APPENDIX D: FUTURE RESOURCE OPTIONS

Overview

This Appendix provides an overview of the supply side resource technologies that were incorporated into the planning analysis conducted in Section V of the 2021 Integrated Resource Plan ("2021 IRP"). The resource technologies were considered for the capacity expansion plan analysis using the EnCompass production cost model, along with demand side alternatives discussed in Appendix B. The information in Appendix D is essential in defining the attributes of each supply side resource alternative.

Resource Option Listing

Through the planning process, Minnesota Power identified potential resources to meet future energy and capacity needs. The options below were considered at the beginning of the planning process:

<u>Short-Term Bilateral and Market Purchases</u>

- Market capacity purchase of 100 MW available through 2035
- Bilateral bridge purchase of 150 MW available from 2025 through 2035

<u>New Generation</u>

- Coal: Super Critical Pulverized Coal ("PC") with carbon dioxide ("CO_2") capture and sequestration ("CCS")
- Natural Gas: Combustion Turbine ("CT"), Combined Cycle ("CC") and Reciprocating Engine
- Renewable Energy: Biomass, wind and solar generation
- Nuclear: Small modular nuclear
- Energy Storage: Batteries, pumped hydroelectric, and Compressed Air Energy Storage ("CAES")

<u>Short-Term Bilateral and Market Purchases for Market Capacity</u>

The capability to purchase up to 100 MW of market capacity has been developed as a short-term capacity resource that can be selected by EnCompass during the 2021–2035 period in 1 MW increments for each year.

<u>Bilateral Bridge Purchase</u>

An unidentified 150 MW bilateral purchase, referred to as a "bridge purchase" was made available in EnCompass as a new resource alternative in the 2025 through 2035 time period. The bilateral transaction is indicative of a type of power supply contract Minnesota Power could potentially enter into with another counterparty during the study period. This contract includes both 150 MW of energy during the peak periods of each day and 150 MW of capacity.

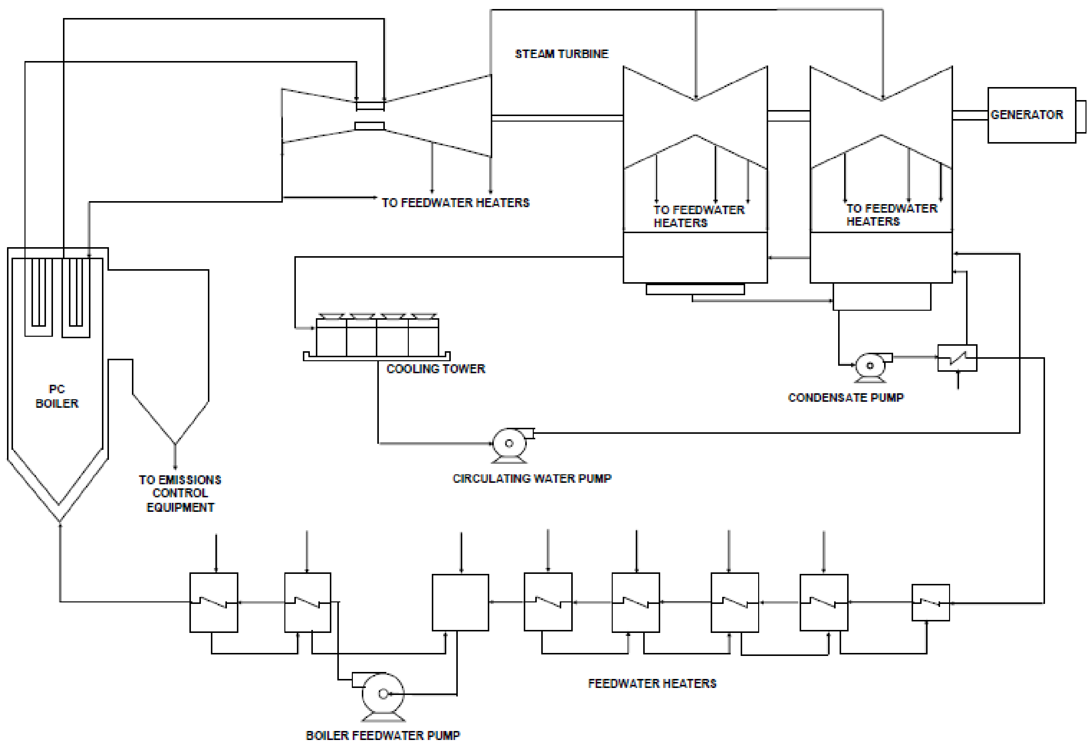
New Generation

<u>Pulverized Coal Generation</u>

PC technology is a reliable energy generation resource throughout the world. PC units can be retrofitted to burn gas, biomass and other fuels based on availability and British Thermal Units ("BTU") characteristics. PC technology can be divided into two distinct designs, distinguished by the maximum operating pressure of the cycle, either subcritical or supercritical. The subcritical or supercritical terms refer to the state of the water used in the steam generation process. The critical point of water, which distinguishes subcritical and supercritical states, is 3,208.2 psia[1] at 705.47 degrees Fahrenheit ("°F"). Subcritical power plants use pressures below this point and supercritical power plants use pressures above it. Supercritical steam generators are generally more efficient than subcritical units of the same size resulting in fuel savings and decreased emissions, but at a higher installation and maintenance cost. To minimize the carbon footprint of the plant, for purposes of this assessment, a supercritical design has been evaluated.

The main components of the PC unit are shown in Figure 1.

Figure 1: PC Unit Diagram



Coal from bunkers is fed into pulverizers, which crush it into fine particles. The primary air system transfers the fine coal particles to the steam generator burners for combustion. In the boiler, high-pressure steam is generated for the steam turbine. The expansion of the steam through the turbine provides the energy required by the generator to produce electricity. The steam turbine exhausts into a condenser. The heat load of the condenser is typically transferred to a wet cooling tower system (assumed for purposes of this study). The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps and high-pressure feedwater heaters.

[1] PSIA is the acronym for pounds per square inch, absolute.

Carbon Dioxide Capture and Sequestration

Capture

For PC technology, the capture of the CO_2 from the combustion byproducts is done on a post-combustion basis. Carbon capture technologies for pulverized coal-based generation continue to develop as more demonstration projects move forward. The coal unit in this assessment includes CCS using the advanced amine process. The advanced amine process is an enhancement on the Monoethylamine ("MEA") process that was developed over 60 years ago, and has been adapted to treat flue gas streams for CO_2 capture. Other organic chemicals belonging to the family of compounds known as "amines" are now being used to reduce cost and power consumption as compared to the traditional MEA solvent. Numerous companies are developing their own proprietary amine solvents including Fluor Corporation, Hitachi, Ltd, MHI (Mitsubishi Heavy Industries Ltd), Shell, and other companies.

The amine technology is the most developed of the large scale coal plant CCS technologies on the market. In the advanced amine process, a continuous scrubbing system is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber where CO_2 is removed from the flue gas and absorbed into an amine solvent, and a regenerator (or stripper), where CO_2 is released (in concentrated form) from the solvent and the original solvent is then recovered and recycled. Cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (amine in a water solution, with some additives). The amine reacts chemically with the CO_2 in the flue gas to form a weakly bonded compound, called carbamate. The scrubbed gas is then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat recovery exchanger, and is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the sorbent and producing a concentrated CO_2 gas stream. The hot CO_2-lean sorbent is then returned to the opposite side of the heat exchanger where it is cooled and sent back to the absorber. Fresh reagent is added to make up for losses incurred during the process.

In North America multiple CCS projects have gone through various stages of development, and several examples follow. SaskPower, the Saskatchewan provincial utility, completed its Boundary Dam 120 MW CCS project near Estevan, Saskatchewan in October 2014, making it the first power station in the world to successfully use CCS technology. The facility utilizes the Shell Cansolv amine-based post combustion capture system. Second, NRG Energy, Inc.'s 250 MW slipstream Petra Nova facility near Houston, Texas became operational in December of 2016, utilizing Fluor's amine based post combustion capture system. However, the facility was placed in reserve shutdown in May 2020 due to economic conditions. A third project, the Texas Clean Energy Project located near Odessa, Texas, was an IGCC unit with CCS proposed by the Summit Power Group that has been discontinued. Finally, Minnkota Electric's Project Tundra is proposed to be the world's largest CO_2 capture facility, which would capture CO_2 from the Milton R. Young Station in North Dakota. Project Tundra is in the Front-End Engineering and Design study phase based on Fluor's capture system technology.[2] All of these projects utilize the captured CO_2 for enhanced oil recovery ("EOR").

Sequestration

Other than the mid-continent rift, no potential geological sequestration sites exist in Minnesota. It is important to note that the mid-continent rift requires extensive evaluation that will require many years of research at a high cost before it can be determined if it is a viable

[2] https://www.fluor.com/client-markets/energy-chemicals/carbon-capture

sequestration site. Potential EOR, coal bed methane and saline aquifer sequestration sites have been identified and characterized in North Dakota. Of the identified sequestration options, only EOR has been commercially proven. The existing commercial EOR project is able to obtain value for the CO_2 because of the value of the additional oil that is produced. The long-term "value" of CO_2 will be impacted by the amount of CO_2 that is available in the region, which is also subject to the number and size of carbon capture projects that are installed. Therefore, for the purposes of the resource assessment, a North Dakota EOR site was selected for sequestration for both plant location options. No commodity value was assigned for the CO_2.

Location

The location of a new coal generating resource for Minnesota Power would be dependent on the ability to site and permit the facility as well as the fuel, transmission, and carbon implications of the proposed location. A North Dakota location was used as the starting point in the assessment for the 2021 IRP.[3] Prior IRPs considered new coal resources located in both Minnesota and North Dakota. Given that it is unlikely that a new coal generation facility would be selected in the IRP analysis due to its higher cost compared to other technologies, and utilizing the high level coal resource location screening assessment shown in Table 1, the Company chose to include one coal generation alternative and selected the North Dakota location.

Table 1: New Coal Resource Location Considerations

	Minnesota Powder River Basin Coal	North Dakota Lignite Coal	
Fuel Cost	Higher	Lower	North Dakota mine mouth plant eliminates the cost of rail.
Capital Costs	Lower	Higher	Lignite fuel characteristics require a larger boiler.
Transmission	Lower	Higher	Minnesota location will be closer to the load centers.
Sequestration Costs	Higher	Lower	North Dakota mines are adjacent to sequestration options, reducing the amount of capital for CO_2 piping and the operating costs of the compressor booster stations.
Impact on the limited northeast Minnesota Air Shed Increment	High	Low	The limited northeast Minnesota Air Shed increment is important to Minnesota Power's natural resource based customers who can't relocate their operations.

Natural Gas Technologies

Natural gas-fired generators provide the most electricity generating capacity in the United States, surpassing coal-fired generators in 2018. They are a versatile energy source for supporting the intermittency of renewable energy. Current advanced class gas turbines are

[3] Minnesota law prohibits constructing a new large energy facility that would contribute to statewide power sector carbon dioxide emissions. Minn. Stat. § 216H.03, subd. 3.

capable of burning a mixture of up to 30 percent hydrogen fuel and manufacturers are working on retrofits that will enable gas turbines to burn more than 30 percent hydrogen and eventually burn 100 percent hydrogen.

Gas Turbine Simple Cycle Generation

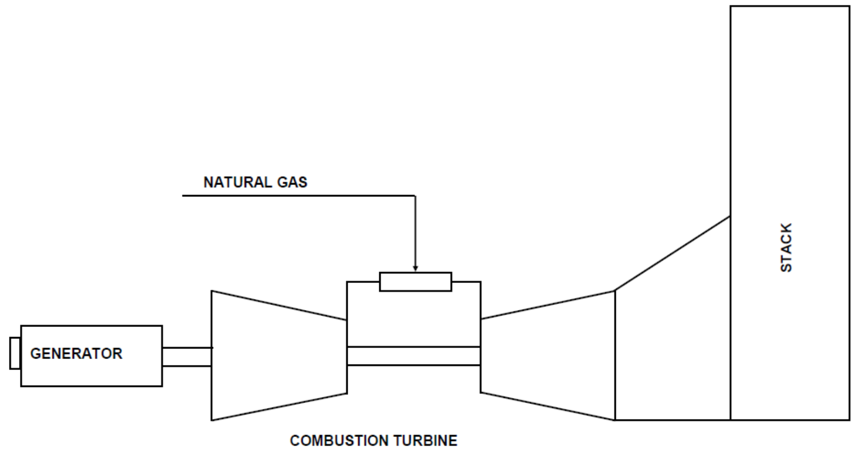
The gas turbine cycle is one of the most efficient ways to convert natural gas or fuel oil to mechanical power or electricity. A simple cycle gas turbine consists of a compressor section, combustor, and turbine section. Ambient air is compressed in the compressor. Fuel is mixed with the compressed air in the combustor section. The combustion products exit the combustor and expand through the turbine section. Typically, more than 50 percent of the turbine shaft work produced is consumed by the compressor section. The remaining shaft work is used to drive a generator. The exhaust gas exits at approximately 800–1,200°F through the exhaust stack. The simple cycle gas turbine also provides the benefit of a generation facility that can be readily converted to a larger CC generation unit to quickly (within 24 months) provide additional capacity and energy to support significant load generation.

Gas turbines are broken up into two main categories, aero derivatives and frames. An aero derivative engine is based on jet engine design for airplanes so they are robust, fast starting, low maintenance and very efficient. The aero derivative uses high quality alloy materials which allow them the ability to endure much higher cycling with lower maintenance costs. Aero derivative maintenance is not affected by startups and is only based on hours of operation. Based on these characteristics, the aero derivative is typically used as a peaker or for load following that requires very high cycling. Aero derivatives are more expensive on a $/kW basis compared to a frame and the largest turbines generate approximately 100 MW. Also due to their high efficiency and subsequent low exhaust temperatures (800-1,000°F), the aero derivatives are less economical to convert to CC.

The frame gas turbines are much larger and heavier than the aero derivatives. They have traditionally had longer start times, are less efficient than the aero derivatives, require more maintenance that is start and hour based, but are much larger and less expensive on a $/kW basis. The largest frame gas turbines exceed 300 MW per engine. The frame gas turbine is also very conducive to CC conversion since they have much higher mass flow and exhaust temperatures (1,000-1,200°F) compared to the aero derivatives. Recently, gas turbine manufacturers have been pushing designs for faster start times, higher efficiencies, and larger engines with the ability to burn alternate fuels including Hydrogen and renewable natural gas. Frame gas turbines have become much more flexible in the past years but are still not achieving the attributes of aero derivatives.

The main components of a simple cycle gas turbine unit are shown in Figure 2.

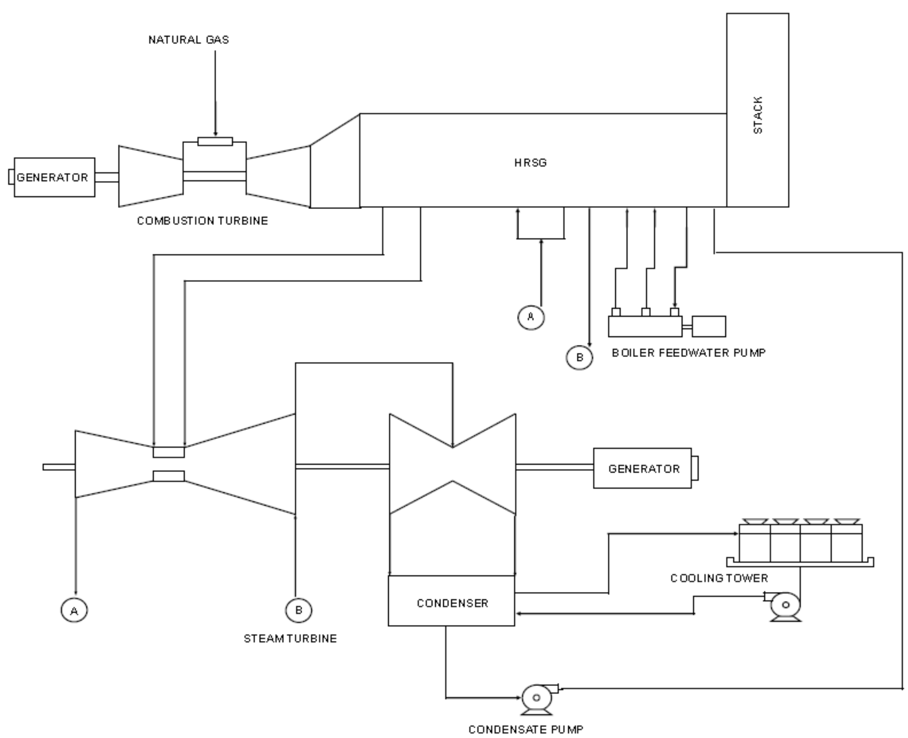
Figure 2: Simple Cycle Unit Diagram



<u>Gas Turbine Combined Cycle Generation</u>

The use of both the gas turbine cycle (also known as the Brayton Cycle) and the steam turbine cycle (Rankine Cycle) in a single plant is referred to as a gas turbine CC. The basic principle of the CC is to fire natural gas (or fuel oil) in a gas turbine, which produces power directly via a coupled generator. The exhaust from the turbine is used to create steam in a heat recovery steam generator ("HRSG") that can drive a steam turbine generator. The main components of a CC unit are shown in Figure 3.

Figure 3: Combined Cycle Unit Diagram



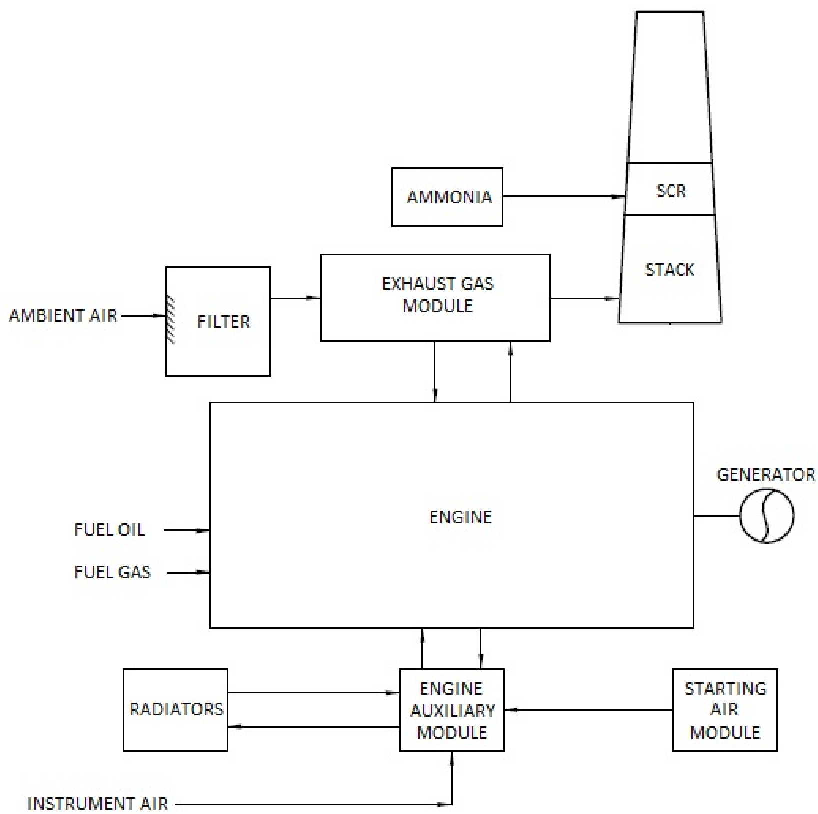
A CC facility results in high energy conversion efficiencies and low emissions (with selective catalytic reduction ("SCR") and CO_2 catalyst). The gas turbine cycle, as noted above, is one of the most efficient for converting fuel (natural gas or fuel oil) to mechanical power or electricity. Adding a steam turbine to utilize the steam produced by the HRSG increases the efficiencies to a range of 52 to over 60 percent in current advanced class turbines, compared to the efficiency range of 30 to 40 percent for a frame CT. To increase peaking power output, additional natural gas firing (duct firing) can be performed in the HRSG, and steam can be injected into the gas turbine for power augmentation.

Gas turbine CCs can be arranged in multiple configurations. The diagram above shows a 1x1 configuration (one gas turbine/HRSG and one steam turbine). A 2x1 configuration would include two gas turbines/HRSG's feeding one steam turbine. Assuming the same gas turbines, a 2x1 plant will generate approximately twice as much power as a 1x1 plant. A 2x1 plant will also have a slightly higher efficiency.

Reciprocating Engine Generation

A reciprocating engine utilizes the Carnot cycle to mechanically convert fuel to energy. The reciprocating engine burns fuel in a combustion chamber which pushes a piston connected to a crankshaft which turns the generator. Most large reciprocating engines for power generation have 18 or 20 cylinders and the largest engines generate approximately 18 MW. Multiple banks of engines are typically installed to meet generation needs and result in a highly dispatchable facility. The main components of a reciprocating engine are shown in Figure 4.

Figure 4: Reciprocating Engine Diagram



A reciprocating engine's efficiency is approximately 45 percent for current technology. It is as efficient as the most efficient simple cycle gas turbines. A reciprocating engine for power generation comes standard with a SCR and CO_2 catalyst to control oxides of nitrogen and CO_2. With these controls, reciprocating engines have low emission rates but not as low as CC gas turbines.

Renewable Technologies

Biomass Generation

The term biomass refers to any fuel that can be grown, harvested and regrown or animal manure and human sewage.[4] For the purposes of this estimate, untreated wood products such as mill and forest residue are assumed to be the biomass fuel source. Wood-fired boilers are typically a derivative of either older stoker type designs, or the newer bubbling fluidized bed design, and range in size from 10 to 50 MW. Though not evaluated in this IRP, other potential alternative biomass fuels are agricultural residues such as straw from cereal production, torrefied biomass (i.e. industrial wood pellets), residues from crop processing, energy crops grown specifically for use as a fuel, and animal waste.

The steam cycle and main components of a biomass unit are similar to those of a PC unit shown in Figure 1, with the exception of the reheat cycle. For units of this size, the capital cost and complexity added by addition of a reheat cycle are not often economically justified.

Wind Generation

The rapid evolution of wind turbine technology combined with the federal Production Tax Credit ("PTC") has resulted in wind turbine generators becoming a standard resource option on a utility scale. Key to that evolution has been the increase in the size of the wind turbine units that has provided the economy of scale required to be competitive. Although the larger size units have been a key part of the puzzle, it is also critical that the turbines are located in an area with a good wind resource to yield an effective renewable energy resource, as well as ensuring access to the bulk transmission system. The wind PTC has been extended by one additional year through its inclusion in the COVID-19 pandemic virus relief bill passed in December 2020. The PTC will continue to apply at 60 percent for any project that begins construction by the end of 2021.

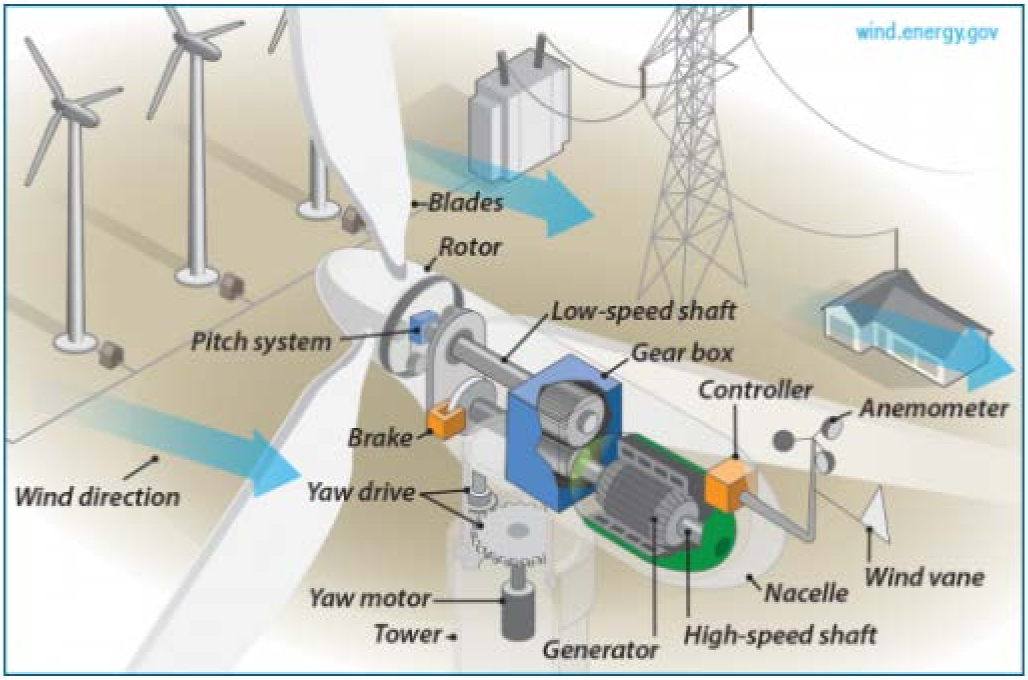
The basics of wind are the conversion of the kinetic energy in wind to turn a shaft that turns a generator. The main components of a wind generator are shown in Figure 5 below.

Locations that have a high average velocity of wind over a large area of land are key to making a viable energy resource. Within Minnesota Power's service territory, the best wind resource is located along the Laurentian Divide near active iron mining areas. However, the wind resource in the Company's service territory is lower than in other parts of the upper Midwest. Within the upper Midwest region, the best wind resource is in southwestern Minnesota, North Dakota and South Dakota. These areas have a lower busbar cost, but may have transmission constraints.

Wind generation is a variable resource, and as such cannot sustain the needs of a reliable electric system alone. To ensure reliability when the wind resource is not available, other dispatchable resources or energy storage is needed.

[4] As defined by the U.S. Energy Information Administration ("EIA"), https://www.eia.gov/energyexplained/biomass/#:~:text=Biomass%20is%20renewable%20organic%20material%20that%20comes%20from,especially%20for%20cooking%20and%20heating%20in%20developing%20countries.

Figure 5: Wind Generator Diagram

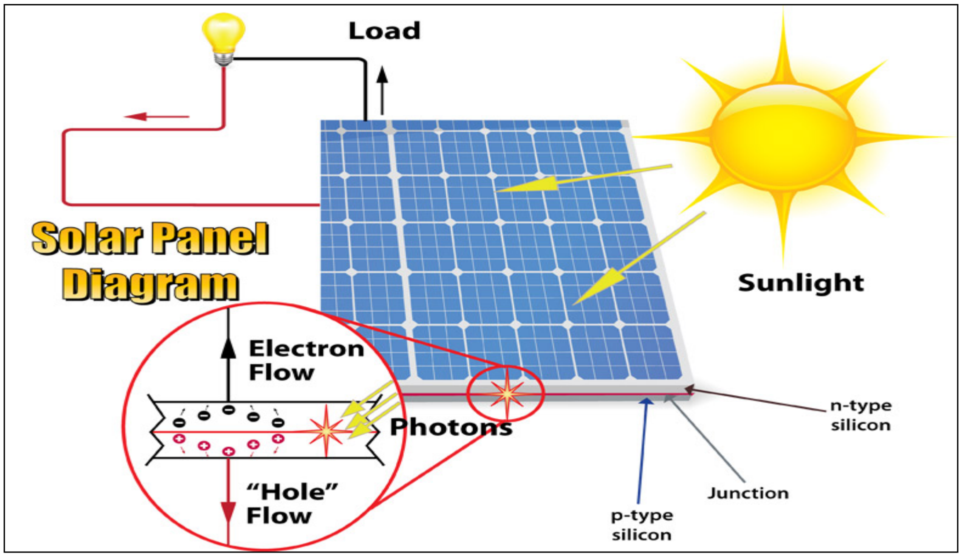


Solar Generation

Solar energy utilized for electric generation is typically classified into either solar thermal or photovoltaic generation categories. For the 2021 IRP, the Company focused on the photovoltaic technology, which is the solar technology typically deployed regionally. Solar thermal is most economical in the desert areas of the southwest where there is limited cloud cover to diffuse the energy. The less than optimal atmospheric conditions coupled with abundant lower-cost renewable alternatives make solar thermal a non-competitive utility scale option in the upper Midwest.

Solar Photovoltaic ("PV") generation directly converts the energy in sunlight into electricity when the semiconductors absorb the photons in the sunlight. There are two primary types of PV cells: crystalline silicon and thin film. Figure 6 demonstrates this technology. Typically, in the upper Midwest PV is the technology chosen for distributed generation and utility scale solar projects.

Figure 6: Photovoltaic Diagram



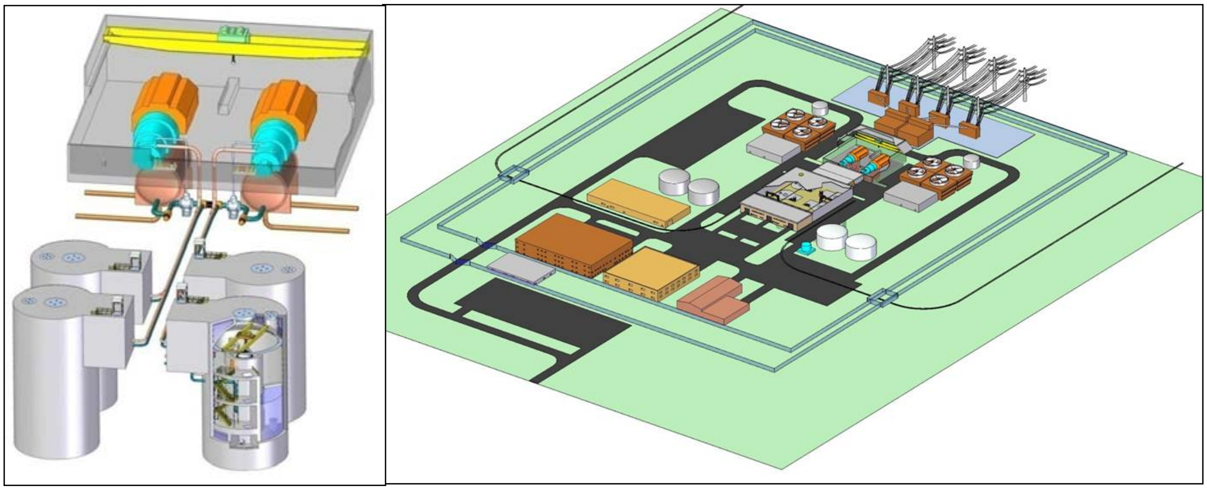
Solar generation installation is incentivized by the federal Investment Tax Credit ("ITC"). The ITC has been extended by two years through its inclusion in the COVID-19 pandemic virus relief bill passed in December 2020. The ITC for solar projects will retain the current 26 percent credit for projects that begin construction through the end of 2022.

Nuclear Technology – Small Modular Reactor

Manufacturers, NuScale Power, Holtec and GE/Hitachi, have begun designing small modular reactors ("SMRs") with the intent to create a smaller scale, completely modular nuclear reactor. According to these manufacturers, the benefit of these SMRs is two-fold: 1) the smaller unit size of less than 300 MW will allow more resource generation flexibility; and 2) the modular design will reduce overall project costs. The conceptual technologies are similar to Advanced Pressurized-Water Reactors and the entire process and steam generation is contained in one, modular vessel. The steam generated in this vessel is then tied to a steam turbine for electric generation. Due to the design's modularity, most of the fabrication is planned to be done in the manufacturing facility before the vessel is shipped to the site. The goal is to reduce field labor and the construction schedule.

Several manufacturers have begun conceptual design of these modular units to target lower output and overall costs of nuclear facilities. However, there is currently little industry experience with developing this technology outside of the conceptual phase. Therefore, the information provided in this assessment for the SMR option is based on feedback and initial indications from SMR manufacturers. Ontario Power Generation announced in November 2020 the resumption of planning activities for future nuclear power generation that would utilize SMRs at its Darlington Nuclear Station. The development is anticipated to be completed as early as 2028. Figure 7 demonstrates SMR technology.

Figure 7: SMR Nuclear Generation Diagram



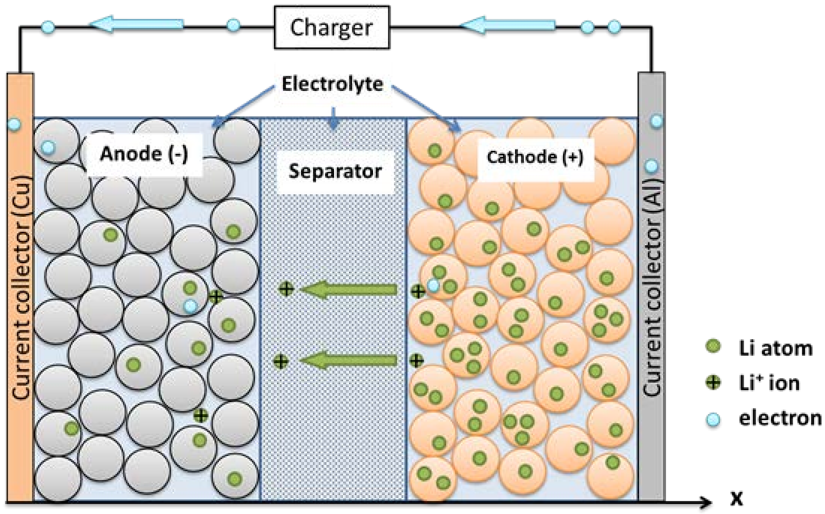
Energy Storage Technologies

This method of operation takes advantage of using excess energy during lower demand or high renewable generation, for generation during periods of higher demand. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Energy storage technology continues to be developed at a rapid pace with different technologies providing different benefits. As commercially available lithium ion and Redox Flow batteries provide a current slate of benefits, emerging developments are anticipated to present evolving benefits and options for grid applications.

Lithium Ion Battery Storage

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container than can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell, and the lithium ion type is one of the most common designs. A lithium ion battery schematic is shown in Figure 8.

Figure 8: Lithium Ion Battery Diagram



Lithium ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Lithium ion technology has seen an advance in development interest due to its high energy density, low self-discharge, high cycling tolerance and efficiency, and fast response times. The life cycle is dependent on cycling (charging and discharging) and depth of charge (charged load depletion), and can range from 2,000 to 3,000 cycles at high discharge rates, up to 7,000 cycles at very low discharge rates.

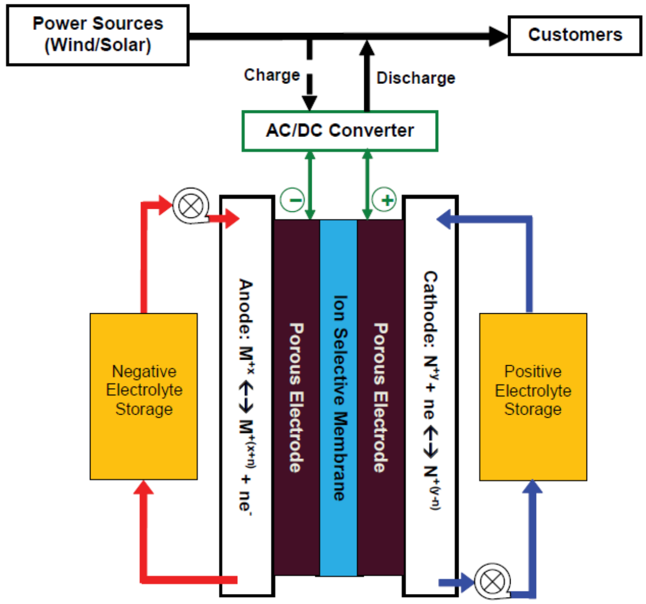
Lithium ion batteries have gained traction in several markets, including the utility and automotive industries. Most of the utility-scale battery systems used for energy storage on the U.S. electric grid use lithium-ion batteries.[5]

Flow Battery Energy Storage

In essence, the flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system, as shown in Figure 9. Note that the cells can be stacked in series to achieve the desired voltage difference.

[5] https://www.eia.gov/todayinenergy/detail.php?id=41813

Figure 9: Flow Battery Diagram



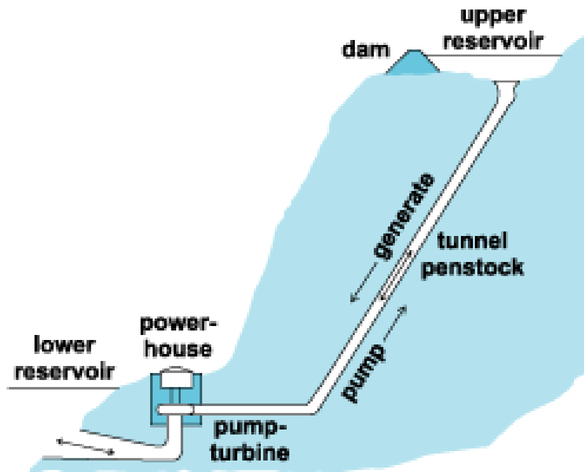
The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electro-neutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

There are three primary differences between a flow battery and the traditional battery. In a flow battery, the electro-active materials are stored in a liquid electrolyte chemical external to the device, introduced only during charging and discharging operations. Also, energy conversion occurs as a direct result of the redox reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in a high cycling life of the flow battery. Flow batteries are better suited for larger applications due to the complexity of the electrochemical fuel delivery system and the length of discharge, which can be far longer than that of a traditional lithium ion at full capacity and provide up to 12 hours of discharge. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, which allows the system to approach its theoretical energy density. All of these critical differences: longer asset life, longer discharge period, and cost effective scalability make flow batteries an ideal utility investment for larger grid applications.

Pumped Hydro Energy Storage

A pumped hydroelectric plant (pumped hydro) is a peaking energy storage power generating facility. The plant includes a lower reservoir (usually existing), a powerhouse, an upper reservoir (usually constructed with the pumped hydro project), and a means for conveying water between the upper and lower reservoirs. The powerhouse includes reversible generator/motors and pump/turbines. This is illustrated in Figure 10.

Figure 10: Pumped Hydro Diagram

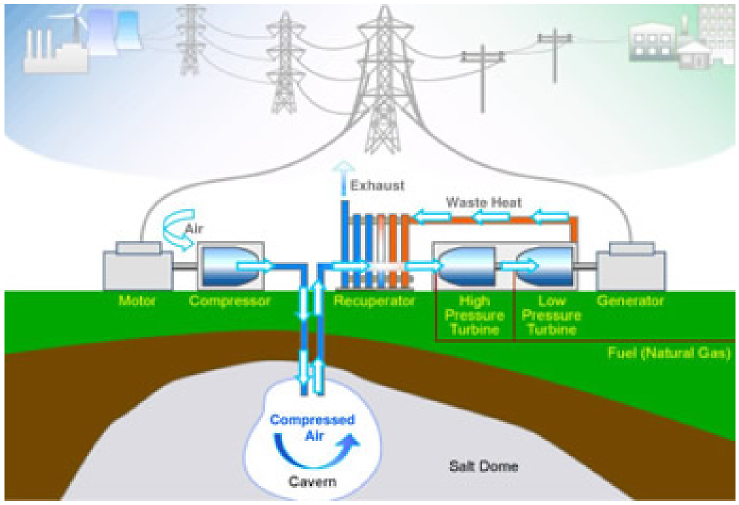


During off peak hours or periods of high renewable generation, when a surplus of lower costing electrical energy exists, the plant is operated in the pump mode to pump water from the lower reservoir to the upper reservoir. During peak periods, the water is released from the upper reservoir through the pump/turbines to generate electrical energy to meet the system peak demand.

<u>Compressed Air Energy Storage</u>

CAES offers a way of storing off-peak energy that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. To utilize CAES, the project needs a suitable storage site, often below ground, and availability of transmission and fuel sources. CAES facilities use lower cost energy during off peak hours or periods of high renewable generation to compress air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically with natural gas firing), and generating power as the heated air travels through an expander. The process is shown in Figure 11.

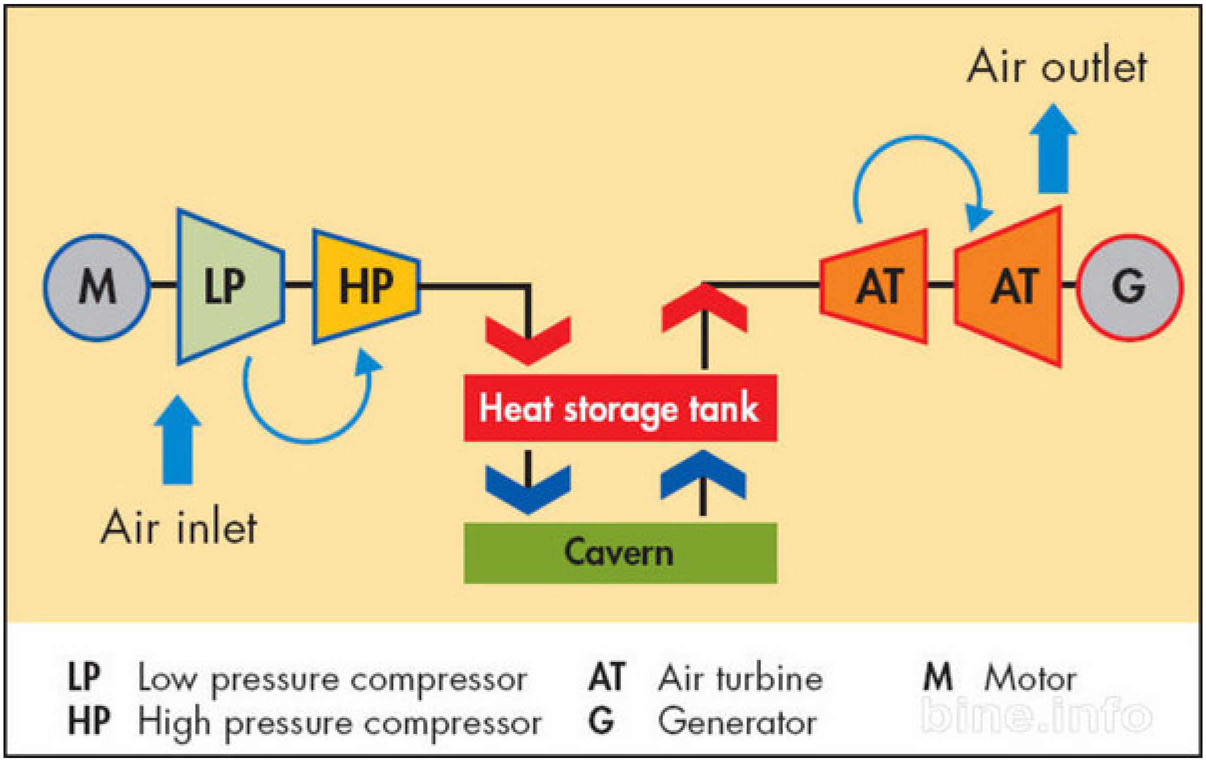
Figure 11: Compressed Air Energy Storage Diagram



CAES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and CAES can provide spinning reserve capacity with its rapid ramp-up capability.

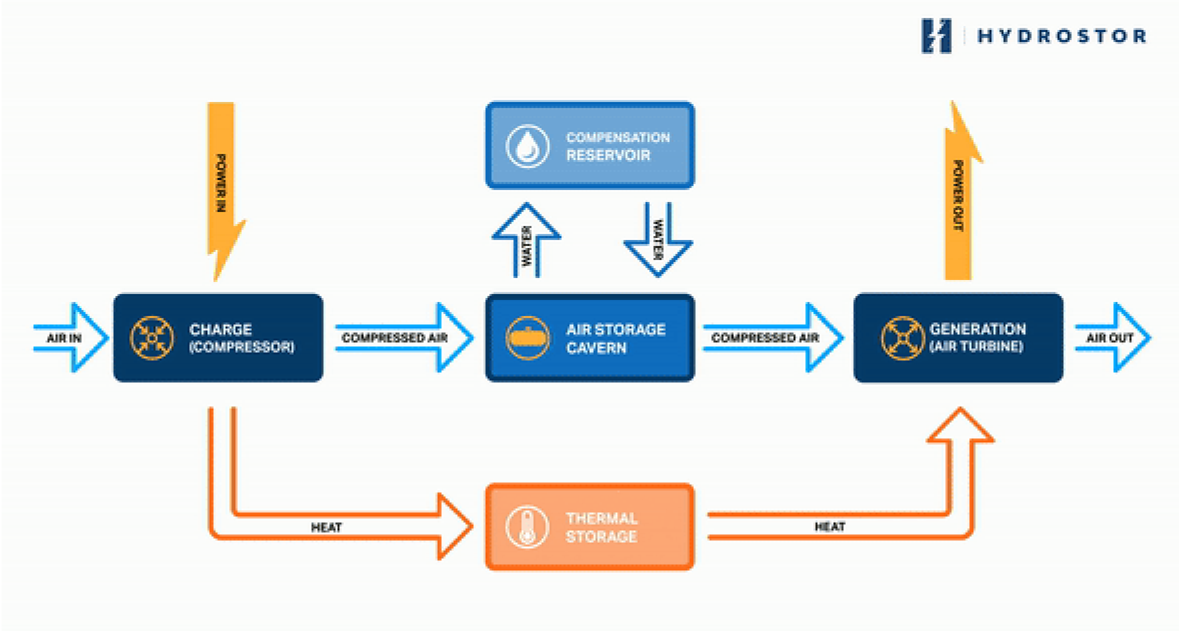
"Second generation" CAES designs have recently been developed and are undergoing testing, but do not yet have commercial operating experience. These conceptual designs incorporate a separate gas turbine for additional generation capacity and use the exhaust energy as a source of preheat for the stored air before entering the expansion process. The compression-expansion portion of these designs is similar to "first generation" CAES designs. The designs differ in that a simple cycle gas turbine plant operates in parallel to the compression-expansion train and the exhaust is used in a recuperator instead of utilizing a combustor to preheat the stored air. The process is shown in Figure 12.

Figure 12: "Second Generation" Compressed Air Energy Storage Diagram



A recent innovation to CAES technology is an Advanced Compressed Air Energy Storage ("A-CAES") technology developed by Hydrostor. The charging process is similar to traditional CAES where off-peak or surplus electricity from the grid is used to operate a compressor that produces heated compressed air. The heat is extracted from air stream and stored inside a proprietary thermal store. The adiabatic process increases overall efficiency and eliminates the need for fossil fuels during operation. Compressed air is stored in a purpose-built air storage cavern where hydrostatic compensation is used to maintain the system at a constant pressure during operation. To convert compressed air to electricity, hydrostatic pressure forces air to the surface where it is recombined with the stored heat and expanded through a turbine to generate electricity. The round-trip efficiency of the A-CAES process is estimated to be ~60 percent, compared to the ~40-50 percent efficiency of traditional CAES. The process is shown in Figure 13.

Figure 13: Hydrostor Advanced Compressed Air Energy Storage (A-CAES) Process[6]



Minnesota Power's Proposed RFP Bidding Process

In the Nemadji Trail Energy Center ("NTEC") Order, the Minnesota Public Utilities Commission (or "Commission") ordered Minnesota Power in its next IRP to propose a bidding process for Commission consideration and potential approval under Minnesota Statutes § 216B.2422, subd. 5. The bidding process should apply to supply-side acquisitions of 100 MW or more and lasting longer than five years and include the six reforms proposed by the Company in the NTEC docket.[7]

Minnesota Power proposes for all future supply-side acquisitions of 100 MW or more, lasting longer than five years, to adhere to the six steps that were set forth in testimony and ordered by the Commission in the NTEC docket. These six steps are:

1. Ensure that the Request for Proposals ("RFP") is consistent with the Commission's then-most-recent IRP order and direction regarding size, type, and timing;
2. Provide the Department of Commerce (or "Department") and other stakeholders with notice of RFP issuances;
3. Notify the Department and other stakeholders of material deviations from those timelines;
4. Update the Commission, the Department, and other stakeholders regarding changes in the timing or need that occur between IRP proceedings;

[6] https://www.hydrostor.ca/technology/
[7] *In re Minnesota Power's Petition for Approval of the EnergyForward Res. Package*, Docket No. E-015/AI-17-568, Order Approving Affiliated-Interest Agreements with Conditions at 29 (Jan. 24, 2019).

5. Where Minnesota Power or an affiliate proposes a project, the Company will engage an independent evaluator to oversee the bid process and provide a report for the Commission; and
6. Request that the independent evaluator specifically address the impact of material delays or changes of circumstances on the bid process.[8]

Minnesota Power believes that implementing these six steps will provide the Commission, the Department, and all stakeholders the necessary assurances that in evaluating the acquisition of new supply side resources over 100 MW, that the Company will continue to follow processes that lead to customer protections and benefits. In addition, the Company recognizes a timely process is important to ensure that customer benefits, including available tax benefits and available resources, are captured.

[8] *Id.* at 29, Attachment A, p. 18 (citing Ex. MP-24 at 14-16 (Frederickson Rebuttal)).