
Max Mass Flow In (lbs/hr)	184,408	238,290	185,325	N/A
Min Mass Flow In (lbs/hr)	0	135,005	49,722	N/A
Average Mass Flow Out (lbs/hr)	91,416	185,924	124,090	477,047
Heat Supplied to Process	83 MMBtu/hr 24 MWth	169 MMBTU/hr 50 MWth	112 MMBtu/hr 33 MWth	432 MMBtu/hr 127 MWth
Percent of Total Heat Available	19.1%	39.1%	26.0%	100%

The steam accumulator is able to buffer the variable steam flow available from the power generation cycle and provide a constant flow of high-quality heat that can be used in for a process. The steam produced under part load would either be bypassed to the condenser and ultimately rejected to the environment, or the reaction would be slowed through the use of control rods. Bypassing steam wastes the energy produced by the fuel while control rod movement could theoretically preserve some fuel. In reality, the fuel is likely to be replaced

on a time-based schedule rather than a load-based schedule, meaning a reduction in fuel usage will not result in any fuel savings when the bundles are replaced. Providing process heat is a good way to take advantage of the excess available heat and potentially replace a fossil fuel.

5.5 Economics of Operating the Steam Accumulator

Many times, the decision whether or not to install new equipment is based on money. An investment that pays for the capital cost associated with it quickly is desirable.

5.5.1 Using the Steam Accumulator for Power Generation

The savings associated with operating the nuclear power plant with and without the steam accumulator were analyzed. It was assumed that the best-case scenario of cost savings could be achieved if the nuclear power plant were to operate in load-follow mode. This means all the variable costs associated with the running the plant will be scaled with the output. A reduction in MWh generation will result in a reduction of the variable costs of operating the plant. As mentioned before, this is optimistic since there are stringent scheduling and cycling rules that supersede fuel utilization with respect to refueling. From Section 3.2, the variable cost of operating the nuclear power plant was found to be $0.0186/kWh.

The area under the time progression of demand is the energy provided by the power plant. The most energy output would occur when the maximum capacity is being generated all the time. Generating 45 MW of power for each hour in a year will produce 394,200 MWh of energy. Table 5 describes the summer and winter capacity factors which can be used to extrapolate the actual energy generated by the power plant over the course of a year. Shoulder months could be expected to have higher savings than winter with less variability. Since the demand is more constant in the shoulder months, the accumulator may not be as useful as it would in the

summer or winter. To be more conservative in estimating cost savings, only the summer and winter savings will be considered. In practice, refueling outages are typically scheduled for the shoulder months, rendering the savings associated with load-following invalid occasionally. Using half the hours of the year for summer and winter demand profiles, the total annual savings is shown below.

$$LF\ Cost\ Savings = (Var.Cost)(Max\ Energy)\left(\frac{hours\ used}{\frac{hrs}{yr}}\right)(1 - CF) \tag{21}$$

$$LF\ Cost\ Savings = \left(\frac{\$0.0186}{kWh}\right)\left(394.2x10^6\frac{kWh}{yr}\right)\left(\frac{2{,}920\ hrs}{8{,}760\frac{hrs}{yr}}\right)(1 - 0.760)$$

$$LF\ Cost\ Savings = \frac{\$586{,}570}{yr\ (summer)}$$

Similarly, the annual cost savings of operating the plant in load following mode in the winter. With a capacity factor of 67.5%, was found to be near $800,000 per year. Shoulder months had the highest savings with a capacity factor of 51.4% and a savings of 1.2 million for the four shoulder months per year. The total savings are estimated to be over $2.6 million annually. This cost savings is an estimate of the potential variable cost savings associated with load following a nuclear power plant. Next, the revenue loss must be considered.

When the grid demands more power than the SMR can supply, auxiliary power stations must be brought online. Many times, these plants are powered by small, fossil fueled engines such as natural gas turbines or petroleum internal combustion engines. Efficiencies are usually low

since the auxiliary power plants are rarely used and do not generate much profit if any. The cost to generate electricity from these peaking plants can be tens of cents per kilowatt hour. When the system is installed as part of a larger grid, it can still be used to offset some of the inefficient peaking plants, although they may not have such a high cost since the power can be balanced out among more customers. The conservative approach will be to use the average cost of power in an existing grid to estimate how much money the generated electricity will bring in. The average cost of power for North and South Carolina was researched and described in Chapter 3. The result was that the end-use customer pays an average of $0.0941/kWh of energy. Applying this rate to the difference in energy that could have been generated by the plant for the three seasons results in the opportunity cost of operating in load-follow mode.

The capacity factor means that only 76.0% of the energy that could have been generated actually was generated and sold. The remaining 24% represents the opportunity cost that could have brought in more revenue to the plant. For summer, the number of kilowatt hours that could have been generated and were not was found to be 31.5×10^6 kWh or $2.97 million for the season. A similar analysis was performed for winter and shoulder months resulting in 42.7×10^6 missed kilowatt hours and a potential revenue of $4.02 million for winter, and 63.9×10^6 missed kilowatt hours at $6.01 million potential revenue for the shoulder months. Overall, the plant saved $2.6 million in operating cost while it missed out on almost $13 million in revenue. Operating in load-follow resulted in an opportunity cost of $10.4 million per year. For comparison, the total revenue possible from a 45 MWe power plant at this electrical rate would be $37.1 million per year.

With the installation of a steam accumulator, the reactor would be operating at a higher load for more hours of the year. Therefore, the variable cost savings is not realized but more megawatt hours are being sold to customers, meaning more revenue. Since the revenue per MWh is significantly higher than the increase in cost to generate that same MWh when compared to load following, a higher capacity factor translates to higher profits. Revenue of the plant with the accumulator installed was calculated using the same process shown above, and the results are displayed in the following tables. The "Effective Revenue" column is the revenue from power generated plus any cost savings. This column can be used to compare the effectiveness of the accumulator since any cost reduction would have the same effect as receiving higher revenue for a given amount of energy generated.

Table 7 Revenue Analysis of SMR Power Generation Capabilities

Season	Max Energy Possible (MWh/yr.)	Actual Energy Produced (MWh/yr.)	Cost Reduction	Revenue Generated	Effective Revenue
Summer	131,400	99,864	$586,570	$9,397,202	$9,983,772
Shoulder	131,400	67,540	$1,187,803	$6,355,476	$7,543,280
Winter	131,400	88,695	$794,313	$8,346,200	$9,140,513
Total:	394,200	256,099	$2,568,686	$24,098,878	$26,667,564

Table 8 Revenue Analysis of SMR with Steam Accumulator

Season	Max Energy Possible (MWh/yr.)	Actual Energy Produced (MWh/yr.)	Cost Reduction	Revenue Generated	Effective Revenue
Summer	131,400	119,837	$0	$11,276,643	$11,276,643
Shoulder	131,400	81,074	$0	$7,629,045	$7,629,045
Winter	131,400	106,434	$0	$10,015,439	$10,015,439
Total:	394,200	307,345	$0	$28,921,127	$28,921,127

The addition of the accumulator bumped the yearly revenue up to almost $29 million compared to the $26.7 million brought in by load following and the associated cost reduction. The accumulator brings in an extra $2.25 million annually compared to load following. These cost savings are based the power requirements of a standalone grid with variable summer and winter demand curves. The system could potentially be optimized more if it was interconnected with other generation sources. In a larger grid where the SMR is not the only source of power, an accumulator can be used more selectively when the economics are favorable.

The cost of alternative generation sources could influence whether or not installing an accumulator is a cost-effective solution to meeting a higher demand. If the accumulator is not installed, some additional generation source must be used if the scaled-up demand is to be met. The accumulator increases the profitability of the SMR, but if the cost of installing and operating another generation source is lower, it would likely get installed. The carbon impact of power generation could swing the decision in favor of the steam accumulator since it would be a carbon-free way to meet higher peak demand.

5.5.2 Natural Gas Cost Analysis

In 2016, the EIA published the cost per kilowatt for many generation technologies that were installed in 2013. Natural gas was the cheapest fuel source at $965/kW to install. [23] The cost to install a combustion turbine plant capable of delivering a peak demand of 9 MW (the additional demand added by scaling the grid up 20%) would be $8.7 million. The plant would be operating at a capacity factor of 20.3% in the summer, 2.3% in the winter, and not used during the shoulder months. Installing the plant would bring in the same additional revenue as the accumulator, but the key difference is the variable fuel cost associated with operation. At

the time of writing this report, natural gas is an abundant and relatively low-cost fuel. The historical prices tell a different story. Figure 23 shows the variability in natural gas prices. The end user cost will be slightly higher than the spot price due to transportation costs.

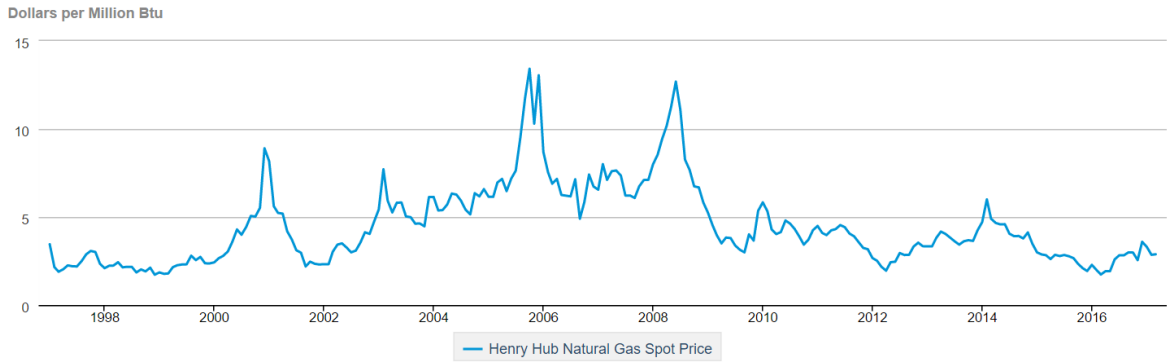

Figure 23 Historical Natural Gas Prices at the Henry Hub [24]

The data in Figure 23 was retrieved from the EIA website. The price of natural gas as of March 2017 was reported to be $2.88/MMBtu. Hydraulic fracturing and horizontal drilling are some factors attributed to low natural gas prices, and the predictions are that it will remain low for several years to come. The natural gas price that will be used for cost analysis is $3.00/MMBtu. This price will be used to compare the energy of the accumulator with the energy of natural gas as an alternative.

Simple cycle gas turbines would likely be used for small trimming loads in a power grid. Since the capacity factor will be low, the economics do not favor installing a more efficient combined cycle. The efficiency of these small, simple cycle gas turbines is somewhere between 20% to 35% according to the U. S. Department of Energy. [25] Taking the conservative estimate of

35% efficiency, the gas turbine would use approximately 51,970 MMBtu of natural gas to generator the required 5,330 MWh of electricity during the summer season described above. The winter demand profile would consume 5,990 MMBtu of natural gas to generator 614 MWh of energy. The total natural gas consumption would be almost 57,960 MMBtu per year which would cost $173,875 annually in fuel. The installation of the steam accumulator does not consume any additional fuel to meet the excess peak demand and would only have a maintenance cost associated with operating it. The accumulator itself does not have many moving parts that can wear out and would not likely require much maintenance. The peaking turbine would require regular maintenance. These costs are neglected since the gas turbine would likely have similar maintenance costs.

The lowest cost alternative generation source that could be used at the time of this research is natural gas. The cost to install a natural gas turbine is the cost to compare to when assessing the steam accumulator's feasibility. The installation cost of the steam accumulator is dependent on many factors such as the number of tanks, the required pressure rating, the location (under cover or outside), the amount of insulation, the geometry, etc. Since this study does not consider many of these factors, if would be difficult to estimate the cost of installation of the steam accumulator. The savings and operating cost comparisons can be used to estimate what the project would need to cost for the desired payback period.

The cost savings of operating the steam accumulator compared to the cost of operating a natural gas turbine will come from the natural gas fuel cost. The $173,875 per year will not be an expenditure if the accumulator is used to meet peak demand. Since it will be assumed that one system or the other must be purchased to meet the demand, the simple payback will be

implementation cost to install the accumulator compared to the implementation and operating cost for the gas turbine plant. The gas turbine will cost $8.7 million to install and $173,875 annually. Therefore, at the end of the first year, the gas turbine will have incurred a cost of $8.86 million. If the accumulator system costs $8.86 million to install, then the simple payback period would be one year. Following the same pattern, the implementation cost would have to be $9.55 million for a five-year simple payback and $10.42 million for a ten-year simple payback. These estimates are subject to change if the natural gas price changes.

5.5.3 Using the Steam Accumulator for Process Heat

The last area studied is the use of stored steam for process heat. The economics of this projects depend heavily on the cost of the alternative fuel that would be needed to generate the steam the accumulator supplies. Again, natural gas was selected at the comparison fuel due to its low price and flexibility. Many systems that use natural gas have the capability to run on No. 2 fuel oil as a backup to reduce downtime in the event of a natural gas shortage or issue. The constant heat process would require a boiler if it was not being supplied with steam from the accumulator. The system can be served by three, 1,800 HP boilers with a combined maximum capacity of 180.8 MMBtu/hr. The cost of each boiler is estimated at $679,500 installed based on 2015 RSMeans Mechanical Cost Data [26] for a total installation cost of $2.04 million. There would also be an operating cost associated with running the boilers on natural gas.

Combustion boilers have an efficiency loss associated with the hot flue gasses leaving in the exhaust stream. After visiting several manufacturing facilities with boilers, the average boiler efficiency was found to be between 75% and 85% using a stack gas analysis tool. The conservative approach will again be used with 85% boiler efficiency. The accumulator can

provide 83 MMBtu/hr for one-third of the hours of the year (summer), 112 MMBtu/hr for a third of the annual hours (winter), the 169 MMBtu/hr for the remaining hours. The equates to a total of 1,062,880 MMBTU of heat supplied to the process. The amount of natural gas needed will be the heat provided divided by the boiler efficiency. Over the course of a year, the process will require 1,250,000 MMBtu of natural gas at a cost of $3.75 million. Therefore, using the same cost comparison analysis from above, the five-year payback cost for a steam accumulator will be $20.8 million, and the ten-year simple payback would be $39.6 million. If the accumulator can be used in this fashion, this results in a much faster payback than generating power since the heat is required all year long compared to the low capacity factors of the gas turbines.

6 Conclusion

This study aimed to assess the performance and economics associated with using large scale steam accumulator for energy storage in nuclear hybrid energy systems. The accumulator acts as a buffer between steam production and demand so that production can be more constant even when demand is variable. The goal was to use a Small Modular Reactor, modeled after the NuScale SMR, to supply electricity to a grid and store energy when electrical demand was low. Sizing a power plant to meet the peak demand of its customer base means that it will be operating below its rated output most hours of the year. Combining the daily variations in demand with the seasonal variations means that many times a generator is significantly oversized for the power it is actually supplying. A single piece of generation equipment is forced to change output rapidly and repeatedly, which can result in poor operating efficiency or maintenance issues. Being able to store some of the energy can change the way the system handles varying loads.

Power data was collected for North Carolina and South Carolina. In the summer season, electrical demand is periodic over the course of 24 hours with a single peak around mid-afternoon and a dip overnight. This sinusoidal pattern can be attributed to high cooling loads during active hours. In the winter, this region has a significant percentage of electric heating, resulting in a double-peak during the course of a day. The power data was collected for the whole region and scaled down so that the peak of the combined data was the maximum output of the SMR being used to supply the power or 45 MW. The demand was scaled based on the summer data meaning the winter demand was far below a peak of 45 MW.

It was found that nuclear reactors do not have a high variable cost of operation. The sum of variable costs was found to be $0.0186/kWh. The reason the power is still expensive is due to a high upfront cost that needs to be made up over the lifetime of the plant. Operating at any power output less than full-rated capacity means the reactor is not as profitable as it can be. The capital costs can be made up faster if the plant sells more power. Additionally, a portion fuel it typically changed out every 18 to 24 months meaning the variable cost of fuel may not be saved if the load is reduced. Safety and reliability trump fuel efficiency when it comes to operating a nuclear plant. In a large grid with multiple units, the nuclear plants are used for constant baseload power.

A steam accumulator was added to the SMR system in an effort to improve the economics of operating the plant. The steam accumulator and Rankine cycle that is powered by the nuclear reactor were modeled to simulated the effects of following a specified demand curve. The original SMR without storage was able to meet the demand curve since they were scaled down to the peak of the plant. The demand was then scaled up to simulate the effect of adding more end-users to the grid. With a higher peak demand, the SMR can no longer meet all the needs of the grid. The steam accumulator is used to make up the difference. When the demand is less than 45 MW, the reactor is maintained at full power and full steam output. Any excess steam that is not consumed by the main turbine, which is operating at a reduced output, is sent to the accumulator. When the demand exceeds 45 MW, the pressure in the accumulator is reduced, flashing some of the liquid contained within to steam. This steam is then run through a separate peaking turbine to generate more power than the rated capacity of the SRM alone.

The higher power output is only achievable for a few hours at a time. The accumulator and amount of grid scaling were optimized so that the system could operate continuously. The optimal parameters were found to be a 2.8-million-gallon storage vessel and a 20% increase in the grid size. An accumulator of this size was just able to supply the required excess energy during the highest peak in a summer week. The steam was run through a 12 MW steam turbine via an appropriately sized flow control valve to regulate output. The turbine needed to be slightly oversized since the accumulator will be operating at a reduced pressure when the full output is required. Sizing based on the fully charged pressure would result in a failure to meet the required demand.

The system was also simulated with a winter demand curve input after it had been sized to handle the summer demand. The result was an oversized accumulator serving an undersized customer base. The peak demand rarely exceeded 45 MW meaning the accumulator was not fully utilized. If the system was installed to meet the needs of a standalone grid, such as a military base or island, then the customer base would not change seasonally. This means the system needs to be sized to handle the highest peak demand leaving it overdesigned for the other season. If the system was part of a larger grid, then the accumulator could be used in conjunction with the operation of other power plants to maximize utility. Since the grid was still scaled up, the capacity factor did improve significantly still, which would not have been possible if the system couldn’t meet the summer peak.

Another option considered was supplying a process with a constant supply of heat. If the reactor was located near a facility that had a need for constant heat, the steam accumulator could be used to supply steam at a constant rate while absorbing any excess steam available

from the nuclear steam generator. In this case, the power output of the plant would still peak at 45 MW. When there is excess steam, it will be sent to the accumulator, which is constantly venting steam to meet a heating requirement. The heat exchanger selected for this process heater will take in steam at 100 psia and expel condensate at the same pressure. The condensate is then routed back into the condenser where it rejoins the main reactor steam loop.

The total potential heat output from operating a heat exchanger at 100 psia was found to be 127 MWth. The discrepancy between this max heat output and the thermal rating of the reactor comes from the difference in pressure of the heat exchanger and the condenser. Some energy is rejected in the cooling water due to flashing. While the reactor was following the summer demand curve, 24 MWth were constantly available from the accumulator. Similarly, 33 MWth were available during the winter and 50 MWth during the shoulder months.

Finally, an economic analysis was performed on the resulting performance increases achieved by adding the steam accumulator. When generating power, the capacity factor was found to increase by 15.2% and 13.5% in the summer and winter respectively and only 10.3% during the shoulder months. This translated to an additional revenue $2.25 million per year when compared to load-following on a smaller grid. The best-case-scenario savings associated with load following on a smaller grid resulted in a cost reduction of almost $2.6 million while the accumulator model brought in an additional revenue of $4.8 million, resulting in the higher revenue. The variable cost used to estimate reduced load operating cost was $0.0186/kWh. The end-user cost used for revenue calculations was based on the average power cost of the region where demand data a collected from, or $0.0941/kWh.

If the energy provided by the accumulator must be supplied by any generation means, then implementation costs can be calculated for various payback periods. Since many parameters that would determine system cost are not considered in this study, the required implementation cost for a five and ten-year paybacks were calculated. The best alternative found for power generation was a 9 MW natural gas turbine. The maintenance costs are likely to be similar for both systems. Therefore, only the fuel cost for natural gas was considered as the difference in variable costs. Natural gas was estimated to cost $3.00/MMBtu based on EIA data. The gas turbine was estimated to cost $8.7 million to install and $173,875/yr. to operate. The required implementation cost of the accumulator system was found to be $9.6 million for a five-year simple payback or $10.4 million for a ten-year payback. Most of the cost comparison is in the fixed installation cost since the capacity factor on an installed unit would be low. Changing natural gas prices could also strongly impact the economics of installing a gas turbine.

The process heat application would need to be replaced by natural gas-fired boilers if the accumulator was not in place. It was estimated that the cost to install the appropriately sized boilers would be $2.0 million. The operating cost was found to be $3.75 million per year with 85% efficient boilers and the natural gas price mentioned above. The required implementation cost of the steam accumulator was found to be $20.8 million and $39.6 million for a five and ten-year payback. Here, gas prices play a significant role in the cost since the system is operating year-round. Both of these options are heavily dependent on fuel prices. If the site was forced to use a more expensive fuel, say No. 2 fuel oil or propane, then the economics would strongly favor the installation of the steam accumulator.

Currently, there are not many practical technologies to store power or heat a large scale. The front runners are batteries and pumped hydro for power, but there are many challenges associated with both technologies. Batteries are costly to produce, requiring many hazardous chemicals and processes that are resource intensive. Compounding on that is their limited number of charge/discharge cycles. The capacity of a battery diminishes with time over the span of its life. After the life cycle, the batteries must be replaced, contributing to a very high maintenance cost. Pumped hydro is better in terms of maintenance requirements, but the locations where it can be implemented are limited. A large enough reservoir with significant elevation is required to make a pumped hydro system work. Steam accumulators offer the advantage of low maintenance and flexibility. They can be used to provide heat directly or supply steam to a turbine and make power. The required storage volume is the biggest hurdle to overcome for the technology since it will occupy a significant amount of space at a facility to store several hours of energy. Materials must also be chosen carefully since the container will be subject to cyclic stresses, high pressure, and high temperatures.

The accumulator is being applied to the nuclear hybrid energy system, but it will also be good to implement with intermittent energy sources such as renewables. The accumulator can be used anywhere there is a difference between supply and demand. It is already used in small scale to make industrial plants more efficient and lower costs. The focus of this study was on SMRs supplying power to a remote grid, but the technology can also be applied to larger grids as well. Adding a steam accumulator to a utility's arsenal gives them the flexibility to choose the most economical source of power and trim with stored energy. The effects could be more efficient use of fuel and lower costs.

6.1 Future Work

One area of this research that was not extensively studied is the effects on the nuclear reaction and how the addition of thermal storage can change reactivity and thus heat output of the plant. The models used in this study do not take into account the increase in reactor power that is associated with a reduction in feedwater temperature. It is understood that the reactor would make more steam at lower feedwater temperatures but, to be conservative, this effect was not modeled. Some researchers have developed and continuously update extensive models that simulate every part of the nuclear power plant system. This accumulator model could be integrated with these nuclear models to better understand how the whole system would be affected. To date, Dr. J. Michael Doster with the Nuclear Department at North Carolina State University in the process of constructing a model of the NuScale reactor that could be used to further assess the effects of adding a steam accumulator.

Another area that can be looked into is losses. This model requires the use of feedwater and assumes no losses. Picking a geometry, material, and configuration would allow the modeler to better take into account the expected heat loss to the environment. Ideally, energy losses are to be minimized as they usually translate directly to financial losses, but there is a tradeoff between the diminishing returns of adding more insulation and the cost of installation. If heat loss turns out to be a significant component of the operation of the device, then control modifications could be made to take advantage of this effect to reduce the required feedwater during operation.

One last area that could be further explored is integration with a batch process requiring heat. One such application could be a digester in a paper mill. A high-demand batch process could

take advantage of a steam storage system that could supply steam at a high flow rate for brief periods of time. A model describing the steam demand profile of a batch process could be developed and integrated with the steam accumulator models developed for this research. This combination of storage and excess steam from the reactor could offset the need for a high capacity boiler, used to meet the high steam demands of the batch process. If appropriately located, the reactor could provide power and heat to a large-scale industrial facility that consumes high amounts of both electricity and heating fuel.

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Appendix

Appendix A: Additional Simulation Results

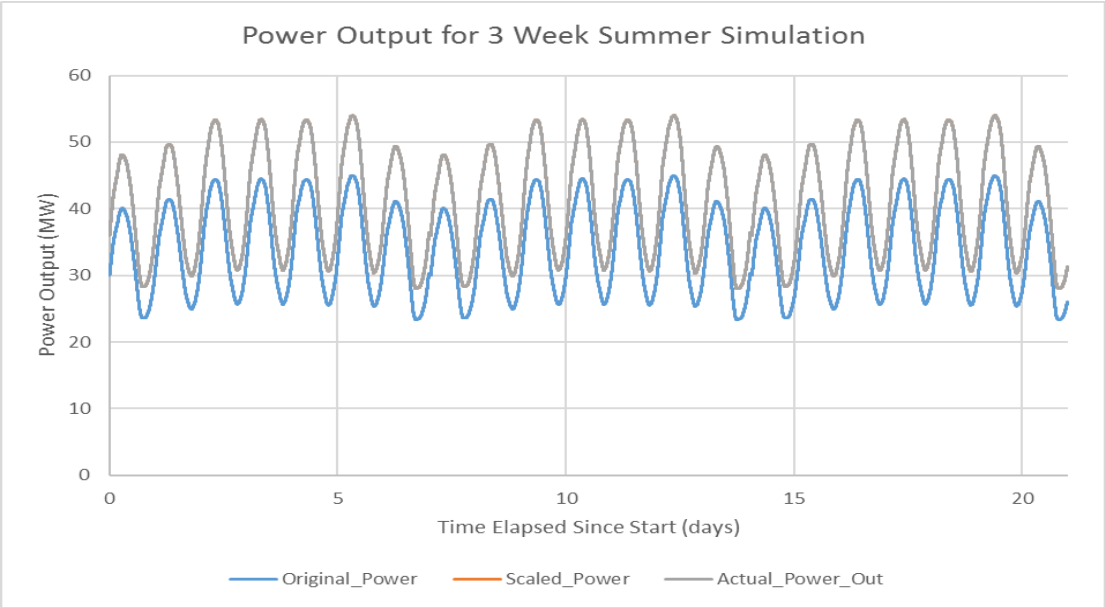

Figure 24 Power Output for Correct Accumulator Size and Summer Demand Scaling

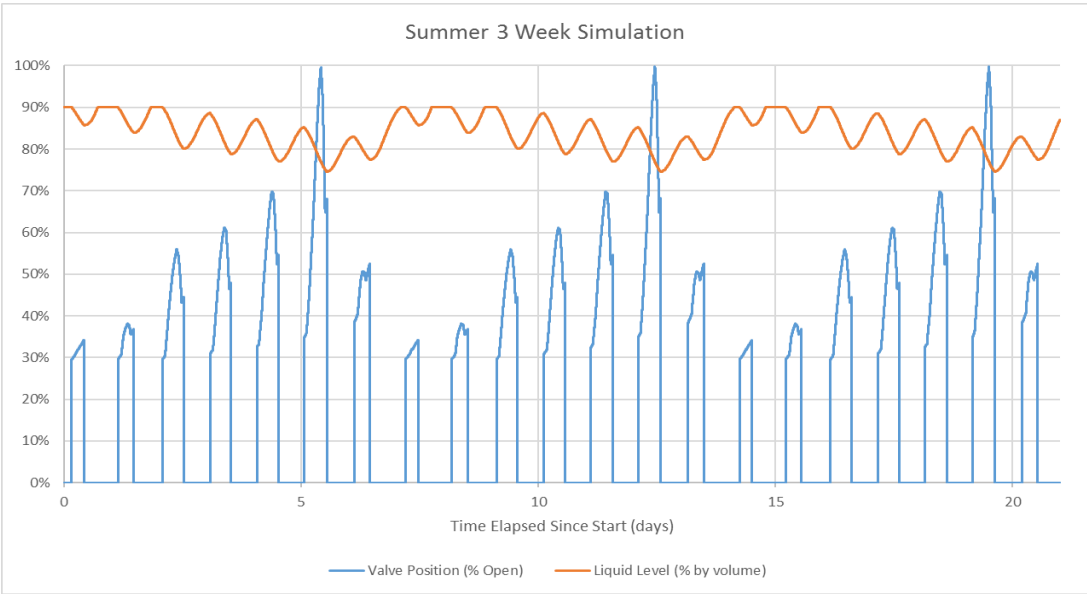

Figure 25 Valve Position and Liquid Level for Correct Sizing (Summer)

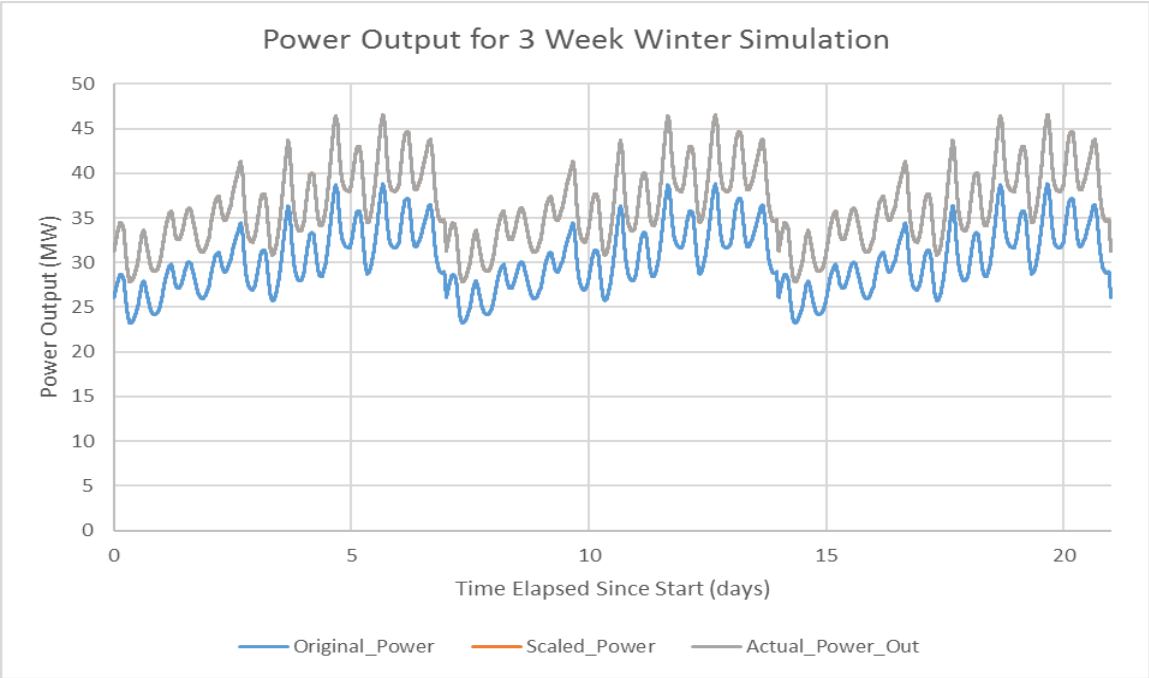

Figure 26 Power Output for Correct Accumulator Size and Winter Demand Scaling

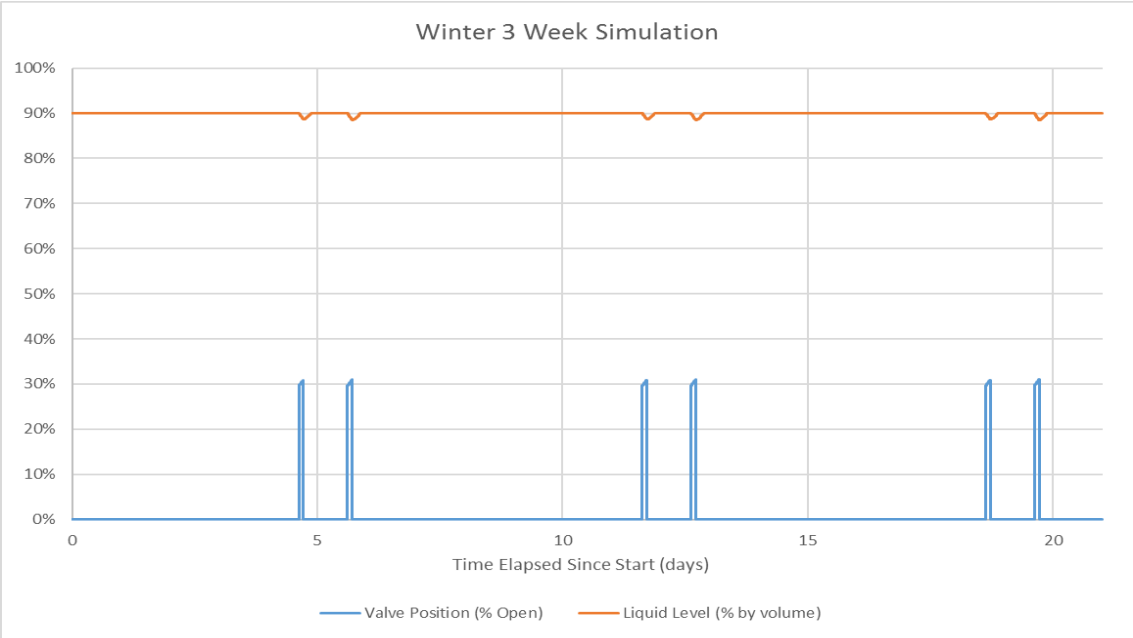

Figure 27 Valve Position and Liquid Level for Correct Sizing (Winter)

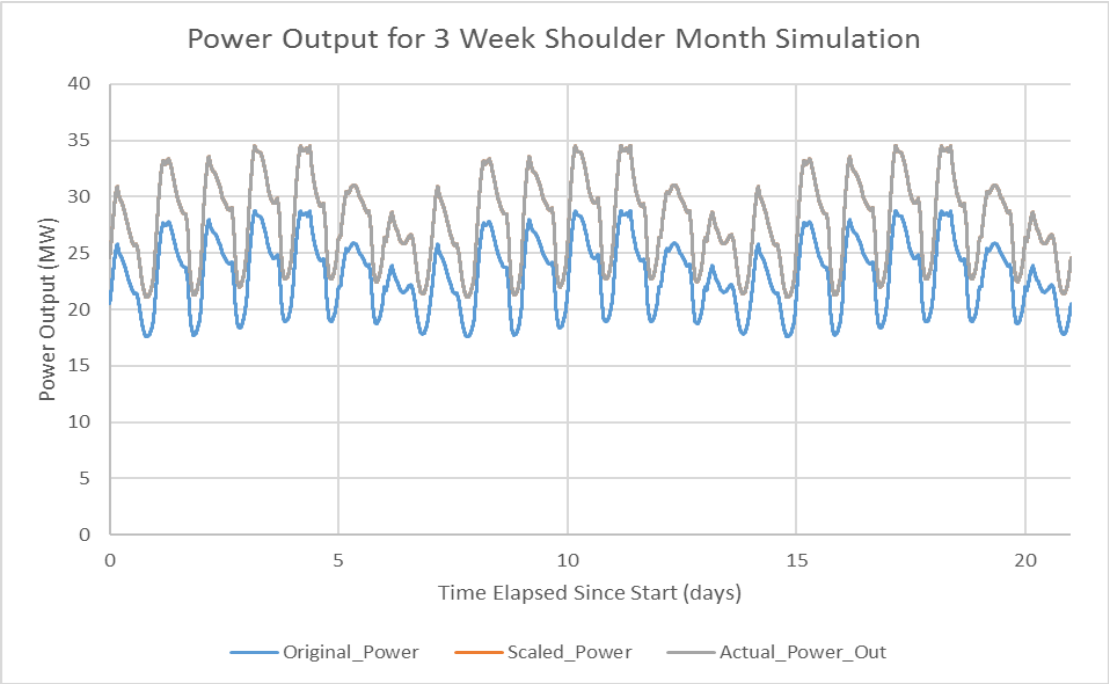

Figure 28 Power Output for Correct Accumulator Size and Shoulder Demand Scaling

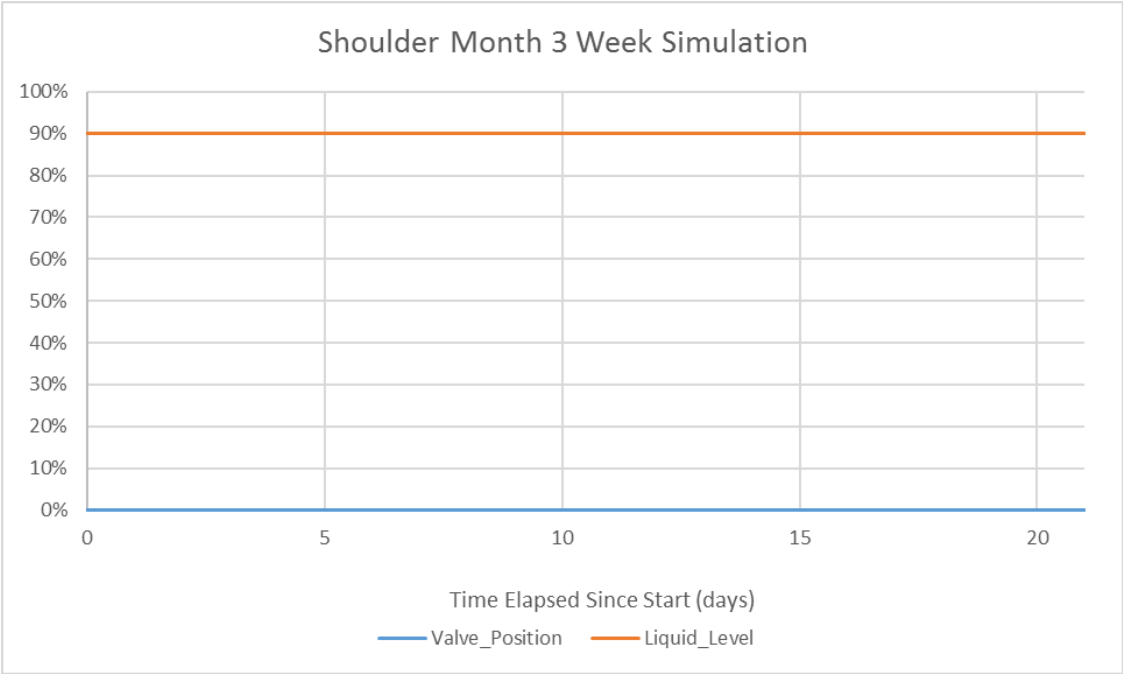

Figure 29 Valve Position and Liquid Level for Correct Sizing (Shoulder)